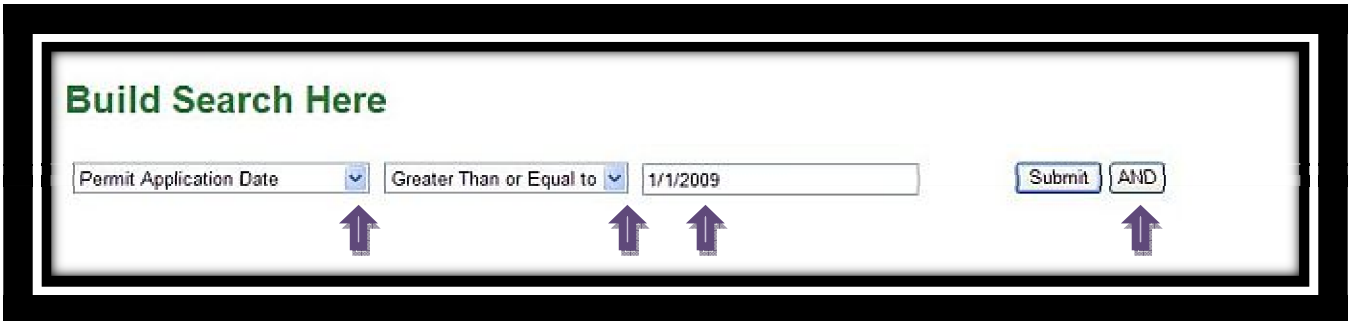
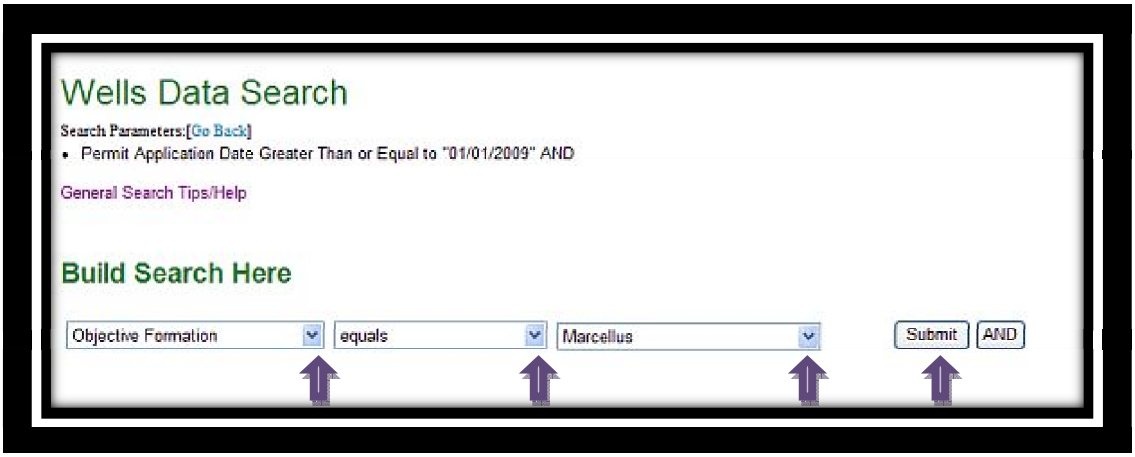
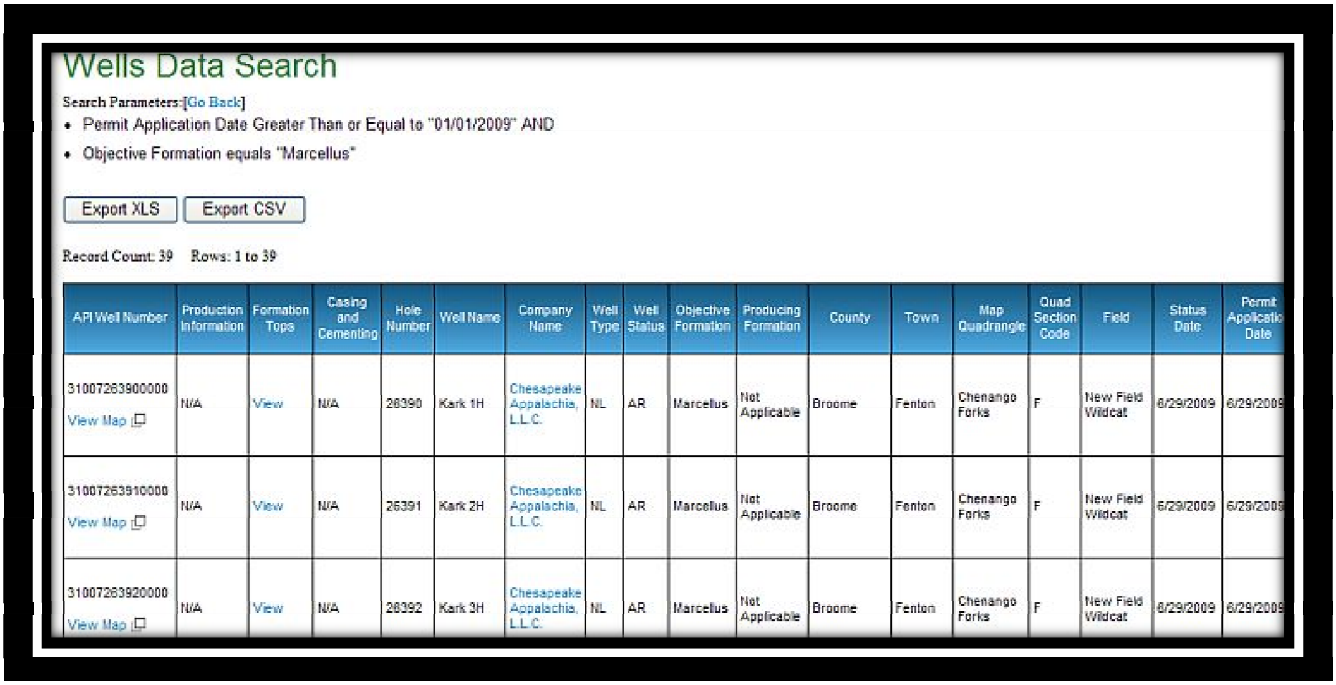
2. Select your search criteria. To find all permit applications filed in 2009 that target a specific geologic formation, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permit applications filed in 2009 for the Marcellus formation, select Objective Formation equals Marcellus. Click the Submit button.



4. View Results.

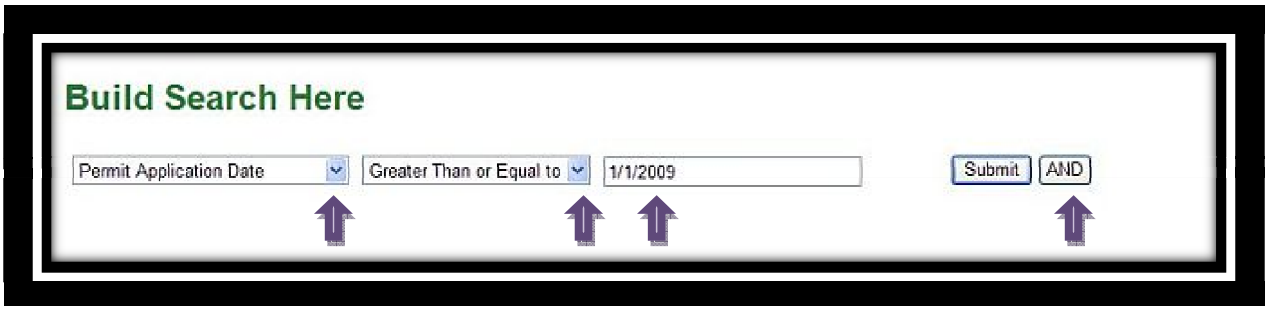


API Well Number	Production Information	Formation Tops	Casing and Cementing	Hole Number	Well Name	Company Name	Well Type	Well Status	Objective Formation	Producing Formation	County	Town	Map Quadrangle	Quad Section Code	Field	Status Date	Permit Applicatio Date
31007263900000 View Map	N/A	View	N/A	26390	Kark 1H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009
31007263910000 View Map	N/A	View	N/A	26391	Kark 2H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009
31007263920000 View Map	N/A	View	N/A	26392	Kark 3H	Chesapeake Appalachia, L.L.C.	NL	AR	Marcellus	Not Applicable	Broome	Fenton	Chenango Forks	F	New Field Wildcat	6/29/2009	6/29/2009

How to Narrow Your Search to Applications Submitted For a Specific County

1. Select Wells Data to begin your search.

2. Select your search criteria. To find all permit applications filed in 2009 in a specific county, select Permit Application Date is Greater Than or Equal to 1/1/2009. Click the AND button.



3. Select your next set of search criteria. To find all permits applied for in 2009 in Allegany County, select County equals Allegany. Click the Submit button.

New York State

DEC

Appendix 27

NYSDOH Radiation Survey Guidelines and Sample Radioactive Materials Handling License

New July 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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Radiological Survey Requirements

I. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

II. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

III. Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

IV. Survey Frequency

Radiological survey data must be conducted within 6 months following the start of gas production and at intervals not to exceed 12 months thereafter.

The permit tee must conduct surveys of all equipment used on the production train prior to disposal, recycling or transfer to any entity.

Equipment that exceeds 50microrem/hr is subject licensure by the New York State Department of Health.

V. Survey data reports

Survey data must be submitted within 30 days following the survey, and must contain the information required by Section III.

NEW YORK STATE
DEPARTMENT OF HEALTH
BUREAU OF ENVIRONMENTAL RADIATION PROTECTION

Radiation Guide 1.15

GUIDE FOR APPLICATION TO POSSESS NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM) INCIDENT TO NATURAL GAS INDUSTRY

I. INTRODUCTION

PURPOSE OF GUIDE

The purpose of this regulatory guide is to provide assistance to applicants in preparing applications for new licenses for the possession of naturally occurring radioactive materials (NORM) incident to natural gas exploration and production. This regulatory guide is intended to provide you, the applicant, with information that will enable you to understand specific regulatory requirements and licensing policies as they apply to the license activities proposed.

After you are issued a license, you must conduct your program in accordance with (1) the statements, representations and procedures contained in your application; (2) the terms and conditions of the license; and (3) the Department of Health's regulations in 10 NYCRR 16 and 12 NYCRR 38. The information you provide in your application should be clear, specific and accurate.

II. FILING AN APPLICATION

You, as the applicant for a materials license, must complete Items 1 through 4 and 18 on the attached application form. For other applicable Items, submit the information on supplementary pages. Each separate sheet or document submitted with the application should be identified and keyed to the item number on the application to which it refers. All typed pages, sketches, and, if possible, drawings should be on 8 ½ x 11 inch paper to facilitate handling and review. If larger drawings are necessary, they should be folded to 8 ½ x 11inches. You should complete all items in the application in sufficient detail for the Department to determine that your equipment, facilities, training and experience, and radiation safety program are adequate to protect health and to minimize danger to life and property.

You must submit two copies of your application with attachments. Retain one copy of the application for yourself, because the license will require that you possess and use licensed material in accordance with the statements and representations in your application and in any supplements to it.

Mail your completed application and the required non-refundable triennial fee ($3000) to:

New York State Department of Health
Bureau of Environmental Radiation Protection
Flanigan Square, 547 River Street
Troy, New York 12180

Please Note: Applications received without fees will not be processed .

III. CONTENTS OF AN APPLICATION

Item 1. Name and address.

Enter the name and corporate address of the applicant and the telephone number of company management. The name of the firm must appear exactly as it appears on legal papers authorizing the conduct of business. Indicate if the name and address are different from those listed on the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill.

Item 2A. Addresses at which radioactive material will be used.

List all addresses and locations where radioactive material will be used or stored, i.e., the NYS Department of Environmental Conservation, Division of Mineral Resources Permits to Drill Nos., well name, and town name.

2.B. Not applicable

Item 3. Nature of business

Enter the nature of the business the applicant is engaged in and the name and telephone number (including area code) of the individual to be contacted in connection with this application.

Item 4. Previous radioactive materials license

Enter any previous or current radioactive materials license numbers and identify the issuing agency. Also indicate whether you possess any radioactive material under a general license.

Describe the circumstances of any denial, revocation or suspension of a radioactive materials license previously held.

Item 5. Department to Use Radioactive Material

Not Applicable

Item 6. Individual Users of Radioactive Materials

Not Applicable,

Item 7. Radiation Safety Officer

State the name, title and contact information (phone, fax, and e-mail) of the person designated by, and responsible to, management for the coordination of the radiation safety program. This person will be named on the license as the Radiation Safety Officer. He/she will be responsible to oversee and ensure that licensed radioactive material is possessed in accordance with regulations and the radioactive materials license.

Item 8. Radioactive Material

No response is required. The license will list Naturally Occurring Radioactive Material (NORM).

Item 9. Purpose for which Radioactive Material Will be Used

No response is required. (The type of use will be specified on the license as possession and maintenance of radiologically contaminated equipment, with specific limitations.)

Item 10. Training of individual users

Persons who perform radiological surveys that are required by regulation and radioactive materials license must receive initial and annual radiation protection training. The scope of training needs to be commensurate with their duties. Appendix A contains a model training program. Confirm that you will follow the model or submit your proposed training program for review.

Item 11. Experience with radioactive materials for individual users

No response is required. Implementation of a training program as required in Item 10 of the application addresses Item 11 for the scope of license tasks.

Item 12. Instrumentation

Instrumentation utilized to determine exposure rates must be capable of measuring 1 microrem to at least 3 millirem per hour.

A pressurized ionization detector/instrument is an optimal choice for gamma exposure rate measurements because the displayed reading provides a true (accurate) exposure rate, therefore no correction factor is necessary.

An instrument with a sodium iodide detector calibrated to cesium-137 (typical/standard calibration) has a high sensitivity but may require the use of a correction factor to determine the true exposure rates associated with the energy emissions from NORM isotopes. Provide a description of the instrumentation including the make(s) and model number(s) of the instrument(s) and detector(s). (Detector information is not needed for instruments that use a detector that is physically mounted within the instrument body.) The instrument must be designed for exposure rate measurement of gamma emissions with energies similar to NORM. Caution: radiological survey instruments may not be safe for use in environments with combustible vapors - Consult the manufacturer.

A model procedure for conducting a radiological survey is provided in Appendix C.

Item 13. Calibration and operational checks of instrumentation

Instrument calibrations must be performed before first use of the instrument and at intervals not to exceed 12 months by an entity that is licensed by the US Nuclear Regulatory Commission or an Agreement State to perform radiological survey instrument calibrations. The instrument must be checked for proper operation (minimally a battery condition check must be performed, and a response to a radiation source is recommended) on each day of use. Records of instrument calibrations must be maintained for a period of 5 years for review by the Department. Confirm that calibrations and daily battery checks will be performed as indicated above and that instrument calibration records will be maintained.

Item 14. Personnel monitoring and bioassays

Not applicable.

Item 15. Facilities and Equipment

Submit simple sketches of any storage area(s), pipe yards, etc., for contaminated equipment.

Item 16. Radiation Protection Program

The applicant does not need to establish a comprehensive radiation safety program. However, the applicant needs to implement a radiation protection program that is commensurate with the type of radioactive material authorized by the license. Appendix B contains a model radiation protection program. Please confirm that you will implement the model program or submit your proposed program for review.

Item 17. Waste Disposal

The applicant must plan for proper disposal of radiologically contaminated equipment when their use has been discontinued. Confirm that you will dispose of radiologically contaminated items in accordance with all applicable state and federal requirements.

Item 18. Certification

Provide the signature of the chief executive officer of the corporation or legal entity applying for the license or of an individual authorized by management to sign official documents and to certify that all information in this application is accurate to the best of the signator's knowledge and belief.

IV. AMENDMENTS TO LICENSES

Licensees are required to conduct their programs in accordance with statements, representations and procedures contained in the license application and supporting documents. The license must therefore be amended if the licensee plans to make any changes in the facilities, equipment, procedures, and authorized users or radiation safety officer, or the radioactive material to be used.

Applications for license amendments may be filed either on the application form or in letter form. The application should identify the license by number and should clearly describe the exact nature of the changes, additions, or deletions. References to previously submitted information and documents should be clear and specific and should identify the pertinent information by date, page and paragraph.

APPENDIX A Training Program for Individuals Performing Radiological Survey Measurements.

The applicant/licensee may use the services of a health physicist, licensed medical physicist or an individual who is authorized by a radioactive materials license to conduct radiological surveys. In these situations, the applicant/licensee needs to obtain documentation that the individual is qualified. Examples of documentation include a radioactive materials license that names the person as an authorized user, or copy of a resume for the health physicist or licensed medical physicist. Records of training must be maintained for a period of 5 years.

However, if the applicant/licensee plans to use his/her staff to conduct surveys, such individuals must receive training.

Individuals must demonstrate competence in the following subjects that prior to being approved to perform required surveys. Training must be conducted by an individual who is knowledgeable in health physics principles and procedures.

I. Fundamentals of Radiation Safety

- A. Characteristics of radiation
- B. Units of radiation dose and quantity of radioactivity
- C. Levels of radiation from sources of radiation
- D. Methods of minimizing radiation dose:
  1. working time
  2. working distance
  3. shielding

II. Radiation Detection Instruments

- A. Use of radiation survey instruments
  1. operational
  2. calibration

- B. Survey techniques

III. Requirements of the regulations and License Conditions

IV. Records of training will be maintained for a period of 5 years. Records will include the date of training, name of persons trained, name of the trainer and his/her employer, a copy of the training agenda or topics covered, and the results of any test or determination of proficiency. Records will be maintained for review by the Department.

APPENDIX B Radiation Protection Program

I. Responsibility

A. The owner/licensee will delegate authority to the Radiation Safety Officer to implement the program and the responsibility to oversee the day to day oversight of the program

B. Ensure that individuals receive initial and annual radiation protection training.

C. Ensure that radiological surveys are performed in an effective manner and at the time intervals required by the License.

D. Ensure that notifications required by regulations and License Conditions are made.

E. Ensure that an inventory of radiologically contaminated equipment is maintained.

F. Ensure that contaminated equipment in storage is labeled as containing radioactive material and is not released for unrestricted use.

G. Ensure that radioactive waste is disposed in accordance with all applicable state and federal requirements.

H. Ensure that only entities that have a specific license to perform decontamination perform service of equipment that exceeds 50 microrem at any accessible surface.

II. Maintain Records of:

A. Radiation Protection Training Program

B. Results of radiological surveys including instrumentation calibrations and operational checks.

C. Inventories of contaminated equipment

D. Waste disposal records

E. Service of contaminated equipment that exceeds 50 microrem at any accessible surface, including documentation of the service provider's radioactive materials license.

F. Radiological survey data

G. Maintain a complete radioactive materials license

APPENDIX C

Radiological Survey Guidance

I. General

Performance of daily (on days of use) operational check is recommended. This can be accomplished by measuring a radiation source of known activity to confirm that instrument is properly functioning, i.e., the reading is consistent from measurement to measurement.

Instruments must be used within the manufacturer's recommended operational conditions, i.e. temperature, etc.

It is recommended that the user remove batteries from instruments during periods of non-use to avoid potential damage from “leaking” batteries.

II Survey Procedure

Confirm that the instrument is calibrated and functioning properly.

The background exposure rate should be measured in an area unaffected by elevated NORM prior to measuring equipment (pipes, tanks, etc.). (Typical background readings are in the range of 3-15 uR/hr but can vary.)

The orientation of the instrument is important. In general the face/front of the instrument should be directed toward the surface being measured.

For instruments that have an audio function the switch should be in the on position. The audio feature will assist the user in identifying elevated exposure rates.

The survey instruments or detector should be held close (within approximately 1 inch) to the surface of the item being surveyed.

The instrument reading should be taken after sufficient time is allowed for the reading to stabilize, generally 10-20 seconds.

Surveys should be conducted systematically. In general, follow the gas production train. Equipment that exceeds 50 uR/hour should be marked/tagged.

Maintain survey records for a period of 5 years. The records include the date, name of person who conducted the survey, the background exposure rate (in an unaffected area), the survey instrument description/make, model, serial number, calibration date, and a diagram or sketch of the areas surveyed and the survey data.

NEW YORK STATE DEPARTMENT OF HEALTH
RADIOACTIVE MATERIALS LICENSE

Pursuant to the Public Health Law and Part 16 of the New York State Sanitary Code, and in reliance on statements and representations heretofore made by the licensee designated below, a license is hereby issued authorizing radioactive material(s) for the purpose(s), and at the place(s) designated below. The license is subject to all applicable rules, regulations, and orders now or hereafter in effect of all appropriate regulatory agencies and to any conditions specified below.

---

1. Name

_____

2. Address

_____

_____

Attention:
Radiation Safety Officer

3. License Number

4. a. Effective Date

_____

b. Expiration Date

_____

5. Reference Number
DH No. _____

---

6. Radioactive Materials (element & mass no.)	7. Chemical and/or Physical Form	8. Maximum quantity licensee may possess at one time
A. Radium 226	A. Any	A. As necessary
B. Naturally Occurring Radioactive Material (NORM)	B. Any	B. As necessary

9. Authorized use. The authorized locations of use are those specified in New York State Department of Environmental Conservation Permit to Drill Nos. _____.

A. The licensee is authorized for possession only of NORM listed in License Condition No. 6 as contamination in equipment incidental to oil and gas exploration and production.

B. The licensee may perform maintenance, not inculding decontamination or removal of scale containing radioactive material on equipment that does not exceed 50 microrem per hour at any accessible point.Only a licensee authorized by the US Nuclear Regulatory Commission or an

Agreement State to perform decontamination and decommissioning services shall service equipment that exceeds 50 microrem per hour at any accessible point.

10. A. Radioactive material listed in Item 6 shall be used by, or under the supervision of the Radiation Safety Officer.

_____ B.

C. The licensee shall notify the Department by letter within 30 days if the Radiation Safety Officer permanently discontinues performance of duties under the license.

11. Except as specifically provided otherwise by this license, the licensee shall possess and use licensed material described in Items 6, 7 and 8 of this license, in accordance with statements, representations, and procedures contained in the documents (including any enclosures) listed below:

A. Application for New York State Department of Health Radioactive Materials License dated _____, signed by _____.

B. Letter dated _____, signed by _____.

The New York State Department of Health's regulations shall govern the licensee's statements in applications or letters unless the statements are more restrictive than the regulations.

12. A. Transportation of licensed radioactive material shall be subject to all regulations of the U.S. Department of Transportation and other agencies of the United States having jurisdiction insofar as such regulations relate to the packaging of radioactive material, marking and labeling of the packages, loading and storage of packages, monitoring requirements, accident reporting, and shipping papers.

B. Transportation of low level radioactive waste shall be in accordance with the regulations of the New York State Department of Environmental Conservation as contained in 6 NYCRR Part 381.

13. The licensee shall have available appropriate survey instruments which shall be maintained operational and shall be calibrated before initial use and at subsequent intervals not exceeding twelve months by a person specifically authorized by the U.S. Nuclear Regulatory Commission or an Agreement State to perform such services. Records of all calibrations shall be kept a minimum of five years.

14, The licensee shall conduct gamma exposure rate measurements of accessable areas of gas production equipment within 6 months of the effective date of the license and at subsequent

intervals not to exceed 12 months. The licensee shall maintain measurement records for review by the Department. The licensee shall notify the Department within 7 calendar days following identification of any exposure rate measurement that meet or exceed 2 millirem per hour. Notification may be made by phone or in writing.

15. Equipment in storage that exceeds 50 microrem per hour at any accessible point shall be labeled by means of paint or durable label or tag.

16. The licensee shall maintain an inventory of equipment, including but not limited to tubular goods, piping, vessels, wellheads, separators, etc., that exceeds 50 microrem per hour at any accessible point. The records of the inventories shall be maintained for inspection by the Department, and shall include the location and description of the items, and the date that items were entered on the inventory record.

17. A. Before treatment or disposal of any gas production water in a manner that could result in discharge or release to the environment, the licensee shall obtain from the New York State Department of Environmental Conservation either:

    i) A valid permit, or

    ii) A letter stating that no permit is required.

    B. The licensee shall maintain the letter or valid permit required in paragraph A of this condition on file for the duration of the license and make such letter or permit available for inspection by the Department upon request.

18. The licensee shall submit complete decontamination procedures to the Department for approval ninety (90) days prior to the termination of operations involving radioactive materials.

19. Plans of facilities which the licensee intends to dedicate to operations involving the use of radioactive material shall be submitted to the Department for review and approval prior to any such use.

20. The licensee shall maintain records of information important to safe and effective decommissioning at the location listed in License Condition No. 2 and at other locations as the licensee chooses. The records shall be maintained until this license is terminated by the Department and shall include:

    A. Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site;

    B. As-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored, and locations of possible inaccessible contamination, such as buried pipes, which may be subject to contamination;

C. Records of the cost estimate performed for the decommissioning funding plan or the amount certified for decommissioning, and records of the funding method used for assuring funds if either a funding plan or certification is used.

21. The licensee may transfer contaminated equipment that exceeds 50 microrem at any accessible point to a Department licensee if the equipment is to be used in the oil and gas industry. The licensee shall maintain records of each transfer of equipment authorized by this License Condition.

FOR THE NEW YORK STATE DEPARTMENT OF HEALTH

Date: By _____
CJB/ :

Charles J. Burns, Chief
Radioactive Materials Section
Bureau of Environmental Radiation Protection

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context of this SGEIS and in accordance with Subpart 200.6 requirement defined in Section 6.5.1 to assure all potential adverse impacts are identified and rectified. The additional assessments performed for these short term impacts are addressed separately to distinguish certain information for PM10/PM2.5 gathered from industry since the initial modeling analysis in the SGEIS.

A) PM 10 and PM2.5 24-hour Impact Modeling and Potential Mitigation Measures.

As part of the Industry's Responses (dated September 16, 2009) to Information Requests, IOGA referenced a modeling assessment performed by consultants for Chesapeake Energy which incorporated a number of revisions to and recommendations on the Department's modeling analysis[90]. The analysis was based on one year of Binghamton meteorological data which indicated compliance with the PM10 NAAQS and much lower PM2.5 impacts than the Department's results, but still exceedances of the PM2.5 NAAQS. Mitigation measures were listed for resolving the latter exceedances. The analysis incorporated a set of assumptions which are summarized below with the Department's position on each of these:

The PM emissions provided by ALL consultants in the Industry Information Report were not speciated with respect to PM10 and PM2.5. Based on factors in EPA's AP-42 for large uncontrolled diesel engines, the PM10 and PM2.5 emissions represent 82% and 69%, respectively, of the total PM emissions. The Department has reviewed the information and agrees that the corresponding emissions should be adjusted accordingly;

The set of 15 completion equipment engines were represented in the Department's modeling as three sets of 5 units stationed next to each other. Industry noted that since these units contributed significantly to the modeled exceedances, each of the engines should be model as a separate point source. The Department had noted this conservative step and has remodeled the units are 15 separate sources. However, unlike Chesapeake's approach of separating the 15 units in two sets at the extreme ends of the pads, the Department has no reason to believe the engines would not be placed next to each other. Thus, the engines are re-modeled as depicted in revised Figure 6-5;

[90] June 21, 2010 letter from Brad Gill of IOGA-NY to Kathleen Sanford and associated modeling files.

It is claimed that the use of ULSF would result in an additional 10% reduction in PM emissions. The Department could not readily verify the level of reduction specifically for all diesel fuel sulfur contents, but it has been considered in our discussion of resultant impacts;

It was notes that the maximum emissions provided for the completion equipment engines are only representative of two hours in the operation cycle of these units. Thus, the hourly emission rate in the modeling was "prorated" to better characterize the likely 24-hour emission rate. The Department does not agree with this approach. As noted in our previous analysis, the ALL report noted a typical hydraulic fracturing operation can require up to 10 stages of total 5 hour periods. Thus, it is likely that a relevant portion of a day could experience the maximum hourly emission rate associated with worst case impacts, as we had previously assumed. Since there is no justified or simplified approach to account for this possibility, we believe it prudent to use the maximum hourly emission rate for the revised analysis; and

It was noted that for drilling engines, the use of the EPA "capping" stack option is not appropriate since the cap is "open" when the engines are in operation. This assumption has been revised in the reassessment by using the actual stack velocities and temperatures.

Finally, the Chesapeake modeling report noted that the background levels used were the maxima observed at representative monitors and are unreasonably high. The SGEIS recognizes the conservative nature of the background levels chosen as worst case observations, but notes that more representative values can be determined in instances where such refinement is necessary. For PM2.5, the reassessment has taken a less conservative approach in accord with the Department's and EPA's modeling guidance by reviewing the monitoring data and the expected associated average values in the Marcellus Shale area. In its March 23, 2010 guidance memo[91] on PM2.5, EPA provided a screening first Tier conservative approach to addressing NAAQS compliance which was to be followed by further guidance with more refined methods.

Lacking the follow-up guidance, most states, including New York, have allowed methods more in line with Section 8.2 of EPA's Modeling Guidelines. One such approach recognized by the March 23, 2010 memo is to allow for seasonal average observed concentrations. In reviewing

[91] Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS, Stephen Page, 3/23/10.

the data at monitors in the Marcellus Shale area, especially for the latest three years, we have identified a value of 15 µg/m^3 as appropriate for the purpose of determining representative 24-hour "regional" background level. The data also indicates that more recent observations than the 2005-7 levels in the SGEIS have in general shown a downward trend. It is also noted that the modeled impacts would dominate the total impacts which are to be compared to the NAAQS. For this reason, it is deemed appropriate to use the 8th highest concentration, as the form of the NAAQS, instead of the maximum 24-hour value recommended as a first screening Tier. A conservative step was to use the 8th highest maximum from each year of meteorological data modeled since these were limited to only two years per site.

In addition to these modifications to the original PM10 and PM2.5 modeling in the SGEIS, we have incorporated industry's assertion that there would not be simultaneous drilling and hydraulic fracturing operations at a single well pad. In order to better characterize the contribution of the completion equipment engines, the drilling rig engine and the air compressors, in addition to calculating the maximum overall impacts, the modeling results were also separated for each operation to determine the need for mitigation associated with each engine type. The modeling approach was otherwise identical to the previous analysis, except the version of AERMOD was updated to the version (09292) available at the time of the analysis.

The first step in the modeling exercise was to determine the maximum 24-hour PM10 and PM2.5 impact for each of the modeled years. These results are presented in Table 6.18. It is seen that the refined impacts which incorporate the above considerations are much lower than the values in Table 6.15. This reduction is due mainly to the speciated emission rates and the modeling of completion equipment engines as individual point sources. However, the impacts are still projected to be above the PM10 and PM2.5 NAAQS, except for the PM10 impacts associated with the drilling engines. As was noted previously, these maximum impacts occur next to the well pad and concentrations drop-off relatively sharply with downwind distance. The modeled impacts were reviewed and indicate that impacts above the NAAQS-minus-background levels value occurred at distances up to a maximum of 60m for completion equipment engines and PM10, while for PM2.5 the corresponding maximum distances were 120 and 150m for the drilling and completion equipment engines, respectively. The levels of the maximum impacts

also indicate that the different sets of engines could be dealt with using different mitigation measures.

As required by Part 617.11(5) (see next section for more details), the Department would pursue mitigation measures which eliminate potential adverse impacts to the maximum extent practicable. The August 26, 2009 industry report, the Industry Information Report and technical information from the public[92] identified a set of such potential measures which have been reviewed with this SEQRA requirement in mind. Certain of these suggestions would unlikely be practically implemented to any extent; for example, the use of electric engines could be very limited due to the remote nature of the drilling sites, while cleaner fuel engines are currently being investigated by engine manufacturers for future use. To the extent these alternative cleaner engines are available, the Department recommends their use. On the other hand, PM control equipment or the use of newer and cleaner engines are two measures recognized by both industry and the public as viable and the Department's review has concluded that these measures are practical. Appendix 18A provides the Department's review of the emission factors for various tiers of engines and potential after-treatment methods. Its conclusions are incorporated in the following discussions.

The discussions are limited to PM2.5 since these are the controlling impacts; that is, any measures to eliminate the PM2.5 exceedances would also assure compliance with the PM10 NAAQS. For the drilling rig and air compressor engines, the results in Table 6.18 were further analyzed to determine the impacts from each. The contribution to the overall maximum impact (Buffalo, 2007) for drilling operations was associated with the rig engines. Furthermore, industry has suggested and operational diagrams confirm that these engines are used close to the center of the well pad where the drilling actually occurs. The modeling results in Table 6.18 indicate that at a distance of 75m (from the center to the edge of the well pad) the drilling engine impacts are 30 $\mu g/m^3$, essentially due to the rig engine, which would still require mitigation when a background level of 15 $\mu g/m^3$ is used. Even if the 10% reduction in PM emissions due to the use of ULSF is achieved, as argued by industry, the resultant impact would still exceed the NAAQS. The rig engine impacts, however, are associated with ALL report's assumed Tier 1

[92] For example, comments by AKRF consultants on behalf of NRDC, Memorandum from Hillel Hammer, dated December 3, 2009, page 5.

engine emission factor. If the rig engines class was restricted to the use of Tier 2 and higher, then the PM2.5 impacts would be reduced by at least a factor of 2.7 (see Table Two of Appendix 18A, 0.4/0.15) which would result in compliance with the NAAQS regardless of where these engines are located on the well pad.

Industry data in the IOGA-NY information responses indicate that a majority (71%) of engines currently in use are Tier 2 and Tier 3 engines. In addition, a small fraction (3.5%) are uncertified (Tier 0), with "unknown" emissions. It is the Department's conclusion that these latter engines cannot be used for drilling in New York's Marcellus Shale since it has not been demonstrated that these would result in NAAQS compliance. Furthermore, since 25% of the current drilling engines are Tier 1, their use in New York should only take place with certain control measures. The discussions in Appendix 18A conclude that of the two exhaust after-treatment measures, Diesel Oxidation Catalyst (DOC) and Continuously Regenerating Diesel Particulate Filter (CRDPF) or particulate "traps", the latter is by far the more effective method in that it achieves almost three times the emission reduction (i.e., 85% vs 30%). The level of control achieved by the traps is necessary to alleviate all PM2.5 NAAQS exceedances from any Tier 1 drilling engines. Thus, the CRDPF traps should be the after-treatment for Tier 1 drilling engines if these are to be used in New York. This conclusion also applies to the air compressors for which the maximum PM2.5 impact is calculated to be 65ug/m^3 for Tier 1 emissions. On the other hand, Tier 2 and above drilling rig engines and air compressors demonstrate NAAQS compliance without these controls.

The Department also considered the "mitigation" of the NAAQS exceedances by stack height and distance restriction measures identified previously in the SGEIS. Although the IOGA-NY response also lists the stack height increase on the drilling engines as a potential measure, there is no indication from industry if such measures are practical given the stack configuration of these engines and the height to which these would be extended. In addition, this measure is not in strict accord with the need to mitigate the adverse impacts to the maximum extent practicable. The combination of operating these engines closer to the drilling rig, but more importantly the use of CRDPF traps on Tier 1 engines are deemed the necessary mitigation measures.

Turning next to the completion equipment engines, it seems even less practical to apply the distance and stack height increase restrictions to this class of engines. In fact, industry has previously indicated that stack height increase on these mobile units cannot be practically accomplished. A modeling run indicates that in order to meet the PM2.5 standard under the revised set of assumptions, the stack height would need to be at least doubled. Furthermore, the distance at which impacts are projected to be below the NAAQS-minus-background level was noted previously to be 150m. This is based on the Tier 2 emission factor modeled for these engines as provided by the ALL report. Consequently, the required practical approach to these engines would also require the use of the CRDPF traps as after-treatment on Tier 2 engines. For the maximum 24-hour PM2.5 case of Table 6.18 (Buffalo, 2006), the 202 $\mu g/m^3$ impact reduces to 44 $\mu g/m^3$ at a distance of 75m from the engines. Again, a 10% reduction in PM emissions due the use of ULSF does not alleviate these exceedances. Furthermore, unlike the smaller drilling engines, the ability of placing the 15 completion equipment engines (typically 14 used in Pennsylvania) near the center of the well pad is questionable. Based on industry's depiction, it is possible to separate these into two sets at either side of the hydraulic fracturing operations to further reduce impacts. In sum, however, the number of Tier 2 completion equipment engines which would require the installation of the particulate traps ranges from at least two thirds to all of the 15 engines per hydraulic fracturing job. For practical purposes, it is recommended that all Tier 2 engines be equipped with the CRDPF traps. Otherwise, each well operation might need to undergo more site specific analysis to demonstrate that a certain configuration or PM trap installation alternative would assure compliance with the 24-hour PM2.5 and PM10 NAAQS. Further details on the practicality of requiring these traps and other after-treatment control measures are discussed in the section following the SO_2 and NO_2 modeling results.

With respect to the Tier 0 and Tier 1 completion equipment engines, these emissions have not been analyzed or modeled, but for the same reasons as for the drilling engines, Tier 0 completion equipment engines should not be used in New York. In addition, based on the scaling of the maximum impact in Table 6.18 by the ratio of Tier 1 to Tier 2 emission factors (2.7), it is determined that Tier 1 engines have the potential to cause a modeled exceedance even if equipped with a particulate trap (maximum impact of 82 $\mu g/m^3$ with 85% control). Industry can suggest impact mitigation in addition to the use of PM traps in order to show compliance with

the NAAQS, but lacking such a demonstration, it is the Department's interim conclusion that Tier 1 completion equipment engines should not be used in New York. On the other hand, and as also suggested by industry and the public, newer Tier 4 engines, which would likely be equipped with traps in order to achieve the required emission factors for those engines, can be used as an alternative to the Tier 2 engines with a PM trap.

B) SO_2 and NO_2 1-hour Impacts and Potential Mitigation Measures.

The 1-hour SO_2 and NO_2 NAAQS were promulgated since September 2009. Permitting and SEQRA actions after the effective date of an NAAQS are addressed by the Department to assure compliance with the NAAQS in accord with standard Department and EPA policy and requirements. EPA Region 2 recommended that the Department consider the new NAAQS in the SGEIS. In accord with the SEQRA process and the Department's Subpart 200.6 requirement, the Department has modeled the 1-hour SO_2 and NO_2 impacts to assure that all NAAQS are met.

With respect to the 1-hour SO_2 standard of 196 $\mu g/m^3$, no detailed modeling was determined necessary. Instead, the results of the previous SO_2 3-hour modeling in Table 6.15 indicated that the use of the ULSF would likely result in 1-hour impacts being below the NAAQS. Thus, the 1-hour maximum CO impact in Table 6.15 was used to scale the corresponding 1-hour maximum SO_2 impacts using the ratio of the fracturing engine SO_2 and CO emissions since these engines were responsible for the overall maxima. The resultant maximum impact is calculated to be 24 $\mu g/m^3$. Using a representative, yet conservative, maximum 1-hour SO_2 level of 126 $\mu g/m^3$ from the Elmira monitor for 2009 gives a total impact of 150 $\mu g/m^3$ which is below the corresponding NAAQS of 196 $\mu g/m^3$. Thus, no further modeling was necessary to demonstrate compliance with the 1-hour SO_2 standard.

Simple scaling to demonstrate compliance was not possible for the NO_2 1-hour impacts due to the very large concentrations projected using the same method. Instead, it was necessary to account for a number of refinements in the modeling based on EPA and Department guidelines. There are at least two main aspects to the NO_2 modeling which need to be addressed in such refinements. These issues have been raised by EPA, industry and regulatory agencies as needing

further guidance. Similar to the PM2.5 guidance, EPA released a memorandum[93] on June 29, 2010 which provides guidance on how to perform a first Tier assessment for the NO_2 NAAQS. More recently, EPA has provided further guidance [94]on particulars in the modeling approach for NO_2 1-hour NAAQS compliance determinations.

The two main issues which have been raised deal with: 1) the form of the standard, as the 3 year average of the 98% of the daily maximum 1-hour value, which the AERMOD model used for the original modeling and the revised PM2.5 modeling are not set to calculate, and 2) the ratio of NO_2 to NO_x emissions assumed for stacks from various source types. Of these, the latter is more critical since NO_2 is a small fraction of the NO_x emissions in essentially all source types and assuming all of the NO_x emissions are NO_2 is unrealistic. These issues, however, are not insurmountable. For example, there are model post processors offered by consultants which can readily resolve the first issue. At the time of our re-analysis, EPA provided the Department with a "beta" version of AERMOD which performs the correct averages for NO_2. Some limited preliminary supplemental modeling used that model version, but the Department has recalculated these impacts using the final version of AERMOD (11059) released on 4/8/11 to assure proper calculation of the 8th highest 1-hour maximum per day of meteorological data. The results discussed below reflect the use of this version of AERMOD. It should be noted that the revised version of AERMOD does not contain any changes significant enough to affect the PM2.5 analysis.

With respect to the second issue, a number of entities, including EPA and the Department, have gathered information on the NO_2 to NO_x ratios from various source types which can be incorporated in the modeling. For the specific drilling and completion equipment engines, Department staff has undertaken a review of available information and has made recommendations on this issue. The details of the recommendations are provided in Appendix 18A which are used in the analysis to be discussed shortly. In addition to this ratio, EPA and Department guidance allows the use of two methods to refine NO_2 modeled impacts; the Ozone

[93] *Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program.* Memo from Stephen Page, EPA OAQPS, dated June 29, 2010.

[94] *Additional Clarifications Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS.* Memo from Tyler Fox, EPA OAQPS, dated March 1, 2011.

Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM). There is no preference indicated in EPA guidance as to which method might provide more refinement. However, based on limited model evaluation results presented in the March 1, 2011 EPA guidance memorandum, the current analysis has relied upon the OLM method with the appropriate "source group" option (OLMGROUP ALL) noted in the EPA memo.

In addition to the NO_2/NO_x ratio, hourly O_3 data is necessary for the use of the method. These were taken from available Department observations at monitor sites representative of the meteorological data bases discussed in the original analysis section. Furthermore, for the determination of background 1-hour NO_2 values, we have refined EPA's first Tier screening approach of using the highest observed levels by calculating the average of the readily available 3rd-highest observations from the Department's Amherst and Pinnacle State Park monitors for the year 2009. This calculated value is 50 $\mu g/m^3$ and is still conservative relative to the form of the NO_2 standard, as well as relative to further refinements allowed by EPA and Department guidance.

Appendix 18A recommends that, for engines for which emissions were calculated by the Industry Information Report and used in the Department's modeling, the NO_2 fraction of NO_x is 11% without after-treatment. Thus, an initial set of model runs were performed for the completion equipment engines using the two years of Albany data and this ratio of 0.11 in AERMOD. The results indicate that the maximum impacts from the hydraulic fracturing operations with the 0.11 factor (without the OLM approach) were approximately 3500 $\mu g/m^3$ which, although lower than those from the simple scaling of the CO impacts, are still an order of magnitude above the 1-hour standard of 188 $\mu g/m^3$ for the hydraulic fracturing operations. The impact was noted to be above the NAAQS out to a distance of 300 m from the pad. Thus, further refinements were necessary by the AERMOD-OLM approach.

First to consider, however, is that a confounding issue which this initial modeling did not include was the discovery that the NO_2 to NO_x ratio is increased by the particulate trap from 0.11 to 0.35 due to the generation of NO_2 in order to oxidize and remove the particulates (see Appendix 18A). This would lead to even higher NO_2 impacts. These results clearly indicate that some form of after-treatment exhaust control method is necessary for the completion equipment

engines. The after-treatment methods to reduce NO_x emissions are discussed in Appendix 18A which indicates that at present the recommended exhaust treatment method in practical use for on-road engines or engines in general is the SCR system. As noted in Appendix 18A, this preferred after-treatment method for NO_x control would reduce the NO_2 to NO_x ratio (with the CRDPF traps in place) down to essentially the same value as without the traps (i.e. 0.10). Of course, the SCR system would also substantially reduces the NO_x emissions by 90%. Therefore, the last step in the modeling of the completion equipment engines was to use the 90% reduction in emissions and the NO_2/ NO_x ratio of 0.10 with the OLM option. The analysis relied on the Tier 2 emissions provided by the Industry Information Report as the base emissions which were then reduced by 90% by the SCR controls. This level of modeling was deemed the most refinement allowed currently by Department and EPA guidance.

For the drilling engines, an initial modeling was performed first without the SCR controls and the 0.11 NO_2/NO_x ratio and the drilling rig Tier 1 emissions provided in the Industry Information Report as representative of the maximum emission case. For the compressors, Tier 2 was provided as the worst case emissions for the modeling of short term impacts. Based on two years of Albany meteorological data, it was found that the rig engines would exceed the NO_2 1-hour standard by about a factor of two and impacts would be above the NAAQS-minus-background level out to a distance of 150 m. From the modeling for PM2.5, it was found that the Tier 1 rig engines would need to be equipped with a PM trap in order to project compliance with the 24-hour PM2.5 standard. Since the traps were found to increase the NO2/ NO_x ratio by three fold, it is clear that the Tier 1 rig engine impacts would be substantially above the 1-hour NO_2 NAAQS without reductions in the NO_2 emissions. Thus, it is concluded that any Tier 1 rig engines (and compressors by analogy) would need to be equipped with both a PM trap and SCR for use in New York drilling activities.

Thus, the final set of modeling analysis used the SCR controlled Tier 2 completion equipment engine emissions with a NO_2/NO_x ratio of 0.10 and Tier 2 drilling rig engines and air compressor engines (both of which do not require PM traps) with the NO_2/ NO_x ratio set to 0.11 as noted previously. As for the completion equipment engines, the NO_2 modeling for the rig engines and compressors was based on more realistic representation of the units as individual units of five separate, but contiguous point sources as a further refinement to represent their configuration.

The emissions for each were scaled from the totals in Table 8 of the 8/26/09 Industry Report and these were placed in a north-south orientation at the same location as in Figure 6-2.

The set of NO_2 modeling with all of the meteorological data sites considered all potential sources as in previous analysis, but also provided the maximum impact for each of the three types of engines in order to determine specific potential necessary mitigation measures. However, initial modeling of the combined "drilling" scenario using two years of Albany data indicated an inconsistence in the total projected impacts in comparison to the results from the rig engines and compressors separately. This raised a potential issue with the "combined" impacts from these two operations which was related to the specifics of the OLM Ozone "distribution" approach. The resolution of this issue for the purposes of determining impacts from the rig engines and compressors and the need for potential mitigation measure was to recommend to place these two types of engines near the rig in the center of the well pad (as in the case of the PM results) and, furthermore, to separate these on either side of the drill rig to minimize combined impacts. A single year model run indicated this minimized combined impacts. From information and diagrams available, it is clear that these engines are in fact placed near the center of the pad when in actual operation.

The results of the 1-hour NO_2 impacts are presented in Table 6.18. As noted in the table, all engine are based on Tier 2 emissions, with the completion equipment engines assume to use SCR controls. The results for each of the meteorological data years, the overall maxima, the impacts at a 75-m distance (from center of pad to boundary), and the distance at which the impacts fall off to the NAAQS-background value of 138 $\mu g/m^3$ are presented for the completion equipment engines, the rig engines and the compressors. It is seen that the overall maxima are above the NAAQS. However, these need to be qualified relative to the other information tabulated in terms of potential mitigation measures necessary. It should be noted that a number of conservative assumptions are related to these impacts. First, it is noted that if the sources are placed in the center of the pad, as recommended, the impacts are much lower and essentially below the 1-hour NAAQS. Furthermore, these impacts should be adjusted downward by 10% since the tiered emission "limits" for Tier 2 and above are at most 90% NO_x as described in Appendix 18A. In addition, the background level used is conservative in that it represents the average of the third highest observations in the shale area and can be adjusted downwards.

Lastly, the distance to achieve the NAAQS minus background level is seen in the Table to be very close to the edge of the well pad. Using concentration maps for the three engine types indicate a sharp drop off of impacts such that the NAAQS minus background level is reached essentially at the well pad edge with only the 10% downward adjustment to impacts. In total, these considerations result in the NO_2 impacts being below the 1-hour NAAQS with the proper placement of the engines near the center of the well pad and the use of SCR control on the fracturing engines, coupled with Tier 2 or higher engines.

As discussed in Appendix 18A, SCR control is the only currently available NO_x reduction system for these size engines which has demonstrated the ability to practically achieve the level of reduction necessary (i.e., minimum 90%) to meet the NAAQS. Since the results of the PM2.5 modeling concluded that Tier 0 (uncertified) and Tier 1 completion equipment engines are not recommended for use in New York if CRDPF (particulate traps) are retrofitted to these, the application of SCR to Tier 2 and newer engines were considered. It is the Department's understanding from the manufacturers of these engines that the Tier 4 engines would have to be equipped with PM traps and SCR in order to meet the more stringent emission limits. It should be recalled that without the SCR control, the particulate traps increase the NO_2 to NO_x ratio by three fold and the corresponding impacts by a similar magnitude. Thus, the SCR system should be installed on all engines in which PM traps are being required for PM2.5 NAAQS compliance purposes. Any alternate system proposed by industry which has a demonstrated ability to achieve the same level of PM and NO_x reduction and, concurrently, resolve the NO_2 increase by the particulate traps in order to meet the NAAQS would be considered by the Department. At the present time, the Department is not aware of such an alternative system which has a proven record. For the purposes of the SGEIS, the Department has determined that the SCR system is necessary and adequate for this purpose. The next section discusses the practicality of using both the particulate traps and SCRs on completion equipment engines.

A summary of the Department's determination on the EPA Tier engines and the necessary mitigations to achieve the 24-hour PM2.5 and 1-hour NO_2 NAAQS is presented in tabular form in Table 6.19. The first column provides the various EPA tiers for the drilling and completion equipment engines and their time lines as presented in Appendix 18A. The next column presents sample percent of each Tier engines currently in use as provided by industry in the Information

Report. Note that based on the previous discussions, the uncertified (Tier 0) engines would not be allowed to be used in NY for Marcellus Shale activities. The third column provides the ratio of the Tier 1 emission rates for PM and NO_x to the other tiers, based on the information in Appendix 18A. The last column summarizes the determinations made by the Department on the control requirements necessary to meet the 24-hour PM2.5 (and PM10) and the 1-hour NO_2 ambient standards. As seen from the table, Tier 1 drilling engines and air compressors would require a PM trap and SCR controls, with the same controls being required on most of the completion equipment engine tiers.

Another purpose of this table is to provide an important demonstration that the Department's recommendations on control measure for these engines would result in substantial emission reduction over the current levels allowed in any other operations in other states. That is, in terms of air quality impacts, the emission reduction factor column of Table 6.19 indicates at least a factor of 3 and 2 reductions in PM2.5 and NO_2 emissions, respectively, from the Tier 1 engines. Thus, although Tier 2 and 3 drilling engines make up a majority of the engines in current use (71%), their relative emissions are much lower than the Tier 1 engines, which are recommended not to be used in NY (or have PM traps and SCR controls with about 90% reductions in emissions). Therefore, in terms of emissions reductions, the Department's requirements on the drilling engines would reduce emissions by at least half. Furthermore, since the completion equipment engines are about four times larger than the drilling engines, the imposition of PM traps and SCR on most completion equipment engines means a substantial reduction in overall PM and NO_x emissions from the set of engines to be used in New York. Any alternative emission reduction schemes which industry might further pursue would be judged against these reductions. It is clear however, that the Department would assure that any such control or mitigation measure would explicitly demonstrate compliance with the ambient air quality standards.

6.5.2.6 The Practicality of Mitigation Measures on the Completion Equipment and Drilling Engines.

The supplemental modeling assessment has concluded that in order to meet the ambient standards for the 24-hr PM2.5 and the 1-hour NO_2 NAAQS, it is necessary that the completion equipment engines tiers allowed to be used in New York to be equipped with particulate filter

traps (CRDPF) and SCR control for NO_x. These are Tier 2 and newer completion equipment engines. Similarly, the Tier 1 rig engines and air compressors would be required to be equipped with both control devices if these are used in New York. The determination on the specific after-treatment controls was based on the review of available control methods used in practice (see Appendix 18A). Currently available alternative control measures considered were deemed inadequate for the purpose of achieving the level of PM2.5 and NO_x emission reductions necessary to demonstrate NAAQS compliance and/or having a proven record of use in practice.

Although industry can attempt to perform an independent assessment of alternatives to the recommended exhaust after-treatment controls, it is highly likely that a certain level of control equipment recommended would be necessary on these engines. If industry indentifies viable alternative control measure which can be demonstrated to achieve the same level of emission reduction for NAAQS standard compliance, these alternative schemes would need to be submitted for Department review and concurrence prior to their use in New York. Furthermore, in recommending the use of particulate traps and the SCR technology, Department staff has considered the requirements of subsection 617.11.5 and the practicality of the chosen measures.

Taking the diesel particulate traps and the SCR controls separately, it is fair to say that since the former have a longer established history of actual use than the latter on types of engines of size in the rig engine class, the demonstration of practicality for the traps might be less onerous. For example, industry itself has identified these diesel particulate traps on Tier 2 and 3 engines in their list of mitigation measure.[95] In addition, public information (see footnote 17) also has identified the ongoing use of diesel traps as a required mitigation measure by Metropolitan Transportation Authority (MTA) for non-road engines in major construction projects in NYC. These latter engines, however, are in the size range of the smaller rig engines and not in the completion equipment engine range. Information on the ongoing practical use of particulate traps in these and similar activities have been further confirmed by Department staff through publically available information. Thus, while it can be concluded that the requirement to use particulate traps on certain EPA tiered engines is in accord with Subsection 200.6 and 617.11 of the Department's requirements, it is nonetheless necessary for industry to further assess the

[95] Page 43 of the ALL/IOGA September 16, 2010 Information Request Report.

practicality of their use for the completion equipment engine size range. Based on limited conversations with two of the engine manufacturers indicated that the main issue still to be resolved is the details of the engineering necessary to use PM traps as after-treatment equipment. The concern relates to the need for "stand alone" equipment for each of the completion equipment engines which differs from the built-in or add on components being currently used for the smaller on-road or off-road engines. To the Department's knowledge, currently neither PM and NO_2 control measures are being used by the gas drilling industry for other shale activities to any extent. However, it is the Department's assumption that the PM traps can be feasibly used on the Tier 1 drilling engines and compressors and the Tier 1 and 2 completion equipment engines.

For the use of SCR as the Department's preferred control measure to reduce NOx emissions from all of the completion equipment engines allowed to be used in New York, there is less information on similar size engines. As Appendix 18A notes, however, these units are widely used in a package with particulate traps on heavy duty vehicles and there is no operational reason that the same cannot be achieved with the larger completion equipment engines. One way to judge the practicality of using SCR control on these engines is to consider the costs involved. The Department has undertaken a simple approach to this issue by using the analogy to reducing exhaust stream NOx emission and its "cost effectiveness" as a means for major stationary sources to get a "waiver" from the emission control limits set forth in Subpart 227-2 (Reasonably Available Control Technology (RACT) for Oxides of Nitrogen (NO_x)). That is, if a source can demonstrate that the costs associated with the imposed emission limits are unreasonable, the Department and EPA would consider granting a waiver from meeting these limits.

Details of an analysis of the "cost effectiveness" of the SCR controls for completion equipment engines and the comparable value currently used by the Department for stationary sources is provided in Appendix 18B. It is important to note that the "cost effectiveness" is based on acceptable "engine size scaling-up" method for the completion equipment engines with certain assumptions which might not be representative of the actual cost of installation of SCR after treatment. The calculations in Appendix 18B indicate that the cost of requiring SCR on the completion equipment engines is within the value used by the Department for stationary sources

and is deemed reasonable. The cost effectiveness for the smaller drilling engines should be lower. It is recognized that the applicability of 227.2 RACT requirements are meant for major individual stationary sources, but it is also to be noted that the potential annual NO_x emissions from the sum total of engine use throughout the Marcellus Shale are rather large, as discussed in the next section. Based on the conversations with the engine manufacturers, the main concern with the installation of SCR as an after-treatment control relates again to the need for a "stand-alone" system on the completion equipment engines, with the added complexity that these systems would require "continuous" maintenance to achieve the level of reduction assumed in the Department's analysis. In addition, these discussions indicate that the cost associated with the installation of the PM traps and SCR are likely above those assumed by the Department. A calculation using the approach in Appendix 18C for PM after-treatment indicates that the "cost effectiveness" value is well above the value used for NO_x RACT waiver determinations. Thus, it is recommended that industry undertake a detailed assessment of the PM traps and SCR controls in addressing the Department's recommendations of these controls as the required mitigation measures on certain Tier drilling and completion equipment engines in order to demonstrate compliance with the 24-hour PM2.5 and 1-hour NO_2 NAAQS.

Based on the above discussions, the Department believes that the use of particulate traps and SCR controls are reasonable and practical in achieving the mitigation of potential adverse 24-hour PM2.5 and 1-hour NO_2 impacts, respectively. As noted previously, industry can present equivalent control measures and background information for further Department considerations. Regardless of the specific measure, however, it should be made clear that the Department is required to assure compliance with ambient standards with respect to any other control measures which could put forth by industry or the public. One of the mitigation "measures" noted by industry in their Information Report, at least for NO_x emissions, is to allow for the "natural" fleet turnover of the EPA tiers as these requirements would "kick-in" over time. This suggestion is not an acceptable scheme, given that none of the engines currently in use or contemplated are the interim Tier 4 engines, which become effective in 2011, based on the Department's knowledge and industry data. If industry is to advance such a mitigation scheme, it would submit an acceptable timeline which clearly sets out an aggressive schedule to implement the Tier 4 engines. Based on engine manufacturer's information, there is ongoing efforts to achieve the

Tier 4 emission standards before the 2014/15 timelines noted in Table 6.19. Such an implementation schedule can be tied to the specific tiered engine after-treatment controls required by the Department.

6.5.2.7 Conclusions from the Modeling Analysis

An air quality impact analysis was undertaken of various sources of air pollution emissions from a multi-horizontal well pad and an example compressor station located next to a typical site in the area underlain by the Marcellus Shale. The analysis relied on recommended EPA and Department modeling procedures and input data assumptions. Due to the extensive area underlain by the Marcellus Shale and other low-permeability gas reservoirs in New York, certain assumptions and simplifications had to be made in order to properly simulate the impacts from a "typical" site such that the results would be generally applicable. At the same time, an adequate meteorological data base from a number of locations was used to assure proper representation of the potential well sites in the area underlain by the Marcellus Shale in New York.

Information pertaining to onsite and offsite combustion and gas venting sources and the corresponding emissions and stack parameters were initially provided by industry and independently verified by Department staff. The emission information was provided for the gas drilling, completion and production phases of expected operations. On the other hand, emissions of potential additive chemicals from the flowback water impoundments, which were proposed by industry as one means for reuse of water, were not provided by industry or an ICF report to NYSERDA. Thus, worst-case emission rates were developed by the Department using an EPA emission model for a set of representative chemicals which were determined to likely control the potential worst case impacts, using information provided by the hydraulic fracturing completion operators. The information included the compounds used for various purposes in the hydraulic fracturing process and the relative content of the various chemicals by percent weight. The resultant calculated emission rates were shared with industry for their input and comment prior to the modeling.

The modeling analysis of all sources was carried out for the short-term and annual averages of the ambient air quality standards for criteria pollutants and for Department defined threshold levels for non-criteria pollutants. The initial modeling used limitations on simultaneous

operations of the various equipment at both onsite and offsite operations for a multi-well pad in the analysis for the short-term averages, while the annual impacts accounted for the potential use of equipment at the well pad over one year period for the purpose of drilling up to a maximum of ten wells. For the modeling of chemicals in the flowback water, two impoundments of expected worst case size were used based on information from industry: a smaller on-site and a larger off-site (or centralized) impoundment.

Initial modeling results indicated compliance with the majority of ambient thresholds, but also identified certain pollutants which were projected to be exceeded due to specific sources emission rates and stack parameters provided in the Industry Information Report. It was noted that many of these exceedances related to the very short stacks and associated structure downwash effects for the engines and compressors used in the various phases of operations. Thus, limited additional modeling was undertaken to determine whether simple adjustments to the stack height might alleviate the exceedances as one mitigation measure which could be implemented. An estimate of the distances at which the impacts would reduce to below all applicable SGCs and SGCs were provided as part of the original analysis.

Based on recent information provided by industry on the operational restrictions at the well pad, the elimination of the flowback impoundments, and a limited modeling of 24-hour PM2.5 impacts, the initial Department assessment was revisited. In addition, due to the promulgation of new 1-hour SO_2 and NO_2 NAAQS after September 2009, further modeling was performed. The significant consequences of the revised restrictions on simultaneous operations of the drilling and completion equipment engines, the number of wells to be drilled per year, and the elimination of the impoundments are incorporated in the initial modeling assessment. Further modeling details for the short term PM2.5, NO_2 and SO_2 impacts are presented in a supplemental modeling section. These results indicate the need for the imposition of certain control measures to achieve the NO_2 and PM2.5 NAAQS. These measures, along with all other restrictions reflecting industry's proposals and based on the modeling results, are detailed in Section 6.5.5 as well permit operation conditions.

Table 6.12 - Sources and Pollutants Modeled for Short-Term Simultaneous Operations

Pollutant → / Source	SO_2	NO_2	PM10 & PM2.5	CO	Non-criteria combustion emissions	H_2S and other gas constituents
Engines for drilling	✔	✔	✔	✔		
Compressors for drilling	✔	✔	✔	✔	✔	
Engines for hydraulic fracturing	✔	✔	✔	✔	✔	
Line heaters	✔	✔	✔	✔	✔	
Off-site compressors	✔	✔	✔	✔	✔	
Flowback gas flaring	✔	✔	✔	✔	✔	
Gas venting						✔
Mud-gas separator						✔
Glycol dehydrator					✔	✔

Table 6.13 - National Weather Service Data Sites Used in the Modeling

NWS Data Site	Meteorology Data Years	Latitude/Longitude Coordinates
Albany	2007-08	42.747/73.799
Syracuse	2007-08	43.111/76.104
Binghamton	2007-08	42.207/75.980
Jamestown	2001-02	42.153/79.254
Buffalo	2006-07	42.940/78.736
Montgomery	2005-06	41.509/74.266

Table 6.14 - National Ambient Air Quality Standards (NAAQS), PSD Increments & Significant Impact Levels (SILs) for Criteria Pollutants (μg/m^3)

Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
SO_2 NAAQS	196	1300		365	80
PSD Increment		512		91	20
SILs		25		5	1
PM10 NAAQS				150	50
PSD Increment				30	17
SILs				5	1
PM2.5 NAAQS				35	15
PSD Increment				9	4
SILs[96]				1.2	0.3
NO2 NAAQS	188				100
PSD Increment					25
SILs					1.0
CO NAAQS	40,000		10,000		
SILs	2000		500		

[96] The PM2.5 standards reflect the 3 year averages with the 24 hour standard being calculated as the 98th percentile value.

Table 6.15 - Maximum Background Concentration from Department Monitor Sites

Pollutant	Monitor Sites	Maximum Observed Values for 2005-2007 ($\mu g/m^3$)
SO_2	Elmira* and Belleayre	3 hour - 125 24-hour - 37 Annual - 8
NO_2	Amherst	Annual - 26
PM10**	Newburgh* and Belleayre	24-hour - 49 Annual - 13
PM2.5	Newburgh* and Pinnacle State Park	24-hour - 30 Annual - 11 (3 year averages per NAAQS)
CO	Loudonville	1-hour - 1714 8 hour - 1112

* Denotes the site with the higher numbers.
** For PM10, data from years 2002-4 was used.

Table 6.16 - Maximum Impacts of Criteria Pollutants for Each Meteorological Data Set

Meteorological Data Year & Location		SO_2 3-hour	SO_2 24-hour	SO_2 Annual	PM10 24-hour	PM10 Annual	PM2.5* 24-hour	PM2.5* Annual	CO 1-hour	CO 8-hour	NO_2 Annual
Albany	2007	15.4	13.3	3.1	459	2.7	355	2.7	9270	8209	57.9
	2008	15.3	13.2	2.9		2.4		2.4	9262	8298	51.0
Syracuse	2007	15.9	12.6	2.8		2.7		2.7	8631	7849	57.1
	2008	15.8	14.3	2.7		2.7		2.7	8626	7774	55.4
Binghamton	2007	18.5	13.4	2.3		2.1		2.1	10122	8751	45.5
	2008	18.6	15.4	1.9		1.8		1.8	9970	8758	37.6
Jamestown	2001	16.7	14.0	2.4		2.1		2.1	8874	8193	46.4
	2002	16.8	14.4	2.7		2.3		2.3	8765	8199	50.9
Buffalo	2006	16.6	15.7	3.2		2.9		2.9	9023	8067	63.2
	2007	16.9	14.4	3.1		2.8		2.8	8910	8270	60.8
Montgomery	2005	17.4	11.6	1.9		1.8		1.8	9362	8226	38.4
	2006	14.4	14.0	2.2		2.0		2.0	9529	8301	41.9
Maximum		18.6	15.7	3.2		2.9		2.9	10122	8758	63.2
Impact at 500m		0.3	0.3	0.05	7.1	.11	5.0	.11	480	253	2.5

Note: 24-hour PM2.5 values are the 8th highest impact per the standard.

Table 6.17 - Maximum Project Impacts of Criteria Pollutants and Comparison to SILs, PSD Increments and Ambient Standards

Pollutant and Averaging Time	Maximum Impact ($\mu g/m^3$)	SIL*	Worst Case Background Level ($\mu g/m^3$)	Total ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Increment Impact** ($\mu g/m^3$)	PSD* Increment ($\mu g/m^3$)
SO_2 - 3 hour	18.6	25	125	143.6	1300	18.6	512
SO_2 - 24-hour	15.7	5	37	52.7	365	15.7	91
SO_2 - Annual	3.2	1	8	11.2	80	3.2	20
PM10 - 24-hour	459***	5	49	508***	150	6.5**	30
PM10 - Annual	2.9	1	13	15.9	50	2.9	17
PM2.5 - 24-hour	355***	1.2	30***	385***	35	6.5**	9
PM2.5 - Annual	2.9	0.3	11	13.9	15	2.9	4
NO_2 - Annual	63.2	1.0	26	89.2	100	5.6**	25
CO - 1-hour	10,122	2000	1714	11,836	40,000	NA	None
CO - 8 hour	8758	500	1112	9870	10,000	NA	None

* SILs and increments for PM2.5 included in revised Table from EPA's final PSD rule for PM2.5

** Impacts from the off-site compressor plus the line heater only for PSD increment comparisons were recalculated for annual NO_2 and PM10 and PM2.5 24-hour cases. NA means not applicable

*** See Supplemental Modeling Section for revised analysis

Table 6.18 - Maximum Impacts of Non-Criteria Pollutants and Comparisons to SGC/AGC and New York State AAQS

Pollutant	Total Venting Emission Rate (g/s)	Impacts from all Venting Sources ($\mu g/m^3$)		All Combustion Sources and Dehydrator Impacts ($\mu g/m^3$)			
		Max 1-hr	SGC	Max 1-hr	SGC	Annual	AGC
Benzene***	0.218	140	1,300	13.2	1,300	0.90 0.10	0.13
Xylene	0.60	365	4,300	NA**	4,300	NA	100
Toluene	0.78	500	37,000	NA	37,000	NA	5,000
Hexane	9.18	5,888	43,000				
H_2S***	0.096	61.5 12.1	14*				
Formaldehyde**				4.4	30	0.20 0.04	0.06
Acetaldehyde				NA	4,500	0.06	0.45
Naphthalene				NA	7,900	NA	3.0
Propylene				NA	21,000	NA	3,000

* Denotes the New York State 1-hour standard for H_2S

** Denotes not analyzed by modeling, but the SGCs and AGCs would be met (see text)

*** AGC exceedance for benzene is eliminated by raising the dehydrator stack to 9.1m

The standard exceedance for H_2S is eliminated by using a minimum stack height of 9.1m for gas venting

The AGC exceedance for formaldehyde is eliminated by using a compressor stack height of 7.6m

Table 6.19 - Modeling Results for Short Term PM10, PM2.5 and NO_2 (New July 2011)

Met Data Location	Met Data Year	PM10, 24-hr (µg/m^3)		PM2.5, 24-hr (µg/m^3)		NO_2, 1-hour impact (µg/m^3) (see NOTE)		
		Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Drilling	Hydraulic Fracturing	Rig Engine	Compressor
Albany	2007	313	76	152	36	198	256	216
	2008	268	84	129	40	198	259	230
Syracuse	2007	224	95	144	34	156	196	198
	2008	327	81	120	27	161	180	208
Binghamton	2007	281	87	154	34	194	239	208
	2008	327	89	121	35	213	231	220
Jamestown	2001	339	74	151	29	180	237	221
	2002	229	83	155	33	181	248	217
Buffalo	2006	338	106	202	55	147	269	231
	2007	318	102	189	59	148	272	231
Montgomery	2005	255	77	104	28	169	198	202
	2006	301	66	108	21	155	211	200
Maximum (µg/m^3)		339	106	202	59	213	272	231
Max @ 75m (µg/m^3)		92	75	44	30	100-140	140-170	120-150
Max Dist to NAAQS - Background (m)		60	60	150	120	<90	<100	<100

NOTE: NO_2 results reflect SCR controls on the completion equipment engines, with Tier 2 emissions used for all completion equipment, rig engines and compressors. Results are from the OLM option in AERMOD. See text for details.

Table 6.20 - Engine Tiers and Use in New York with Recommended Mitigation Controls Based on the Modeling Analysis (New July 2011)

Engine Type (year in place)	Sample Percent in Use	Reduction factors in Emissions	Control measures considered and determined "practical" based on availability, use practice and cost.
Drilling: Tier 1 - 1996 (five @ 500hp)	25	Others relative to Tier 1	Would need PM traps and SCR.
Drilling: Tier 2 - 2002	49	2.7 1.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 3 - 2006	22	2.7 2.6	No PM controls nor SCR necessary for NAAQS.
Drilling: Tier 4 - Interim (not mandated) - 2011	0	40 5.1	Would likely have PM traps built in. No SCR necessary.
Drilling: Tier 4 - 2014	0	40 23.	Would have PM traps and SCR built in.
Completion: Tier 1 - 2000 (15 @ 2250 Hp)	Assumed same as for drilling	Others relative to Tier 1	Based on modeling, propose not to allow Tier 1 engines. Alternative is traps/SCR, plus more mitigation.
Completion: Tier 2 - 2006		2.7 1.6	Would need PM trap and SCR.
Completion: Tier 4 Interim - 2011		5.3 3.5	Would likely have PM traps and SCR built in or would use in-cylinder control for PM.
Completion: Tier 4 - 2015		13 3.5	Would have PM traps and SCR built in.

Note: 3.5% of engines in use are Uncertified or Tier "0". These will not be allowed to be used in NY

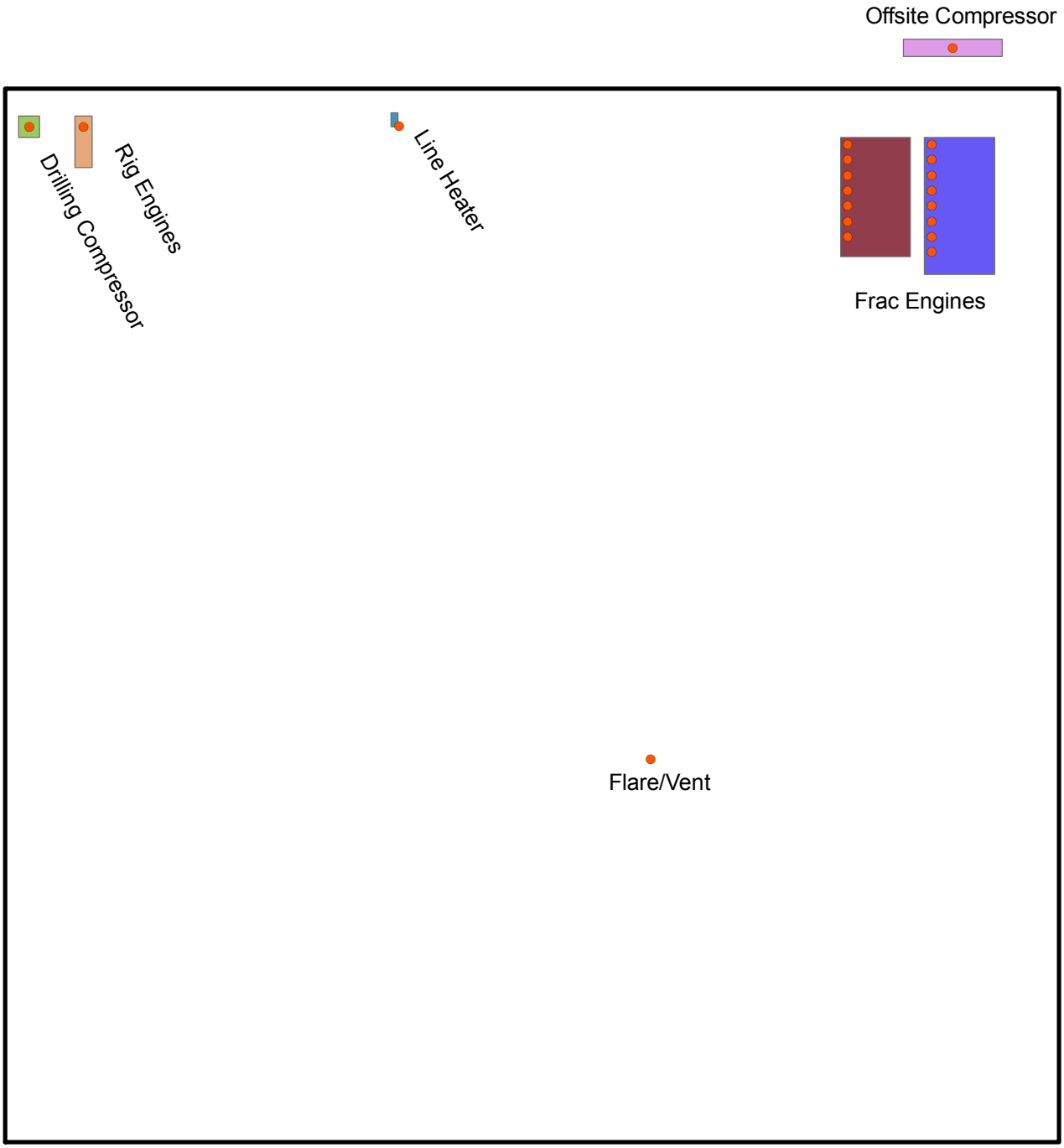


Figure 6.10- Location of Well Pad Sources of Air Pollution Used in Modeling

Buildings

- Drilling Compressor
- Frac Engines1
- Frac Engines2
- Line Heater
- Offsite Compressor
- Rig Engines

0 5 10 20 30 40 50 Meters

6.5.3 Regional Emissions of O_3 Precursors and Their Effects on Attainment Status in the SIP

This section addresses a remaining issue, as stressed by EPA Region 2[97] that the initial analysis did not provide a quantitative discussion of the potential regional emissions of the O_3 precursors, as contemplated in the Final Scoping for the 2009 draft SGEIS. The specific items relate to the impact of these drilling operations on the SIP for O_3 nonattainment purposes, as well as the impact of cumulative emissions from both stationary and mobile sources.

The initial analysis lacked information on the regional emissions of the cumulative well drilling activities in the whole of Marcellus Shale due to the lack of detail from industry on the likely number of wells to be drilled annually and associated emissions. It was determined that information and available data from similar shale development areas would not be suitable for a calculation of these emissions due to a variety of factors. Thus, the Department requested this emission information from industry and received the necessary data in the ALL/IOGA-NY Information Report referenced previously and in a follow-up request for mileage data for on-road truck traffic, as discussed below. The following narrative is intended to address concerns with the regional emissions as these relate to ozone attainment and similar SIP issues.

Attainment Status and Current Air Quality

The most recent nonattainment areas that have been designated by EPA are those for the 1997 8-hour ozone of 0.08 ppm (effectively 84 ppb), 1-hour ozone (0.12 ppm), annual and the 24-hour PM2.5 national ambient air quality standards (NAAQS) of 15 and 35 $\mu g/m^3$, respectively. In March 2008, EPA promulgated a revision of the 8-hour ozone NAAQS by setting the standard as 0.075 ppm. Nonattainment areas for the new standard have not as yet been established due to current efforts by EPA to reconsider a more restrictive NAAQS. EPA proposed its reconsideration of the 2008 ozone NAAQS in January 2010 taking comment on lowering the NAAQS to between 0.060 ppm and 0.070 ppm. EPA is expected to complete its reconsideration in July 2011.

Ozone and particulate matter are two of six pollutants regulated under the CAA as "criteria pollutants." Data from Department monitors through 2010 indicate that monitored air concentrations in the established nonattainment areas for O_3 and PM2.5, as well as in the area

[97] Comments of EPA Region 2 in letter from John Filippelli dated (12/30/09), pages 2-3.

underlain by the Marcellus Shale, do not exceed the currently applicable NAAQS. In addition, there are no areas in New York State that are classified as nonattainment for the remaining four criteria pollutants: CO, lead, NO_2 and SO_2. EPA has recently promulgated revisions to the lead, SO_2 and NO_2 NAAQS and has established new monitoring requirements for the lead and NO_2 NAAQS, as well as new modeling requirements for the SO_2 NAAQS. As a result of these new requirements, the Department cannot yet determine whether ambient air quality complies with these NAAQS values. However, the Department has proposed to EPA to classify the whole state as "unclassifiable" with respect to the NO_2 1-hour NAAQS and would have to submit a recommendation to EPA on SO_2 1-hour NAAQS. As data becomes available in the next few years, the Department would assess the data and recommend to EPA designation of all areas in the State as either attainment or nonattainment.

For O_3, the Department has a wealth of information to compare against the current, but delayed, 2008 NAAQS and the range of the reconsidered NAAQS. Under the 2008 Ozone NAAQS, current air quality in the Poughkeepsie-Newburgh, NYC and Jamestown metropolitan areas would make these areas nonattainment. If the O_3 NAAQS is set at the lower values proposed by EPA, more areas of the state, including those in the Marcellus Shale play, would also be nonattainment.

State Implementation Plans

The process by which states meet their obligations to improve air quality under the CAA, (for example, the applicable NAAQS for criteria pollutants) is established in SIPs. A major component of SIPs is the establishment of emission reduction requirements through the promulgation of new regulatory requirements that work to achieve those reductions. The combined effect of both state and federal requirements is to reduce the level of pollutants in the air and bring each nonattainment area into attainment. These requirements, which apply to both stationary and mobile sources, apply to both new and existing sources and are intended to limit emissions to a level that would not result in an exceedance of a NAAQS, thus preserving the attainment status of that area. In order to judge the potential effects of the projected O_3 and PM2.5 precursors in the Marcellus Shale on the SIP process, the Department has looked at the level of these emissions relative to the baseline emissions and has come to certain conclusions on the approach necessary to assure the goal of NAAQS compliance.

Projected Emissions and Current/Potential Control Measures

The primary contributors (emission sources) to ozone pollution include those that emit compounds known as "precursors" that result in the formation of ozone. The two most important precursors are NO_x and VOCs. PM2.5, another pollutant, is also directly emitted or formed from precursors, such as ammonia, sulfur oxides and NO_x. New York State and the federal government have promulgated emission rules that apply to the sources of these pollutants in order to protect air quality and prevent exceedances of the ambient air standards. In the case of Marcellus Shale gas resource development, most emissions resulting from natural gas well production activities are expected to come from the operation of internal combustion non-road engines used in drilling and hydraulic fracturing, as well as engines that provide the power for gas compression. Additional associated emissions occur with on road truck traffic used for transportation of equipment and hydraulic fracturing fluid components.

Engine emissions have long been known to be a significant source of air pollution. As a result, control requirements for these sources have been in place for many years, and have been updated as engine technology and control methods have improved. Regulations and limits exist on both the federal and state level, and effectively mitigate the effect of cumulative emissions on air quality and the SIP. In New York, these measures include:

Particulate Matter
Locomotive Engines and Marine Compression-Ignition Engines Final Rule
Heavy Duty Diesel (2007) Engine Standard
Part 227: Stationary Combustion Installations

Sulfur
Federal Nonroad Diesel Rule
6 NYCRR Part 225: Fuel Composition and Use

NO_x & VOCs
Part 217: Motor Vehicle Emissions
Part 218: Emission Standards for Motor Vehicles and Motor Vehicle Engines

Part 248: New York State Diesel Emissions Reduction Act (DERA)

Small Spark-Ignition Engines

Federal On-board Vapor Recovery

In addition, to address mobile sources emissions which might occur due to diesel trucks idling during the drilling operations, Subpart 217-3 of the New York State ECL specifically addresses this issue by limiting heavy duty vehicle idling to less than five consecutive minutes when the heavy duty vehicle is not in motion, except as otherwise permitted. Enforcement of this regulation is performed by Department Conservation Officers and violation can result in a substantial fine.

The above requirements for stationary sources apply statewide and not just in nonattainment areas due to New York's status as part of an Ozone Transport Region state. This differs from other areas such as the Barnett Shale project in which different standards apply inside and outside of the Dallas/Fort Worth nonattainment area. Furthermore, additional requirements and potential controls specific to the operations for the Marcellus Shale gas development were addressed in Section 6.5.1 with respect to the well pad and the compressor station (e.g., NSPS and NESHAPs requirements per 40 CFR 60, subpart ZZZZ and Part 63, subpart HH). Certain of these measures restrict the emissions of O_3 precursors to the maximum extent possible with current control measure. In addition to the mandatory requirements that are in place as a result of the above rules that directly affect the types of emissions that are expected with the development of Marcellus Shale gas resources, there are a number of other recommended measures that have been incorporated in previous sections to further reduce the emissions associated with these operations and mitigate the cumulative impacts:

1. NO_x emission controls (i.e., SCRs) and particulate traps on all diesel completion equipment engines and on older tier drilling engines (see section 6.5.2);

2. Condensate and oil storage tanks should be equipped with vapor recovery units (see section 6.5.1.5); and

3. The institution of a fugitive control program to prevent leaks from valves, tanks, lines and other pressurized production operations and equipment (see section on greenhouse gas remediation).

Use of controls for excess gas releases, such as flares by REC should be implemented wherever practicable (see section 6.5.2). In addition, other measures such as the use of more modern equipment and electric motors instead of diesel engines, where available, are recommended.

Regional NO_x and VOC Emission Estimates and Comparison to Estimates from another Gas-Producing Region

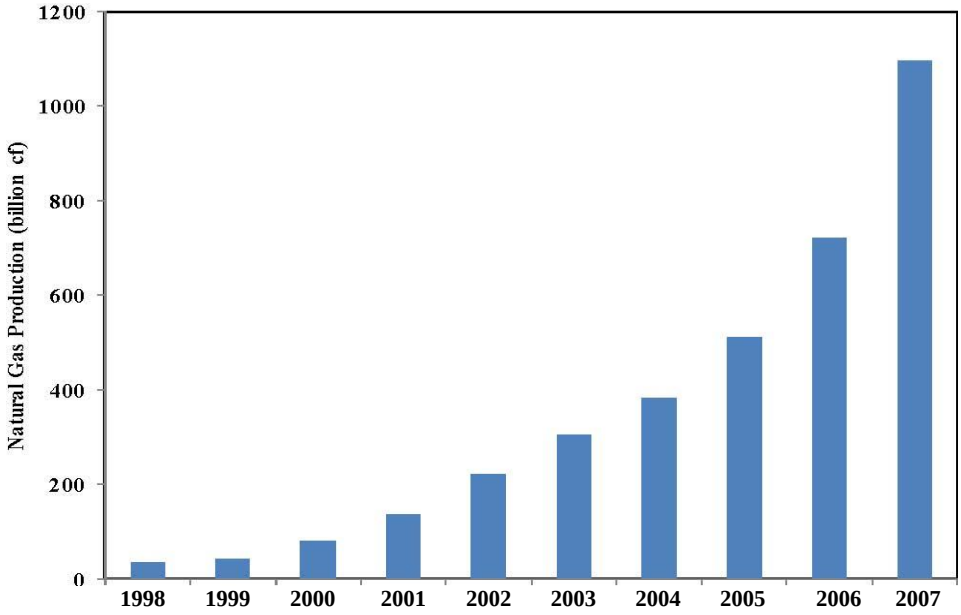
In order to assist the Department to develop a full understanding of the cumulative and regional emissions and impacts of developing the gas resources of the Marcellus Shale, available information from similar activities in other areas of the country has been reviewed. Notably, certain information from the Barnett Shale formation of north Texas, which has undergone extensive development of its oil and gas resources, was reviewed. The examination of the development of the Barnett Shale could be instructive in developing an approach to emissions control and mitigation efforts for the Marcellus Shale. As a result, the Department has examined one commonly referenced study and source of information on the regulation and control of air pollution from the development of the Barnett Shale.

First, the development of the gas resources of the Marcellus Shale, as with the Barnett Shale, not be spatially distributed evenly across the geographic extent of the region, but would likely concentrate in different areas at different times, depending on many factors and limitations, including the price of natural gas at any given moment, the ease of drilling one area versus another, and other legal/environmental constraints such as potential drilling in watersheds. As such, industry cannot project at this time as to where impacts may concentrate regionally within the Marcellus Shale region. Furthermore, well development would occur over time, wherein initially there would be a "ramping-up" period, followed by a nominal "peak" drilling period, and then a leveling off or dropping off period. Some of these factors and caveats are discussed in the ALL/IOGA-NY Information Report.

Thus, the cumulative impacts of gas well drilling within the Marcellus Shale would also vary depending on what point in time those impacts are measured as the development of the gas resource expands over time. As an example of how well development proceeded in the Barnett Shale, the Figure 6.11 indicates that gas production rose dramatically from 1998-2007. This chart is being used by the Department for illustration purposes only to indicate the timeframes

which might be involved in the Marcellus development and not as an actual indication of expected development. Preliminary information from Pennsylvania indicates a more rapid increase in gas well drilling and production.

Figure 6.11 - Barnett Shale Natural Gas Production Trend, 1998-2007[98]



As drilling activities "ramp up," the potential for greater environmental impacts likewise increase. In estimating the air emissions of drilling in the Marcellus Shale, a worst case (conservative) scenario of drilling and development was developed by IOGA-NY in response to an information request from the Department. The estimates are provided in the ALL/IOGA-NY Information Report. There are a number of caveats associated with these estimates so the absolute magnitudes of emissions should be interpreted accordingly. However, an estimate of worst case emissions are projected for the maximum likely number of wells (2216) to be drilled in the Marcellus Shale for the "peak" year of operations and the emission factors and duration of operations provided in the previous industry report (8/26/09) used in the modeling assessment.

[98] Taken from Armendariz (SMU), 2009, p. 2.

Some of the factors which were included in the estimates noted in the ALL/IOGA-NY Information Report include:

- Average emission rates for dry gas are used for every well for every phase of development;
- Maximum number of wells (both horizontal and vertical) in any year;
- No credit is taken for any mitigation measures, permit emissions controls, or state and federal regulatory requirements that are expected to reduce these estimates;
- Drilling emissions are conservatively estimated at 25 days for the horizontal wells;
- Heater emissions are included year-round in the production estimates; however,they would be seasonal and would take place during the non-ozone season;
- Off-pad compressor emissions are included in the production estimates; however, it is anticipated that most well pads would not include a compressor;
- No credit is taken for the rolling nature of development; i.e., that all wells would not be drilled or completed at the same time, on the same pad;
- No credit is taken for improved nonroad engine performance and resultant reduced NO_x emissions from the higher tier engines that would be phased in over time; and
- No credit is taken for reduced emission completions which would significantly reduce flaring and hence related NO_x and VOC emissions.

The ALL/IOGA-NY Industry Information Report predicted the ozone precursor emissions depicted in Table 6.21.

Table 6.21 - Predicted Ozone Precursor Emissions (Tpy)

	Drilling	Completion	Production	Totals
Horizontal - NO_x	8,376	5,903	8,347	22,626
Vertical - NO_x	409	345	927	1,681
Total NO_x	8,785	6,248	9,274	24,307
Horizontal - VOC	352	846	5,377	6,575
Vertical - VOC	17	81	597	695
Total VOC	369	927	5,974	7,270

It is seen that the total for NO_x emissions for the horizontal wells is made up of 37% each from drilling and production and 26% from completion. It is to be noted that for the latter emissions, about half is associated with potential flaring operations. For VOC emissions for the horizontal wells, the production sources dominate (82% of total). This is related to the dehydrator emissions assumed to operate for a full year. It is also noted that the completion VOC emissions are due to venting and flaring. Based on the above numbers, IOGA-NY concluded the impact from the development of the Marcellus at a worst-case peak development rate would add 3.7% to existing NO_x emissions on a statewide basis. This was based on the 2002 baseline emission inventory (EI) year used in New York's 2007 SIP demonstration for the 8-hr ozone standard[99]. A more germane comparison would be to the "upstate" area emissions where Marcellus Shale area is located. This comparative increase would be 10.4% for the same EI year. These upstate area emissions exclude the nine-county New York ozone nonattainment area, as well as the counties north and east of the area underlain by the Marcellus Shale.

The total NO_x emissions increase from this example is deemed significant, but does not account for the number of mitigation measures imposed and recommended in the revised SGEIS. For example, the use of SCR control to reduce NO_x emissions by 90% from the completion equipment engines would reduce the completion emission by about half, while the minimization of flaring operations by the use of REC would reduce the rest of these completion emissions down to a very small value which would significantly reduced the relative percentage. In addition, as noted by the IOGA-NY Information Report, the production sources used in the estimates of NO_x emissions are not likely to be used the full year and might not be even needed at many wells. Furthermore, the estimated drilling emissions assume the maximum number of days would be needed for each well and the associated use of older tier engines throughout the area and over the long-term. Thus, the relative percent of Marcellus well drilling emissions to the existing baseline is highly likely to be substantially less than the value above using the worst case estimates.

The IOGA-NY also concluded that the total VOC emissions of 7,270 Tpy from the development of the Marcellus Shale would add 0.54% to existing VOC emissions on a statewide basis. Using

[99] Ozone Attainment Demonstration for NY Metro Area - Final Proposed Revision, Appendix B, pp. 10-11 http://www.dec.ny.gov/chemical/37012.html.

the same baseline EI year as for NO_x, the relative increase for VOCs would be 1.3%. This increase is deemed small and also does not account for recommended mitigation measures such as the minimization of gas venting by REC.

The above NO_x and VOC relative emission comparisons do not include the contribution from the on road truck traffic associated with Marcellus Shale operations and which had to be estimated by the Department. The ALL/IOGA-NY Information Report included the light and heavy truck trips, but not the associated average mileage which is necessary to calculate emissions. Thus, the Department requested an average Vehicle Miles Traveled (VMT) for the two truck types and ALL consulting provided the data in a response letter.[100] Based on this information, the Department projected the NO_x and VOC emissions from on road truck as discussed in the next subsection.

Effects of Increased Truck Traffic on Emissions

The initial modeling analysis did not address on-road mobile source emissions resulting from the drilling operations, specifically, diesel truck emissions, except at the well pad. The Department has analyzed the impact of increased emissions from truck traffic in the Marcellus Shale affected counties. As part of this analysis, the Department utilized estimates of VMT provided by ALL Consulting/IOGA-NY in response to the Department's information request to determine the environmental impacts of project related truck emissions. Industry estimated that the weighted average one way VMT for both light and heavy duty trucks to be approximately 20 to 25 miles for both horizontal and vertical wells.

The Department used these estimated average VMT for heavy-duty and light-duty trucks and the number of truck trips contained in the ALL/IOGANY Information Report to calculate the total additional VMT associated with drilling activities. These VMT, along with other existing New York-specific data were input to the EPA's Motor Vehicle Emission Simulator (MOVES) model to estimate NO_x and VOC emissions for the various truck activities. EPA Region 2 commented on the SGEIS and requested the use of the MOVES model. As EPA's approved mobile source model, MOVES incorporates revised EPA emission factors for various on-road mobile source activities and associated pollutants. The resulting emissions support a comparison of how traffic

directly related to the drilling operations impacts the overall mobile emissions that normally would occur throughout the Marcellus Shale drilling area.

The estimated emissions of NO_x and VOCs (and well as other pollutants) that result from the additional light and heavy duty truck traffic expected with Marcellus well drilling are detailed in Appendix 18C. The emissions for the counties in the area underlain by the Marcellus Shale are presented for both the existing baseline activities as well as those associated with the drilling activities. In addition, the absolute and percent differences which represent the additional truck emissions are shown.

The results show that the total NO_x and VOC emissions are estimated to be 687 and 70 Tpy, respectively, and are expected to increase the existing baseline emissions by 0.66% and 0.17%. The maximum increase for any pollutant is 0.8%. These increases are deemed very small. In addition, the traffic related NO_x and VOC emissions are noted to be small fractions of the corresponding increased emissions due to other activities associated with gas drilling, as summarized in the last subsection. For example, the traffic related NO_x emissions are about 3% of the total NO_x emissions given in the above mentioned summary table. A simple estimate of traffic related emissions of PM2.5 per pad, using the total emissions and the number of maximum wells is shown in Appendix 18C to be 0.01 Tpy which is comparable to the previously estimated pad specific PM2.5 emissions noted in the modeling section which was estimated with the EPA MOBILE6 model.

Based on these results, the Department concluded that the estimated truck related emissions would be captured during the standard development of the mobile inventories for the SIP. These estimates are also noted to be within the variability associated with the MOVES model inputs.

Comparison to Barnett Shale Emission

A referenced report[101] on the Barnett Shale oil and gas production prepared by Southern Methodist University (SMU) for the Environmental Defense Fund (EDF) has been noted as a source of emission calculation schemes and resultant regional emissions for that region of Texas. In terms of the projected emissions of NO_x and VOCs, while caution should be exercised in

making comparisons between the two areas, a picture of emissions from the Barnett Shale may be a useful point of departure for understanding the magnitude and types of emissions to be expected with the development of the Marcellus Shale. The Department has not undertaken a review of the rationale or the methodologies used in the SMU report and is also aware of the Texas Commission on Environmental Quality (TCEQ)'s critique of the report.[102] Since the report, TCEQ has undertaken a detailed emission inventory development program to better characterize the sources and to quantify the corresponding emissions.

For the present purposes, it is necessary to provide a brief outline of the potential differences between the gas development activities and associated sources between the Barnett report and the industry projections for the Marcellus Shale. For example, the SMU report provided the relative amount of emissions from different source categories and corresponding NO_x and VOC emissions, as presented in Table 6.22 below. For comparison, the industry-provided emissions summarized above are 66.7 and 20 tons per day (Tpd) for NO_x and VOCs, respectively. However, the latter do not include some of the sources tabulated in the SMU report such that a straightforward comparison is not possible. Nonetheless, the SMU report notes that the largest group of VOC sources was condensate tank vents. Table 6.22 also indicates that fugitive emissions from production operations have a significant contribution to the VOC totals.

Table 6.22 - Barnett Shale Annual Average Emissions from All Sources[103]

Source	2007 Pollutants, Tons per day(Tpd)		2009 Pollutants, Tons per day (Tpd)	
	NOx	VOC	NOx	VOC
Compressor Engine Exhausts	51	15	46	19
Condensate And Oil Tanks	0	19	0	30
Production Fugitives	0	17	0	26
Well Drilling and Completion	5.5	21	5.5	21
Gas Processing	0	10	0	15
Transmission Fugitives	0	18	0	28
Total Daily Emissions (Tpd)	**56**	**100**	**51**	**139**

[103] Adapted from Armendariz (SMU), 2009 p. 24.

These might explain the differences in VOC emissions in that industry does not expect to use condensate tanks in New York due to the dry gas encountered in the Marcellus Shale. In addition, these tank emissions, if used, would be controlled by vapor recovery systems as noted in Section 6.5.2. In addition, all efforts would need to be made by industry to minimize fugitive emissions as recommended in the greenhouse gas emission mitigations section which would reduce concomitant VOC emissions.

The SMU report also provides charts which compare the total NO_x plus VOC emissions from the Barnett oil and gas sources to totals from on-road source categories in the Dallas-Fort Worth area, concluding that the former are larger than the on road emissions in some respects. However, these comparisons are not transferrable to the Marcellus Shale situation in New York not only because VOC emissions dominate these totals, but also since the comparisons are to a specific regional mix of sources not representative of the situation to be encountered in New York. On face value, the absolute magnitude of these total emissions is much larger than even a "worst-case" scenario for the Marcellus Shale.

Again, no firm predictions or projections can be made at this time as to where or when gas drilling impacts may concentrate regionally within the Marcellus Shale, but the Department would continue to avail itself of the knowledge and lessons learned from similar regional shale gas development projects in other parts of the country.

Further Discussions and Conclusions

There are stringent regulatory controls already in place for controlling emissions from stationary and mobile sources in New York. With additional required emission controls recommended in the revised SGEIS for the operations associated with drilling activities, coupled with potential deployment of further emission controls arising from upcoming O_3 SIP implementation actions, the Department is confident that the effect of cumulative impacts from the development of gas resources in the multi-county area underlain by the Marcellus Shale would be adequately mitigated. Thus, the Department would be able to continue to meet attainment goals that it has set forth in cooperation with EPA. In addition to eliminating the use of uncertified and certain older tier engines and requiring specific mitigation measures to substantially reduce PM and NO_x emissions in order to meet NAAQS, the Department would review the need for certain additional

mitigation prior to finalizing the SGEIS. As part of the information, the Department is seeking from industry an implementation timeline to expedite the use of higher tier drilling and completion equipment engines in New York. Furthermore, as the Department readies for the soon to be announced revised O_3 NAAQS and potential revisions to the PM2.5 NAAQS, the need for imposing further controls on drilling engines not being currently required to be equipped with PM traps and SCR would be revisited. If it is determined that further mitigation is necessary, further controls would be required. The review would consider the relatively high contribution to regional emissions of NO_x from the drilling engines and result from regional modeling of O_3 precursors which would be performed in preparation of the Ozone SIP.

Regional photochemical air quality modeling is a standard tool used to project the consequences of regional emission strategies for the SIP. The application of these models is very time and resource intensive. For example, these require detailed information on the spatial distribution of the emissions of various species of pollutants from not only New York sources, but from those in neighboring states in order to properly determine impacts of NO_x and VOC precursor emissions on regional O_3 levels. At present, detailed necessary information for the proper applications of this modeling exercise is lacking. However, as part of its commitment to the EPA, and in cooperation with the Ozone Transport Commission to consider future year emission strategies for the Ozone SIP, the Department would include the emissions from Marcellus Shale operations in subsequent SIP modeling scenarios. As such, properly quantified emissions specifically resulting from Marcellus Shale operations would be included in future SIP inventories to the extent that the information becomes available. Interim to this detailed modeling, the Department would perform a screening level regional modeling exercise by adding the projected emissions associated with New York's portion of the Marcellus Shale drilling to the baseline inventory which is currently being finalized. This modeling would guide the Department's finalization of the SGEIS. In addition to the availability of the regional modeling results, the Department has recommended that a monitoring program be undertaken by industry to address both regional and local air quality concerns as discussed in the next section.

6.5.4 Air Quality Monitoring Requirements for Marcellus Shale Activities

In order to fully address potential for adverse air quality impacts beyond those analyzed in the SGEIS relate to associated activities which are either not fully known at this time or verifiable by

the assessments to date, it has been determined that a monitoring program would be undertaken. For example, the consequences of the increased regional NO_x and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions, including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable. Thus, it has been determined that an air monitoring plan is necessary to address these regional concerns as well as to verify the local-scale impact of emissions from the three phases of gas field development: drilling, completion and production. The monitoring plan discussed herein is determined to be the level of effort necessary to assure that the overall activities of the gas drilling in the Marcellus Shale would not cause adverse regional or local air quality impacts. The monitoring is an integral component of the requirements for industry to undertake to satisfy the SEQRA findings of acceptable air quality levels.

Based on the results from the Department's assessments of gas production emissions, and in consideration of the well permitting approach and the modeling analysis, an air monitoring plan has been developed to address the level of effort necessary to determine and distinguish both background and drilling related concentrations of pertinent pollutants. In addition, a review of previous monitoring activities for shale drilling conducted by the TCEQ[104] and the PADEP[105] was undertaken to better characterize the monitoring needs and instrumentation. The approach selected as best suited for monitoring for New York Marcellus Shale activities combines a regional and local scale monitoring effort aimed at different aspects of emission impact characterization. These two efforts are as follows:

1) Regional level monitoring: In order to assess the impact of regional emissions of precursors including VOCs and NO_x, monitoring for O_3 and PM2.5 would need to be conducted at two locations. One would be a "background" site and another would need to be placed at a downwind location sited to reflect the likely impact area from the atmospheric transport and conversion of the precursors into secondary pollutants. These would enhance the current Department O_3 monitoring in the area. These sites would also

[105] See: http://www.dep.state.pa.us/dep/deputate/airwaste/aq/toxics/toxics.htm.

need to be equipped with air toxics monitors so that pollutant levels can be compared to each other and to other existing sites; and

2) Near-field/local scale monitoring at various locations in the Marcellus Shale: This monitoring can be intermittent but would be carried out in areas expected to be directly impacted by one or more wells and compressor stations. The data from this monitoring effort would be used to assess the significance of the various known drilling related activities and to identify specific pollutants that may pose a concern. In addition, possible fugitive emissions of certain VOCs should be monitored to locate and mitigate emissions, beyond those necessary for worker safety purposes. The Department has identified specific well drilling activities and pollutants which have been found to be related to these activities and recommends that these are included in the near-field monitoring program See Table 6.23.

Table 6.23 - Near-Field Pollutants of Concern for Inclusion in the Near-Field Monitoring Program (New July 2011)

Well Pad and Related Activity	Pollutants of Concern
Drilling and Completing (completion equipment) Engines	1-Hour NO_2 and 24-hour PM2.5
Gas venting (could be potentially mitigated by REC)	BTEX, formaldehyde, H_2S or another odorant.
Glycol dehydrator and condensate tanks at either the well pad or at the compressor station (if wet gas is present)	BTEX, benzene, and formaldehyde.
Leaks and fugitives	Methane and VOC emissions

The near-field local scale monitoring is expected to be performed periodically with field campaigns typically lasting a few days when activities are occurring at the well pad and when the compressor station is operational and operating near maximum gas flow conditions. Since the scope of gas related emissions from one area of operation to another is limited, it is anticipated that after a few intensive near-field monitoring campaigns, adequate and representative data would be gathered to understand the potential impacts of the various phases of gas drilling and production. At that point, the level of effort and the further need for the short term monitoring would be evaluated. In addition to the near-field monitoring, it is anticipated that a similar level of short term monitoring would be conducted on a limited basis at a nearby residential location or in a representative community setting to determine the actual exposure to the public.

However, based on the results from the TCEQ and PADEP monitoring, the potential for finding relatively higher concentrations would likely be in close proximity to the well pad and compressor station.

It is expected that the cost and implementation of this monitoring would be the responsibility of industry. To carry out this monitoring plan, a specific set of monitoring equipment and procedures would be necessary. Some of these deviate from the "traditional" compliance oriented monitoring plans; for example, due to the relatively short term and intensive monitoring required at various locations of activities, the suggested approach would be to operate a mobile equipped unit. Department monitoring staff has longstanding expertise in conducting this type of monitoring over the last two decades. The most recent local-scale monitoring project carried out by the Department was the Tonawanda Community Air Quality Monitoring project.

As an alternative to industry implementing this monitoring plan in a repetitive company by company stepwise fashion as gas development progresses, it is the Department 's preference that the monitoring be undertaken by the Department's Division of Air Resources monitoring staff. However, this alternative cannot be carried out with current Department staff or equipment and would only be possible with additional staff and equipment resources. This alternative is preferred from a number of standpoints, including:

1) Overall program cost would be reduced because each operator would not be responsible for their own monitoring program. Even if the operators are able to hire a common consultant, there would be complexities in allocation the work to various locations;

2) The Department would not have to "oversee" contractor work hired either by industry or by the Department;

3) The timing and production of data analysis would be simplified and reports would be under the Department's control;

4) The Department can utilize certain existing monitor sites for the regional monitoring program;

5) The central coordination would minimize the overall costs of the monitoring; and

6) The Department would have the ability to monitor near the compressor stations which might not be within the control of the drilling operators.

If the Department was to receive the necessary funding and staff to conduct the monitoring, the following table identifies some of the specifics associated with the expected level of monitoring.

Table 6.24 - Department Air Quality Monitoring Requirements for Marcellus Shale Activities (New July 2011)

Monitoring Parameters	Purpose of Monitoring	Proposed Scheme and Instrumentation Needs.
Regional scale O_3, PM2.5, NO_2 and add toxics.	To assess the impact of regional VOC and NO_x emissions on Ozone and PM2.5 levels.	Add a Department monitoring trailer to a new site in Binghamton, plus add toxics at existing Pinnacle site and the new site.
Local/near field monitoring for BTEX, methane, formaldehyde, sulfur (plus O_3, PM2.5 and NO_2)	To assess impacts close-by to well pads, compressor stations and associated equipment (e.g. glycol dehydrator, condensate tanks). Also, limited follow-up in nearby communities.	Purpose-built vehicle with generators as a mobile laboratory. A less desirable alternative is a "stationary" trailer which would need days for initialization.
Intermittent methane and VOC leaks from sources (e.g. fugitive)	To detect and initiate company mitigation of fugitive leaks.	Forward Looking Infrared (FLIR) cameras- one for routine inspections, second to respond to complaints.
"Saturated" BTEX and other VOC species monitoring	To verify the spatial extent of the mobile monitoring results.	Manually operated canister samplers which can be analyzed for 1 to 24-hour concentrations of various toxics.

This monitoring would be the minimum level of effort necessary to properly characterize the air quality in the affected areas for the pollutants which have been identified as possibly requiring mitigation measures or having an effect due to regional emissions. In developing the monitoring approach, Department staff has reviewed the results of the monitoring conducted by TCEQ and PADEP to learn from their experiences, as well as from our own toxics monitoring experiences. To that end, it was determined that a mobile unit with the necessary equipment which would best perform the monitoring for both near-field and representative community based areas. The use of an open path Fourier-transform Infrared (FTIR) spectroscopy used in the PADEP study was evaluated, but deemed unnecessary due to the fact that the mobile unit would be detecting the same pollutants at lower more health relevant detection levels. To overcome the potential concern with spatial representativeness of the near-field monitoring program, the Department recommends augmenting the mobile vehicle with manually placed canisters which could be used on a limited basis to provide a wider areal coverage during the various activities and as a secondary confirmation of the mobile unit results.

The monitoring plan outlined above would be used to address public concerns with the actual pollutant levels in the areas undergoing drilling activities. In addition, it could assist in the identification of the level of conservatism used in the emission estimates for the well pads, the Marcellus area region, and modeling analysis which have been noted as concerns.

6.5.5 Permitting Approach to the Well Pad and Compressor Station Operations

The discussions in subsection 6.5.1.9 of the regulatory applicability section outline the approach which the Department has determined is in line with regulatory permitting requirements and which best address the issues surrounding the air permitting of the three phases of gas drilling, completion and production. The use of the compressor station air permit application process to determine the regulatory disposition and necessary control measures on a case-by-case basis is in keeping with the approach taken throughout the country, as affirmed by EPA in a number of instances. This review process would allow the proper determination of the applicable regulations to both the compressor station and all associated well operations in defining the facility to which the requirements should apply. In concert with the strict operational restrictions determined in the modeling section necessary for the drilling and completion equipment engines, the self-imposed operational and emission limits put forth by industry would assure compliance

with all applicable standards. To further assure that these restrictions are adhered to for all well operations, a set of necessary conditions identified in Section 7.5.3 and Appendix 10 will be included in DMN well permits.

DMN Well Drilling Permit Process Requirements

Based on industry's self-imposed limitations on operations and the Department's determination of conditions necessary to avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, mitigation noted in Chapter 7 would be imposed in the well permitting process.

6.6 Greenhouse Gas Emissions

On July 15, 2009, the Department's Office of Air, Energy and Climate issued its *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*.[106] The policy reflected in the guide is used by Department staff in reviewing an environmental impact statement (EIS) when the Department is the lead agency under SEQRA and energy use or GHG emissions have been identified as significant in a positive declaration, or as a result of scoping, and, therefore, are required to be discussed in an EIS. Following is an assessment of potential GHG emissions for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing.

SEQRA requires that lead agencies identify and assess adverse environmental impacts, and then mitigate or reduce such impacts to the extent they are found to be significant. Consistent with this requirement, SEQRA can be used to identify and assess climate change impacts, as well as the steps to minimize the emissions of GHGs that cause climate change. Many measures that would minimize emissions of GHGs would also advance other long-established State policy goals, such as energy efficiency and conservation; the use of renewable energy technologies; waste reduction and recycling; and smart and sustainable economic growth. The *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement* is

[106] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

not the only State policy or initiative to promote these goals; instead, it furthers these goals by providing for consideration of energy conservation and GHG emissions within EIS reviews.[107]

The goal of this analysis is to characterize and present an estimate of GHG emissions for the siting, drilling and completion of 1) single vertical well, 2) single horizontal well, 3) four-well pad (i.e., four horizontal wells at the same site), and respective first-year and post first-year emissions of CO_2, and other relative GHGs, as both short tons and as carbon dioxide equivalents (CO_2e) expressed in short tons, for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. In addition, the major contributors of GHGs are to be identified and potential mitigation measures offered.

6.6.1 Greenhouse Gases

The two most abundant gases in the atmosphere, nitrogen (comprising 78% of the dry atmosphere) and oxygen (comprising 21%), exert almost no greenhouse effect. Instead, the greenhouse effect comes from molecules that are more complex and much less common. Water vapor is the most important greenhouse gas, and CO_2 is the second-most important one.[108] Human activities result in emissions of four principal GHGs: CO_2, methane (CH_4), nitrous oxide (N_2O) and the halocarbons (a group of gases containing fluorine, chlorine and bromine). These gases accumulate in the atmosphere, causing concentrations to increase with time. Many human activities contribute GHGs to the atmosphere.[109] Whenever fossil fuel (coal, oil or gas) burns, CO_2 is released to the air. Other processes generate CH_4, N_2O and halocarbons and other GHGs that are less abundant than CO_2, but even better at retaining heat.[110]

6.6.2 Emissions from Oil and Gas Operations

GHG emissions from oil and gas operations are typically categorized into 1) vented emissions, 2) combustion emissions and 3) fugitive emissions. Below is a description of each type of emission. For the noted emission types, no distinction is made between direct and indirect emissions in this analysis. Further, this GHG discussion is focused on CO_2 and CH_4 emissions

[107] http://www.dec.ny.gov/docs/administration_pdf/eisghgpolicy.pdf.

[108] http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

[109] http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_FAQs.pdf.

[110] http://www.dec.ny.gov/energy/44992.html.

as these are the most prevalent GHGs emitted from oil and gas industry operations, including expected exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. Virtually all companies within the industry would be expected to have emissions of CO_2 - and, to a lesser extent, CH_4 and N_2O - since these gases are produced through combustion. Both CH_4 and CO_2 are also part of the materials processed by the industry as they are produced in varying quantities, from oil and gas wells. Because the quantities of N_2O produced through combustion are quite small compared to the amount of CO_2 produced, CO_2 and CH_4 are the predominant oil and gas industry GHGs.[111]

6.6.2.1 Vented Emissions

Vented sources are defined as releases resulting from normal operations. Vented emissions of CH_4 can result from the venting of natural gas encountered during drilling operations, flow from the flare stack during the initial stage of flowback, pneumatic device vents, dehydrator operation, and compressor start-ups and blowdowns. Oil and natural gas operations are the largest human-made source of CH_4 emissions in the United States and the second largest human-made source of CH_4 emissions globally. Given methane's role as both a potent greenhouse gas and clean energy source, reducing these emissions can have significant environmental and economic benefits. Efforts to reduce CH_4 emissions not only conserve natural gas resources but also generate additional revenues, increase operational efficiency, and make positive contributions to the global environment.[112]

6.6.2.2 Combustion Emissions

Combustion emissions can result from stationary sources (e.g., engines for drilling, hydraulic fracturing and natural gas compression), mobile sources and flares. Carbon dioxide, CH_4, and N_2O are produced and/or emitted as a result of hydrocarbon combustion. Carbon dioxide emissions result from the oxidation of the hydrocarbons during combustion. Nearly all of the fuel carbon is converted to CO_2 during the combustion process, and this conversion is relatively independent of the fuel or firing configuration. Methane emissions may result due to incomplete

[111] IPIECA and API, December 2003, p. 5-2.

[112] http://www.epa.gov/gasstar/documents/ngstar_mktg-factsheet.pdf.

combustion of the fuel gas, which is emitted as unburned CH_4. Overall, CH_4 and N_2O emissions from combustion sources are significantly less than CO_2 emissions.[113]

6.6.2.3 Fugitive Emissions

Fugitive emissions are defined as unintentional gas leaks to the atmosphere and pose several challenges for quantification since they are typically invisible, odorless and not audible, and often go unnoticed. Examples of fugitive emissions include CH_4 leaks from flanges, tube fittings, valve stem packing, open-ended lines, compressor seals, and pressure relief valve seats. Three typical ways to quantify fugitive emissions at a natural gas industry site are 1) facility level emission factors, 2) component level emission factors paired with component counts, and 3) measurement studies.[114] In the context of GHG emissions, fugitive sources within the upstream segment of the oil and gas industry are of concern mainly due to the high concentration of CH_4 in many gaseous streams, as well as the presence of CO_2 in some streams. However, relative to combustion and process emissions, fugitive CH_4 and CO_2 contributions are insignificant.[115]

6.6.3 Emissions Source Characterization

Emissions of CO_2 and CH_4 occur at many stages of the drilling, completion and production phases, and can be dependent upon technologies applied and practices employed. Considerable research – sponsored by the API, the Gas Research Institute (GRI) and the EPA – has been directed towards developing relatively robust emissions estimates at the national level.[116] The analytical techniques and emissions factors, and mitigation measures, developed by the these agencies were used to evaluate GHG emissions from activities necessary for the exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high-volume hydraulic fracturing.

In 2009, NYSERDA contracted ICF International (ICF) to assist with supporting studies for the development of the SGEIS. ICF's work included preparation of a technical analysis of potential impacts to air in the form of a report finalized in August 2009.[117] The report, which includes a

[113] API 2004; amended 2005. p 4-1.
[114] ICF Task 2, 2009, p. 21.
[115] IPIECA and API, December 2003., p. 5-6.
[116] New Mexico Climate Change Advisory Group, November 2006, , pp. D-35.
[117] ICF Task 2, 2009.

discussion on GHGs, provided the basis for the following in-depth analysis of potential GHGs from the subject activity. ICF's referenced study identifies drilling, completion and production operations and equipment that contribute to GHG emission and provides corresponding emission rates, and this information facilitated the following analysis by identifying system components on an operational basis. As such, wellsite operations considered in the SGEIS were divided into the following phases for this GHG analysis:

- Drilling Rig Mobilization, Site Preparation and Demobilization;
- Completion Rig Mobilization and Demobilization;
- Well Drilling;
- Well Completion (includes hydraulic fracturing and flowback); and
- Well Production.

Transport of materials and equipment is an integral component of the oil and gas industry. Simply stated, a well cannot be drilled, completed or produced without GHGs being emitted from mobile sources. The estimated required truck trips per well and corresponding fuel usage for the below noted phases requiring transportation, except well production, were provided by industry.[118]

Drilling Rig Mobilization, Site Preparation and Demobilization

Drill Pad and Road Construction Equipment
Drilling Rig
Drilling Fluid and Materials
Drilling Equipment (casing, drill pipe, etc.)

Completion Rig Mobilization and Demobilization

Completion Rig

[118] ALL Consulting, 2011, Exhibits 19B, 20B.

Well Completion

Completion Fluid and Materials
Completion Equipment (pipe, wellhead)
Hydraulic Fracturing Equipment (pump trucks, tanks)
Hydraulic Fracturing Water
Hydraulic Fracturing Sand
Flow Back Water Removal

Well Production[119]

Production Equipment (5 – 10 Truckloads)

Mileage estimates for both light duty and heavy duty trucks were used to determine total fuel usage associated with site preparation and rig mobilizations, well completion and well production activities. As further discussed below, when actual or estimated fuel use data was not available, VMT formed the basis for estimating CO_2 emissions.

Three distinct types of well projects were evaluated for GHG emissions as follows:

- Single-Well Vertical Project;
- Single-Well Horizontal Project; and
- Four -Well Pad (i.e., four horizontal wells at the same site).

For rig and equipment mobilizations for each of the project types noted above, it was assumed that all work involving the same activity would be finished before commencing a different activity. In other words, the site would be prepared and the drilling rig mobilized, then all wells (i.e., one or four) would be drilled, followed by the completion of all wells (i.e., one or four) and subsequent production of all wells (i.e., one or four). A number of operators have indicated to the Department that activities on multi-well pads would be conducted sequentially, whenever possible, to realize the greatest efficiency but the actual order of work events and number of wells on a given pad may vary. Nevertheless, four wells was the number of wells selected for

[119] NTC Consultants. *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs*, September 2009.

the multi-well pad GHG analysis because industry indicated that number would be the maximum number of wells drilled at the same site in any 12 consecutive months.

Stationary engines and equipment emit CO_2 and/or CH_4 during drilling and completion operations. However, most are not typically operating at their full load every hour of each day while on location. For example, certain engines may be shut down completely or operating at a very low load during bit trips, geophysical logging or the running of casing strings. Consequently, for the purpose of this analysis and as noted in Table 6.25 and Table 6.26 below, it was assumed that engines and equipment for drilling and completion operations generally operate at full load for 50% of their time on location. Exceptions to this included engines and equipment used for hydraulic fracturing and flaring operations. Instead of relying on an assumed time frame for operation for the many engines that drive the high-pressure high-volume pumps used for hydraulic fracturing, an average of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring Pennsylvania and West Virginia was used.[120] In addition, flaring operations and associated equipment were assumed to be operating at 100% for the entire estimated flaring period.

Table 6.25 - Assumed Drilling & Completion Time Frames for Single Vertical Well (New July 2011)

Operation	**Estimated Duration (days / hrs.)**	**Assumed Full Load Operational Duration for Related Equipment (days / hrs.)**
Well Drilling	13 / 312	6½ / 156
Completion	¼ / 6 (hydraulic fracturing) 1 / 24 (rig)	¼ / 6 (hydraulic fracturing) ½ / 12 (rig)
Flaring	3 / 72	3 / 72

Table 6.26 - Assumed Drilling & Completion Time Frames for Single Horizontal Well (Updated July 2011)

Operation	**Estimated Duration (days / hrs.)**	**Assumed Full Load Operational Duration for Related Equipment (days / hrs.)**
Well Drilling	25 / 600	12½ / 300
Completion	2 / 48 (hydraulic fracturing) 2 / 48 (rig)	2 / 48 (hydraulic fracturing) 1 / 24 (rig)
Flaring	3 / 72	3 / 72

[120] ALL Consulting, 2009, Table 11, p. 10.

Stationary engines and equipment also emit CO_2 and/or CH_4 during production operations. In contrast to drilling and completion operations, production equipment generally operates around the clock (i.e., 8,760 hours per year) except for scheduled or intermittent shutdowns.

6.6.4 Emission Rates

The primary reference for emission rates for stationary production equipment considered in this analysis is the GRI's *Methane Emissions from the Natural Gas Industry*. Table GHG-1 "Emission Rates for Well Pad" in Appendix 19, Part A shows greenhouse gas (GHG) emission rates for associated equipment used during natural gas well production operations. Table GHG-1 was adapted from an analysis of potential impacts to air performed in 2009 by ICF International under contract to NYSERDA. GHG emission rates for flaring during the completion phase were also obtained from the ICF International study. The emission factors in the table are typically listed in units of pounds emitted per hour for each piece of equipment or are based on gas throughput. The emissions rates specified in the table were used to determine the annual emissions in tons for each stationary source, except for engines used for rig and hydraulic fracturing engines, using the below equation. The *Activity Factor* represents the number of pieces of equipment or occurrences.

$$\text{Emissions (tons/yr.)} = \text{Emissions Factor (lbs./hr)} \times \text{Duration (yr.)} \times (8{,}760 \text{ hrs/yr.}) \times (1 \text{ US short ton}/2{,}000 \text{ lbs}) \times \text{Activity Factor}$$

A material balance approach based on fuel usage and fuel carbon analysis, assuming complete combustion (i.e., 100% of the fuel carbon combusts to form CO_2), is the preferred technique for estimating CO_2 emissions from stationary combustion engines.[121] This approach was used for the engines required for conducting drilling and hydraulic fracturing operations. Actual fuel usage, such as the volume of fuel needed to perform hydraulic fracturing, was used where available to determine CO_2 emissions. For emission sources where actual fuel usage data was not available, estimates were made based on the type and use of the engines needed to perform the work. For GHG emission from mobile sources, such as trucks used to transport equipment and materials, where fuel use data was not available VMT was used to estimate fuel usage. The calculated fuel used was then used to determine estimated CO_2 emissions from the mobile

[121] API, 2004; amended 2005., p. 4-3.

sources. A sample calculation showing this methodology for determining combustion emissions (CO_2) from mobile sources is included as Appendix 19, Part B.

Carbon dioxide and CH_4 emissions, the focus of this analysis, are produced from the flaring of natural gas during the well completion phase. Emission rates and calculations from the flaring of natural gas are presented in the previously mentioned 2009 ICF International report. In that report, it was determined that approximately 576 tons of CO_2 and 4.1 tons of CH_4 are emitted each day for a well being flared at a rate of 10 MMcf/d. ICF International's calculations assumed that 2% of the gas by volume goes uncombusted. ICF International relied on an average composition of Marcellus Shale gas to perform its emissions calculations.

6.6.5 Drilling Rig Mobilization, Site Preparation and Demobilization

Transportation combustion sources are the engines that provide motive power for vehicles used as part of wellsite operations. Transportation sources may include vehicles such as cars and trucks used for work-related personnel transport, as well as tanker trucks and flatbed trucks used to haul equipment and supplies. Light-duty and heavy-duty vehicles use is accounted for and differentiated in this analysis.[122] The fossil fuel-fired internal combustion engines used in transportation are a significant source of CO_2 emissions. Small quantities of CH_4 and N_2O are also emitted based on fuel composition, combustion conditions, and post-combustion control technology. Estimating emissions from mobile sources is complex, requiring detailed information on the types of mobile sources, fuel types, vehicle fleet age, maintenance procedures, operating conditions and frequency, emissions controls, and fuel consumption. The EPA has developed a software model, MOBILE Vehicle Emissions Modeling Software, that accounts for these factors in calculating exhaust emissions (CO_2, HC, CO, NO_x, particulate matter, and toxics) for gasoline and diesel fueled vehicles. The preferred approach for estimating CH_4 and N_2O emissions from mobile sources is to assume that these emissions are negligible compared to CO_2.[123]

An alternative to using modeling software for determining CO_2 emissions for general characterization is to estimate GHG emissions using VMT, which includes a determination of

[122] ALL Consulting, 2011, Exhibits 19B, 20B.

[123] API, 2004; amended 2005, pp. 4-32, 4-33.

estimated fuel usage, or use a fuel usage estimate if available. These methodologies were used to calculate the tons of CO_2 emissions from mobile sources related to the subject activity. A sample CO_2 emissions calculation using fuel consumption is shown in Appendix 19, Part B. Table GHG-2 in Appendix 19, Part A includes CO_2 emission estimates for transporting the equipment necessary for constructing the access road and well pad, and moving the drilling rig to and from the well site. For horizontal wells, Table GHG-2 assumes that the same rig stays on location and drills both the vertical and lateral portions of a well.

As previously mentioned, because all activities are assumed to be performed sequentially requiring a single rig move, the GHG emissions presented in Table GHG-2 are representative of either a one-well project or four-well pad. As shown in the table, approximately 15 tons of CO_2 emissions are expected from a mobilization of the drilling rig, including site preparation. Site preparation for a single vertical well would be less due to a smaller pad size but for simplification site preparation is assumed the same for all well scenarios considered. The calculated CO_2 emissions shown in this table and all other tables included in this analysis have been rounded up to the next whole number.

6.6.6 Completion Rig Mobilization and Demobilization

Table GHG-3 in Appendix 19, Part A includes CO_2 emission estimates for transporting the completion rig to and from the wellsite. As shown in the table, approximately 4 tons of CO_2 emissions may be generated from a mobilization of the completion rig. For simplification, tramsportation associated with rig mobilization for the completion rig was assumed to be the same as that for the drilling rig. It is acknowledged that this assumption is conservative.

6.6.7 Well Drilling

Vertical wells may be drilled entirely using compressed air as the drilling fluid or possibly with air for a portion of the well and mud in the target interval. For horizontal wells, drilling activities would typically include the drilling of the vertical and lateral portions of a well using compressed air and mud (or other fluid) respectively. Regardless of the type of well, drilling activities are dependent on the internal combustion engines needed to supply electrical or hydraulic power to: 1) the rotary table or topdrive that turns the drillstring, 2) the drawworks, 3) air compressors, and 4) mud pumps. Carbon dioxide emissions occur from the engines needed to

perform the work required to spud the well and reach its total depth. Table GHG-4 in Appendix 19, Part A includes estimates for CO_2 emissions generated by these stationary sources. As shown in the table, approximately 83 tons of CO_2 emissions per single vertical well would be generated as a result of drilling operations. Tables GHG-5 and GHG-6 show CO_2 emissions of 194 tons and 776 tons for the drilling of a single horizontal well and four-well pad, respectively.

6.6.8 Well Completion

Well completion activities include 1) transport of required equipment and materials to and from the site, 2) hydraulic fracturing of the well, 3) a flowback period, including flaring, to clean the well of fracturing fluid and excess sand used as the hydraulic fracturing proppant, 4) drilling out of hydraulic fracturing stage plugs and the running of production tubing by the completion rig and 5) site reclamation. Mobile and stationary engines, and equipment used during the aforementioned completion activities emit CO_2 and/or CH_4. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A include estimates of individual and total emissions of CO_2 and CH_4 generated during the completion phase for a single vertical well, single horizontal well and a four-well pad, respectively.

Similar to the above discussion regarding mobilization and demobilization of rigs, transport of equipment and materials, which results in CO_2 emissions, is necessary for completion of wells. The results of this evaluation are shown in Tables GHG-7, GHG-8 and GHG-9 of Appendix 19, Part A. GHG emissions of CO_2 from transportation provided in the tables rely on estimated fuel usage for both light and heavy trucks. A sample calculation for determining CO_2 emissions based on fuel usage is shown in Appendix 19, Part B. As shown in Table GHG-7, transportation related completion-phase emissions of CO_2 for a single vertical well is estimated at 12 tons. For the single horizontal well and the four-well pad (see Table GHG-8 and GHG-9), transportation related completion-phase CO_2 emissions are estimated at 31 to 115 tons, respectively.

Hydraulic fracturing operations require the use of many engines needed to drive the high-pressure high-volume pumps used for hydraulic fracturing (see multiple “Pump trucks” in the Photos Section of Chapter 6). As previously discussed and shown in Table GHG-5 in Appendix 19, Part A, an average (i.e., 29,000 gallons of diesel) of the fuel usage from eight Marcellus Shale hydraulic fracturing jobs performed on horizontally drilled wells in neighboring

Pennsylvania and West Virginia was used to calculate the estimated amount of CO_2 emitted during hydraulic fracturing. Fuel usage for the single vertical well was prorated to account for less time pumping (i.e., one-eighth). Tables GHG-7, GHG-8 and GHG-9 show that approximately 54 tons and 325 tons of CO_2 emissions per well would be generated as a result of single vertical well and single horizontal well hydraulic fracturing operations, respectively.

Subsequent to hydraulic fracturing in which fluids are pumped into the well, the direction of flow is reversed and flowback waters, including reservoir gas, are routed through separation equipment to remove excess sand, then through a line heater and finally through a separator to separate water and gas on route to the flare stack. Generally speaking, flares in the oil and gas industry are used to manage the disposal of hydrocarbons from routine operations, upsets, or emergencies via combustion.[124] However, only controlled combustion events would be flared through stacks used during the completion phase for the Marcellus Shale and other low-permeability gas reservoirs. A flaring period of 3 days was considered for this analysis for the vertical and horizontal wells respectively although the actual period could be either shorter or longer.

Initially, only a small amount of gas recovered from the well is vented for a relatively short period of time. If a sales line is available, once the flow rate of gas is sufficient to sustain combustion in a flare, the gas is flared until there is sufficient flowing pressure to flow the gas into the sales line.[125] Otherwise, the gas is flared and combusted at the flare stack. As shown in Tables GHG-7 and GHG-8 in Appendix 19, Part A, approximately 1,728 tons of CO_2 and 12 tons of CH_4 emissions are generated per well during a three-day flaring operation for a 10 Mmcf/d flowrate. As mentioned above, the actual duration of flaring may be more or less. The CH_4 emissions during flaring result from 2% of the gas flow remaining uncombusted. ICF computed the primary CO_2 and CH_4 emissions rates using an average Marcellus gas composition.[126] The duration of flaring operations may be shortened by using specialized gas recovery equipment, provided a gas sales line is in place at the time of commencing flowback from the well. Recovering the gas to a sales line, instead of flaring it, is called a REC and is

[124] API, 2004; amended 2005. p. 4-27.

[125] ALL Consulting, 2009. p. 14.

[126] ICF Task 2, 2009, p. 28.

further discussed in Chapter 7 as a possible mitigation measure, and in Appendix 25 (REC Executive Summary included by ICF for its work in support of preparation of the SGEIS).

The final work conducted during the completion phase consists of using a completion rig, possibly a coiled-tubing unit, to drill out the hydraulic fracturing stage plugs and run the production tubing in the well. Assuming a fuel consumption rate of 25 gallons per hour and an operating period of 24 hours, the rig engines needed to perform this work emit CO_2 at a rate of approximately 4 tons per single vertical well and 7 tons per single horizontal well. No stage plug milling is normally required and less tubing is run for a single vertical well as compared to a horizontal well, and less completion time results in less GHG emissions. After the completion rig is removed from the site, earth moving equipment would be transported to the site and the area would be reworked and graded, which adds another 9 tons of CO_2 emissions for either a one-well project or four-well pad. Tables GHG-7, GHG-8 and GHG-9 in Appendix 19, Part A show CO_2 emissions from these final stages of work during the well completion phase for a single vertical well, single horizontal well and a four-well pad, respectively. Site work for a single vertical well would be less due to a smaller pad size but for simplification, site work is assumed the same for all well scenarios considered.

6.6.9 Well Production

GHGs from the well production phase include emissions from transporting the production equipment to the site and then operating the equipment necessary to process and flow the natural gas from the well into the sales line. Carbon dioxide emissions are generated from the trucks needed to haul the production equipment to the wellsite. As previously stated, GHG emissions of CO_2 from transportation rely on estimated fuel usage where available or VMT, which ultimately requires a determination of fuel usage. Such emissions associated with well production activities, include those from transportation related to the removal of production brine, as discussed below. The estimated VMT for each case was then used to determine approximate fuel use and resultant CO_2 emissions. As shown in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A, transportation needed to haul production equipment to a wellsite for a one-well project and a four-well pad results in first-year CO_2emissions of approximately 3 tons and 11 tons, respectively.

Well production may require the removal of production brine from the site which, if present, is stored temporarily in plastic, fiberglass or steel brine production tanks, and then transported off-site for proper disposal or reuse. The trucks used to haul the production brine off-site generate CO_2 emissions. Transportation estimates were used to determine CO_2 emissions from each well development scenario, and emission estimates are presented in Tables GHG-10, GHG-11 and GHG-12 in Appendix 19, Part A. Table GHG-10 presents CO_2 and CH_4 emissions for a one-well project for the period of production remaining in the first year after the single vertical well is drilled and completed. For the purpose of this analysis, the duration of production for a single vertical well in its first year was estimated at 349 days (i.e., 365 days minus 16 days to drill & complete) and for a single horizontal well in its first year 331 days (i.e., 365 days minus 34 days to drill & complete). Table GHG-13 shows estimated annual emissions for a single vertical well or single horizontal well commencing in year two, and producing for a full year. Table GHG-12 presents CO_2 and CH_4 emissions for a four-well pad for the period of production remaining in the first year after all ten wells are drilled and completed. For the purpose of this analysis, the duration of production for the ten-well pad in its first year was estimated at 229 days (i.e., 365 days minus 136 days to drill & complete). Instead of work phases occurring sequentially, actual operations may include concurrent well drilling and producing activities on the same well pad. Table GHG-14 shows estimated annual emissions for a four-well project commencing in year two, and producing for a full year.

GHGs in the form of CO_2 and CH_4 are emitted during the well production phase from process equipment and compressor engines. Glycol dehydrators, specifically their vents, which are used to remove moisture from the natural gas in order to meet pipeline specifications and dehydrator pumps, generate vented CH_4 emissions, as do pneumatic device vents which operate by using gas pressure. Compressors used to increase the pressure of the natural gas so that the gas can be put into the sales line typically are driven by engines which combust natural gas. The compressor engine's internal combustion cycle results in CO_2 emissions while compression of the natural gas generates CH_4 fugitive emissions from leaking packing systems. All packing systems leak under normal conditions, the amount of which depends on cylinder pressure, fitting and alignment of the packing parts, and the amount of wear on the rings and rod shaft.[127] The emission rates

[127] http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.

presented in Table GHG-1, Appendix 19, Part A "Emission Rates for Well Pad" were used to calculate estimated emissions of CO_2 and CH_4 for each stationary source for a single vertical well, single horizontal well and four-well pad using the equation noted in Section 6.6.4 and the corresponding Activity Factors shown in Tables GHG-10, GHG-11, GHG-12, GHG-13 and GHG-14 in Appendix 19, Part A. Based on the specified emissions rates for each piece of production equipment, the calculated annual GHG emissions presented in the Tables show that the compressors, glycol dehydrator pumps and vents contribute the greatest amount of CH_4 emissions during the this phase, while operation of pneumatic device vents also generates vented CH_4 emissions. The amount of CH_4 vented in the compressor exhaust was not quantified in this analysis but, according to Volume II: Compressor Driver Exhaust, of the 1996 Final Report on Methane Emissions from the Natural Gas Industry, compressor exhaust accounts for "about 7.9% of methane emissions from the natural gas industry."

6.6.10 Summary of GHG Emissions

As previously discussed, wellsite operations were divided into the following five phases to facilitate GHG analysis: 1) Drilling Rig Mobilization, Site Preparation and Demobilization, 2) Completion Rig Mobilization and Demobilization, 3) Well Drilling, 4) Well Completion (includes hydraulic fracturing and flowback) and 5) Well Production. Each of these phases was analyzed for potential GHG emissions, with a focus on CO_2 and CH_4 emissions. The results of these phase-specific analyses for a single vertical well, single horizontal well and four-well pad are detailed in Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A. In addition, the tables include estimates of GHG emissions occurring in the first year and each producing year thereafter for each project type.

The goal of this review is to characterize and present an estimate of total annual emissions of CO_2, and other relative GHGs, as both short tons and CO_2e expressed in short tons for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing. To determine CO_2e, each greenhouse gas has been assigned a number or factor that reflects its global warming potential (GWP). The GWP is a measure of a compound's ability to trap heat over a certain lifetime in the atmosphere, relative to the effects of the same mass of CO_2 released over the same time period. Emissions expressed in equivalent terms highlight the contribution of the various gases to the overall inventory.

Therefore, GWP is a useful statistical weighting tool for comparing the heat trapping potential of various gases.[128] For example, Chesapeake Energy Corporation's July 2009 Fact Sheet on greenhouse gas emissions states that CO_2 has a GWP of 1 and CH_4 has a GWP of 23, and that this comparison allows emissions of greenhouse gases to be estimated and reported on an equal basis as CO_2e.[129] However, GWP factors are continually being updated, and for the purpose of this analysis as required by the Department's 2009 *Guide for Assessing Energy Use and Greenhouse Gas Emissions in an Environmental Impact Statement*, the 100-Year GWP factors provided in below Table 6.27 were used to determine total GHGs as CO_2e. Tables GHG-15, GHG-16, GHG-17, GHG-18 and GHG-19 in Appendix 19, Part A include a summary of estimated CO_2 and CH_4 emissions from the various operational phases as both short tons and as CO_2e expressed in short tons.

Table 6.27 - Global Warming Potential for Given Time Horizon[130]

Common Name	Chemical Formula	20-Year GWP	100-Year GWP	500-Year GWP
Carbon dioxide	CO_2	1	1	1
Methane	CH_4	72	25	7.6

Table 6.28 is a summary of total estimated CO_2 and CH_4 emissions for exploration and development of the Marcellus Shale and other low-permeability gas reservoirs using high volume hydraulic fracturing, as both short tons and as CO_2e expressed in short tons. The below table includes emission estimates for the first full year in which drilling is commenced and subsequent producing years for each project type (i.e., single vertical well, single horizontal well and four-well pad), sourcing of equipment and materials.

The noted CH_4 emissions occurring during the production process and compression cycle represent ongoing annual GHG emissions. As noted above, for the purpose of assessing GHG impacts, each ton of CH_4 emitted is equivalent to 25 tons of CO_2. Thus, because of its recurring nature, the importance of limiting CH_4 emissions throughout the production phase cannot be overstated.

[128] API, August 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

[129] Chesapeake Energy Corp., July 2009. *Greenhouse Gas Emissions and Reductions* Fact Sheet.

[130] Adapted from Forster, et al. 2007, Table 2.14. Chapter 2, p. 212. http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf.

Table 6.28 - Summary of Estimated Greenhouse Gas Emissions (Revised July 2011)

	CO_2 (tons)	**CH_4 (tons)**	**CH_4 Expressed as CO_2e (tons)[131]**	**Total Emissions from Proposed Activity CO_2e (tons)**
Estimated First-Year Green House Gas Emissions from Single Vertical Well	8,660	246	6,150	14,810
Estimated First-Year Green House Gas Emissions from Single Horizontal Well	8,761	240	6,000	14,761
Estimated First-Year Green House Gas Emissions from Four-Well Pad	13,901	402	10,050	23,951
Estimated Post First-Year Annual Green House Gas Emissions from Single Vertical or Single Horizontal Well	6,164	244	6,100	12,264
Estimated Post First-Year Annual Green House Gas Emissions from Four-Well Project	6,183	565	14,125	20,300

[131] Equals CH_4 (tons) multiplied by 25 (100-Year GWP).

Some uncertainties remain with respect to quantifying GHG emissions for the subject activity. For the potential associated GHG emission sources, there are multiple options for determining the emissions, often with different accuracies. Table 6.29, which was prepared by the API, illustrates the range of available options for estimating GHG emissions and associated considerations. The two types of approaches used in this analysis were the "Published emission factors" and "Engineering calculations" options. These approaches, as performed, rely heavily on a generic set of assumptions with respect to duration and sequencing of activities, and size, number and type of equipment for operations that would be conducted by many different companies under varying conditions. Uncertainties associated with GHG emission determinations can be the result of three main processes noted below.[132]

- Incomplete, unclear or faulty definitions of emission sources;
- Natural variability of the process that produces the emissions; and
- Models, or equations, used to quantify emissions for the process or quantity under consideration.

Nevertheless, while the results of potential GHG emissions presented in above Table 6.15 may not be precise for each and every well drilled, the real benefit of the emission estimates comes from the identification of likely major sources of CO_2 and CH_4 emissions relative to the activities associated with gas exploration and development. It is through this identification and understanding of key contributors of GHGs that possible mitigation measures and future efforts can be focused in New York. Following, in Chapter 7, is a discussion of possible mitigation measures geared toward reducing GHGs that would be required, with emphasis on CH_4.

[132] API, August 2009, p. 3-30. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

Table 6.29 - Emission Estimation Approaches – General Considerations[133]

Types of Approaches	General Considerations
Published emission factors	· Accounts for average operations or conditions · Simple to apply · Requires understanding and proper application of measurement units and underlying standard conditions · Accuracy depends on the representativeness of the factor relative to the actual emission source · Accuracy can vary by GHG constituents (i.e., CO_2, CH_4, and N_2O)
Equipment manufacturer emission factors	· Tailored to equipment-specific parameters · Accuracy depends on the representativeness of testing conditions relative to actual operating practices and conditions · Accuracy depends on adhering to manufacturers inspection, maintenance and calibration procedures · Accuracy depends on adjustment to actual fuel composition used on-site · Addition of after-market equipment/controls will alter manufacturer emission factors
Engineering calculations	· Accuracy depends on simplifying assumptions that may be contained within the calculation methods · May require detailed data
Process simulation or other computer modeling	· Accuracy depends on simplifying assumptions that may be contained within the computer model methods · May require detailed input data to properly characterize process conditions · May not be representative of emissions that are due to operations outside the range of simulated conditions
Monitoring over a range of conditions and deriving emission factors	· Accuracy depends on representativeness of operating and ambient conditions monitored relative to actual emission sources · Care should be taken when correcting to represent the applicable standard conditions · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Periodic or continuous[a] monitoring of emissions or parameters[b] for calculating emissions	· Accounts for operational and source specific conditions · Can provide high reliability if monitoring frequency is compatible with the temporal variation of the activity parameters · Instrumentation not available for all GHGs or applicable to all sources · Equipment, operating, and maintenance costs must be considered for monitoring equipment
Footnotes and Sources: [a] Continuous emissions monitoring applies broadly to most types of air emissions, but may not be directly applicable nor highly reliable for GHG emissions. [b] Parameter monitoring may be conducted in lieu of emissions monitoring to indicate whether a source is operating properly. Examples of parameters that may be monitored include temperature, pressure and load.	

[133] API August 2009, p. 3-9, http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

6.7 Naturally Occurring Radioactive Materials in the Marcellus Shale

Chapter 4 explains that the Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations, and Chapter 5 provides some sample data from Marcellus Shale cuttings. Activities that have the potential to concentrate these constituents through surface handling and disposal may need regulatory oversight to ensure adequate protection of workers, the general public, and the environment. Gas wells can bring NORM to the surface in the cuttings, flowback fluid and production brine, and NORM can accumulate in pipes and tanks (pipe scale and sludge.) Based upon currently available information it is anticipated that flowback water will not contain levels of NORM of significance, whereas production brine is known to contain elevated NORM levels. Radium-226 is the primary radionuclide of concern from the Marcellus.

Elevated levels of NORM in production brine (measured in picocuries/liter or pCi/L) may result in the buildup of pipe scale containing elevated levels of radium (measured in pCi/g). The amount and concentration of radium in the pipe scale would depend on many conditions, including pressures and temperatures of operation, amount of available radium in the formation, chemical properties, etc. Because the concentration of radium in the pipe scale cannot be measured without removing or disconnecting the pipe, a surrogate method is employed, conducting a radiation survey of the pipe exterior. A high concentration of radium in the scale would result in an elevated radiation exposure level at the pipe's exterior surface (measured in mR/hr) and can be detected with a commonly used survey instrument. The Department of Health would require a radioactive materials license when the radiation exposure levels of accessible piping and equipment are greater than 50 microR/hr (µR/hr). Equipment that exhibits dose rates in excess of this level will be considered to contain processed and concentrated NORM for the purpose of waste determinations.

Oil and gas NORM occurs in both liquid (production brine), solid (pipe scale, cuttings, tank and pit sludges), and gaseous states (produced gas). Although the highest concentrations of NORM are in production brine, it does not present a risk to workers because the external radiation levels are very low. However, the build-up of NORM in pipes and equipment (pipe scale and sludge) has the potential to expose workers handling (cleaning or maintenance) the pipe to increased radiation levels. Also wastes from the treatment of production brines may contain concentrated

NORM and therefore may require controls to limit radiation exposure to workers handling this material as well as to ensure that this material is disposed of in accordance with 6 NYCRR § 380.4.

Radium is the most significant radionuclide contributing to oil and gas NORM. It is fairly soluble in saline water and has a long radioactive half life - about 1,600 years (Table 6.30). Radon gas, which under most circumstances is the main human health concern from NORM, is produced by the decay of radium-226, which occurs in the uranium-238 decay chain. Uranium and thorium, which are naturally occurring parent materials for radium, are contained in mineral phases in the reservoir rock cuttings, but have very low solubility. The very low concentrations and poor water solubility are such that uranium and thorium pose little potential health threat.

Table 6.30 - Radionuclide Half-Lives

Radionuclide	Half-life	Mode of Decay
Ra-226	1,600 years	alpha
Rn-222	3.824 days	alpha
Pb-210	22.30 years	beta
Po-210	138.40 days	alpha
Ra-228	5.75 years	beta
Th-228	1.92 years	alpha
Ra-224	3.66 days	alpha

In addition to exploration and production (E&P) worker protection from NORM exposure, the disposal of NORM-contaminated E&P wastes is a major component of the oil and gas NORM issue. This has attracted considerable attention because of the large volumes of production brine (>109 billion bbl/yr; API estimate) and the high costs and regulatory burden of the main disposal options, which are underground injection in Class II UIC wells and offsite treatment. The Environmental Sciences Division of Argonne National Laboratory has addressed E&P NORM disposal options in detail and maintains a Drilling Waste Management Information System

website that links to regulatory agencies in all oil and gas producing states, as well as providing detailed technical information.

In NYS the disposal of processed and concentrated NORM in the form of pipe scale or water treatment waste is subject to regulation under Part 380. Because disposal of Part 380 regulated waste is prohibited in Part 360 regulated solid waste landfills, this waste would require disposal in out-of-state facilities approved to accept NORM wastes. Disposal facilities that can accept this type of waste include select RCRA C facilities and low-level radioactive waste disposal sites.

6.8 Socioeconomic Impacts[134]

This section provides a discussion of the potential socioeconomic impacts on the Economy, Employment, and Income (Section 6.8.1); Population (Section 6.8.2); Housing (Section 6.8.3); Government Revenues and Expenditures (Section 6.8.4); and Environmental Justice (Section 6.8.5). A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS.

To estimate the socioeconomic impacts associated with the use of high-volume hydraulic fracturing techniques for extracting natural gas, several assumptions must be made about the amount of natural gas development that would occur, the expected rate of development, the length of time over which that development would occur, and the distribution of this development throughout the state.

For the purposes of this SGEIS, the expected rate of development is measured by the number of wells constructed annually. Two different levels of development are analyzed – a low development scenario, and an average development scenario. These development scenarios were developed by the Department based on information the Department had requested from the Independent Oil & Gas Association of New York (IOGA-NY). IOGA-NY started with an estimated average rate of development based on the following assumptions:

[134] Section 6.8, in its entirety, was provided by Ecology and Environment Engineering, P.C., August 2011, and was adapted by the Department.

- Approximately 67% of the area covered by the Marcellus and Utica shale is developable;
- Approximately 90% of wells would be horizontal wells, with an average of 160 acres/well; and
- Approximately 10% of wells would be vertical wells, with an average of 40 acres/well.

For the low rate of development, DEC assumed a rate of 25% of IOGA-NY's estimated average rate of development.

Table 6.31 provides a highlight of the major assumptions for each of these scenarios. In both scenarios, the maximum build-out of new wells is assumed to be completed in Year 30. Under the low development scenario, a total of 9,461 horizontal wells and 1,071 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). Under the average development scenario a total of 37,842 horizontal wells and 4,284 vertical wells are assumed to be constructed at maximum build-out (e.g., Year 30). The high development scenario, which is analyzed in the Economic Assessment Report, assumes a total of 56,508 horizontal and 6,273 vertical wells are constructed at maximum build-out (e.g., Year 30).

Analysis of the high development scenario is not included in this socioeconomic section of the SGEIS in order to be conservative in assessing the positive potential economic benefits of high-volume hydraulic fracturing in New York State. The high development scenario was used as the conservative assumption of activity for all other sections of this SGEIS.

Economic realities, including diminishing marginal returns associated with drilling wells further from the fairway in less than ideal locations, and the exclusion of high-volume hydraulic fracturing wells from certain sensitive locations, would make it highly unlikely that the maximum build-out under the high development scenario would occur. Therefore, only the low and average development scenarios are discussed throughout this section.

These development scenarios are designed to provide order-of-magnitude estimates for the following socioeconomic analysis and are in no way meant to forecast actual well development levels in the Marcellus and Utica Shale reserves in New York State. These scenarios should be

viewed as a "best estimate" of the range of possible amounts of development that could occur in New York State.

Table 6.31 - Major Development Scenario Assumptions (New August 2011)

	Scenarios	
	Low	**Average**
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	9,461	37,842
Vertical	1,071	4,284
Total	**10,532**	**42,126**
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	371	1,484
Vertical	42	168
Total	**413**	**1,652**

Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year "ramp-up" period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end. This assumption, which does not significantly affect the socioeconomic impact analysis, was used to remain consistent with other sections of the SGEIS. In actuality, well development would more likely gradually ramp up, reach a peak, and then gradually ramp down as fewer and fewer wells were completed. However, this curve would not necessarily be smooth.

It is unlikely that new well construction would occur under a steady, constant rate. Economic factors such as the price of natural gas, input costs, the price of other energy sources, changes in technology, and the general economic conditions of the state and nation would all affect the yearly rate of well construction and the overall level of development of the gas reserves. The actual track of well construction would likely be much more cyclical in nature than as described in the following sections.

The average development scenario should be viewed as the upper boundary of possible development, while the low development scenario should be viewed as the likely lower boundary of possible development. As shown in Table 6.31, the maximum number of new wells

developed in a year under the low development scenario is 371 horizontal and 42 vertical wells, and the maximum number of new wells developed in a year under the average development scenario is 1,484 horizontal and 168 vertical wells.

Each newly constructed well is assumed to have an average productive life of 30 years. For example, wells constructed in Year 1 are assumed to still be producing in Year 30, and wells constructed in Year 10 are assumed to produce until Year 40. Because of the assumption of a 30-year development period, wells constructed in Year 30 are assumed to be productive until Year 60. Assuming a 30-year development period and a 30-year production life for each well, the number of productive wells in New York State would be expected to grow until Year 30, at which point, the number of productive wells would peak. After Year 30, with no new wells being constructed, the number of wells in production would begin to decline. Because the number of annual wells approved and developed each year is different for the two development scenarios, the peak number of operating wells at Year 30 also differs for each scenario.

Under both development scenarios, natural gas production in New York State would occur from Year 1 until Year 60, with Year 30 having the maximum number of wells in production. After Year 30, producing wells would gradually decline until Year 60, at which time it is assumed that production stops.

As discussed in Section 2.4.13, no site-specific project locations are being evaluated in the SGEIS. Therefore, for purposes of analysis, three distinct regions were identified within the area where potential drilling may occur in order to take a closer look at the potential impacts at the regional and local levels. The three regions were selected to evaluate differences between areas with a high, moderate, and low production potential; areas that have experienced gas development in the past and areas that have not experienced gas development in the past; and differences in land use patterns. The three representative regions and the respective counties within the region are:

- Region A: Broome County, Chemung County, and Tioga County;
- Region B: Delaware County, Otsego County; and Sullivan County; and
- Region C: Cattaraugus County and Chautauqua County

This analysis is not intended to imply that impacts would occur only in these three regions. Impacts would occur at the local and regional levels wherever high-volume hydraulic fracturing wells are constructed. The actual locations of these wells have not yet been determined, and they could be constructed wherever there is low-permeable shale. Similar to the development scenarios described above, the representative regions are designed to give a range of possible socioeconomic impacts. Therefore, the results of the local and regional analysis should also be seen as order-of-magnitude estimates for the range of possible impacts. Further descriptions of the regions are provided in Section 2.4.11.

6.8.1 Economy, Employment, and Income

The following discusses the potential impacts on the economy, employment and income for New York State, and the local areas within each of the three regions (Regions A, B and C).

6.8.1.1 New York State

Economy and Employment

Development of low-permeability natural gas reservoirs in the Marcellus and Utica shale by high-volume hydraulic fracturing would be expected to have a significant, positive impact on the economy of New York State. Construction and operation of the new natural gas wells are expected to increase employment, earnings, and economic output throughout the state. According to statistics collected and calculations made by the Marcellus Shale Education and Training Center (the Center), in Pennsylvania, an average natural gas well using the high-volume hydraulic fracturing technique requires 410 individuals working in 150 different occupations. The manpower requirements to drill a single well were calculated to be 11.53 full-time equivalent (FTE) construction workers (Marcellus Shale Education and Training Center 2009).

A full-time equivalent worker is defined as one worker working eight hours a day for 260 days a year, or several workers working a total of 2,080 hours in a year. While the Center found that up to 410 individuals are required to build one well, only 11.53 FTE workers were needed. Typically, a high-volume hydraulic fracturing well is constructed over a 3- to 4-month period, and many of the individuals and occupations are needed for only a very short duration. Therefore, to accurately assess the economic impacts of constructing a high-volume hydraulic fracturing well, the FTE workforce was considered.

The Center also calculated the work force requirements for operating a well as 0.17 FTE workers, or approximately 354 person hours per year. In other words, approximately 1 FTE worker is required to operate and maintain every 6 wells in production (Marcellus Shale Employment and Training Center 2009). Unlike the construction workforce that drills the well within a few months and is finished, the operational workforce is required for the productive life of the well. For the purposes of this analysis, a 30-year productive life has been assumed for each well drilled. Therefore, for every new well drilled, 0.17 FTE workers are employed for 30 years.

In its study, the Marcellus Shale Employment and Training Center did not differentiate between the labor requirements needed to drill a horizontal versus a vertical well. Typically, it is much more costly and labor-intensive to drill a high-volume hydraulic fracturing horizontal well than it is to drill a high-volume hydraulic fracturing vertical well. Therefore, in an effort to be conservative and not overstate the positive economic impacts, a factor was applied to the 11.53 FTE figure for vertical wells in the estimates used for this analysis. This factor was calculated using the average depth of a vertical well compared to the average depth of a high-volume hydraulic-fracturing horizontal well. The resulting ratio of 0.2777 was applied to the 11.53 FTE labor requirement to estimate the overall labor requirements of a vertical well.

Using the workforce requirement figures developed by the Marcellus Shale Employment and Training Center and the two development scenarios described above, the expected impacts on employment and earnings from high-volume hydraulic fracturing were projected for New York State as a whole.

As shown in Table 6.32, annual direct construction employment is directly related to the number of wells drilled in a given year. At the maximum well construction rate assumed for each development scenario, total annual direct construction employment is predicted to range from 4,408 FTE workers under the low development scenario to 17,634 FTE workers under the average development scenario. These employment figures correspond to the annual construction of 413 horizontal and vertical wells under the low development scenario and 1,652 horizontal and vertical wells under the average development scenario. In order to reach the full build-out

potential used in the scenarios, it is assumed that construction employment and new well construction would remain at these levels for 20 years, starting in Year 10 (see Table 6.32).

The maximum direct production employment under each development scenario is also shown in Table 6.32. These figures represent the peak production year (Year 30), when the maximum build-out potential has been reached before any of the wells have stopped producing. The preceding and the following years all would have fewer production workers. At the peak, production employment would be expected to range from 1,790 FTE workers under the low development scenario to 7,161 FTE workers under the average development scenario (Table 6.32).

Table 6.32 - Maximum Direct and Indirect Employment Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Direct Employment Impacts		
Construction Employment[1]	4,408	17,634
Production Employment[2]	1,790	7,161
Indirect Employment [3]	7,293	29,174
Total Employment Impacts	13,491	53,969
Total Employment as a Percent of New York State 2010 Labor Force	0.2%	0.7%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

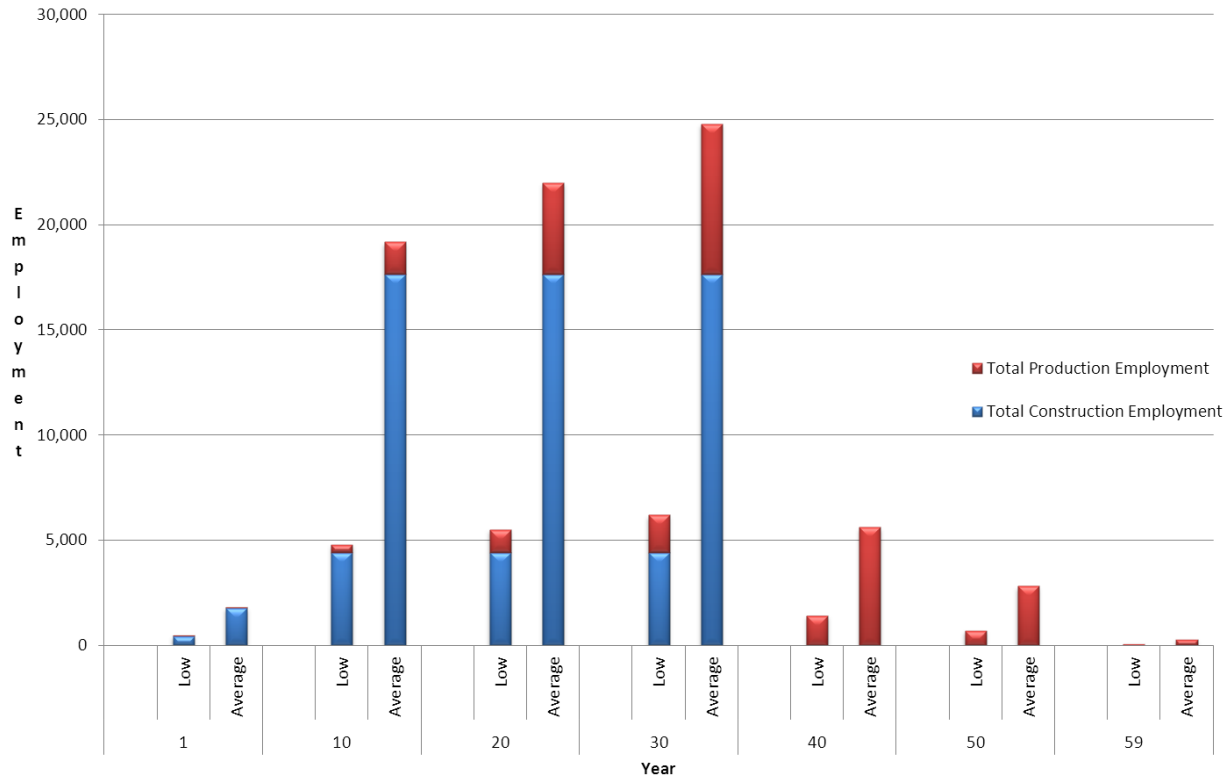
[1] These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

[2] These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production employment for all other years.

[3] Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

Figure 6.12 illustrates the projected direct employment in New York State that would result from implementation of each development scenario over the 60-year time frame. The figure shows how construction and production employment levels are expected to vary, with peak direct employment occurring in Year 30.

Figure 6.12 – Projected Direct Employment in New York State Resulting from Each Development Scenario (New August 2011)

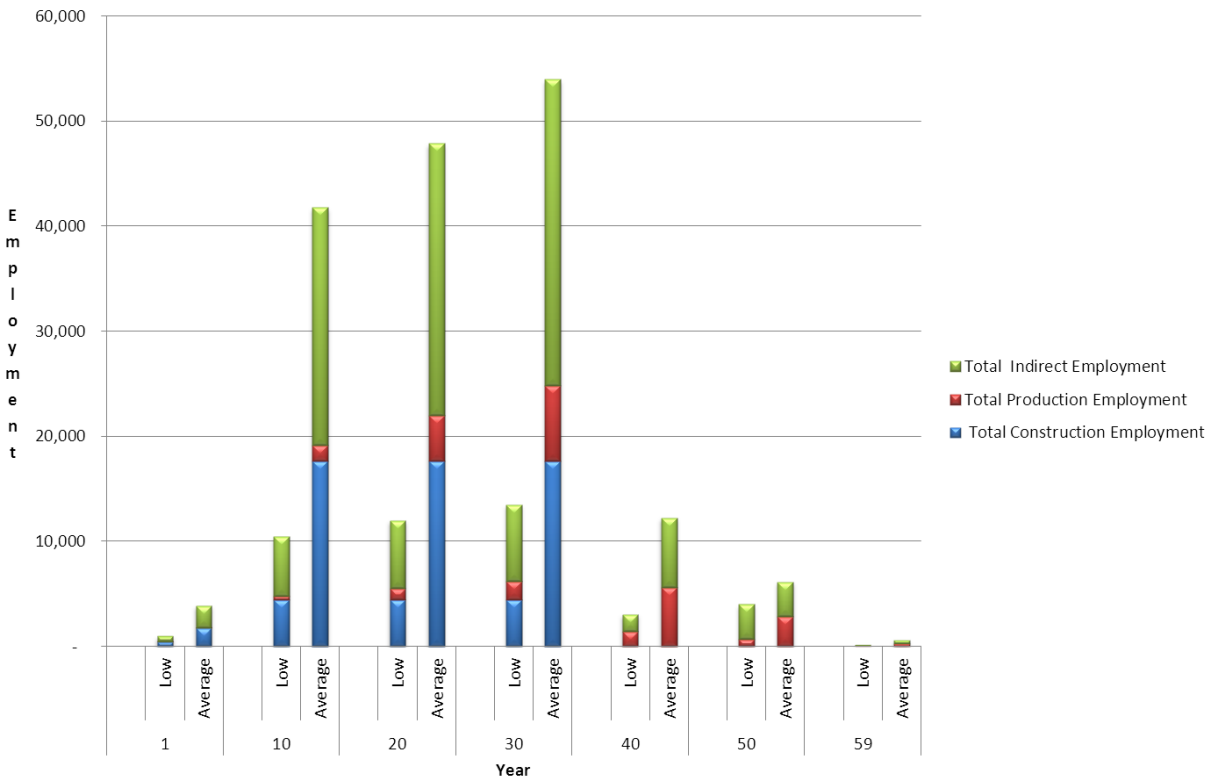


In addition to the direct employment impacts described above, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from suppliers in New York State, the overall demand for goods and services in the state would expand. Revenues at the wholesale and retail outlets and service providers within the state would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the state, thus "multiplying" the positive economic impacts of the original increase in construction/production spending. These "multiplier" effects would continue on until all of the original funds have left New York State's economy through either taxes or savings, or through purchases from outside the state.

Indirect employment impacts are expected to range from an additional 7,293 FTE workers under the low development scenario to an additional 29,174 FTE workers under the average development scenario. These annual figures represent the year with the maximum employment (Year 30). The years before and after this date would have less direct and indirect employment.

In total, at peak employment years, state approval of drilling in the Marcellus and Utica Shales is expected to generate between 13,491 and 53,969 direct and indirect jobs, which equates to 0.2% and 0.6%%, respectively, of New York State's 2010 total labor force, depending on the level and intensity of development that occurs (see Table 6.32). Figure 6.13 graphically illustrates the projected total employment in New York State that would result from each development scenario. As shown on the figure, total employment levels would be highest in Year 10 through Year 30. Once new well construction ends in Year 31, the direct and indirect employment would be greatly reduced.

Figure 6.13 - Projected Total Employment in New York State Resulting from Each Development Scenario (New August 2011)



The majority of these indirect jobs would be concentrated in the construction, professional, scientific, and technical services; real estate and rental/leasing; administrative and waste management services; management of companies and enterprises; and manufacturing industries.

Income

The increase in direct and indirect employment would have a positive impact on income levels in New York State. Table 6.33 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 through Year 30), total annual construction earnings are projected to range from $298.4 million under the low development scenario to nearly $1.2 billion under the average development scenario. Employee earnings from operational employment are expected to range from $121.2 million under the low development scenario to $484.8 million under the average development scenario in Year 30, the year that the maximum number of operational workers are assumed to be employed.

Table 6.33 - Maximum Direct and Indirect Annual Employee Earnings Impacts on New York State under Each Development Scenario (New August 2011)

	Total Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Direct Earnings Impacts		
Construction Earnings[1]	$298.4	$1,193.8
Production Earnings[2]	$121.2	$484.8
Indirect Employee Earnings Impacts[2,3]	$202.3	$809.2
Total Employee Earnings Impacts	$621.9	$2,487.8
Total Employee Earnings as a Percent of New York State's 2009 Total Wages	0.1%	0.5%

Source: U.S. Bureau of Economic Analysis 2011a; NYDOL 2009.

[1] These figures represent the maximum annual change in construction earnings under each scenario and correspond to construction earnings in Years 10 - 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

[2] These figures represent the maximum annual production earnings and indirect employee earnings under each development scenario. These figures correspond to operations earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation earnings for all other years.

[3] Type I direct earnings multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II) were used to estimate the indirect employment impacts.

As described above, the construction and production activities would also generate significant indirect economic impacts. Indirect employee earnings are anticipated to range from $202.3 million under the low development scenario to $809.2 million under the average development scenario in Year 30. The total direct and indirect impacts on employee earnings are projected to range from $621.9 million to $2.5 billion per year at peak production and construction levels in Year 30. These figures equate to increases of between 0.1% and 0.5% of the total wages and salaries earned in New York State during 2009 (see Table 6.33).

Owners of the subsurface mineral rights where wells are drilled will also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or more of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas production is at its peak, can result in significant increases in income. Signing bonuses/bonus bids also can provide significant additional income to property owners.

6.8.1.2 Representative Regions

As noted above, three representative regions were selected to show the range of possible socioeconomic impacts that could occur at the local and regional levels. This analysis in no way is meant to imply that impacts will occur only in these three regions.

For purposes of this analysis, it is assumed that 50% of all new well construction would occur in Region A (Chemung, Tioga, and Broome counties); 23% would occur in Region B (Otsego, Delaware, and Sullivan counties); 5% would occur in Region C (Chautauqua and Cattaraugus counties); and the remaining 22% of new well construction would occur in the rest of New York State. Geological data on the extent and thickness of the low-permeability shale in New York State, including the Marcellus Shale and Utica Shale fairways, were the basis for these assumptions.

Table 6.34 details the major assumptions for each development scenario for each representative region. In all cases, total development is assumed to be reached at Year 30. As shown in the table, Region A is anticipated to receive the majority of the new well construction. The analysis of Region A is designed to show the upper bound of potential regional economic impacts. Under

the low development scenario, a total of 5,281 new wells would be constructed in the counties of Tioga, Chemung, and Broome. Under the average development scenario, a total of 21,067 new wells would be constructed in Region A. The projected maximum number of new wells developed per year in Region A would range from 207 to 826 wells, depending on the development scenario considered. The projected maximum number of new wells developed per year in Region B would range from 2,425 to 9,690 wells, depending on the development scenario (see Table 6.34).

In contrast, Region C is assumed to experience a much smaller level of well development than Region A or Region B. The analysis of Region C is designed to show the lower bound of potential regional economic impacts. Under the low development scenario, a total of 534 new wells would be constructed in Region C. Under the average development scenario, a total of 2,095 new wells would be constructed in Region C. The maximum number of new wells constructed each year in Region C is assumed to be 21 wells under the low development scenario and 82 wells under the average development scenario. The remaining 22% of the development would occur in the rest of the state (see Table 6.34).

Table 6.34 - Major Development Scenario Assumptions for Each Representative Region (New August 2011)

	Scenarios	
	Low	**Average**
Region A		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	4,743	18,923
Vertical	538	2,144
Total	5,281	21,067
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	186	742
Vertical	21	84
Total	207	826
Region B		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,170	8,697
Vertical	255	993
Total	2,425	9,690
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	85	341
Vertical	10	39

	Scenarios	
	Low	**Average**
Total	95	380
Region C		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	483	1,888
Vertical	51	207
Total	534	2,095
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	19	74
Vertical	2	8
Total	21	82
Rest of State		
Total Wells Constructed (Year 1 to Year 30)		
Horizontal	2,065	8,334
Vertical	227	940
Total	2,292	9,274
Maximum Number of New Wells Developed per Year (Year 10 to Year 30)		
Horizontal	81	327
Vertical	9	37
Total	90	364

Economy and Employment

The proposed approval of the use of high-volume hydraulic fracturing technique would have a significant positive economic impact at the regional and local levels. Using the same methodology described above for the statewide analysis, the FTE labor requirements needed to construct and operate these wells were estimated for each region. Table 6.35 provides the maximum direct and indirect employment impacts that are predicted to occur under each development scenario for each region.

In Region A, which is used to define an upper boundary of the regional socioeconomic impacts, it is projected that direct construction employment would range from 2,204 FTE construction workers at the maximum employment levels under the low development scenario to 8,818 FTE construction workers at the maximum employment levels under the average development scenario. The new production employment in the region is expected to range from 895 to 3,581 FTE production workers per year.

In contrast, employment impacts are not anticipated to be as large in Region C, which is used to define a lower boundary for the regional socioeconomic impacts. At the maximum employment levels under the low development scenario, an estimated 221 new FTE constructions workers

and 90 new FTE production workers would be needed for drilling and maintaining the new natural gas wells. These figures would increase to 882 new FTE construction workers and 358 new FTE production workers under the average development scenario (see Table 6.35).

Table 6.35 - Maximum Direct and Indirect Employment Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Total Employment (in number of FTE jobs)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Employment[1]	2,204	8,818
Production Employment[2]	895	3,581
Indirect Employment Impacts[3]	650	2,600
Total Employment Impacts	3,749	14,999
Total Employment as a Percentage of Region A's 2010 Total Labor Force	2.3%	9.3%
Region B		
Direct Employment Impacts		
Construction Employment[1]	1,014	4,056
Production Employment[2]	412	1,647
Indirect Employment Impacts[3]	191	762
Total Employment Impacts	1,617	6,465
Total Employment as a Percentage of Region B's 2010 Total Labor Force	1.8%	7.3%
Region C		
Direct Employment Impacts		
Construction Employment[1]	221	882
Production Employment[2]	90	358
Indirect Employment Impacts[3]	66	263
Total Employment Impacts	377	1,503
Total Employment as a Percentage of Region C's 2010 Total Labor Force	0.4%	1.4%

Source: U.S. Bureau of Economic Analysis 2011a; NYSDOL 2010.

[1] These figures represent the maximum annual construction employment under each scenario and correspond to construction employment in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction employment for all other years.

[2] These figures represent the maximum annual production employment under each scenario. These figures correspond to production employment in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected operation employment for all other years.

[3] Separate Type I direct employment multipliers for the oil and gas extraction industry from the U.S. Bureau of Economic Analysis, Regional Input-Output Modeling System (RIMS II), were used for each region to estimate the indirect employment impacts.

Figure 6.14, Figure 6.15, and Figure 6.16 illustrate the projected direct employment in each representative region that would result from implementation of each development scenario over the 60-year time frame. The figures show how construction and production employment levels are expected to vary, with the peak direct employment occurring in Year 30.

Figure 6.14 - Projected Direct Employment in Region A Resulting from Each Development Scenario (New August 2011)

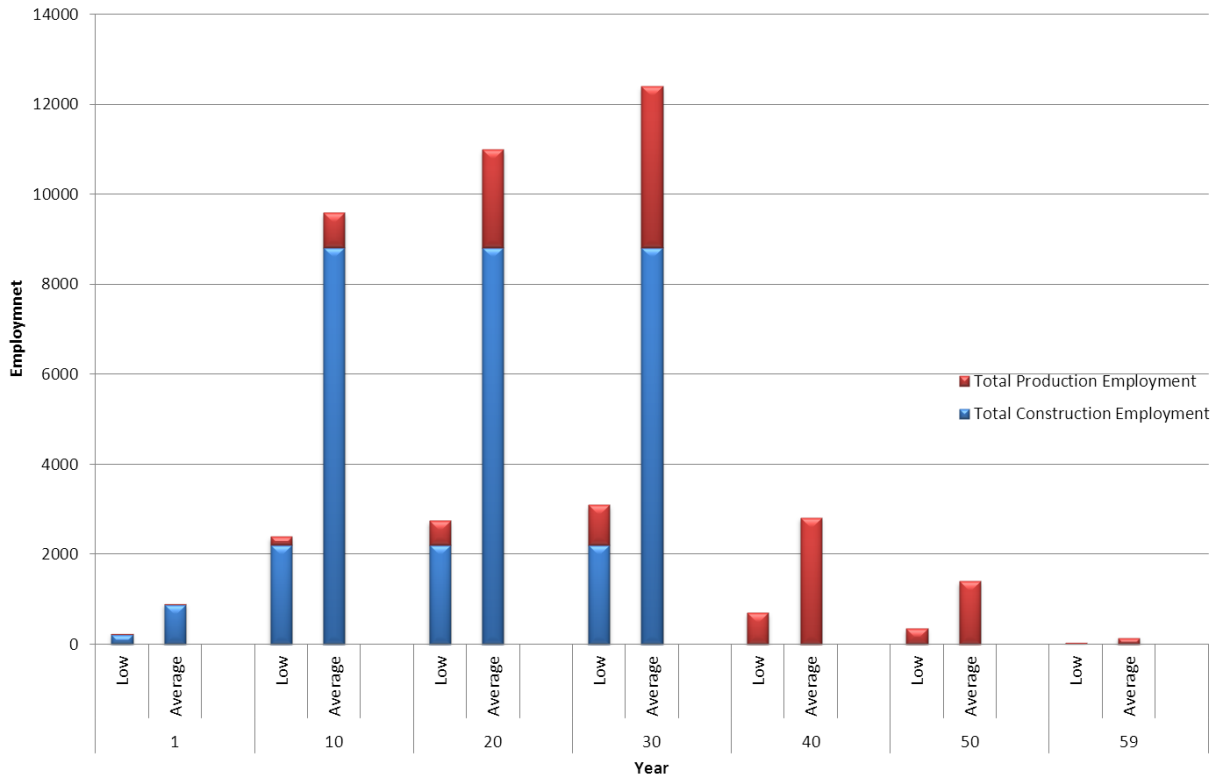


Figure 6.15 - Projected Direct Employment in Region B Resulting from Each Development Scenario (New August 2011)

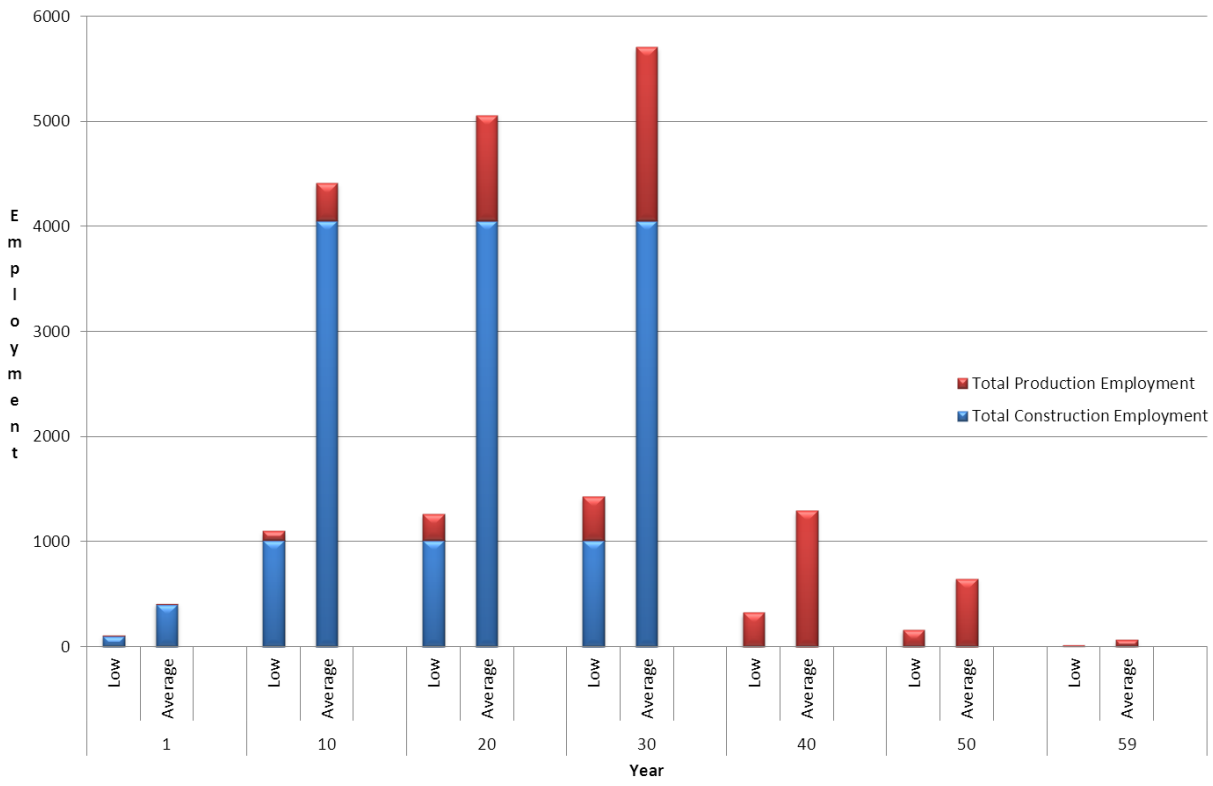
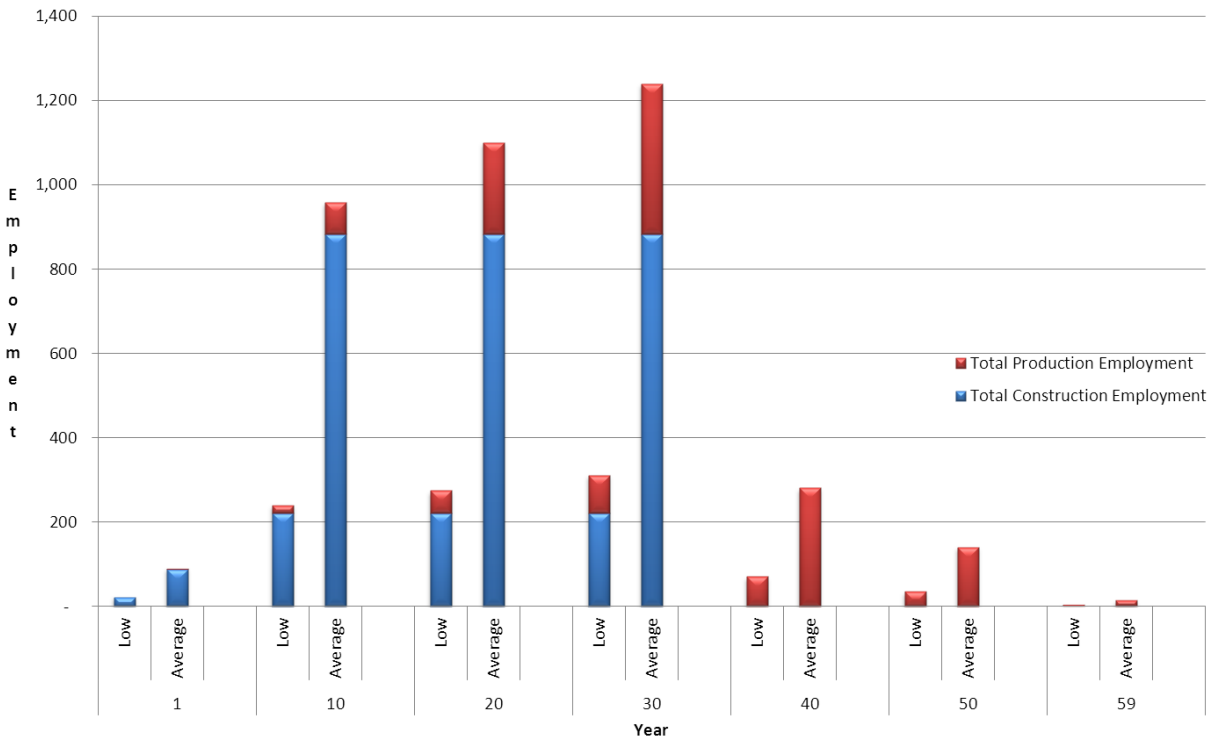


Figure 6.16 - Projected Direct Employment in Region C Resulting from Each Development Scenario (New August 2011)



As described previously for the statewide impacts, in addition to the direct employment impacts, the proposed drilling would also indirectly generate additional employment in other sectors of the economy. As the new construction and operations workers spend a portion of their payroll in the local area, and as the natural gas companies purchase materials from regional suppliers, the overall demand for goods and services in the region would expand. Revenues at the region's wholesale and retail outlets and service providers would increase. As these merchants respond to this increase in demand, they may, in turn, increase employment at their operations and/or purchase more goods and services from their providers. These providers may then increase employment in their establishments and/or spend a portion of their income in the region, thus "multiplying" the positive economic impacts of the original increase in construction/operation spending. These "multiplier" effects would continue on until all of the original funds have left the region's economy through either taxes or savings, or through purchases from outside the region.

Indirect employment impacts are expected to range from a high of 650 to 2,600 indirect workers in Region A to a low of 66 to 263 indirect workers in Region C, depending on the development scenario. Direct employment multipliers of 1.4977 for Region A, 1.3272 for Region B, and 1.4657 for Region C for the oil and gas extraction industry were used in this analysis (U.S. Bureau of Economic Analysis 2011b; 2011c; 2011d). In contrast, New York State as a whole had a direct employment multiplier of 2.1766 for the oil and gas extraction industry (U.S. Bureau of Economic Analysis 2011a).

The employment and earnings multipliers in these regions are much smaller than in New York State as a whole, underscoring the fact that portions of these study areas do not have as well-developed, self-sufficient, and diverse economies as the state as a whole. In particular, the low multipliers reflect the fact that much of the goods and services that would be needed to construct and operate the new wells would be purchased outside the regions.

However, it can be expected that as the natural gas industry matures in these regions, more local suppliers and service providers would enter the markets and be able to respond to the natural gas industry's needs. As time goes by, a larger portion of the indirect economic impacts would remain in the region, further stimulating the local economies.

Figure 6.17, Figure 6.18, and Figure 6.19 graphically illustrate the projected total employment in Region A, Region B, and Region C, respectively, that would result from each development scenario. As shown on the figures, total employment levels would be greatest in Year 10 through Year 30. Once new well construction ends in Year 30, the projected direct and indirect employment would be greatly reduced.

Figure 6.17 – Projected Total Employment in Region A Under Each Development Scenario (New August 2011)

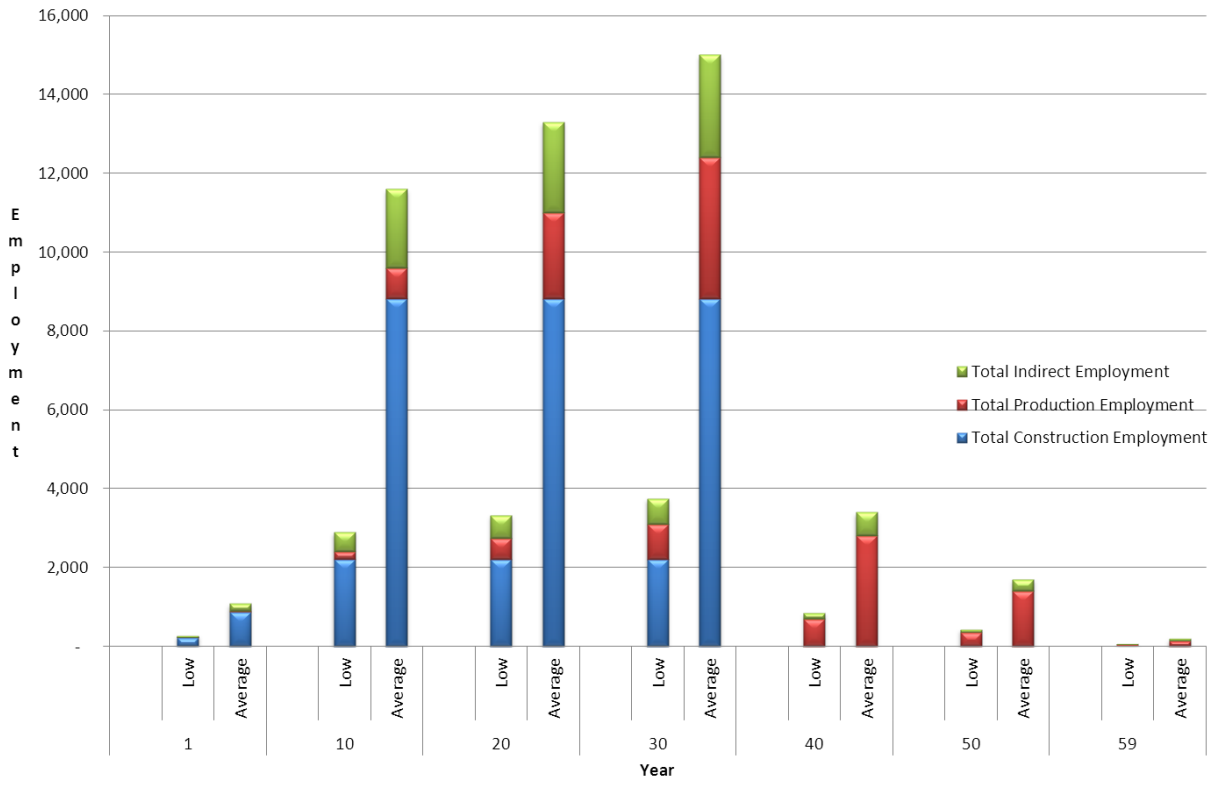


Figure 6.18 - Projected Total Employment in Region B Under Each Development Scenario (New August 2011)

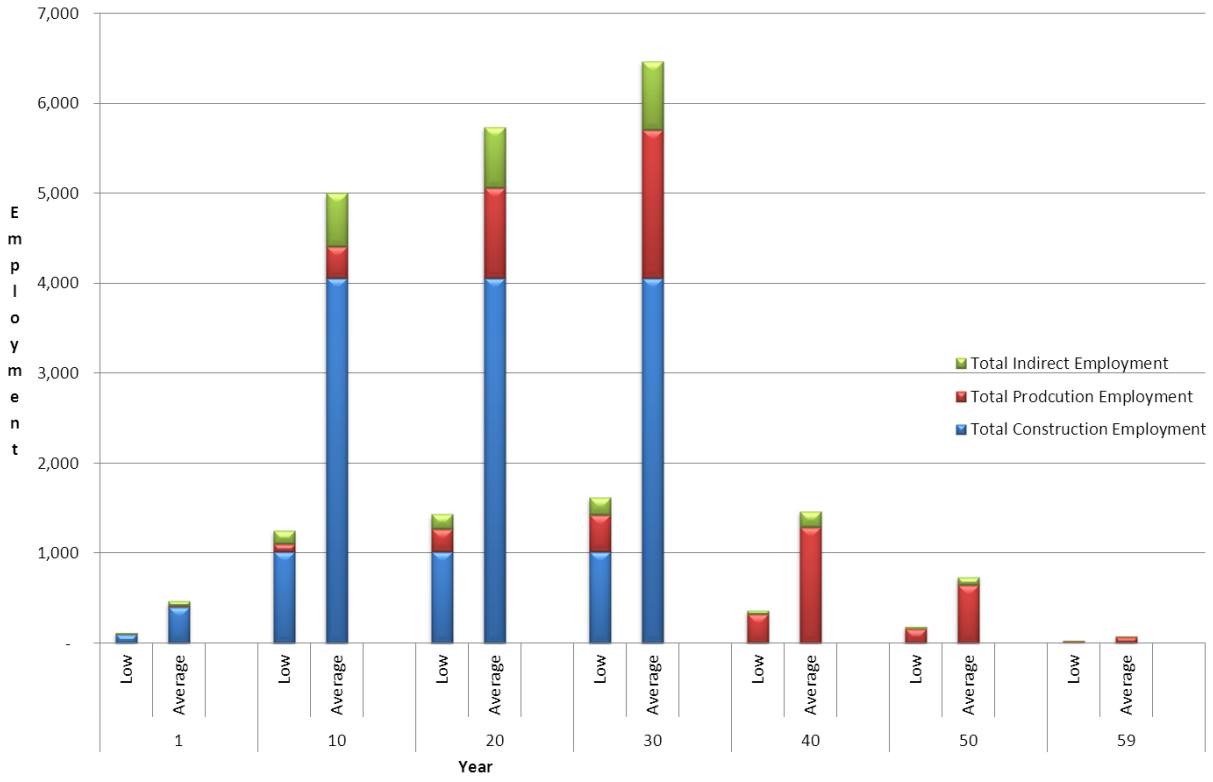
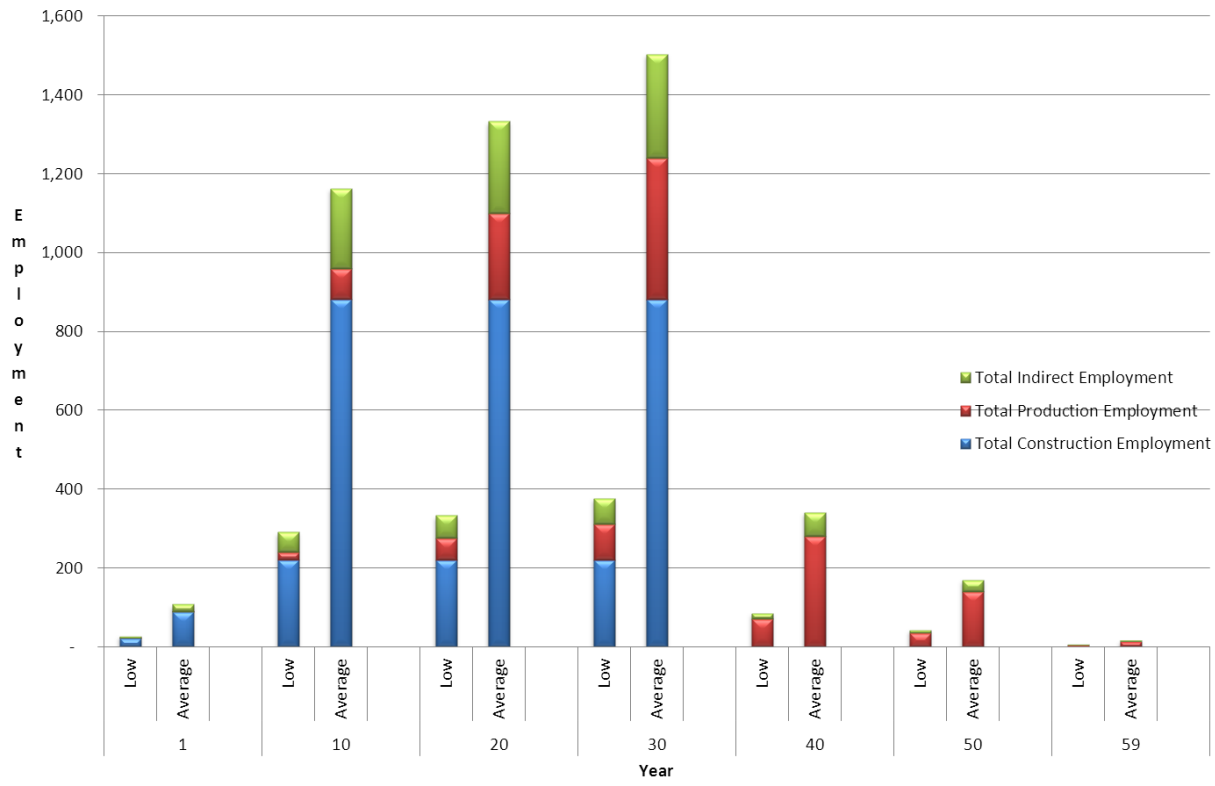


Figure 6.19 - Projected Total Employment in Region C Under Each Development Scenario (New August 2011)



The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeable shale is located. Many geological and economic factors would interact to determine the exact location that wells would be drilled. The location of productive wells would determine the distribution of impacts.

In some regions in the state where drilling is most likely to occur, the increases in employment may be so large that these regions may experience some short-term labor shortages. The increase in direct and indirect employment related to the natural gas extraction industry could drive wage rates up in the areas in the short term and make it more difficult for existing industries to recruit and retain qualified workers. In addition, the increase in wage rates could have a short-term, negative impact on existing industries as it would increase their labor costs. These potential short-term labor impacts would be less severe because specialized labor from

outside the region would likely be required for certain jobs, and the existence of employment opportunities would cause the migration of workers into the region. In addition, the positive employment impacts from well construction and development—and the related economic impacts derived from that employment—would generate more in-migration to the region. In time, the additional new residents to the areas would expand the regional labor force and reduce the pressure on labor costs.

Income

The increase in direct and indirect employment would have a positive impact on income levels in regions where natural gas development occurs. Table 6.36 provides estimates of the maximum direct and indirect employee earnings that would be generated under each development scenario. When well construction reaches its maximum levels (Year 10 to Year 30), total annual construction earnings in a region could range from a low of $15.0 million in Region C under the low development scenario to nearly $597.0 million under the average development scenario in Region A. In Year 30, the year that the maximum number of production workers are assumed to be employed, regional employee earnings from production employment could range from a low of $6.1 million in Region C under the low development scenario to a high of $242.4 million in Region A under the average development scenario.

Table 6.36 - Maximum Direct and Indirect Earnings Impacts on Each Representative Region under Each Development Scenario (New August 2011)

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Region A		
Direct Employment Impacts		
Construction Earnings[1]	$149.2	$597.0
Production Earnings[2]	$60.6	
Indirect Earnings Impacts[3]	**$44.0**	**$176.0**
Total Earnings Impacts	**$253.8**	**$1,015.4**
Total Earnings as a Percentage of Region A's 2009 Total Wages	4.7%	18.7%
Region B		
Direct Earnings Impacts		
Construction Earnings[1]	$68.6	$274.6
Production Earnings[2]	$27.9	$111.5
Indirect Earnings Impacts[3]	**$12.9**	**$51.6**

	Employee Earnings ($ millions)	
Scenario	**Low**	**Average**
Total Earnings Impacts	**$109.4**	**$437.7**
Total Earnings as a Percentage of Region B's 2009 Total Wages	4.8%	19.3%
Region C		
Direct Earnings Impacts		
Construction Earnings[1]	$15.0	$59.7
Production Earnings[2]	$6.1	$24.2
Indirect Earnings Impacts[3]	$4.5	$17.8
Total Earnings Impacts	$25.6	$101.7
Total Earnings as a Percent of Region C's 2009 Total Wages	0.9%	3.7%

Source: U.S. Bureau of Economic Analysis 2011b, 2011c, 2011d; NYSDOL 2009.

[1] These figures represent the maximum annual construction earnings under each scenario and correspond to construction earnings in Years 10 – 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected construction earnings for all other years.

[2] These figures represent the maximum annual production earnings under each development scenario. These figures correspond to production employee earnings in Year 30. See Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report for expected production and indirect employee earnings for all other years.

[3] Separate Type I direct earnings multipliers for the oil and gas extraction industry from the US Bureau of Economic Analysis, Regional Input- Output Modeling System (RIMS II) for each region were used to estimate the indirect employment impacts.

Total employee earnings in all of the regions are expected to increase significantly. Region A would experience annual increases in employee earnings of approximately $254 million to $1.0 billion, or 4.7% to 18.7% of the 2009 total wages and salaries for the region. Similarly, Region B would experience annual increases in employee earnings of approximately $109 million to $438 million, or 4.8% to 19.3% of 2009 total wages and salaries for the region. Region C would also experience a significant impact in its annual employee earnings. Employee earnings in this region would increase from approximately $26 million to $102 million, or 0.9% to 3.7% of the 2009 total wages and salaries for the region (see Table 6.36).

Owners of the subsurface mineral rights where wells are drilled would also experience a significant increase in income and wealth. Royalty payments to property owners typically amount to 12.5% or greater of the annual value of production of the well (NYSDEC 2007a). These royalty payments, particularly in the initial stages of well production when natural gas

production is at its peak, could result in significant increases in income. In addition, mineral rights owners often receive large signing bonuses/bonus bids as part of the lease agreements.

Impacts on Other Industries

The proposed high-volume hydraulic-fracturing operations would affect not only the size of the regional economies as described above, but would also have an impact on other industries in the economy.

As previously described, suppliers of the natural gas extraction industry would experience significant increases in demand for their goods and services. Over time, these industries would expand and their importance in the regional economies would likewise increase. As shown in Section 2.4.11, Economy, Employment, and Income, the industries expected to experience the greatest indirect, or secondary, growth due to expansion of the natural gas extraction industry would be real estate; the professional, scientific, and technical industries; the management of companies and enterprises; construction; and manufacturing industries. For every $1 million change in the final demand generated in the natural gas extraction industry, a corresponding significant level of output would be generated in these industries. Typically, a change in final demand in an industry is defined as the change in output of that industry multiplied by the value or price of its output. In this case, a $1 million increase in the value of output from the natural gas extraction industry would generate $47,100 in the real estate and rental and leasing industry; $30,500 in the professional, scientific, and technical services industry; and $27,600 in the management of companies and enterprises industry. See Section 2.4.15 for a discussion of indirect impacts on other industries in New York State.

Each of these secondary industries would experience increases in their output, employment, income and value added. As a result, industries that supply these secondary industries would also experience a positive economic impact, and they would expand as demand for their goods and services increases. Secondary, and eventually even tertiary, suppliers would start to tailor their products to meet the needs of the natural gas extraction industry.

Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the natural gas drilling and

production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.

Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry. Property values also may experience some increase as a result of the natural gas development and the resulting increase in economic activity. The potential increase in land prices, which is one of the main factors of production for agriculture, could impact the industry's input costs in areas experiencing the most intense development.

6.8.2 Population

This section presents a summary of the population and demographic findings of the Economic Assessment Report (2011) written by Ecology and Environment Engineering, P.C.

As described previously, three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels. The designation of these areas as representative regions does not mean that the impacts would necessarily be limited to those areas. Until the production potential of low-permeability reservoirs is proven, it is not possible to predict where every potential high-volume hydraulically fractured well may be sited; wells could be developed anywhere there is low-permeability shale. The local and regional impacts presented here are intended only to provide order-of-magnitude estimates for the range of potential impacts. See the Economic Assessment Report for a more detailed discussion on the selection of these representative regions.

To assess the maximum potential population impacts, the discussion below is based on a hypothetical situation in which all workers hired for the construction and production phases of the natural gas wells either migrate into the regions from other areas, or workers migrate into the regions from other areas to fill positions which local construction and production workers vacate

to work on the natural gas wells.. Although this hypothetical situation is used to examine the maximum potential population impacts, it is more likely that the actual outcome would be less than described. Not all workers employed during the construction and production phases would necessarily live in New York State or one of the representative regions. Particularly in the case of well development and production in the Southern Tier, existing natural gas workers currently residing in Pennsylvania, for example, may simply choose to maintain their residency in Pennsylvania and commute to work in New York.

In addition, actual population impacts may also be less than what is described in the following section because some currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

The hiring of currently employed local workers (i.e., those workers that leave existing jobs to work in the natural gas industry) is not expected to reduce total in-migration to the regions as it is assumed that the jobs these local workers are leaving would need to be filled. Given the finite number of workers in the regional labor force, any growth in the total number of jobs available in regional economies not filled by currently unemployed or underemployed persons would lead to in-migration to the areas.

The following additional assumptions were used to project population impacts:

- The majority of construction jobs and related population migration to the regions would be temporary and transient in nature in the beginning of the well development phase. As well construction continues, these jobs would gradually be filled by permanent residents.

- Transient construction workers are assumed to temporarily relocate to the region for a short-duration and are assumed to not be accompanied by their households. Permanent construction workers are assumed to relocate to the region for the duration of the well development phase and would be accompanied by their entire households.

- Production jobs and related population migration to the regions would be permanent and entire households would relocate to the regions.

- Natural gas development and production would not “crowd out” employment in other unrelated industrial sectors, and employment in these sectors would remain unchanged.

- Job vacancies created when local employees leave existing industries to take jobs in the natural gas extraction industry would be filled.

- The 2010 average household sizes in New York State (2.64 persons per household), Region A (2.47 persons per household), Region B (2.52 persons per household), and Region C (2.49 persons per household) were used in estimating the population impacts associated with permanent construction and production jobs (USCB 2010).

- There would be no involuntary displacement of persons due to construction of the natural gas wells, as no buildings would be demolished to make way for wells and wells need to be drilled at least 500 feet away from private wells and 100 feet from inhabitated dwellings.

6.8.2.1 New York State

Both transient and permanent population impacts are expected to occur as a result of natural gas well construction. Given the highly specialized nature of natural gas construction, workers with the skills required to complete a high-volume hydraulic fracturing operation would not be currently available in New York State or in the representative regions. If high-volume hydraulic fracturing operations were to begin in New York State, most of the skilled workers would initially need to be recruited from outside the state and would be both temporary and transient in nature.

As the industry matures and as more natural gas development occurs in the state and representative regions, more local persons would acquire the requisite skills needed for these jobs, and recruitment from within the existing labor force would therefore increase. Also, as the industry expands and development becomes more assured, the incentive for previously transient workers to become permanent residents within the state or representative regions would increase. Therefore, it would be expected that eventually there would be a decline in the number of transient construction workers and an increase in the number of permanent construction workers.

In an effort to estimate the mix of transient and permanent construction workers, data collected by the Marcellus Shale Education and Training Center on the occupational composition of the natural gas workforce and data from the U.S. Bureau of Economic Analysis' 2008 National Employment Matrix were used to help forecast the amount of local labor that would be employed in natural gas well development (Marcellus Shale Education and Training Center 2009; U.S. Bureau of Economic Analysis 2011e). Initially no more than 23% of the construction

workforce is expected to be hired locally. Due to New York State's small existing natural gas industry, the remaining 77% of the workforce would have specialized skills that would most likely be unavailable among New York's labor force in Year 1. Given the newness of the industry, it is assumed that, in Year 1, 77% of the total workforce would be transient workers from outside the state.

As the natural gas industry matures the number of qualified workers in the state and representative regions would increase. This pool of qualified workers would expand as existing local residents gain the requisite skills and/or formerly transient workers permanently relocate to the state or representative regions. The total number of transient construction workers would gradually increase as the rate of well development increased until Year 10 when the maximum number of transient construction workers under both development scenarios is reached. From Years 11 to 30 the transient population would gradually decrease as a proportion of the total construction workforce. By Year 30 it is assumed that the natural gas industry would be sufficiently mature that 90% of all workers could be hired locally. Table 6.37 shows the transient, permanent, and total construction employment for select years. See the Economic Assessment Report for a more detailed discussion of how these figures were derived.

Table 6.37 - Transient, Permanent and Total Construction Employment Under Each Development Scenario for Select Years: New York State (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	342	97	439	1,370	389	1,759
5	1,517	693	2,210	6,051	2,766	8,817
10	2,409	1,999	4,408	9,639	7,995	17,634
15	1,759	2,649	4,408	7,038	10,596	17,634
20	1,181	3,227	4,408	4,725	12,909	17,634
25	740	3,668	4,408	2,959	14,675	17,634
30	441	3,967	4,408	1,763	15,871	17,634

Since the natural gas wells are expected to stay in operation for 30 years, production workers are assumed to be permanent workers who reside close to where the wells are located. Thus, these workers would live in or relocate their families to the area. Wells drilled in Year 1 are expected

to remain in operation until Year 30; wells drilled in Year 30 would remain in operation until Year 60.

It is assumed that the households of permanent construction workers and production workers would, on average, be the same size as existing New York households (i.e., 2.64 persons, including the single worker). Therefore, in projecting population impacts, it is anticipated that transient construction workers would be temporary residents unaccompanied by family members, whereas permanent construction workers and all production workers would be permanent residents accompanied by an average of 1.64 family members.

Based on the above assumptions, Table 6.38 displays, for New York State as a whole and for each development scenario, the estimated transient and permanent populations resulting from construction and production activities for Years 1, 10, 20, 30, 40, 50, and 59.

Table 6.38 - Estimated Population Associated with Construction and Production Employment for Select Years: New York State (New August 2011)

		Transient Population	**Permanent Population**		
Production Year	**Development Scenario**	**Construction**	**Construction**	**Production**	**Total**
1	Low	342	256	18	275
	Average	1,370	1,026	74	1,100
10	Low	2,409	5,277	1,019	6,296
	Average	9,639	21,107	4,079	25,186
20	Low	1,181	8,519	2,872	11,392
	Average	4,725	34,080	11,492	45,572
30	Low	441	10,473	4,726	15,198
	Average	1,763	41,898	18,905	60,803
40	Low	0	0	3,707	3,707
	Average	0	0	14,829	14,829
50	Low	0	0	1,853	1,853
	Average	0	0	7,413	7,413
59[1]	Low	0	0	185	185
	Average	0	0	742	742

Note:

[1] Year 59 is used instead of Year 60 since it is assumed that all operational wells would cease production at the beginning of Year 60.

Under the low development scenario, between Years 10 and 30, it is projected that a maximum of 4,408 construction workers would temporarily or permanently migrate into the areas. The maximum transient construction workforce would occur in Year 10, with an estimated 2,409 transient workers. (During this same year, there would be 1,999 permanent workers relocating to the area.) Under the average development scenario, between Years 10 and 30, it is projected that a maximum of 17,634 construction workers would temporarily or permanently migrate to the well construction areas. The maximum transient workforce would occur in Year 10, with an estimated 9,639 transient workers. (During this same time period, there would be 7,995 permanent workers relocating to the area.) The population impact of the maximum number of transient workers, 9,639 transient workers for the average development scenario, represents less than 0.1% of the total present population of New York State, indicating that transient workers would have only a minor short-term population impact at the state level.

Under the low development scenario, the number of persons permanently migrating to the impacted areas to construct and operate the wells is projected to reach its maximum of 15,198 persons during Year 30 (see Table 6.39). Under the average development scenario during Year 30, it is projected that 60,803 persons would permanently migrate to the impacted areas. Since it is assumed that permanent construction and production workers would relocate with their households, these population estimates include the permanent construction and production workers and members of their households. The maximum impact on the permanent population under the average development scenario is 60,803 persons in Year 30. This figure represents approximately 0.3% of the total present population of New York State, indicating that some long-term population impact could occur at the state level as a result of the operation of the new natural gas wells.

Table 6.39 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production: New York State (New August 2011)

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
New York State	19,378,102	Low	2,409	>0.1%	15,198	>0.1%
		Average	9,639	>0.1%	60,803	0.3%

Notes:

[1] Existing population from U.S. Census Bureau's *2010 Census of Population* (USCB 2010).

[2] Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

[3] Maximum operational impacts occur during production year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

According to the population projections developed by Jan K. Vink of the Cornell University Program on Applied Demographics, the population of New York State is expected to increase by 1,037,344 persons over the next 20 years (i.e., by an average of approximately 52,000 persons per year) (Cornell University 2009). Consequently, the maximum cumulative population impact of 60,803 persons, which occurs during production year 30, is slightly more than one year's projected incremental population growth for New York State.

Although the maximum population impacts would be relatively minor at the level of the whole state, natural gas wells would not be spread evenly across the state; they would be concentrated in particular areas where the influx of construction workers and production workers and their families may have more significant population impacts. Similarly, because new wells would not be developed evenly over time due to swings in well development activity, the population impacts would be greater in some years than in others.

In addition to direct employment (employment impacts from construction and production), there are projected indirect employment impacts from the development of hydraulic fracturing operations in the area underlain by the Marcellus and Utica Shales (see Section 6.10.1). Given the relatively high unemployment rates currently being experienced in these regions, it is likely that some of these new, indirectly created jobs (e.g., gas station clerks, hotel lobby personnel,

etc.) would be filled by local, previously unemployed or underemployed persons. These indirect employment impacts would reduce local unemployment and help stimulate the local economies. The impacts associated with the influx of construction workers, both transient and permanent, would last as long as wells are being developed in an area, whereas the impacts associated with the production phase could last up to 60 years.

6.8.2.2 Representative Regions

Table 6.40,Table 6.41 and Table 6.42 show the estimated transient, permanent, and total construction employment for Regions A, B, and C under the low and average development scenario.

Table 6.40 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region A (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	171	48	219	686	194	880
5	758	347	1,105	3,026	1,383	4,409
10	1,205	999	2,204	4,820	3,998	8,818
15	880	1,324	2,204	3,520	5,298	8,818
20	591	1,613	2,204	2,363	6,455	8,818
25	370	1,834	2,204	1,480	7,338	8,818
30	220	1,984	2,204	882	7,936	8,818

Table 6.41 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region B (New August 2011)

	Low Scenario			**Average Scenario**		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	79	22	101	315	89	404
5	349	159	508	1,392	636	2,028
10	554	460	1,014	2,217	1,839	4,056
15	405	609	1,014	1,619	2,437	4,056
20	272	742	1,014	1,087	2,969	4,056
25	170	844	1,014	681	3,375	4,056
30	101	913	1,014	406	3,650	4,056

Table 6.42 - Transient, Permanent, and Total Construction Employment Under Each Development Scenario for Select Years for Representative Region C (New August 2011)

	Low Scenario			Average Scenario		
Year	**Transient**	**Permanent**	**Total Construction Employment**	**Transient**	**Permanent**	**Total Construction Employment**
1	17	5	22	69	19	88
5	75	35	110	303	138	441
10	121	100	221	482	400	882
15	88	133	221	352	530	882
20	59	162	221	236	646	882
25	37	184	221	148	734	882
30	22	199	221	88	794	882

Table 6.43 shows the maximum population impacts associated with transient and permanent construction workers and permanent production workers for the three representative regions. As noted above, the three representative regions were selected to assess the range of potential socioeconomic impacts that could occur at the local and regional levels, and the projected local and regional impacts presented here are intended to provide order-of-magnitude estimates for the range of potential impacts. In constructing Table 6.43 it was assumed, as discussed above, that a portion of the construction workers would be temporary, transient residents in an area and would not be accompanied by members of their households. The remainder of the construction workers would be permanent residents. The proportion of permanent workers to transient workers would gradually increase over time. All production workers are assumed to be permanent residents and would relocate their families to the area. Since the households of permanent construction and production workers are assumed to be the same size as average households in their respective regions, permanent workers are assumed to be accompanied by an average of 1.47 family members in Region A, 1.52 family members in Region B, and 1.49 family workers in Region C.

Table 6.43 - Maximum Temporary and Permanent Impacts Associated with Well Construction and Production

Region	Total 2010 Existing Population[1]	Development Scenario	Maximum Transient Impacts[2]	% Increase from Total Existing 2010 Population	Maximum Permanent Impacts [3]	% Increase from Total Existing 2010 Population
A	340,555	Low	1,205	0.4%	7,111	2.1%
		Average	4,820	1.4%	28,447	8.4%
B	187,786	Low	554	0.3%	3,339	1.8%
		Average	2,217	1.2%	13,348	7.1%
C	215,222	Low	121	<0.1%	720	0.3%
		Average	482	0.2%	2,868	1.3%

Notes:

[1] Existing population from US Census Bureau's *2010 Census of Population* (USCB 2010).

[2] Maximum transient impacts occur during Year 10. For details on the population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

[3] Maximum permanent impacts occur during production Year 30, when the number of producing wells is at a maximum. For details on population impacts for all other years, see Ecology and Environment Engineering, P.C., 2011, Economic Assessment Report.

The upper bound of the potential impacts is found in Region A under the average development scenario, when in Year 10 there are projected to be 4,820 unaccompanied transient workers, representing 1.4% of the region's total population. The upper bound of the potential impacts from permanent population changes can be found in Region A under the average development scenario in Year 30, when 28,447 permanent construction and production workers and their household members would be residing in the region. This figure represents 8.4% of the existing population in Region A. According to the population projections presented in Section 2.4.11, in the absence of gas well development, Region A is expected to experience a future population decrease and to have a 2030 population of 279,675 persons, a decrease of 60,880 persons, equal to 17.9% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 28,447persons in Year 30 under the average development scenario, would offset approximately 47% of the projected population decline in Region A and would, therefore, have a beneficial impact.

Under the average development scenario, Region B is projected to have a maximum of 2,217 unaccompanied, transient construction workers and 13,348 permanent construction and

production workers and their family members residing in the region. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. The maximum transient population would account for 1.2% of the existing population in Region B, and the maximum permanent population would account for 7.1% of the existing population, respectively. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region B is expected to experience a future population decrease and to have a 2030 population of 183,031 persons, a decrease of 4,755 persons, equal to 2.5% of the total existing population. The influx of workers and their family members associated with gas well development, which totals 13,348 persons in Year 30 under the average development scenario, would more than offset the projected population decline in Region B but would not add significantly to the existing population.

The lowest maximum potential population impact is found in Region C under the low development scenario, when in Year 10 only 121 unaccompanied, transient construction workers are expected to reside in the region. Under the same development scenario 720 permanent construction and production workers and their families would reside in Region C in Year 30, representing a total of approximately 1.3% of the existing population. Note that maximum transient population impacts occur in Year 10, while the maximum permanent population impacts occur in Year 30. In contrast, under the average development scenario in Year 30, Region C is projected to have a maximum of 482 unaccompanied, transient construction workers and a maximum of 2,868 permanent construction and production workers and household members in the region. The maximum transient population represents 0.2% of the existing population, and the maximum permanent population represents 1.3% of the existing population. According to population projection figures presented in Section 2.4.11, in the absence of gas well development, Region C is expected to experience a future population decrease and to have a 2030 population of 188,752 persons, a decrease of 26,470 persons, equal to 12.3% of the total existing population. The influx of permanent workers and their family members associated with gas well development, totaling 2,868 persons in Year 30 under the average development scenario, would offset more than 10% of the projected population decline in Region C and would have a small-scale beneficial impact.