June 1, 2020

VIA FEDERAL ERULEMAKING PORTAL
Office of NEPA Policy and Compliance
U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585

Re: DOE NEPA/NG Procedures, RIN 1990-AA49

To Whom it May Concern:

The United States Department of Energy ("DOE") proposes to update its National Environmental Policy Act ("NEPA"),[1] implementing procedures regarding authorizations issued under Section 3 of the Natural Gas Act ("NGA").[2] This update would categorically exclude all approvals and disapprovals of new authorizations or amendments of existing authorizations to export natural gas as well as any associated transportation of natural gas by marine vessel.

DOE invited public comments on the proposed changes on May 1, 2020, with a commenting deadline of June 1, 2020.[3] The Delaware Riverkeeper Network and Maya van Rossum, the Delaware Riverkeeper (collectively, "DRN"), submit the following comments for DOE's consideration.

As an initial matter, DRN requests that DOE extend the public comment period an addition sixty (60) days, to close on Friday, July 31, 2020. DOE should take into account the devastating effects of the coronavirus pandemic on the public's ability to fully and fairly engage in the rulemaking process. Hardships endured by members of the public affect their access to time and resources that had been previously freely available. This rulemaking must not be rushed without adequate input from the public, which can only be provided if accommodations are made during this unprecedented global pandemic.

[1] 42 U.S.C. §§ 4321–4370h.
[2] 15 U.S.C. § 717b.
[3] National Environmental Policy Act Implementing Procedures, 85 Fed. Reg. 25,340 (proposed May 1, 2020) (to be codified at 10 C.F.R. Part 1021).

DELAWARE RIVERKEEPER NETWORK
925 Canal Street, Suite 3701
Bristol, PA 19007
Office: (215) 369-1188
fax: (215)369-1181
drn@delawareriverkeeper.org
www.delawareriverkeeper.org

I. DOE's NGA Authority

The NGA provides that DOE "shall" authorize exports to non-Free Trade Agreement countries "unless . . . it finds that the proposed exportation . . . will not be consistent with the public interest."[4] The NGA thus charges DOE with "assur[ing] the public a reliable supply of gas at reasonable prices,"[5] while simultaneously granting DOE the "authority to consider conservation, environmental, and antitrust questions."[6]

At the same time, the Federal Energy Regulatory Commission ("FERC") has the "exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal."[7] An LNG terminal "includes all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is . . . exported to a foreign country from the United States . . . ."[8] Based on its interpretation of Supreme Court precedent regarding the purposes of the NGA, FERC has exercised its Section 3 authority only as to LNG facilities that "have pipelines connecting the facility with either the interstate or an intrastate grid."[9]

II. NEPA's Requirements

NEPA has two primary aims: (1) it obligates an agency to "consider every significant aspect of the environmental impact of a proposed action"; and (2) it "ensures that the agency will inform the public that it has indeed considered environmental concerns in its decisionmaking process."[10] The "action-forcing" portion of NEPA relevant to this proposed rulemaking is Section 102:

> The Congress authorizes and directs that, to the fullest extent possible: (1) the policies, regulations, and public laws of the United States shall be interpreted and administered in accordance with the policies set forth in this chapter, and (2) all agencies of the Federal Government shall—
>
> . . . .
>
> (C) include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on—
>
> (i) the environmental impact of the proposed action,

---

[4] 15 U.S.C. § 717b(a).
[5] *United Gas Pipe Line Co. v. McCombs*, 442 U.S. 529 (1979).
[6] *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 670 n.4, n.6 (1976); *see also Sierra Club v. U.S. Dep't of Energy (Freeport II)*, 867 F.3d 189, 202–03 (D.C. Cir. 2017).
[7] 15 U.S.C. § 717b(e)(1).
[8] 15 U.S.C. § 717a(11).
[9] Shell U.S. Gas & Power, LLC, 148 FERC ¶ 61,163 (Sept. 4, 2014), Emera CNG, LLC, 148 FERC ¶ 61,219 (Sept. 19, 2014); *see also FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 610 (1944), and *Phillips Petroleum Co. v. Fed. Power Comm'n*, 347 U.S. 672 (1954).
[10] *Baltimore Gas & Elec. Co. v. Nat. Res. Def. Council, Inc.*, 462 U.S. 87, 97 (1983) (first quoting *Vermont Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc.*, 465 U.S. 519, 553 (1978), and then citing *Weinberger v. Catholic Action of Haw.*, 454 U.S. 139, 143 (1981)).

> (ii) any adverse environmental effects which cannot be avoided should the proposal be implemented,
>
> (iii) alternatives to the proposed action,
>
> (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and
>
> (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.[11]
>
> "[B]y focusing the agency's attention on the environmental consequences of a proposed project, NEPA ensures that important effects will not be overlooked or underestimated, only to be discovered after resources have been committed or the die otherwise cast."[12]

"Major Federal actions" requiring preparation of an EIS include projects and programs entirely or partly financed, assisted, conducted, regulated, or approved by Federal agencies.[13] The Council on Environmental Quality ("CEQ") is an agency within the Executive Office of the President and has promulgated regulations implementing NEPA.[14] CEQ regulations direct Federal agencies to adopt their own regulatory procedures to supplement CEQ regulations.[15] DOE's NEPA regulations are found at 10 C.F.R. Part 1021. CEQ regulations describe the process by which a Federal agency must decide whether to prepare an EIS.[16] First, a Federal agency must determine whether the proposed action is one which normally requires an EIS or whether the proposed action is categorically excluded by the Federal agency's supplemental NEPA regulations.[17] If the proposed action does not belong in either category, CEQ regulations direct the Federal agency to "prepare an environmental assessment [("EA")]" and to "involve environmental agencies, applicants, and the public, to the extent practicable, in preparing" the EA.[18] CEQ regulations direct the Federal agency to "make its determination whether to prepare an [EIS]" based on the EA.[19] If the Federal agency "determines on the basis of the environmental assessment not to prepare an [EIS]," then it should "[p]repare a finding of no significant impact," also known as a FONSI.[20]

In this proposed rulemaking, DOE seeks to categorically exclude all "[a]pprovals or disapprovals of new authorizations or amendments of existing authorizations to export natural gas under section 3 of the Natural Gas Act and any associated transportation of natural gas by marine vessel" from the requirement to prepare an EA or EIS.[21] A categorical exclusion ("CE") is a "category of actions which do not individually or cumulatively have a significant effect on the human environment and which have been found to have no such effect in procedures adopted by a Federal agency in implementation of these regulations . . . and for which, therefore, neither an environmental assessment nor an

---

[11] 42 U.S.C. § 4332. *See also Robertson v. Methow Valley Citizens*, 490 U.S. 332, 348–49 (1989).
[12] *Id.* at 349.
[13] 40 C.F.R. § 1508.18(a).
[14] 40 C.F.R. §§ 1500-1508.
[15] 40 C.F.R. § 1507.3.
[16] 40 C.F.R. § 1501.4.
[17] 40 C.F.R. § 1501.4(a).
[18] 40 C.F.R. § 1501.4(b).
[19] 40 C.F.R. § 1501.4(c).
[20] 40 C.F.R. § 1501.4(e).
[21] *Tracked Proposed Revisions*, DOE-HQ-2020-0017, RIN 1990-AA49.

environmental impact statement is required."[22] "Categorical exclusions, by definition, are limited to situations where there is an insignificant or minor effect on the environment."[23] In deciding whether an action meets this definition, an agency should consider "the unique characteristics of the applicable geographic areas, the degree to which effects on the quality of the environment [are] controversial or the risks were unknown, the degree to which the CEs might establish a precedent for future actions with significant effects or represent[] a decision in principle about future considerations, the degree to which the actions might affect endangered species, and whether there exist[] cumulative impacts from other related actions."[24]

DOE justifies this proposed CE by improperly narrowing the scope of approvals and disapprovals of new authorizations and amendments of existing authorizations to export natural gas under section 3 of the Natural Gas Act. It does this by relying on the Supreme Court's decision in *Department of Transportation v. Public Citizen*,[25] and the D.C. Circuit's decision in *Sierra Club v. Federal Energy Regulatory Commission (Freeport I)*.[26] In *Public Citizen*, the Supreme Court held that "where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect."[27] In *Freeport I*, the D.C. Circuit held that FERC's NEPA analysis of the redesign of a liquefied natural gas ("LNG") facility did not need to include an evaluation of the environmental consequences of exporting natural gas because "the Department of Energy, not the Commission, has sole authority to license the export of any natural gas going through" the facility.[28]

Based on these cases, DOE asserts that it "need not review potential environmental impacts associated with the construction or operation of natural gas export facilities because DOE lacks authority to approve the construction or operation of those facilities."[29] DOE also states that the only potential environmental impacts resulting from the exercise of its NGA Section 3 authority "occur at or after the point of export."[30] DOE's conclusions are wrong for two reasons: (1) DOE is required to consider the direct and indirect effects of natural gas export authorizations because it has the statutory authority to deny such authorizations on the basis that the authorization would pose too great a harm to the environment; and (2) DOE's view of the environmental impacts of natural gas export is too narrow and excludes the indirect effects of such action.

A. DOE Section 3 Authority and its Effect on the Scope of DOE's NEPA Analysis

The environmental effects of increased production of natural gas due to a NGA Section 3 authorization to export a specified amount of natural gas from a specified location fall within the scope of the required NEPA analysis. Because these effects are typically significant and vary from application to application, DOE's proposal to categorically exclude authorizations to export natural gas under NGA Section 3 is improper.

---

[22] 40 C.F.R. § 1508.4.
[23] *Sierra Club v. Bosworth*, 510 F.3d 1016, 1027 (9th Cir. 2007) (quoting *Alaska Ctr. For Env't v. U.S. Forest Serv.*, 189 F.3d 851, 859 (9th Cir. 1999)).
[24] *Id.* (citing 40 C.F.R. § 1508.27(b)).
[25] 541 U.S. 752 (2004).
[26] 827 F.3d 36 (D.C. Cir. 2016).
[27] 541 U.S. at 770.
[28] 827 F.3d at 47.
[29] National Environmental Policy Act Implementing Procedures, 85 Fed. Reg. 25,340, 25,341–42 (proposed May 1, 2020) (to be codified at 10 C.F.R. Part 1021).
[30] *Id.* at 25,342.

In a companion case to *Freeport I*, the D.C. Circuit rejected petitioners' argument that FERC should have considered the increased production of gas for export and the increased cost of domestic gas that could prompt greater reliance on coal in its NEPA analysis of a liquefied natural gas terminal.[31] The court reasoned that these effects could not occur "unless a greater volume of liquefied natural gas is shipped from the Terminal and enters the international marketplace" which "the Department of Energy alone has the legal authority to authorize."[32] Accordingly, petitioner "remain[ed] free to raise these issues in a challenge to the Energy Department's NEPA review of its export decision."[33] Later, the petitioner in that case *did* challenge DOE's NEPA review of its export decision.[34] In *Freeport II*, the D.C. Circuit considered DOE's Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States ("Addendum")[35] and its Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States ("Life Cycle Report")[36] as a part of DOE's "hard look" NEPA analysis of its Section 3 export authorization for the Freeport LNG Terminal in Texas.[37]

In a third D.C. Circuit case, *Sierra Club v. Federal Energy Regulatory Commission (Sabal Trail)*,[38] the court clarified that "the fact that a second agency's approval was necessary before the environmental effect at issue could occur" was not sufficient to break the causal chain between an agency action and an environmental effect, but rather an agency must have "*no legal authority to prevent* the adverse environmental effects . . . ."[39] This means that, for an environmental effect to be outside the scope of DOE's NEPA analysis, DOE must be "forbidden to rely on" the potential harm of those effects "*as a justification for* denying" an export authorization.[40] The question is not "What activities does [DOE] regulate?" but rather "What factors can [DOE] consider when regulating in its proper sphere?"[41] In evaluating FERC's NGA Section 7 authority to approve applications to construct and operate interstate pipelines, the D.C. Circuit held that "[b]ecause FERC could deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment, the agency is a 'legally relevant cause' of the direct and indirect environmental effects of pipelines it approves."[42] Similarly, here, because DOE can deny an export authorization on the ground that the export of a certain amount of natural gas would be too harmful to the environment, it is a legally relevant cause of the direct and indirect environmental effects of pipelines it approves.

B. Environmental Effects of Natural Gas Export

Direct effects of natural gas export include the environmental impacts at or after the point of export. With regard to an LNG terminal, FERC typically evaluates the upland operations in its own NEPA analysis, which it completes as the "lead agency" for a natural gas export operation.[43] However, FERC has made clear that not all points of export will be subject to its Section 3 jurisdiction, specifically when

---

[31] *Sierra Club v. Fed. Energy Regulatory Comm'n*, 827 F.3d 59, 68 (D.C. Cir. 2016).
[32] *Id.*
[33] *Id.* at 68–69.
[34] *See Sierra Club v. U.S. Dep't of Energy (Freeport II)*, 867 F.3d 189 (D.C. Cir. 2007).
[35] 79 Fed. Reg. 48,132 (Aug. 15, 2014).
[36] 79 Fed. Reg. 32,260 (June 4, 2014).
[37] *Id.* at 197.
[38] 867 F.3d 1357 (D.C. Cir. 2017).
[39] *Id.* at 1373.
[40] *Id.*
[41] *Id.*
[42] *Id.*
[43] 15 U.S.C. § 717n(b)(1); *see also Freeport I*, 827 F.3d at 41.

those facilities do not connect to a pipeline.[44] Accordingly, when an export facility does not meet FERC's interpretation of an "LNG terminal," DOE must evaluate the direct environmental impacts of that facility, as it is located "at" the point of export. Each of these facilities will be unique and may have a substantial effect on the environment. A failure to analyze the impacts of such a facility in the absence of FERC jurisdiction will result in a regulatory gap. Thus, a categorical exclusion for all NGA Section 3 export authorizations is inappropriate.

DOE in its proposed rule also neglects to consider the indirect effects of authorizing natural gas exports. Indirect impacts caused by "reasonably foreseeable" future actions are recognizable under NEPA and must be considered throughout the NEPA process. Natural gas exports will increase U.S. gas production.[45] Thus, an approval for export of a specified amount of natural gas has a measurable impact on production, and is a legally-relevant cause of that increased production. As the D.C. Circuit explained in the context of a Section 7 pipeline approval, "[b]ecause FERC could deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment, the agency is a 'legally relevant cause' of the direct and indirect environmental effects of pipelines it approves."[46] Here, too, because DOE could deny an application for authorization to export natural gas based on environmental concerns, DOE's approval is a legally-relevant cause of upstream gas production. In this respect, the approval for export from a specific site is similar to the construction of a logging road in *Thomas v. Peterson*,[47] a case that discussed the appropriate scope of a NEPA analysis. In that case, the Ninth Circuit reasoned:

> The location, the timing, or other aspects of the timber sales, or even the decision whether to sell any timber at all affects the location, routing, construction techniques, and other aspects of the road, or even the need for construction.
>
> . . . .
>
> The Forest Service argues that the sales are too uncertain and too far in the future for their impacts to be analyzed along with that of the road. This comes close to saying that building the road now is itself irrational. We decline to accept that conclusion. Rather, we believe that if the sales are sufficiently certain to justify construction of the road, then they are sufficiently certain for their environmental impacts to be analyzed along with those of the road.[48]

In sum, if the production of natural gas is sufficiently certain to justify an export authorization, then it is sufficiently certain for DOE to analyze its environmental impacts, as required by NEPA.

That an export authorization for an increased amount of natural gas will necessarily lead to additional demand for natural gas, with consequences for its price, production, and use, is eminently

---

[44] *See* Shell U.S. Gas & Power, LLC, 148 FERC ¶ 61,163 (Sept. 4, 2014), Emera CNG, LLC, 148 FERC ¶ 61,219 (Sept. 19, 2014; *see also* Congressional Research Service, *Liquefied Natural Gas by Rail: Policy Issues* (Nov. 18, 2019) (describing "virtual pipelines" created by transporting LNG via trucks and rail cars) (attached).
[45] *See* NERA Economic Consulting, Macroeconomic Impacts of LNG Exports from the United States ("NERA Study") 51–52, fig. 30 (2012).
[46] *Sabal Trail*, 867 F.3d at 1373.
[47] 753 F.2d 754 (9th Cir. 1985).
[48] *Id.* at 760.

foreseeable. The D.C. Circuit has recently held that such "generally applicable economic principles," as the relationship between the price of a good and its production and consumption, are "sufficiently 'self-evident'" to "require 'no evidence outside the administrative record.'"[49] The results of generally applicable economics are all the more foreseeable here, as DOE performed an export study in 2012.[50]

The Council on Environmental Quality's ("CEQ's") regulations implementing NEPA provide illustrations of indirect effects that are closely analogous to those at issue here: "growth inducing effects and other effects related to induced changes in the pattern of land use, population density or growth rate[.]"[51] Like impacts on gas production and use, growth-inducing effects and induced changes in the pattern of land use reflect responses—generally market-based—to changes in the supply of, and demand for, various resources. Further reflecting the need to consider such impacts, the regulations include economic as well as environmental impacts among those that an agency must consider.[52]

For that reason, courts have consistently required that agencies extend the ambit of their analysis to include effects akin to upstream production and downstream consumption. The Eighth Circuit has addressed circumstances that closely parallel those here, holding that when an agency approves a rail-line extension that would result in "an increase in availability and a decrease in price" of coal, NEPA demands that the agency examine the environmental "effects that may occur as a result of the reasonably foreseeable increase in coal consumption."[53] In *Mid-States,* the agency's decision enabled an increase in the supply of coal to the domestic market; here, as described below, DOE's Section 3 authorizations will cause an increase in demand for natural gas. In *Mid-States,* that decision had foreseeable effects on the price of coal, its production, and its use.

DOE's Section 3 authorizations have foreseeable impacts on natural gas's price, production, and use. In *Mid-States,* the Eighth Circuit held that the agency could not responsibly or lawfully ignore those effects under NEPA.[54] Likewise, neither could DOE do so here. Other Circuits have reached similar conclusions. When authorizing a runway that would expand capacity and "spur demand," the Ninth Circuit has held that the Department of Transportation must examine the increased usage that will result from that demand.[55] The First Circuit has refused to let an agency construct a causeway and port without examining the "industrial development" that would be enabled by that construction.[56] Those cases establish that when an agency takes an action that will increase demand for a resource, it cannot ignore the effects of that increased demand.

Additionally, DOE must consider the cumulative effects of actions similar to the proposed action, whether existing or reasonably foreseeable. Cumulative impacts include "impact[s] on the environment which result from the incremental impact of the action *when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such*

---

[49] *Airlines for Am. v. Transp. Sec. Admin.,* 780 F.3d 409, 410-11 (D.C. Cir. 2015) (finding standing based on "basic proposition that 'increasing the price of an activity . . . will decrease the quantity of that activity demanded in the market'" (alteration in original) (quoting *Branton v. FCC*, 993 F.2d 906 (D.C. Cir. 1993))).
[50] 2012 LNG Export Study, 77 Fed. Reg. 73,627 (Dec. 11, 2012).
[51] 40 C.F.R. § 1508.8(b) (2019).
[52] *Id.*
[53] *Mid-States Coal. for Progress v. Surface Transp. Bd.,* 345 F.3d 520, 549-50 (8th Cir. 2003) (requiring that agency address air pollution resulting from increased coal use).
[54] *Id.*
[55] *Barnes v. U.S. Dep't of Transp.,* 655 F.3d 1124, 1138-9 (9th Cir. 2011).
[56] *Sierra Club v. Marsh,* 769 F.2d 868, 877-79 (1st Cir. 1985). *See also Friends of the Earth v. U.S. Army Corps of Eng'rs,* 109 F. Supp. 2d 30, 39-40 (D.D.C. 2000) (invalidating agency decision approving casino, without considering economic development that would result).

other actions."[57] "Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time."[58] Cumulative impacts include "coincident effects (adverse or beneficial) on specific resources, ecosystems, and human communities of all related activities, not just the proposed project or alternatives that initiate the assessment process."[59] A cumulative effects analysis focuses on resource sustainability, and has expanded geographic and time boundaries. In the specific context of Section 3 natural gas export authorizations, DOE should consider all pending natural gas export authorization applications before it in order to appropriately assess the cumulative impacts of its actions.

While DOE created an Addendum to Environmental Review Documents Concerning Exports of Natural Gas from the United States,[60] that document did not "specifically project where or to what extent the impacts of increased production might occur in response to any particular amount of exports."[61] NEPA does not allow agencies to consider only those effects whose specifics are known and certain. As the Eighth Circuit held, "when the *nature* of the effect is reasonably foreseeable but its *extent* is not . . . [an] agency may not simply ignore the effect."[62] Indeed, where an action's effects are not precisely known, the Council on Environmental Quality's regulations suggest that the action is more—not less—likely to warrant an environmental impact statement.[63]

NEPA's implementing regulations provide detailed instructions as to how such uncertainty is to be addressed in an environmental impact statement.[64] That the precise location of natural gas production is unknown, therefore, does not render such production unforeseeable, or allow DOE to dismiss its effects as insignificant. "It is well recognized that a lack of certainty concerning prospective environmental impacts cannot relieve an agency of responsibility for considering reasonably foreseeable contingencies."[65] Rather, "[a]t the threshold stage of the NEPA inquiry . . . an agency must determine, to the extent feasible, whether the sum of all reasonably foreseeable effects, discounted by the probability of their occurrence, represent a 'significant' effect on the environment."[66] If so, the "agency must issue an EIS analyzing the probabilistic facets of the prospective environmental impact."[67]

Analysts, experts, and modelers use the location of interstate transmission gas lines as a predictor of where gas production will take place. The reality of the industry is that there is a direct relationship between the siting and construction of well pads and the location of existing or proposed interstate pipelines. These pipelines then lead to natural gas liquefaction facilities, where the gas is

---

[57] 40 C.F.R. § 1508.7 (emphasis added).
[58] 40 C.F.R. § 1508.7.
[59] COUNCIL ON ENVIRONMENTAL QUALITY, EXECUTIVE OFFICE OF THE PRESIDENT, CONSIDERING CUMULATIVE EFFECTS UNDER THE NATIONAL ENVIRONMENTAL POLICY ACT at *v* (Jan. 1997).
[60] 79 Fed. Reg. 48,132 (Aug. 15, 2014).
[61] *Freeport II*, 867 F.3d at 195.
[62] *Mid-States Coal. for Progress,* 345 F.3d at 549-50 (when agency permits rail extension that will increase "availability of coal," it may not ignore "the construction of additional [coal-fired] power plants" that may result merely because agency does not "know where those plants will be built, and how much coal these new unnamed power plants would use").
[63] *See* 40 C.F.R. § 1508.27(b)(5) (intensity depends upon "[t]he degree to which the possible effects on the human environment are highly uncertain or involve unique or unknown risks"); *see also Found. on Econ. Trends,* 756 F.2d at 154-55 (It is not "sufficient for the agency merely to state that the environmental effects are currently unknown," because uncertainty is "one of the specific criteria for deciding whether an [environmental impact statement] is necessary").
[64] 40 C.F.R. § 1502.22(b) (specifying how the agency should proceed when "the information relevant to reasonably foreseeable significant adverse impacts cannot be obtained because the overall costs of obtaining it are exorbitant or the means to obtain it are not known").
[65] *Potomac Alliance v. U.S. Nuclear Reg. Comm'n,* 682 F.2d 1030, 1036-37 (D.C. Cir. 1982).
[66] *Id.*
[67] *Id.*

liquefied for export. DOE could use this information to determine the probable location of upstream environmental impacts. As an example, DRN attaches a region-wide analysis of the impacts of natural gas development in the Marcellus Shale formation, as well as a more specific watershed-based analysis of the potential impacts of natural gas development in the Delaware River Basin.[68,69]

Accordingly, the scope of environmental impacts caused by a DOE Section 3 approval includes existing and reasonably foreseeable shale development/production that would be advanced, induced and supported if a specific amount of natural gas was authorized for export. The reasonably foreseeable actions—the environmental and community impacts of which must be considered—include the construction, operation and maintenance of the shale gas wells that will be the source of the gas ultimately exported—both the new wells that would be constructed and the production that would be induced at pre-existing wells by the proposed export. The analysis of impact for these gas wells must include the associated access roads, gathering lines, compressor stations, water quality effects, water pipelines, water consumption and water disposal, truck traffic, and other supporting infrastructure which is necessary for the construction, development, and operation of these wells.

IV. Conclusion

DOE should not promulgate the proposed rule categorically excluding approvals or disapprovals of new authorizations or amendments of existing authorizations to export natural gas under Section 3 of the NGA. Not only is it contrary to NEPA and governing case law, it runs the risk of creating a void in the review of environmental harms of LNG export facilities where FERC does not exercise jurisdiction. Instead, it should continue to evaluate NGA Section 3 export authorizations on a case-by-case basis to determine whether an EIS or EA is appropriate in accordance with NEPA.

Maya K. van Rossum

the Delaware Riverkeeper
Delaware Riverkeeper Network

Enclosures

[68] CNA Analysis & Solutions, Potential Environmental Impacts of Full-development of the Marcellus Shale in Pennsylvania (Sept. 2016).
[69] CNA Analysis & Solutions, The Potential Environmental Impact from Fracking in the Delaware River Basin (Aug. 2015).

Congressional Research Service
Informing the legislative debate since 1914

INSIGHT

Liquefied Natural Gas by Rail: Policy Issues

November 18, 2019

On October 24, 2019, the Pipeline and Hazardous Materials Safety Administration (PHMSA), in coordination with the Federal Railroad Administration (FRA), published a proposed rule to authorize the transportation of liquefied natural gas (LNG) in rail tank cars. This publication was the latest federal action intended to provide "greater flexibility in the modes of transportation" of LNG to serve domestic and export markets. The proposed rule could conflict with legislation approved by the House of Representatives earlier this year.

Natural gas cooled below -260° F at normal atmospheric conditions condenses into a liquid with 1/600th of its gaseous volume. In this form, it can be economically transported in insulated tanks. When LNG is warmed it "regasifies" and is used the same way as natural gas supplied by pipeline. Like other gaseous or vaporized fuels, natural gas is combustible, so an uncontrolled release of LNG poses a risk of fire or, in confined spaces, explosion. Due to its low temperature, LNG also could injure people or damage facilities through direct contact. Partly because of these safety risks, LNG shipment and the development of related facilities have been controversial in some communities.

Virtual Pipelines

Domestic transportation of natural gas occurs mainly by pipeline. However, not all parts of the United States have sufficient pipeline capacity to meet expected growth in demand. Furthermore, proposed pipelines in New England, New York, and the Mid-Atlantic have encountered legal and regulatory challenges. These challenges have prompted proposals to ship LNG by rail to markets with constrained pipeline capacity. The Federal Energy Regulatory Commission has determined that such "virtual pipelines" are not an economically practical alternative to a major pipeline project "based on the number of ... rail cars that would be needed to transport the project volumes and the facilities, time, and cost necessary to process and deliver these volumes." Nonetheless, some in the energy sector believe LNG by rail may be economic in specific markets or at specific times, such as peak heating season in the Northeast. Consequently, certain natural gas market participants and trade groups assert LNG shipment by rail presents "a growing opportunity."

LNG has been shipped between U.S. and overseas ports in large marine vessels for over 60 years. LNG also has been transported domestically by road in specialized tanker trucks since the 1970s. However, domestic shipment of LNG by rail is relatively new. Federal Hazardous Materials Regulations prohibit rail shipment of LNG except by PHMSA special permit or with FRA approval. The FRA granted the first

Congressional Research Service
https://crsreports.congress.gov
IN11202

such approval in 2015 to the Alaska Railroad Corporation, which has subsequently transported LNG by rail in multi-modal tank containers (**Figure 1**) from Anchorage to Fairbanks. The FRA issued a second approval in 2017 to the Florida East Coast Railroad, which is using LNG as a locomotive fuel and is testing LNG transport in tank containers from Jacksonville to Miami for export to the Caribbean.

Figure 1. Alaska LNG Shipment on Flatbed Rail Cars

Source: Federal Railroad Administration, Office of Technical Oversight, slide presentation.

PHMSA's proposed rule could expand rail shipment of LNG well beyond what the FRA has allowed. The agency's rule aligns with an April 10, 2019, executive order directing the Secretary of Transportation to propose a rule that would "permit LNG to be transported in approved rail tank cars" to be issued by May 2020. It also responds to a 2017 petition from the Association of American Railroads (a trade group) and a 2019 special permit application from Energy Transport Solutions, a prospective LNG shipper.

PHMSA's draft environmental assessment for the special permit states that the applicant intends to ship LNG in "unit trains," which carry one commodity in as many as 100 rail cars. Unit trains are already used in the United States for the shipment by tank car of other energy commodities such as propane and crude oil. However, the FRA has stated that "the transportation of large quantities of LNG in a single train presents unique safety risks." For similar reasons, a 2014 study for the Maritime Administration examining LNG as a maritime fuel recommended that prospective shippers of LNG by rail (to ports) "perform a detailed study of potential routes for LNG transportation ... that avoid densely populated areas and identify emergency response capabilities." PHMSA's rulemaking is examining potential limitations for routes and train length specifically for LNG shipments in rail tank cars. Speed restrictions and advanced braking devices are also under consideration.

PHMSA's proposed rule would allow LNG to be carried in DOT-113C120W specification tank cars (**Figure 2**), which are designed to carry liquefied ethylene, "another flammable cryogenic liquid which shares similar chemical and operating characteristics with LNG." The proposed rule does not discuss specific tank car features designed to reduce the chances of tank car punctures during derailment, such as those newly required of cars carrying crude oil. The proposed rule also does not specifically indicate whether LNG would be restricted to routes equipped with positive train control, an advanced signaling system designed to avert collisions due to conflicting train movements, although it does reference an industry standard that implies this requirement.

Figure 2. Insulated Rail Cars Proposed for LNG

Source: Courtesy of Chart Industries.

On June 24, 2019, the House approved an appropriations bill amendment (H.Amdt. 468 to H.R. 3055) to prohibit the Secretary of Transportation from using appropriated funds to carry out the LNG by rail provisions of the April 10 executive order. It also would prohibit the Secretary from using appropriated funds to authorize LNG transportation in rail tank cars by issuance of a special permit or approval. On September 12, 2019, the Chairman of the House Committee on Transportation and Infrastructure introduced the Protecting Communities from Liquefied Natural Gas Trains Act (H.R. 4306), which would require the FRA and PHMSA "to conduct an evaluation of the safety, security, and environmental risks of transporting liquefied natural gas by rail." To what extent large rail shipments of LNG materialize, and where, will be determined by market factors as well as regulation.

Author Information

Paul W. Parfomak
Specialist in Energy and Infrastructure Policy

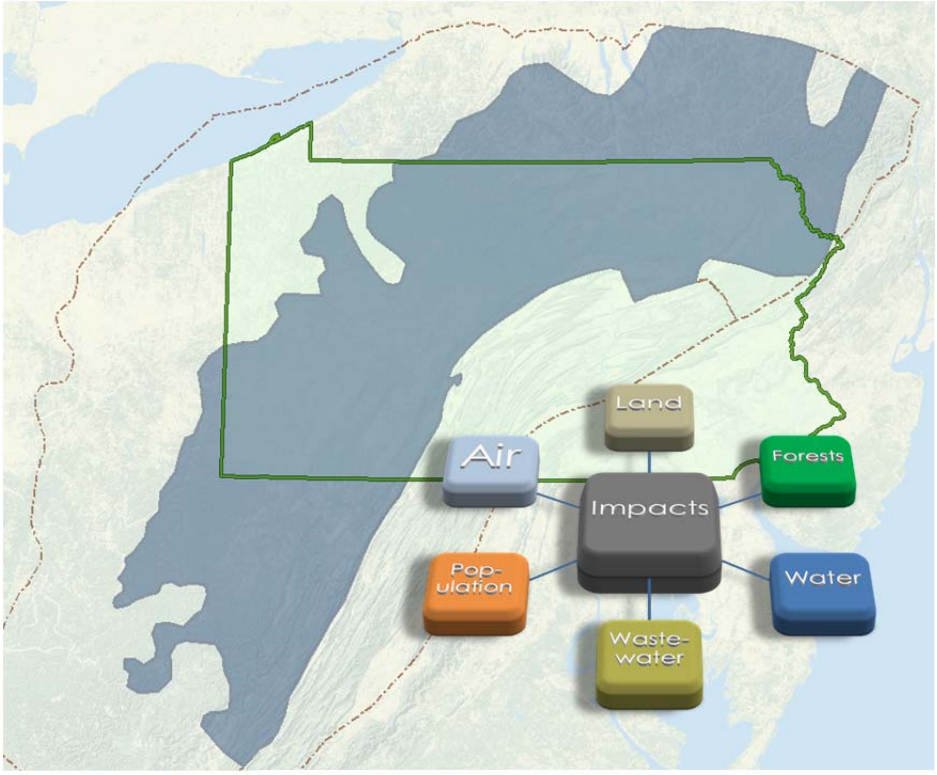
John Frittelli
Specialist in Transportation Policy

Disclaimer

Potential Environmental Impacts of Full-development of the Marcellus Shale in Pennsylvania

Lars Hanson, Steven Habicht, and Paul Faeth

September 2016



CNA
ANALYSIS & SOLUTIONS

Acknowledgements: The authors of this report would like to recognize the study's reviewers including Gerald Shapiro (CNA), Kim Deal (CNA), and Dr. John Stolz (Duquesne University) who completed an independent external review. Any errors that remain are our own responsibility. We would also like to recognize our editor, Maurine Dahlberg.

The Delaware Riverkeeper Network funded this research effort, and we would like to express our thanks for their support.

Authors: Lars Hanson, Steven Habicht, PhD, and Paul Faeth

Document Number: IRM-2016-U-013695

Note: This document contains *projections* of potential impacts that are subject to assumptions and conditions which are documented in the report. Changes to the assumptions could change the results. This report does not constitute a prediction of future conditions, and should not be used to make investment decisions or for commercial purposes.

Distribution:

Unlimited Distribution

Image Credit: CNA

Approved by: **July 2016**

David Kaufman, Director
Safety and Security
Institute for Public Research

Abstract

Unconventional natural gas development using hydraulic fracturing has spurred a rapid expansion of natural gas extraction in Pennsylvania from the Marcellus Shale formation in particular. Further, the gas reserves in the Marcellus Shale could support significantly more gas development. We did a conditional analysis investigating the potential impacts to Pennsylvania's land, forests, water, air, and population *if* development of the Marcellus Shale should continue until all of the technically recoverable reserves are exhausted. We developed a geospatial analysis methodology to identify the most likely future well locations, and derived impacts per well or well pad from published literature or data sets. Our primary output is an *atlas*: a set of maps that puts the potential impacts of the projected natural gas development into useful spatial context. The maps cover several categories of impacts including land use changes, forest fragmentation, population living in proximity to well pads, air emissions, water withdrawals, and wastewater generation. These maps, and the data developed to generate them, will be useful to policy-makers, decision-makers, and others concerned about managing the impacts of Marcellus shale gas extraction in Pennsylvania.

This page intentionally left blank.

Executive Summary

Unconventional natural gas development using hydraulic fracturing has spurred a rapid expansion of natural gas extraction in Pennsylvania especially in the Marcellus Shale formation. Through the almost nine years of unconventional gas development in Pennsylvania, the Commonwealth has witnessed significant changes to energy costs, employment, communities, and the environment. While the price of natural gas has led to fluctuations in the rate of development, the significant quantity of gas reserves in the Marcellus Shale could support significantly more gas development in coming years.

The activities associated with unconventional natural gas development including drilling, land disturbance, water withdrawals, material handling and waste management, and operation of equipment have clear potential impacts to environmental resources and human health. The actual impacts and outcomes of these activities can vary considerably depending on industry practices, technology changes, and regulation, but in general they are proportional to the level of development. Improved practices, regulation, and monitoring can assist in managing impacts as they are occurring, but the overall level of impact will depend on the total amount of development that will occur. While many studies have investigated environmental impacts of gas development as it happens, relatively few consider the long range impacts of what might happen as development continues. In this study, we ask:

> What would be the potential environmental impacts from natural gas development activities in Pennsylvania if the Interior Marcellus Shale resources were fully developed?

To answer this question, we developed a geospatial analysis methodology to identify the most likely future well locations based on the locations of existing wells relative to spatial data layers describing the shale characteristics, terrain, infrastructure, and hydrology of the region. We combined the probability surface generated from this analysis with recent estimates of total recoverable reserves and average production per well to determine how many wells could be developed and their most likely locations. We computed potential impacts based on the well (or well pad) numbers in a given geographic unit, and we derived impacts per well or well pad from published literature or data sets. With information on well locations and level of impact per well, we analyzed the spatial characteristics of impacts of natural gas development.

The scope of this study is limited to investigating potential impacts of additional well development in Pennsylvania in the Interior Marcellus[1] shale play. It does not consider other shale plays such as the Utica Shale. This study does not examine the full range of potential impacts from all activities associated with the natural gas sector[2], does not consider all potential impact pathways (e.g. accidental wastewater discharges), and it does not project possible environmental and human health *outcomes* based on the impacts.

For the Commonwealth of Pennsylvania, we estimated the following potential impacts associated with this study's projections of well development of the Marcellus Interior Shale formation:

- **Well development** – We estimated that 47,600 additional wells could be developed on 5,950 well pads over the next 30 years *if* the Interior Marcellus's technically recoverable resources were fully developed.

- **Land use change** – The construction of natural gas infrastructure (well pads, gathering pipelines, and access roads) to support projected well development would result in about 94,000 acres of land disturbance. Over half (about 51,000 acres) of the land disturbance would impact agricultural land, while about 28,000 acres would constitute the clearing of forest cover.

- **Forest change –** Of the 28,000 acres of forest that would be cleared, we found that 12,700 acres were core forest areas (over 100 meters from the nearest forest edge). Additionally, over 88,000 acres of core forest would be fragmented by road and pipeline development and converted to edge forest. Thus, over 100,000 acres of core forest would be lost due to the combined effect of clearing and fragmentation.

- **Population in proximity to well pads –** We estimated that the current population in Pennsylvania living within one-half mile of a well pad is about 100,000, and, based on our projections, this number could increase to 639,000. Similarly, we estimate that the population living within one mile of a well pad could increase from about 311,000 today to over 1.8 million at full build-out.

[1] The Interior Marcellus is the primary gas-producing portion of the Marcellus formation, with over 95 percent of its gas reserves.

[2] For example, this study does not consider the impacts associated with construction and operation of interstate gas transmission pipelines. Other potential impacts such as road traffic or groundwater contamination are not well suited to analysis using the methods employed for this study.

- **Air emissions –** The additional well development would result in greater emissions of NOx, VOCs, and CH_4 from activities related to well pre-production and production, and compressor stations for moving gas through gathering lines. When the play nears full development (i.e., ongoing emissions from producing wells reach their peak), the annual average air emissions could reach 37,000 tons per year for NOx, 22,500 tons per year for VOCs, and 388,000 tons per year for methane.

- **Water use, withdrawal, and consumptive use –** We determined that the projected natural gas development in the Marcellus would require 242 billion gallons of water in total, in order to mix frac fluid for the hydraulic fracturing process. Averaged over 30 years, this is a water use rate of 34 cubic feet per second or 22 million gallons per day. We found that roughly 200 billion gallons of fresh surface water would be withdrawn to support this development, and that 167 billion gallons would be used consumptively and would not re-join the hydrologic cycle after hydraulic fracturing injection.

- **Wastewater generated –** We estimated that 84 billion gallons of wastewater would be generated from projected natural gas development in Pennsylvania. Wastewater includes drilling fluid waste, plus flowback and produced water/brine recovered from the shale after frac fluid injection and during gas production.

These metrics offer a sense of the scale of the total statewide impacts of natural gas development through full development of the Interior Marcellus Shale. But these aggregated metrics do not tell the full story of the impacts, which have important geographic variations. Thus, the primary output of this research is an *atlas:* a set of maps that puts the impacts of the projected natural gas development into useful spatial context. These maps, and the data developed to generate them, present useful information to policy-makers, decision-makers, and other researchers concerned about managing the range of impacts of shale gas extraction in Pennsylvania.

The maps can be downloaded in sets corresponding to each chapter of this report at: www.cna.org/PA-Marcellus

Section Break.

Contents

List of Figures

List of Tables

Glossary

Abbreviations

DRB	Delaware River Basin
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FEMA	Federal Emergency Management Agency
NLCD	National Land Cover Dataset
PA	Pennsylvania
PA DEP	Pennsylvania Department of Environmental Protection
USGS	United States Geological Survey
CH_4	methane (gas)
EUR	Expected ultimate recovery
HF, HVHF	Hydraulic fracturing, High-volume hydraulic fracturing
HUC	Hydrologic Unit Code
NOx	Nitrogen oxides (including NO_2, NO_3)
TRR	Technically recoverable resources
UNGD	Unconventional natural gas development
VOC	Volatile organic compound
ac	acres
cf/ Bcf/ Tcf	cubic feet / Billion cubic feet / Trillion cubic feet
cfs	cubic feet per second
ft	feet
gal	gallons
gpd	gallons per day
mi	miles
mi^2	square miles
MG	million gallons
MGD/MGY	million gallons per day / million gallons per year

Key terms

brine/produced water	Wastewater recovered during gas production consisting of frac fluid and contaminants from the shale formation.
consumptive use	The portion of water use for fracking that is not recovered from shale.
core forest	Forest of high ecological value more than 100 meters from other land use types, or infrastructure such as roads
edge forest	Forest adjacent to (less than 100 meters) other land use types, or infrastructure such as roads
flowback	Wastewater consisting primarily of frac fluid recovered in the first few weeks after hydraulic fracturing
frac fluid	Fluid composed of water, sand, and chemicals injected at high volume into wells during the hydraulic fracturing process in order fracture gas-bearing shale
gathering pipeline	Type of pipeline used to move gas from producing wells to the gas transmission pipeline network
hydraulic fracturing	The process used to open fissures in gas bearing rock (esp. shale) using high-pressure injection of liquid.
lateral	The horizontal portion of the well drilled in the shale formation.
Maxent	Maximum Entropy (geospatial analysis technique)
play	Layer of rock of similar age/type that contain petroleum products such as natural gas
unconventional natural gas development	General term for the combination of industry practices and technologies (e.g., hydraulic fracturing, horizontal drilling, multiple wells per well pad) used to extract natural gas from shale formations such as the Marcellus
water withdrawal	The portion of the water used for fracking that is withdrawn directly from surface water sources.
well pad	The location from which wells are drilled

Introduction

Since 2007, Pennsylvania has become a major natural gas producing hub due to technology advances that have facilitated gas extraction from the Marcellus Shale play, which underlies portions of Pennsylvania, West Virginia, New York, Maryland, and Ohio. The unconventional natural gas development (UNGD) technology that has enabled this shift is high-volume hydraulic fracturing (HVHF) paired with horizontal drilling on well pads with multiple wells per pad. Hydraulic fracturing uses a high-volume injection of "frac" fluid (water, sand, and added chemicals) to fracture the shale formation, which generally holds gas tightly. Horizontal drilling has allowed each well to travel along the shale layer for several thousand feet, and the ability to drill multiple wells per well pad has increased the speed and efficiency of gas extraction. The net result is that the Marcellus play, which as recently as 2006 was a small player in gas production, now accounts for over 20 percent of total U.S. dry gas production [1].

Unlike several declining shale plays in other parts of the country, the Marcellus Shale play still has a large portion of its reserves available, and can support continuing development [2]. The pace of development will largely be tied to economic factors. The price of natural gas has a significant effect on development activity, as demonstrated by the recent declines in drilling activity in 2015 due to low gas prices. So does the marginal cost of production, which varies regionally across the Marcellus by a factor of three or more [1]. Economic factors in Pennsylvania (such as workforce development) and the role of the natural gas industry in the Pennsylvania economy will also influence development going forward. Over the long term, these economic forces will significantly influence the pace and timing of development, but the ultimate determinant of the amount of gas that could be developed is set by the amount of gas reserves and the technology available to recover the gas (subject to applicable restrictions and regulations pertaining to gas development).

According to the U.S. Energy Information Administration's (EIA) estimates, the Marcellus Shale contains over 144 trillion cubic feet (Tcf) of technically recoverable reserves, of which over 65 Tcf are considered proven reserves [3], and of which most are in Pennsylvania. Over 11 Tcf has been produced in Pennsylvania through the end of 2014, and over 8,800 wells have already been drilled. Taken together, these statistics indicate that tens of thousands more wells would be needed to fully develop the Marcellus Shale resources in Pennsylvania.

Inevitably, UNGD results in some potential impacts to the environment across the landscape of development due to the activities needed to support the phases of development. Land must be cleared and developed in order to build the well pads, roads, and pipelines necessary to access the gas. During production, HVHF requires water to mix frac fluid, and produces volumes of wastewater along with gas that must be handled. Equipment that is necessary to run gas development operations (drilling rigs, pumps, trucks, compressors, and other equipment) produces air emissions, dust, and noise. All of these activities necessary for UNGD have impacts to land cover (including forests), watersheds, air, and human populations [4-22]. Some of these impacts can be mitigated more easily than others, and regulations, industry practices, and simple probability (large variations well-to-well) can have a large effect on the level of impact, or the risk of certain impacts occurring. The outcomes associated with these impacts are largely tied to the density and pace of natural gas development, and the underlying conditions and vulnerability of the affected areas' resources. But in order to understand these impacts, it is first necessary to understand the activities that cause them.

This analysis begins to answer the question: What happens if the Marcellus Shale is fully developed?

Understanding this report

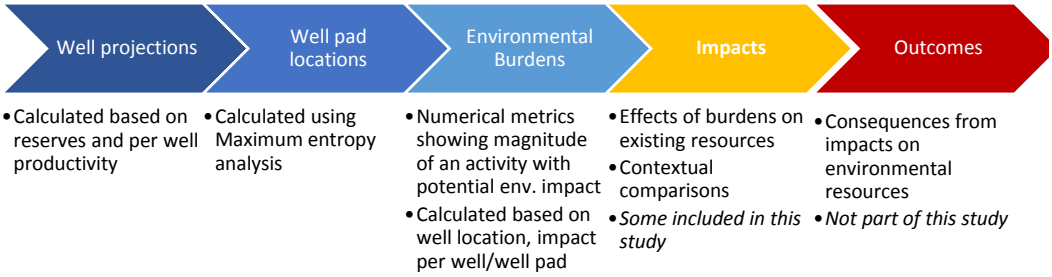
We present this analysis as one projection of what the impacts of full development of the Marcellus Shale may look like across the landscape of Pennsylvania. This study is not intended to be a comprehensive examination of all potential impacts of gas development, but rather is meant to be a starting point and useful guide that can help identify impact categories where more in-depth analysis may be warranted. The geographic breadth of this study limits the depth of the impact analysis.

Our methodology is relatively straightforward: Determine the number of wells required to fully develop the technically recoverable shale resources in the Interior Marcellus, and estimate the most likely well pad locations associated with this level of development. Then, using the projected numbers and locations of the wells and well pads, estimate the level of impacts using available data and scientific literature. In general, we multiply data on "per well pad" impact by projected number of well pads to estimate overall impact, and disaggregate results using useful geographic delineations (counties and watershed boundaries).

The metrics used to evaluate the impacts of gas development can be most easily explained by using the *Burdens* > *Impacts* > *Outcomes* framework advanced by Krupnick et al. [23] to discuss potential environmental impacts of fracking. *Burdens* are the numeric quantification of different activities that may have a potential impact. *Impacts* are the resulting effects of these activities on an environmental

resource. *Outcomes* refer to the secondary or indirect impacts on measures of environmental health that are generally not solely tied to a given impact (i.e. they depend on other factors such as the current condition of the resource). Figure 1 shows how this research effort fits within this framework. The foundation of this analysis is the well projections and associated well pad locations calculated for the full development of Interior Marcellus Shale. From this basis, the environmental burdens, impacts, and outcomes may be computed.

Figure 1. This analysis and environmental burdens, impacts, and outcomes.



This report is best understood as primarily a calculation of the location and magnitude of *environmental burdens* associated with gas development. That is, the metrics used relate primarily to activities (e.g., land disturbance, water withdrawal, air emissions), but not necessarily to the direct impacts or outcomes that may result from these activities.

Where possible, we investigate the *impacts* of these burdens on applicable resources—for example, forest cover lost as a portion of existing forest cover. In this study, we do not evaluate the *potential outcomes* associated with the impacts. For example, the loss of forest cover could potentially reduce the population of a particular bird species, or air emissions could increase the prevalence of respiratory illness. While burdens (and some impacts) can be calculated in a relatively straightforward manner based on the well and well pad projections, assessing outcomes requires a much greater understanding of the current state of environmental resources and potentially affected communities, and the mechanisms by which stressors (burdens and impacts) may influence outcomes. These types of evaluations are not within the scope of this study. Though we do note there is a growing body of literature investigating connections between gas development and these types of outcomes (see, for example [5, 8, 12-13]).

The burdens and impacts examined in this report are also not a comprehensive list of potential impacts. The impacts investigated are those that can be reasonably calculated in a straightforward manner based on the well projections. We aim to present a set of useful impact metrics that can support decision-making and more detailed future analyses, potentially including investigations of probable outcomes.

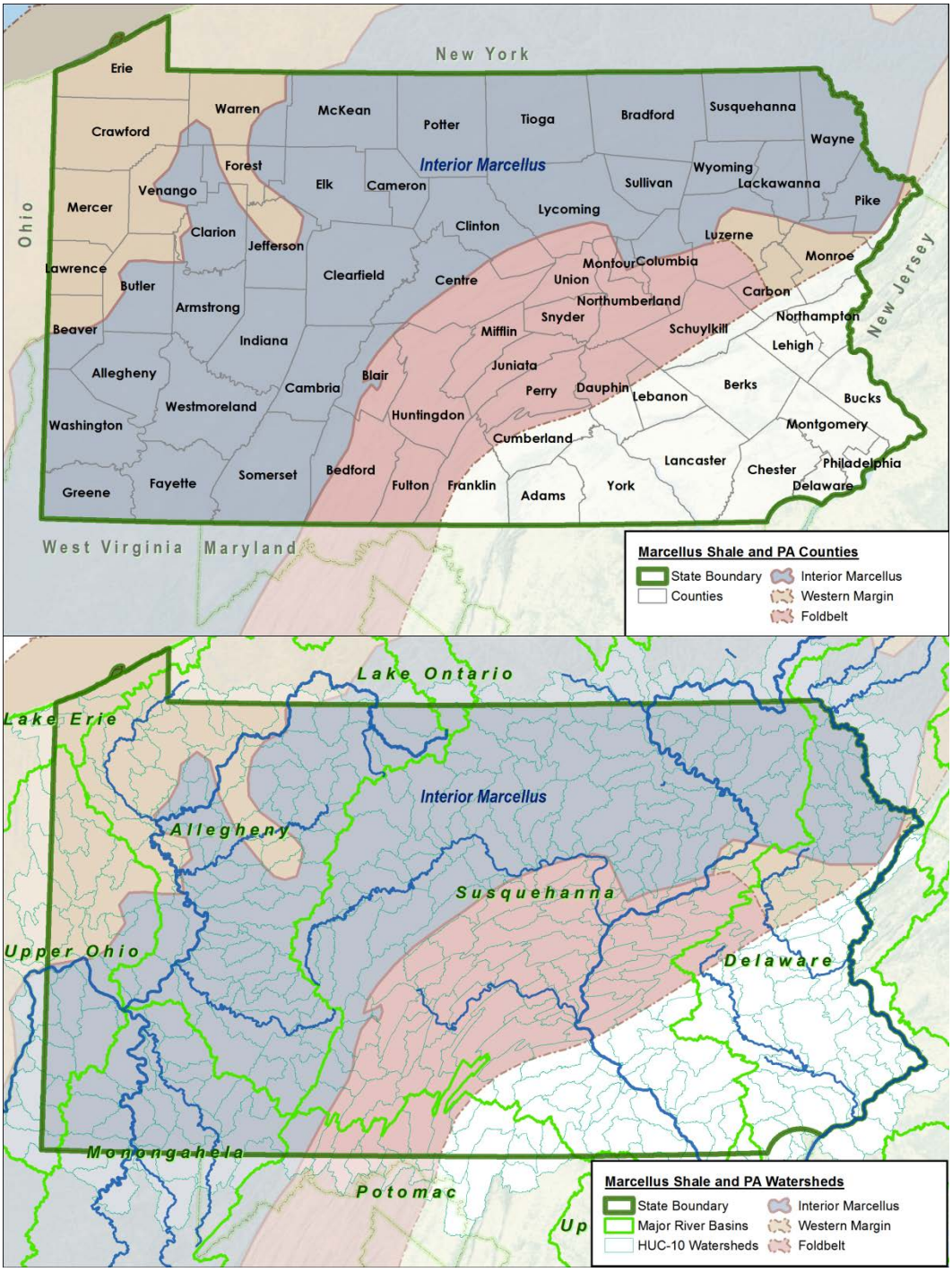
Specifically, we ask: What will be the approximate level of environmental burdens to land resources, forests, water, air, and the population of Pennsylvania that can be reasonably expected based on projections of the numbers of wells and well pads needed to fully develop the Marcellus Shale? We investigate particular impact metrics such as land area needed for infrastructure, forest and core forest loss, water withdrawals, wastewater generated, populations living in close proximity to wells, and air emissions. The impacts investigated tend to be those that can be reasonably estimated based on the well development numbers and locations using average per-well factors (from peer-reviewed literature or publicly available data sources), or additional geospatial analysis or modeling. In general, these impacts reflect average conditions for activities necessary for well development (e.g., building well pads, water withdrawals to mix frac fluid, or running compressors to pump natural gas).

This analysis does not investigate some other potential impacts often associated with gas development, because of data limitations or difficulty assessing impacts at such a large spatial scale. Some impacts such as groundwater contamination (associated with well-casing failures, surface spills of wastewater fluids, etc.) are difficult to investigate because the probabilistic nature of the impact cannot be directly tied to well locations without overly simplistic assumptions. Other impacts such as wastewater treatment and discharge, and community impacts such as truck traffic cannot be investigated easily because they require knowing information about natural gas operations (e.g., wastewater disposal method and location, preferred routes) that cannot easily be determined for long-range projections of well development. Finally, some impacts such as erosion and pollutant loading impacts associated with land development are not investigated because the analysis required is too complex and time-consuming to be completed at this geographic scale.

The primary output of this analysis is a series of maps displaying potential impact from a full development of the shale in several impact categories. We present the information in relevant geospatial context, recognizing that the impacts do vary considerably across Pennsylvania in relation to the relative intensity of gas development and existing condition of local resources. Specifically, we map the impacts by county or watershed (see Figure 2) depending on the nature of the impact. For instance, air emissions and population data are collected at the county level, while water withdrawal impacts are associated with watersheds. For mapping watershed impacts, we use Hydrologic Unit Code 10 (HUC-10) watershed boundaries from the United States' Geological Survey's (USGS's) Watershed Boundary dataset. In Pennsylvania, there about 330 HUC-10s, with an average size of 162 square miles.

The maps can be downloaded in sets corresponding to each chapter of this report at: www.cna.org/PA-Marcellus.

Figure 2. The Marcellus Shale formation and Pennsylvania counties (top), and watersheds (bottom). This analysis focuses on potential future development within the Interior Marcellus portion of the formation only.



This page intentionally left blank.

Projected Natural Gas Development

This chapter presents the current landscape of the Marcellus Shale play in order to predict how it may change in the future in response to the expansion of natural gas extraction. In particular, we focus on the potential development in the Interior Marcellus Shale Assessment Unit, since 95 percent of the shale's reserves are estimated to fall within this boundary [24], and 98 percent of the new wells developed in the region since 2011 have been within this boundary.[3]

For this report, we focused our analysis to determine where this development would most likely occur through Pennsylvania to realize full extraction of natural gas reserves. We then modeled the extent of potential infrastructure (gathering pipelines and access roads) necessary to support these well pads in the DRB. We did not assess impacts from additional infrastructure needed to support natural gas extraction that is not directly tied to individual well pads.[4] Additionally, we did not assess other types of pipeline infrastructure (e.g., interstate and intrastate transmission pipelines, or intermediate collector pipelines to connect to several gathering pipelines) that may be developed beyond the gathering lines that bring the gas from the well pad to the nearest connection to the existing pipeline network.

Methods, data sources, and assumptions

Well location modeling

To predict the most likely locations for the placement of future wells in Pennsylvania, we used the same approach as in our previous analysis of the Delaware River Basin [4], which is based on methodology employed by Johnson et al. (2010)

[3] The other assessment units (Western Margin and Foldbelt) are generally thinner and less rich in gas. Additionally, there were not a sufficient number of existing wells in these areas to complete the geospatial analysis necessary for well location modeling.

[4] For example, equipment storage sites, industrial wastewater treatment plants, centralized wastewater impoundments, quarries, water withdrawal sites, and other supporting infrastructure not associated with individual well pads.

[18]. Briefly, we combined geospatial analysis and maximum entropy (Maxent) modeling using historical well location data and geological and environmental data layers for the Marcellus Shale. This method produced a probability surface in which each pixel contained a value that denoted the likelihood for development. We then determined the projected well pads' locations across the surface by using spatial averaging to center the locations on the highest Maxent value neighborhoods, and used exclusion distances to ensure adequate average well pad spacing.[5] While a full description of the methodology can be found in our previous report [4], we present below the assumptions, data sources, and updates that we used for this analysis:

- Well development will occur at eight wells per well pad on average, based on recent trends of development in the state. New well pads would be built to accommodate each new set of wells. All wells drilled are horizontal wells.

- Development continues until all technically recoverable reserves for the Interior Marcellus (144 trillion cubic feet) are exhausted, at an estimate of 1.9 Billion cubic feet (Bcf) estimated ultimate recovery (EUR) per well. Both values are based on EIA estimates for the Marcellus Shale. We did not include development outside of the Interior Marcellus (e.g., in the Foldbelt or Western Margin Marcellus) or in other shale plays such as the Utica.

- For this analysis, "build-out" or "full development" are terms that refer to the condition when the EIA estimate of technically recoverable reserves in the Interior Marcellus play has been exhausted. We assume that build-out will occur over 30 years. We do not explicitly factor in economics (natural gas price projections, costs of development, etc.) in determining extent of development.

- Well spacing was based on an average lateral length of 5,000 feet and lateral spacing of 600 feet with eight horizontal wells per well pad, consistent with average Marcellus wells in 2014 [26].

- Well pad location exclusions followed PA regulations [27]:

    - Buildings — 500 ft (GIS address points [28]);

    - Streams and Wetlands — 300 ft; (NHDPlus v2 flowlines, NHDPlus v2 waterbodies [29]);

    - Outside 100-year floodplains (FEMA flood hazard layer [30]);

[5] This methodology differs from that of a previous analysis [25], which used fixed or grid spacing for estimating well pad locations. The spatial averaging of Maxent values helps place the well pad in the center of a favorable development zone.

  - Protected areas (USGS Gap Analysis Program Protected Areas Database, class 1 and 2 [31]).

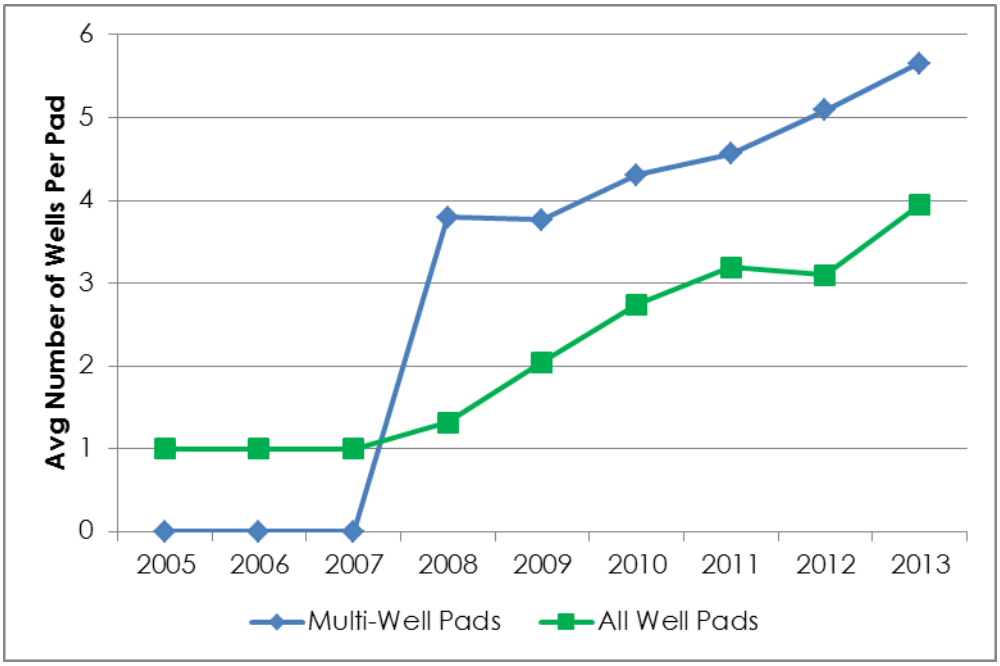
- UNGD development with HVHF is not currently permitted in the portion of Pennsylvania within the Delaware River Basin (primarily affecting Wayne and Pike counties). For this analysis, we assumed that development *would be permitted* in this area, in order to analyze potential impacts to the Delaware River Basin.

Key parameters

The projections of the ultimate number of wells and well pads across the Marcellus are sensitive to several key assumptions. Notably, the number of wells per well pad, the estimated EUR per well, overall reserves estimate, and the number of horizontal versus vertical or directional wells drilled all affect the overall well numbers. Average well pad spacing (a function of lateral length and wells per pad), and exclusion areas will impact well locations. We also assume that all future well development will use HVHF with horizontally drilled wells. Although vertical and directional wells are still drilled in the Marcellus, nearly all new Marcellus wells in Pennsylvania are drilled with horizontal drilling [2].

We used an assumption of eight wells per well pad on average as reflective of typical development practice over the time horizon of this study (roughly 30 years). This is higher than the current average, but there is a clear upward trend in both the number of well pads with multiple well drilling, and the number of wells drilled on multi-well pads [32]. Also, recent analysis has found that nearly all new development is completed with multiple wells per pad [2]. Figure 3 presents the trend of well pad development in the Marcellus Shale and shows that the average number of wells on a multi-well pad has increased from fewer than three wells per pad in 2008 to almost six wells per pad in 2013. Further, there are already instances of well pads with 16 or more wells drilled. The number of wells per pad can have a significant influence on the level of impacts for several impact categories (e.g., land disturbance, forest fragmentation, population affected), and less influence for others (e.g., water withdrawal, air emissions). With more wells per pad, fewer well pads get developed across the landscape, given the same total number of wells. Previous studies [4, 18] have investigated how impacts differ depending on the number of wells per pad.

Figure 3. Average number of wells drilled per well pad in the Marcellus Shale from 2005 to 2013. After UNGD with hydraulic fracturing started in PA in 2007, drilling multiple wells per pad has become common, and the trend is still increasing.



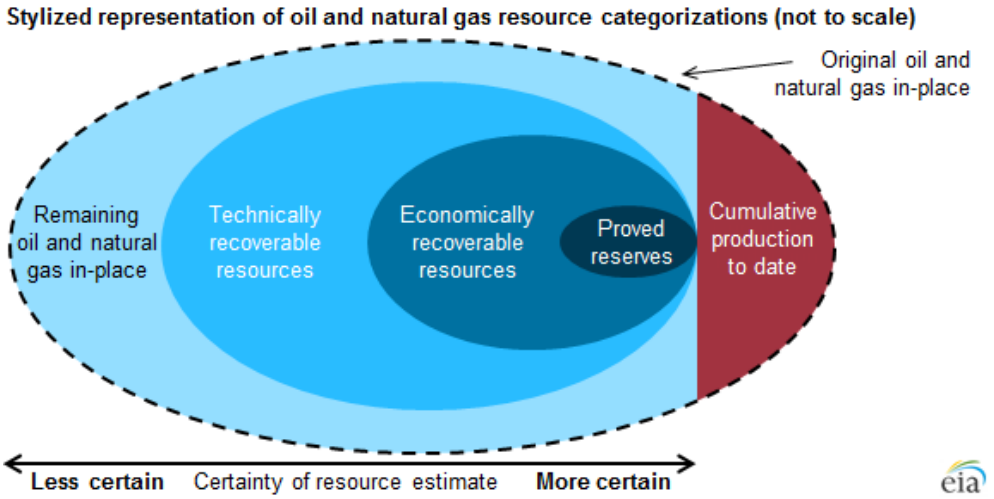
Source: Based on data from [32].

Based on recent EIA estimates [24], we assumed an average EUR per well of 1.9 Bcf. This value is lower than current average EUR estimates for wells drilled in the past few years, which range from approximately 4 to over 6 Bcf per well [3, 33].[6] But the current wells are drilled in some of the most favorable locations, and this analysis, which takes a longer-term view, includes projected drilling in the future when many of the most productive areas would have been fully developed. Development outside of these "sweet-spot" areas currently targeted has a lower expected per-well productivity (by initial production, and correspondingly, EUR) [34]. In any case, the EUR estimate is used only to project number of wells that would be needed to exhaust the current estimate of technically recoverable resources. (We do not project expected gas production by county or watershed in this report.)

[6] In some 'sweet spot' areas, there are reports of much higher per well recovery (over 10 Bcf). Additionally, some wells are being drilled with much longer laterals (over 9,000 ft), which also increases per well recovery.

We also use EIA estimates for assumed technically recoverable resources as 144 Tcf for the entire Interior Marcellus (including areas outside Pennsylvania, but only where drilling is permitted). Technically recoverable resources are unproven, and represent an estimate of the portion of total gas in place (excluding production to date) that can be extracted with current technology. As shown in Figure 4, the technically recoverable resources are larger than the economically recoverable resources and the proven reserves (which EIA estimates at 65 Tcf of gas for the Marcellus). Resource estimates can and do change in response to better information about production from across the shale, more geological data, and changes in technology that allow more recovery (HVHF is an example). And, economically recoverable resources can expand as technology improves over time (lowering development costs), or in response to gas price changes. Since both economics and technology may change over time, it is reasonable to use technically recoverable resources as an estimate for this type of full development or build-out analysis.

Figure 4. Resource categories for various gas-in-place estimates used in industry



Source: US Energy Information Administration, 2014 [35].

There may be considerable debate about the "best" EUR or reserves estimates to use for this type of analysis, and many organizations have their own values they use to support their own analyses. We have selected the EIA estimates of these values because they are the most widely accepted, are publicly available, and are transparent with respect to methodology and limitations. We recognize that changing the estimates could significantly change outcomes. Of course, our well placement methodology is flexible enough that it would be a relatively simple change to increase or decrease the estimate of total wells projections, and investigate the differences in potential impacts.

Infrastructure modeling

In addition to well pads, we considered other natural gas infrastructure required to support development, which at a minimum includes roads to move equipment and materials to and from the well pad, and gathering pipelines which move gas produced at the well pad to market. To model the roads and gathering lines, we used the least-cost path-optimization approach, which is a common approach for siting and analyzing linear infrastructure. This methodology was used in our earlier study of the DRB, and we provide further detail in that report. [4] Briefly, to perform this modeling, we first developed a cost surface for Pennsylvania by combining a variety of geospatial layers[7] relevant to routing, and assigning a cost to the values associated with each layer. We used this cost surface with the "Least Cost Path" tool in ArcGIS 10.2 to determine the most efficient route from each of the projected well pads to the existing infrastructure.[8]

Results

Based on the EIA estimate of technically recoverable resources divided by the EIA average total production per well, and subtracting the number of existing Marcellus wells, we get the number of new wells expected, which is over 66,000 for the entire Interior Marcellus. In our modeling, Pennsylvania accounts for 72 percent of these expected wells (47,600). Based on a scenario of 8 wells per pads, this amounts to 5,950 well pads that may be developed throughout the Commonwealth to accommodate these new wells.

Based on our infrastructure modeling, we found that 5,832 miles of gathering pipeline and 1,342 miles of road would be developed to support full build-out of the Marcellus Shale in Pennsylvania based on our projections of well pad locations. The infrastructure modeled only includes roads/pipelines needed to connect well pads to

[7] These geospatial layers, including slope, land use, roadways, streams, floodplains, and protected lands, are used in least-cost optimization to reflect the *relative* difficulty of building infrastructure through or across these landscape features. For example, building on flat land is easier than building on steep slopes, and crossing wetlands is more difficult than crossing pastures. In general, the least-cost "path" will be the most efficient path to minimize distance while avoiding terrain features that are difficult to cross.

[8] We modeled the least-cost path for each well pad independently, but in (the many) cases where pipeline or road infrastructure followed the same path, we assumed they could share a road/pipeline (i.e., we did not double count this length). Modeling the infrastructure build-out in sequence, well pad by well pad, or centralized planning of intermediate collector lines could result in slightly lower distances per well pad, but likely would not change results significantly.

the nearest (or least costly to reach) point in the existing road or pipeline network. The analysis does not consider additional infrastructure needed to support increasing gas production on regional or statewide basis such as interstate or intrastate gas transmission pipelines. Note that these projections are intended to illustrate the potential scale of infrastructure with a reasonable estimation of spatial extent and are not meant to predict exact locations.

We have developed a variety of maps to present the statewide results of projected natural gas development, in order to provide spatial context for our discussions. Table 1 gives an overview of these maps. The discussion section provides descriptions and information that will help readers understand each map.

Table 1. Well Projections Map Index.
Access maps at www.cna.org/PA-Marcellus

Map	Title
1.1	Probability surface for well pad development in the Interior Marcellus
1.2	Projected well pad development locations
1.3	Projected well development by county
1.4	Projected well development by watershed
1.5	Projected well development density
1.6	Projected natural gas infrastructure by county

Discussion

Map 1.1 – Probability surface for well pad development in the Interior Marcellus

This map shows the probability surface generated by the Maxent program based on existing well locations, and 'environmental variables' including shale characteristics, existing infrastructure, land use, and terrain. The surface has 30-meter resolution and uses a color scheme to depict the relative likelihood of development (i.e., Maxent value) based on the environmental variables, with "cooler" colors denoting areas with a lower probability of development, and "warmer" colors denoting those with a higher probability of development. These probabilities are based on the characteristics of the underlying geospatial layers at existing Marcellus wells developed from 2007 to 2013. The Maxent surface was developed for the Interior Marcellus play only. We have also included the boundaries of the full extent of the Marcellus formation. These boundaries will be included in all maps generated from this analysis for spatial context. The two major hotspots for existing drilling are in the southwest and northeast portions of the Marcellus Shale in Pennsylvania.

Map 1.2 – Projected well pad development locations

This map shows the location of projected additional well pads that would be developed in the Pennsylvania portion of the Interior Marcellus Shale through full development of EIA technically recoverable resources. We determined the projected well pad locations from the probability surface by using spatial averaging to center the locations on high Maxent value "neighborhoods" instead of particular individual pixels with high probability scores. The 5,950 well pads are divided into color-coded quintiles based on their Maxent value, to illustrate the relative suitability of each location. The existing Marcellus wells in the state are also depicted on the map, in grey, for reference.

Map 1.3 – Projected well development by county

This map shows the number of projected additional wells that would be developed in the Pennsylvania portion of the Interior Marcellus Shale through build-out by county. We developed well projections based on the projected well pad locations (see Map 1.2) with an average of eight wells per pad. The bars show the number of horizontally drilled to date, and then the projected number of additional wells broken into five groups (quintiles) ranging from most likely (red) to least likely (blue) as determined from the Maxent probability score.

Map 1.4 – Projected well development by watershed

This map shows the number of projected additional wells that would be developed in the Pennsylvania portion of the Interior Marcellus Shale through build-out by HUC10 watershed. We developed well projections based on the projected well pad locations (see Map 1.2) with an average of eight wells per pad.

Map 1.5 – Projected well development density

This map, like Map 1.4, shows the number of additional wells to be developed in each watershed based on the projections in this study. In this case, the map shading shows the additional wells normalized to watershed area in terms of wells per square mile. This map shows the relative density of well development independent of watershed size. (Large watersheds can accommodate more well pads, which might skew the perception of where development is most intense, absent this correction.)

Map 1.6 – Projected natural gas infrastructure by county

This map shows the amount of projected road and gathering pipeline infrastructure, in miles, that would be developed in Pennsylvania to support natural gas development to build-out. We used least-cost path optimization to model the gathering pipelines and access roads that could be developed to connect the projected well pads to existing infrastructure in the state. The map includes the existing pipeline infrastructure in the state, in red, for reference and context (the existing road infrastructure is too dense to provide meaningful information). Within each county, we also present the average miles of infrastructure developed to support a well pad in the county, which is a function of the proximity or density of existing infrastructure. The values show first the average miles of pipeline per well pad, and then the average miles of road per well pad.

General discussion

To begin the study, we examined potential well development across the full extent of the Interior Marcellus. Evaluation of the probability surface shows two distinct areas with a concentrated high probability of development: one in the northeast region of Pennsylvania (around Tioga, Bradford, and Susquehanna counties), and the other in the southwest region of the state (around the Pittsburgh area). These two areas are consistent with a majority of the existing shale gas development seen in the Marcellus region. There are several other smaller hotspots, and large regions with somewhat lower potential for development.

The probability surface and well projection estimates are subject to several important caveats. By necessity, the reserves estimates represent a snapshot in time; they are constantly changing based on new information collected from drilling productivity and geological review. It is likely these estimates will continue to change, but we have elected to use the most recent EIA data available at the time of the study. Since this a long-range analysis, we also assume no regulatory constraints (other than those listed in the methods section)[9] or economic constraints when developing the probability surface.

Our projections show that 12 counties could each see development of over 2,000 new wells to support full extraction of the resources in the Interior Marcellus. Many of these counties are located within the current hot spots, but a few, such as Potter,

[9] For example, this analysis does allow development in the Delaware River Basin, and in state forests, which are locations that currently have moratoriums on new development.

Elk, and Armstrong counties, are not experiencing as much development today and thus would see larger increases in development, albeit possibly not until the current hot-spots are nearly fully developed. Even with the updated assumptions used in the modeling for this analysis, it is worth noting that our results for Wayne County (2,328 potential wells) are still very consistent with those from our previous analysis (2,424 potential wells) that focused on the Delaware River Basin.

We project well pad locations to support the calculation of impacts, but they should *not* be interpreted as explicit *predictions* of where wells will actually go. Although high-resolution spatial data allows fairly precise well pad siting, this analysis is most useful for identifying which portions of the Marcellus Shale may be most suitable for development (relative to all the others). Actual locations of wells depend on many site-specific factors, not the least of which is a legal lease contract to perform drilling on a property. Furthermore, the projected well pad locations should not be used to estimate impacts at small scales, such as for individual parcels or neighborhoods. Further, our modeling of the natural gas infrastructure was based on a standard GIS approach to provide a representative picture of this development, and carries the same caveat as the well pad locations. The actual routes could depend on additional site-specific factors, such as lease holds and applicable laws and regulations.

We found that the average length of pipeline developed to support well pads varied widely across the state, owing to the extent of existing infrastructure in place. Counties in northeast Pennsylvania showed an average length of about 1.5 miles of pipeline per pad, which is consistent with previous studies on pipeline development [36-37]. However, the counties in the southwestern part of the state showed much lower averages of a half-mile or less per pipeline. Examination of the existing pipeline infrastructure supports these results, as the pipeline network is much denser in southwest Pennsylvania, reducing average distance needed to connect to it. This produced a statewide average of pipeline length per pad of around 1 mile. The average length of road per well pad was much more consistent across the state, not deviating much from about 0.2 miles per pad, likely owing to the dense network of road infrastructure already in place.

Of course, there are several caveats to keep in mind related to the infrastructure modeling. The infrastructure modeled only includes the well pads, gathering pipelines, and roads that are necessary, at minimum, for unconventional gas development. In the next section, land cover impacts are limited to these infrastructure types, and do not include other facilities such as equipment storage, or centralized waste processing facilities. The routes selected by the least cost path analysis do not consider the suitability of the existing roads or pipelines for handling the traffic or gas volume from the new wells. Rather they consider the most efficient route to the nearest (or least costly to reach) existing road or pipeline. A longer path could be necessary if there are access, capacity, or usage issues with the nearest road/pipeline. Also note that the roads and especially pipeline data may not be

completely up to date if they are available at all [38], so shorter paths could exist in areas that have had recent road or pipeline construction. Finally, planning pipeline or road layouts for several well pads at a time (if a single company operated them, for instance) could result in different infrastructure development patterns (total length could be shorter or longer).

In general, our estimates for gathering pipeline length are lower than some other estimates such as the 25,000 miles estimated by former PA Department of Environmental Protection (DEP) secretary John Quigley [38], or the 10,000 miles estimated by the Nature Conservancy for a similar number of well pads (based on an average of 1.65 miles per well pad) [36]. One potential explanation is that our infrastructure modeling reflects regional differences in existing pipeline density. Further, the other estimates may include some other intermediate gathering and transmission pipeline infrastructure beyond the immediate gathering pipelines.

There are several ways this analysis could be revised and extended in the future. The maximum entropy analysis in particular is flexible, and can be updated to include more recent data, and additional data layers not included in this study. Simply repeating the analysis will a larger set of existing wells to 'seed' the model should result in improved projections. Similarly, updated maps of underlying layers such as gas pipeline infrastructure, and roads could affect the relative probability of development where there has been rapid change in the past few years.

There are several possibilities for other data layers to include in the maximum entropy modeling. As more Marcellus wells are drilled, improved maps of shale richness (e.g., total gas in place) and well productivity are being generated by the gas industry and academics. These could be helpful to add additional weight to development in known hot-spots. We did not include such maps as a data input to the maximum entropy analysis, as there was no authoritative data source, the maps available (e.g., investor presentations from the gas industry) vary widely in their estimates, and the geospatial data sets are either not publicly accessibly or not well-documented. We also did not consider the presence of other shale plays in the region (e.g., the Utica), but it is likely the ability to access multiple plays influences the likelihood of drilling. Finally, leasehold data could be included in the maximum entropy analysis to identify areas with particular likelihood for drilling.

While these data sets could improve the projections, we intentionally limited the maximum entropy analysis to layers reflecting physical parameters of the shale, land surface, and infrastructure that are *publicly available* and *not subject to rapid change*. In general, the marginal information gained for Maxent analysis decreases as more input layers are added. As the available data sets improve, and become more widely accessible, these additional factors plus economic and regulatory considerations could be explicitly included in follow-on studies.

This page intentionally left blank.

Impact on Land Cover

When assessing the environmental impacts of natural gas development, one of the most unavoidable aspects of such development is the impact on land cover. A typical well pad may cover three to five acres of land to support the well-drilling and hydraulic process, which includes the well site and room for supporting equipment, onsite water and wastewater storage (impoundments and/or closed tanks), and adjacent disturbed areas (e.g., land for regrading and leveling the well pad). In addition to the well pad, development of land to support natural gas extraction requires access roads to the site and gathering or feeder pipelines to transport the extracted gas from the site to the existing transmission infrastructure [14, 36-37, 39]. The resulting land disturbance from this development can present both short- and long-term risks to the use of the land, depending on the remediation and reclamation procedures used [40-41].

One issue associated with the development activities from natural gas extraction in the Marcellus Shale is the impact on forests [14, 18, 39-40]. Pennsylvania's dense forest cover provides the region with a variety of ecosystem services, such as carbon sequestration, clean air, aquifer recharge, and recreation/eco-tourism [42]. Furthermore, forest cover in the region is home to a variety of different plant and animal species that rely on the forest for their habitat. The edge transition from non-forest to forest area creates a habitat that tends to favor generalist species over rare or vulnerable species, and an increase of edge forest can promote the spread of invasive species [40].

Another issue of interest focuses on the relationship between land and water. Clearing of forests and other natural land cover for natural gas infrastructure and subsequent conversion to impervious cover or compaction of soil in construction right-of-way can change the hydrologic behavior of the landscape, leading to more runoff and erosion and less groundwater infiltration. Impervious cover (or more broadly, changes in the perviousness of the landscape) can be used to assess impacts on water quality, since it represents how much water can infiltrate the soil versus how much will run off into nearby streams [43]. Stream quality in a watershed will generally become impacted once impervious cover reaches above 10 percent, though some studies have shown impacts to streams above as little as 2 percent [44]. Stream crossings by road and pipeline infrastructure can also have an impact on flow characteristics in the stream, sediment loads, and water quality, and on the health and movement of aquatic species [45-48].

To assess the potential impacts of natural gas development on land cover in Pennsylvania, we combined our projections of natural gas well and infrastructure development in the state with a suite of GIS tools and methodology. We used the projected well pad locations and supporting infrastructure to survey the impacts to current land cover, and the potential for forest fragmentation. Then, to give context to the amount of area impacted, we compared the total disturbance area to the amount of existing developed land.

Methods, data sources, and assumptions

Before the infrastructure to support natural gas extraction—e.g., well pads, gathering pipelines, and access roads—can be constructed, the land must be cleared. In the previous chapter, we documented how the natural gas infrastructure locations were modeled as points for well pads, and linear features for roads and pipelines. To determine the land area affected by disturbance from these activities, we used the "Buffer" tool in ArcGIS to map the spatial extent of the well pads and pipeline and road rights-of-way.

We then used this footprint to extract the impacted land cover values from the 2011 National Land Cover Dataset (NLCD) raster. "Land disturbance" refers to all land that falls within this footprint. By contrast, for the purpose of this study, "new clearing" refers to all land cover types within this footprint except for developed land (open space, low density, medium density, or high density), which has already been cleared. For this analysis, we considered the land necessary for initial development of the infrastructure including the construction rights-of-way necessary for equipment access to build the roads and pipelines.

Given the prevalence of forest cover in Pennsylvania (approximately 60 percent of total land cover) and the potential for impact, we extended our land cover analysis to focus on the extent of potential forest fragmentation caused by this disturbance. To assess this impact, we generated a baseline core forest raster from the NLCD raster using the Landscape Fragmentation Tool v2.0 [49] and applied a forest edge width of 100 meters. After we generated the baseline condition, we assessed the potential impact from natural gas development by applying an additional 100-meter buffer to the projected spatial footprint of gas infrastructure (i.e., well pads and road and pipeline rights-of-way) to determine the changes in core and edge forest due to new edge effects.

We also performed an analysis to compare the total new land cleared for gas infrastructure to existing developed land, in order to put the area of development into context. We estimated existing developed area from 2011 NLCD by computing the total of the developed land cover categories for low-, medium-, and high-density

development (NLCD codes 22, 23, and 24), which represent most urban and suburban development areas (though not transportation or open cleared land).

To evaluate land cover burdens associated with Marcellus gas infrastructure development, we used the following assumptions:

- Each well must be located on a well pad, and each well pad must be connected via road to an existing road, and via gathering pipeline to the existing natural gas pipeline network in PA (exclusive of distribution or "downstream" pipelines that bring natural gas directly to homes and businesses).
- Each well pad occupies 3.5 acres.
- Each gathering pipeline requires a 30-meter right-of-way, and each access road requires a 10-meter right-of-way.
- Core forest represents forest patches that lie 100 meters inward from the nearest non-forest land cover (i.e., the forest edge).
- Potential new stream crossings were identified as intersection points between the modeled gathering pipeline and access road routes and Pennsylvania streams in the National Hydrography Dataset Plus version 2 (NHDPlus v2) database [29].

The baseline results are presented using both the county and HUC10 watershed boundaries, but the impacts on forest and stream crossings are presented only for watershed boundaries.

The assumptions for development area reflect the area generally needed for *initial construction* of infrastructure. After construction, some of this area may be partially returned to existing uses during operation, or at the conclusion of development. This report does not examine the evolution of the landscape through the development period as it responds to varying rates of development and varying remediation and reclamation practices. Instead, this report focuses on the direct area impacted by construction of well pads, gathering pipelines and roads.

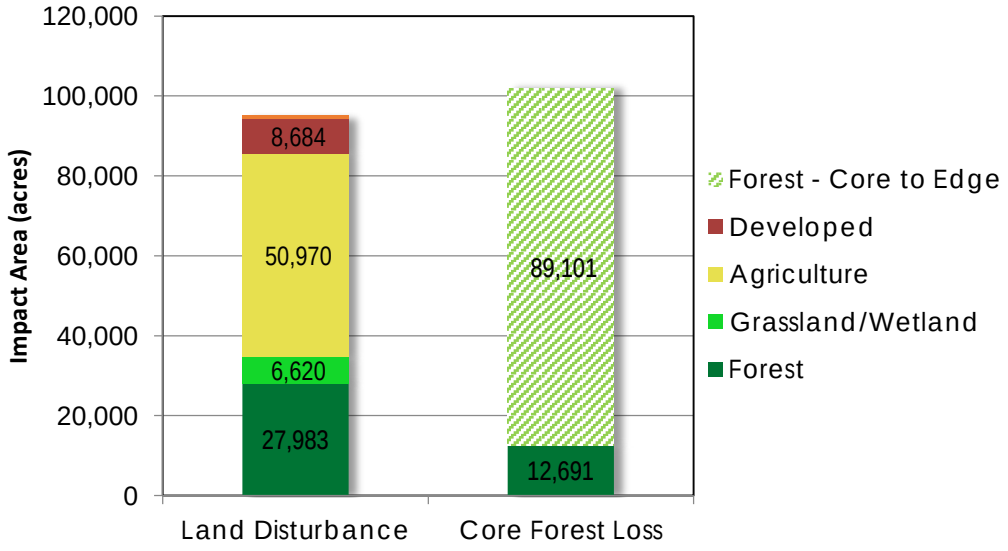
It is important to note that many of these infrastructure types do not cover the full range of land development activities associated with gas development, and they do not consider the estimates of additional area needed for equipment storage, centralized impoundments, wastewater treatment facilities, mining and quarry areas for soil/sand/gravel, earth moving (cut and fill) outside of the rights-of-way, landfill areas, or other areas needed to otherwise support natural gas development.

Results

Based on our projections of well pad development and associated supporting infrastructure, we generated Pennsylvania-wide estimates of land cover burdens. Figure 5 shows the results of our analysis at the statewide level. We found that just under 95,000 acres of land could be disturbed by construction of natural gas infrastructure in the state, about 28,000 acres of which would constitute the clearing of forest cover. However, over 100,000 acres of core forest could be lost as a result of the combined effect of clearing and fragmentation due to the creation of new forest edges.

These estimates are similar to, but slightly lower than previous Pennsylvania estimates of forest disturbance. The *Pennsylvania Energy Impacts Assessment* [18] completed by the Nature Conservancy found that for 60,000 wells, direct forest clearing would be between 38,000 acres (10 wells per pad) and 61,000 acres (six wells per pad). They estimated that additional core forest loss from fragmentation would be between 91,000 acres (10 wells per pad) and 147,000 acres (six wells per pad).

Figure 5. Pennsylvania statewide land cover impacts from natural gas development including land disturbance by initial land cover type and core forest loss due to land disturbance and core to edge forest transition due to fragmentation.



While these figures are informative for comparisons to other shale gas basins or across industries, the importance of the impacts within Pennsylvania is difficult to

discern from the statewide figures. For example, the 28,000 acres of forest cleared only represents 0.2 percent of the total forest cover in Pennsylvania. Breaking these impacts down to the county or HUC10 watershed level offers a more informative picture of where these impacts may be concentrated. Table 2 gives an overview of the maps generated for this impact category. The discussion section provides descriptions and useful information for understanding each map.

We also found that in many counties affected by natural gas development, the construction of new gas infrastructure could affect an area comparable to or larger than all existing developed land (e.g., residential, commercial, industrial land uses).[10]

Table 2. Land Cover Impacts Map Index.
Access maps at *www.cna.org/PA-Marcellus*

Map	Title
2.1	Land disturbance by county
2.2	Land disturbance by watershed
2.3	Forest cleared by watershed
2.4	Core forest loss by watershed
2.5	Existing developed area versus new clearing for gas infrastructure
2.6	Stream crossings by watershed

Discussion

Map 2.1 – Land disturbance by county

This map shows the total amount of land disturbed from natural gas development by county. This metric represents the total area of land, in acres, that would underlie well pads or rights of way for pipelines or roads. In this map, we use pie charts to represent the breakdown of the land cover impacted from natural gas development in each county. For visibility on the map, we combined the 11 land cover classifications from the NCLD dataset into broader groups, as shown in Table 3.

[10] We excluded Developed Open Space (NLCD code 21), which primarily includes undeveloped parcels and transportation.

Table 3. Land cover groupings by 2011 National Land Cover Dataset classifications.

Grouping	NLCD Classifications
Forest	41 – Deciduous Forest; 42 – Evergreen Forest; 43 – Mixed Forest
Grassland/ Wetland	71 – Grassland Herbaceous; 52- Shrub/Scrub; 90 – Woody Wetlands; 95 – Emergent Herbaceous Wetlands
Agriculture	81 – Pasture/Hay; 82 – Cultivated Crops
Developed	21 – Developed Open Space; 22 – Developed Low Intensity; 23- Developed Medium Intensity; 24 – Developed High Intensity; 31 – Barren Land

Map 2.2 – Land disturbance by watershed

This map shows the total amount of land disturbed from natural gas infrastructure development by HUC10 watershed. This metric (shown in shading on the map) represents the total area of land, in acres, that would underlie well pads or rights of way for pipelines or roads at the time of initial construction. In this map, we also use bar charts to represent the breakdown of the impacted area by land cover type (according to the 2011 NLCD) in each watershed with over 100 acres of disturbance.

Map 2.3 – Forest clearing by watershed

This map shows the total amount of forest projected to be cleared from natural gas infrastructure development by HUC10 watershed. This metric represents the total area of forest, in acres, that would underlie well pads or rights-of-way for pipelines or roads at the time of initial construction. We presented this impact at the HUC10 watershed level due to the role that forest cover plays in preserving water quality.

Map 2.4 – Core forest loss by watershed

This map shows the impact of forest fragmentation as core forest lost from natural gas development by HUC10 watershed. This metric, shown in the shading, represents the total area of core forest, in acres, that could be lost due to construction of well pads or rights-of-way for pipelines or roads. Within each watershed on the map we also label the percentage of total pre-development core forest that would be impacted (for cases where this value exceed 1 percent). Note that this loss in core forest area comprises both forest that is cleared for infrastructure (i.e., direct losses shown in Map 2.3) and the indirect losses resulting from core to edge forest conversion along the road and gathering pipeline rights-of-way.

Map 2.5 – Existing developed area versus new clearing for gas infrastructure construction

This map puts the land disturbance area associated with gas infrastructure development in context relative to total existing urban and suburban developed area by watershed. We computed the existing developed area in each watershed by summing the developed low-density, medium-density, and high-density land cover areas (NLCD codes 22, 23, 24) from the 2011 NLCD dataset. These estimates include most urban and suburban developed area in residential, commercial, and industrial land uses, but exclude most undeveloped open space and land use for transportation. The map compares the total land needed for initial construction of natural gas infrastructure with these existing developed areas.[11] Yellow bars indicate the relative amount of land clearing for initial gas infrastructure construction by watersheds. The shading indicates the ratio of new gas infrastructure clearing area compared to existing developed area; a value of 1 indicates that the new infrastructure for gas development will occupy an area equal to all existing development in the watershed.

Map 2.6 – Stream crossings by watershed

This map shows the projected number of new stream crossings associated with construction of road and pipeline infrastructure. Each stream crossing represents the intersection of the modeled gathering pipeline or road routes and streams in the USGS NHDPlus v2 database. Stream crossings within 250 feet of each other were treated as one crossing. On the map, the blue bars show the relative numbers of crossings by watershed, and the shading indicates the density of new stream crossings in units of crossings per 100 square miles. (The average watershed area of 162 square miles is on the same order of magnitude.)

General discussion

Our results showed that the construction of well pads and associated infrastructure to support shale gas development would have an impact on the land cover of Pennsylvania of over 100,000 acres, affecting primarily agricultural land (54 percent

[11] This is purely to give context to the scale of impacted area on a watershed basis, and is not meant to imply that the land use types for gas infrastructure are similar in character to general urban/suburban development.

of disturbed land) and forest land (30 percent). This assessment of land disturbance only accounts for the well pad and rights-of-way for gathering pipelines and access roads to support those well pads. It does not account for additional construction that could occur to support natural gas development, such as new transmission pipelines that may be needed to help move gas to market, or new compressor stations to support gas transmission through the pipeline network. This construction could be expected to add to the footprint of development and cause additional land cover impacts to the state.

Land-cover change from shale gas development is unavoidable, and disturbance can be significant at build-out. The loss of forest cover, in particular, can have significant impacts at the watershed level, such as degraded water quality and a loss of biodiversity from disappearing flora and fauna that cannot tolerate "edge effects." For instance, we found that some Pennsylvania watersheds could lose over 5 percent of the existing core forest. Furthermore, remediation procedures to restore vegetation on the impacted land often do not replace mature forest cover, both because of the need to maintain access to gathering lines and use roads, and because mature forests take a long time to grow.

Many of the environmental impacts and outcomes related to land cover changes are difficult to understand at this level of analysis because they are highly dependent on how the changes occur over time, something we did not investigate in this study. It is relevant to note that the land cover changes will not occur all at once, but build over time as development continues. This analysis only considers total area within

Further study related to these impacts could include:

- Investigating effects of timing or rate of development and remediation and reclamation practices used on land cover over time
- Estimating potential erosion and sediment loadings associated with land clearing and infrastructure development over time, subject to varying assumptions of development rate and management practices
- Assessing vulnerability of species to the changes in forest area, loss of core forests, or potential water quality effects.

Impact on Population

The distance from active well pads has been shown to correlate with certain health and environmental risk factors. Distance from activity is often used as a primary discriminator for determining dose intensity in public health studies. As a result, knowing the potential population within several distances of the proposed well pads is useful for evaluating potential impacts to Pennsylvania residents. In this study, we do not assess the likelihood of particular health outcomes occurring for populations within the specified distances.

We report the populations living within two distances of well pads: one-half mile and one mile. These distances represent a close to moderate distance from well pads, and a moderate to farther distance, respectively. Several health studies have used similar distances to divide experimental groups when investigating variations in health risk factors related to natural gas extraction [13, 19, 50-52].

The maps in this section should be read only as reporting the population (based on the 2010 Census) within the specified distances from well pads through full development of the Interior Marcellus play. These maps do not account for potential or projected population growth, or population living within the specified distance of other gas infrastructure such as roads, pipelines, equipment yards, compressor stations, or wastewater treatment facilities.

Methods, data sources, and assumptions

We evaluate the population within two distances of Marcellus Shale well pads, one mile and one-half mile, using 2010 census block data for Pennsylvania [53]. Unlike our previous analysis for the DRB ([4]), which has a moratorium on natural gas development, there are existing Marcellus well pads in many parts of the Commonwealth. We analyzed the population within each county within the specified distance for “Current” Marcellus well pads, for “Additional” well pads developed through build-out, and population “Outside” the specified distance.

We used a buffer method in ArcGIS to compute the areas within the specified distances, and intersected these areas with the Census population blocks to determine population affected. Our previous report, *The Potential Environmental Impact from Fracking in the Delaware River Basin* [4], has a full description of

methodology associated with computing the population living within a given distance of projected well pad locations. In brief, the following assumptions and data sources were used.

- Population estimates were computed from 2010 census, census block data (2010 Census Bureau – SF1 data [53]), which is the finest resolution available. Population is assumed to be distributed with constant density within each census block to make population estimates where a portion of the census block falls outside the designated distance from a well pad location.
- Existing well pad locations were computed based on commercially available well location data (IHS, 2014 [54]) through September 2014.[12]
- Projected well pad locations from this analysis were used to determine "Additional" area. We only counted new area affected, and did not double-count area within the specified distances of existing well pads.
- Total population estimates reflect the sum of "Current" and "Additional" population within the designated distances.

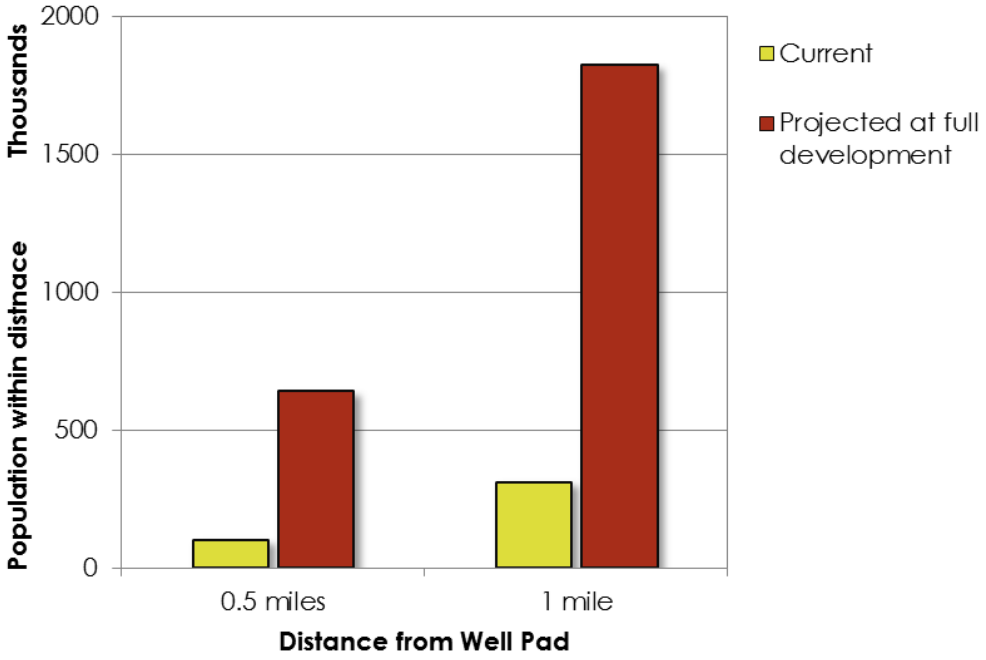
Results

Based on the well pad locations generated for this analysis, and county-level data on population in U.S. census blocks, we estimated Pennsylvania-wide impact estimates for area and population within one-half and one mile of well pads. For area, we found 1,813 square miles within one-half mile of existing wells, and 6,354 square miles after all projected wells are included. The corresponding values are 4,680 and 14,450 square miles for the one-mile distance from well pads.

Figure 6 shows the Pennsylvania population estimated to be living within these distances both currently and at our projection of full development.

[12] Only wells designated as being drilled in the Marcellus play and having a status of "Active" or "Inactive" (not "Abandoned") were used.

Figure 6. Pennsylvania statewide population within 0.5 and 1 mile of current or projected Marcellus well pad locations at full development. Roughly six times more people will be within these distances by full development relative to the current numbers.



On a statewide basis, the population living within one-half mile of a well pad would increase from 100,600 to 639,000. The population living within one mile would increase from 311,000 to 1.8 million. These calculations are based on 2010 census data. For context, Pennsylvania's population in the 2010 census was 12.7 million, and its estimated 2015 population is 12.8 million [55].

The scale of the affected population is difficult to discern from the statewide figures alone. Mapping these impacts on a county basis offers a much clearer picture of where the populations near gas development live. Table 4 gives an overview of the maps generated for this impact category. The discussion section after Table 4 provides descriptions and useful information for understanding each map.

Table 4. Population Impacts Map Index.
Access maps at www.cna.org/PA-Marcellus

Map	Title
3.1	Area within 0.5 mile of well pads
3.2	Area within 1 mile of well pads
3.3	Population within 0.5 mile of well pads
3.4	Population within 1 mile of well pads

Discussion

Map 3.1 – Area within 0.5 mile of well pads

This map shows the portion of county area within one-half mile of existing and projected well pads by county. The brown shading indicates counties that have existing or projected well development. The light tan overlay shading indicates the areas within a half mile of existing or projected well pad locations. The area of each county with existing or projected Marcellus Shale development is represented as a pie chart, broken into three categories. First, in yellow, is the portion of the county area within one-half mile of an existing well pad, labeled "Current" in the legend. Second, in dark red, is the additional area that will fall within one-half mile of projected well pads built through build-out. This is additional area that does not double-count any area within the half-mile distance of existing well pads, and is labeled "Additional" in the legend. The sum of the yellow and red sections represents the total percentage of the county area within one-half mile of well pads. Finally, the light blue section of the pie charts is the remaining portion of county area that is outside the one-half-mile distance through the end of development. It is labeled "Outside" in the legend.

Map 3.2 – Area within 1 mile of well pads

This map shows the portion of county area within one mile of existing and projected well pads by county. The legend and pie charts are the same as in Map 3.1 to enable comparisons, except that in all cases, the relevant distance is one mile.

Map 3.3 – Population within 0.5 mile of well pads

This map shows the 2010 population within one-half mile of existing and projected well pads by county. The shading indicates the raw population total by county living within one-half mile at build-out. The population of each county with existing or

projected Marcellus Shale development is shown with a pie chart, indicating the percentage of the county population in three categories. First, in yellow, is the portion of the population living within one-half mile of an existing well pad, labeled "Current" in the legend. Second, in dark red, is the additional portion of the population that will fall within one-half mile of projected well pads built through build-out. This is "Additional" population, and does not double-count any population within the half-mile distance of existing well pads. Finally, the remaining portion of the population, shown in light blue, is that which is "Outside" of the one-half-mile distance all the way through build-out condition.

Map 3.4 – Population within 1 mile of well pads

This map shows the 2010 population within one mile of existing and projected well pads by county. The shading by county is scaled identically to Map 3.3 in order to allow comparisons between the maps. The definitions for the pie chart are also the same as in Map 3.3, except that in all cases, the relevant distance is one mile instead of one-half mile.

General discussion

These results present an estimate of population within certain radii of well pad locations. These population estimates are based on 2010 U.S. census data [53], and do not account for future population change. Further, this assessment only considers distance from well pads—the primary location for most natural gas development activity—and not other types of gas infrastructure.

This analysis is best interpreted as a way to understand the number of Pennsylvania residents that will experience natural gas development first-hand close to their residences. We can conclude that the number of Pennsylvania residents within these one-half-mile and one-mile radii of well pads will increase significantly—roughly six-fold—over the population currently living within this proximity of existing well pads.

We also see regional patterns in the impacts on population. The largest such impacts in terms of pure numbers are in the southwest portion of the state, an area that already has significant existing gas development and, importantly, has a relatively high population density. By contrast, the counties in the northeast portion of the Commonwealth project tend to have most "coverage" of the county's land area within the specified distances. For instance, in Map 3.1, almost all of Bradford, Susquehanna, Washington, Greene, and Armstrong counties could be within one mile of a well pad at some point during the development period. As a result, the portion of these county's populations living within the specified distances is extremely high. Due to the lower population density of these counties, the raw total population

affected in the northeast portion of the state is lower than that in the southwest region of Pennsylvania.

This information could be useful for several types of follow-on analysis, including economics and public health. In terms of economics, proximity to well pads may indicate how much of the population could be affected by economic impacts from development (e.g., property value change, royalties).

While many studies show some correlation between distance from well pads and certain health risk factors, we did not attempt to connect these results to potential health impacts. Some potential follow-on health-related risk analyses could include, for example, potential groundwater contamination, or exposure to particular air pollutants. Or, public health studies could be used to estimate how incidence of certain health outcomes might change. We note that doing so would require a fuller, more detailed understanding of the specific nature of various gas development activities and facilities, and the intensity, duration, and frequency of potential health risk stressors associated with each. .

Impact on Air Emissions

Unconventional natural gas development is an industrial process that involves a host of machinery and operations to extract natural gas from shale deposits. Shale gas operations release a variety of criteria pollutants that can degrade local air quality, including nitrogen oxides (NO_x); sulfur oxides (SO_x); particulate matter (PM); and volatile organic compounds (VOCs), such as formaldehyde, benzene, toluene, ethylbenzene, and xylene (BTEX) [51-52, 56-58]. These emissions stem from diesel-powered equipment used for the well pad construction, drilling, hydraulic fracturing, and production processes. In addition, significant emissions can also arise from combustion-powered compressor stations that compress natural gas to keep it flowing through the pipeline system. Further, these activities could contribute to climate change due to greenhouse gas (GHG) emissions from shale gas development, which stem from the leakage of natural gas (i.e., methane, or CH_4) at various points throughout the development cycle, from extraction to processing and transmission.

For this analysis, we calculated the potential contributions to NO_x, VOC, and methane emissions from projected natural gas development in Pennsylvania. We used the data from the Marcellus Shale Air Emissions Inventory [59] from the PA DEP to develop per-well emissions factors to apply to our projections. We also use DEP data to estimate the emissions contributions from additional compressor stations needed to support this development. We then present the emissions estimates from projected development at the county level across the state, along with the relative increase from emissions in the state today. We did not analyze the potential for any more localized impacts on air quality, as this was beyond the scope of the study.

Methods, data sources, and assumptions

To assess the impacts to air quality, we applied relevant values from the PA DEP 2014 natural gas emissions inventory and professional literature to our build-out scenarios in order to calculate the emissions associated with natural gas development at the county level. We used an average development rate scenario to illustrate the impacts of development on air quality. This provides the average pace of development and shows the potential variation in emissions that could be expected from natural gas development activities in each county. We do note that in reality there would likely be considerable yearly variations in development per

county as operators focus on the more favorable locations first. We then developed a final year emissions estimate to represent the cumulative impact of ongoing emissions from natural gas production and the compression needed in order to bring it to market.

To estimate the number of new compressor stations required to support our projected natural gas development, we used a data extract from the PA DEP listing of the midstream compressor stations in their 2014 inventory [59]. This extract included 509 facilities, which, PA DEP explained, included both gathering and transmission compressor stations. We used GIS analysis to classify any stations within 0.1 mile of a transmission pipeline as a transmission station and eliminate it from the list. This resulted in 320 gathering stations, or 1 compressor station for about every 9 well pads in Pennsylvania. Applying this ratio to our well pad projections, we estimate that 661 compressor stations will be developed to support natural gas development.

We developed emission factors to apply to our projected natural gas development based on either the 2014 PA DEP natural gas emissions inventory or values from scientific literature. We classified development into three phases: pre-production, production, and gathering. Table 5 shows the emissions factors for NOx, VOC, and methane for each of these phases. Pre-production represents the emissions from drilling, hydraulic fracturing, and completion of the well. We developed this factor using the reported emissions from “drill rigs” and “completions” in the natural gas emissions inventory. Production represents the ongoing production of natural gas from the well. We developed this factor for NOx and VOC based on the study by Livovitz et al. [60]. For methane emissions, we used a recent study by Goetz et al. [61]. Finally, gathering represents the collection of natural gas from multiple well pads and compression of this gas to deliver it to transmission pipelines. We developed this factor based on the average emissions from the gathering stations in the seven counties within Pennsylvania that are most representative of UNGD: Bradford, Butler Greene, Lycoming, Susquehanna, Tioga, and Washington. These counties contain 75 percent of the UNGD in Pennsylvania through 2014, and would be most representative of the facilities used to support development moving forward.

Table 5. Emissions factors used in this study to evaluate air quality impacts from projected natural gas development

	Emissions Factor (tons/yr)		
Development Phase	**NOx**	**VOC**	**Methane**
Pre-production (per well)	6.97	0.37	1.08
Production (per well)	0.59	0.62	8.44
Gas gathering and compression (per compressor station)	18.03	6.83	170.09

Source: Pre-production [59], Production [60-61], Gathering [59].

[a.] Pre-production includes drilling, hydraulic fracturing, and completion of the well.

For the air quality analysis, we assumed the following to generate the annual emissions:

- Well development occurs at a constant rate over a 30-year build-out within each county. Overall, this amounts to a statewide development of 1,587 wells per year.
- Compressor station development also occurs at a constant rate over a 30-year build-out, which amounts to development of 22 compressor stations per year. We apportioned these compressor stations geographically based on the total expected development in each county.
- First-year emissions from new well development equal pre-production emissions plus one half of production emissions (to simulate development over the course of the year).
- First-year emissions from new compressor stations equal one half of average annual gathering emissions to simulate development over the course of the year.
- Annual emissions from existing infrastructure equal production emissions from existing wells plus gathering emissions from existing compressor stations
- Wells have a 20-year lifetime for production[13] and compressor stations go offline in conjunction with and in proportion to well retirement.

[13] Although most gas production of Marcellus wells tends to be in the first three to five years, the lifetime of the well can extend further and depends on a variety of factors. For example, data from the PA DEP show that over half of the unconventional wells drilled in 2007 are still active, and over 80 percent of those drilled in 2008 are still active.

- Total annual emissions equal pre-production plus production plus gathering and compression emissions.

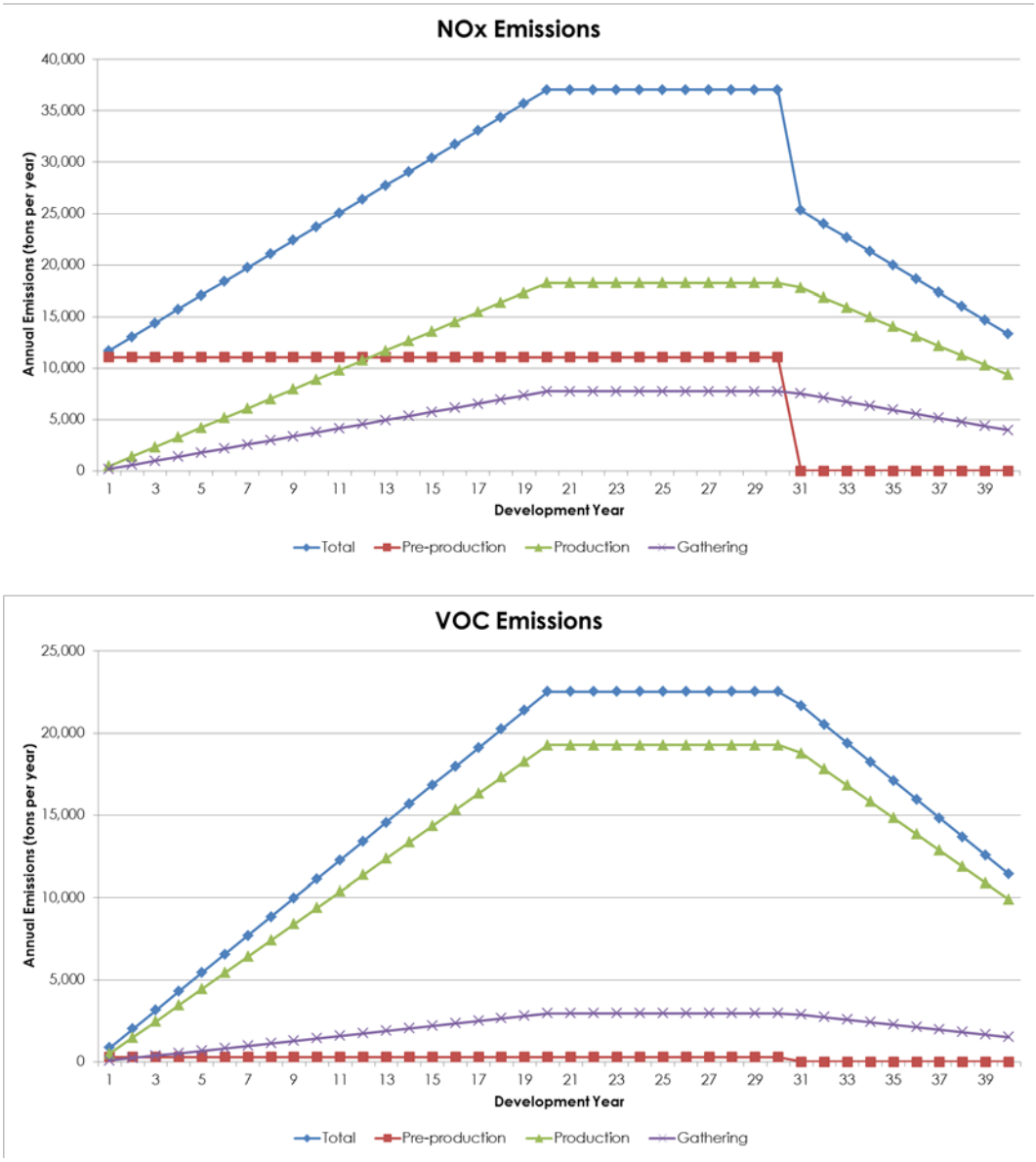
Results

Using our projections of wells and compressor stations, we generated estimates of annual emissions of NOx, VOC, and methane from projected natural gas development in Pennsylvania. The contributions to these emissions from the different phases of natural gas development will change over time, as shown in Figure 7. Based on our 30-year build-out scenario, the pre-production phase contributes the majority of NOx emissions for the first 12 years, after which emissions from the production phase become the primary contributor. However, the pre-production phase contributes very little to the overall VOC and methane emissions from development. These graphs also illustrate the cumulative impact that ongoing emissions from production and gathering contribute to overall emissions from development.

We find that given constant development rate, emissions tend to "peak" and plateau for several years. We use these "peak" annual emissions rates as the primary metric for mapping analysis, as they reflect the highest combination of pre-production, production and gathering emissions during the development period.[14]

[14] This peak will likely be lower than true peak emissions during the development period, as yearly development will not occur at a constant rate. Individual county peaks may be even higher if development is particularly concentrated over a short time period.

Figure 7. Cumulative NOx, VOC, and methane emissions from projected natural gas development over a 30-year build-out. Pre-production is the largest contributor to NOx emissions until Year 13, when ongoing emissions overtake it. Production is the largest contributor to VOC and methane emissions from the onset of development.



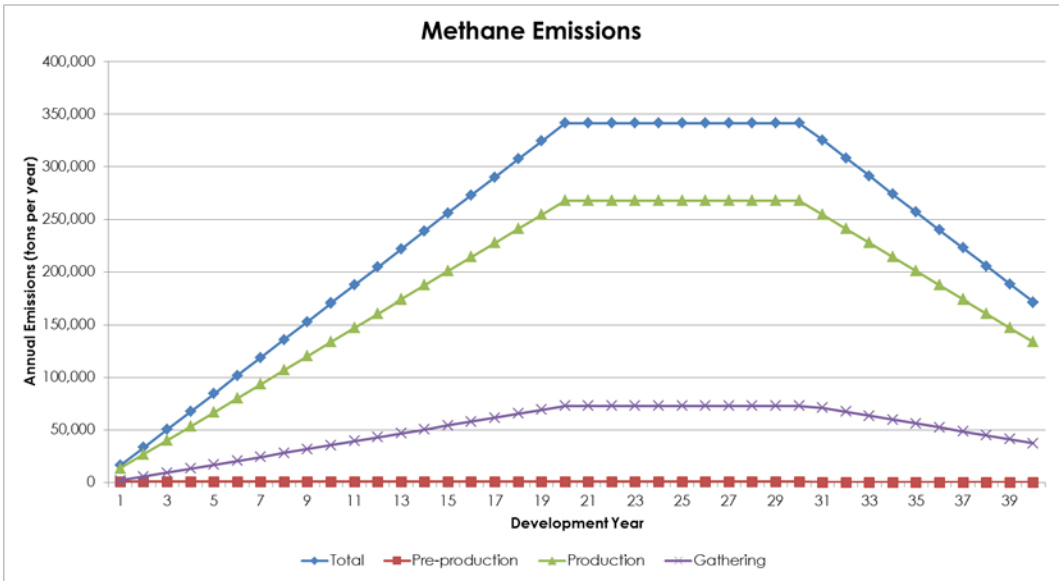
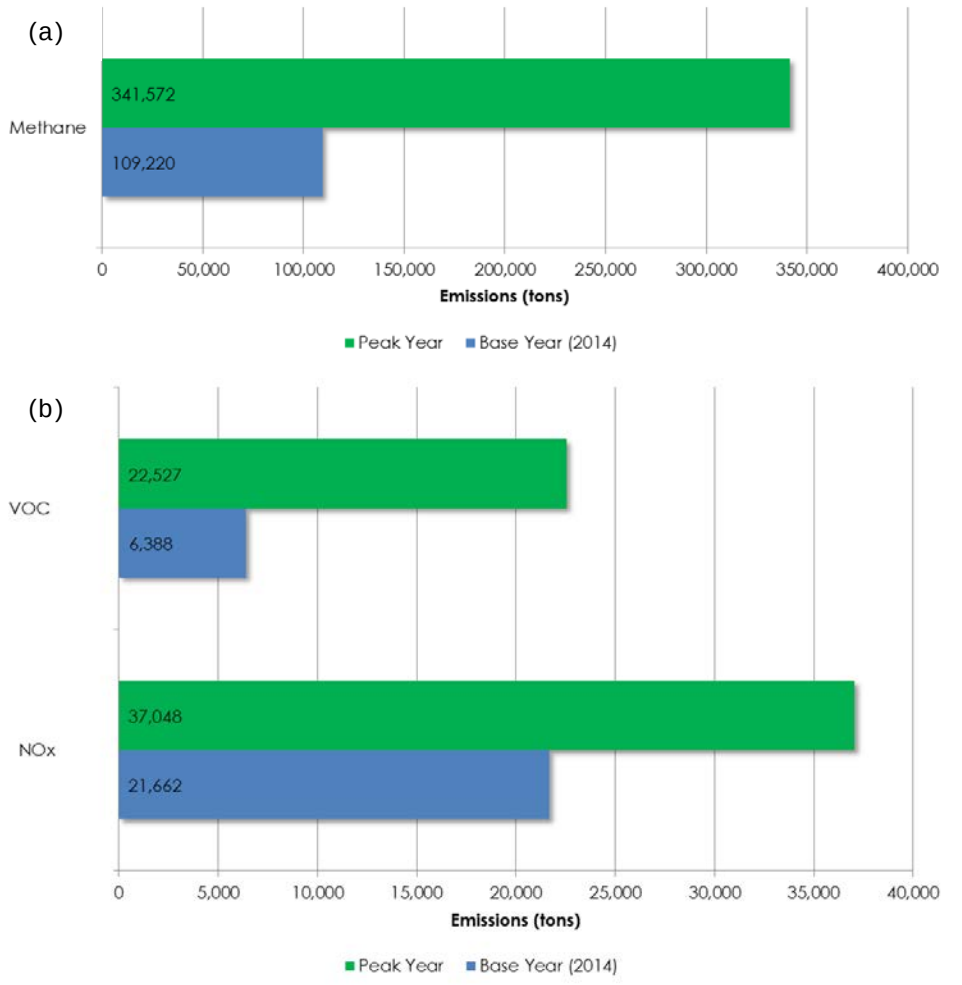


Figure 8 shows the statewide results from the peak emissions years against the emissions from the 2014 PA DEP natural gas emissions inventory. Based on our analysis, during the peak emissions years, annual NOx emissions will have increased by 1.5 times, VOC emissions will have increased by 3.6 times, and methane emissions will have increased 3.1 times relative to the reported emissions data from the natural gas sector in Pennsylvania in 2014.

Figure 8. Pennsylvania annual statewide emissions from projected natural gas development activities (when ongoing production and compressor emissions reach their peak): (a) Methane, (b) VOC and NOx.



Source: Baseline: PA DEP (2014) [59]; Projected: CNA.

For additional context, we have generated a series of maps that depict how the average year of development and final year of development would impact emissions at the county level. Table 6 gives an overview of the maps generated for this impact category. The discussion section provides descriptions and useful information for understanding each map.

Table 6. Air Emissions Impact Map Index.
Access maps at www.cna.org/PA-Marcellus

Map	Title
4.1	NOx emissions from projected development
4.2	VOC emissions from projected development
4.3	Methane emissions from projected development

Discussion

Map 4.1– NOx emissions from projected development

This map shows a peak year of NOx emissions from projected natural gas development by county. This metric represents the NOx emissions from new development plus the cumulative emissions from ongoing natural gas production and compressor stations to support this production. We compared the projected NOx emissions for each county to the current county NOx emissions from the 2014 PA DEP natural gas emissions inventory, and the result is depicted by the shading on the map. Bar charts also indicate the yearly emissions for 2014, and the projected values in order to compare both current and projected future emissions regionally.

Map 4.2 – VOC emissions from projected development

This map shows a peak year of VOC emissions from projected natural gas development by county. The layout of the map is the same as Map 4.1, with all values now depicting VOC emissions.

Map 4.3 – Methane emissions from projected development

This map shows a peak year of methane emissions from projected natural gas development by county. The layout of the map is the same as Map 4.1, with all values now depicting methane emissions.

General discussion

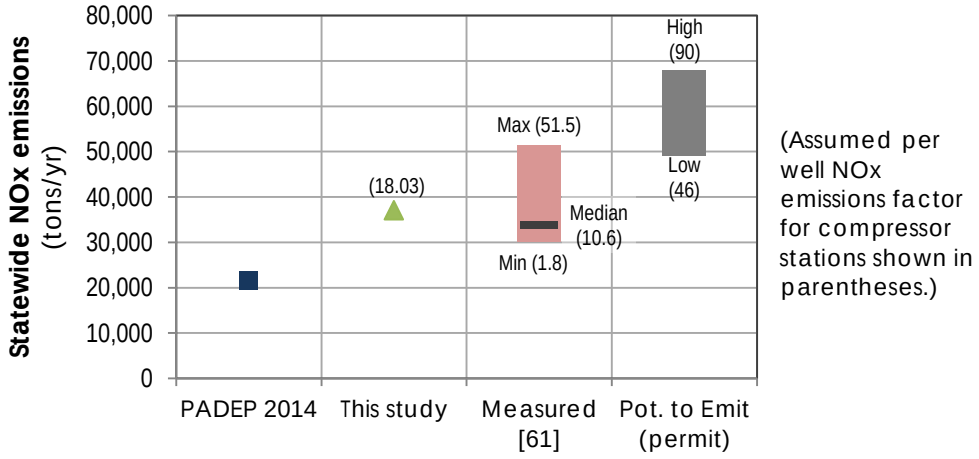
Overall, we found that projected natural gas development could lead to significant increases in NOx, VOC, and methane emissions across the state. We found that of the counties currently experiencing natural gas development, 25 would increase their NOx, VOC, and methane emissions profile compared to the 2014 emissions inventory. Further, five counties that did not report natural gas sector emissions in 2014 would have new emissions. Although we focused only on the county-level impacts for this study, it should be noted that more localized or concentrated development in subsections of each county could present a larger potential for reduction in air quality than what is presented here. Recent studies have attributed this localized development to a variety of airborne health risk factors [13, 51-52, 62].

One interesting result from this analysis compared to our previous look at the Delaware River Basin [4] is the contribution to NOx emissions from compressor stations. In the DRB analysis, the cumulative effect of compressor station build-out accounted for a majority of the overall emissions profile from natural gas development. In this analysis, however, ongoing production represents a larger cumulative contribution than compressor stations. The explanation for this finding lies in the emission factors used to represent compressor stations. In our previous work, we relied on literature values for NOx emissions from compressor stations that were based on the facility's permitted "potential to emit" value, which indicate the maximum amount of emissions the facility is permitted to emit by the PA DEP. Those values ranged from 46 to 90 tons per year of NOx. For this study, we obtained the list of compressor stations and actual emissions inventory data collected by the PA DEP to produce the emission factor based on the average observed NOx emissions, which were not available to us for the DRB study [4]. The emission factor used for this study was 18.03 tons per year. While the potential to emit values still represents an upper bound of emissions, these results should provide a more accurate representation of projected emissions in Pennsylvania.[15]

Figure 9 shows the effect that the emissions rate assumption has on total annual emissions. The annual emissions data reported to PADEP in 2014 are compared to the projected annual emissions using three different emissions rate data sources. First, the emissions factor used in this study. Then, the potential ranges of values are shown for the measured data by Goetz et al. [61], and for the potential to emit values in the permits.

[15] It is worth noting that a recent study using a mobile laboratory to measure emissions from Marcellus Shale facilities in Pennsylvania obtained a median value of 10.6 tons per year, with a maximum observed value of 51.5 tons per year, for NOx emissions from eight compressor stations [61].

Figure 9. Uncertainty in statewide Marcellus annual NOx emissions due to emissions factor used for natural gas gathering compressor stations. Annual emissions reported to PADEP for 2014 are shown for comparison. (Emissions attributed to pre-production and production are the same for all cases at 29,300 tons.)



Source: CNA, based on data from: PA DEP [59], Goetz et al., 2015 [61]

Given that NOx and VOC are the precursors to ozone formation, a potential by-product of increased development is an increase in ozone formation for the impacted counties. A recent study found that natural gas development in the Barnett Shale contributed to an increase in ozone pollution in the Dallas-Fort Worth area [63]. Ground-level ozone is a primary component of smog, which can cause respiratory illness and other decreases in lung function. Due to its potential to cause harm to human health, the EPA monitors ozone, and this pollutant is subject to national ambient air-quality standards (NAAQS). The Pittsburgh-Beaver Valley region (i.e., Allegheny County and the surrounding counties) has struggled in the past with air quality issues related to ozone and even received a non-attainment status for ozone [64]. Projected development in this area could further contribute to these air quality issues.

Some potential follow-on analysis possibilities include scenario or contextual analysis. For example, a study could investigate effects of timing or rate of development in order to refine and evaluate the air quality impacts in each county over time. Or, a different study could compare the projected air quality impacts from gas development to air quality impacts from other sectors in order to determine the impact on total emissions in each county and state-wide.

Water and Wastewater Impact

Water and wastewater management is a significant part of the unconventional natural gas extraction process. Hydraulic fracturing requires a significant amount of water to mix the "frac fluid" that is pumped into the horizontal wells at high pressure in order to fracture the shale and release gas. Most of the water needed to mix the frac fluid is withdrawn from nearby surface water resources, though some of the water needs are met through recycling of wastewater, groundwater, and other sources (e.g., purchase from municipal water providers).

After injection, most of the frac fluid remains in the shale formation, but some returns to the surface along with the gas. The early portion of the water that returns in the first 10–30 days is known as flowback. Later, additional wastewater known as "produced water" or "brine" returns with the gas for as long as the gas well is producing, and roughly in proportion with gas production. Both flowback and produced water are types of wastewater with high concentrations of dissolved solids (salts), metals, volatile organic compounds, and, in some cases, radioactive materials. Some of these contaminants may originate as additives in frac fluid, but many are picked up from the shale formation itself. The final type of wastewater is drilling fluid recovered after drilling the wells. (There are also several types of solid waste, including drill cuttings, and solids settled out from flowback or produced water, but they are not part of this analysis.)

In this analysis, we analyze the volumes of water and wastewater associated with the projected development of gas wells in the Interior Marcellus. Notably, we focus on four key metrics related to natural gas water management:

- **Water use**: the total volume of water used for mixing the frac fluid that is injected into the shale during hydraulic fracturing
- **Water withdrawal**: the volume of water used to mix frac fluid that is withdrawn from surface water resources
- **Consumptive use**: the volume of water in the frac fluid that remains in the shale after injection
- **Wastewater generation**: the volume of wastewater produced from the wells as either flowback or produced water plus used drilling fluid.

All of these metrics are important as they can be used for different impact assessments. *Water use* is important to report, as it is the total volume of water needed for hydraulic fracturing regardless of source. In theory, all of this water could be taken from local streams, but in many cases, other water sources are used including groundwater and recycled wastewater (either from the natural gas industry or from municipal or industrial wastewater sources). For this reason, *water withdrawal* is reported as the average quantity that would be taken from local streams. After frac fluid injection, some portion of the water used for fracking comes back as wastewater, and can potentially return to the watershed (after some level of wastewater treatment). But the consumptive use - or the portion of frac fluid does not return - is important to understand as it indicates the (minimum) amount flow is reduced in the watershed. Finally, it is important to understand the volume of *wastewater generated* that must be managed due to the potential risks associated with the high concentrations of water pollutants it natural gas wastewaters[4].

All of these metrics refer to water volumes, but considering the large number of wells involved, and the long period of well development, reporting volumes for these metrics would result in very large numbers that are difficult to put into context. Instead, we report these metrics in terms of average flow rate—that is, volume per unit of time. We assume a 30-year development period as the unit of time, so all of the metrics are expressed as the average volume over that period. We use the U.S. Geological Survey's preferred unit of flow, cubic feet per second (cfs) to report these metrics in the results. We also report the 30-year statewide total volume in billions of gallons. (1 cubic foot equals 7.48 gallons.)

Methods, data sources, and assumptions

In this report, we use four major metrics for water use for fracking. They relate to the major water management stages for unconventional gas development with hydraulic fracturing.

For calculation of water and wastewater impacts, we assume that:

- Well development will occur at eight wells per well pad on average. Each well is fracked once, and there is no-re-stimulation.[16]
- All wells within a HUC-8 have the same water use.

[16] Some wells can be re-stimulated (or-refracked) to boost or prolong gas recovery. There has been limited re-fracking to date, and few data exist on the amount of water needed. We have not included re-fracking in this analysis.

- Well development occurs at a constant average rate over a 30-year development period. We report water use as an average flow rate for each HUC-10 watershed. The volume is estimated based on the number of wells and the water use per well, and the rate is calculated by dividing the time associated with development—in this case, 30 years. This rate shows the average pace of development, but there may be considerable yearly and monthly variations in water use.
- Eighty percent of water use is met by surface water withdrawals, and 20 percent of water use is met by water reuse, including recycled frac fluid, and other sources.
- All surface water withdrawals for wells are taken from the same HUC-10 as the well pad location.
- Sixty-nine percent of frac fluid water volume remains in the shale, and is considered consumptive use.
- Thirty-one percent of frac fluid water volume returns to the surface as wastewater.

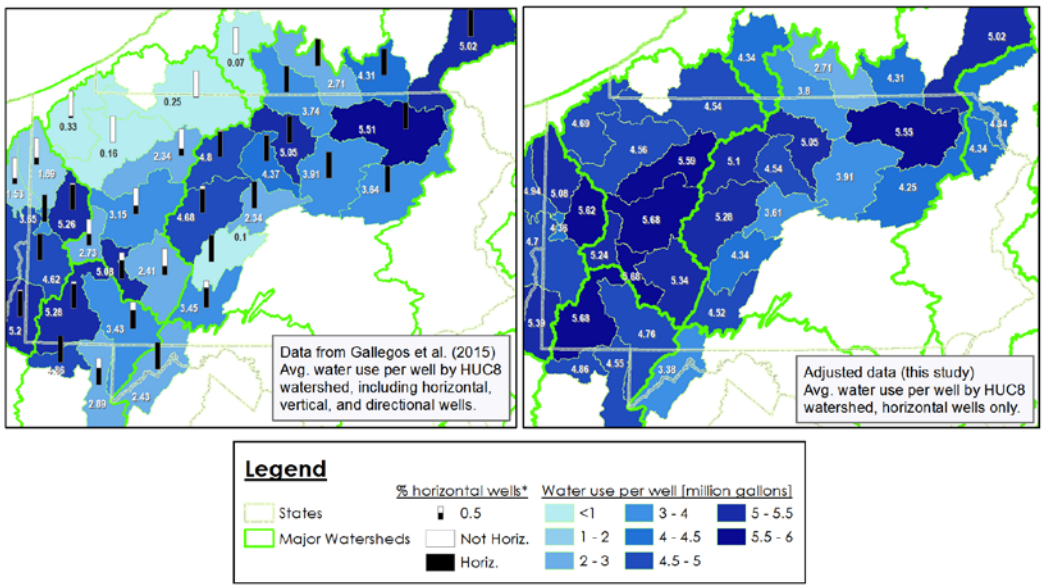
Water use per well

We estimated water use from Gallegos et al. (2015) [65], who analyzed water use for fracking by HUC-8 watershed for major U.S. shale plays including the Marcellus. The data were reported as average water use per well, including horizontal, vertical, and directional wells. Because of this averaging, these data under-estimate average usage for horizontal wells [66], which use much more water than vertical wells. Gallegos et al. do report the number of horizontal, vertical, and directional wells in each HUC-8 watershed, and we used these data to estimate 'adjusted' water use for horizontal wells only.[17]

[17] We adjusted the average water use per well based on Gallegos et al.'s reported averages of 300 m^3 for vertical wells and 2,000 m^3 for directional wells. For HUC8 watersheds with fewer than 50 percent horizontal wells, we averaged the adjusted horizontal well estimate with the Marcellus average per well reported by Kondash and Vengosh [66], using the percentage of horizontal wells as the weighting factor. (e.g., if 37 percent of wells were horizontal, we used 63 percent as the weight for the Marcellus average reported by Kondash and Vengosh). To avoid overestimates, we also limited the maximum water use per well for the adjusted values to the maximum value for HUC-8s with at least 90 percent horizontal wells (roughly 5.6 million gallons.

Figure 10 shows side-by-side comparison of the unadjusted and adjusted Gallegos et al. data by HUC-8, on a per well basis.

Figure 10. Estimates of per well water use by HUC-8 watershed. Gallegos et al. (2015) estimates (left), and adjusted (right) to consider only horizontal wells.



Source: Data from Gallegos et al. (2015); Maps created by CNA.

We note that Figure 10 shows that the adjusted data are much more consistent per across the formation once the vertical and directional wells are excluded. The overall average water use for the projected wells is 4.9 million gallons, which is near or slightly above the reported average water use for some previous studies [67-69]. We believe that this is reasonable, considering that water use per well has been trending upward slightly, mostly because lateral length is increasing. Kondash and Vengosh also reported on data from Chesapeake Energy, which indicated average use of 5.6 million gallons; this closely matches several of the highest HUC-8 averages in terms of water use per horizontal well (see Figure 10). The range is 2.7 to 5.7 million gallons

Water withdrawal, consumptive use, and wastewater

We base our estimates of water withdrawal, consumptive use, and wastewater generation on literature values for these figures in relation to total water use for fracking. Specifically, we gathered the most recent estimates [66] for the portion of total water use met by new water withdrawals from fresh surface water, and the

relative proportion of injected frac fluid that remains in the shale (consumptive use) versus returns as flowback or brine wastewater.

We assume that most of the water demand for hydraulic fracturing will be met by surface water withdrawals. Trends in the industry are towards more reuse of natural gas wastewaters for water supply, and there has been some interest in non-traditional sources such as municipal wastewater treatment plant effluent or mine drainage waters. For this study, consistent with the previous CNA study for the Delaware River Basin, we assume that 80 percent of the total water use for fracking is met by surface water withdrawals, which accounts account for wider availability of recycled wastewater as more wells are developed. This percentage is slightly below figures by other research on the topic [68-69], though comparable to recent data published by the Susquehanna River Basin Commission [70]. Transporting water is a significant cost, so we assume that all wells will be supplied by surface water withdrawals from within the same watershed (i.e., HUC-10) as the well pad site. At this level of analysis, we make no assumption about the stream order within the watershed from which the withdrawal is taken. Finally, we assume that the 80 percent factor is constant across the study area.

For determining the fate of the injected water in the frac fluid, we used recent research by Kondash and Vengosh (2015) [66]. Early analysis of unconventional drilling in the Marcellus Shale had indicated that only a small portion, perhaps 10-15 percent, of water injected as frac fluid would return to the surface as natural gas wastewater. But these analyses were mostly focused on the flowback fluid, which can be measured easily as it returns over the first 30 days after hydraulic fracturing. Kondash and Vengosh, by contrast, accounted for more of the produced water which comes up the well in small quantities along with produced gas for 10 years or longer. Taking this longer view, Kondash and Vengosh calculated that 31 percent of the average injected frac fluid volume would return as wastewater. The remaining 69 percent is "consumptive use" as it is not recovered from the shale. Since our study covers a long time horizon, we use these figures to calculate consumptive use and volume of wastewater generated. We assume that these percentages remain constant across the study area.[18]

[18] We did investigate Pennsylvania Oil and Gas wastewater reporting data for geographic trends in wastewater volume, but we found insufficient data to clearly indicate geographic differences. In many cases, we could not connect water use per well from FracFocus with wastewater records. Additionally, the wastewater reporting data were often incomplete due to omissions or, more likely, because not enough time had passed since drilling and fracking to collect, process, and report wastewater volumes.

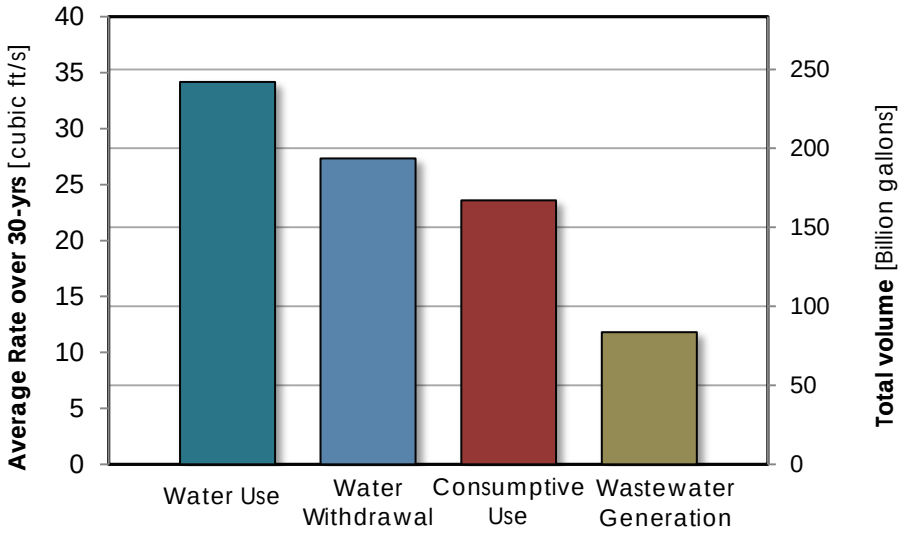
Results

The results for this chapter are focused on four key water and wastewater metrics, including water use, water withdrawal, consumptive use, and wastewater generation.

As mentioned previously, we report these water impacts both in terms of total statewide volumes, but also in terms of average flow rates over the development period. We use cubic feet per second for all water metrics to allow comparisons with streamflow, and thousands of gallons per day for wastewater.

Statewide, we determined that the development of the roughly 48,000 additional wells in the Marcellus would result in an average water use rate of 34 cfs over 30 years, or 242 billion gallons in total. Figure 11 shows the corresponding values for water withdrawal (200 billion gallons), consumptive use (167 billion gallons), and wastewater generation (84 billion gallons).

Figure 11. Total water and wastewater impacts for Pennsylvania associated with hydraulic fracturing of projected wells through full development of the Marcellus Shale. The average rates and total volume are shown on the left and right axes, respectively, for water use, surface water withdrawals, consumptive use, and wastewater generation.



As in previous chapters, the statewide totals do not present the full picture of these impacts. For water-related impacts, it is most appropriate to analyze the impacts by watershed. But since water flows from one watershed to another, it is not sufficient to simply assess the impacts of natural gas development solely within the watershed

the development occurs. We have generated four categories of maps to give greater understanding and context to this analysis.

- **Volume/Flow-rate** – Standard analysis of water-related impacts in each HUC-10 watershed based only on development within the watershed, expressed as average-flow over the development period.
- **Specific or Area-averaged flow** – measures the 'intensity' of water use by dividing the flow computed for each watershed by watershed area. This will show where development will be most concentrated.
- **Cumulative flow** – presents a more comprehensive view of the water impacts by including both the impacts within each watershed and the total impact from all watersheds upstream. This is particularly relevant to consumptive use.
- **Contextual analysis** – compares the flow-rates calculated in this analysis to existing water usage.

Table 7 presents an overview of the water and wastewater maps by metric and category. Not all categories of map are relevant for all of the metrics. Maps 5.1–5.4 present the water use, withdrawal, consumptive use, and wastewater generation by HUC-10 watershed in terms of average flow rate. Maps 5.5 and 5.6 present area-averaged or "specific" flow rates for water use and water withdrawal. Since assessing the water use in each watershed individually does not present the full picture of how water flows between watersheds, we created Maps 5.7 and 5.8 to show cumulative water use and consumptive use for each watershed including the upstream usage. Finally, in Map 5.9, we compare consumptive use for hydraulic fracturing relative to all other consumptive uses, this time at the larger HUC-8 watershed scale.

Table 7. Water and wastewater maps by metric and category.

Metric	Volume/ Flow-rate	Area-averaged flow	Cumulative flow	Contextual analysis
Water Use	Map 5.1	Map 5.5	Map 5.7	
Water Withdrawal	Map 5.2	Map 5.6		
Consumptive Use	Map 5.3		Map 5.8	Map 5.9
Wastewater Generated	Map 5.4			

Table 8 introduces the maps generated for this category. The following discussion section offers commentary on how to read and interpret each map.

Table 8. Water and Wastewater Impacts Map Index.
Access maps at www.cna.org/PA-Marcellus

Map	Title
5.1	Water use by watershed
5.2	Water withdrawal by watershed
5.3	Consumptive water use by watershed
5.4	Wastewater generation by watershed
5.5	Specific water use
5.6	Specific water withdrawal
5.7	Cumulative water use
5.8	Cumulative consumptive use
5.9	Consumptive use relative to existing consumptive uses

Discussion

Map 5.1 – Water use by watershed

This map shows projected water use for hydraulic fracturing by HUC-10 watershed. The water use metric represents total water use volume for hydraulic fracturing by all projected wells within each HUC-10 through build-out, expressed as flow rate in cubic feet per second (cfs). The rate represents the average water use rate over the full build-out time frame, assumed to be 30 years. This metric does not include water uses for anything other than fracking (e.g., for drilling fluid or site preparation).

To generate this map, we used well projection numbers on a HUC-10 basis and the adjusted estimates of water use per well, which are computed from Gallegos et al. [65] on a HUC-8 basis. Therefore, the differences in the results by HUC-10 reflect differences in projected number of wells developed, and geographic differences in the average amount of water used for hydraulic fracturing.

Map 5.2 – Water withdrawal by watershed

This map shows the projected freshwater withdrawal for hydraulic fracturing through build-out by HUC-10 watershed. This metric represents total freshwater withdrawal volume for hydraulic fracturing by all projected wells within each HUC-10 through build-out, expressed as flow rate in cubic feet per second. The freshwater withdrawal rate is less than total water use rate because we assume that 20 percent

of the total water use for hydraulic fracturing is met by other water sources, primarily wastewater reuse, instead of freshwater withdrawal.

Map 5.3 – Consumptive use by watershed

This map shows the projected consumptive use associated with hydraulic fracturing through build-out by HUC-10 watershed. This metric represents the volume of hydraulic fracturing fluid left within the shale for all projected wells within each HUC-10 through build-out, expressed as flow rate in cubic feet per second. The consumptive water use rate is less than total water use rate because a portion of the injected fluid returns to the surface as wastewater.

We assume a standard fixed relationship across the Marcellus for percentage of the total water used for hydraulic fracturing that is left in the shale as consumptive use. Based on figures from Kondash and Vengosh [66], we assume that consumptive use is, on average, 69 percent of total water use for hydraulic fracturing.

Map 5.4 – Wastewater generation by watershed

This map shows the projected wastewater generation associated with hydraulic fracturing through build-out by HUC-10 watershed. This metric represents the volume of natural gas wastewaters returning from the shale after fracking for all projected wells plus drilling fluid wastewater within each HUC-10 through build-out, expressed in thousands of gallons per day. The wastewater generation rate for flowback and produced water is equal to total water use rate minus the consumptive use rate (water from the injected fluid left in the shale), or simply 31 percent of the total water use rate. We added another 185,000 gallons per well for drilling wastewater, slightly higher than the amount in previous research [71] to account for increasing lateral length.

This metric indicates the total volume of wastewater that must be handled within each HUC-10 watershed. This analysis does not consider how the wastewater is managed, treated, recycled, transported, or discharged. Separate analyses would be needed to determine how different wastewater treatment or disposal methods may affect water quality, human health, or ecological outcomes. The map does show currently (as of April 2016) permitted facilities for handling oil and gas wastewaters, for context.

Map 5.5 – Specific water use

This map, similar to Map 5.1, shows water use for hydraulic fracturing by HUC-10 watershed. The water use metric is identical to the one in Map 5.1, but is normalized

to the area of the watershed. The metric is presented as water withdrawal in cubic feet per second per 100 square miles. We use 100 square miles to make the numbers easier to comprehend, and because HUC-10 watersheds are on the order of 100 square miles in area. We could also present this metric as a depth over the watershed. For conversion, 1 cfs per 100 square miles (for a year) is equivalent to a depth on the watershed of 0.136 inches, or 3.45 millimeters, per year.

In Map 5.1, the largest watersheds typically also show the highest water use because they contain more well pads due to their size. Normalizing by watershed area removes this issue, and Map 5.5 shows the watersheds with high water use because they have a high relative density of development.

Map 5.6 – Specific water withdrawal

This map, similar to Map 5.2, shows freshwater withdrawal associated with hydraulic fracturing by HUC-10 watershed. The water withdrawal metric is identical to the one in Map 5.2, but is normalized to the area of the watershed. The metric is presented as water withdrawal in cubic feet per second per 100 square miles.

In Map 5.2, the largest watersheds typically also show the highest water withdrawal because they contain more well pads due to their size. Normalizing by watershed area removes this issue, and Map 5.6 shows the watersheds with high water withdrawal because they have a high relative density of development.

(Note: We do not show similar maps for consumptive use or wastewater generation because the relationship between the direct flow rate map and area-averaged map is similar to those for water use and water withdrawal.)

Map 5.7 – Cumulative water use

This map shows cumulative projected water use for hydraulic fracturing by HUC-10 watershed. The water use metric represents total water use volume for hydraulic fracturing by all projected wells within each HUC-10 through build-out plus the water use for all upstream HUC-10s, expressed as flow rate in cubic feet per second (cfs). This metric shows the cumulative upstream water use on an average basis through build-out.

This map is similar to Map 5.1, but adds all of the upstream water use to the water use for each HUC-10. This map shows water use in more HUC-10 watersheds than Map 5.1 because the water use is traced farther downstream until all water use for hydraulic fracturing is captured. In some cases, the watersheds are outside of Pennsylvania. This metric does show total upstream water use for hydraulic fracturing on an average basis, but the metric may not be meaningful with respect to

streamflow because alternate water sources and return flow (after wastewater treatment) are not taken into account. A more physically meaningful cumulative water use metric is the consumptive use, which is shown in Map 5.8.

The map also labels the average daily water use by major river basin. (Note that the Upper Ohio includes the cumulative flow from both the Allegheny and Monongahela.) Based on current data, these estimates appear reasonable; the Susquehanna River Basin Commission reported total water use of 15.4 cfs for 2012, and 13.2 cfs for 2013 [70], closely matching the 13.9 cfs reported for this study.

Map 5.8 – Cumulative consumptive use

This map shows cumulative projected consumptive use associated with hydraulic fracturing by HUC-10 watershed. This metric represents total consumptive water use volume associated with hydraulic fracturing by all projected wells within each HUC-10 through build-out plus the consumptive use for all upstream HUC-10s, expressed as an average flow rate in cfs.

This map is similar to Map 5.3, but adds all of the upstream consumptive use to the consumptive use for each HUC-10. It shows, on an average basis, the potential reduction in streamflow at the outlet point of each HUC-10 watershed. This map shows consumptive use in more HUC-10 watersheds than Map 5.3 because the water use is traced farther downstream until all water use for hydraulic fracturing in the Marcellus formation in Pennsylvania is captured. In some cases, the watersheds are outside of Pennsylvania due to the flow of rivers across state boundaries. Actual consumptive use could be higher or lower depending on how water is sourced and how wastewater is handled (recycling versus treatment with effluent disposal versus deep well injection). The consumptive use will also vary considerably over time and space due to variations in development rate.

For context, the total cumulative consumptive use for gas development at Pittsburgh is roughly 10.9 cfs (Allegheny plus Monogahela). Pittsburgh's municipal water supplier, PWSA, treats roughly 70 million gallons per day, or 108 cfs of potable water supply. Assuming a typical consumptive use rate of 10 percent for municipal supply, Pittsburgh's consumptive use for water supply is roughly 10.8 cfs (i.e., almost exactly equal to the average consumptive use for hydraulic fracturing upstream of Pittsburgh). Map 5.9 shows similar comparisons statewide, but for all existing consumptive water uses including agricultural and industrial use.

(Note: We did not generate similar maps to Maps 5.7 and 5.8 for water withdrawal or wastewater generation. The water withdrawal map would be similar to Map 5.7, and would not account for possible return flow after wastewater treatment. A cumulative wastewater generation map would not be especially instructive unless we assumed

that all wastewater is returned to the same watershed in which it was produced, and is not reused or transported to other watersheds for treatment.)

Map 5.9 – Consumptive use by watershed relative to existing consumptive uses

This map shows projected consumptive use for hydraulic fracturing on a HUC-8 basis, and relative to all other existing consumptive uses. We acquired the baseline consumptive use data by HUC-8 from Caldwell et al. (2013) [72], which is based on 2005 USGS water use data disaggregated to HUC-8 scale, and accounts for end use specific and geographically specific consumptive use factors relative to reported water use. These data would predate water usage related to UNGD with HVHF, but also do not account for changes in water use over the past decade.

The map shading indicates the total volume of consumptive water use associated with hydraulic fracturing by all projected wells within each HUC-8 through build-out, expressed as an average rate over 30 years. Using the vertical bars, we indicate the ratio of this consumptive use associated with fracking over the total estimated consumptive use for each HUC-8 as a percentage. This metric can be read as either the ratio of UNGD consumptive use to existing (2005) consumptive use, or the amount by which consumptive use would increase over existing usage in the HUC-8 due to UNGD.

This map puts the consumptive use for hydraulic fracturing in context with existing consumptive uses. In some areas of Pennsylvania, water use for fracking could dramatically increase overall consumptive use. In other areas (even with similar average usage for fracking), the existing consumptive use is much higher and the ratio is lower.

General discussion

The analysis presented considers four primary volumetric water and wastewater metrics presented on an average basis over a 30-year development period. This analysis considers only the total volumes of water and wastewater associated with hydraulic fracturing, presented as an average rate over a 30-year development horizon.

For at least four reasons, this analysis does not capture the full potential impacts of water and waste management associated with natural gas development. First, there are additional water uses and wastes that are not included in this analysis. Some additional water use is associated with indirect uses such as site preparation, materials processing and quarrying, and equipment washing. [68] Other waste

streams including spent lubricants and solid wastes such as drilling cuttings are not considered in this report. [16]

Secondly, the well development rate, and by extension the water use rate will vary geographically and temporally. The pace of development will likely correlate with energy prices, ability to sign leases, ability to permit and construct natural gas infrastructure, and other factors. The pace of development in turn affects flow rates associated with all phases of water management. The freshwater withdrawal rate could be several times higher than the average rate during peak periods [4], which can increase potential impacts on streams. Likewise, the consumption rate and wastewater generation rate will increase.

Thirdly, there may be variability in the water use rates from well to well[19], and there may be changes over time due to evolving industry practices and regional development characteristics. Recently, water use per well has been increasing as average lateral length and the number of fractures per well has increased [70] (though primarily in "hotspot" areas with especially rich gas deposits). In addition, seasonal variations in drilling and hydraulic fracturing activity may play a large role in timing of withdrawals. Also, as development continues, more wastewater will be available for reuse, which could lower the portion of water use met by freshwater withdrawal for wells developed later. Finally, re-fracking is not included in this analysis, but could raise water usage in some areas of the play. Capturing these temporal aspects of water management is beyond the scope of this study, and would require a methodology for projecting well development on a year-by-year (or even month-by-month) basis.

Fourth, there is potential for movement of water and wastewater across watersheds. We assume that the demand for water withdrawal is met within the same HUC-10 as the well pad. This is generally a reasonable assumption, but in some cases may not be correct. Given costs to permit and develop new water withdrawals, it is possible that an existing, permitted water withdrawal location in an adjacent HUC-10 may make more sense for a particular well pad or operator. Our analysis focuses only on wastewater generation by watershed, as significant quantities of natural gas wastewaters (and other wastes) are routinely transported even across major river basin boundaries [16], and a full examination of wastewater disposal scenarios was beyond the scope of this study.

[19] The data we used had a range of per well water use (averaged over each HUC-8) from 2.7 to 5.7 million gallons per well, an average of 4.9, and a median of 5.0. The total water use we computed for the projected 47,600 wells is 242 billion gallons based on the average computed for each HUC-8. If *all* wells used water at the highest end of the range, the total water use would be 270 billion gallons, an 11 percent increase.

Overall, this analysis generates projections of water and wastewater volumes, but does not investigate the context of the source (or receiving waters). That is, this is an analysis of environmental "burdens", but not "impacts". We present the water volumes in terms of flow rates, which is useful for supporting additional research. Specifically, this analysis does not put the magnitude of withdrawals and wastewater volumes into context by comparing them to the available streamflow in the watershed. Just as there can be significant variations in the rates of water use and wastewater generation, the actual impacts of water withdrawals on stream flow are highly dependent on the location of withdrawal, and the natural variability in the flow of the source waters. Withdrawing water in the spring from the mainstem of the Susquehanna River may have a negligible impact on flow, while withdrawing from a small headwater stream during late summer could have a substantial impact.

Similarly, we report only the wastewater volumes associated with development, and do not investigate potential impacts on water quality. Disposal of treated natural gas wastewaters can raise the concentration of certain pollutants (e.g., dissolved solids, barium, strontium, bromide) with potential ecological and human health effects. Our previous report on the Delaware River basin [4] investigated the potential impacts of water usage on available flow, and disposal of treated wastewater on the in-stream concentrations of pollutants for three case study watersheds, and found that the level of impact did vary (often by an order of magnitude) with development rate, in-stream flow, and stream order.

There are several ways this analysis could support additional studies. Examining the effects of water withdrawals on available flow is a logical extension. The wastewater impacts, however, may be of particular concern, especially given the potential risks to drinking water supplies. [5, 73-78] The method of wastewater management (e.g., on-site reuse of wastewater, treatment at a centralized wastewater facility, or exporting wastewater for disposal via deep well injection) is important; each has very different consequences for water quality. Investigating potential water quality impacts and key vulnerabilities (ecosystem and human health) for various wastewater management scenarios could be a useful topic for future analysis, and informing policy.

Conclusion

Unconventional natural gas development using hydraulic fracturing has spurred a rapid expansion of natural gas extraction in Pennsylvania due to the presence of the Marcellus Shale—which, though rich in gas, could not be economically developed with traditional drilling methods. Through the almost nine years of unconventional gas development in Pennsylvania, the Commonwealth has witnessed significant changes to energy costs, employment, communities, and the environment. While the price of natural gas has led to fluctuations in the amount of development, the quantity of remaining gas reserves in the Marcellus Shale could support significantly more gas development in coming years.

In this study, we ask, "What would be the environmental burdens associated with natural gas development activities in Pennsylvania if the Interior Marcellus Shale resources were fully developed?"

Specifically, we investigate the potential impacts to Pennsylvania's land, forests, water, air, and population if development of the Marcellus Shale were to continue until all of the technically recoverable reserves were exhausted.

One significant difficulty with investigating potential future impacts of gas development is determining where those impacts may occur. To address this challenge, we developed a geospatial analysis methodology to identify the most likely locations of potential future wells, based on finding geologic, environmental, and land use conditions similar to where wells have already been drilled. Using the probability surface generated from this analysis and recent estimates of total recoverable reserves and average production per well, we determined how many wells would be developed until reserves are depleted, and their most likely locations. That is, we developed one set of "projections" of well numbers and locations through (what is currently estimated) as build-out condition. These are not formal *predictions* of wells and their locations, just one possible configuration identified as likely based on current information on gas development in the Interior Marcellus Shale.

With information on well locations and level of impact per well, we analyze the spatial characteristics of impacts of natural gas development. For the most part, we compute these impacts based on the well (or well pad) numbers in a given geographic unit, and impacts per well or well pad derived from published literature or data sets. We also apply additional geospatial and mathematical analysis techniques to estimate several of the impacts, as appropriate.

The primary output of this research is an *atlas:* a set of maps that puts the impacts of the projected natural gas development in useful spatial context. These maps, and the data developed to generate them, present useful information to policy-makers, decision-makers, and other researchers concerned about managing the range of impacts of shale gas extraction in Pennsylvania. We strive to present the impacts using straightforward, relevant metrics useful for comprehension and supportive of follow-on analysis. At this time, the metrics are focused on environmental burdens and impacts (e.g., land areas, emissions, volumes, and flow rates) that can be reasonably and directly estimated from the well and well pad projections. This analysis does not address the potential "outcomes" resulting from the impacts (e.g., endangered species populations, water pollutant concentrations, and human health outcomes).

Key findings

For the Commonwealth of Pennsylvania, the key impacts we determined to be associated with the full development of the Marcellus Interior shale formation include:

- **Well development** – We estimated that 47,600 additional wells could be developed on 5,950 well pads over the next 30 years *if* the Interior Marcellus's technically recoverable resources were fully developed.

- **Land use change** – The construction of natural gas infrastructure (well pads, gathering pipelines, and access roads) to support projected well development would result in almost 100,000 acres of land disturbance. Over half (about 51,000 acres) of the land disturbance would impact agricultural land, while about 28,000 acres would constitute the clearing of forest cover.

- **Forest change –** Of the 28,000 acres of forest that would be cleared, we found that nearly 13,000 acres were core forest (patches of forest at least 300 feet from a forest edge). An additional 89,000 acres of core forest would be fragmented by the projected gas infrastructure development, resulting in a conversion to edge forest.

- **Population in proximity to well pads –** We estimated that the current population in Pennsylvania living within one-half mile of a well pad is about 100,000, and this number could increase to 639,000 based on our projections. Similarly, we estimate that the population living within one mile of a well pad could increase from about 311,000 today to over 1.8 million at full build-out.

- **Air emissions –** The additional well development would result in greater emissions of NOx, VOCs, and CH_4 from activities related to well pre-production, and production, and compressor stations for moving gas through gathering lines. When the play nears full development (i.e., ongoing emissions from producing wells reach their peak), the average air emissions per year could reach 37,000 tons for NOx, 22,500 tons for VOCs, and 342,000 tons for methane.

- **Water use, withdrawal, and consumptive use –** We determined that the projected natural gas development in the Marcellus would result in an average water use rate of 34 cfs over about 30 years, or 242 billion gallons in total in order to mix frac fluid for the hydraulic fracturing process. We found that roughly 200 billion gallons of fresh surface water would be withdrawn to support this development, and that 167 billion gallons would be used consumptively and would not re-join the hydrologic cycle after injection.

- **Wastewater generated –** We estimated that 84 billion gallons of wastewater would be generated from projected natural gas development in Pennsylvania. Wastewater includes drilling fluid waste, plus flowback and produced water/brine recovered from the shale after frac fluid injection and during gas production.

All of these metrics offer a sense of the scale of the total statewide impacts of natural gas development through full development of the Marcellus Shale. But these aggregated metrics do not tell the full story of the impacts, which have important geographic variations. The maps accompanying this work show these variations and can help identify areas of comparatively higher and lower impacts. Readers are encouraged to view and download these maps at: www.cna.org/PA-Marcellus

We do not provide an opinion on the overall significance of these impacts—we leave that to policy-makers and decision-makers with local knowledge of the impacted areas to decide. But this analysis takes the initial step of looking at the long-term future of natural gas development in Pennsylvania. Development appears likely to continue over the coming years, and will continue to have some level of environmental impact wherever development occurs. Tolerance for and management of these impacts will be a continuing area of debate among policy-makers, regulators, land owners, the natural gas industry, and the general public. This analysis provides information that any of the relevant stakeholders—especially policy-makers—may consider as they decide how gas development is to be managed and regulated over the coming decades.

References

[1] Hanson, Mark P. 2014. "Shale Shock - How the Marcellus Shale Transformed the Domestic Natural Gas Landscape and What It Means for Supply in the Years Ahead." *Morningstar Energy Observer*. February 2014.

[2] Hughes, J. David. 2014. *Drilling Deeper - A reality check on U.S. government forecasts for a lasting tight oil & shale gas boom*. Post Carbon Institute. http://www.postcarbon.org/publications/drillingdeeper/.

[3] Staub, John. 2015. "The Growth of U.S. Natural Gas: An Uncertain Outlook for U.S. and World Supply." 2015 EIA Energy Conference, Washington, DC, June 15, 2015. http://www.eia.gov/conference/2015/pdf/presentations/staub.pdf.

[4] Habicht, S., L. Hanson, and P. Faeth. 2015. *The Potential Environmental Impact from Fracking in the Delaware River Basin*. https://www.cna.org/cna_files/pdf/IRM-2015-U-011300.pdf.

[5] Brantley, Susan L., Dave Yoxtheimer, Sina Arjmand, Paul Grieve, Radisav Vidic, Jon Pollak, Garth T. Llewellyn, Jorge Abad, and Cesar Simon. 2014. "Water resource impacts during unconventional shale gas development: The Pennsylvania experience." *International Journal of Coal Geology* 126: 140-156. doi: 10.1016/j.coal.2013.12.017.

[6] Vidic, R. D., S. L. Brantley, J. M. Vandenbossche, D. Yoxtheimer, and J. D. Abad. 2013. "Impact of Shale Gas Development on Regional Water Quality." *Science* 340 (6134). doi: 10.1126/science.1235009.

[7] Krupnick, A. J., H. Gordon, and S. M. Olmstead. 2013. *Pathways to Dialogue: What the Experts Say about the Environmental Risks of Shale Gas Development*. Resources for the Future. www.rff.org/shaleexpertsurvey.

[8] Olmstead, Sheila M., Lucija A. Muehlenbachs, Jhih-Shyang Shih, Ziyan Chu, and Alan J. Krupnick. 2013. "Shale gas development impacts on surface water quality in Pennsylvania." *Proceedings of the National Academy of Sciences* 110 (13): 4962-4967. doi: 10.1073/pnas.1213871110.

[9] Evans, J. S., and J. M. Kiesecker. 2014. "Shale gas, wind and water: assessing the potential cumulative impacts of energy development on ecosystem services within the Marcellus play." *PLoS One* 3929665 9 (2): e89210. doi: 10.1371/journal.pone.0089210. http://www.ncbi.nlm.nih.gov/pubmed/24586599.

[10] New York Department of Environmental Conservation. 2011. *Revised Draft Supplemental Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs*. Accessed Jan. 13, 2015. http://www.dec.ny.gov/energy/75370.html.

[11] NYS DOH. 2014. *A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development*. New York State Department of Health.

[12] Penningroth, S. M., M. M. Yarrow, A. X. Figueroa, R. J. Bowen, and S. Delgado. 2013. "Community-based risk assessment of water contamination from high-volume horizontal hydraulic fracturing." *New Solut* 23 (1): 137-66. doi: 10.2190/NS.23.1.i. http://www.ncbi.nlm.nih.gov/pubmed/23552652.

[13] Rabinowitz, P. M., I. B. Slizovskiy, V. Lamers, S. J. Trufan, T. R. Holford, J. D. Dziura, P. N. Peduzzi, M. J. Kane, J. S. Reif, T. R. Weiss, and M. H. Stowe. 2014. "Proximity to Natural Gas Wells and Reported Health Status: Results of a Household Survey in Washington County, Pennsylvania." *Environmental Health Perspectives*. doi: 10.1289/ehp.1307732. http://www.ncbi.nlm.nih.gov/pubmed/25204871.

[14] Racicot, A., V. Babin-Roussel, J. F. Dauphinais, J. S. Joly, P. Noël, and C. Lavoie. 2014. "A Framework to Predict the Impacts of Shale Gas Infrastructures on the Forest Fragmentation of an Agroforest Region." *Environmental Management* 53 (5): 1023-1033. http://link.springer.com/article/10.1007%2Fs00267-014-0250-x.

[15] Brittingham, Margaret C., Kelly O. Maloney, Aïda M. Farag, David D. Harper, and Zachary H. Bowen. 2014. "Ecological Risks of Shale Oil and Gas Development to Wildlife, Aquatic Resources and their Habitats." *Environmental Science & Technology*. Accessed 2014/09/15. doi: 10.1021/es5020482. http://pubs.acs.org/doi/abs/10.1021/es5020482.

[16] Maloney, K. O., and D. A. Yoxtheimer. 2012. "Production and Disposal of Waste Materials from Gas and Oil Extraction from the Marcellus Shale Play in Pennsylvania." *Environ. Pract.* 14 (04): 278-287.

[17] Entrekin, S., M. Evans-White, B. Johnson, and E. Hagenbuch. 2011. "Rapid expansion of natural gas development poses a threat to surface waters." *Front. Ecol. Environ.* 9 (9): 503.

[18] Johnson, N. 2010. *Pennsylvania Energy Impacts Assessment Report 1: Marcellus Shale Natural Gas and Wind.*

[19] Hays, J., and S.B.C. Shonkoff. 2016. "Toward an understanding of the environmental and public health impacts of shale gas development: an analysis of the peer-reviewed scientific literature, 2009-2014." *PLOS One*. doi: 10.1371/journal.pone.0154164.

[20] Moore, C.W., B. Zielinska, G. Petron, and R.B. Jackson. 2014. "Air Impacts of Increased Natural Gas Acquisition, Processing, and Use: A Critical Review." *Environ. Sci. Technol.* 48 (15): 8349-8359.

[21] Vengosh, Avner, Robert B. Jackson, Nathaniel Warner, Thomas H. Darrah, and Andrew Kondash. 2014. "A Critical Review of the Risks to Water Resources from Unconventional Shale Gas Development and Hydraulic Fracturing in the United States." *Environmental Science & Technology* 48 (15): 8334-8348. Accessed 2014/09/15. doi: 10.1021/es405118y. http://pubs.acs.org/doi/abs/10.1021/es405118y.

[22] Werner, A. K., S. Vink, K. Watt, and P. Jagals. 2015. "Environmental health impacts of unconventional natural gas development: A review of the current strength of evidence." *Sci Total Environ* 505C: 1127-1141. doi: 10.1016/j.scitotenv.2014.10.084. http://www.ncbi.nlm.nih.gov/pubmed/25461113.

[23] Krupnick, Alan, and Sheila Olmstead. 2013. "Cumulative Risks of Shale Gas Development." Resources For the Future, Washington, DC, May 31, 2013. http://sites.nationalacademies.org/cs/groups/dbassesite/documents/webpage/dbasse_083435.pdf.

[24] US Energy Information Administration. 2015. *Assumptions from the 2015 Annual Energy Outlook.*

[25] Bearer, S., E. Nicholas, T. Gagnolet, M. Dephilip, T. Moberg, and N. Johnson. 2012. *Environ. Pract.* 14 (04): 308.

[26] Cabot Oil & Gas Corporation. 2014. "Investor Presentation: Barclays' 2014 CEO Energy-Power Conference." September 2-3, 2014.

[27] Brannon, Travis L., Walton C. Shepherd, and James M. Van Nostrand. 2012. *Marcellus Shale Drilling Comparative White Paper: The Regulatory Approaches of New York, Ohio, Pennsylvania, and West Virginia.*

[28] PAMAP Program. 03/08/2007. Geographic Information Systems dataset. *PAMAP - Building/Address (Points).* vector digital data. PAMAP Program, PA Department of Conservation and Natural Resources, Bureau of Topographic and Geologic Survey.

[29] McKay, L., T. Bondelid, T. Dewald, J. Johnston, R. Moore, and A. Rea. 2012. Geographic Information Systems dataset. *NHDPlus Version 2*. U.S. Environmental Protection Agency (USEPA) and the U.S. Geological Survey (USGS).http://www.horizon-systems.com/nhdplus/NHDPlusV2_documentation.php.

[30] FEMA. 2015. Geographic Information Systems dataset. *FEMA National Flood Hazard Layer (NFHL).* Federal Emergency Management Agency.https://hazards.fema.gov/femaportal/wps/portal/NFHLWMS.

[31] Gergely, K.J., and A. McKerrow. Geographic Information Systems dataset. *PAD-US - National inventory of protected areas.* US Geological Survey.http://gapanalysis.usgs.gov/padus/data/.

[32] Manda, Alex K., Jamie L. Heath, Wendy A. Klein, Michael T. Griffin, and Burrell E. Montz. 2014. "Evolution of multi-well pad development and influence of well pads on environmental violations and wastewater volumes in the Marcellus shale (USA)." *Journal of Environmental Management* 142: 36-45.

[33] International, ICF. 2014. *Detailed Production Report.* http://www.icfi.com/news/2014/06/icf-detailed-production-report-second-quarter.

[34] Berman, Arthur, and Lyndon Pittinger. 2014. *Resource Assessment of Potentially Producible Natural Gas Volumes From the Marcellus Shale, State of New York.*

[35] US Energy Information Administration. 2014. "Oil and natural gas resource categories reflect varying degrees of certainty." Today in Energy - US Energy Information Adminstration. July 17, 2014. http://www.eia.gov/todayinenergy/detail.cfm?id=17151.

[36] Johnson, N., T. Gagnolet, R. Ralls, and J. Stevens. 2011. *Natural Gas Pipelines: Excerpt from Report 2 of the Pennsylvania Energy Impacts Assessment.*

[37] Slonecker, E.T., L.E. Milheim, C.M. Roig-Silva, A.R. Malizia, D.A. Marr, and G.B. Fisher. 2012. *Landscape consequences of natural gas extraction in Bradford and Washington Counties, Pennsylvania, 2004–2010*. USGS Open-File Report 2012-1154.http://pubs.usgs.gov/of/2012/1154/.

[38] Philips, Susan. 2015. "Unmapped, unregulated maze of rural pipelines poses hidden risks." *State Impact: A reporting project of NPR member stations*. Aug 04, 2015https://stateimpact.npr.org/pennsylvania/2015/08/04/unmapped-unregulated-maze-of-rural-pipelines-poses-hidden-risks/.

[39] Kiviat, E. 2013. "Risks to biodiversity from hydraulic fracturing for natural gas in the Marcellus and Utica shales." *Ann. N.Y. Acad. Sci.* 1286: 1-14.

[40] Souther, S., M. W. Tingley, V. D. Popescu, D. T. S. Hayman, M. E. Ryan, T. A. Graves, B. Hartl, and K. Terrell. 2014. "Biotic Impacts of energy development from shale: research priorities and knowledge gaps." *Front. Ecol. Environ.* 12 (6): 330-338.

[41] Drohan, P., and M. Brittingham. 2012. "Topographic and Soil Constraints to Shale-Gas Development in the Northcentral Appalachians." *Soil Sci. Soc. Am. J.* 76 (5): 1696.

[42] Kauffman, Gerald. 2011. *Socioeconomic Value of the Delaware River Basin in Delaware, New Jersey, New York, and Pennsylvania* University of Delaware. http://www.nj.gov/drbc/library/documents/SocioeconomicValueDRB-UDEL-FinalRpt.pdf.

[43] Schueler, Thomas R., Lisa Fraley-McNeal, and K. Cappiella. 2009. "Is Impervious Cover Still Important? Review of Recent Research." *Journal of Hydrologic Engineering* 14 (4): 309-15.

[44] King, R.S., M.E. Baker, P.F. Kazyak, and D.E. Weller. 2011. "How novel is too novel? Stream community thresholds at exceptionally low levels of catchment urbanization." *Ecol. Appl.* 21 (5): 1659-78.

[45] Kidd, K. R., and W.M. Aust. 2014. "Recreational Stream Crossing Effects on Sediment Delivery and Macroinvertebrates in Southwestern Virginia, USA." *Environmental Management* 54: 505-516. doi: 10.1007/s00267-014-0328-5. http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprd3846828.pdf.

[46] Aust, W.M., M.B. Carroll, M.C. Bolding, and C.A. Dolloff. 2011. "Operational Forest Stream Crossings Effects on Water Quality in the Virginia Piedmont." *South. J. Appl. For.* 35 (3): 123-130. http://www.srs.fs.usda.gov/pubs/ja/2011/ja_2011_aust_001.pdf.

[47] Vaughan, D.M. 2002. *Potential Impact of Road-Stream Crossings (Culverts) on the Upstream Passage of Aquatic Macroinvertebrates.* The Xerces Society. US Forest Service Report.http://www.fs.fed.us/t-d/programs/eng/projects/aopxing/pdfPubs/xerces_7-02_invert.pdf.

[48] The Nature Conservancy. 2015. *Reducing Ecological Impacts of Shale Development: Recommended Practices for the Appalachians: Stream Crossings.* http://www.nature.org/ourinitiatives/regions/northamerica/areas/centralappalachians/recommended-shale-practices-stream-crossings.pdf.

[49] Vogt, Peter, Kurt H. Riitters, Christine Estreguil, Jacek Kozak, Timothy G. Wade, and James D. Wickham. 2007. "Mapping spatial patterns with morphological image processing." *Landscape Ecology* 22: 171-177. ArcGIS tool downloaded from: http://clear.uconn.edu/tools/lft/lft2/.

[50] Colborn, Theo, Carol Kwiatkowski, Kim Schultz, and Mary Bachran. 2011. "Natural Gas Operations from a Public Health Perspective." *Human and Ecological Risk Assessment: An International Journal* 17 (5): 1039-1056. Accessed 2014/09/15. doi: 10.1080/10807039.2011.605662. http://dx.doi.org/10.1080/10807039.2011.605662.

[51] Macey, G.P., R. Breech, M. Chernaik, C. Cox, D. Larson, D. Thomas, and D.O. Carpenter. 2014. "Air concentrations of volatile compounds near oil and gas production: a community-based exploratory study." *Environmental Health* 13 (82): 1-18.

[52] McKenzie, Lisa M., Roxana Z. Witter, Lee S. Newman, and John L. Adgate. 2012. "Human health risk assessment of air emissions from development of unconventional natural gas resources." *Science of The Total Environment* 424 (0): 79-87. doi: http://dx.doi.org/10.1016/j.scitotenv.2012.02.018.

[53] US Census Bureau. 2010. Census block data by county. *SF1 100% Data - Profile of General Population and Housing Characteristics.* Spreadsheet document. US Census Bureau, Department of Commerce.http://factfinder.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t.

[54] IHS. Dec 31 2014. Geographic Information Systems Geodatabase. *"US Oil and Gas Pipeline and Facilities Data."*.

[55] US Census Bureau. 2016. "Quick Facts: Pennsylvania." https://www.census.gov/quickfacts/table/PST045215/42.

[56] Colborn, Theo, Kim Schultz, Lucille Herrick, and Carol Kwiatkowski. 2012. "An Exploratory Study of Air Quality Near Natural Gas Operations." *Human and Ecological Risk Assessment: An International Journal* 20 (1): 86-105. Accessed 2014/09/15. doi: 10.1080/10807039.2012.749447.

[57] Eastern Research Group, and Sage Environmental Consulting. 2011. *City of Fort Worth Natural Gas Air Quality Study.* City of Fort Worth, TX.

[58] Olaguer, Eduardo P. 2012. "The potential near-source ozone impacts of upstream oil and gas industry emissions." *Journal of the Air & Waste Management Association* 62 (8): 966-977. doi: 10.1080/10962247.2012.688923.

[59] Pennsylvania Department of Environmental Protection. "Air Emissions Data from Natural Gas Operations." http://www.dep.pa.gov/Business/Air/BAQ/BusinessTopics/Emission/Pages/Marcellus-Inventory.aspx#.VtQgu_krLIV.

[60] Litovitz, A., A. Curtright, S. Abramzon, N. Burger, and C. Samaras. 2013. "Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania." *Envrion. Res. Lett.* 8: 014017.

[61] Goetz, J. Douglas, Cody Floerchinger, Edward C. Fortner, Joda Wormhoudt, Paola Massoli, W. Berk Knighton, Scott C. Herndon, Charles E. Kolb, Eladio Knipping, Stephanie L. Shaw, and Peter F. DeCarlo. 2015. "Atmospheric Emission Characterization of Marcellus Shale Natural Gas Development Sites." *Environmental Science & Technology* 49 (11): 7012-20.

[62] Jemielita, T., G.L. Gerton, M. Neidell, S. Chillrud, B. Yan, M. Stute, M. Howarth, P. Saberi, N. Fausti, T.M. Penning, J. Roy, K.J. Propert, and R.A. Panettieri Jr. 2015. "Unconventional Gas and Oil Drilling Is Associated with Increased Hospital Utilization Rates." *PLoS One* 10 (7). doi: 10.1371/journal.pone.0131093. http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0131093.

[63] Ahmadi, Mahdi, and Kuruvilla John. 2015. "Statistical evaluation of the impact of shale gas activities on ozone pollution in North Texas." *Sci Total Environ* 536: 457-467.

[64] Environmental Protection Agency. 2008. "8-Hour Ozone Area Information (2008 Standard)." Green Book Nonattainment Areas. https://www3.epa.gov/airquality/greenbook/hindex.html.

[65] Gallegos, T.J., B.A. Varela, S.S. Haines, and M.A. Engle. 2015. "Hydraulic fracturing water use variability in the United States and potential environmental implications." *Water Resour. Res.* 51 (7): 5839.

[66] Kondash, A., and A. Vengosh. 2015. "Water Footprint of Hydraulic Fracturing." *Environmental Science & Technology Letters.* doi: http://dx.doi.org/10.1021/acs.estlett.5b00211.

[67] Mantell, M.E. 2011. "Produced water reuse and recycling challenges and opportunities across major shale plays." Unclassified. EPA hydraulic fracturing study technical workshop #4 - water resources management, March 29, 2011. Accessed November 27, 2014. http://www2.epa.gov/sites/production/files/documents/09_Mantell_-_Reuse_508.pdf.

[68] Jiang, Mohan, Chris T. Hendrickson, and Jeanne M. VanBriesen. 2014. "Life Cycle Water Consumption and Wastewater Generation Impacts of a Marcellus Shale Gas Well." *Environmental Science & Technology* 48: 1911-1920. doi: 10.1021/es4047654.

[69] Hansen, E., D. Mulvaney, and M. Betcher. 2013. *Water Resource Reporting and Water Footprint from Marcellus Shale Development in West Virginia and Pennsylvania*. Downstream Strategies.

[70] Richenderfer, J.L., B. Wagner, M.K. Shank, J. Balay, D. Hintz, J. Hoffman, P.B. Ballaron, S. McFeaters, and J. Zimmerman. 2016. *Water Use Associated with Natural Gas Shale Development: An Assessment of Activities Managed by the Susquehanna River Basin Commission July 2008 through December 2013*. Susquehanna River Basin Commission. Publication No. 299.

[71] Lutz, B. D., A. N. Lewis, and M. W. Doyle. 2013. "Generation, transport, and disposal of wastewater associated with Marcellus Shale gas development." *Water Resour. Res.* 49 (2): 647.

[72] Caldwell, P., G. Sun, S. McNulty, J.M. Myers, E. Cohen, R. Herring, and E. Martinez. 2013. *WaSSI Ecosystem Services Model Version 2.1 User Guide*. United States Forest Service. http://www.wassimap.sgcp.ncsu.edu/help/wassiuserguide.pdf.

[73] Ferrar, K. J., D. R. Michanowicz, C. L. Christen, N. Mulcahy, S. L. Malone, and R. K. Sharma. 2013. "Assessment of Effluent Contaminants from Three Facilities Discharging Marcellus Shale Wastewater to Surface Waters in Pennsylvania." *Environmental Science & Technology* 47 (7): 3472. http://pubs.acs.org/doi/abs/10.1021/es301411q.

[74] Hammer, R., Jeanne VanBriesen, and L. Levine. 2012. *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater*. Natural Resources Defense Council. 12-05-A.

[75] Harkness, J., G.S. Dwyer, N. Warner, K.M. Parker, W.A. Mitch, and A. Vengosh. 2015. "Iodide, Bromide, and Ammonium in Hydraulic Fracturing and Oil and Gas Wastewaters: Environmental Implications." *Environmental Science & Technology*. doi: 10.1021/es504654n. http://pubs.acs.org/doi/abs/10.1021/es504654n.

[76] Hladik, M.L., M.J. Focazio, and M. Engle. 2014. "Discharges of produced waters from oil and gas extraction via wastewater treatment plants are sources of disinfection by-products to receiving streams." *Science of the Total Environment* 466-467: 1085-1093. doi: 10.1016/j.scitotenv.2013.08.008.

[77] Parker, K.M., T. Zeng, J. Harkness, A. Vengosh, and W.A. Mitch. 2014. "Enhanced Formation of Disinfection Byproducts in Shale Gas Wastewater-Impacted Drinking Water Supplies." *Environmental Science & Technology* 48 (19): 11161-11169. doi: 10.1021/es5028184. http://pubs.acs.org/doi/abs/10.1021/es5028184.

[78] Warner, N. R., C. A. Christie, R. B. Jackson, and A. Vengosh. 2013. "Impacts of Shale Gas Wastewater Disposal on Water Quality in Western Pennsylvania." *Environ. Sci. Technol.* 47 (20): 11849. doi: 10.1021/es402165b. http://pubs.acs.org/doi/abs/10.1021/es402165b.

CNA

This report was written by CNA's Energy, Water, and Climate (EWC) group within the Safety and Security (SAS) division of the Institute for Public Research (IPR).

EWC provides integrated analysis of energy, water, and climate to gain a better understanding of the implications of their interrelationships and to help develop sound policies and programs to improve energy security, foster efficiency, and increase the likelihood of a secure, climate-friendly energy future.

CNA's Institute for Public Research provides research and analysis to a diverse array of federal, state, and local government agencies, and non-governmental organizations. At CNA, we take a systematic, evidence-based approach to problem solving. We define the problem, collect data through observation and experiment, and formulate and test hypotheses, to deliver impartial answers grounded in a thorough understanding of the issues. Read more about our research principles, and see our recent publications at:

https://www.cna.org/research/

IRM-2016-U-013695

CNA is a not-for-profit research organization
that serves the public interest by providing
in-depth analysis and result-oriented solutions
to help government leaders choose
the best course of action
in setting policy and managing operations.

Nobody gets closer—
to the people, to the data, to the problem.

www.cna.org • 703-824-2000

3003 Washington Boulevard, Arlington, VA 22201

The Potential Environmental Impact from Fracking in the Delaware River Basin

Steven Habicht, Lars Hanson and Paul Faeth

August 2015

Cleared for Public Release

CNA
ANALYSIS & SOLUTIONS

Acknowledgements: This report was extensively reviewed, so we have quite a few people to thank. They include Michele Adams, Art Berman, Don Cymrot, Kim Deal, Peter Demicco, Kevin Heatley, Robert Howarth, Anthony Ingraffea, Katherine McGrady, Paul Rubin, Gerald Shapiro, and David Vordick. Any errors that remain are our own responsibility. We would also like to recognize our editors, Peter Pavilionis and Andrea Wiltse, as well as our colleagues who helped with production, Veronica Hoban and Cynthia Roberson.

The Delaware Riverkeeper Network provided the funding for this research and we would like to express our thanks for their support.

Authors: Steven Habicht, Lars Hanson and Paul Faeth

This document represents the best opinion of CNA at the time of issue.

Distribution unlimited

Approved by: **August 2015**

David J. Kaufman, Vice President and Director
Institute for Public Research
Safety and Security Division

Abstract

This study aims to model the landscape of the Marcellus Shale region to predict how it may change in the future in response to the expansion of natural gas extraction, and, in particular, what impact this may have on the Delaware River Basin (DRB). Our approach combined geospatial analysis and statistical modeling to create a probability surface that predicts the most favorable locations for the placement of future wells based on the location of existing wells. Using the probability surface and an estimate of the number of wells that would be needed to fully exploit the shale resource, we estimated the future landscape of development in the Interior Marcellus Shale and DRB. Using affected subwatersheds and counties as study areas, we then investigated potential impacts associated with land cover, water and wastewater management, water quality due to changes in land cover, air emissions, and health risk factors. The results are intended to help decision-makers and the public understand the scale of the potential impacts.

This page intentionally left blank.

Executive Summary

Hydraulic fracturing, or "fracking," combined with horizontal drilling, has opened up natural gas fields that were previously thought to be inaccessible; however, this activity has the potential to impact the regional environment. To date, there has been no systematic analysis to evaluate multiple impacts of fracking in an integrated way. Published research has predominantly looked at individual environmental impacts associated with fracking in a subset of wells. Few studies have considered multiple impacts, and no study has provided a reasonably complete, integrated regional environmental assessment of fracking. We aim to help fill this knowledge gap and inform the public debate concerning fracking by providing comprehensive, long-term estimates of a set of environmental impacts of natural gas fracking in the Interior Marcellus Shale. This play, which covers parts of Pennsylvania, New York, West Virginia, Maryland, and Ohio, is now considered to be the second-largest gas field in the world.

This research project models the potential natural gas development of the Marcellus Shale to predict what environmental impacts this expansion may have on the Delaware River Basin (DRB). The DRB—which spans Pennsylvania, Delaware, New Jersey, and New York—contains one part of the Interior Marcellus Shale play where fracking has been under a moratorium, by the Delaware River Basin Commission. (The State of New York has separately banned hydraulic fracturing after implementing a five-year moratorium). For this reason, the DRB is a good candidate for a prospective analysis of potential impacts.

Our approach combines geospatial analysis and statistical modeling to create a probability surface that predicts the most favorable locations for the placement of future wells based on the locations of existing wells. Using the probability surface and an estimate of the number of wells that would be needed to fully develop the shale resource, we estimated the future landscape of development across the Interior Marcellus Shale.

We then investigated the potential impacts of this development on land cover, water and wastewater management, water quality, air emissions, and health risk factors in three DRB sub-watersheds. Our calculations were designed to give reasonable upper bounds on each of these potential impacts. Based on our analysis, we offer the following key points to help stakeholders and decision-makers evaluate the potential impacts of natural gas development:

- If the moratoriums on fracking were lifted, there could be as many as 4,000 **wells** fracked in the Interior Marcellus within the DRB in future years, requiring between 500 – 1,000 **well pads**.

- Development of natural gas infrastructure including well pads, and rights-of-way for access roads and natural gas gathering lines, results in 17-23 acres of **land cover disturbance** per well pad. In watersheds we studied, this land cover disturbance could reduce forest cover directly by 1-2 percent, and result in a 5-10 percent reduction in **core forest area**.

- **Water withdrawals** during periods of maximum well development could remove up to 70 percent of water if taken from small streams during low-flow conditions, and less than 3 percent during normal flow conditions.

- Discharge of **wastewater effluent** from fracking could raise in-stream concentrations of some key contaminants (notably barium and strontium) up to 500 percent above reference values during maximum development periods at low-flow conditions, if all wastewater were treated to Pennsylvania effluent standards.

- Land cover conversions could increase **erosion rates** up to 150 percent during the initial development phase and up to 15 percent in a post-development state, despite affecting less than 3 percent of land cover in affected watersheds we studied.

- The installation of multiple **compressor stations** (needed to transport gas away from wells through pipelines) in the DRB could as much as double nitrogen oxide emissions in the impacted counties (compared to present-day, county-wide emissions).

- In the DRB, roughly 45,000 people would live within one mile of the projected well pad locations, a distance that has been related to **health risk factors** in scientific literature. This population would predominantly reside in Wayne County, PA, where nearly 60 percent of the county's population (over 30,000 people) may be affected.

Of these risks, changes to land cover and associated impacts to area forests, hydrology, and water quality appear the most likely to occur and most difficult to mitigate completely. The water and wastewater and air quality risks pose some significant management challenges, but the actual level of impact is uncertain and highly influenced by potential regulation and policy. The health risks require more study because a significant number of people in the Upper Delaware River Basin live in areas that are close to potential well locations.

This report presents an estimate of full natural gas development based on technically recoverable resources in the Interior Marcellus Shale play, and focuses on some of the locations where concentrated development can reasonably be expected in the DRB portion of the play (if development were allowed). As such, the well development projections and associated impact calculations likely would be a conservative (high-end) estimate of potential development or impacts. Actual development will ultimately depend on laws and regulations, ability to sign leases, ability to recover gas, and economics (price of gas, cost of production, well productivity, etc.). While regulatory, economic, and other factors may limit the actual level of development, policymakers should be prepared to handle the impacts from a scenario in which the shale resources could be fully developed.

This study only investigates the Interior Marcellus shale play, and does not consider other shale plays underlying the DRB such as the Utica Shale. This study does not examine the full range of potential impact categories that the region may experience, does not consider all potential impact pathways (e.g. accidental wastewater discharges), and it does not project possible environmental and human health outcomes based on the impacts.

This page intentionally left blank.

Contents

List of Figures

List of Tables

This page intentionally left blank.

Glossary

Ba	Barium
Bcf	billion cubic feet
BMP	Best Management Practice
BTEX	Benzene, Toluene, Ethylbenzene, and Xylene
CO_2	carbon dioxide
Cl	Chloride
DRB	Delaware River Basin
DRBC	Delaware River Basin Commission
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESRI	Environmental Systems Research Institute
EUR	Estimated Ultimate Recovery
GIS	geographic information system
GW	groundwater
HUC	hydrologic unit code
JAS	July-August-September
Maxent	maximum entropy (modeling technique)
MGD	million gallons per day
NEI	National Emissions Inventory
NLCD	National Land Cover Dataset
NO_x	nitrogen oxides
PADEP	Pennsylvania Department of Environmental Protection
PAH	polycyclic aromatic hydrocarbon
PM	particulate matter
SO_x	sulfur oxides
SO_4	sulfate
Sr	Strontium
TDS	Total Dissolved Solids
TSS	Total Suspended Solids
TN	Total Nitrogen
TP	Total Phosphorus
UNGD	unconventional natural gas development
USGS	U.S. Geological Survey
VOC	volatile organic compound
WW	wastewater

This page intentionally left blank.

Introduction

Hydraulic fracturing, or "fracking," combined with horizontal drilling, has allowed access to natural gas in shale deposits previously thought to be inaccessible. This type of unconventional natural gas development (UNGD) has significant implications for energy supplies and fuel choice in the American economy. For the first time in 30 years, coal's share of power generation dipped below 40 percent in 2012, while gas's share increased. Leading this charge is the Marcellus Shale play, which currently accounts for almost 40 percent of U.S. natural gas production and is projected to increase [1]. This play, which covers parts of Pennsylvania, New York, West Virginia, Maryland, and Ohio, is now considered to be the second-largest gas field in the world.

While these newly accessible resources are transforming the nation's energy economy, the fracking process carries a potential environmental burden in the nature and scale of the extraction activities involved—particularly well development [2-7]. The amount of water required to fracture a well typically varies from one to five million gallons (but can be more depending on well-specific conditions). Much of the water that is tapped to inject into the wells contains a variety of chemicals and additives to aid in fracturing the shale rock. About 80 percent of the injected water is consumed by the process (i.e., remains underground), and the "produced water" that returns to the surface must be handled as required by environmental law. The nature of well pad development has raised concerns over soil erosion, sedimentation/siltation, and eutrophication of nearby streams, as well as ecosystem fragmentation. Local air quality could suffer from increased ozone creation, the release of volatile organic compounds and toxic chemicals, greenhouse gas emissions from fugitive methane releases, and increased airborne particulates from extensive diesel engine use. These are potential environmentally hazardous byproducts of the fracking process itself.

While recent years have seen a significant increase in the peer-reviewed literature on the various impacts of fracking, substantive data gaps remain [8]. To date, there has been no systematic analysis to evaluate the multiple, integrated impacts of fracking. Published research has looked predominantly at individual environmental impacts associated with fracking in a subset of wells. Few studies have considered multiple impacts, and no study has provided a reasonably complete, regionally integrated environmental assessment of fracking, or developed the methodology to do so. Thus, even with more information, regulators are left attempting to extrapolate study

results to their region to assess impacts—and at a time of shrinking government budgets and resources.

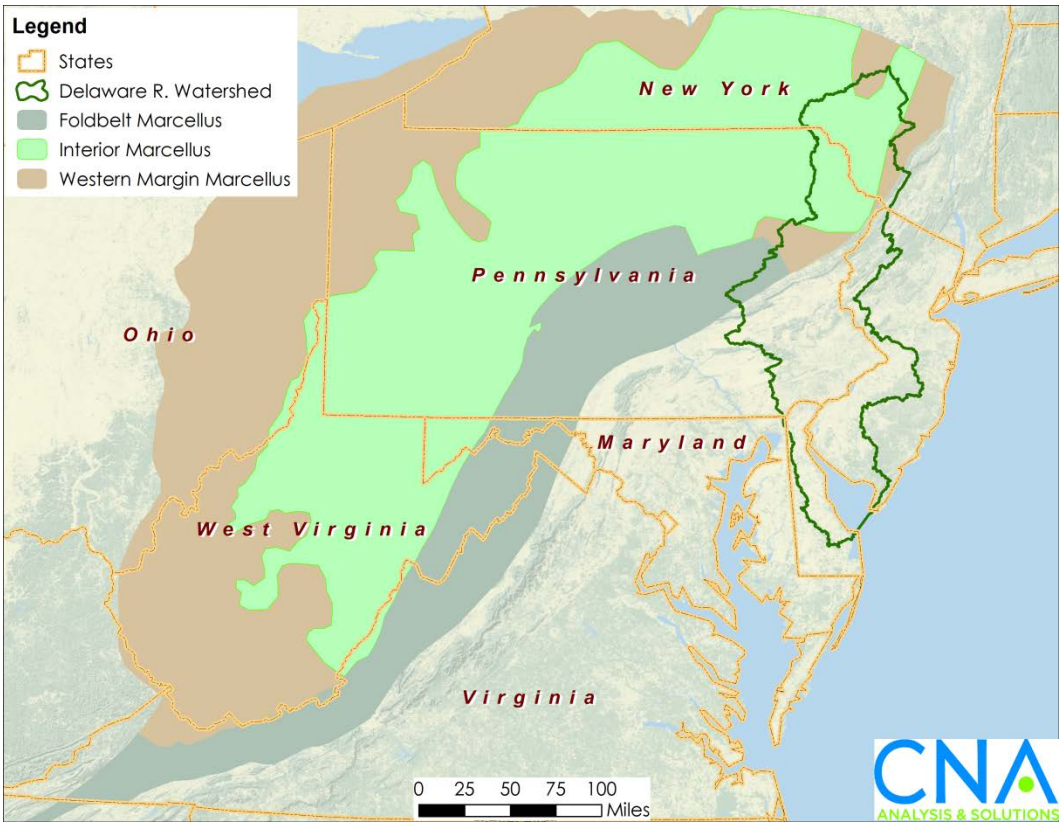
One of the primary barriers to conducting this type of research is the difficulty in predicting where future natural gas wells will be located. For example, in a recent report to Congress, the U.S. Government Accountability Office stated, "The risks identified in the studies and publications we reviewed cannot, at present, be quantified, and the magnitude of potential adverse effects or likelihood of occurrence cannot be determined for several reasons. First, it is difficult to predict how many and where shale oil and gas wells may be constructed" [9]. With this report, our objective is to correct this critical deficiency in the research.

The Delaware River Basin (DRB)—which spans Pennsylvania, Delaware, New Jersey, and New York—contains one part of the Marcellus Shale play that has not been developed (see Figure 1 on the following page); therefore, it is a good candidate for a prospective analysis of potential impacts. Due to state and regional regulation, gas development is currently limited in the DRB. The State of New York recently announced a ban on hydraulic fracturing after investigating its impacts during a five-year moratorium on the practice. Similarly, in the Pennsylvania portion of the basin, no hydraulic fracturing has occurred because the Delaware River Basin Commission (DRBC) has had a moratorium in place on the practice for some years. In this analysis, we investigate a hypothetical case where no moratorium prevents development.

Furthermore, this analysis focuses on the Interior Marcellus, which is most suitable for gas development with hydraulic fracturing. The Western Margin Marcellus is generally less than 50 feet thick, and the Foldbelt Marcellus shows the extent of the shale formation, but is generally not thought to be deep enough or thick enough for development.

In this report, we summarize the methodology to identify the probable placement and extent of future wells in the DRB region of the Interior Marcellus Shale through the statistical evaluation of existing well locations in the play. We then demonstrate the utility of the well-development projections to evaluate a variety of potential environmental impacts to some subwatersheds of the DRB. These impacts include land cover disturbance, including forest fragmentation; issues related to water and wastewater management; water quality issues resulting from changes to land cover; air quality issues; and affected population. Each chapter of the report examines one of these impacts in the context of existing basin conditions, as well as relevant activities where appropriate, for framing of results.

Figure 1. The extent of the Marcellus Shale play and the Delaware River Basin. This study focuses on the Interior Marcellus.



Source: U.S. Geological Survey (Marcellus, DRB), U.S. National Park Service (Terrain Basemap)

Understanding this report

This report presents an estimate of full natural gas development (based on technically recoverable resources) in the Marcellus Shale play, and focuses on some of the locations where concentrated development can reasonably be expected in the Delaware River Basin portion of the play. As such, the development projections and associated impact calculations likely would be a conservative (high-end) estimate of potential development or impacts. Actual development will ultimately depend on laws and regulations, ability to sign leases, ability to recover gas, and economics (price of gas, cost of production, well productivity, etc.). Like the projections for well pad development, we calculated potential impacts using several scenarios to give reasonable upper bounds of potential impacts. While regulatory, economic, and other factors may limit the actual level of development, policymakers should be prepared

to handle the impacts from a scenario in which the shale resources could be fully developed.

We project locations to calculate impacts, but they should *not* be interpreted as explicit *predictions* of where wells will actually go. Although high-resolution spatial data allows fairly precise well pad siting, this analysis is most useful for identifying which portions of the Marcellus Shale may be most suitable for development (relative to all the others). Actual locations of wells depend on many site-specific factors, not the least of which is a legal lease contract to perform drilling on a property. Furthermore, the projected well pad locations should not be used to estimate impacts at small scales, such as for individual parcels or neighborhoods.

Instead, the level of impacts estimated in this report should be viewed as a first iteration of investigating a range of potential impacts. While the impacts selected cover a broad range of topics, there are other potential impacts that are not covered here (e.g. truck traffic, long-range transmission pipelines, or induced seismicity). The selected impacts in this report are suited to analysis using the well pad projections; are documented in peer-reviewed literature; and are likely to occur, given current trends in the development of the gas sector. We present each potential impact in its own chapter with its own analysis, though all depend on the projections of wells and well pads. Furthermore, this report only examined the potential for development of wells and well pads in the portion of the Marcellus Shale play that underlies the DRB; there are other shale formations (e.g., the Utica Shale and Newark Basin) that lie beneath that DRB that were not considered in our projections.

We selected study areas, scenarios, and analysis methods to investigate the range of outcomes associated with each impact category. Table 1 outlines the assessment unit, development scenarios, and additional analysis scenarios for each section. The assessment unit is the geographic area under consideration. For land- and water-related impacts, we used the drainage areas of defined subwatersheds in the basin with extensive projected gas development. For impacts to air quality and human health, we used counties as study areas.

We generated projections for well development for two well pad–density scenarios: a *concentrated* scenario (eight wells per pad = fewer well pads) and a *dispersed* scenario (four wells per pad = more well pads). The land cover changes, water quality issues from land cover changes, and health risk are all related to the development of well pads (and associated infrastructure). By contrast, the water/wastewater and air quality impacts depend primarily on the number of wells. Since the number of wells is approximately equal for the scenarios, the well pad density is not important when analyzing these impacts and only one scenario was selected. The water and wastewater management chapter used the "concentrated" scenario because slightly more wells were developed in the assessment units being considered than for the "dispersed" scenario.

Furthermore, each chapter's topic required additional analysis dimensions particular to the impact to capture the potential consequences. For example, water/wastewater and air quality results depend on the rate of well development per year, so we investigated scenarios for average yearly development and for maximum development within a year. The water quality impacts associated with land cover disturbance vary over time, such as during initial infrastructure construction or after infrastructure is built and the gas wells are in production. Finally, we investigated the affected population affected at six different distances from the nearest well pad, which academic literature uses in evaluating certain health risk factors as a function of distance from the well pad.

Table 1. Chapter breakdowns of analysis in this report. Land cover and water impacts were considered at the drainage basin level; air and health impacts were considered at the county level.

Report Chapter Topic	Assessment Unit	Development Scenarios	Additional Analysis Dimensions
Land Cover Changes	Drainage basin	Both	• Direct Conversion • Forest Fragmentation
Water and Wastewater Management	Drainage basin	*Concentrated*	• Average Dev. • Maximum-Year Dev. • Wastewater reuse
Water Quality	Drainage basin	Both	• Initial Infrastructure • Post-Development
Air Quality	County	*Dispersed*	• Average Dev. • Maximum-Year Dev.
Health Risks and Affected Population	County	Both	• Six distances from well pad

This page intentionally left blank.

Potential Natural Gas Development in the Marcellus Shale

Key Findings

- Based on Energy Information Administration resource estimates for technically recoverable reserves, the Interior Marcellus could see an additional 63,000 wells developed in the future. Our analysis did not include other portions of the Marcellus, or other shale plays in the region.
- Most of the future development in the Interior Marcellus would be expected in Pennsylvania (74 percent), followed by West Virginia (19 percent), New York (4 percent), Ohio (2 percent), and Maryland (1 percent), assuming no moratoriums throughout the Marcellus region.
- Eleven counties in Pennsylvania could each see development of over 2,000 additional new wells, including Wayne County in the DRB.
- Were the moratoriums in the DRB lifted, there could be approximately 4,000 wells at full development of the Interior Marcellus. This number of wells would require 500 – 1,000 well pads depending on the number of wells per well pad.

This chapter presents the current landscape of the Marcellus Shale play in order to predict how the landscape may change in the future in response to the expansion of natural gas extraction. In particular, we focus on the potential development in the Interior Marcellus Shale Assessment Unit (see Figure 1 on page 3), since 95 percent of the shale's reserves are estimated to fall within this boundary [10], and 98 percent of the new wells developed in the region since 2011 have been within this boundary. We then focus our analysis to determine where this development would most likely extend into the Delaware River Basin if the moratoriums on drilling were lifted.

To predict the most likely locations for the placement of future wells, we used an approach combining geospatial analysis and maximum entropy (Maxent) modeling. This approach is commonly used in ecological sciences to predict the most probable

distribution of species based on the environmental conditions of their known habitat [11-13]. This approach has also been used previously to predict the location of future well pad sites in Pennsylvania's Marcellus Shale play [14] to assess the impacts of habitat disturbance. We expand the use of this model here to the entire Interior Marcellus Shale region to project where natural gas development may occur at full development of the shale play.

Model Variables

For this research, we used geographic information system (GIS) tools (Environmental Systems Research Institute [ESRI] ArcGIS 10.2) to process a variety of environmental variable layers that are known to be relevant in the siting of natural gas well pads [15]. These layers are based on the best available data and include characteristics of the shale, itself, and characteristics of the states' landscapes, such as the terrain and infrastructure:

- **Shale characteristics** provide insight into the amount of natural gas that may be present. The layers depicting the depth and thickness of the Marcellus Shale we used for this analysis were developed by the Penn State Marcellus Center for Outreach and Research [16]. Shale thermal maturity was based on the work of Wrightstone [15] and was obtained from Rystad Energy [17].

- **Land cover and slope variables**, which outline the terrain of the region, can help to gauge the relative effort required when developing a well pad. We used the National Land Cover Dataset (NLCD) [18] as the land cover variable layer. We created the slope layer from the USGS 30-meter national elevation dataset [19] using the "Slope" tool in ArcGIS.

- **Distance variables** represent the importance of a well pad's proximity to critical infrastructure that supports the extraction process. We used geospatial pipeline data from IHS Energy [20] and geospatial road data (primary and secondary roads only) from the U.S. Census Bureau [21] to represent infrastructure. We then used the Distance tools in ArcGIS to create the distance variable layers.

All layers were sampled to 30 meters and formatted for the Maxent application by using the "Extract by Mask" tool in ArcGIS to align all layers to the Interior Marcellus boundary.

We used the coordinates for wells drilled in the Marcellus Shale between 2005 and 2013 (from Rystad Energy [17]) as inputs for the model, amounting to about 8,000 well locations. We then used the well locations to estimate the number of unique well pad locations as inputs for the Maxent model, since multiple wells can be drilled on a

single well pad. We accomplished this by placing a 50-meter buffer around each well and taking the center point of any overlapping buffers as the pad location, resulting in approximately 3,600 unique pad locations.

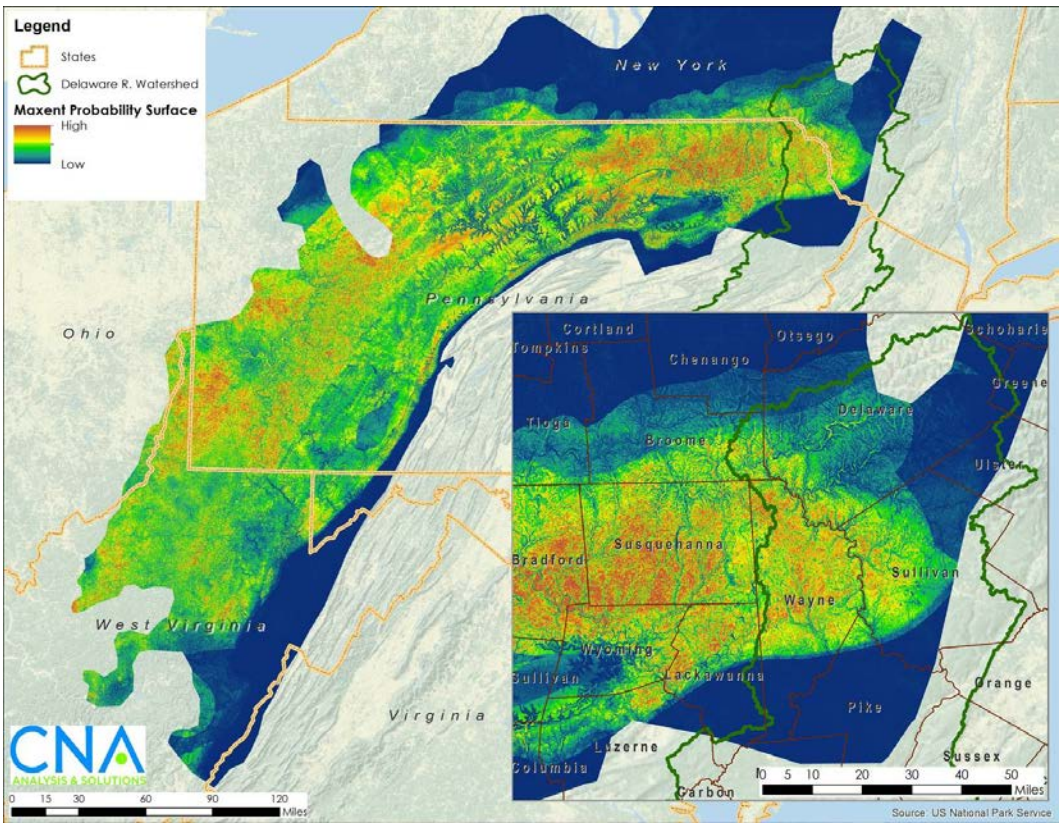
Well-Location Modeling

We input the well pad locations and environmental layers into the Maxent modeling application (Version 3.3.3k [22]) to evaluate the layer values at each of the locations. Maxent uses the characteristics of the environmental layers at existing well locations to develop a scoring model, which translates these layer characteristics into a probability model for future locations. From the 3,600 locations that we input into the program, about 2,900 were randomly chosen to build the model; the remaining locations were used to validate the model. The program produced a probability surface that depicted the most probable locations for well pads. We analyzed the probability surface using ArcGIS to evaluate the extent of potential natural gas development in the region.

To begin the study, we examined the full extent of the Interior Marcellus. There are other shale plays in the region, but we did not consider them in this analysis. Figure 2 shows the probability surface generated by the Maxent program. This analysis is based on physical parameters only and assumes no regulatory or economic constraints. The surface has 30-meter resolution and uses a color scheme to depict the suitability of the region for development based on the environmental variables, with "cooler" colors denoting areas with a lower probability of development, and "warmer" colors denoting those with a higher probability of development. Evaluation of the surface shows two distinct areas with a concentrated high probability of development: one in the northeast region of Pennsylvania (around Tioga, Bradford, and Susquehanna Counties), and the other in the southwest region of the state (around the Pittsburgh area). These two areas are consistent with a majority of the shale gas development seen in the region.

The probability surface also shows potential in Wayne County in northeast Pennsylvania, as well as some parts of Broome, Delaware, and Sullivan Counties in New York along the NY–PA border. No development has occurred in these areas, as they are under moratoriums put in place by the DRBC and New York State. Following examination of the full probability surface, we focused on these areas of the Interior Marcellus Shale that fall within the Delaware River Basin (Figure 2, inset).

Figure 2. Map depicting the Maxent probability surface for the Interior Marcellus Shale. The northeastern and the southwestern parts of Pennsylvania have the highest probability of future development. Some drilling could occur within the Delaware River Basin if the moratoriums were lifted.



Source: U.S. National Park Service (Terrain Basemap)

Development Scenarios

To determine the number of wells that would be needed to fully develop the Marcellus Shale, we used the U.S. Energy Information Administration's (EIA's) estimate [10] of technically recoverable resources: 113.9 trillion cubic feet for the Interior Marcellus, divided by the EIA average total production per well (Estimated Ultimate Recovery [EUR] of 1.6 billion cubic feet [Bcf] per well). We subtracted the number of existing Marcellus wells from this total to get the number of new wells expected, which is over 63,000. We then developed two scenarios to model how well pads may be developed throughout the region to accommodate these new wells. The scenario names, referring to well pad distribution across the landscape, are as follows:

- **Dispersed:** Development of four wells per pad (more well pads built)
- **Concentrated:** Development of eight wells per pad (fewer well pads built)

Table 2 shows the number of well pads associated with each scenario. For this research, we assumed that new well pads would be built to accommodate each new set of wells. These scenarios and estimates are in line with trends in the industry. Currently, Marcellus Shale well pads average a bit less than three wells, though the trend in this region is toward more wells per pad, and there have been pads here with up to 19 wells drilled. These scenarios likely bracket the expected range of average wells per pad in the future.

Table 2. Scenarios used to project well pad development in the Marcellus Shale. Each scenario has the same number of wells, but the "concentrated" scenario has half as many well pads and twice the spacing between the pads.

Scenario	Total Wells	Wells Per Pad	Well Pads	Spacing[a]
Dispersed	63,412	4	15,853	367 acres
Concentrated	63,412	8	7,926	735 acres

[a] Spacing was based on an estimated drainage area for each well pad and calculated by extending half of the well laterals in one direction, and the other half 180 degrees in the opposite direction. We assumed a 4,000-foot lateral length and 500 feet of spacing between laterals.

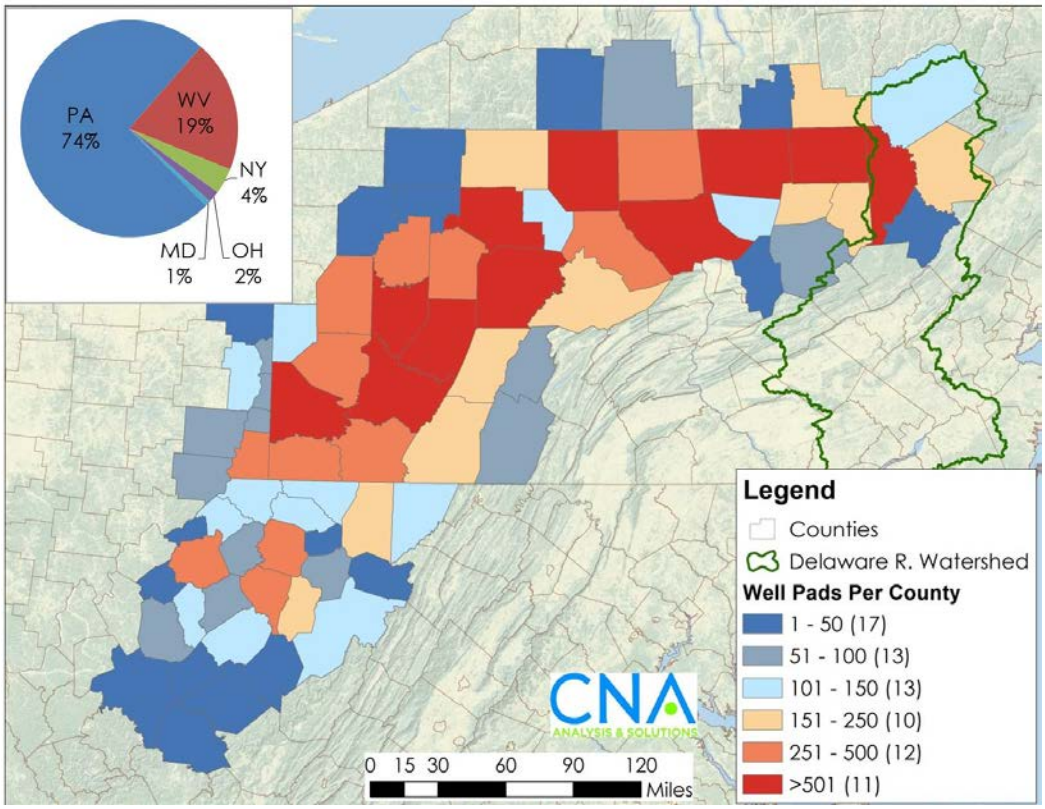
After developing the probability surface and scenarios, we devised a methodology to analyze the probability surface and choose the most likely locations for natural gas well pads. First, we used GIS tools to exclude areas in the probability map that would most likely be prohibited from development (e.g., existing well pad locations, wetlands, flood plains, and additional areas based on setbacks from streams, reservoirs, and buildings).

Next, we used a combination of spatial averaging and exclusion techniques in ArcGIS to ensure that well pads were sited over "hotspots" on the Maxent surface, and that well pads had adequate spacing (see Table 2) to prevent overlapping laterals. When completed, this analysis produced a distribution of unique cells on the Maxent best suited to well pads across the Marcellus Shale. For example, for the "dispersed" scenario, we selected the top 15,853 well pad locations as measured by Maxent values. These locations were converted to a set of points representing well pad locations across the Marcellus Shale that could be used for further analysis. By focusing on the locations within the DRB, we can begin to understand the scope of shale gas development if the moratoriums were lifted.

Based on the "dispersed" scenario, Figure 3 shows a breakdown of the number of well pads projected from future development in each county throughout the

Marcellus Shale. The inset for this figure also shows the aggregate percent total of well pads expected in each state overlaying the Marcellus. As expected, we see a majority of potential future development (74 percent) occurring in Pennsylvania, based on both the favorable conditions for development and the fact that a majority of the Marcellus Shale is found under the state. Furthermore, all 11 of the highest developed counties (>500 well pads) are located within Pennsylvania. The highest number of wells we found in a county is about 2,900 in Washington County.

Figure 3. Map depicting the number of *new* well pads that could be developed in each county based on the "dispersed" scenario (15,853) if fracking were allowed across the whole Marcellus. Inset shows the breakdown of new well pads by state. Eleven counties in Pennsylvania are likely to experience the most shale gas development, including Wayne County, PA, in the DRB.



Source: U.S. National Park Service (Terrain Basemap)

Results and Study Area Selection

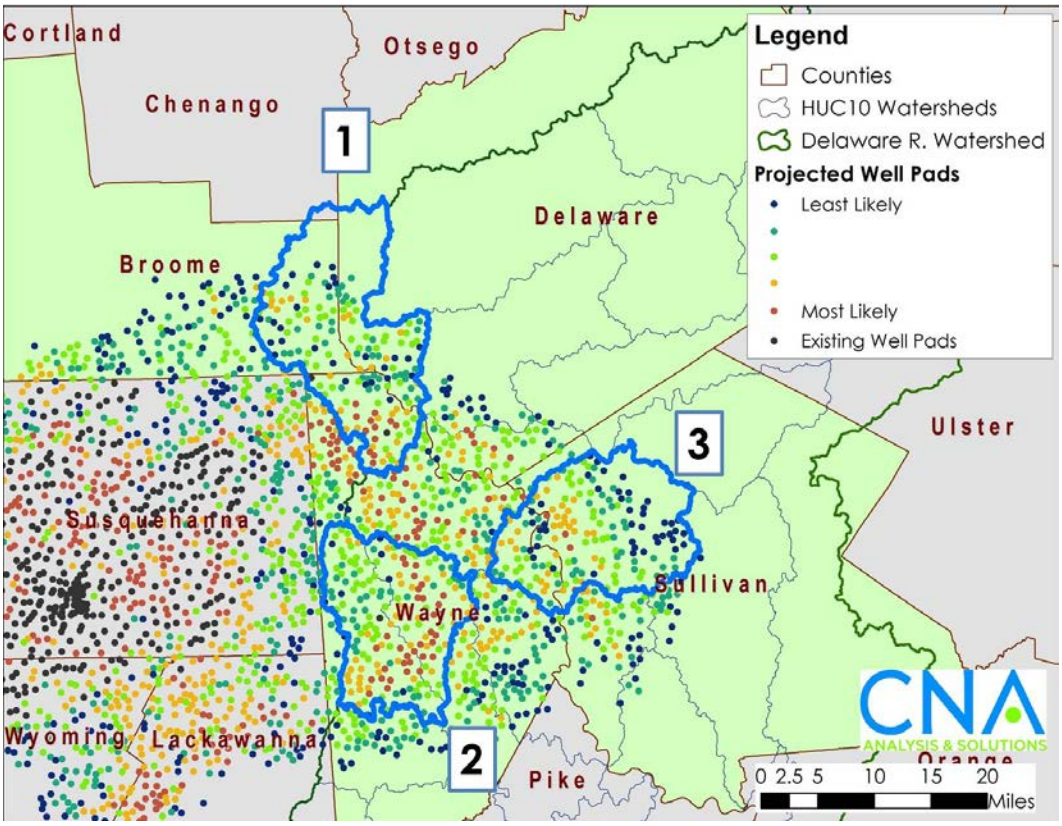
Figure 4 shows an expanded view of the potential landscape of natural gas development in the DRB, based on our development projection using the "dispersed" scenario. The well pads are color-coded according to their potential for development, again using the warm-to-cool scale to indicate most to least likely. Based on this modeling, the DRB potentially could see 500 ("concentrated" scenario) to 1,000 ("dispersed" scenario) well pads (or about 4,000 wells) developed were the moratoriums to be lifted. In either scenario, we expect that a majority of the development within the DRB would occur in Wayne County, PA.

We chose three study areas within the DRB to localize our assessment of potential water-related impacts to the environment. Each study area is based on the USGS hydrologic unit code (HUC)–10 watershed boundaries and is approximately 160–210 square miles in size. (For reference, the city limits of Philadelphia cover an area of 143 square miles.) The study areas are highlighted in Figure 4 and cover areas in both New York and Pennsylvania that would most likely be impacted by development. We will reference these study areas throughout the following chapters when evaluating each of the different impacts. Study Area 1 includes portions of Broome (NY), Delaware (NY), and Wayne Counties (PA), and is just downstream of the Cannonsville Dam. Study Area 2 includes two adjacent HUC-10s in Wayne County. Study Area 3 is primarily in Sullivan County, NY.[1]

[1] The USGS 10-digit Hydrologic Unit Codes for these areas are as follows:

Study Area 1 – 0204010103; Study Area 2 – 0204010301 and 0204010302;
Study Area 3 – 0204010105.

Figure 4. Potential locations for new well pads in the DRB, based on the "dispersed" scenario. We chose from three study areas (blue outline) or four counties (green fill) as assessment units for further analysis.



For each of the following chapters, we chose assessment units (i.e., drainage areas or counties) best suited to quantify and describe the extent of impacts that may be expected (see Table 1). For land- and water-related impacts, we used the drainage areas of defined subwatersheds in the DRB. For impacts to air quality and human health, we used county boundaries. Table 3 shows the extent of natural gas development in the DRB that our methodology projects, broken down by these different assessment units for reference throughout the report.

Table 3. Projected natural gas development in the DRB, broken down by development scenario and assessment units. Of the four impacted counties in the DRB, Wayne County, PA is projected to experience the most development.

		Dispersed Scenario		Concentrated Scenario	
Assessment Unit	Area (sq mi)	Well Pads	Wells	Well Pads	Wells
Study Area 1	212	162	648	90	720
Study Area 2	162	191	764	93	744
Study Area 3	178	170	680	79	632
Wayne Co., PA[a]	751	590	2,360	303	2,424
Broome Co., NY[a]	715	58	232	34	272
Delaware Co., NY	1,468	204	816	93	744
Sullivan Co., NY	997	123	492	67	536
DRB Total	3,150[b]	975	3,900	497	3,976

[a] These numbers reflect only the portion of expected development that would fall within the DRB; Wayne Co., PA, and Broome Co., NY, could see development outside of the DRB.

[b] This area represents the portion of the DRB that lies above the Interior Marcellus. Roughly one-third of this area has projected well pad development.

Discussion

Our results depict a model of potential development in the Interior Marcellus Shale—and particularly in the DRB—assuming full exploitation of the Shale's technically recoverable resources (as estimated by the EIA). Our goal with this model was to provide a projection and spatial context to this development in order to evaluate what environmental impacts it could have on the basin (assuming drilling was allowed to proceed). Given the importance of shale characteristics to the model, the use of additional variables (e.g., total organic carbon, or the inclusion of potentially more-accurate proprietary data) could lead to a different projection.

We estimate that about 4,000 wells could be drilled in the Marcellus Shale within the DRB. This projection falls within a wide range of other published and unpublished estimates of well development in this region. For example, the National Park Service used the overlap of the Marcellus Shale and DRB boundaries with some spacing and exclusion assumptions to arrive at an estimate of 16,000 to 32,000 wells that could be drilled in the DRB [23]. Kaufman and Homsey estimated the amount of gas that could be produced in the DRB by using estimates of reserves and excluding lands based on proposed regulations to assess the economic value of shale gas development in the region [24]. Their results indicate an estimate of approximately 2,500 wells drilled in the DRB (based on their production estimates for the DRB and applying our assumption that wells have an EUR of 1.6 Bcf), a number in fair agreement with our projections. The Nature Conservancy used a similar methodology to ours to project the location of potential wells in Pennsylvania, which we estimate

from their report includes approximately 350 wells drilled in Wayne County, PA [14]. While this estimate is noticeably lower than ours (we project approximately 2,600 wells in Wayne County), the authors did add a caveat that their results may have underestimated Wayne County, based on comments from reviewers. Berman and Pittinger recently estimated potential development in New York based on well production data in Pennsylvania [25]. Their results indicate that although Broome County could see the most development in New York, this development would be focused mostly on the western to central portion of the county, with little apparent development in the DRB portion. The study also estimates no development in Delaware and Sullivan Counties (NY), in contrast with our results. The authors do state that the lack of well-production data in New York (due to the moratorium) does add uncertainty to this area. These studies demonstrate the variation in potential for well development in the region, and the results of our study fall within the range of well development that the previous studies have found .

Impacts on Land Cover

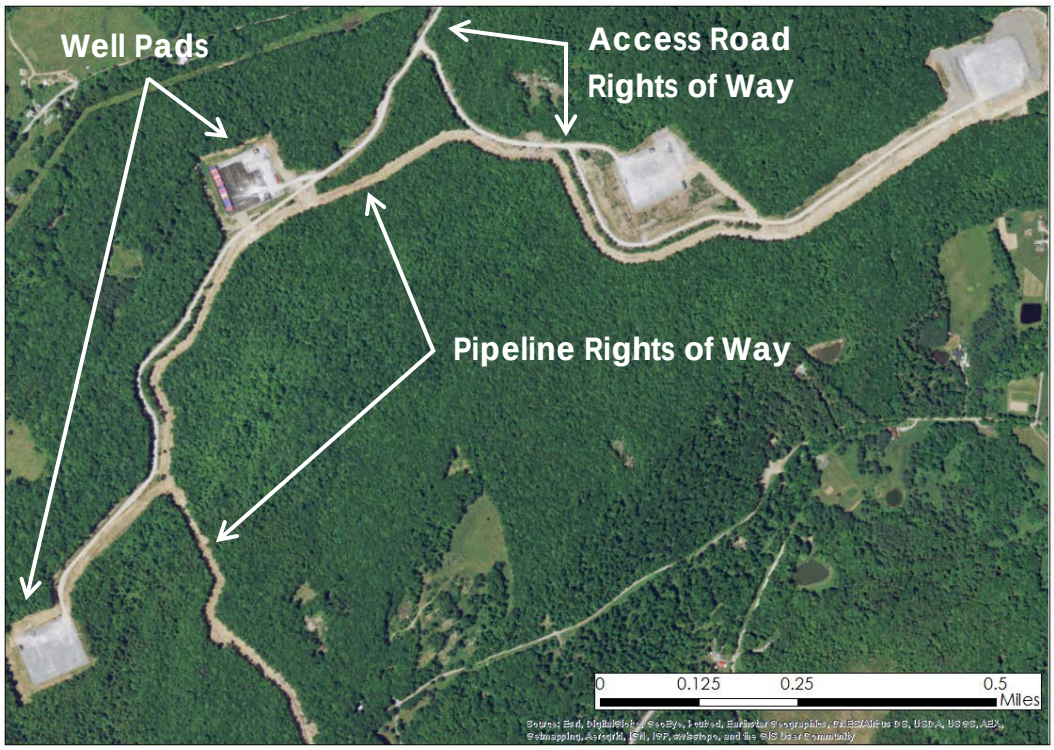
Key Findings

- We analyzed land cover changes in three study watersheds with extensive projected gas development. Land converted for each well pad, including the pad itself, access roads and the rights-of-way for gathering pipelines, would directly impact 17-23 acres per well pad. Gathering pipelines account for 75 percent of this area.
- Gas infrastructure could directly convert 2–3 percent of the land in areas affected by fracking, with most of the impacted area made up of agricultural land and forests.
- Shale gas development could lead to a 1–2 percent loss of total forest land in impacted DRB watersheds that we studied, and between 5 and 10-percent loss of core forest.
- The total area of land disturbed in the DRB at the completion of gas development in the Interior Marcellus could be 18 – 26 square miles. This is about the same area as 570 to 840 Wal-Mart Supercenters including their parking lots.

When assessing the environmental impacts of natural gas development, one of the most unavoidable aspects of such development is the impact to land cover. A typical well pad may cover 3–5 acres of land to support the fracking process, which includes the well site, itself, and room for supporting equipment, such as drilling equipment, water impoundments, quarries, temporary construction areas, and truck parking [2, 14, 26]. The well pad site is typically cleared of any previous land cover to produce a barren surface to support the extraction activities. In addition to the well pad, development of land to support natural gas extraction requires access roads to the site and gathering or feeder pipelines to transport the extracted gas from the site to the existing transmission infrastructure [27-30]. Figure 5 shows an example of this development in Susquehanna County, PA. Development of this supporting infrastructure requires clearing land not only for the infrastructure, itself, but also

for the accompanying right-of-way to accommodate construction equipment and future maintenance. The resulting land disturbance from this development can present both short- and long-term risks to the use of the land, depending on the remediation and reclamation procedures used [26, 31]. Furthermore, the design and practices used by pipelines and roads to cross streams and wetlands can adversely impact the health of these ecosystems by altering channel geomorphology and restricting the movement of fish and wildlife [32-33].

Figure 5. Imagery depicting several existing well pads and associated infrastructure rights-of-way in Susquehanna County, PA. This provides an example of the potential footprint associated with natural gas development.



Source: ESRI World Imagery Layer from ArcGIS Online (ESRI, DigitalGlobe, GeoEye, i-cubed, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community)

One particular issue associated with the development activities from natural gas extraction in the Marcellus Shale is the impact on forests [14, 27-28, 31]. The portion of the DRB that lies above the Marcellus Shale includes over two million acres of forest, and forested land is the dominant land cover in each of our three study areas (approximately 65,000–110,000 acres each, which is more than 50 percent of each study area). This dense forest cover provides the region with a variety of ecosystem

services, such as carbon sequestration, clean air, aquifer recharge, and recreation/eco-tourism. These services are in addition to the key role that forests play in maintaining the water quality of the Delaware River, which supplies drinking water to over 17 million people [24].

Furthermore, forest cover in the region is home to a variety of different plant and animal species that rely on the forest for their habitat. Forest habitats are divided into two primary classes: edge and core forest. Edge forest is generally described as the area that is adjacent to the non-forest area, extending inward approximately 300 feet (or 100 meters) [27-28]. The edge transition from non-forest to forest area creates a habitat that tends to favor generalist species over rare or vulnerable species, and an increase of edge forest can promote the spread of invasive species [31].

To assess the potential land cover impacts on the DRB from natural gas development, we combined our above projections of natural gas development in the watershed with a suite of GIS tools and methodology. We first used least-cost path-optimization to model the extent of potential infrastructure (gathering pipelines and access roads) that could be developed to support these well pads in the DRB. We did not account for additional potential construction that could occur to support natural gas development (e.g., new transmission pipelines or compressor stations), which was beyond the scope of this study. We then performed a buffer analysis using the projected well pad locations and supporting infrastructure to survey the impacts to current land cover (and further the potential for forest fragmentation) that could be expected from development in these areas. Finally, we compared the projected land cover impacts to other recognizable development activities to provide context to the scale of these impacts.

Methodology

To model the infrastructure required to support our projections of natural gas development, we used the least cost path optimization approach, which is a common approach for siting and analyzing roads and pipelines. To perform this modeling, we first developed a cost surface for each study area by combining a variety of geospatial layers relevant to routing, and assigning a cost to the values associated with each layer. “Cost” in this sense refers to a penalty for following a less-efficient route, and we assigned costs to the layers based primarily on the ESRI Pipeline Optimization Route Interface [34], with additional input from industry methods and reports [35-37]. These layers covered a variety of factors that can impact infrastructure route design, such as topography, affected population, and environmentally sensitive areas. For example, we assigned a higher cost for development on terrain with steep slopes, compared to relatively flat areas. We used

this cost surface with the "Least Cost Path" tool in ArcGIS to determine the most efficient route from the projected well pads to the existing infrastructure.

The construction of well pads, gathering pipelines, and access roads to support natural gas extraction requires the clearing of land to accommodate this infrastructure. To assess both the area and type of land that may be disturbed from these activities, we used GIS tools to map the spatial extent of the well pads and associated infrastructure. We estimated that each well pad occupies 3.5 acres, each pipeline requires a 30-meter right-of-way, and each road requires a 15-meter right-of-way, based on studies that examined aerial imagery depicting areas with shale gas development [14, 29-30]. We used these values to buffer the appropriate features to create the spatial footprint of development in each study area. We then used this footprint to extract the impacted land values from the NLCD. Furthermore, to determine the number of stream and wetland crossings that could occur from pipeline and road development, we used the "Intersect" tool in ArcGIS to count the number of intersections between the new infrastructure and the stream and wetland networks in each of the study areas.

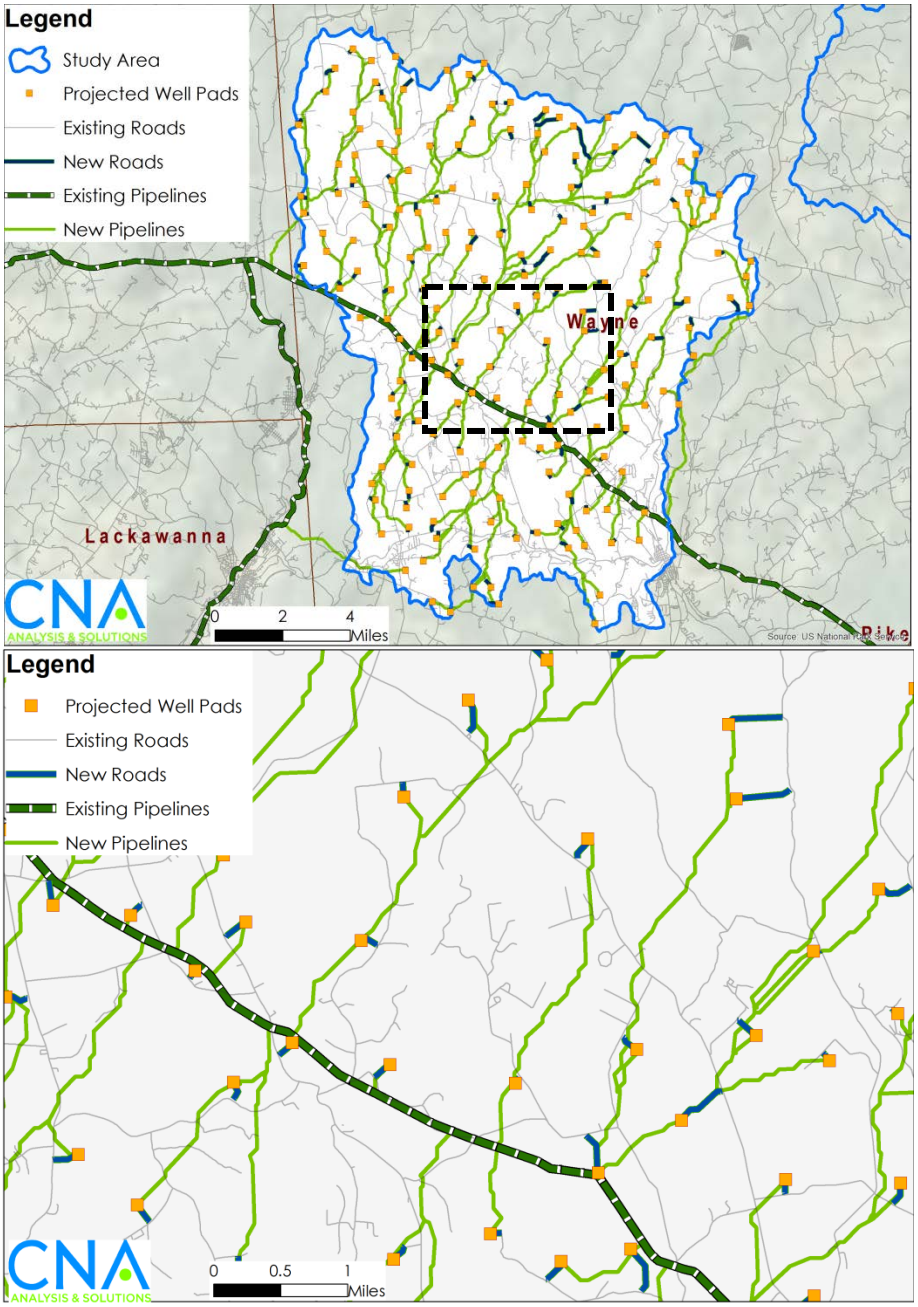
Given the prevalence of forest cover in the DRB and the potential for impact, we extended our land cover analysis to focus on the extent of forest fragmentation caused by this disturbance. To assess this impact, we calculated the baseline total area of forest in each study area through GIS analysis of the NLCD. We updated this dataset with rights-of-way from the existing road, pipeline, and rail networks to more accurately depict the baseline condition. To calculate core forest, we used GIS tools to generate a 100-meter buffer into the baseline forest from the edges. We refer to this 100-meter buffer as "edge forest." After we generated the baseline condition, we assessed the potential impact from natural gas development by applying the same spatial footprint as above. We then generated a 100-meter buffer into the forest from all new forest edges (i.e., from well pads and along the road and pipeline rights-of-way) to represent the changes in core and edge forest.

Results

Infrastructure Modeling

Using least-cost path-optimization, we modeled the gathering pipelines and access roads that could be expected to support the new well pads in the three study areas. Figure 6 shows an example of these results from Study Area 2 ("dispersed" scenario), and Table 4 lists the results of all modeling. Note that these projections are intended to illustrate the potential scale of infrastructure with a reasonable estimation of spatial extent and are not meant to predict exact locations.

Figure 6. Projected gathering pipeline and access road development in Study Area 2 to support 191 well pads under the "dispersed" scenario. The installation of new gathering pipelines would be the primary driver of land disturbance from natural gas development.



Source: National Park Service (background)

Table 4. Projected infrastructure (gathering pipelines and access roads) needed to support natural gas development in the three study areas. Units = miles.

Scenario	Study Area	Well Pads	Pipelines		Roads	
			Total Length	Avg. Length Per Pad	Total Length	Avg. Length Per Pad
Dispersed	1	162	184	1.13	30.8	0.19
	2	191	235	1.23	35.6	0.19
	3	170	250	1.47	25.0	0.15
Concentrated	1	90	130	1.44	21.3	0.24
	2	93	163	1.75	20.5	0.22
	3	79	162	2.05	12.1	0.15

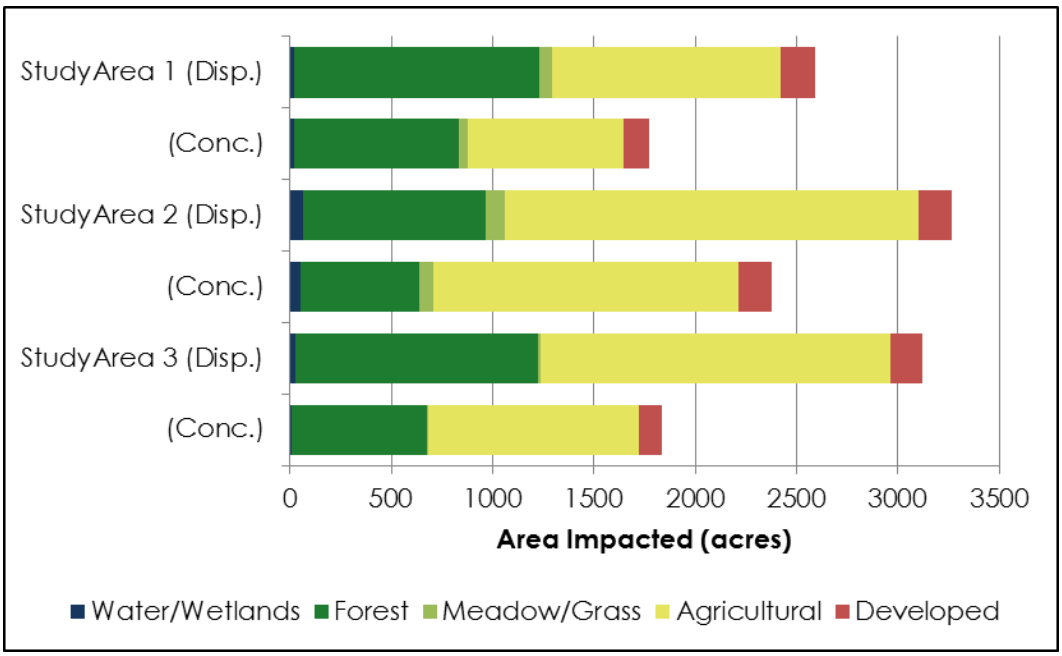
Our infrastructure modeling results compare favorably to recent retrospective studies on Marcellus Shale infrastructure development in Bradford County, PA [29-30]. For pipelines, the average length to support a well pad dropped by 26 percent from the "concentrated" to "dispersed" scenarios, which may be attributed to the location of the existing pipelines within the study areas and the relative spread of well pad locations. The well pad locations under the "concentrated" scenario are already spread out across the study areas, so many of the longest pipelines were modeled in this scenario, and the addition of more well pads under the "dispersed" scenario served to fill in the area. The average length of road developed per well pad was fairly consistent, at about 0.2 miles per pad among the study areas and scenarios, likely owing to the network of road infrastructure already in place throughout the study areas.

Land Cover Disturbance

Using our projections of potential well pads and supporting infrastructure within the DRB, we assessed the extent and form of land disturbance that would be observed from natural gas development. Figure 7 shows the breakdown of impacted land for each study area from natural gas development under the two build-out scenarios.

We project that each study area could see between 2,500 and 3,300 acres of impacted area in the "dispersed" scenario, and between 1,700 and 2,400 acres of impacted area in the "concentrated" scenario at well build-out. On average, these impacts represent 2 to 3 percent of the land area of the study areas. Although a large majority of the baseline land cover (more than 59 percent) in each study area is classified as forest cover, only Study Area 1 shows forest cover as the most impacted land area (and, even then, only slightly more impacted than agricultural land). This finding most likely is due to the higher cost associated with developing forest land versus agricultural land based on the method that we used to model infrastructure. However, a significant amount (28–47 percent) of the impacted land in each study area is forested.

Figure 7. Breakdown of total potential land cover disturbance from natural gas development in each DRB study area, broken out by scenario ("dispersed" or "concentrated"). A majority of the impacted area in each study area is agricultural or forested.



Our modeling revealed that a majority of the land disturbance associated with natural gas development would be attributed to gathering pipeline development (74 percent of the impacted land was due to new pipelines, versus 21 percent from well pads and 5 percent from new roads). This makes sense, considering that each new well pad would average 1.28 ("dispersed" scenario) to 1.75 ("concentrated" scenario) miles of gathering pipeline development, which would directly impact about 15 to 21 acres of land, respectively, versus 3.5 acres for the well pad, itself. This result also explains why, even though the "concentrated" scenario contains only about half as many well pads as the "dispersed" scenario, the concentrated scenario shows closer to two-thirds as much land cover impact as the dispersed scenario.

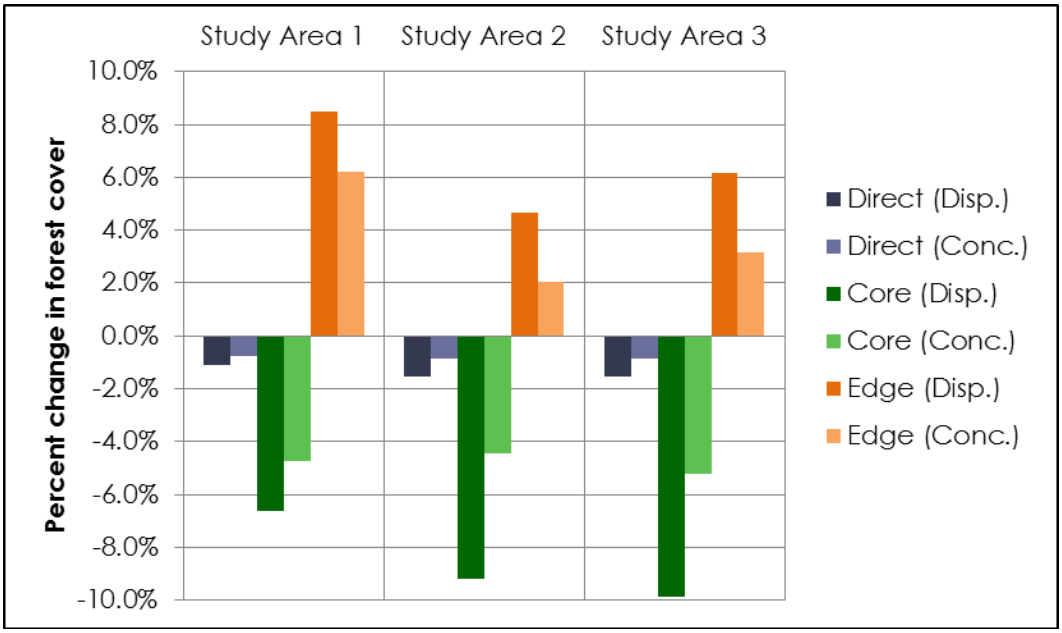
We also determined the number of stream and wetland crossings that could be encountered from development of supporting infrastructure. From our GIS analysis, we found an average of 115 stream crossings and 130 wetland crossings from new pipelines in each study area, and an average of 12 stream and 10 wetland crossings from new roads in each study area. We generated these results using the "dispersed" scenario; the "concentrated" scenario resulted in about 30–40 percent fewer

crossings, due to the reduction in total infrastructure needed to support fewer well pads.

Forest Fragmentation

The results of our land cover analysis showed that development of natural gas well pads and supporting infrastructure would directly impact the extensive forest cover present in the DRB. Deforestation activities can also present a variety of indirect impacts to a forest's ecosystem that extend beyond the actual trees that are cleared. To evaluate the extent of these additional impacts, we performed a second buffer analysis to represent the baseline and impacted core forest in each DRB study area. Figure 8 shows the results of this analysis.

Figure 8. Percent-change in forest cover and type (core vs. edge) from infrastructure development in the DRB study areas, broken out by scenario ("dispersed" and "concentrated"). Results show direct conversion of about 1-2 percent of total forest, and indirect effects (a shift from core to edge forest) of 4–10 percent.



From Figure 8, we see that site and infrastructure development can have significant impacts on the core forest of the DRB. In the "dispersed" scenario, we found that the total forest area cleared for this development amounts to a loss of about 1 to 2 percent for each study area. This same development could amount to upwards of almost 10-percent loss in core forest area. Note that this loss in core forest area comprises both forest that is cleared for infrastructure and the resulting conversion

from core to edge forest along these rights-of-way (the latter results appearing as the net gain of edge forest in Figure 8).

Discussion

Our results showed that the construction of well pads and associated infrastructure to support shale gas development would have an impact on the land cover of the DRB, affecting primarily agricultural and forest lands. Our modeling of the natural gas infrastructure was based on a standard GIS approach to provide a representative picture of this development. Thus, just as was stated for our projected well pad locations, the projected infrastructure is used for calculating impacts, but should *not* be interpreted as explicit *predictions* of where this infrastructure will actually go. The actual locations could depend on additional site-specific factors, such as lease holds and applicable laws and regulations.

Our assessment of land disturbance only accounts for the well pad and rights-of-way for gathering pipelines and access roads to support those well pads. We did not account for additional construction that could occur to support natural gas development, such as new transmission pipelines that may be needed to help move gas to market, or new compressor stations to support gas transmission through the pipeline network. This construction could be expected to add to the footprint of development and cause additional land cover impacts to the area.

To provide context to the scale of the projected land cover disturbance from natural gas development, we compared the impacted land area to other large construction projects that have been completed in the region. The projected amount of land cleared for development in Study Area 2 could be comparable to building 58 King of Prussia Malls, which is one of the largest malls in the United States. The projected amount of land cleared for development in Study Area 3 could be comparable in area to building 155 Wal-Mart Supercenters with parking lots (about 20 acres each).

If we assume that land cover impact stays constant on a per well pad basis, we can roughly project the total land cover change for the entire DRB. Based on the average of the results for the three study areas, the total land cover impact is 17-23 acres, depending on the development scenario. Based on these per-well pad numbers, and the number of well pads projected in the DRB, we estimate the total area of DRB land cover change as between 18 and 26 square miles. This makes up 0.5 to 0.8 percent of the total Interior Marcellus area within the DRB (3150 square miles), but within the portion with well pad development projected (950 -1000 square miles), the total land cover conversion percentage should be roughly in line with the study area results at about 2 percent. Or, to use a prior example, the total land cover change would be equal in area to between 570 and 840 Wal-Mart Supercenters including parking lots.

Land-cover change from shale gas development is unavoidable, and disturbance can be significant at build-out. The loss of forest cover, in particular, can have significant impacts on the watershed, such as degraded water quality (for more details, see the "Impacts on Water Quality due to Changes in Land Cover" chapter of this report) and a loss of biodiversity from disappearing flora and fauna that cannot tolerate "edge effects." Furthermore, remediation procedures to restore vegetation on the impacted land often do not replace mature forest cover, in part because of the need to maintain access to gathering lines and use roads, and because mature forests take a long time to grow.

Impacts on Water and Wastewater Management

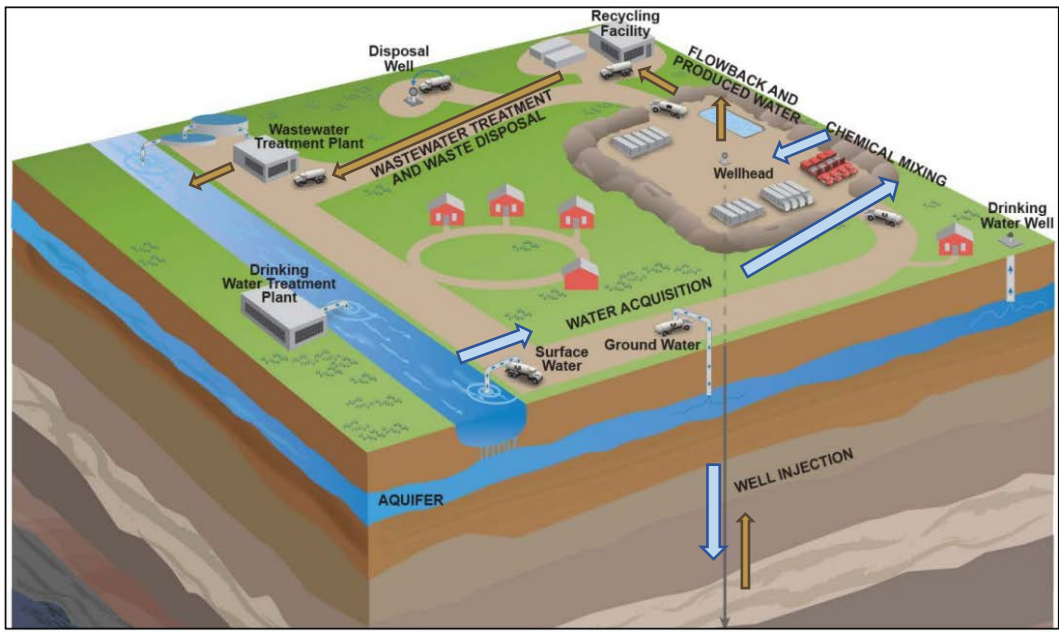
Key Findings

- Unconventional natural gas development requires about 4.5 million gallons per well, mostly to mix the "frac" fluid injected into the shale during hydraulic fracturing. Most of this water does not return from the shale after injection during the fracturing process and is a consumptive use.
- The impacts of water withdrawal on streamflow vary widely, depending on location, development rate, and flow conditions. During maximum periods of well development, the percentage reduction in streamflow ranges from over 70 percent during low-flow conditions to less than 3 percent during median or average flow conditions if withdrawals are taken from small streams.
- Natural gas wastewaters (flowback and brine) are concentrated, carrying high loads of dissolved solids, salts, some metals, hydrocarbons, and radioactive materials.
- If all wastewater were treated to meet Pennsylvania's effluent standards and discharged in the study areas, the amount effluent produced during maximum-development periods could raise in-stream concentrations of some contaminants (notably barium and strontium) up to 500 percent above background levels during low-flow conditions.

One of the principal ways that unconventional gas drilling differs from conventional gas drilling is in its use of water for the extraction process and the amount of wastewater produced. There are two primary water uses in the process (drilling fluids and "frac" fluid), and three primary types of wastewater generated (waste drilling fluid, "flowback," and brine wastewaters) that must be treated and either

recycled or disposed. Figure 9 illustrates the flows of water and wastewater (WW) during the fracking and gas-extraction process.

Figure 9. The fracking water cycle. This cycle includes water acquisition (withdrawal), mixing into "frac" fluid, injection into the well, recovery of wastewater (flowback and produced water) from the well, wastewater reuse (recycling), and then wastewater treatment and disposal.



Source: Environmental Protection Agency [38]

Water plays a key role in hydraulic fracturing as the base of the frac fluids that are injected at high volume into the shale to fracture it and release tightly held gas. A smaller quantity of water is used for drilling the wells before fracking. The bulk of the water use is consumptive, because most the frac fluid remains in the ground (and wastewater is often reused or sent outside the basin for treatment).

The main wastewaters include drilling fluids recovered after drilling and frac fluid that returns from the shale after hydraulic fracturing. The drilling wastewater is often recycled and reused as new drilling fluids or is disposed (in injection wells, among other disposal methods). The flowback is composed primarily of frac fluid that returns back up the well bore due to the high pressures in the fractured shale in the 10–14 days (up to 30+ days) after fracking and before gas production. Following the flowback period, as the well is producing natural gas, a smaller amount of wastewater continues flowing along with the gas. This wastewater is composed mainly of frac fluid, but also picks up pollutants from the shale, notably salts, which

earns it the name "brine" (also called "produced water"). After collecting flowback and brine, the wastewater can be reused in making new frac fluid, disposed via deep groundwater injection, or treated at special wastewater treatment plants.

Disposal of this flowback and brine wastewater is a significant concern due to the high concentrations of dissolved solids (mostly salts), metals, hydrocarbons, and radioactive materials [39]. Some particular contaminants of concern include ions such as chloride, sulfate, ammonium, and iodide; metals such as barium and strontium; solvents and aromatic hydrocarbons such as benzene and formaldehyde, and radioactive elements such as radium. Appendix A contains an expanded list of chemicals that have been detected in flowback and brine wastewaters, including approximate concentrations at which they are found. Even with treatment, concentrations of pollutants (especially dissolved solids, salts, and ammonium) in wastewater effluent have often been measured at concentrations exceeding water quality standards [40]. In addition to potentially harming aquatic life [41], some of these chemicals are difficult to remove in drinking water–treatment plants [42] and can lead to enhanced formation of disinfection byproducts [43-44] in drinking water, which can increase risk of some health effects (including cancer) [45]. Industrial wastewater treatment has improved since UNGD started in Pennsylvania, as have regulations that now limit Total Dissolved Solids (TDS) effluent concentrations to 500 mg/L, equivalent to current DRBC discharge regulations [46], yet these limits are many times higher than existing water quality in the basin's special protection waters (50–100 mg/L TDS) [47].

The rest of this chapter investigates the impacts of the hydraulic fracturing water cycle for both water and wastewater. First, we computed the volumes of water and wastewater for the study areas, and we examined the withdrawal rates in the context of the available streamflow. The second portion of the results focuses on the pollutant loadings in the hydraulic fracturing wastewater, which we contextualize with the ambient loadings of these pollutants carried by the nearby streams.

Methodology

UNGD water and wastewater processes are linked, though their environmental impacts are manifested rather differently. In this analysis, we compute a median estimate of water use and wastewater production on a per-well basis, and then multiply by the number of projected wells for each case study area to determine the volumes of water withdrawals needed and wastewater generated in each. We estimate water usage; wastewater generation and recovery; and reuse rates from publicly available databases and peer-reviewed literature. Since the "concentrated" and "dispersed" scenarios result in a similar number of wells developed, we consider only the "concentrated" scenario in this chapter (as it has slightly more wells).

To estimate the impact of the water acquisition, we compare the withdrawal to available freshwater flow in the study areas. The water-related impacts are more easily judged using expected flow rates than overall volume. Well development is not likely to occur at a constant rate, and impacts are magnified during periods of rapid development, so we considered two scenarios to explore the range of impact the well development rate may have on water availability:

- **Average Development Year:** Assumes that development occurs at a constant rate over a 30-year build-out.
- **Maximum Development Year:** Assumes that 20 percent of well development build-out in each study area occurs in one year.[2]

The average- and maximum-year scenarios show the range in flow rates for water withdrawal and wastewater generation—and, by extension, the watershed impacts.

To estimate wastewater impacts, we investigated how discharge of treated wastewater effluent according to Pennsylvania regulations would raise concentrations of five key pollutants in streams. We only consider the flowback and brine wastewaters, as the drilling fluids and cuttings are generally disposed as solid waste. We multiplied the wastewater flow rates by concentrations of pollutants reported in the literature to calculate pollutant loads. The total loading rate of contaminants of concern in the various types of wastewater (flowback and brine) is estimated after treatment of wastewater (i.e., in wastewater treatment effluent), and for cases with and without reuse of wastewater.

Using local streamflow statistics, we developed an initial estimate of how much these loadings would raise concentrations of five key pollutants in the runoff coming from each study area, and compared this change to reference concentrations in the basin. Since these estimates lack the context of actual location and method of treatment, and cover a limited set of pollutants, we recommend future studies with more specific scenarios. Furthermore, this study considers only the most likely pollutant pathway (wastewater effluent) for water quality impacts [5], but other pathways such as spills from trucks or at the drilling site may have impacts [5, 49-50], though often at more localized scales.

[2] The maximum-year scenario represents an estimate of maximum development that may occur in one study area. Based on observations of Baker Hughes rig count data [48], the maximum rig densities appear to be about one rig per 20 square miles, or 6–10 per study area. If we assume an average completion time of 20 days for wells, then rigs may be able to drill 18 wells per year. This would be sufficient to drill about 20 percent of the wells in a study area. For consistency, we applied this 20-percent assumption to all of the study areas.

Results

Water Use and Wastewater Generated

Water needs and wastewater generation are significant for natural gas operations, but must be properly compared to overall water availability and put into context by existing water uses in the DRB. Figure 10 shows the average per-well volumes of water and wastewater expected for projected well development in the DRB.

Reuse of drilling fluid, flowback, and brine plays an important role in reducing both freshwater demand and the volume of wastewater that must be disposed. After accounting for reuse, the remaining freshwater withdrawal and wastewater disposal volumes are the most important metrics for planning.

Figure 10. Sankey diagram of water volumes for the fracking water and wastewater management cycle estimated for this study, on a per well basis. "Frac" fluid dominates water use, and most is not recovered. Units = million gallons per well.

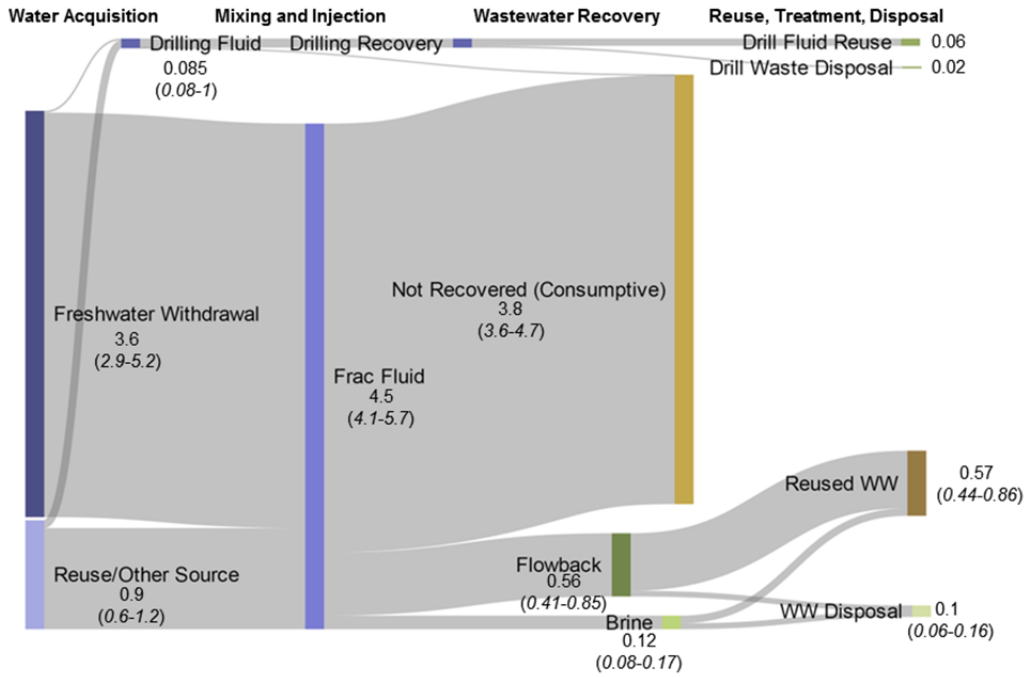


Figure by CNA via *SankeyMATIC*

[a] Numbers show expected value. Expected range in parentheses.

We estimated water use based on FracFocus database records [51] of frac fluid water use per well across the Marcellus Shale. We calculated the per-well average water use based on 2012 and 2013 data for six counties in northeast Pennsylvania (Bradford, Lycoming, Sullivan, Susquehanna, Tioga, and Wyoming). The range represents the highest and lowest county average. Adding the water use for drilling fluid (about 85,000 gallons [52-53]), we compute the average water demand at 4.5 million gallons per well. Mantell estimated that alternative sources (such as recycling and reuse of flowback) reduce freshwater needs by 10–30 percent [52], and we assumed a median of 20 percent. We assumed that this reused water could come from reuse of flowback and brine within the study area or other sources (e.g., wastewater treatment plant effluent, groundwater, or purchases from public supply) within the DRB.

Flowback wastewater is generated at a rate of 10–15 percent of the volume of frac fluid injected [53-55], while brine production is about 50–100 million gallons per million cubic feet of gas produced [52]. The reuse rates of these wastewaters based on current industry practices are estimated to be about 90–95 percent for flowback and 56 percent for brine [53]. Though we do not include indirect uses in our analysis, Jiang et al. [53] estimated that indirect water consumption for well pad preparation might account for an additional 0.5 million gallons of water per well, and total indirect uses might account for as much as 2 million gallons per well.

Table 5 displays average daily rates of water use, withdrawal, wastewater generation, and wastewater effluent disposal for each study area, based on the per-well factors in Figure 10 and the number of wells developed. Note that the DRB total at the bottom includes wells not in the three study areas.

We account for reuse of wastewater (based on literature values of recent industry averages) in two ways. “Withdrawal” reflects remaining freshwater need after accounting for reuse and alternate sourcing. “Wastewater Generated” includes all flowback and brine recovered, but “Effluent Disposal” includes only the remaining portion of wastewater that is sent for treatment at industrial wastewater treatment facilities. We assume that the disposal volume is treated at wastewater treatment plants in the basin (instead of disposed through deep well injection or transported outside the basin), so this “disposal” volume can be called wastewater “effluent.” To establish the full potential range of impacts, we also consider the case where all wastewater is treated and disposed later in this chapter (i.e. no reuse).

Table 5. Projected rates of well development, water use, withdrawal, wastewater generation, and effluent for disposal, by study area and scenario. Units = 1,000 gallons per day, except wells per year.

Study Area	Scenario	Wells Per Year	Water Use	Withdrawal (Freshwater)	Wastewater Generated	Effluent Disposal
1	Average	22	270	210	40	6
2	Average	25	320	250	50	7
3	Average	23	280	230	50	6
1	Max.-Year	130	1,610	2,570	270	36
2	Max.-Year	153	1,900	3,040	320	43
3	Max.-Year	136	1,690	2,700	280	38
DRB	Average	133	1,650	1,320	270	37

Since water withdrawals are often not constant over a development period, we developed a reasonably high-withdrawal scenario. In the maximum–year scenario (20 percent of wells developed), we further assumed that water withdrawal occurs over a limited time window during the well-development process, equal to half of the well completion time (roughly 20 days). This doubles the effective withdrawal rate because the same amount of water is collected over 50 percent fewer days. Actual peak withdrawal rates could be higher if the water needed for each well fracturing is collected in only a few days to minimize water storage time onsite.

The withdrawals are highest in the maximum-year scenario, and it is these rates of withdrawal that may have the highest potential impact on flows in the DRB. The wastewater flow generated, as expected, is small relative to water use (but at 50,000–300,000 gallons per day in the study areas, it is still a large volume that must be managed).

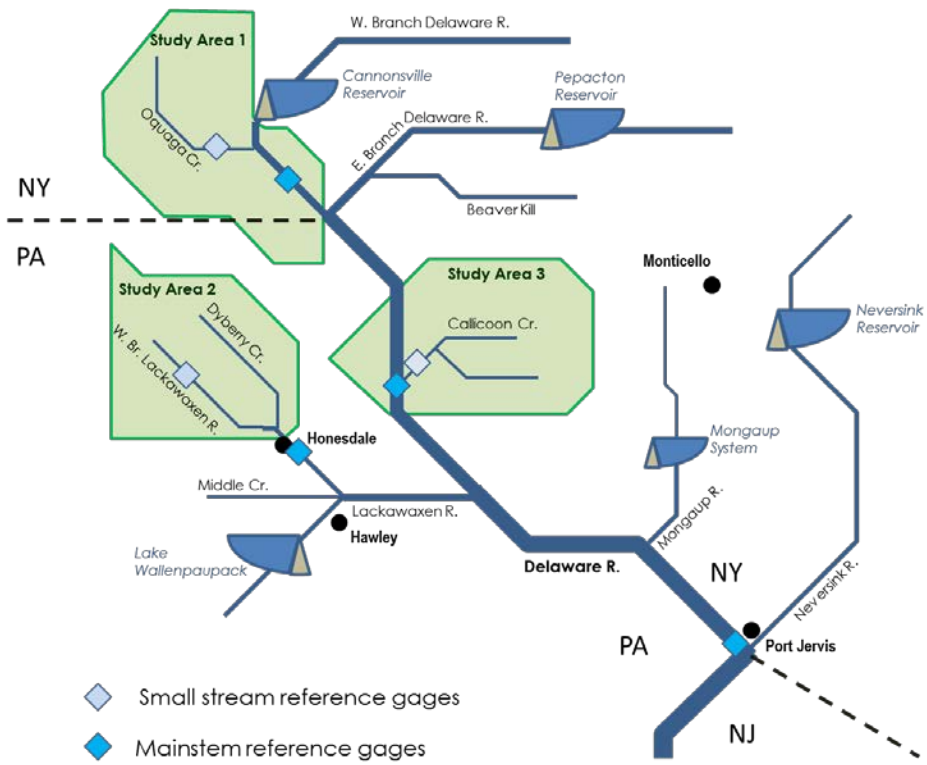
Impacts from Water Withdrawal

The impact of water withdrawals for fracking depends on the rate of extraction and the available water resources in the study area. This withdrawal rate is roughly 2.6–3.0 million gallons per day (MGD) for each study area. To determine the impact of these extractions on water availability in the study areas, we compared the water-extraction rate to water availability using two types of reference stream gages: "small stream" and "mainstem." We obtained all stream gage records from the USGS Surface Water Daily Data database [56-57] (see Appendix B for details on the gages used).

The schematic in Figure 11 shows the relative locations of the two types of reference gages. Conveniently, all projected wells are upstream of the stream gage at Port Jervis, NY, which is useful for assessing basin-wide impacts. The small stream gages

represent smaller headwater drainage basins whose flow depends almost entirely on rainfall within the study area. The mainstem gages measure larger rivers flowing through the study area that have a significant portion of flow coming from upstream of the study area. Notably, the mainstem of the Delaware River flows through Study Areas 1 and 3, and water availability is influenced by upstream flows, including releases from the Cannonsville and Pepacton Reservoirs. Study Area 2 is different than 1 and 3 because it is entirely a headwater area and has no upstream drainage area to boost flow to the mainstem gage.

Figure 11. Flow schematic for the Upper DRB, showing locations of study areas and reference gages.



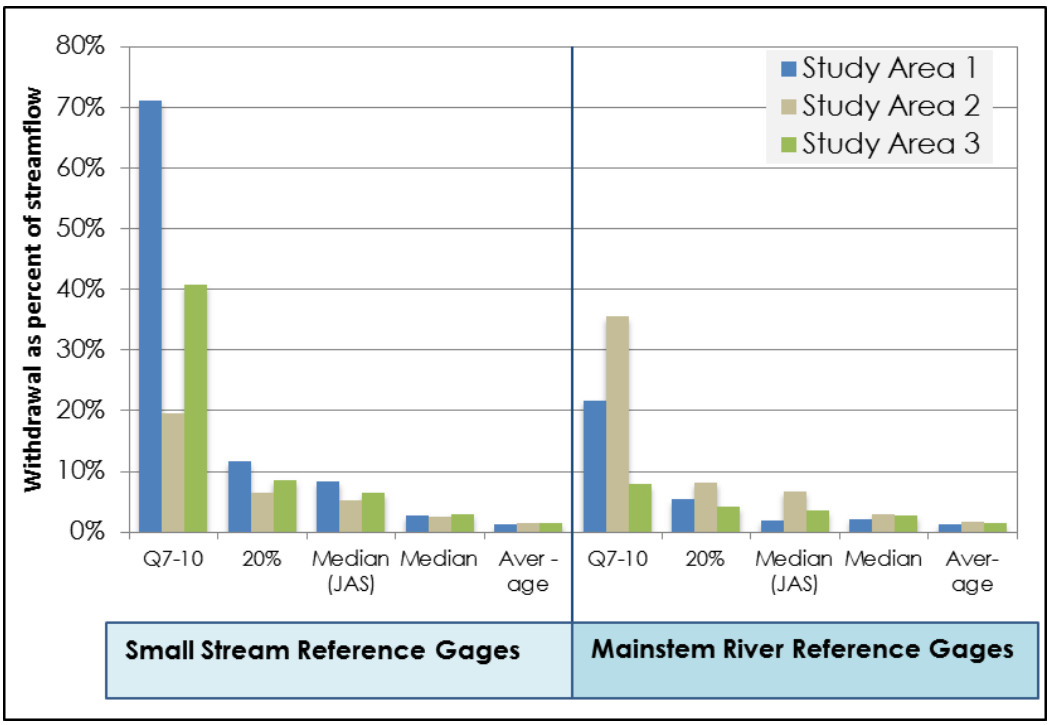
Note: The schematic is not to scale. Source: CNA.

For all gages, streamflow statistics were calculated including the Q7-10 (lowest seven-day average flow expected to occur once every 10 years), the 20th-percentile flow (sometimes called the Q80), median flow for the summer months (July–August–September [JAS]), median flow, and average flow per square mile (using the stream gages' contributing area). See Appendix B for these flow metric values. We divide the projected water withdrawal by the study area size to put demand on a per-square-mile basis, allowing a comparison.

We calculated water availability by dividing the maximum-year water demand for UNGD by the flow metric and expressing the result as a percentage. This is the percentage by which flow would be reduced under the listed flow conditions on days with water withdrawal (roughly half of days). Figure 12 shows the percentage of flow reduction for several flow metrics for both the small stream and mainstem reference gages.

The water availability analysis in the figure suggests that water withdrawals would reduce median or average flows by 1–3 percent, but the withdrawals may reduce flows 5–70 percent during summer and low-flow periods. Mainstem withdrawals would have a less-noticeable effect on flows under a range of flow conditions. By contrast, during periods of low-flow, withdrawal rates may noticeably reduce in-stream flow on small streams.

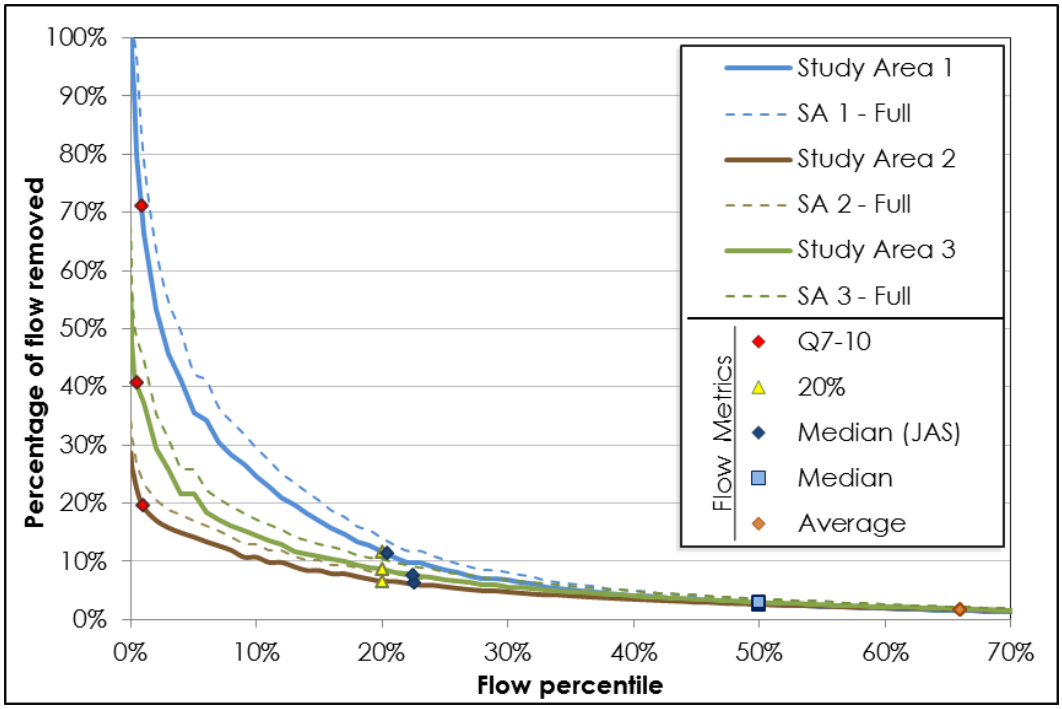
Figure 12. Withdrawals as percent of available streamflow for maximum-year development scenario. Shown for several flow metrics for both the small stream and mainstem gages. Withdrawals can take a high percentage of flow during low flow, when taken from small streams, and a lower percentage during average flow or when taken from mainstem rivers. (Units = percentage of flow removed.)



Notes: Q7-10 is lowest 7-day average flow experienced on average every ten years. 20% is the 20th percentile of daily streamflow. Median (JAS) is the 50th percentile daily flow for the months of July, August and September. Median is the 50th percentile of all daily flows. Average is the daily average flow.

For completeness, we also display the results over the full-flow distribution for the small stream gages. In Figure 13, lines show the percentage that flow would be reduced versus the flow percentile. The same flow metrics are shown as points along the line. The dashed lines represent an additional scenario if the full water demand were met with freshwater withdrawal (versus a combination of freshwater and reused water as depicted in Figure 10).

Figure 13. Withdrawal as percent of available flow versus flow percentile, small stream gages, maximum-year withdrawal scenario. At lower flows, the percentage of flow removed is higher. Dashed lines show the difference if all water needed for hydraulic fracturing were supplied by the streams.



Actual impacts would depend on the specific withdrawal location, withdrawal rates, and flow at the time of the withdrawal. Some ecosystems are highly sensitive to changes in flow regime, including changes to the low-flow magnitude, timing, and duration, which this study indicates may be a risk for smaller streams in the study areas. Several reviews of environmental flow literature have found that decreased magnitudes of low flows can lead to a range of effects on water quality and ecosystems, including decreased richness of species, increased densities of predators, increased abundance of generalist and highly mobile species, and decreased abundance of specialist and cold-water obligate species, among many others [58-59].

The total water volume needed to develop all 4,000 wells in the DRB is roughly 14 billion gallons, which, spread evenly over 30 years, is 1.3 million gallons per day. This average daily withdrawal amount would be sufficient to meet the domestic water needs[3] for more than 17,000 people. Of course, the water withdrawals for fracking would be roughly 80-percent consumptive, versus about 20-percent consumptive for domestic water use.

Relative to existing water demands in the study areas' watersheds [61], the UNGD water demands would increase water use in the three study areas by a factor of 5 to 12.

Wastewater Pollutant Loadings

Table 6 shows expected concentrations (derived from literature values) of some of the key regulated contaminants in the flowback and brine wastewater [41, 43, 62-68] and industrial wastewater effluent [40, 43], compared to the effluent discharge limits [69] and the reference conditions in the watershed's streams [41]. The natural gas wastewaters contain dozens of pollutants, including salts, metals, hydrocarbons, volatile organic compounds, and radioactive compounds, among others[70]. This study focuses on five pollutants whose effluent concentrations are regulated from treatment plants treating oil and gas wastewater in Pennsylvania. These pollutants include Total Dissolved Solids, Chloride, Sulfate, Barium, and Strontium.

[3] The average for Delaware, New Jersey, New York, and Pennsylvania is 75 gallons per day, per capita [60].

Table 6. Wastewater concentrations of key contaminants in flowback and brine wastewater. Discharge regulations on effluent concentrations, and reference conditions for surface water in the upper DRB are shown for context. Units = mg/L.

Pollutant	Flowback	Brine	Range	Discharge Regulations	DRB Reference
Total Diss. Solids (TDS)	73,000	205,600	38,500–261,000	500	46.5
Chloride (Cl)	54,600	99,600	19,600–174,700	250	5.8
Sulfate (SO_4)	51	55	2.4–300	250	5.1
Barium (Ba)	1,020	33,630	4–84,300	10	0.021
Strontium (Sr)	1,190	5,230	350–4,800	10	0.025

Since 2010, Pennsylvania regulations [69] require new wastewater treatment facilities treating Marcellus Shale wastewater to meet additional standards for TDS, salts, and some metals before discharging to streams or conventional treatment plants. The newer industrial treatment facilities will have to more-effectively remove salts, metals, and other contaminants through advanced treatment technologies (e.g., desalination and distillation; reverse osmosis and other membrane processes; capacitive deionization [39]) to meet the newer regulations. The reference conditions reflect an average for four sites in the Upper DRB measured in 2012 [41].

These pollutant measures show the concentrated nature of the wastewaters being generated relative to the regulatory effluent discharge standards, many of which are equivalent to U.S. Environmental Protection Agency (EPA) maximum contaminant levels for drinking water. The low concentrations in the reference conditions indicate how susceptible the surface waters in the study area are to even small discharges of wastewater. The potential environmental effects depend on the loadings of the contaminants to surface water in addition to the location and flow conditions at point of discharge. Different measures of loading may be appropriate, depending on the planning objective.

The total loading of contaminants in flowback and brine wastewater sets an upper bound for the mass of contaminants that must be treated. For the five regulated contaminants in Table 6, we calculate the total contaminant loading in wastewaters by multiplying flowback and brine generation flow rates by their respective contaminant concentrations to compute mass loads, and then sum the flowback and brine loads. The process is similar for industrial wastewater effluent (after typical wastewater reuse), but we assume that the effluent concentrations comply exactly with regulatory limits for discharge (see Table 6, above).

Table 7 shows the potential average daily loadings of key contaminants from all flowback and brine wastewater ("Avg. WW") and from treated effluent ("Avg. Effl."). The treated effluent volume is lower because it reflects the remaining wastewater

volume after much of the original flowback and brine has been recycled. For context, the average daily loadings (computed based on the reference concentrations and average flow conditions) are shown on the final line for the Delaware River at Port Jervis, NY. The river naturally carries some solids and salts at low concentrations, but with high flow rates, the river loading is large.

The same is not true of the metals barium and strontium, which have only trace concentrations in the waters of the Upper DRB. In untreated wastewater (the Avg. WW scenario), the loadings of barium and strontium can dwarf those in the river, indicating significant risk associated with spills. Wastewater reuse reduces volume (the difference between Avg. WW and Avg. Effl. flow), and treatment reduces contaminant concentrations, which combined reduce average loadings in effluent discharged to rivers.

Table 7. Potential average daily loadings of key contaminants from all flowback and brine wastewater and from treated effluent. Natural gas wastewaters are very concentrated, and loadings of key contaminants in the raw wastewater ("Avg. WW") can be similar to the totals carried by the Delaware River ("*Reference*" condition). For the effluent loading scenario ("Avg. Effl."), which includes wastewater reuse, the loadings are greatly reduced, though not eliminated. Units = lbs/d, except flow (MGD).

Scenario[a]	Study Area	Flow	*TDS*	*Cl*	*SO_4*	*Ba*	*Sr*
Reference	*DRB[b]*	*3,260*	*573,400*	*71,700*	*62,300*	*264*	*305*
Avg. WW	1	0.040	32,000	23,100	19	2,490	700
	2	0.047	37,700	24,500	20	2,640	740
	3	0.042	33,600	21,800	18	2,350	660
	DRB[b]	0.245	142,400	127,400	105	13,800	3,870
Avg. Effl. (w. reuse)	1	0.006	25	13	13	0.50	0.50
	2	0.007	30	15	15	0.59	0.59
	3	0.006	26	13	13	0.53	0.53
	DRB[b]	0.037	154	77	77	3.1	3.1

[a] Multiply loadings by 6 for maximum-year, and by 30 (times 365) for total loading.

[b] Reference DRB loadings based on average flow at Port Jervis, NY. DRB scenario loadings include all wells in the DRB, including those not in the three study areas.

Note: TDS – Total dissolved solids, Cl – Chloride, SO4 – Sulfate, Ba – Barium, Sr - Strontium

Finally, we note that the high contaminant concentrations in untreated wastewater make wastewater handling a potentially risky activity in case of spills. Comparing the average wastewater loads to the reference loads, it is evident that spilling even small volumes of untreated wastewater into streams could significantly raise loadings of these contaminants (and many others in the untreated wastewater), posing an

environmental risk. This study does not investigate spill scenarios, but the sensitivity of the basin's waters to spills may warrant further study.

Impacts of Wastewater Discharge

The salts, metals, and other pollutants in the flowback and brine wastewater can create significant loads, despite relatively low flow rates, because the pollutants are concentrated. The TDS concentration in brine makes it nearly six times saltier than seawater (roughly 35,000 mg/L). One way to judge the impacts of the effluent discharges in context is to determine how much the wastewater discharge would raise concentrations of key contaminants in surface waters.

Water quality risk is highest when a high effluent flow is discharged during low-flow conditions, because there is less water for dilution. We investigated two discharge flow scenarios to set a range on the potential water quality changes during a period of lower flow—in this case, the 20th-percentile flow (sometimes called the "Q80"). In both cases, we assumed that the discharge pollutant concentrations exactly met the quality standards in the "Discharge Regulations" column of Table 6 (see page 36).

The first scenario ("Max. Effl. w reuse") has the effluent disposal flow from the maximum development year (final column from Table 5, page 31) as its flow. This is the flow remaining after reuse. The second scenario ("Max. Effl. no reuse") has the total wastewater generated in the maximum development year (sixth column from Table 5) as its flow, but it meets the same effluent quality standards.

Given that potential effluent or discharge locations are unknown, we compute the concentration increase caused by diluting the wastewater pollutant loads in the reference streamflow on area-averaged basis. We use the small stream–gage statistics calculated per square mile to estimate the 20th-percentile flow and multiply by the area of the study area to get the flow rate. Table 8 shows the *increase* in concentration the wastewater effluent discharge would cause for the three study areas for the five pollutants. The first row of Table 8 shows the reference pollutant concentrations for natural flow from Table 6. Comparing the concentration increase to these reference concentrations shows the approximate magnitude of the change in water quality.

Table 8. Increase in concentration of pollutants caused by maximum-year effluent discharge during the 20 percent–flow condition. The "Max Effl. no reuse" scenario leads to larger increases than the "Max Effl. with reuse" scenario because of higher flow. Barium and Strontium concentrations change most relative to reference concentrations. Units = MGD for streamflow, effluent flow; mg/L for reference concentration, concentration increase

Scenario	Study Area	Streamflow	Effluent Flow	Concentration Increase				
				TDS	*Cl*	*SO_4*	*Ba*	*Sr*
Reference Concentrations for DRB:				*46.5*	*5.8*	*5.1*	*0.021*	*0.025*
Max Effl. w reuse	1	22.2	0.036	0.817	0.409	0.409	0.016	0.016
	2	40.2	0.043	0.530	0.265	0.265	0.011	0.011
	3	31.4	0.038	0.605	0.302	0.302	0.012	0.012
Max Effl. no reuse	1	22.2	0.240	5.412	2.706	2.706	0.108	0.108
	2	40.2	0.283	3.513	1.757	1.757	0.070	0.070
	3	31.4	0.251	4.004	2.002	2.002	0.080	0.080

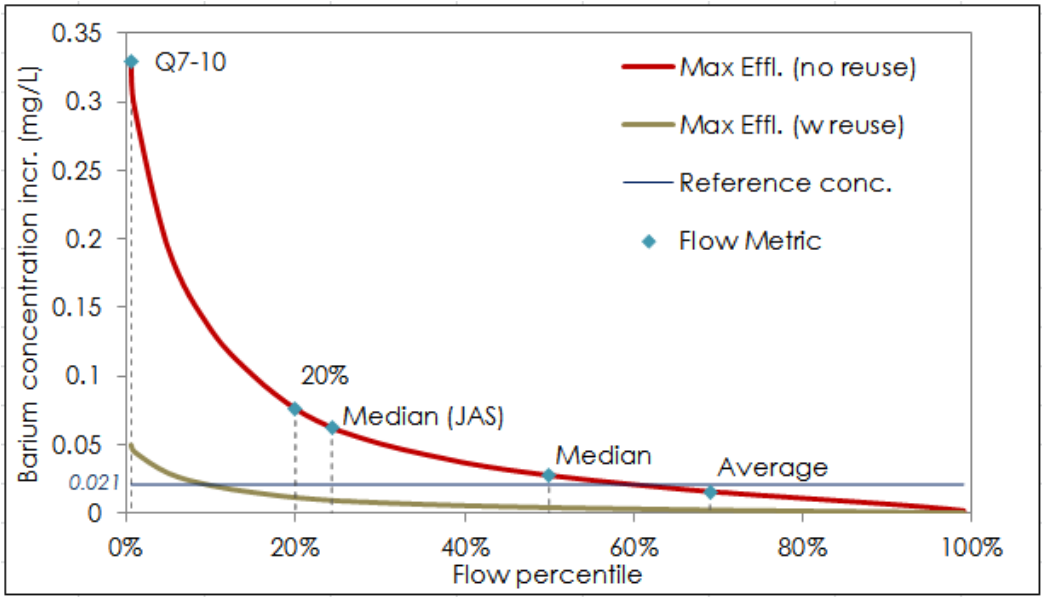
Note: TDS – Total dissolved solids, Cl – Chloride, SO_4 – Sulfate, Ba – Barium, Sr - Strontium

The Max. Effl. with reuse scenario's increased concentrations reflect a wide variation in percentage changes, with TDS increasing about 1.5 percent over reference concentrations in the study areas, and barium and strontium increasing 50–70 percent. The increased barium loadings are especially of concern, because barium accounts for up to 90 percent of eco-toxicity potential in flowback and brine wastewaters [71]. The lower the wastewater reuse rate, the higher the potential effluent loadings. For barium and strontium, treating all of the wastewater (i.e. no reuse) instead results in a 300–500-percent increase over reference concentrations.

The water quality changes also depend on the flow conditions in the effluent's receiving water due to the dilution effect. Figure 14 illustrates how the increase in barium concentration changes depending on the flow conditions at the time of discharge. This example considers the same scenarios for Study Area 2. The horizontal blue line shows the reference concentration for barium.

Unsurprisingly, we observe that the concentration increases are much higher during lower flows, and the larger discharge volumes of the no reuse scenario result in larger changes to concentrations. This general pattern will be reflected for all of the pollutants in all of the study areas, though the reference concentrations will be different.

Figure 14. Barium concentration increase versus flow percentile, Study Area 2. The concentration increases are most substantial for the lower flow percentiles. Scenario with no reuse has higher increases. Units = mg/L.



Discussion

If natural gas development were allowed in the DRB, water resources would be affected by both water withdrawals and wastewater discharges. Water withdrawals are small relative to total water availability in the basin, but are large compared to existing demands in the study areas. The withdrawals could remove a significant portion of flow if maximum year withdrawals are taken from smaller streams during critical low-flow periods. In this analysis, we compared the withdrawal rate and available flow generation on the basis of 'flow per unit area' over the area of the watershed for the three study areas. While this analysis method is necessary to compare relative flows where actual withdrawal location and timing are unknown, in reality, the impact would depend on the specific location and flow conditions during the withdrawal. On smaller streams, especially, the magnitude of water permanently removed for fracking could reduce the flow considerably during high or peak withdrawal periods. The duration of the impact is uncertain and would depend on how many wells would be served by a particular withdrawal location, and the rate of development.

Wastewater handling, management, and treatment are important for Marcellus wastewaters, notably the flowback and brine, due to the high concentrations and potential toxicity of pollutants in the wastewaters. We considered only the impact that the discharge of wastewater effluent treated to current Pennsylvania standards would have on in-stream concentrations of five pollutants with specific discharge limits. Our analysis showed that under these conditions, in-stream loadings of some pollutants (notably barium and strontium) could increase between 50 and 500 percent, depending on what portion of the wastewater is reused versus treated and discharged. These effects would be most pronounced on smaller streams and during low-flow periods, where the discharge flowrate is a reasonable proportion of the ambient flow.

There are several other potential risk pathways and risks to water quality [50, 72] that this study does not consider. Pollutants other than the five included here—as well as their degradants or derivatives—may pose additional risks to water quality and human and environmental health. The treatment processes needed to meet the 2010 discharge regulations on TDS, chloride, and sulfate may also treat other salts and ionic compounds, and limits on barium and strontium may result in reduced concentrations of other metals. Yet, for many of the pollutants found in natural gas wastewaters (many of which have no regulatory discharge limits), understanding of potential health impacts is still evolving (see the "Health Risks and Affected Population" chapter for more discussion of this issue). For instance, iodide and ammonium (two chemicals not usually measured in water quality analyses of flowback or brine) in Marcellus wastewater effluent have recently been shown to impact formation of disinfection byproducts in drinking water, as well as having ecologic effects [43-44, 73]. Naturally occurring radioactive materials (NORM) in flowback and brine have attracted attention because they are not easily treated and do not quickly degrade in the environment, whether in effluent or solid waste discharge [74-75]. Additional research on effluent concentrations of a wider range of chemicals from wastewater treatment plants meeting the newer Pennsylvania standards would be useful in assessing potential impacts of these other pollutants.

While effluent discharge was the primary water pollution pathway that we included in this analysis, there are other documented pollution pathways by which natural gas wastewaters could be released. For example, Reaven and Rozell performed a probability bounds analysis to determine the likelihood and potential volume of water contamination via transportation of wastewater, well casing failure, migration through subsurface fractures, wastewater spills at the drilling sites, and wastewater disposal [5]. They found that although wastewater disposal (i.e., effluent discharge) was by far the most likely pathway with the highest potential contamination volume, other pathways could lead to low-probability scenarios with high-contamination volumes, especially spills at drilling sites. These "accident" pathways [50] are important considerations in a full consideration of UNGD risk, as some spills will be nearly inevitable [74]. Pennsylvania's Department of Environmental Protection has

been tracking and reporting permit violations for natural gas operators, and their violations data show that many of these pathways are a reality in Pennsylvania, with 4,006 violations since 2009 (roughly 7,800 wells drilled) [76]. As an example, there have been roughly 290 violations at about 240 well sites involving improper discharge of UNGD wastewaters to Pennsylvania's streams [76].

The next chapter of this report investigates a different category of water quality risks: those associated with the changes to land cover we described in the "Impacts on Land Cover" chapter.

Impacts on Water Quality due to Changes in Land Cover

Key Findings

- Changes in land cover associated with natural gas infrastructure would lead to short- and long-term changes in hydrology and water quality.
- Changes in land cover could increase erosion rates up to 150 percent immediately after infrastructure construction and 15 percent in the long term.
- Soil-erosion rates during winter months are up to 25 times higher than during summer months.
- Runoff rates could increase by up to 4 percent, offset by an equivalent volumetric decline in groundwater contribution to streamflow.

Unconventional natural gas development results in landscape disturbance based on the need to construct infrastructure to support operations. This report's chapter titled "Impacts on Land Cover" described the potential changes to land cover associated with constructing well pads, roads, and gas gathering pipelines. These changes to the landscape also change the hydrologic character of the DRB, and can affect water quality through changes to sediment and nutrient export. Building roads, pipelines, and well pads requires clearing the land, removing topsoil, regrading, and compacting soil both in the infrastructure footprint and a right-of-way wide enough to install infrastructure. Mitigation measures—such as erosion- and sediment-control practices (silt fences, filter socks, and so forth) and remediation with planting of cover crops—can limit the loss of soil, but some permanent impact due to the initial land clearing and soil compaction is inevitable.

The full scope of water-quality outcomes resulting from land cover changes depends on the location of the infrastructure, the existing watershed conditions, and the

mitigation measures put in place by developers. Infrastructure that is built on land with high slopes and erodible soils; near or adjacent to stream banks; or necessitating the crossing of a stream or disturbance of wetlands will have a larger potential for ecological damage, primarily through erosion. The current condition of the basin in the three study areas is predominantly forested and agricultural, with limited residential and commercial development.

The previous chapter covered some of the potential impacts of the natural gas wastewaters on water quality. This chapter, by contrast, focuses on potential impacts on water quality due to the largely unavoidable land cover changes associated with UNGD. Such land-use changes often correlate to changes in hydrology, water quality, and—by extension—stream health. At the site scale, well pad development has been observed to increase sediment and nutrient concentrations, though vegetated stream buffers and erosion- and sediment-control practices can reduce loadings [77]. At a regional scale, development of well pads has been shown to correlate with increased in-stream Total Suspended Sediment loads [4], due to erosion and sedimentation.

Methodology

We modeled each of the study areas with the MapShed program developed by Penn State University [78]. The water quality calculations were performed with MapShed's integrated GWLF-E model based on the Generalized Watershed Loading Function [79], which simulates runoff, sediment, and nutrient loads based on watershed source areas. We modeled each of the study areas under three conditions:

- **Baseline:** Existing land cover
- **Initial Infrastructure:** Well pad, gathering pipeline, and new roads during or immediately after installation with minimum mitigation
- **Post-Development:** Infrastructure after the hydraulic fracturing operations are complete and gas is being produced, with partial remediation

The Initial Infrastructure condition represents a worst case of erodibility conditions that would likely persist from several days to a few months as the well pads, roads, and pipelines are constructed. This scenario is useful for setting the upper limit on the potential sediment and nutrient loadings, and determining which months of the year have conditions most conducive to erosion in the study areas. This scenario also assumes that the entire land conversion for infrastructure in a study area occurs at once, when, in reality, it would be installed at the pace of development over 30 years.

The Post-Development condition considers the long-term effects of land-use change after all the gas wells have been drilled and are in production. The well pads are

partially deconstructed (leaving only a well head, pump, and brine storage), and the gathering pipeline rights-of-way are revegetated with cover vegetation (low grasses and herbaceous plants); pipelines are operating, and the roads are little changed. We assumed (through parameter selection, not direct modeling) that some erosion and sediment control best management practices (BMPs) are installed, though not optimally, and that the post-development soil would remain somewhat compacted. Ultimately, the Initial Infrastructure and Post-Development scenarios should bracket a range of conditions reflecting a range of potential remediation cases.

We also assumed that all land cover changes are permanent, that there are no other land cover changes in the study area, and that there are no secondary land cover changes (e.g., converting additional forest to farmland to make up for arable area lost to gas infrastructure). We also did not include long-distance transmission pipelines to move natural gas to market and other appurtenant natural gas infrastructure (e.g., centralized storage or wastewater treatment facilities) in this analysis.

The results presented consider only runoff and streamflow produced within the study area (no upstream flow for Study Areas 1 and 3), and only loadings associated with land-use and in-stream processes (no point sources, livestock, or septic systems are included in the model). The results focus on the hydrologic and loading changes on the uplands—that is, the changes in flow or pollutant loadings coming directly from changes in the land surface.

The metrics we used to assess the changes include the following MapShed model outputs:

- **Runoff:** The volume of water that flows off the land surface and into streams during storms
- **Groundwater Recharge:** The volume of water that soaks into the ground during rain events and contributes to streamflow
- **Erosion:** The mass of soil that is dislodged from the land surface by precipitation runoff and is carried into streams
- **Sediment:** The mass of soil that is deposited on land (generally as dust) that gets washed off into streams
- **Nutrients:** The mass of nitrogen (Total Nitrogen, or "TN") and phosphorus (Total Phosphorus, or "TP") compounds washed off the land surface in runoff or in groundwater entering the stream[4]

[4] These can contribute to algal growth, which can lower available oxygen in the stream.

Results

The land-use changes associated with UNGD in the DRB affect hydrology, loadings of sediments, and (to a lesser extent) nutrients in the study areas. The results vary significantly by scenario and condition (Initial Infrastructure versus remediated condition). Table 9 indicates changes in hydrology (runoff and groundwater recharge) and upland loadings (erosion, sediment, nutrients) for each scenario, expressed as a percent change from the baseline total. Only the land surface processes are included in the total.

Table 9. Changes in hydrology and loadings for each scenario. The land cover changes result in large increases in erosion and sediment ("Sed.") loadings compared to the baseline, especially for Dispersed scenario/Initial Infrastructure ("Initial Infra.") conditions. The hydrology and nutrient loading changes are smaller in magnitude. Units = % change from baseline.

Study Area	Development Scenario	Condition	Runoff	GW	Erosion	Sed.	TN	TP
1	Dispersed	Initial Infra.	2.8	-0.17	98	54	6.3	11
	Dispersed	Post-Dev.	1.6	-0.09	15	-2.1	-1.6	-5.0
	Concentrated	Initial Infra.	1.7	-0.10	67	33	3.7	6.9
	Concentrated	Post-Dev.	1.0	-0.09	10	-5.5	-1.8	-4.8
2	Dispersed	Initial Infra.	3.4	-0.64	138	125	32.0	49
	Dispersed	Post-Dev.	1.8	-0.32	16	14	2.6	2.7
	Concentrated	Initial Infra.	2.1	-0.43	102	93	23.0	35
	Concentrated	Post-Dev.	1.1	-0.27	13	11	1.8	2.1
3	Dispersed	Initial Infra.	3.4	-0.46	110	96	12.3	20.0
	Dispersed	Post-Dev.	1.9	-0.18	14	12	0.7	-1.6
	Concentrated	Initial Infra.	1.9	-0.18	66	57	7.2	12
	Concentrated	Post-Dev.	1.0	-0.14	8.0	6.8	0.3	-1.1

Notes: GW = Groundwater recharge

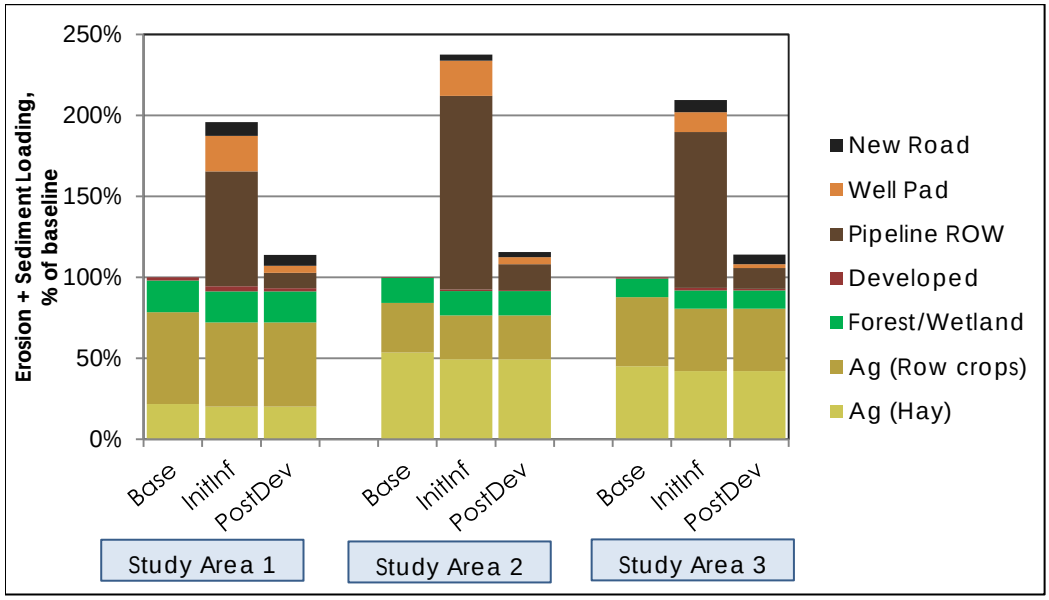
The hydrologic changes show increases in runoff of 1–3 percent, with reductions in groundwater recharge of a few tenths of a percent. On a volume basis, however, these changes are nearly equal, so average yearly streamflow is nearly unchanged, but flow distribution changes. The flows increase (roughly 1.5 percent) at peak flows, and decrease (1 percent or less) across the rest of the flow distribution. In volume terms, the groundwater contribution to flow will decrease by somewhere between 70 (Concentrated scenario, Post-Development conditions) and 145 million gallons per year (Dispersed Scenario, Initial Infrastructure conditions) for Study Area 1. The corresponding ranges are 140–330 million gallons for Study Area 2, and 90–305

million gallons for Study Areas 3. On an area-averaged basis, the approximate range of decreased groundwater flow is 0.35–2 million gallons per year, per square mile.

Table 9 also shows a noticeable change in the erosion and sediment loadings, and less significant changes in nutrient loading. Erosion and sediment changes both increase suspended sediment loadings in streams, but the sediment loadings are much smaller in magnitude. Combining these loadings gives a clearer picture of the potential changes in soil volume leaving the landscape.

Figure 15 illustrates how the combined erosion and sediment loadings change, and how the individual land-use changes affect them. Results are shown as a percentage of the baseline total load (upland only). Thus, the baseline load equals 100, and 240 would represent a 140-percent increase. The stacked bars show the relative contribution of each existing land cover (forest/wetland, agricultural hay and pasture, agricultural row crops, and developed area) and gas infrastructure land cover (well pads, pipelines, roads) to the total loading. The largest contribution to the erosion and sedimentation impacts are from the pipeline right-of-ways, especially for the Initial Infrastructure ("InitInf") condition. The impacts from roadways are smaller in magnitude but are not reduced as much in the Post-Development ("PostDev") condition, as compared to well pads and pipeline rights-of-way.

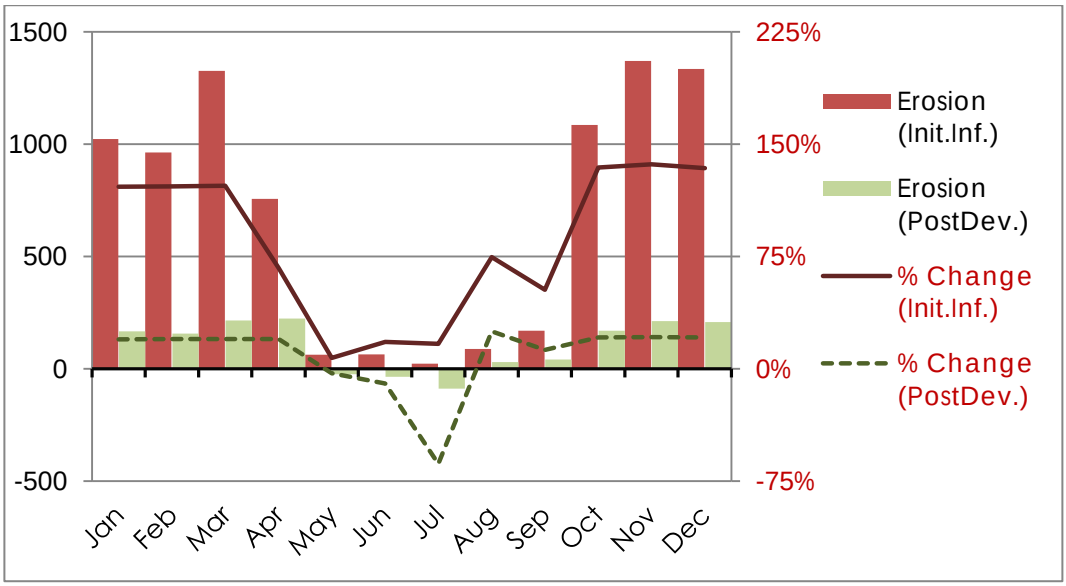
Figure 15. Total upland erosion plus sediment loading, as percent of the baseline loading. Increases in erosion and sedimentation are caused mainly by the pipeline rights-of-way and are more severe in the Initial Infrastructure ("InitInf") condition than the Post-Development ("PostDev") condition. Units = percent of baseline. (baseline = 100)



The total change in loading also depends on the types of land cover affected by the conversion. The relative amount of agricultural versus forest area converted has a strong influence on the upland loading results. For example, converting forest area to natural gas infrastructure increases loads, while agricultural (and especially cropland) conversions may lead to net reductions in some loads, especially nutrients. This accounts for much of the variation in the nutrient results in Table 9 (page 46).

We also found the potential changes to erosion rates vary widely during the year. Figure 16 shows the monthly variation in erosion relative to the baseline condition for both the Initial Infrastructure and remediated condition. The changes in winter erosion predominate and account for most of the total change. The difference is such that if the Initial Infrastructure conditions persisted for three months, 25 times more erosion would occur if all infrastructure were built in October through December versus May through July.

Figure 16. Monthly variation in erosion relative to the baseline condition for both the Initial Infrastructure and Post-Development condition. Most of the increase in erosion between baseline and developed conditions occurs in winter months. Units = tons (left axis); percent change (right axis).



Discussion

The land-use changes associated with UNGD in the DRB have the potential to cause noticeable changes in hydrology and erosion, despite affecting a relatively small proportion of the basin. The Initial Infrastructure conditions result in the highest susceptibility of the study area to erosion, noticeably in the winter months. Even in the Post-Development condition, the additional roads, pipelines, and well pads do not perform the same hydrologic functions as the forests they replace, resulting in potentially long-term increases in peak runoff, erosion, and nutrient loading, and possible decreases in stream base flow.

By way of context, in Study Area 2 (178 square miles), the volume of runoff-increase and groundwater recharge–decrease both equal roughly 330 million gallons per year (0.9 million gallons per day) for the "dispersed" scenario for the Initial Infrastructure condition. This yearly volume of water would fill the Empire State Building 1.2 times. Also, if the Initial Infrastructure conditions persisted for three months, on average, approximately 18,000 tons of soil would be eroded. If piled on top of an average suburban house lot (one-quarter acre), the pile of soil would be 45 feet tall.

The results report only the net changes averaged across the entire case study watersheds. The most prominent changes are likely to occur in the upland portions of the watersheds and in small streams and ponds adjacent to the infrastructure development. Further modeling would be needed to assess potential impacts on a smaller scale. Additional land development (for housing, more agriculture, other uses) in the watershed may be more likely to cause downstream impacts, as the hydrologic and water quality functions of upland streams would start as more degraded.

This analysis is a limited one and does not account for the full range of impacts that may result from land-use changes associated with gas development. This analysis used the Mapshed model to estimate pollutant changes over the study area using typical factors for the types of land covers described. It does not cover the large potential variation in parameters such as curve number, soil bulk density (compaction), or other soil factors. Furthermore, the model parameters cannot directly account for the impact of best management practices, or the impacts that may occur were these practices to fail. Pennsylvania data on permit violations indicate that erosion- and sediment-control violations at well sites are relatively common (roughly 630 violations at 530 well sites since 2009) [76]. The severity of these violations is not known, but in some of these cases, the failure (or absence) of best management practices for erosion and sedimentation could result in loadings closer to the Initial Infrastructure condition than the Post-Development condition presented here.

In addition, the flow changes and changes to sediment loadings are likely to affect the ecological conditions of the watershed. The land cover changes will likely result in environmental flow changes (especially increased peak flows and decreased base and low flows), which can affect the health and relative distribution of a wide range of plant and animal species [58-59].

We recommend further study to better assess water-quality outcomes using more-detailed models with greater spatial resolution and more-detailed parameters using sampling data from the modeled watershed. For instance, variability in agricultural practices can have a strong influence on erosion rates and nutrient export. Further study could also compare alternate future land-use changes (e.g., more suburban development) with results for land-use change specifically associated with gas development. Additional study with a more-detailed case study model could also investigate the combined effects of water withdrawal, wastewater effluent disposal, and land cover changes.

Impacts on Air Quality

Key Findings

- Natural gas development could as much as double nitrogen oxides (NO_x) emissions, compared to current emissions in affected DRB counties.
- The primary source of NO_x emissions from natural gas development could stem from compressor stations to move the gas through gathering pipelines, rather than from well development or completion.
- Compressor stations represent a long-term source of NO_x emissions in impacted areas, rather than the short-term, intermittent impact from well development.
- Methane leakage from natural gas development in the DRB could contribute an additional 0.5–2.2 percent per year to the current methane emissions from Marcellus Shale development now occurring in Pennsylvania and West Virginia.

Unconventional natural gas development is an industrial process that involves a host of machinery and operations to extract natural gas from shale deposits. Shale gas operations release a variety of pollutants that can degrade local air quality, including nitrogen oxides (NO_x); sulfur oxides (SO_x); particulate matter (PM); and volatile organic compounds (VOCs), such as formaldehyde, benzene, toluene, ethylbenzene, and xylene (BTEX) [80]. NO_x, SO_x, and PM are subject to national ambient air-quality standards, (NAAQS) due to their potential to cause harm to human health and the environment [81]. Furthermore, NO_x and VOCs are the precursors to ozone, the primary component in smog, which can cause respiratory illness [82].

Impacts on air quality from industrial emissions occur during each of the stages of shale gas development [82]. These emissions stem from the use of diesel-powered equipment to prepare well pads and diesel trucks to transport water and supplies to and from well pads. The drilling, hydraulic fracturing, and production processes also

utilize diesel machinery and contribute to these emissions. In addition, condensate tanks and waste ponds at well pad sites can produce emissions. Significant emissions can also arise from combustion-powered compressor stations that compress natural gas to keep it flowing through the pipeline system.

While these local risks to air quality would most likely impact the DRB in the short term, there is a large field of research that has focused on the potential climate change impacts due to greenhouse gas (GHG) emissions from shale gas development [80, 82-84]. These GHG emissions stem from the leakage of natural gas (i.e., methane, or CH_4) at various points throughout the development cycle, from extraction to processing and transmission. However, the combustion of natural gas to generate electricity releases half as much carbon dioxide (CO_2) as coal, leading many to champion the climate benefits of natural gas and term it a "bridge" fuel to the future. There is considerable debate as to whether the methane leakage from natural gas operations eclipses any of these gains from reduced CO_2 emissions, especially considering that methane has 34 times the greenhouse-warming potential (GWP) of CO_2 (on the 100-year time horizon); on the 20-year time horizon, methane has 86 times the GWP of CO_2) [85]. A recent study suggests that methane leakage should be below 3.2 percent to realize net climate benefits from the transition [86], while field measurements of methane losses have found a range from between 0.3 percent and 17 percent (see Table 11 below for references).

In this chapter, we focus on the potential emissions and impacts to air quality in the DRB from natural gas development. In particular, we calculated the potential contributions to VOC, NO_x, PM, and SO_x emissions from projected natural gas development in four DRB counties: Wayne County (PA), Broome County (NY), Delaware County (NY), and Sullivan County (NY). We performed this analysis at the county-wide scale to compare the results to EPA emission inventories. In addition to criteria pollutants, we calculated the potential contribution to methane emissions from projected natural gas development in these counties. We did not analyze the potential for any more localized impacts on air quality, as this was beyond the scope of the study.

Methodology

To assess the impacts to air quality, we applied relevant values from the professional literature to our build-out scenarios to calculate the emissions associated with natural gas development. For ease of comparison with the common emission values, we report the calculated emissions at the county level, rather than by study area. Furthermore, we used the two development rate scenarios described in Table 1 ("dispersed" and "concentrated") to illustrate the impacts of the development rate on air quality:

- **Average Development Year:** Assumes that development occurs at a constant rate over a 30-year build-out
- **Maximum Development Year:** Assumes that 20 percent of total well build-out in each county occurs in one year (up to a maximum of 200 wells/year, which is representative of the highest-developing counties in the Marcellus Shale today).

The average and maximum-year scenarios show the potential variation in emissions that could be expected from natural gas development activities in each county.

To assess the local impacts on air quality that might be expected from shale gas development in the DRB, we applied the emissions estimates from a recent study on Marcellus Shale development in Pennsylvania [87] to our projected well development results. This study provided emissions values for VOCs, NO_x, PM, and SO_x on a per-well basis during various well site activities, based on data reported from Marcellus Shale gas producers. In addition to well development, the study reported the contribution from compressor stations that support production. The study estimated emissions from compressor stations based on the reported "potential to emit" values from permits, which indicate the maximum amount of emissions the facility is permitted to emit by the Pennsylvania Department of Environmental Protection. We estimated the number of compressor stations in each county by assuming that a centralized station would serve all well pads within a 50-square-mile radius, based on estimates from Marcellus Shale operators in the New York Department of Environmental Conservation's Draft Supplemental Generic Environmental Impact Statement [88]. The study reported the high and low values of the range for each pollutant from multiple sites, and we used the average of these values to report results. To estimate the impact of the emissions, we compared the calculated emissions to the counties' reported emissions from the EPA 2011 National Emissions Inventory (NEI) [89].

To assess the greenhouse gas contributions that might result from shale gas development in the DRB, we calculated methane leakage as a percentage of the natural gas production expected in the DRB. To determine the natural gas production, we assumed that all wells would exhibit an average EUR of 1.6 Bcf per well (the same EUR value that we used to develop our build-out scenarios, see page 9), and applied a well decline curve based on a similar EUR [90] to estimate the monthly production per well in the DRB. We applied this value to the average number of wells that would be developed per month in the two annual scenarios to determine annual production. Using these production values, we then applied leakage rates based on relevant values from professional literature describing field measurements (top-down) of methane leakage (see page 58). We chose to focus on top-down studies for this assessment, based on a recent review of methane leakage from natural gas systems that found that assessments based on inventories (bottom-up) tend to underestimate this leakage [91].

For both the methane and non-methane assessments, our well-development results from the "concentrated" and "dispersed" scenarios result in similar number of wells developed. Thus, only the "dispersed" scenario is considered throughout this chapter.

Results

Criteria Pollutant Emissions

Table 10 shows the estimated annual pollutant emissions from shale gas development in the DRB, based on average and maximum annual well development scenarios. In addition to the number of new wells, we project that 22 new compressor stations could be built in the DRB to support transmission of natural gas through new gathering pipelines. We present the range of potential emissions expected from the two scenarios by evaluating emissions with one compressor station in each county, followed by the emissions with all 22 compressor stations present in the DRB. In each scenario, NO_x emissions would be the largest contributor to air pollution in the DRB from this development.

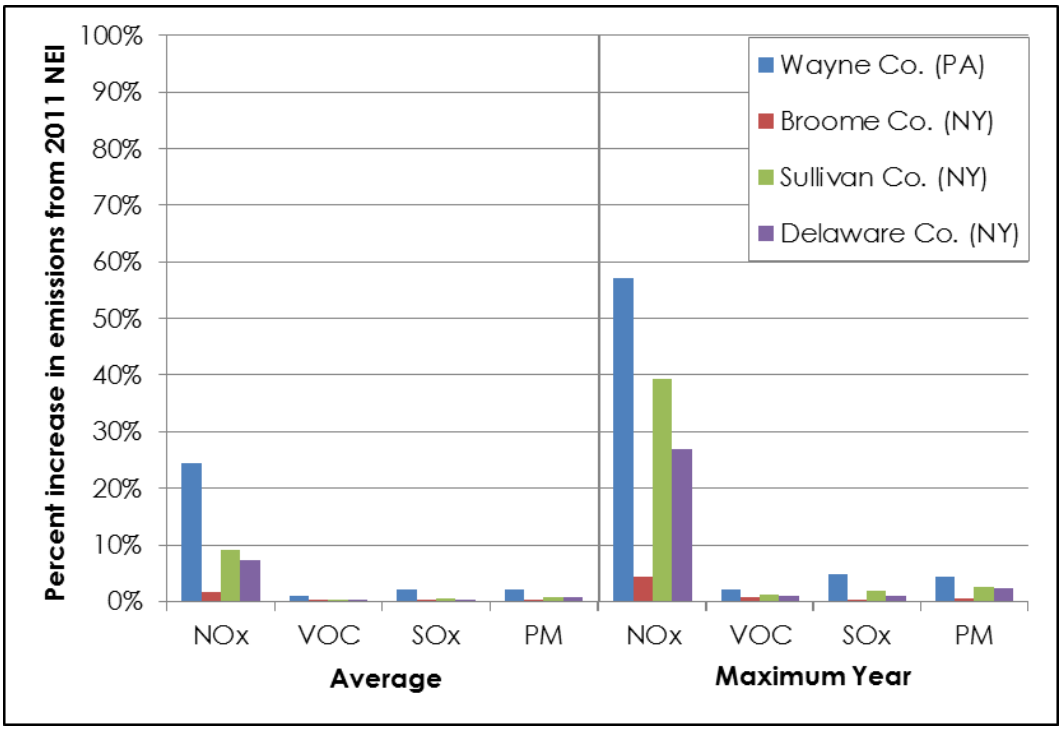
Table 10. Annual emissions estimates for projected natural gas development by county (and for one compressor station) in the DRB. NO_x emissions would be the largest contributor to air pollution by weight. Units = metric tons, unless noted otherwise.

County	Scenario	Wells	CH_4 (Bcf[a])	NO_x	VOC	PM	SO_x
Wayne	Avg	78	832	441	91	14	5.6
Broome	Avg	8	93	105	34	4.5	1.3
Sullivan	Avg	27	256	197	50	7.2	2.5
Delaware	Avg	16	184	146	41	5.7	1.8
DRB	Avg	129	1,365	889	216	32	11
Wayne	Max	200	2,081	1,026	190	31	13
Broome	Max	46	483	290	66	10	3.7
Sullivan	Max	163	1,698	850	160	26	11
Delaware	Max	98	1,024	539	108	17	6.8
DRB	Max	507	5,287	2,705	522	84	34

[a] Bcf = billion cubic feet.

To determine the extent of these emissions impacts, we compared the projected annual emissions from development in each county (plus one compressor station) to the total emissions of each pollutant in each county from the EPA's 2011 NEI. Figure 17 shows the results of this comparison for the two scenarios of annual well development.

Figure 17. Pollutant emissions from well development (and one compressor station) for average-year (left) and maximum-year (right) scenarios, relative to total county emissions from the 2011 NEI. Natural gas development could lead to a significant increase in NO_x emissions for three of the four DRB counties.



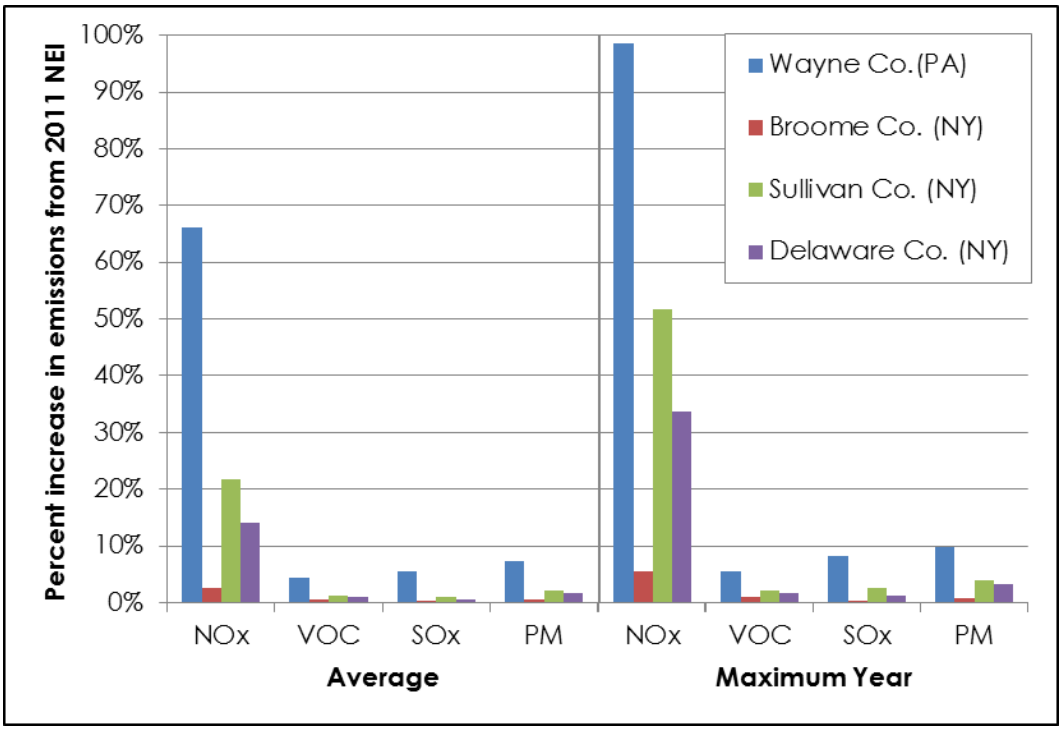
We see noticeable potential increases in NO_x emissions for three of the four counties: Wayne County (PA) and Sullivan and Delaware Counties (NY) could all see greater than a 27-percent increase in NO_x emissions under the maximum annual-development scenario. Under the average annual-development scenario, Wayne County could still see a substantial increase in NO_x emissions (25 percent) from the shale industry, but NO_x contributions from the other counties were all below 9 percent. Broome County (NY) did not see a significant increase in NO_x emissions in either scenario. This is not surprising, since only a small portion of Broome County falls within the DRB.

The contributions to VOC, SO_x, and PM emissions from annual shale gas development did not appear as significant compared to other activities in these counties. None of the counties showed a noteworthy increase in either the average year (less than 2 percent) or maximum year (less than 5 percent) scenarios at the county scale, though the individual pollutants, especially VOCs, could have impacts at a local scale (see "Health Risk Factors and Affected Population" chapter) .

While the emissions attributed to well pad development and well completion represent one-time contributions in the year the well was drilled, compressor stations will continually contribute to a county's emissions inventory after they are built. With this fact in mind, we determined the annual emissions from well development with all 22 compressor stations in place to see the impact on the DRB. Based on our projections, the 22 compressor stations would be spread out in the DRB counties according to the following breakdown: 12 in Wayne Co. (PA), 5 in Sullivan Co. (NY), 3 in Delaware Co. (NY), and 2 in Broome Co. (NY). This breakdown corresponds to the expected number of wells projected in each county. Figure 18 shows the updated annual emissions inventory for the two scenarios with the higher count of compressor stations. Note that these projections for new compressor stations only account for supporting gathering pipelines, and do not account for any additional compressors that may be needed to support larger transmission pipelines to carry the natural gas to market.

With the addition of a full complement of compressor stations, we see significant potential increases in NO_x emissions for three of the four counties. Wayne County (PA) and Sullivan and Delaware Counties (NY) could all now see greater than a 34-percent increase in NO_x emissions under the maximum annual-development scenario. In fact, NO_x emissions could almost double in Wayne County under that scenario, due to the addition of 12 compressor stations. Under the average annual-development scenario, Wayne County would still see a substantial increase in NO_x emissions (66 percent) from the shale industry, but NO_x contributions from the other counties were all below 21 percent. Broome County (NY) still did not see a significant increase in NO_x emissions in either scenario.

Figure 18. Pollutant emissions from well development (and 22 compressor stations) for average-year (left) and maximum-year (right) scenarios, relative to total county emissions from 2011 NEI. The full complement of compressor stations leads to a large increase in NO_x emissions in 3 of the 4 DRB counties.



The contributions to VOC, SO_x, and PM emissions from annual shale gas development did not appear as significant compared to other activities in these counties. Only Wayne County (PA) showed any relative emissions higher than 5 percent across these pollutants at the county scale.

Methane Emissions

Natural gas and petroleum systems represent the largest contributing sector to methane emissions in the United States [16]. Table 10 shows the projected methane emissions from natural gas development in the DRB. Using the well decline curve for a 1.6 Bcf EUR-model well, we estimated the annual production from natural gas development in the DRB to be 22.6 Bcf in an average year, and 87.5 Bcf in a maximum year. We applied methane leakage rates from the academic/professional literature to these production values to estimate the potential methane emissions from development in the DRB. Table 11 presents these results.

Table 11. Potential methane emissions from projected development in the DRB, based on methane leakage rates reported from field measurement (top-down) studies. Units = Bcf – billion cubic feet.

		Potential Methane Emissions (Bcf)	
Study	Leakage Rate	Average Year	Maximum Year
Peischl (2015) [92]	0.3%	0.1	0.3
Peischl (2015) [92]	1.6%	0.4	1.4
Peischl (2015) [92]	1.9%	0.4	1.7
O'Sullivan (2012) [93]	3.6%	0.8	3.2
Miller (2013) [94]	3.7%	0.8	3.2
Petron (2012) [95]	4.0%	0.9	3.5
Karion (2013) [96]	8.9%	2.0	7.8
Schneising (2014) [97]	9.1%	2.1	8.0
Caulton (2014) [98]	10.0%	2.3	8.8
Peischl (2013) [99]	17.3%	3.9	15.1
Average	6.0%	1.4	5.3

Applying the average leakage rate from the literature of 6 percent, we estimated annual methane emissions of 1.4 Bcf in an average year and 5.3 Bcf in a maximum development year. Applying the same methodology to current annual Marcellus Shale production, which is about 4 trillion cubic feet, we estimate total Marcellus emissions to be 240 Bcf. Thus, shale gas development in the DRB could contribute an additional 0.5 percent to 2.2 percent per year to the current methane emissions of the Marcellus Shale.

Discussion

If natural gas development were to proceed in the DRB, there could be varying impacts to air quality. Compared to activities that are already occurring in the DRB counties, our results suggest that NO_x emissions would be the biggest contributor to air pollution from shale gas development. By comparison, the projected NO_x emissions in Wayne County, PA, from the average year of natural gas development (with one compressor) would be equivalent to adding over 53,000 cars to the road in the county that year.[5]

[5] This is based on EPA's average NO_x emissions (0.693 g/mile driven) per year (12,000 miles driven) for passenger cars [100].

These counties currently enjoy clean, high-quality air, due to the absence of any major emissions sources such as power plants. However, localized development in certain parts of each county could still pose a reduction in air quality due to this development. Some studies have attributed this localized development to a variety of airborne health risk factors (see the "Health Risks and Population" chapter for more details and references). The primary contribution to these NO_x emissions could come from compressor stations, which represent a long-term source of emissions, versus the one-time contribution from well-development activities.

Furthermore, methane releases from natural gas operations are a significant contributor to methane emissions in the United States. Each year, if all 1.4 Bcf of potential methane leakage could be captured and used to fuel a natural gas power plant, roughly 139 gigawatt hours of electricity could be produced[6], enough to power over 16,000 homes in the area[7] for a year. While atmospheric methane does not necessarily have significant local effects, it is a powerful greenhouse gas that could have impacts beyond the DRB.

[6] The EIA estimates that 1,000 cubic feet of natural gas can generate 99 kilowatt-hours of electricity [101].

[7] Average monthly household electricity use in the Middle Atlantic region is 701 kWh [102].

This page intentionally left blank.

Health Risks and Affected Population

Key Findings

- More research and better tracking of health impacts are needed to reliably project how shale gas development could affect health *outcomes*. Scientific literature has shown that some health risk factors are related to distance (e.g., 1 km, 1 mile) from a well pad.
- Roughly 45,000 people live within one mile of a projected well pad location. This population predominantly resides in Wayne County, PA, where nearly 60 percent of the county's population could be affected by increased well development.
- Development of more wells per pad reduces the number of people in close proximity (<0.5 mile) to well pads, but potential exposures to certain risk factors could be prolonged.

Of the environmental impacts of unconventional natural gas development, those that pose a potential risk to human health often attract the most attention and concern. In large part, the link between unconventional Marcellus Shale gas development and adverse health outcomes has not been rigorously tracked in a manner that has produced conclusive scientific literature [103]. There has been considerable research into the potential pathways and risks of exposure, but the potential health outcomes depend on type, magnitude, duration, and frequency of exposure to contaminants and risk factors [104]. Just as previous chapters noted that there is variation in productivity of individual wells, water use, concentrations of wastewater contaminants, and air emissions rates, the potential risks to human health may vary considerably across the study area, and even from well pad to well pad.

While it is not possible to use the scientific literature to derive rigorous estimates of specific health metrics (e.g., cancer cases above baseline), a number of studies (see Table 12) provide some evidence that risk factors and possibly health outcomes correlate with distance from primary gas development activities (i.e., well pads). This

analysis quantifies the population within certain distances from well pads as an initial estimate of the potential affected population.

While the link between natural gas development and health outcomes has not been rigorously investigated [103], the major potential exposure pathways have been explored. Krupnick et al. [50] documented the risk pathways (routine and accidental) of UNGD agreed upon by a wide range of experts. Of the 15 consensus risk pathways (those with priority for further regulation or voluntary action), 14 involved routine or accidental releases (of frac fluid, wastewater, methane, etc.) to air, surface water, or groundwater, indicating the potential for human health exposures. Where possible, this study considers the risk pathways and accompanying research indicating that risks or health outcomes vary with distance from the activity associated with the risk pathway.

Table 12 summarizes some of the risks and health outcomes identified in the literature based on distance from natural gas activities (most often associated with the well pad). Typically, these studies evaluate risk factors or metrics of health risks/outcomes at several distances from primary gas development activities, such as the injection well site. The most common distance-threshold for measuring the most likely risks is 1,000 meters or a half-mile. To evaluate more general risks, or establish a threshold distance for a control population, the selected distances are commonly 2,000 meters or one mile. For example, a recent study by Rabinowitz et al. [82] investigated health outcomes by surveying residents living within one kilometer, between one and two kilometers, and more than two kilometers from wells in Washington County, PA, regarding health symptoms they were experiencing. Several of the studies simply report sampling results for contaminants, including distance from the potential (gas infrastructure) source. To capture some of these values that might be experienced at the very closest distances, we also consider a distance of roughly 1,000 feet or less. Finally, for distances of less than 300 feet, we consider at-site exposures that residents with well pads very close to their homes might experience, as well as oil and gas workers working on a well pad.

One of the most commonly discussed risk pathways is groundwater contamination via casing and cementing failures [50], allowing methane and/or frac fluid and flowback to enter the groundwater aquifers overlaying the shale. According to a recent analysis of Pennsylvania Department of Environmental Protection violations data, unconventional well casing and cementing failures do occur regularly (in about 2 percent of wells inspected after initial drilling), and appear to occur more often in the northeastern part of the Marcellus (8.5 times higher risk than the rest of the state) [105]. The likelihood of groundwater contamination by methane from these types of failures appears correlated with distance, as Jackson et al. [106] found concentrations of methane in groundwater 6–23 times higher within 1 kilometer of an unconventional gas well than outside that distance. Other pathways include potential for accidents, leaks, or spills of frac fluid or wastewater fluids to infiltrate

into groundwater from the surface. This risk pathway is particularly relevant for Broome (NY), Delaware (NY), Sullivan (NY), and Wayne (PA) Counties, whose population primarily (77–100 percent) uses groundwater for drinking [60].

Krupnick et al. [50] also interviewed experts who identified several risk pathways related to air contaminants emitted from activities in the drilling and production phases of development. Notably, there are air emissions associated with machinery and trucks during drilling and fracking; venting and flaring of methane during completion, production, and transport of gas; and emissions of volatile compounds from frac fluid and waste fluids (especially when stored in open impoundments). Many of these emissions are located near the well pad, but some are much more regionalized (truck traffic) or are associated with particular activities that may occur away from the well pad (e.g., volatile emissions from fluid or wastewater storage). Our analysis primarily considers distance from well pads, but health risks may be equally tied to distance from other activities, such as wastewater storage in impoundments.

Volatile air pollutants are of special concern in much of the health literature, and the first step in quantifying their risk is detecting their presence. Colborn et al. [107] detected dozens of VOCs, polycyclic aromatic hydrocarbons (PAHs), and carbonyls within 1.1 kilometers of a well pad, and noted health impacts, including endocrine disruption associated with exposures to many of the chemicals. A study completed for Forth Worth, Texas [108] detected many of the same chemicals at a slightly greater distance. Presence of these chemicals does not equate to health risk if concentrations are very low.

Studies by Macey et al. [109] and McKenzie et al. [7] computed health risks associated with exposure to the air pollutants (especially benzene, formaldehyde, and hydrogen sulfide) at a few distances from the gas development activities. They found potential for slight increases in cancer risk, and toxicity risk based on computing hazard indices for the measured concentrations of pollutants for chronic and subchronic exposures. More recently, some studies have been seeking evidence these exposures might lead to adverse health outcomes. A study by Rabinowitz et al. [110] indicated that there may be a relationship between dermal and upper respiratory symptoms (reported in health surveys) and distance from well pads. In addition, a study by Jemielita et al. [111] found that hospitalization rates in several Pennsylvania counties correlated with a number of active unconventional gas wells per square kilometer in patients' zip codes, especially for cardiology- and neurology-related hospital admissions.

Table 12. Health risk factors and impacts cited in literature, versus distance from gas development activities. Abbreviation and symbol definitions, as well as color-coding, appear below the table.

Environmental Health Risk	At-site <300 ft	<1000 ft	~0.5mi/1km	~1mi/2km	2 km or more	Studies
VOCs detected			14 (39/68)[a]		8 (45/59)[b]	[107], [108]
Benzene	A I C C4	C5	C5	C6		[109], [7]
Carbonyls detected			4 (8/12)[a]		8 (9/11)[b]	[107], [108]
Formaldehyde	A I C C5					[109]
PAHs detected			3 (12/16)[a]			[107]
Hydrogen Sulfide	A I	I				[109]
Cumulative excess cancer risk – air			5-6 per million	5-10 per million		[7]
Total Hazard Index – air, subchronic			0.4 - 5	0.1 – 0.2		[7]
Total Hazard Index – air, chronic			0.3 - 1	0.2 - 0.4		[7]
# health symptoms reported			3.27	2.56	1.60	[110]
Dermal symptoms (OR)			4.13	2.44 NS	Ref.	[110]
Upper respiratory symptoms (OR)			3.10	1.76 NS	Ref.	[110]
Silica exposure (% samples > PEL/REL)	47%/ 79%					[112]
Noise levels (dB)	*Max 102*	63 *(Max:95)*	54 *(Max:80)*	52 *(Max:74)*		[113]
Methane conc. in GW (times ref. values)		>6	6	Ref.	Ref.	[106]

VOC- Volatile Organic Compound; PAH – Polycyclic Aromatic Hydrocarbon; IRIS – Integrated Risk Information System; ATSDR – Agency for Toxic Substances and Disease Registry; MRL – Minimum Risk Level; GW - Groundwater; PEL – Permissible Exposure Limit; REL – Recommended Exposure Limit; OR – Odds Ratio; NS – Not statistically significant

[a] Chemicals detected in >50% of samples (# chemical detected/ # tested) [107]
[b] Chemicals detected in >90% of samples (# chemical detected/ # tested) [108]

Concentration exceeds ATDR MRL A Acute level I Intermediate Level C Chronic level

Excess IRIS cancer risk at C4 1/10,000 C5 1/100,000 C6 1/1,000,000 level

Odds ratio (increased likelihood relative to a reference ["Ref."] population) # Value times Ref. value #

Chemicals detected (air)	Health risks (air)	Health outcomes (symptoms)	Exposures To Noise & Dust	Ground-water risks	No or insufficient data	Moderate health risk	Lesser health risk	No significant health risk indicated

Occupational exposures are another category of exposure worth mentioning. Gas industry workers are likely to have higher exposures to volatile chemicals, due to their proximity to emissions sources. Additional health risks for workers and

residents living close to well pads could result from worksite accidents; exposure to airborne silicates (dust) from the mixing of frac sand [112]; and elevated noise levels, which have been found to exceed 100 decibels (dB) at well pad sites during hydraulic fracturing and that persist at lower levels (roughly 60-80 dB) for 60 days or more [88, 113-114]. The noise levels decrease as distance from well increases.

Methodology

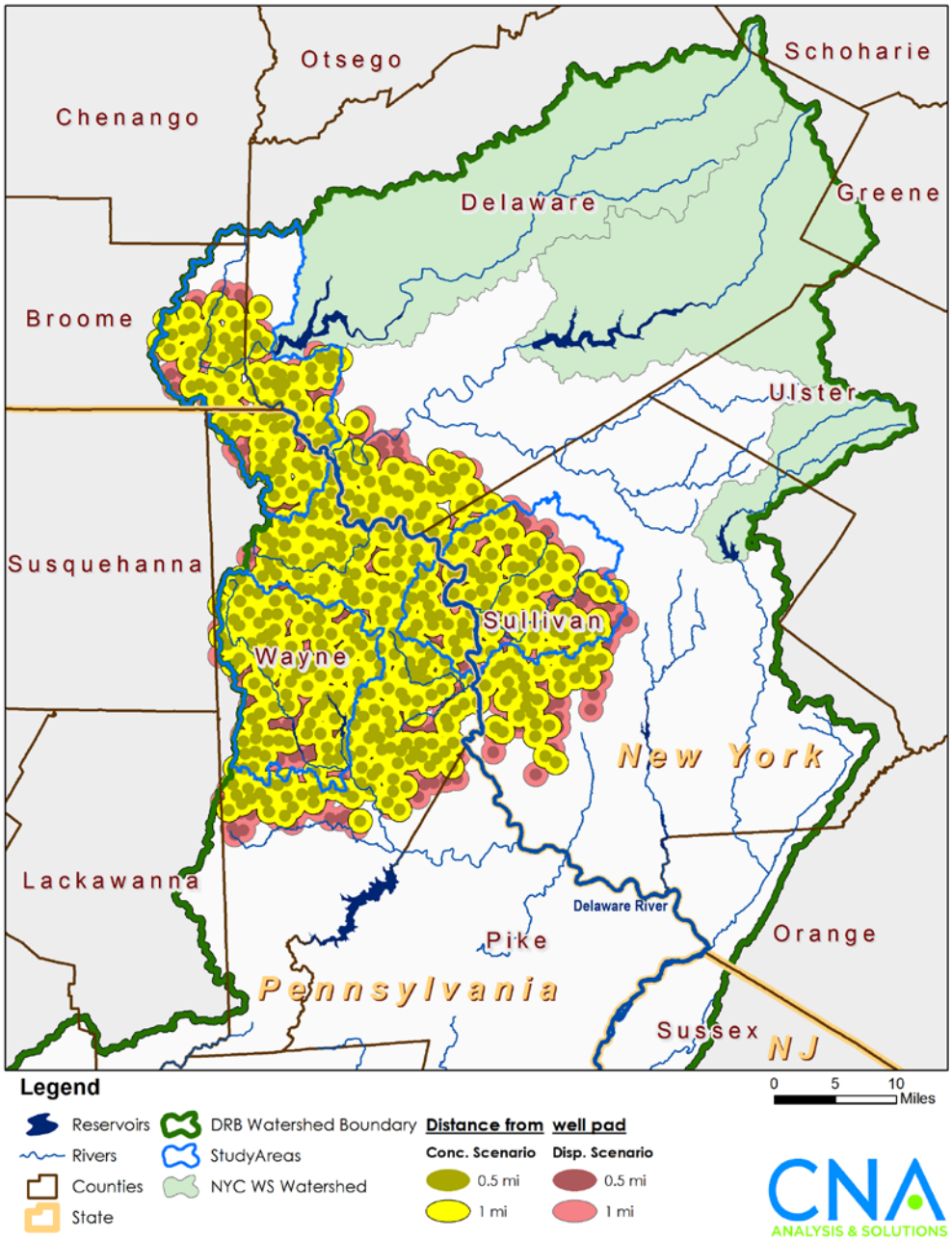
Until more rigorous data on health outcomes, exposure pathways, risk of exposure, and expected dosages become available, it is difficult to perform a detailed assessment of health impact, especially in a prospective analysis. Furthermore, actual risks of exposure depend strongly on both industry practices and regulations. Instead, this study identifies the potential population at risk based on distance to well pad locations identified in this study.

This study uses a buffer-analysis method to determine the approximate number of people and houses within several distances of the well pad commonly cited in the health literature. Using projected DRB well pad locations, we generated circular buffer polygons of 1,000 and 2,000 feet; 0.5 and 1 mile; and 1,000 and 2,000 meters in GIS software.

Figure 19 shows a map of the 0.5-mile and 1-mile buffers around well pads superimposed on county and study area boundaries. The yellow buffers are for the "concentrated" scenario. The red buffers show the additional area affected in the "dispersed" scenario (all of the yellow areas are also included). Similar buffers were created for 1,000 and 2,000 feet, and 1,000 and 2,000 meters.

Using the U.S. Census Bureau's Census Block data (the finest resolution available) and the associated 2010 Census housing and population counts, we computed the expected population within each buffer distance. We also intersected the census blocks with the buffer areas to determine overlap, and we determined population and house counts based on an assumption of uniform density within blocks (a reasonable assumption, since the blocks are relatively small). Finally, we performed additional intersections with county and study area boundaries to determine the distribution of potential impacts on populations.

Figure 19. Map of the 0.5-mile and 1-mile buffers around well pads superimposed on county and study area boundaries. Most of the population within the portion of the DRB with projected gas development would be within one mile of a well pad. At smaller distances, a smaller population would be affected. Except on a few fringes of the development area, there is not much difference between the concentrated and dispersed scenarios.



Note: NYC WS Watershed – Watershed area of New York City water supply reservoirs.

Results

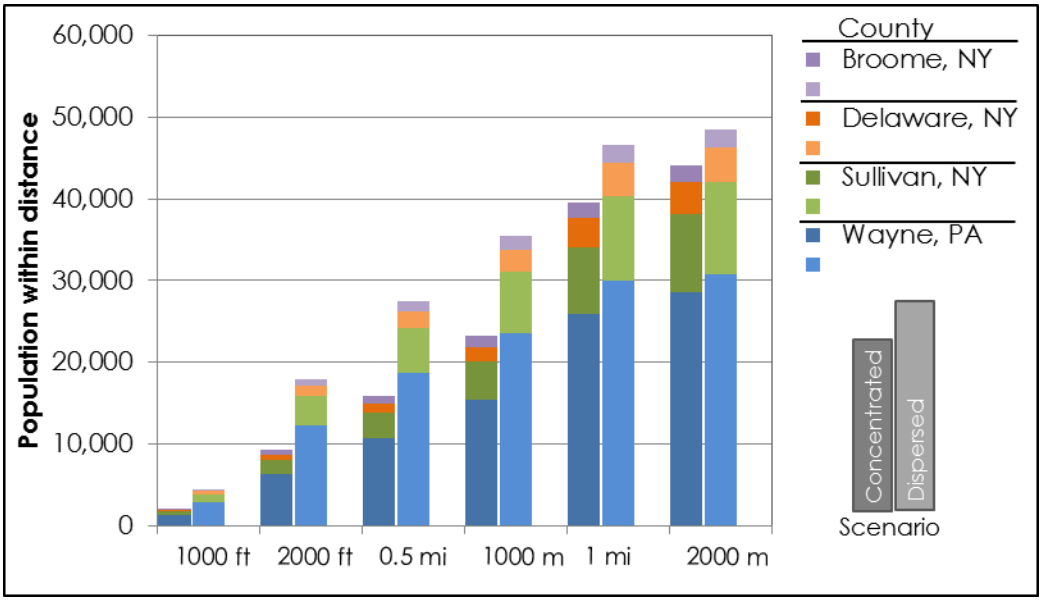
Hydraulic fracturing gas development with multiple wells per pad results in reasonably low overall well pad density, but fairly even distribution across the landscape. This even spacing results in large areas within reasonably short distances of the nearest wells. Figure 19 (previous page) illustrates the extensive portion of the study areas within a mile of the nearest well pad. While the portion of the DRB with well pads has few gaps in between well pads, the areas within a certain radius of well pads are more important to consider in the context of the portions of the study areas and the counties with population in the affected areas. Table 13 shows the area within 0.5 mile and 1 mile of the well pads in square miles, and as a portion of the study areas and most affected counties. The 0.5- and 1-mile distances are representative of the closer and farther distances referenced in the literature (see Table 12). As expected, the "dispersed" scenario results in more total area affected, because there are more well pads developed.

Table 13. Area within 0.5 mile and 1 mile well pad buffer, by county. The "dispersed" scenario affects a larger area, but at 1 mile, the gap between scenarios narrows. Units = square miles, % of county area.

		Within 0.5 mile		Within 1 mile	
County	**Scenario**	Area	%	Area	%
Wayne County, PA	Dispersed	362.1	*48%*	528.1	*70%*
751 sq. mi.	Concentrated	221.6	*30%*	472.3	*63%*
Broome County, NY	Dispersed	37.8	*5%*	68.7	*10%*
715 sq. mi.	Concentrated	24.2	*3%*	56.2	*8%*
Delaware County, NY	Dispersed	80.4	*5%*	134.9	*9%*
1,468 sq. mi.	Concentrated	52.3	*4%*	117.4	*8%*
Sullivan County, NY	Dispersed	130.0	*13%*	223.9	*22%*
997 sq. mi.	Concentrated	72.1	*7%*	177.7	*18%*

Figure 20 indicates the population (estimated by 2010 U.S. Census Block data) within several radii common to health-assessment literature. The population is shown by county and stacked to indicate cumulative population in the DRB. The adjacent bars show the difference between the "concentrated" (left) and "dispersed" (right) scenarios. Notably, at distances less than 1,000 meters, there is a significant difference between the scenarios. At distances of 1 mile or more, there is less difference between scenarios. Overall, 40,000–50,000 people live within about 1 mile (or 2 km) of the projected well pad locations.

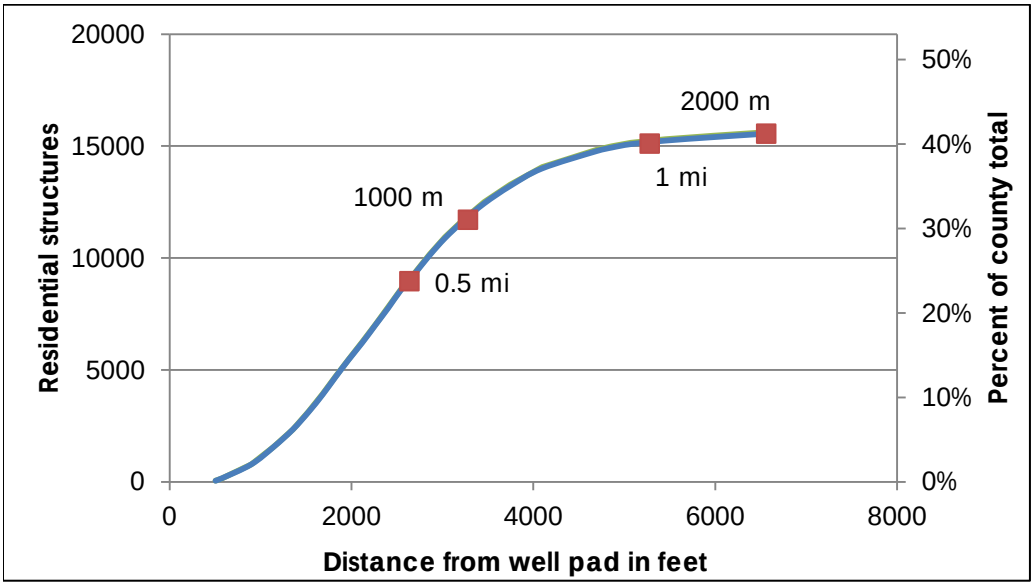
Figure 20. Population within several radii common to health-assessment literature. The population living within several distances (cited in health risk literature) of well pads depends on development scenario. At smaller distances, more people are affected with the "dispersed" scenario. Most of the population that could be affected lives in Wayne County, PA.



The majority of the population potentially affected lives in Wayne County, PA. For this county, we also assessed the portion of residential buildings within these distances using attributed building address points zoned as residential structures. In Figure 21, the horizontal axis shows the distance from well pad (in feet), the left axis shows total residential structures within that distance, and the right axis shows the percentage of the residential structures in Wayne County represented. Note that no structures are within 500 feet of any well pad based on exclusions used in siting the projected well pads. Roughly 40 percent of the residential structures in Wayne County would fall within one mile of a well pad.

These building level results contrast with the affected population results (slightly less than 60 percent of Wayne County's population of 52,000. The discrepancy may be due to more persons per household in the affected area, or some of the residential buildings being unoccupied or functioning as seasonal/vacation residences.

Figure 21. Wayne County residential structures within x distance (ft) of a well pad (total and percent of all county residential structures). Roughly 40 percent of the residential structures in the county would fall within one mile of a projected well pad location.



Discussion

Within the portion of the DRB projected to have gas development in this study, virtually the entire population falls within roughly one mile (or two kilometers) of the potential well pad sites identified. In total, roughly 45,000 people in the basin are within this distance, which can be compared to the population of nearby cities such as Easton (27,000), Wilkes-Barre (41,000), Bethlehem (75,000), and Scranton (76,000).

At smaller buffer distances (e.g., 2,000 feet, 0.5 mile, or 1,000 meters) representing the areas with most likely health impacts, less of the population is affected. At these buffer distances, there is a significant difference in affected population between scenarios. A smaller population is in close proximity to the wells in the "concentrated" scenario (eight wells per pad). However, the likelihood, dosage, and duration of exposure would likely be higher for those living within the smaller buffer distances for the "concentrated" scenario, due to the greater intensity and duration of gas extraction activities needed to develop eight wells per pad.

Chemical exposure may be higher still near other infrastructure not explicitly considered in this study, including wastewater impoundments or storage facilities,

centralized waste-treatment plants, and gas compressors and pumping equipment. The longer-lived nature of these facilities and potential to handle material from multiple well sites may increase potential exposures for populations living near them. There may be some additional exposure to air pollutants, as well, due to regional air transport from active gas development areas in other parts of the Marcellus Shale, especially in Susquehanna, Bradford, and Wyoming Counties in Pennsylvania.

These estimates of population at risk within the DRB may be an underestimate of current and future population. The population estimates are based on the 2010 Census and include neither population change since that time, nor projected population growth through the completion of natural gas development.

It is important to remember that the well pad locations are not explicit predictions, so the exposure risks of specific properties should not be considered based on the results or maps presented. Across the study areas and this portion of the DRB, the calculated populations within the buffer distances give a reasonable first estimate of populations with potential for different levels of exposures should drilling begin.

Finally, this study does not assess the likelihood of occupational or vehicle accidents, spills, or the ability of the existing emergency response and healthcare systems to handle potential surges in demand. These questions are important to preparedness for local governments, but the projected population affected and maps of affected areas do provide a first step in assessing these needs.

Conclusions

This report presents an estimated projection of potential development of natural gas within the Delaware River Basin, concentrating on three study areas. The actual level of development would depend strongly on the actual production of the wells drilled in the DRB and on the price of gas within the energy markets, which can fluctuate rapidly. For the three study areas, we assessed potential environmental and health impacts using the best current understanding and data on well development. The results are intended to help decision-makers and the public understand the scale of the potential consequences.

We project ultimate development of the DRB portion of the Marcellus Shale could be as high as 4,000 wells, with development of up to about 500-1,000 well pads (based on an average of 8 or 4 wells per pad). This development would be most concentrated in Wayne County, PA. These estimates result from geospatial analysis performed with publicly available information on land and geological characteristics and on actual well-development data.

If natural gas development occurs as projected, natural gas infrastructure will become a widespread and prominent feature of the landscape in the Upper DRB. The repercussions of drilling and infrastructure-building activities would cover a broad range of issue areas, including forest fragmentation, water withdrawal and wastewater discharge, hydrologic and water-quality changes, air emissions, and potential health impacts. There may be others that are not included in this report. At a basic level, drilling rigs and truck traffic will have temporary effects near any one well pad, but over a long build-out, they could become common within the basin. The well pads, roads, and pipelines would most likely be long-term (30+ years)—or, in some cases, permanent—features of the landscape. Similarly, management of water, wastewater, and air emissions can create both short- and long-term impacts to the region.

This report specifically investigated potential consequences associated with land cover change, water and wastewater management, surface water hydrology and quality, air emissions, and affected population in three study areas across the DRB, considering significant projected well development. Key findings include the following:

- **Land cover change:** We found each well pad would cause on average 17-23 acres of land disturbance due to construction of well pads, roads, and

pipeline rights-of-way. Pipeline construction would cause about 75 percent of land disturbance. In the most heavily developed areas that would be fracked, 2-3 percent of total area would be affected. The land cover types in each case study replaced by infrastructure include agriculture (43–63 percent) and forests (24–46 percent). By extrapolating results for our study areas, we estimate the total area required to fully develop the projected well pads, roads, and gathering pipelines in the DRB is between 18 and 26 square miles.

- **Forest fragmentation:** Pipelines and roads associated with gas development could have a noticeable effect on forest habitat in the study areas. Despite only clearing about 1 percent of forested area, the core forest area could decline up to 10 percent, while edge forest could increase by up to 8 percent. These changes have the potential to alter ecosystems and the relative abundance of forest species.

- **Water withdrawal:** If current water use and recycling trends hold, roughly 4.5 million gallons of water withdrawal would be needed for each well. These withdrawals would amount to 1.3 million gallons per day if averaged across the entire DRB over 30 years, but might reach 10 or more times higher during a peak year. Withdrawals during peak years could remove up to 70 percent of available flow from small streams during low-flow periods, but a negligible portion of flow if the withdrawal occurs on mainstem rivers during average-flow conditions.

- **Wastewater discharge:** Wastewater management would be an important issue, due to the high pollutant loadings in untreated flowback and brines. The amount of wastewater reuse, and types of treatment and disposal methods used for natural gas wastewaters would have a strong influence on the pollutant loadings that may enter the basin. If there were no wastewater reuse and all wastewater were treated to exactly meet effluent standards, in-stream concentrations of barium and strontium could increase by up to 500 percent from baseline concentrations at low-flow periods. Total dissolved solids, chloride, and sulfates would see smaller increases. Similar to water withdrawals, the magnitude of these consequencess may vary considerably by time and location, but these impacts would occur over a duration of 30 years.

- **Hydrology and surface water quality:** Changes in land cover associated with infrastructure development could lead directly to hydrologic and water-quality changes for the DRB. The initial land clearing could leave the watershed especially vulnerable to increased upland erosion and sedimentation loadings in the short-term (up to 140 percent increase over baseline). Following development, the upland changes in runoff and erosion would persist at lower levels (around 15 percent above baseline). The land

cover changes would also change hydrology by increasing runoff by 1-3 percent during peak flow periods, and reducing groundwater recharge.

- **Air quality:** Industrial processes associated with natural gas development could produce emissions that would degrade the air quality in the DRB. In addition to the contributions from well site–development and well completion, the installation of compressor stations could present significant increases (as much as doubling) in NO_x emissions for three of the four DRB counties. The contributions to VOC, SO_x, and PM emissions from annual shale gas development did not appear as significant compared to other activities in these counties at the county-wide scale (note that this analysis did not look at the potential impacts of these emissions at the local level). Development in the DRB would contribute methane emissions from leakage throughout the process, though small in the context of total emissions from the Marcellus Shale.

- **Affected population:** Due to the relatively even spacing of the projected well pads in the DRB, a large percentage of the population in the affected area would live within one mile of the nearest well, which may present certain health risks, based on current scientific literature. At full development, about 45,000 people in the DRB would live within about one mile of the nearest projected well pad location. Wayne County, PA would be most affected, with 30,000 people (nearly 60 percent of its population) potentially living within one mile of a well pad. At smaller distances of about a half-mile, roughly 15,000 to 25,000 people in the DRB could be affected, depending on the number of wells per pad. Increasing the number of wells per pad from four to eight would reduce the population affected at the closest radii, but may result in longer duration of some exposures due to more wells developed.

Of these findings, change in land cover and associated impacts to forests, hydrology, and water quality appear the most difficult to avoid. The wastewater and air quality risks could pose significant management challenges. The potential health impacts require more study to understand extent and risk levels.

These findings do not cover the full range of potential impacts that may occur if gas development does occur. Instead, the results offer an initial view of the overall level and potential range of impacts. The development projections assume a high degree of development that may never be reached, but the maximum-year development projections for a given year are possible. The scenarios presented focus on identifying conditions when the consequences may be highest and on what the corresponding level of impact would be, averaged across a study area (either county

or watershed).[8] In assessing risk, it is this type of information that is most useful for planning.

[8] Of note, this analysis does not account for the maximum potential impacts to sites that may occur within the study areas as a result of locally high development densities, accidents, or variations in practices by gas drilling operators. If development begins, the range of potential impacts could be expected to vary widely through time and across geography.

Appendix A: Chemicals in Natural Gas Wastewaters

The "Impacts on Water and Wastewater Management" chapter investigates a limited set of five contaminants that have effluent-discharge concentration limits under Pennsylvania regulations[69] for wastewater treatment facilities built after 2010 that treat natural gas wastewater. Analyses that have tested water quality of natural gas wastewaters have documented the presence of many more potential contaminants. In Table 14, we have assembled data from 13 studies on the concentrations of contaminants in flowback and brine wastewaters.

The values for flowback and brine reported reflect the average of median values across studies. The range reflects the low and high values reported in either flowback or brine wastewater samples reported in the studies. There have also been some studies of wastewater treatment plant effluent where effluent discharge concentrations have been measured. We include these values in the final column, but note that these facilities represent older industrial wastewater treatment plants that are not required to meet the 2010 Pennsylvania regulations. For cells left blank, no data were available.

Table 14. Pollutants measured in natural gas wastewaters. For cells left blank, no data were available. Units = milligrams per liter, unless otherwise noted.

	Pollutant	Flowback	Brine	Range	Industrial WW effluent
Primary (regulated)	Total Dissolved Solids (TDS)	73,000	205,600	38,500 – 261,000	123,500
	Chloride (Cl)	54,600	99,600	19,600 – 174,700	84,300
	Barium (Ba)	1,017	8,281	4 – 84,300	20
	Strontium (Sr)	1,187	5,225	350 – 4,800	2,005
	Sulfate (SO_4)	30	55	2.4 - 300	810
Physical and Nutrients	Turbidity	230	207	11 – 3,330	
	pH	6.6	6	4.7 - 7.2	
	Specific Conductance [µmho/cm]	138,000	300,800	6,800 – 710,000	
	Alkalinity	138	70	49 - 327	254
	Acidity			<5 - 470	
	Total Organic Carbon	62.8	984	4 – 19,250	
	Dissolved Organic Carbon	114	43	5 - 700	
	Chemical Oxygen Demand	3100	8,530	195 – 71,000	
	Biochemical Oxygen Demand	100	448	37 - 2070	
	Hardness (as CaCO3)	22,100	34,000	630 – 95,000	
	Ammonia (NH_3 as N)	71	125	29 - 200	68
	Total Kjehldahl Nitrogen	86	116	38 - 200	
	Nitrate (as N)	0.02		0 - 1.2	
	Nitrite (as N)	1.2		0.06 - 29.3	
	Total Phosphorus (as P)	1.3		0 - 8	
Halides (salts)	Bromide (Br)	559	730	108 – 1,200	740
	Fluoride (F)			<0.05 - 50	
	Iodide (I)	6.3		0.2 - 19.3	21
Metals	Sodium (Na)	23,500	37,700	10,700 – 95,500	27,300
	Potassium (K)	49	351	2.4 - 351	
	Calcium (Ca)	7,280	16,900	1,400 – 23,500	13,950
	Magnesium (Mg)	735	1,410	140 – 1,600	941
	Boron (B)	12.2		3.1 - 97.9	
	Chromium (Cr)			0.005 - 151	
	Manganese (Mn)	5	9	1.9 - 18.6	
	Iron (Fe)	45.1	107	13.8 - 242	
	Lead (Pb)	0.01		0 - 0.6	

	Pollutant	Flowback	Brine	Range	Industrial WW Effluent
Hydrocarbons	Oil and Grease	24.2		4.6 - 655	
	Benzene [µg/L]	150			8
	Ethylbenzene [µg/L]	53			5
	Toluene [µg/L]	622			46
	Xylene [µg/L]	699			32
	Styrene [µg/L]	11			
NORM	Naturally Occurring Radioactive Materials [pCi/L]		2460	0 - 18000	

Sources: [39-43, 62-68, 88]

Notes: µg/L = micrograms per liter; pCi/L = picocuries per liter; µmho/cm = micromhos per centimeter

This page intentionally left blank.

Appendix B: Stream Gages

We used the following stream gages operated by the U.S. Geological Survey (USGS) to develop streamflow statistics for the chapter of this report titled "Impacts on Water and Wastewater Management." Table 15 identifies the stream gages we used, including their record length and drainage area. Table 16 presents several flow statistics (especially low-flow statistics) that we used for computing water and wastewater impacts. The flows are presented in units of million gallons per day, per square mile.

Table 15. USGS stream gages used in this study.

Study Area	ID (this study)	Type [a]	USGS ID	Name	Record Length	DA (sq.mi)
1	1.1	Small Stream	01426000	Oquaga Creek at Deposit, NY	1940–1973	67.6
	1.2	Mainstem	01426500	West Branch Delaware River at Hale Eddy, NY	1912 – 2013	595
2	2.1	Small Stream	01428750	West Branch Lackawaxen River near Aldenville, PA	1986–2013	40.6
	2.2	Mainstem	01430000	Lackawaxen River near Honesdale, PA	1948–2013	164
3	3.1	Small Stream	01427500	Callicoon Creek at Callicoon, NY	1940–1982, 2000–2011	110
	3.2	Mainstem	01427510	Delaware River at Callicoon, NY	1975–2013	1820
DRB	4	Mainstem	01434000	Delaware River at Port Jervis, NY	1960–2013	3070

Source: USGS, compiled by CNA.

a. Small stream gages have their drainage area (DA) entirely within the study areas; by contrast, mainstem gages include some additional upstream area (except 01430000).

Table 16. Daily flow statistics for the stream gages used in this study. Units = million gallons per day, per square mile.

ID	Q7-10[a]	5% [b]	20% [c]	Median (JAS)[d]	Median (50%)	Average
1.1	0.017	0.034	0.105	0.147	0.459	1.010
1.2	0.056	0.106	0.228	0.657	0.566	0.950
2.1	0.096	0.132	0.287	0.362	0.732	1.379
2.2	0.053	0.091	0.229	0.279	0.631	1.163
3.1	0.037	0.071	0.176	0.235	0.511	1.039
3.2	0.194	0.259	0.362	0.434	0.558	1.058
4	0.164	0.282	0.366	0.426	0.636	1.061

Source: USGS, calculations by CNA.

a. Lowest seven-day average flow expected to occur once every 10 years

b. Fifth percentile flow. Also referred to as the Q95

c. Twentieth percentile flow, also referred to as the Q80

d. JAS = July, August, September

This page intentionally left blank.

References

[1] US Energy Information Administration. 2015. *Drilling Productivity Report For key tight oil and shale regions.* Accessed Jan 28, 2015. http://www.eia.gov/petroleum/drilling/.

[2] Entrekin, S., M. Evans-White, B. Johnson, and E. Hagenbuch. 2011. "Rapid expansion of natural gas development poses a threat to surface waters." *Frontiers in Ecology & Environment* 9 (9): 503.

[3] Rahm, B. G., and S. J. Riha. 2012. "Toward strategic management of shale gas development: Regional, collective impacts on water resoures." *Enviromental Science & Policy* 17: 12-23.

[4] Olmstead, Sheila M., Lucija A. Muehlenbachs, Jhih-Shyang Shih, Ziyan Chu, and Alan J. Krupnick. 2013. "Shale gas development impacts on surface water quality in Pennsylvania." *Proceedings of the National Academy of Sciences USA* 110 (13): 4962-4967. doi: 10.1073/pnas.1213871110.

[5] Rozell, D.J., and S.J. Reaven. 2012. "Water pollution risk associated with natural gas extraction from the Marcellus Shale." *Risk Analysis* 32: 1382-1393.

[6] Vidic, R. D., S. L. Brantley, J. M. Vandenbossche, D. Yoxtheimer, and J. D. Abad. 2013. "Impact of Shale Gas Development on Regional Water Quality." *Science* 340 (6134). doi: 10.1126/science.1235009.

[7] McKenzie, Lisa M., Roxana Z. Witter, Lee S. Newman, and John L. Adgate. 2012. "Human health risk assessment of air emissions from development of unconventional natural gas resources." *Science of The Total Environment* 424 (0): 79-87. doi: http://dx.doi.org/10.1016/j.scitotenv.2012.02.018.

[8] Hays, J., and S.B.C. Shonkoff. 2015. Toward an understanding of the environmental and public health impacts of shale gas development: an analysis of the peer-reviewed scientific literature, 2009-2014. edited by Scientists Physicians, & Engineers for Healthy Energy.

[9] US Government Accountability Office. 2012. *Information on Shale Resources, Development, and Environmental and Public Health Risks.* GAO-12-732.

[10] US Energy Information Administration. 2014. *Assumptions to the Annual Energy Outlook 2014.*

[11] Phillips, S.J., R.P. Anderson, and R.E. Shapire. 2006. "Maximum entropy modeling of species geographic distributions." *Ecological Modelling* 190: 231-259.

[12] Elith, J., C. H. Graham, R. P. Anderson, M. Dudı´k, S. Ferrier, A. Guisan, R. J. Hijmans, F. Huettmann, J. R. Leathwick, A. Lehmann, J. Li, L.G. Lohmann, B. A. Loiselle, G. Manion, C. Moritz, M. Nakamura, Y. Nakazawa, J. McC. Overton, A. T. Peterson, S. J. Phillips, K. S. Richardson, R. Scachetti-Pereira, R. E. Schapire, J. Sobero´n, S. Williams, M. S. Wisz, and N. E. Zimmermann. 2006. "Novel methods improve prediction of species' distributions from occurrence data." *Ecography* 29: 129-151.

[13] Elith, J., S.J. Phillips, T. Hastie, M. Dudı´k, Y.E. Chee, and C.J. Yates. 2011. "A statistical explanation of MaxEnt for ecologists." *Diversity and Distributions* 17: 43-57.

[14] Johnson, N. 2010. *Pennsylvania Energy Impacts Assessment Report 1: Marcellus Shale Natural Gas and Wind.*

[15] Wrightstone, G. 2009. "Marcellus Shale – Geologic Controls on Production." In *AAPG Annual Convention, Denver, CO, Jun 7-10, 2009.* Accessed Oct 29, 2014. http://www.searchanddiscovery.com/documents/2009/10206wrightstone/.

[16] Research, Penn State Marcellus Center for Outreach and. 2014. "Resources: Maps and Graphics." http://www.marcellus.psu.edu/resources/maps.php.

[17] Rystad Energy. 2014. "NASMaps (North American Shale Maps)." http://www.rystadenergy.com/ResearchProducts/NASAnalysis/nasmaps.

[18] Fry, J., G. Xian, S. Jin, J. Dewitz, C. Homer, L. Yang, C. Barnes, N. Herold, and J. Wickham. 2011. "Completion of the 2006 National Land Cover Database for the Conterminous United States." *Photogrammatic Engineering & Remote Sensing* 77 (9): 858-864. Accessed Oct 28, 2014.http://www.mrlc.gov/nlcd2006.php.

[19] *National Elevation Dataset.* Accessed Sep 25, 2014. http://nationalmap.gov/.

[20] IHS. 2014. "Products and Solutions: Energy Equipment." https://www.ihs.com/industry/energy-equipment.html.

[21] *TIGER/Line Shapefiles.* Accessed Sep 30, 2014. https://www.census.gov/geo/maps-data/data/tiger-line.html.

[22] Shapire, R.E. 2013. "Maxent software for species habitat modeling." http://www.cs.princeton.edu/~schapire/maxent/.

[23] O'Dell, P.M. 2010. *Potential for Development of Natural Gas Exploratory Wells to Adversely Affect Water Resources of the Delaware River Basin.* National Park Service Geologic Resource Department.

[24] Kauffman, Gerald J., and Andrew R. Homsey. 2013. *Economic value of Marcellus Shale gas in the Delaware Basin.* Accessed Jan 29, 2015. http://www.wra.udel.edu/wp-content/uploads/2013/11/Economic-Value-of-Marcellus-Shale-Gas-in-the-Delaware-Basin-Kauffman-and-Homsey-2013.pdf.

[25] Berman, Arthur, and Lyndon Pittinger. 2014. *Resource Assessment of Potentially Producible Natural Gas Volumes From the Marcellus Shale, State of New York.*

[26] Drohan, P., and M. Brittingham. 2012. "Topographic and Soil Constraints to Shale-Gas Development in the Northcentral Appalachians." *Soil Science Society of America Journal* 76 (5): 1696.

[27] Kiviat, E. 2013. "Risks to biodiversity from hydraulic fracturing for natural gas in the Marcellus and Utica shales." *Annals of the New York Academy of Sciences* 1286: 1-14.

[28] Racicot, A., V. Babin-Roussel, J. F. Dauphinais, J. S. Joly, P. Noël, and C. Lavoie. 2014. "A Framework to Predict the Impacts of Shale Gas Infrastructures on the Forest Fragmentation of an Agroforest Region." *Environmental Management* 53 (5): 1023-1033. http://link.springer.com/article/10.1007%2Fs00267-014-0250-x.

[29] Johnson, N., T. Gagnolet, R. Ralls, and J. Stevens. 2011. *Natural Gas Pipelines: Excerpt from Report 2 of the Pennsylvania Energy Impacts Assessment.*

[30] Slonecker, E.T., L.E. Milheim, C.M. Roig-Silva, A.R. Malizia, D.A. Marr, and G.B. Fisher. 2012. *Landscape consequences of natural gas extraction in Bradford and Washington Counties, Pennsylvania, 2004–2010.* USGS Open-File Report 2012-1154.http://pubs.usgs.gov/of/2012/1154/.

[31] Souther, S., M. W. Tingley, V. D. Popescu, D. T. S. Hayman, M. E. Ryan, T. A. Graves, B. Hartl, and K. Terrell. 2014. "Biotic Impacts of energy development from shale: research priorities and knowledge gaps." *Frontiers in Ecology and the Environment* 12 (6): 330-338.

[32] Alberti, M., D. Booth, K. Hill, B. Coburn, C. Avolio, S. Coe, and D. Spirandelli. 2007. "The impact of urban patterns on aquatic ecosystems: An empirical analysis in Puget lowland sub-basins." *Landscape and Urban Planning* 80: 345-361.

[33] Carlisle, D.M., J. Falcone, and M.R. Meador. 2009. "Predicting the biological condition of streams: Use of geospatial indicators of natural and anthropogenic characteristics of watersheds." *Environmental Monitoring and Assessment* 151: 143-160.

[34] Environmental Systems Research Institute (ESRI) Utility Team. 2011. *Pipeline Route Optimization Interface: Documentation v1.0.* Accessed Sep 4, 2014. http://www.arcgis.com/home/item.html?id=9bdbafe0b52b44c5add6f82ef08cc13f.

[35] Menon, E.S. 2011. *Pipeline Planning and Construction Field Manual.* New York: Elsevier.

[36] Potter, E., and W. Dorshow. 2013. "Optimizing Pipeline Routing in the 21st Century." In *2013 GeoGathering Conference, Colorado Springs, CO, Aug.21-22, 2013.*

[37] Ferri, N. 2011. "Pipeline Route Optimization for the Eagle Ford Shale Play." In *2011 ESRI Petroluem Users Group Conference, April 18-21, 2011.* http://proceedings.esri.com/library/userconf/pug11/papers/pipeline_route_optimization_for_the_eagle_ford_shale_play.pdf.

[38] EPA. 2012. *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources.* U.S. Environmental Protection Agency. EPA/601/R-12/011.http://www2.epa.gov/sites/production/files/documents/hf-report20121214.pdf#page=209.

[39] Hammer, R., Jeanne VanBriesen, and L. Levine. 2012. *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewater.* Natural Resources Defense Council. 12-05-A.

[40] Ferrar, K. J., D. R. Michanowicz, C. L. Christen, N. Mulcahy, S. L. Malone, and R. K. Sharma. 2013. "Assessment of Effluent Contaminants from Three Facilities Discharging Marcellus Shale Wastewater to Surface Waters in Pennsylvania." *Environmental Science & Technology* 47 (7): 3472. http://pubs.acs.org/doi/abs/10.1021/es301411q.

[41] Stroud Water Research Center. 2013. *Ecotoxicity study for mayflies exposed to ambient stream water from the upper Delaware River Basin, reference toxicant, and to produced-water from natural gas drilling.* Stroud Water Research Center. 2013003.Delaware River Basin Commission. http://www.state.nj.us/drbc/library/documents/naturalgas/StroudStudyFinal082113.pdf.

[42] Warner, N. R., C. A. Christie, R. B. Jackson, and A. Vengosh. 2013. "Impacts of Shale Gas Wastewater Disposal on Water Quality in Western Pennsylvania." *Environ. Sci. Technol.* 47 (20): 11849. doi: 10.1021/es402165b. http://pubs.acs.org/doi/abs/10.1021/es402165b.

[43] Harkness, J., G.S. Dwyer, N. Warner, K.M. Parker, W.A. Mitch, and A. Vengosh. 2015. "Iodide, Bromide, and Ammonium in Hydraulic Fracturing and Oil and Gas Wastewaters: Environmental Implications." *Environmental Science & Technology.* doi: 10.1021/es504654n. http://pubs.acs.org/doi/abs/10.1021/es504654n.

[44] Parker, K.M., T. Zeng, J. Harkness, A. Vengosh, and W.A. Mitch. 2014. "Enhanced Formation of Disinfection Byproducts in Shale Gas Wastewater-Impacted Drinking Water Supplies." *Environmental Science & Technology* 48 (19): 11161-11169. doi: 10.1021/es5028184. http://pubs.acs.org/doi/abs/10.1021/es5028184.

[45] EPA. 2013. "Basic Information about Disinfection Byproducts in Drinking Water: Total Trihalomethanes, Haloacetic Acids, Bromate, and Chlorite." EPA Office of Water. Dec 13, 2013. http://water.epa.gov/drink/contaminants/basicinformation/disinfectionbyproducts.cfm.

[46] DRBC. 2008. *Administrative Manual Part III. Water Quality Regulations.* Delaware River Basin Commission. 18 CFR Part 140.

[47] DRBC. 2008. *Delaware River State of the Basin Report.* Delaware River Basin Commission.

[48] Baker Hughes, Inc. 2014. "Interactive Rig Counts." Baker Hughes. Accessed Nov 7, 2014. http://gis.bakerhughesdirect.com/RigCounts/default2.aspx.

[49] Krupnick, A. J. 2013. *Managing the Risks of Shale Gas: Key Findings and Further Research.* Resources for the Future.

[50] Krupnick, A. J., H. Gordon, and S. M. Olmstead. 2013. *Pathways to Dialogue: What the Experts Say about the Environmental Risks of Shale Gas Development.* Resources for the Future. www.rff.org/shaleexpertsurvey.

[51] SkyTruth, FracFocus via. 2013. *FracFocus Chemical Disclosure Registry - 2013 Reports Data.* Unclassified. Digital Dataset. Accessed 10/01/2014. https://s3.amazonaws.com/skytruth_public/2013_FracFocusReport.txt.zip.

[52] Mantell, M.E. 2011. "Produced water reuse and recycling challenges and opportunities across major shale plays." Unclassified. EPA hydraulic fracturing study technical workshop #4 - water resources management, March 29, 2011. Accessed November 27, 2014. http://www2.epa.gov/sites/production/files/documents/09_Mantell_-_Reuse_508.pdf.

[53] Jiang, Mohan, Chris T. Hendrickson, and Jeanne M. VanBriesen. 2014. "Life Cycle Water Consumption and Wastewater Generation Impacts of a Marcellus Shale Gas Well." *Environmental Science & Technology* 48: 1911-1920. doi: 10.1021/es4047654.

[54] Maloney, K. O., and D. A. Yoxtheimer. 2012. "Production and Disposal of Waste Materials from Gas and Oil Extraction from the Marcellus Shale Play in Pennsylvania." *Environmental Pracices.* 14 (04): 278-287.

[55] Wilson, J.M., and Jeanne VanBriesen. 2012. "Oil and Gas Produced Water Management and Surface Drinking Water Sources in Pennsylvania." *Environmental Practices* 14: 288-300.

[56] Survey, United States Geological. 2015. Daily Surface Water observations. *USGS Surface-Water Daily Data for Pennsylvania.* Digital download. http://waterdata.usgs.gov/pa/nwis/dv?

[57] Survey, United States Geological. 2015. Daily surface water observations. *USGS Surface-Water Daily Data for New York.* Digital download. http://waterdata.usgs.gov/ny/nwis/dv?

[58] Dephilip, M., and T. Moberg. 2013. *Ecosystem Flow Recommendations for the Delaware River Basin.* The Nature Conservancy. http://www.state.nj.us/drbc/library/documents/TNC_DRBFlowRpt_dec2013.pdf.

[59] Poff, N. L., and J.K.H. Zimmerman. 2010. "Ecological responses to altered flow regimes: a literature review to inform the science and management of environmental flows." *Freshwater Biology* 55: 194-205. doi: 10.1111/j.1365-2427.2009.02272.x. http://www.oregon.gov/owrd/docs/SB839/2010_Poff_Ecological_Responses_Altered_Flow_Regimes_Literature_Review.pdf.

[60] Maupin, M.A., J.F. Kenny, S.S. Hutson, J.K. Lovelace, N.L. Barber, and K.S. Linsey. 2014. *Estimated use of water in the United States in 2010.* U.S. Geological Survey. USGS Circular 1405. Accessed 1 Dec 2014. doi: 10.3133/cir1405.

[61] DRBC, USACE &. 2008. *Enhancing Multi-jurisdictional Use and Management of Water Resources for the Delaware River Basin, NY, NJ, PA, and DE.* US Army Corps of Engineers and Delaware River Basin Commission. Dec 2008.http://www.nap.usace.army.mil/Portals/39/docs/Civil/DelComp/Enhancing_Multi-Jurisdictional_Use_and_Management_of%20Water_Resources_for_the_Delaware_River_Basin.pdf.

[62] Haluszczak, Lara O., Arthur W. Rose, and Lee R. Kump. 2013. "Geochemical evaluation of flowback brine from Marcellus gas wells in Pennsylvania, USA." *Applied Geochemistry* 28 (0): 55-61. doi: 10.1016/j.apgeochem.2012.10.002. http://www.sciencedirect.com/science/article/pii/S0883292712002752.

[63] Gregory, Kelvin B., Radisav D. Vidic, and David A. Dzombak. 2011. "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing." *Elements* 7 (3): 181-186. doi: 10.2113/gselements.7.3.181.

[64] Dresel, P., and A. Rose. 2010. *Chemistry and Origin of Oil and Gas Well Brines in Western Pennsylvania.* Pennsylvania Geological Survey, Pennsylvania Department of Conservation and Natural Resources.

[65] Duraisamy, R.T., A. Heydari Beni, and A. Henni. 2013. "State of the Art Treatment of Produced Water." *Water Treatment*. Edited by W. Elshorbagy, and R.Z. Choudhury. 199-222. Online.: InTech, doi: 10.5772/53478. InTech.

[66] Hayes, T. 2009. *Sampling and Analysis of Water Streams Associated with the Development of Marcellus Shale Gas.* Marcellus Shale Coalitition.

[67] Hayes, T., and B.F. Severin. 2012. *Barnett and Appalachian Shale Water Management and Reuse Technologies.* Research Partnership to Secure America. 08122-05. http://www.barnettshalewater.org/documents/RPSEAReport_Final_082112.pdf.

[68] Olmstead, S. M. 2013. "Wastewater Characteristics from Marcellus Shale Gas Development in Pennsylvania." Resources for the Future: Managing the Risks of Shale Gas Development, Washington, D.C., Jun 27, 2013. Resources for the Future.

[69] Commonwealth of Pennsylvania. 2010. *95.10 Treatment requirements for new and expanding mass loadings of Total Dissolved Solids (TDS).* Aug 20, 2010. PA Code 025 § 95.10. http://www.pacode.com/secure/data/025/chapter95/chap95toc.html.

[70] New York State Department of Environmental Protection. 2015. *FINAL SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM.* New York State Department of Environmental Protection.

[71] Jiang, Mohan, W. Michael Griffin, Chris Hendrickson, Paulina Jaramillo, Jeanne VanBriesen, and Aranya Venkatesh. 2011. "Life cycle greenhouse gas emissions of Marcellus shale gas." *Environmental Research Letters* 6 (3): 034014. doi: 10.1088/1748-9326/6/3/034014.

[72] Lampe, D.J., and J.F. Stolz. 2015. "Current perspectives on unconventional shale gas extraction in the Appalachian Basin." *Journal of Environmental Science and Health, Part A: Toxic/Hazardous Substances and Environmental Engineering* 50 (5): 434-446. doi: 10.1080/10934529.2015.992653.

[73] Hladik, M.L., M.J. Focazio, and M. Engle. 2014. "Discharges of produced waters from oil and gas extraction via wastewater treatment plants are sources of disinfection by-products to receiving streams." *Science of the Total Environment* 466-467: 1085-1093. doi: 10.1016/j.scitotenv.2013.08.008.

[74] Brown, V.J. 2014. "Radionuclides in Fracking Wastewater: Managing a Toxic Blend." *Environmental Health Perspectives* 122 (2): A51-A55. doi: 10.1289/ehp.122-A50

[75] Kargbo, D. M., R. G. Wilhelm, and D. J. Campbell. 2010. "Natural Gas Plays in the Marcellus Shale: Challenges and Potential Opportunities." *Environmental Science & Technology* 44 (15): 5679. http://pubs.acs.org/doi/pdfplus/10.1021/es903811p.

[76] Pennsylvania Department of Environmental Protection. March 16, 2015. Database. *Violations, Oil and Gas Compliance.* Unclassified. Online. http://stateimpact.npr.org/pennsylvania/drilling/violations/.

[77] McBroom, M., T. Thomas, and Y. Zhang. 2012. "Soil Erosion and Surface Water Quality Impacts of Natural Gas Development in East Texas, USA." *Water* 4 (4): 944-958. doi: 10.3390/w4040944.

[78] MapShed version 1.1 - User's Guide. 2014. University Park, PA: The Pennsylvania State University.

[79] Haith, D.A., and L.L. Shoemaker. 1987. "Generalized Watershed Loading Functions for Stream Flow Nutrients." *Water Resources Bulletin* 23 (3): 471-478.

[80] Moore, C.W., B. Zielinska, G. Petron, and R.B. Jackson. 2014. "Air Impacts of Increased Natural Gas Acquisition, Processing, and Use: A Critical Review." *Enviromental Science & Technoogy.* 48 (15): 8349-8359.

[81] US Environmental Protection Agency. 2014. "National Ambient Air Quality Standards (NAAQS)." http://www.epa.gov/air/criteria.html.

[82] Jackson, Robert B., Avner Vengosh, J. William Carey, Richard J. Davies, Thomas H. Darrah, Francis O'Sullivan, and Gabrielle Pétron. 2013. "The Environmental Costs and Benefits of Fracking." *Annual Review of Environment and Resources* 39 (1): 140822120156004. doi: 10.1146/annurev-environ-031113-144051.

[83] Howarth, R.W., R. L. Santoro, and A. R. Ingraffea. 2011. "Methane and the greenhouse-gas footprint of natural gas from shale formations." *Climate Change* 106 (4): 679-690.

[84] Weber, C.L., and C. Clavin. 2012. "Life cycle carbon footprint of shale gas: Review of evidence and implications." *Environmental Science & Technology* 46 (11): 5688-5695.

[85] Intergovermental Panel on Climate Change (IPCC). 2013. *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.*

[86] Alvarez, R.A., S.W. Pacala, J.J. Winebrake, W.L. Chameides, and S.P. Hamburg. 2012. "Greater focus needed on methane leakage from natural gas infrastructure." *Proceedings of the National Academy of Sciences USA* 109 (17): 6435-6440.

[87] Litovitz, A., A. Curtright, S. Abramzon, N. Burger, and C. Samaras. 2013. "Estimation of regional air-quality damages from Marcellus Shale natural gas extraction in Pennsylvania." *Environmental Research Letters.* 8: 014017.

[88] New York Department of Environmental Conservation. 2011. *Revised Draft Supplemental Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program: Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs.* Accessed Jan. 13, 2015. http://www.dec.ny.gov/energy/75370.html.

[89] *National Emissions Inventory (NEI) Database.* http://www.epa.gov/ttn/chief/eiinformation.html.

[90] US Energy Information Administration. 2014. *Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2014.* Accessed Jan 6, 2015. http://www.eia.gov/forecasts/aeo/nems/documentation/ogsm/pdf/m063(2014).pdf.

[91] Brandt, A.R., G.A. Heath, E.A. Kort, F. O'Sullivan, G. Petron, S.M. Jordaan, P. Tans, J. Wilcox, A.M. Gopstein, D. Arent, S. Wofsy, N.J. Brown, R. Bradley, G.D. Stucky, D. Eardley, and R. Harriss. 2014. "Methane Leaks from North American Natural Gas Systems." *Science* 343: 733-735.

[92] Peischl, J., T.B. Ryerson, K.C. Aikin, J.A. de Gouw, J.B. Gilman, J.S. Holloway, B.M. Lerner, R. Nadkarni, J.A. Neuman, J.B. Nowak, M. Trainer, C. Warneke, and D.D. Parrish. 2015. "Quantifying atmospheric methane emissions from the Haynesville, Fayetteville, and northeastern Marcellus shale gas production regions." *Journal of Geophysical Research: Atmospheres* Accepted Articles. doi: 10.1002/2014JD022697.

[93] O'Sullivan, F., and S. Paltsev. 2012. "Shale gas production: potential versus actual greenhouse gas emissions." *Environmental Research Letters* 7: 044030.

[94] Miller, S.M., S.C. Wofsy, A.M. Michalak, E.A. Kort, A.E. Andrews, S.C. Biraud, E.J. Dlugokencky, J. Eluszkiewicz, M.L. Fischer, G. Janssens-Maenhout, B.R. Miller, J.B. Miller, S.A. Montzka, T. Nehrkorn, and C. Sweeney. 2013. "Anthropogenic emissions of methane in the United States." *Proceeding of the National Academy of Sciences USA* 110 (50): 20018-20022.

[95] Petron, G. 2012. "Hydrocarbon emissions characterization in teh Colorado Front Range: A pilot study." *Journal of Geophysical Research* 117: 27.

[96] Karion, A. 2013. "Methane emissions estimate from airborne measurements over a western United States natural gas field." *Geophysical Research Letters* 40: 1-5.

[97] Schneising, O. 2014. "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations." *Earth's Future* 2: 548-558.

[98] Caulton, D.R. 2014. "Toward a better understanding and quanitification of methan emissions from shale gas development." *Proceeding of the National Academy of Sciences USA* 111 (17): 6237-6242.

[99] Peischl, J. 2013. "Quantifying sources of methane using light alkanes in the Los Angeles basin, California." *Journal of Geophysical Research: Atmospheres* 118: 4974-4990.

[100] EPA. 2008. *Average Annual Emissions and Fuel Consumption for Gasoline-Fueled Passenger Cars and Light Trucks.* EPA420-F-08-024.http://www.epa.gov/otaq/consumer/420f08024.pdf.

[101] EIA. "Frequently Asked Questions: How much coal, natural gas, or petroleum is used to generate a kilowatthour of electricity?" http://www.eia.gov/tools/faqs/faq.cfm?id=667&t=2.

[102] EIA. 2012. Data Table. *Table T5.A - Residential average monthly bill by Census Division, and State.* Electronic Download. U.S. Energy Information Administration.http://www.eia.gov/electricity/sales_revenue_price/.

[103] Werner, A. K., S. Vink, K. Watt, and P. Jagals. 2015. "Environmental health impacts of unconventional natural gas development: A review of the current strength of evidence." *Science of the Total Environment* 505C: 1127-1141. doi: 10.1016/j.scitotenv.2014.10.084. http://www.ncbi.nlm.nih.gov/pubmed/25461113.

[104] EPA. 1992. *Guidelines for Exposure Assessment.* Unclassified. US Environmental Protection Agency. EPA/600/Z-92/001. Accessed 8 Dec 2014. http://www.epa.gov/raf/publications/pdfs/GUIDELINES_EXPOSURE_ASSESSMENT.PDF.

[105] Ingraffea, A. R., M. T. Wells, R. L. Santoro, and S. B. Shonkoff. 2014. "Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000-2012." *Proceeding of the National Academy of Sciences USA* 4121786 111 (30): 10955-60. doi: 10.1073/pnas.1323422111. http://www.ncbi.nlm.nih.gov/pubmed/24982144.

[106] Jackson, Robert B., Avner Vengosh, Thomas H. Darrah, Nathaniel R. Warner, Adrian Down, Robert J. Poreda, Stephen G. Osborn, Kaiguang Zhao, and Jonathan D. Karr. 2013. "Increased stray gas abundance in a subset of drinking water wells near Marcellus shale gas extraction." *Proceedings of the National Academy of Sciences USA* 110 (28): 11250-11255. doi: 10.1073/pnas.1221635110.

[107] Colborn, Theo, Kim Schultz, Lucille Herrick, and Carol Kwiatkowski. 2012. "An Exploratory Study of Air Quality Near Natural Gas Operations." *Human and Ecological Risk Assessment: An International Journal* 20 (1): 86-105. Accessed 2014/09/15. doi: 10.1080/10807039.2012.749447.

[108] Eastern Research Group, and Sage Environmental Consulting. 2011. *City of Fort Worth Natural Gas Air Quality Study.* City of Fort Worth, TX.

[109] Macey, G.P., R. Breech, M. Chernaik, C. Cox, D. Larson, D. Thomas, and D.O. Carpenter. 2014. "Air concentrations of volatile compounds near oil and gas production: a community-based exploratory study." *Environmental Health* 13 (82): 1-18.

[110] Rabinowitz, P. M., I. B. Slizovskiy, V. Lamers, S. J. Trufan, T. R. Holford, J. D. Dziura, P. N. Peduzzi, M. J. Kane, J. S. Reif, T. R. Weiss, and M. H. Stowe. 2014. "Proximity to Natural Gas Wells and Reported Health Status: Results of a Household Survey in Washington County, Pennsylvania." *Environmental Health*

Perspectives. doi:10.1289/ehp.1307732. http://www.ncbi.nlm.nih.gov/pubmed/25204871.

[111] Jemielita, T., G.L. Gerton, M. Neidell, S. Chillrud, B. Yan, M. Stute, M. Howarth, P. Saberi, N. Fausti, T.M. Penning, J. Roy, K.J. Propert, and R.A. Panettieri Jr. 2015. "Unconventional Gas and Oil Drilling Is Associated with Increased Hospital Utilization Rates." *PLoS One* 10 (7). doi: 10.1371/journal.pone.0131093. http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0131093.

[112] NIOSH. 2014. "Hazard Alert- Worker Exposure to Silica during Hydraulic Fracturing." Occupational Safety and Health Administration. Oct 21 2014. https://www.osha.gov/dts/hazardalerts/hydraulic_frac_hazard_alert.html.

[113] Milton, D., S. Wilson, C. Jiang, L. Dalemarre, A. Sapkota, T. Sangaramoorthy, and M. Boyle. 2014. *Potential Public Health Impact of Natural Gas Development and Productin in the Marcellus Shale in Western Maryland.* Maryland Institute for Applied Health, School of Public Health, University of Maryland - College Park.

[114] McCawley, M. 2013. *Air, Noise, and Light Monitoring Results For Assessing Environmental Impacts of Horizontal Gas Well Drilling Operations.* West Virginia Department of Environmental Protection Division of Air Quality.

CNA

This report was written by CNA's Energy, Water, and Climate (EWC) division.

EWC division provides integrated analysis of these issues to gain a better understanding of the implications of their interrelationships and to help develop sound policies and programs to improve energy security, foster efficiency, and increase the likelihood of a secure, climate-friendly energy future.

CNA is a not-for-profit research organization
that serves the public interest by providing
in-depth analysis and result-oriented solutions
to help government leaders choose
the best course of action
in setting policy and managing operations.

Nobody gets closer—
to the people, to the data, to the problem.

www.cna.org • 703-824-2000

3003 Washington Boulevard, Arlington, VA 22201