May 1, 2017

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington D.C. 20426

RE: <u>Comment Letter - Environmental Assessment – Millennium Eastern System Upgrade Project (Docket No. CP16-486).</u>

Dear Secretary Bose:

The Delaware Riverkeeper Network ("DRN") submits the following comment on the issuance of the Environmental Assessment ("Assessment") by the Federal Energy Regulatory Commission ("Commission" or "FERC") with respect to the Millennium Pipeline Company, LLC's ("Millennium") Eastern System Upgrade Project (the "Project"). Millennium is requesting to construct and operate the Project in order to provide 223,000 dekatherms per day (dt/day) of natural gas from Millennium's existing Corning Compressor Station to an interconnect with Algonquin Gas Transmission, LLC ("Algonquin") in Ramapo, New York.

Millennium proposes that in order to transport this volume of natural gas it must Construct approximately 7.8 miles of 30- and 36-inch-diameter pipeline loop ("Huguenot Loop") in Orange County, New York, a new compressor station in

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Sullivan County, New York, additional compression at the Hancock Compressor Station in Delaware County, New York, modifications at the Westtown Meter Station and Wagoner Interconnect in Orange County, New York, modifications at the Ramapo Meter Station in Rockland County, New York, and other appurtenant facilities.

For the reasons explained below, the environmental review fails to meet the requirements of the National Environmental Policy Act ("NEPA"), 42 U.S.C. § 4321 *et seq*. (2006), and its implementing regulations, 40 C.F.R. Pts. 1500-08. The Assessment cannot serve as the basis for an adequate hard look at the Project's environmental impacts or support a finding of no significant impact ("FONSI"). Based on this flawed environmental review, the Commission cannot determine that the public benefits of the proposed Project outweigh its adverse impacts, thus violating the Natural Gas Act ("NGA"), 15 U.S.C. §§ 717f (2006) and its implementing regulations, 18 C.F.R. Part 157 (2011). Additionally, DRN requests that the Commission require Millennium submit additional information related to the interconnected nature of this project with several other of Millennium's concurrent Commission-jurisdictional projects.

I. <u>The Eastern System Upgrade Project Overbuilds Capacity in Conflict with the Commission's Policy Statement</u>

The Project is unsupported by market need because there is significant evidence that Millennium designed the Project to add capacity to its natural gas infrastructure beyond the amount disclosed in its application; in essence, the

Project is "overbuilt" because it is designed to provide excess capacity. The Commission's Policy Statement regarding the Certification of Natural Gas Pipeline Projects states that to "[o]verbuild" an energy project means to "build capacity for which there is not a demonstrated market need." 90 FERC ¶ 61,128, at 61,391 (Feb. 9, 2000).

With the exception of the existing Neversink 24-inch segment, which is restricted to an MAOP of 920 psig, the Millennium Pipeline gas transmission mainline was installed and designed to operate as a 30-inch pipeline with a MAOP of 1,200 psig. An expert report[1] generated by Accufacts Inc., examined the Exhibit G flow diagrams included in the application materials for the proposed Project and concluded that "the 36-inch diameter pipeline is larger than needed, even if it were to be installed at a MAOP of 1,200 psig."[2] *See Exhibit A*. Specifically, the report states:

> [O]n Exhibit 4 for the same flow rate, the approximate pressure line between the Hancock CS and Highland CS is less vertical than the pressure line between Highland CS and Huguenot Regulator. The pressure line slope between Highland CS and Huguenot Regulator should be the same or even less vertical because gas flow rate in that segment is the same or less than that for the Hancock CS to Highland CS segment, while the pressures are similar. This deviation in

[1] It should be noted that the report shows that the Exhibit G flow diagrams are riddled with fundamental errors and required Accufacts to make several assumptions when generating its report. These errors alone require additional information and reconciliation by the Project applicant in order for the Commission to appropriately review the Project.

[2] *Observations Concerning the Millennium Eastern System Upgrade Project Proposal,* Accufacts, Inc., March 26, 2017 and Addendum, April 20, 2017

> pressure slope or verticalness, because it can significantly affect the analysis, needs to be properly investigated and reconciled. **A simple comparison analysis of the Exhibits will further demonstrate that a 30-inch pipeline for the Huguenot Loop would be suitable.** Millennium has not adequately justified their proposing a 36-inch diameter pipeline for the Huguenot Loop. Installing a 36-inch pipe segment **that is larger than is needed on this primarily 30-inch Millennium Pipeline system, given the current and proposed MAOPs, signals further expansions are anticipated for this Project**.[3] (emphasis added)[4]

Therefore, absent additional information it appears that based on the record before the Commission that Millennium has proposed a project that is designed to accommodate future upgrade projects and overbuilds the pipeline for its stated needs. As described in the expert report, based on the throughput demand established in the flow diagrams, Millennium could construct a pipeline project that impacts the same, or smaller, footprint using a 30-inch pipeline for the looping rather than a 36-inch pipeline. Had Millennium wanted this project to function seamlessly with it existing 30-inch system, it would have designed the loops at that same pipe diameter and MAOP. The fact that Millennium designed a much larger pipeline loop than necessary, at a much higher MAOP that does not match its existing system indicates that Millennium clearly overbuilt its Project, in order to support anticipated and planned future upgrades.

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[3] The exhibits referenced in the report that support its conclusions contain hydraulic modeling based on CEII data provided by Millennium. These exhibits have been submitted separately to the Commission as privileged.

[3] *Observations Concerning the Millennium Eastern System Upgrade Project Proposal,* Accufacts, Inc., March 26, 2017 and Addendum, April 20, 2017

II. <u>The Commission Failed To Evaluate The Impacts Of The Project In Accordance With Its NEPA Obligations.</u>

NEPA requires an Environmental Impact Statement for proposed "major Federal actions significantly affecting the quality of the human environment." 42 U.S.C. § 4332(2)(C)(i). When scoping the range of actions to include in an Environmental Impact Statement, agencies must consider whether proposed actions are connected, cumulative, or similar. 40 C.F.R. § 1508.25(a)(1)-(3). An agency may avoid preparation of an Environmental Impact Statement by preparing an Environmental Assessment supporting a finding of no significant impact, or by determining the proposed action is not a major Federal action significantly affecting the environment. 40 C.F.R. §§ 1501.4(e)(1), 1508.9.

NEPA requires federal agencies to take environmental considerations into account "to the fullest extent possible." 42 U.S.C. § 4332; 40 C.F.R. § 1500.2; *Bentsen*, 94 F.3d at 684. NEPA ensures that a federal agency, "in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts" and "guarantee[s] that the relevant information [on impacts] will be made available to the larger audience." *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989); 40 C.F.R. § 1500.1(b).

a. The Commission Has Unlawfully Segmented Its Review Of Millennium's Interconnected And Interdependent Pipeline Upgrade Projects Pursuant to 40 C.F.R. § 1508.25(a).

The Commission violated NEPA by segmenting review of Millennium's pipeline system upgrade into at least two separate projects, which includes the proposed Project and the CPV Valley Lateral Project (Commission Docket No. CP16-17). These projects appear to be part of a unified whole with functional interdependence, common timing, and geographic proximity. In short, Millennium's upgrades to its pipeline system is one project divided into segments, ostensibly justified by separate shipping contracts, that have significant adverse environmental impacts and should have been evaluated in a programmatic NEPA document. Indeed, the Valley Later Project begins at precisely the physical location where the Project ends.

An agency should prepare a single programmatic EIS for actions that are "connected," "cumulative," or "similar," such that their environmental effects are best considered in a single impact statement. *Am. Bird Conservancy, Inc. v. FCC*, 516 F.3d 1027, 1032 (D.C. Cir. 2008); 40 C.F.R. § 1508.25(a). "Actions are 'connected' or 'closely related' if they: '(i) Automatically trigger other actions which may require environmental impact statements; (ii) Cannot or will not proceed unless other actions are taken previously or simultaneously; [or] (iii) Are interdependent parts of a larger action and depend on the larger action for their justification.'" *Hammond v. Norton*, 370 F. Supp. 2d 226, 247 (D.D.C. 2005) (quoting 40 C.F.R. § 1508.25(a)(1)). Similar actions have similarities that provide

a basis for evaluating their environmental consequences together, such as common timing or geography. *Id*. at 246; 40 C.F.R. § 1508.25(a)(3).

"Piecemealing" or "segmentation" is the unlawful practice whereby a project proponent avoids the NEPA requirement that an EIS be prepared for all major federal actions with significant environmental impacts by dividing an overall plan into component parts, each involving action with less significant environmental effects. *Taxpayers Watchdog v. Stanley*, 819 F.2d 294, 298 (D.C. Cir. 1987) . Federal agencies may not evade their responsibilities under NEPA by "artificially dividing a major federal action into smaller components, each without a 'significant' impact." *Coal. on Sensible Transp. v. Dole*, 826 F. 2d 60, 68 (D.C. Cir. 1987). *See also* 40 C.F.R. § 1508.27(b)(7).

The general rule is that segmentation should be "avoided in order to insure that interrelated projects, the overall effect of which is environmentally significant, not be fractionalized into smaller, less significant actions." *Town of Huntington v. Marsh*, 859 F.2d 1134, 1142 (2d Cir. 1988). Without this rule, developers and agencies could "unreasonably restrict the scope of environmental review." *Fund for Animals v. Clark*, 27 F. Supp. 2d 9, 16 (D.D.C. 1998).

Millennium has improperly split the overall expansion of its natural gas pipeline system into smaller components, thus avoiding a more rigorous comprehensive environmental review of the construction activity. We remind the Commission of the recent holding in *Delaware Riverkeeper, et al. v. F.E.R.C.*,

where the D.C. Circuit Court held that the Commission was required to assess the construction and operational impacts of four natural gas pipeline projects that were designed to upgrade a single pipeline in one environmental review because the projects were "connected, closely related, and interdependent[.]" *Delaware Riverkeeper*, 753 F.3d 1304, 1309 (D.C. Cir. 2014). There the Commission conducted an Environmental Assessment that was incomplete relative to the degree of the Commission's control over the underlying projects, and the connected actions rule applied because the D.C. Circuit determined that the Commission had improperly *limited* the scope of the review of the actions. Specifically, the Court held that "the agency's determination of the proper scope of its environmental review must train on the governing regulations, which here means 40 C.F.R. § 1508.25(a)." *Id*. at 1315.

In *Delaware Riverkeeper Network*, the Court stated that there was "a clear physical, functional, and temporal nexus between the projects. There are no offshoots to the Eastern Leg. The new pipeline is linear and physically interdependent; gas enters the system at one end, and passes through each of the new pipe sections and improved compressor stations on its way to extraction." *Id*. at 1308-1309.

Millennium's two upgrade projects represent similarly segmented projects, and meet the three factors described in *Delaware Riverkeeper Network*. With regard to physical proximity, Millennium's two projects are along the same

geographic corridor, impact the same sub-watersheds, physically abut one another, and present *overlapping construction zones*. Indeed, at the exact location where the Project ends, is the same location where the Valley Lateral Project begins. The application materials even acknowledge that there may be overlapping construction zones and impacts to the same forested regions, waterways, wetlands, and watersheds. The Valley Lateral project is the segment being constructed to service the CPV powerplant.

Functionally, the two projects are interconnected and indeed rely upon one another for justifying their stated capacity needs. This fact was confirmed by the Accufacts report, which concluded that:

> It should come as no surprise that the older 24-inch, lower 920 psig MAOP, approximately 7.5 mile long segment of the Neversink portion of the Millennium Pipeline is **out of character with the design of the rest of the newer Millennium transmission pipeline that is 30-inch, 1,200 psig MAOP**. The 24-inch Neversink segment has become an increasing bottleneck as gas rates have increased in recent years on the Millennium system. The serious impact of much higher gas rates and actual gas velocities, can be easily demonstrated by reviewing the steep slope (more vertical nature) of the pressure plots on Exhibit 1 and 3 for the existing Neversink segment. These steep slopes, higher pressure loss per mile, **suggest that the Neversink 24-inch pipeline is destined for a different service, such as to serve as a much lower gas flow delivery supply gas line to the proposed CPV power plant. Once the Neversink is looped with a 30-inch 1,200 psig MAOP pipeline, the smaller diameter weaker MAOP Neversink pipeline segment is of little value to the mainline Millennium Pipeline system except to serve as a delivery supply line to customers on that segment, essentially the proposed CPV power plant.**[5]

[5] *Observations Concerning the Millennium Eastern System Upgrade Project Proposal*, Accufacts, Inc., March 26, 2017 and Addendum, April 20, 2017

While Millennium contends that the ESU Project is independent of the previous Valley Lateral Project, there is nothing in Millennium's application that demonstrates that the projects could in fact operate independently. That is to say, Millennium has not demonstrated that the projects could in fact function if one were built and not the other.

Additionally, similar to the pipeline upgrade projects in *Delaware Riverkeeper Network*, which were all proposed in less than three years; the applications for Millennium's two upgrade projects actually overlapped in their administrative review at the Commission. Millennium submitted its application for the Project on July 29, 2016, and, the Valley Lateral Project was not granted its Certificate until November 9, 2016. The Commission was aware of both projects, and simultaneously reviewing related documents for over nine months (this includes pre filing information; both official projects were pending before the Commission for over three months). As such, it is clear that there is a physical, functional, and temporal nexus between Millennium's interrelated and interconnected pipeline upgrade projects.

b. The Commission Has Unlawfully Segmented Its Review Of Millennium's Interconnected And Interdependent Pipeline Upgrade Projects Pursuant To The Factors Identified in *Taxpayers Watchdog v. Stanley*.

In addition to failing to meet the requirements of 40 C.F.R. § 1508.25(a) and the factors relied upon in the *Delaware Riverkeeper Network* case, the Commission also fails to satisfy the three of the factors articulated in *Taxpayers Watchdog v. Stanley*, thus demonstrating that it impermissibly segmented its NEPA analysis. *Taxpayers*, 819 F.2d 294 (D.C. Cir. 1987). To determine whether a project has been unlawfully segmented, "courts have considered such factors as whether the proposed segment (1) has logical termini; (2) has substantial independent utility; (3) does not foreclose the opportunity to consider alternatives[.]" *Taxpayers*, 819 F.2d at 298. Courts consider "independent utility" in concert with other factors, including economic interdependence, timing, and geographic proximity. In *Delaware Riverkeeper*, the court held that even if the court were to expand its analysis from Section 1508.25(a) to the factors articulated in *Taxpayers Watchdog*, the Commission's defense of its action were still deficient. (there the court found that the projects did not have "…logical termini; [or] . . . substantial independent utility.").

A project lacks "independent utility" if it could not function or would not have been constructed in the absence of another project. *Wetlands Action Network v. U.S. Army Corps of Engineers*, 222 F.3d 1105, 1118 (9th Cir. 2000). *See also W. N.C. Alliance v. N.C. DOT*, 312 F. Supp. 2d 765, 774-775 (E.D.N.C. 2003) ("Alliance") (project widening highway section lacked independent utility because it would leave a "bottleneck" of narrow highway to north, such that traffic

congestion between the termini of the project would be worsened until construction of later project widening bottleneck section).

The proposed Project functionally relies on the operation of the Valley Lateral Project and vice versa. In other words, if the Project's facilities were to be deactivated, the Valley Lateral Project would not be able to operate as designed and fulfil its contracted-for volumes of gas. Furthermore, the Accufacts report concludes that the design of the Millennium pipeline "signals further expansions are being anticipated or planned as a result of this Project." The report supports this conclusion by stating that:

> Both the large diameter 36-inch pipeline and the higher pressure 1,350 psig MAOP for the looped pipe proposal are inconsistent with the remainder of Millennium's main gas transmission system of 30-inch pipe and 1,200 psig MAOP upstream and downstream of the proposed loop. There is no way, for example, that the 1,350 psig of the proposed loop can be utilized without **incorporating additional compressor stations and/or mainline pipeline changes beyond the cases filed for this Project's proposal**.
> . . .
> The combination of requested horsepower addition along with the much larger diameter 36-inch higher 1,350 psig MAOP needs additional supporting analysis as these changes suggest additional project expansions are expected well beyond the needs stated in the Project application.[6] (emphasis added)

These conclusions are specifically supported by a number of specific exhibits providing engineering modeling of Millennium's system. Tellingly, the Commission can point to nothing in the record demonstrating its independent

[6] *Observations Concerning the Millennium Eastern System Upgrade Project Proposal,* Accufacts, Inc., March 26, 2017 and Addendum, April 20, 2017

analysis of any engineering principles that would show that the proposed project could operate independently, or refuting any of the data provided in the exhibits provided by DRN. Even more problematically, the Commission apparently believes its rules limiting the extent to which applicants may "over-build" to accommodate future expansion excuse it from NEPA's requirements to review functionally interdependent projects together.

The Commission has previously relied upon the assertion that because pipeline upgrade projects are designed to serve different customers, at different points in time, they have independent utility, and thus warrant individual review. Such an argument improperly rests entirely on the economic independent utility of each project. Taken to its logical conclusion, this argument suggests that if a project sponsor could find individual shippers interested in small volumes of gas that would require only half-mile stretches of looped pipeline along an existing pipeline, FERC could certificate each one of those small individual half-mile loops. Thus, under those circumstances, FERC could theoretically certificate over 400 individual projects along Millennium's pipeline. Such a result undermines the design, purpose, and intent of NEPA.

Indeed, this specious argument was specifically addressed and rejected in *Delaware Riverkeeper*, where the Court rightly identified that the project sponsor "could have proposed two-mile segments, or one-mile segments, or one-hundred-yard segments for NEPA review, so long as it produced shipping contracts in

anticipation of the increased capacity attributable to each of these new segments. To interpret the 'substantial independent utility' factor to allow such fractionalization of interdependent projects would subvert the whole point of the rule against segmentation." *Delaware Riverkeeper*, 753 F.3d. at 1315.

Additionally, the proposed Project does not have logical termini. As shown by the alternatives analyses in the Environmental Assessments for the Project, when pipeline operators add new loops along a larger pipeline corridor to increase gas delivery capacity to the end point of that corridor, the location of the start and end points of individual loops is not fixed by the contracted-for quantity. Where the contracted-for quantity could be satisfied by adding new loops and compressors in a variety of configurations, pipeline owners add loops in locations based on factors including cost and difficulty of construction, environmental considerations, short- and long-term safety, and avoiding the need to acquire additional property rights. In *Delaware Riverkeeper*, the Court noted that "[t]o the extent that the [projects are] comparable to a highway, it is more analogous to a highway that connects two major points than one section of a web of metropolitan roadways for which the logical termini criterion loses significance." *Id*. at 1316. Therefore, because the selection of the termini for each segment did not turn on the projects' individual contract, the existence of that separate contract cannot by itself establish the independence of the project from the expansion of capacity on the Eastern Leg as a whole.

Additionally to the extent the Project was specifically designed to end right where the Valley Lateral Project begins, would only demonstrate the necessary interconnectedness of the Project. Therefore, either the Project has a logical termini (the beginning of the Valley Lateral Project) and therefore is functionally related/reliant on the Valley Lateral Project, or the Project has no logical termini.

Millennium's projects have also foreclosed the alternative of leaving the Millennium Pipeline incomplete. A project may be impermissibly segmented from future projects if it eliminates the "no build" alternatives for those future projects. *See Alliance*, 312 F. Supp. 2d at 775 (project that would exacerbate traffic due to existing bottleneck foreclosed no build option for future widening of bottleneck). Millennium's projects have made the completion of looping the Millennium pipeline inevitable. Once Millennium completes the segments for the proposed Project and begins shipping additional gas under contracts for the Project, the 36-inch pipeline will not be optimally utilized because it does not seamlessly operate with Millennium's existing system. These system inefficiencies make it unavoidable that future upgrades will occur. This is also true because gas velocity erosional limit ranges will eventually dictate such an outcome. As new 36-inch loops are inevitably added to the system to correct the inefficiencies in the system, bottlenecks in the un-looped sections will arise.

The Commission should be well aware of gas velocity erosional limit ranges as made public from another gas transmission company where the Commission

rejected a pipeline alternative in the application "where transporting the current and proposed gas volumes through only the existing pipeline would result in gas velocity significantly above TGP's recommended maximum design velocity of approximately 40 feet per second. This increased velocity could compromise the pipeline's integrity and safety."[7] Consequently, completion of the Project irretrievably committed Millennium to eventually completing the looping of its entire pipeline. As in *Alliance*, the Project has eliminated the option of no further future construction by creating inefficiencies and safety problems that will necessitate future upgrade projects.

c. The Commission's Truncated Cumulative Impacts Review of the Project and the Valley Lateral Project Render The Environmental Assessment Unlawful.

The Commission violated NEPA by failing to provide a meaningful analysis of the cumulative impacts of the interdependent and interconnected projects. NEPA requires "agencies to consider the cumulative impacts of proposed actions." *NRDC v. Hodel*, 865 F.2d 288, 297 (D.C. Cir. 1988) ("Hodel"). *See also TOMAC v. Norton*, 433 F.3d 852, 864 (D.C. Cir. 2006). An agency must analyze the impact of a proposed project in light of that project's interaction with the effects of "past, current, and reasonably foreseeable future actions." 40 C.F.R. § 1508.7. "Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time." *Id*. A finding of "[s]ignificance cannot

[7] Tennessee Gas Pipeline Company ("TGP"), "Northeast Upgrade Project (Docket No. CP11-161-000), Environmental Assessment," November 2011, p. 3-3.

be avoided by terming an action temporary." 40 C.F.R. § 1508.27(b)(7). "[A] meaningful cumulative impact analysis must identify (1) the area in which the effects of the proposed project will be felt; (2) the impacts that are expected in that area from the proposed project; (3) other actions—past, present, and proposed, and reasonably foreseeable—that have had or are expected to have impacts in the same area; (4) the impacts or expected impacts from these other actions; and (5) the overall impact that can be expected if the individual impacts are allowed to accumulate." *Grand Canyon Trust v. FAA*, 290 F.3d 339, 345 (D.C. Cir. 2002). NEPA requires such an analysis because "[e]ven a slight increase in adverse conditions . . . may sometimes threaten harm that is significant . . . may represent the straw that breaks the back of the environmental camel." *Id*. at 343.

NEPA's cumulative impact analysis requirement is not satisfied where the "analysis" merely announces that there may be risks or impacts, but does not provide the kind of information about those risks or impacts that would be "useful to a decisionmaker in deciding whether, or how, to alter the program to lessen cumulative environmental impacts." *Hodel*, 865 F.2d at 299 ("perfunctory references" do not constitute "analysis"). A cumulative impact section that merely "recites the history of [project] development" in the area and then offers the "conclusory statement" that "the cumulative direct impacts have been minimal" does not satisfy NEPA requirements. *FOE v. United States Army Corps of Eng'rs*, 109 F. Supp. 2d 30, 42 (D.D.C. 2000) (citing *Hodel*, 865 F.2d at 298). More

generally, an agency must provide a reasoned explanation to support its assertions and conclusions; otherwise, its decision is arbitrary and capricious. *Alpharma, Inc.v. Leavitt*, 460 F.3d 1, 6 (D.C. Cir. 2006) ("Alpharma").

Here, the Commission failed to take a hard look at the cumulative impacts of the interconnected Millennium projects. The Commission also failed to provide a reasoned basis for excluding the construction and operation of the related gas power-plant from its environmental review.

There is little to no analysis of the impact of the construction and operation of each of the projects on the same sub-watersheds and tributary basins. Also, at no point does the EA consider or analyze whether the individually insignificant post-mitigation impacts on waterways and wetlands from multiple pipeline projects in the same corridor could have a cumulatively significant impact.

In addition to failing to address the disturbance and re-disturbance of wildlife, waterbodies, and wetlands in the same sub-watersheds and abutting construction zones, the Environmental Assessment fails whole-sale to mention any of the numerous violations of permitting conditions, non-compliance issues, failed stormwater controls, failed restoration, and insufficient re-vegetation efforts that plagued the Millennium's initial project and restoration efforts. The Environmental Assessment of cumulative impacts analysis lacks any analysis of the aggregate or synergistic impacts of re-disturbing these specific areas.

The remainder of the cumulative impacts section lumps the Project in with other nearby Commission jurisdictional projects, which it discusses summarily without any of the necessary detail derived from the specific facts of those projects. The Commission's unsubstantiated and abbreviated treatment of cumulative impacts in the Environmental Assessment for the proposed project mimics the Commission's treatment of cumulative impacts in the *Delaware Riverkeeper* case, where the court found that the Commission failed to provide a sufficient hard look at the issue.

The Commission must consider whether a series of individually minimal impacts may nonetheless collectively create significant impacts. The fact that the impacts of the individual projects may have been minimized by imposition of procedures required by the Commission and other agencies does not constitute an analysis of whether the sum of the "minimized" impacts from each project is significant.

Additionally, the cumulative impacts assessment fails to consider the ramifications of the anticipated and inevitable looping of the whole Millennium pipeline that will be necessitated by, and is clearly planned for, by this project.

d. The Commission Unlawfully Neglected its NEPA Duty to Consider and Address Relevant Issues Raised in Public Comments

Under NEPA, the Commission must consider and address all relevant concerns in public comments it receives as it follows the NEPA process. FERC is required to consider, evaluate and respond to these issues in its Environmental

Assessment. While the Commission does mention a selection of concerns in the EA, and acknowledges that "Most comments received are in opposition to the Eastern System Upgrade Project," it does not adequately evaluate and address even the small selection of concerns mentioned. Moreover, no discussion or consideration is given to the fact the nearly all comments on the project are in opposition, particularly for those who live in the counties affected by the Project. An independent review of what citizens have said in public comments done by Key Log Economics found that, across the 12 critical categories analyzed the vast majority of commenters believe there will be negative impacts if the Eastern System Upgrade Project is approved (Geology and Soils (97% of commenters mentioned negative impacts), Land Use (96.8%), Water Resources (98.6%), Vegetation (97%), Wildlife (98.5%), Air Quality (97.7%), Fisheries (98.6%), Wetlands (97%), Cultural Resources (92.3%), Noise (96.7), Endangered and Threatened Species (99%), Public Safety (97.6%)). Among commenters overall as well as those who live or own property in a county potentially impacted by the ESU, the proportion of commenters opposed to the project is about 90%.

> The majority of commenters believe the Eastern System Upgrade Project will have an overall negative effect … Of all commenters who mentioned the economy, 89.4% think the Eastern System Upgrade Project will harm the economy; 83.6% of those mentioning energy needs said the project would not help the U.S. meet a domestic energy need; 97.2% of those mentioning the environment said the project would have a negative impact on the environment; and 97.5% of those mentioning lifestyle expect a negative effect. Interestingly (because it

> is where the impact of spending on construction and operation of the pipeline is most likely to occur…), commenters closest to the proposed project are least likely to believe the Eastern System Upgrade Project would help the economy or contribute to U.S. energy needs. Only 8.3% of such commenters indicated that the Eastern System Upgrade Project would be good for the economy (a score of 4 or 5), and just 16.4% thought there would be a positive contribution to U.S. energy needs.[8]

See Exhibit C. The EA completely ignores the majority of public comments and fails to conduct the comprehensive assessment of adverse impacts to landowners and surrounding communities identified in comments on the docket, as NEPA requires, including important impacts to the local aesthetic value and local economy.

> [An] important issue for citizens residing near the proposed project was how the project would impact the attractiveness of the region for business development and how the project would impact recreation and tourism businesses. Commenters noted that many homes in the area are second homes/vacation homes, with people drawn to the region for the pristine environment and ample recreation activities. Many comments also addressed concern that the project would hurt the tourism industry in the region. Out of 128 commenters that mentioned concerns over how the project would impact the attractiveness of the region or how the project would impact recreation and tourism, 100% of commenters believed the Eastern System Upgrade Project would have a negative impact.[9]

The analysis demonstrates the wealth of concerns that citizens have expressed to the Commission and the depth and breadth of those citizens' beliefs that the

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[8] *Citizen Input Regarding the Proposed Eastern System Upgrade Project, Analysis of Comments to FERC*, Key-Log Economics, LLC. For Delaware Riverkeeper Network, April 2017

[9] Id.

proposed Eastern System Upgrade Project will have negative or adverse effects on the environment, the economy, U.S. energy needs, and people's quality of life. This citizen input is what the Commission is required to consider and address in its EA. The Public Review and Comment Section of the EA, as it stands, is severely inadequate and fails to fully address this wealth of concerns and to take them into consideration as part of their conclusion as to whether the Projects' potential public benefits outweigh the potential adverse effects.

III. Impacts to Streams, Endangered Species that are Water Dependent, and Class A, B, and C Waterbody Impacts

The EA construction methods proposed do not protect the biological integrity or best usages for the streams (Class A, B, and C) and wetlands to be impacted by the proposed ESU project. The EA likewise does not consider cumulative impacts such as past cuts and repeated cuts for future expansions, nor does it consider harm to one sub watershed that may have multiple crossings for the project and the cumulative harm that comes with all of these impacts. For example, at least 25 waterbodies would be crossed by the ESU alone, the majority of which (at least 17 of the 25) are designated by NYSDEC as important cold water fisheries that include best usages of fish propagation and survival, and fishing. For example, Shin Hollow Brook (S-12) is proposed for a flume or dam and pump crossing method, and supports wild brown and brook trout, which will

undoubtedly be negatively impacted through water quality impairments and habitat alterations.

The impacts to the water quality, biological integrity, and the best uses of the Neversink River are likewise particularly problematic. The proposed project crosses this Class B waterbody in a location with mature riparian forest and with a southern riparian zone exhibiting extremely steep slopes (exceeding 100%; see EA Table A-10). Despite the applicant's attempt to reduce impacts through the use of a HDD crossing of the Neversink River; the staging, drilling, and permanent removal of mature riparian forest on these steep slopes for the pipeline ROW and HDD will directly cause increases in suspended sediments, turbidity, water temperature, and nutrients, all in violation of New York State water quality standards, and will indirectly exacerbate the violations of the pH water quality standards that required the listing of the Neversink River as "impaired" on the 303(d) and Integrated Lists for New York State waterbodies through increases in nutrients that lead to excessive growth of algae, weeds, or slimes.

The EA also acknowledges the appreciable risks from HDD in terms of bentonite drilling fluids surfacing within the Neversink River, which would cause direct and immediate violations of turbidity water quality standards. The HDD drilling itself, therefore, is a likely cause of water quality violations for the Neversink River and poses threats to the Dwarf Wedgemussel population in the River. Indeed, the concerns of frac-outs from HDD construction activity under the

Neversink River were so great that Millennium agreed to use an existing pipeline that already traversed under the river when it first installed its system. In the 2006 Final Environmental Impact Statement that FERC issued for the Northeast (NE)-07 Project, a cluster of projects that included the Millennium Pipeline Project, FERC wrote:

> In 2004 and 2005 Millennium conducted a reassessment of the use of a conventional bore technique to construct the Neversink River crossing. The result of this review was that the method was likely to fail based on the subsurface conditions at the site. After review of all possible alternatives, Millennium proposed incorporating a segment of Columbia's existing 24-inch-diameter Line A-5 pipeline between MPs 340.5 and 347.7 into the project to avoid making a new crossing of the Neversink River. The continued utilization of this segment of the existing Line A-5 pipeline would result in the avoidance of any construction in the vicinity of the Neversink River.[10]

The conclusion was drawn then, and it must be true now, that construction activity under this stretch of the river represents too great a risk to the Neversink River.

These impacts to water quality will impair the best uses for this Class B waterbody by negatively affecting water clarity, creating growths of algae and weeds, resulting in the impairment of the primary and secondary contact recreation uses of the Neversink River. More significantly, the Neversink River harbors the only population of the State and Federally Endangered Dwarf Wedgemussel wholly within New York State waters (note: a small population of this species also

[10] Federal Energy Regulatory Commission (FERC). Final Supplemental Environmental Impact Statement (EIS) for the Northeast (NE)-07 Project. Section 4: Environmental Assessment, pg. 4-118-4-119. October 13, 2006. Available Online: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=11155639

exists along the border waters of Pennsylvania and New York State in the Delaware River, with nearly all identified locations within the Pennsylvania jurisdictions of these boundary waters). The only remaining population of this New York Endangered species already has been decimated in recent years, with the current population estimated at approximately 10% of the population identified as recently as the 1990s.[11] In fact, the Neversink population of Dwarf Wedgemussel once was estimated to be the single largest or second largest extant population of this endangered species range-wide.[12] The recent declines in population, however, have reduced the population so severely that relatively small tributary populations are now estimated to exceed the size of the once-preeminent Neversink River population.[13] The tenuous existence of this last remaining New York State population of Dwarf Wedgemussel is thus already in jeopardy and must not be threatened with new impairments to water quality and habitat that threaten its survival and propagation. As noted, the proposed project will directly impact the forested riparian zone of the Neversink River and will lead to water quality

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[11] Strayer, D.L., S.J. Sprague, S. Claypool. 1996. A range-wide assessment of populations of Alasmidonta heterodon, an endangered freshwater mussel (Bivalvia:Unionidae). J North Am. Benth. Soc. 15(3): 208-317.
[12] USFWS (U.S. Fish & Wildlife Service). 1993. Dwarf wedge mussel (Alasmidonta heterodon) recovery plan. U.S.Fish & Wildlife Service, Hadley, Massachusetts. 48 pp. and Strayer, D.L., S.J. Sprague, S. Claypool. 1996. A range-wide assessment of populations of Alasmidonta heterodon, an endangered freshwater mussel (Bivalvia:Unionidae). J North Am. Benth. Soc. 15(3): 208-317.
[13] Galbraith, H.S., W.A. Lellis, J.C. Cole, C.J. Blakeslee, B. St. John White. 2016. Population demographics for the federally endangered dwarf wedgemussel. Journal of Fish and Wildlife Management 7(2): 377–387.

standard violations, impairing the best uses of this stream, particularly for such a sensitive and imperiled obligate aquatic species and its ability to survive and propagate.

These impacts to the Neversink River, while significant, would be at least as severe under the alternatives considered by the applicant or through conventional trenching via flume or dam/pump approaches. All of these alternatives would permanently reduce the extent, health, and function of riparian forests, leading to increased water temperatures, increased turbidity and suspended sediments, and increased nutrient loading to the Neversink River, thus violating New York State's water quality standards and impairing both the biological integrity and the best uses of this Class B stream, including the best uses of fish and wildlife propagation and survival. Permanent and irreversible impacts to the stream, to the riparian corridor, and to the already-diminished Dwarf Wedgemussel population are thus unavoidable under either the preferred route or any of the alternatives considered in the EA, or under other conceivable options. The threat to the Neversink River and the Dwarf Wedgemussel population simply cannot be mitigated or avoided.

The Neversink River also has 3 proposed crossings of tributaries plus 2 crossings for pipeline access roads. One crossing, S-15 at MP 1.4 proposes a dam and pump or flume trenching. When trenching is employed, as acknowledged by

NYSDEC[14], even what is deemed a dry crossing "will negatively impact and affect the riparian and in-stream conditions necessary to provide habitat to support trout presence and preserve water quality". The EA also does not include a trenchless feasibility analysis as has been requested for other New York pipeline projects by NYSDEC. Due to these water quality threats, NYSDEC[15] [16] has denied two other larger pipeline projects deploying similar construction techniques deemed acceptable by FERC:

> It is evident that the impacts from the Project…will impede the best usages of many waterbodies, particularly those with a trout standard or rare species, by degrading the survival and propagation of balanced, indigenous populations of shellfish, fish and wildlife that rely upon these waters. As it relates to State narrative Water Quality Standards, 6NYCRR § 703.2 states that there shall be "no increase [in turbidity] that will cause a substantial contrast to natural conditions." The techniques utilized for construction of the Project will cause numerous violations of the turbidity standard.

Furthermore, pipeline ROW cuts to smaller and narrower headwater streams cause significant harm. The ROW for the Huguenot Loop is 125 feet wide, 80 feet of which is additional to the existing Millennium ROW corridor (40 ft. on either side of the existing ROW). The EA falsely suggests that trenching these smaller streams, many of which have trout and cool water, is an acceptable harm. However, the science clearly shows these headwater streams are harmed, and water

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[14] NYSDEC WQC joint permit denial letter to National Fuel Gas Supply Corporation and Empire Pipeline, April 7, 2017

[15] NYSDEC WQC joint permit denial letter to National Fuel Gas Supply Corporation and Empire Pipeline, April 7, 2017.

[16] NYSDEC WQC joint permit denial letter to Constitution Pipeline Company, April 22, 2016.

quality downstream is impacted as a result of such large ROW crossings through riparian buffers and small headwater streams. These crossings increase turbidity and sediment during construction, increase soil compaction within and in addition to temporary and additional temporary work spaces (TWS and ATWS), remove riparian buffers, and cause thermal impacts[17] to headwater tributaries. The Princeton Hydro[18] expert report regarding ESU impacts submitted November 2016 states the following:

> Headwater streams are ecologically important and have a strong influence on downstream water quality and quantity, and are very sensitive to land use change including soil disturbance and loss of riparian vegetation (Alexander et al., 2007)…. Vegetation clearing and soil compaction increase runoff and associated erosion from the site, as less precipitation is intercepted or infiltrated into the soil. Along with sediment issues downstream of the site, increased runoff is associated with greater pollutant loading. Wetland and stream crossings are particularly sensitive to future erosion and water quality issues owing to their ecological importance. Increased sedimentation and pollutant loading in streams degrades in-stream habitat and causes eutrophication.

NYSDEC[19] also notes the 100% mortality and in-stream aquatic life losses that come with dry trench stream crossings that are dewatered for the length of the ROW, which would be at least 80 feet but up to 125 feet for ESU. According to FERC EA Appendix E, 10 streams would likely be impacted in this way, with proposed crossing width equaling 107 feet total. Using the conservative 80 foot

[17] Delaware Riverkeeper Network, Thermal Impacts to Exceptional Value Waterbodies in Pennsylvania Cut by Gas Pipeline Projects, Sept., 2016.
[18] Princeton Hydro, Environmental Review of the Proposed Millennium Pipeline Eastern System Upgrade, Nov 28, 2016.
[19] NYSDEC WQC joint permit denial letter to National Fuel Gas Supply Corporation and Empire Pipeline, April 7, 2017

ROW disturbance (not the 125 foot ROW) – the impact would total at a minimum 8,560 linear feet of stream habitat having 100% direct mortality. NYSDEC[20] goes on to acknowledge with these stream cuts:

> This [100%] loss will continue for a period of time and only gradually abate under natural conditions when recovery and stabilization of this area occurs following completion of construction and rewatering.

Riparian buffer impacts and in stream habitat destruction from trenching are also noted by NYSDEC[21]:

> The loss and conversion of riparian cover types will increase the input of turbid water (in violation of water quality standards)….construction will destabilize stream banks and increase risks for further erosion and bank instability that would compromise water quality. Excavation across streambeds will remove in-stream habitat forms such as rocks and woody debris that form pools and pockets as habitat for trout and other aquatic organisms…these changes will negatively affect the best usages of trout and trout spawning streams by reducing the habitat to support trout and thereby fish survival, spawning and fishing…The Department finds that these construction techniques [trenching] would cause significant damage or destruction to both riparian and in-stream habitat, in turn causing violations of State water quality standards related to turbidity and best usages of the affected waterbodies.

NYSDEC[22] also cites long-term post construction impacts to riparian vegetation:

> The permanent loss of the native, established riparian vegetation [in the permanent ROW] will have a negative effect on water quality and stream ecological health for the full service life of the pipeline.

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[20] NYSDEC WQC joint permit denial letter to National Fuel Gas Supply Corporation and Empire Pipeline, April 7, 2017

[21] NYSDEC WQC joint permit denial letter to Constitution Pipeline Company, April 22, 2016

[22] NYSDEC WQC joint permit denial letter to Constitution Pipeline Company, April 22, 2016

To assess the scope of turbidity violations from open trench waterbody cuts, NYSDEC[23] calculated a conservative estimate of turbidity violations for each stream cut to include at least two days at each stream crossing for another proposed pipeline project. If the same approach for just this leg of Millennium's ESU project is calculated, according to the FERC EA Appendix E, at least 10 streams are proposed for trenched stream crossings or access road modifications that may involve instream work. That would result in at least 20 stream pollution violations for the ESU project using NYSDEC's conservative estimate. 16 wetland crossings are proposed to be open cut which would add an additional 32 sediment pollution violations in wetlands using NYSDEC conservative calculations. If one is to also consider the steep slopes, erodibility of soils, and low soil revegetation qualities, this number is likely to be much higher than two instances per stream crossing. And as indicated in earlier comment, Millennium segmented connected projects that, if examined together, would likely lead to NYSDEC denial based on cumulative harm from open trenches alone.

Because open trench pipeline installations may unnaturally alter both stream bank and streambed (i.e., channel) stability, there is an increased likelihood of scouring within backfilled pipeline trenches. This is because open trenches themselves, when backfilled, may not be compacted to stable pre-trench sediment permeability conditions. Flooding rivers can scour river bottoms and expose

[23] NYSDEC WQC joint permit denial letter to National Fuel Gas Supply Corporation and Empire Pipeline, April 7, 2017

pipelines to powerful water currents and damaging debris. Additionally, unusually heavy rains including those associated with climate change, threaten to increase overall stream degradation and channel migration – thereby exposing shallowly buried pipelines.

Scour hole development proximal to pipelines is well-documented in both stream and seabed settings.[24] Stream-based pipe "(f)ailures [have been] caused not only by vertical scour of the streambed but also by bank erosion, lateral channel migration, avulsions, bridge scour, and secondary flows outside the main channel. … Several of the pipelines in [a] study failed as a result of a meander migration or avulsion of the stream into previously less active or nonexistent channels."[25] Based on field observations and hydraulic modeling for the 100-year design flood, researchers documented maximum vertical scour to 26.6 feet (8.1 meters) and lateral scour to 6,274 feet (2,050 meters) at some failed pipeline crossings.

An expert at HydroQuest has determined that, at a minimum, any pipeline installed using the open trench cut method needs to be installed at least 24 feet

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[24] Fogg, J. and Hadley, H., 2007, Hydraulic Considerations for Pipelines Crossing Stream Channels. Technical Note 423. BLM/ST/ST-07/007+2880. U.S. Department of the Interior, Bureau of Land Management, National Science and Technology Center, Denver, CO. 20 pp. http://www.blm.gov/nstc/library/techno2.htm.

[25] Doeing, B.J., Williams, D.T. and Bradley, J.B., 1997, Gas Pipeline Erosion Failures: January 1993 Floods, Gila River Basin, Arizona. In Storm - Induced Geologic Hazards, Case Histories from the 1992 - 1993 Winter in Southern California and Arizona; Geological Society of America; Reviews in Engineering Geology, Volume XI (ed. Robert A. Larson).

below the stream bed in order to prevent exposure from scour.[26] While bridge piers are more readily exposed to stream scouring than pipelines, it is telling that bridge failure analyses have determined that channel scour occurs to depths of up to three times that of maximum river floodwater depth (e.g., scour to 30 feet with a 10 foot floodwater depth).

Studies documenting the effects of stream crossing construction on aquatic ecosystems identify sediment as a primary stressor for construction on river and stream ecosystems and confirm conclusions also cited by NYSDEC.[27] During the construction of pipeline stream crossings, discrete peaks of high suspended sediment concentration occur due to blasting, trench excavation, and backfilling.[28] Excavation of streambeds can generate persistent plumes of sediment concentration and turbidity.[29] This sedimentation has serious consequences for the benthic invertebrates and fish species whose vitality is crucial for healthy aquatic ecosystems. There have been documented reductions in benthic invertebrate densities, changes to the structure of aquatic communities, changes in fish foraging behavior, reductions in the availability of food, and increases in fish egg mortality

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[26] Hydroquest Memorandum re: Hydrologic and Environmental Rationale to Bury Gas Pipelines using Horizontal Directional Drilling Technology at Stream and River Crossings, 6/8/2012 (Hereafter Hydroquest Report)
[27] Scott Read, *Effects of Sediment Released During Open-cut Pipeline Water Crossings*, Canadian Water Resources Journal, 1999, 24: (3) 235-251.
[28] *Id*.
[29] *Id*.

rates.[30] In addition to the stream crossing construction activity itself, the associated new road construction increases the risk of erosion and sedimentation.[31]

There are numerous environmental risks associated with open trench burial of gas pipelines (wet, dry, slurry). Open trench burial involves the excavation of sediments for pipeline installation perpendicular to or across streams and their sometimes wide floodplains, along with removal of vegetation and well-established ecosystems. Disruption of the stream channel and banks can cause destabilization of the stream's natural flows, causing channel migration and erosion that are harmful to the stream. [32] The open trench cut method of crossing streams results in sedimentation, impacts to benthic habitat, and can result in changes to stream morphology that can further affect downstream habitats.[33]

Sedimentation results from the actual crossing activity itself as well as the removal of vegetation and activity that takes place on the stream-adjacent (riparian) lands. While dam and pump methods, can reduce sediment loadings associated with a wet cut method, there are still sediment releases at levels of concern and impact, and the diversion of the water creates impediments to fish and flows that also have impacts on waterways. Additionally, this method of crossing

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[30] Norman, *supra* note 12, at 9-10.
[31] *En Banc* Hearing of the Pennsylvania Public Utility Commission on Jurisdictional Issues Related to Marcellus Shale Gas Development, Docket No. I-2010-2163461.
[32] Expert Report from HydroQuest, attached.
[33] See Effects of Sediments Released During Open-Cut Pipeline Water Crossings, Canadian Water Resources Journal, Vol. 24, No. 3, 1999.

takes longer, and so it results in longer-term direct impacts to the stream and sediment releases over a prolonged period.

Sediment carried in the water column is abrasive and can result in increased erosion downstream.[34] Deposited sediment from construction activities can fill in the interstitial spaces of the streambed, changing its porosity and composition, and thereby increasing embeddedness and reducing riffle area and habitat quality.[35] Furthermore, deposited sediment has the potential to fill in pool areas and reduce stream depth downstream of the construction area.[36]

Benthic invertebrates can have higher drift rates during stream crossing construction and reduced densities following open trench cut methods of crossing. Reduced densities can be the result of both the higher drift and the increased sedimentation that affects suitability of habitat resulting from the pipeline installation.[37] Changes in downstream diversity and structure of benthic invertebrate communities can also result. While, in time, the benthic community generally restores, that does not diminish or negate the ecosystem affects during the time of damage including the other cascading affects to other ecosystem services otherwise provided by the invertebrates – including as food for other dependent species, the water quality benefits provided by invertebrates' breakdown

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[34] Pipeline Associated Watercourse Crossings, 3rd Edition, publication prepared for CAPP, CEPA, and CGA by Tera Environmental Consultants
[35] Read, *supra* note 22, at 235-251.
[36] Norman, *supra* note 12, at 9-10.
[37] Ibid 1.

of nutrients, and the breakdown of instream detritus creating food for other species.[38]

Using the open trench cut method of crossing can also affect fish, including direct harm but also by reducing the suitability of habitat for eggs, juveniles and overwintering.[39] Fish exposed to elevated suspended solids levels can experience reduced feeding rates, physical discomfort or damage from the abrasive materials on their gills, decreased instream visibility, reduced food supply, and increased competition as fish attempt to move to cleaner waters.[40] The filling of riffles not only can have adverse impacts for invertebrates and fish, in terms of taking important habitat, but it can also diminish the ability of the riffles to help create oxygen important for aquatic life.[41] Over time these impacts can depress the immune system of fish, result in lower growth rates, result in increased stress on individuals and populations, and cause damage to the gills – all of which can result in a decline in fish and population health and survival rates.[42] This is compounded by adverse effects to the suitability of habitat for eggs and juveniles both of which

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[38] See e.g. Sweeney, B. W., et al. 2004. Riparian deforestation, stream narrowing, and loss of stream ecosystem services, PNAS, September 2004; 101: 14132-14137.
[39] Ibid 1.
[40] Pipeline Associated Watercourse Crossings, 3rd Edition, publication prepared for CAPP, CEPA, and CGA by Tera Environmental Consultants
[41] Ibid 1.
[42] Ibid 1.

compounded by adverse effects to the suitability of habitat for eggs and juveniles necessary to support the overall community and population.[43] Additionally, downstream sedimentation and disruption of flows during crossing activities can result in areas of the stream that are shallower or dewatered, thereby taking preferred habitat.[44]

Pipeline construction results in the loss of riparian (streamside) vegetation.[45] For each of the pipeline construction techniques there is a resulting loss of vegetation and foliage associated with clearing the stream banks. Riparian vegetation is an important part of a healthy ecosystem and protects the land adjoining a waterway which in turn directly affects water quality, water quantity, and stream ecosystem health.

Riparian corridors protect and restore the functionality and integrity of streams. A reduction in healthy and mature streamside vegetation reduces stream shading, increases stream temperature and reduces its suitability for incubation, rearing, foraging and escape habitat.[46] While horizontal directional drilling may move the construction footprint further away from the stream, it too results in vegetative losses and soil compaction that can have direct stream impacts. The body of scientific research indicates that stream buffers, particularly those

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[43] Pipeline Associated Watercourse Crossings, 3rd Edition, publication prepared for CAPP, CEPA, and CGA by Tera Environmental Consultants
[44] Ibid 1.
[45] Norman, *supra* note 12, at 8.
[46] CAPP (2005), *supra* note 16, at 1-4.

dominated by woody vegetation that are a minimum 100 feet wide, are instrumental in providing numerous ecological and socioeconomic benefits. [47] The loss of vegetation also makes the stream more susceptible to erosion events, exacerbating the sedimentation impacts of construction. In crossings that result in open forest canopies, increases in channel width, reduced water depth, and reduced meanders have persisted in the years after using an open cut method of installation.[48]

IV. Wetland Impacts

Appendix F of the FERC EA notes at least 16 wetlands to be open cut by the ESU project. Using NYSDEC's same conservative approach above, this would equal another 32 instances of turbidity and sediment pollution entering these sensitive wetland habitats. Nine of these wetlands are characterized as PFO or a combination of PFO/PEM, meaning that with these open cuts, mature trees in the wetland would be cut down. This cutting of mature forested wetlands leads to thermal impacts that are sustaining to those wetlands for decades in temporary cleared areas and for the life of the project in the permanent ROW. NYSDEC and

[47] See e.g. Newbold et al. 1980, Welsch 1991, Sweeney 1992, Sweeney and Newbold 2014
[48] Ibid 1.

PA DEP[49] have acknowledged this impact for PFO wetlands for past pipeline projects.

NYSDEC[50] acknowledges wetland impacts include:

> Disturbances to wetlands…will have permanent and temporary negative impacts on New York's surface and subsurface water quality by decreasing wetland functions and benefits directly associated with protecting and preserving the integrity of water chemistry and biology…Changing the type and species of vegetation in the wetland will permanently change ecological community dynamics and the types and composition of wildlife using that wetland…Project activities will not only cause permanent changes to surface water, those project activities will cause soil compaction and alter soil profile. These activities will also cause at least temporary and possibly permanent changes to soil dynamics from the altered soil characteristics, including complete removal and "replacement" of the pre-existing soil layers. Infiltration rates of water and the flow of water through the soil will also be impacted which will affect local subsurface water quality.

NYSDEC also cites the need for permit issuance in wetlands only when it has been determined that there is no alternate to accomplish the applicant's objectives.

The FERC EA claims 3.1 acres of wetland impacts for construction and 1.8 acres for operation of the pipeline. 1.14 acres consist of PFO wetlands (according to Appendix F). Two wetlands are noted as potentially having shallow bedrock which could require blasting. Again, the ESU project should be considered with the other clearly related projects that Millennium wants to undertake but treats as segmented projects.

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[49] PA DEP Technical Deficiency Letter to Transco Gas Leidy Pipeline, (E40-748), Sept. 4, 2014

[50] NYSDEC WQC joint permit denial letter to National Fuel Gas Supply Corporation and Empire Pipeline, April 7, 2017

V. Steep Slopes and Erodible Soils – More Potential for Water Impacts

The FERC EA falsely concludes impacts and potential impacts from steep slopes will be minimal, despite Millennium clearing steep slopes from MP 0.8 to MP 2.8 and MP 5.3 to MP 6.5 (Table A-10). Despite concerns regarding erodible soils and steep slopes provided in a Princeton Hydro expert report in November 2016, the EA outlines 3.1 miles of steep slope trench cuts (the Huguenot loop is 7.8 miles total). The EA notes 14 percent of the Huguenot Loop, or 1.1 mile, would traverse slopes and side slopes greater than 30 percent, and that these areas are more prone to landslides (these numbers do not match numbers in EA Table A-10 for steep slopes not being HDD'd). Landslides involve the downslope mass movement of soil, rock, or a combination of materials on an unstable slope. The EA states that landslide incidence and susceptibility mapping compiled by the USGS for the Project area shows that landslide incidence at the Huguenot Loop is considered low from MP 2.7 to MP 7.8 and moderate from MP 0.0 to MP 2.7 (USGS 2016e). (Despite moderate landslide incidence, in the EA, MP 0.8 to MP 2.8 is proposed to be cleared of vegetation and trenched.) Landslide incidence is moderate at the Highland Compressor Station. Additionally, portions of the Highland and Hancock Compressor Stations are comprised of steep slopes. FERC's EA states there would be no harm from landslides because of Millennium's proposed E&S measures. DRN field observations, the record of Soil Conservation E&S pipeline Notice of Violations (NOVs), nor the science bares out

this conclusion since similar E&S measures on steep slopes have failed for similar pipeline projects – including the use of temporary swales, sediment traps during construction and remediation with trench breakers, compacted back fill, slope breakers, jute matting and other E&S controls.[51]

The Princeton Hydro expert report[52] cites problems with construction on steep slopes and failing E&S measures:

> The prevalence of steep slopes in the construction area greatly increase the likelihood of short term construction related erosion in addition to long term decreased stability of these steep slopes, which will be damaging to both upland areas and nearby waterbodies. Despite Millennium's assurances that they will use sediment control measures appropriately and mitigate damages, these measures frequently are applied incorrectly, fail, or fall short. There have been multiple occasions of fines levied against pipeline construction companies for improper erosion and sediment control, equipment outside of the permit area, drilling mud spills, discharge of fluids, and failure to minimize wetland disturbance (e.g. Legere, 2014; Mayer, 2009; Phillips, 2016; Rittenbaugh, 2014; Hamill and Olson, 2012).

Princeton Hydro's expert report found discrepancies with Millennium soil calculations in the Resource Reports – this issue that could cause increased erosion and sediment pollution and turbidity to nearby streams does not appear to be addressed in the FERC EA:

> Millennium claims that only 9.75 acres or 0.05 % of the total project area affects soils that are highly erodible [Resource Report 7, p.11, 24]. However, erodibility was determined by the average K-factor of each soil type, which is a problem for several reasons. The K-factor is a function of soil physical

[51] Delaware Riverkeeper Network, People's Dossier of FERC Abuses
[52] Princeton Hydro, Environmental Review of the Proposed Millennium Pipeline Eastern System Upgrade, Nov 28, 2016.

> characteristics such as grain size and structure, and does not take into account the slope of the soil, which is critical component of erosion risk. Also, Millennium calculated the overall K-factor of each soil type as an average of all the soil horizons, when most erodible soil in the construction zone, aside from the trench itself, will be the surface soil layers. Finally the k-Factor is designed to represent soils in the natural condition, and the reported K-factor is not accurate for disturbed soils (NRCS-USDA). Millennium reports slopes of greater than 30% at 28 locations along the Huguenot Loop for a combined distance of 1 mile along the pipeline route. This is 13% of the total length of the project [Rpt. 6, p.16], and does not account for slopes less than 30% which might still be prone to significant erosion. (PH report)

Table B-1 of the EA provides further concerns with soil qualities. Over 48% of the project has soils that are prone to have low revegetation potential – 66.3 acres along the pipeline corridor and ATWS areas have low revegetation potential alone. This characteristic can lead to continual runoff and erosion problems long after pipeline construction is completed. Finally, shallow bedrock is noted for 41.8 percent of the project area (see table B-1) which could mean more blasting being needed if mechanical ripping of rock is not feasible – further disturbing the soils natural qualities and potential incidence for higher erodibility.

VI. Forest Impacts and Additional Temporary Work Spaces Near Waterbodies

ESU is proposing to impact 84 acres of forest lands during construction and 27.6 acres during permanent operation, increasing forest edge effects, predation by opportunistic species, increased wind throw, and microclimate changes to the surrounding forests along the ROW that will extend up to 300 feet on either side of

the ROW. ESU is proposing 50 ATWS (additional temporary work spaces) for upland forest habitats. Forests take generations to grow back to maturity – these impacts are neither "temporary" nor acceptable. Many of these ATWS are proposed near sensitive waterbodies which will lead to increased runoff, thermal impacts and water quality threats.

VII. Groundwater Impacts

Pipelines have been seen by experts to be conduits for diverting groundwater from its natural path. Several sensitive, shallow and principal aquifers of New York including the Ramapo River Basin Aquifer, the Delaware River Streamflow Zone recharge area for the New Jersey Coastal Plains Aquifer SSA, and the New Jersey Fifteen Basin Aquifers Systems SSA could be impacted by the ESU project. According to expert observation, pipeline trenches can divert groundwater and as a result "permanently alter the hydrologic cycle in the vicinity of the pipeline right-of-way. This alteration will decrease the water resources available to support wetland hydrology and stream base flow in the summer and fall dry season."[53] For example, observations of the Tennessee Gas Pipeline's 300 Line Upgrade project by a hydrologist determined that "pipeline trenches intercepted shallow groundwater in places, creating preferential paths for dewatering shallow groundwater not just in the disturbed construction areas, but also in areas

[53] Affidavit of Peter M. Demicco, DRN v. PA DEP an TGP NEUP, 2012.

surrounding the right-of-way, further negatively impacting ground water resources and wetlands."[54] As a result, it was observed that the 300 Line Upgrade pipeline project had "already resulted in permanent changes to wetlands…."[55]

VIII. Endangered and Threatened Species Impacts Beyond the Dwarf Wedgemussel

The FERC EA (Table B-9) lists "May affect, not likely to adversely affect" or "No effect" for a number of sensitive endangered and threatened federal and state listed species yet it is clear from the EA that many of these determinations that are in consultation with the Fish and Wildlife Service and the NYSDEC, have yet to be finalized and are still ongoing and under review by these consulting agencies. How is FERC backing up the determinations they are clearly making prematurely before consultations are completed? There is an abundant chance of multiple sensitive species being impacted that are found in the survey areas or vicinity of the project indicating the unique, intact and healthy ecosystem through which this pipeline would cut. Bog turtle, dwarf wedgemussel (noted above in Neversink River), brook floater mussel, northern long-eared bat, bald eagles, puttyroot orchid (*Apelcrum hyemale*), and Indiana bat are all documented. For bog turtle, 6 wetlands (W-28A, W-21, W-20, W-19, W-16, W-07) were identified as potential bog turtle habitat in Phase I surveys. Considering the length of the

[54] Affidavit of Peter M. Demicco, DRN v. PA DEP an TGP NEUP, 2012
[55] Affidavit of Peter M. Demicco, DRN v. PA DEP an TGP NEUP, 2012.

project, this amount of harm to potential wetlands that could impact the bog turtle and that FERC suggests that HDD under 2 of these wetlands is sufficient to protect 2 of the 6 wetland habitats where bog turtles may be located does not support FERC's premature determination (not yet confirmed by the FWS and its review of Phase 2 studies).

The putty root orchid, a NY state listed endangered plant (this orchid is also endangered in New Jersey and rare in Pennsylvania) has a preference for dappled sunlight during the fall, winter and spring and the root system of this orchid benefits from (and may require) a symbiotic relationship with compatible mycorrhizal fungi. Otherwise, this orchid may fail to flourish. Propagation by seed is very difficult and rarely successful. A moist to mesic loamy soil with abundant organic material is preferred. Soil pH can vary from mildly acidic to neutral. FERC suggests that even with these unique qualities and micro-climate conditions required of the orchid, though it is located near the location of the Highland Compressor station, "Millennium will plant conifers along the limits of the [compressor station] workspace nearest the puttyroot orchid location to minimize potential habitat changes."

The EA recognized that there may be "foraging area" near the Highland Compressor Station yet there is no mention of the Delaware Riverkeeeper Network letter submitted on October 18, 2016 where a potential den and a juvenile timber rattlesnake was observed by a member of the public in the area of the compressor in

August, 2016. The distance between the potential den and the closest area of permanent disturbance was measured to be approximately 266 feet. The distance between the potential den and the closest Temporary Work Space (TWS) was measured to be approximately 142 feet. Timber rattlesnakes are especially sensitive to vibrations so the notion that the compressor's continual operations of a station in the vicinity of this currently undisturbed parcel is absurd. Rattlesnakes were also observed 900 feet from the Ramapo Meter station. Furthermore, in FERC's Final Supplemental EIS (FERCEIS0-195F) (Dockets CP98-150-006, CP98-150-007, CP98-150-00, et. al) for the Millennium pipeline indicated at least 14 rattlesnake dens were likely to be disturbed for that pipeline project. These cumulative impacts from repeated cuts and harms over time need be considered fully and not segmented out. Each population and den destroyed or habitat now having a potential compressor site within 142 feet of TWS, with its continued noise and impacts, clearly leads to more decimation to populations that deserve protection – a premature determination by FERC of "May affect, not likely to adversely affect" is not appropriate.

IX. Past Harm by Millenium Pipeline in New York – Record of Violations Shows FERC and Pipeline BMPs are not Effective Nor Protective to New York's Natural Resources

Millennium is proposing similar construction techniques, best management practices, and Erosion and Sediment Control practices that were implemented and

used as industry standard practices for its 2006 Millennium Pipeline Project, which involved construction of 182 miles of 30-inch-diameter pipe across eight counties in Southern New York. Construction began in the middle of June 2007. (FERC Dockets: Millennium Pipeline CP98-150-006, CP98-150-007, Columbia Gas Docket Nos: CP98-151-003, et al.).

On June 20, 2008, the New York State Department of Environmental Conservation (NYSDEC) issued a "Stop Work Order" to Millennium[56] for inadequate and failing construction practices impacting the East Branch Delaware River. The pipeline company had cleared a 100-foot ROW path along a 50% steep slope which caused a mudslide, discharging sediment directly into the East Branch Delaware River, and along its banks, and causing violations of the turbidity standard for this Class C waterbody. Millennium was cited for inadequate erosion control devices that were not in compliance with DEC Technical Standards, i.e., the New York Standards and Specifications for Erosion and Sediment Control, aka the Blue Book.

> there was a mudslide earlier in the week and there is sediment from the site on the banks and in the river. The erosion stabilization controls, to the extent they are in place on the face of the mountainside, don't meet DEC technical standards including the hay bales along the slope. Furthermore the Department didn't provide approval to exceed 5 acres of disturbed area which is required under the stormwater permit. Your client is hereby notified that they must cease all construction activity on the site and immediately stabilize all areas of disturbance to prevent discharges from the

[56] NYSDEC, Region 4 Letter to Millennium Counsel, Mr. Thomas West, West Firm, Stop Work Order, Town of Hancock, No NYR10P622 and Stormwater Discharge Permit: GP-02-01. June 20, 2008.

> site and contravention to the water quality…Measures to mitigate impacts from forecasted rain should also be undertaken immediately as needed.[57]

A July 3, 2008 NYSDEC letter[58] after a site inspection at this one location along the East Branch Delaware River outlines 14 concerns and issues needing attention by Millennium Pipeline during the pipeline stop work order to address concerns and pollution issues related to inadequate and problematic construction practices causing pollution to the East Branch Delaware River:

> the grading at the top of the hillside prevents the installation of water bars to outlet to a stabilized area per NYS technical standards…the elevation outside the ROW allowed for drainage from temporary slope breakers to undisturbed areas…rills and gullies were observed mid slope indicating the need for additional slope breakers…concern was raised with method of dispersion of the water existing the temporary slope breakers such that it did not re-concentrate given the extreme grades…evidence of undercutting and erosion were evident around and below (BMP) practices (i.e. haybales)…the rock channel installed to receive flow from the hillside...has several design issues that have the potential to cause this practice to be the source of sediment (pollution) rather than remove it…stockpiles that are not subjected to day to day activities need to be stabilized per the SPDES permit…it is unclear why the permanent stabilization cannot begin once the heavy equipment access point shifts to the top of the hill…it appeared there was not sufficient topsoil available to establish a dense vegetative cover.[59]

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[57] Id.
[58] NYSDEC, Region 4 Letter to Millennium Counsel, Mr. Randolph West, URS Corporation, SPDES Millennium Pipeline Permit No: 10P622. July 3, 2008.
[59] Id.

On November 24, 2008, NYSDEC[60] issued a notice of "Complaint" to Millennium Pipeline Company, documenting hundreds of state and federal water quality violations spanning from August 23, 2007 to November 3, 2008. The complaint cited over eleven "causes of action" outlining 104 actions by DEC affecting multiple waterbodies over multiple instances including receiving streams and watersheds of: Mongaup River, Black Ash Creek, Ramapo River, Stony Brook Creek, Indian Kill Reservoir, Spring Brook, East Branch Delaware River, Torne Brook, Phelps Creek, Greenwood Lake, Greenwood tributary, Calkins Creek, Trib to Baldwin Creek, Trib to Dean Creek, Ten Mile River, Trib of Callicoon Creek, Longhouse Creek, Trib to Stanley Hollow Creek, Stratton Mill Creek, Tuscarora Creek and Trib to Tuscarora Creek, Mitchell Pond, Hankins Creek, Owego Creek, Halfway Brook, Tarbell Creek, Trib to Sand Creek, Marsh Creek, Hoolihan Brook, Roods Creek, Sands Creek, Crystal Lake, Trib of Gold Creek, Laurel Creek, Wheeler Creek, Basket Creek, Nanticoke Creek, Mahwah River, Bouchoux Brook, and multiple wetlands and additional unnamed tributaries. DEC complaints included as subset of examples from Complaint letter:

- The General Permit states that the owner shall not disturb greater than five acres of soil at any one time without prior written approval by the department. Millennium "continuously" disturbed an excess of five acres during the 2007 and 2008 construction seasons and never requested authorization from DEC.

[60] NYSDEC, Region 4 Complaint Letter to Millennium Pipeline Company, R3-2008-0130-3, R4-2008-1017-146, R7-2008-1017-82, R8-2008-1017-82. November 24, 2008.

- The General Permit requires the permittee to comply with state water quality standards. **Millennium was cited 169 times for violating NYS Narrative Water Quality Standards for turbidity and oil and floating substances**.
- The General Permit requires the permittee to prepare a Final Storm Water Pollution Prevention Plan (SWPPP) prior to filing the NOI. Millennium had not filed an SWPPP with Department as of the date that the Complaint was filed (over fifteen months after beginning construction).
- Additionally, Third Party Monitors documented the following violations of the General Permit:

Wetland and Waterbody Construction and Mitigation Procedures:

  - *Failure to have Plans for ROW greater than 75 feet*
  - *Failure to have Sediment barriers*
  - *Failure to construct bridges for unrestricted flows and no soil discharge*
  - *Failure to install temporary erosion and sediment controls*
  - *Failure to maintain Temporary Erosion and Sediment Controls*
  - *Failure to install and maintain (daily) Erosion Controls During Grading*
  - *Failure to store Soil Piles Ten Feet From Water-body*
  - *Failure to Install Temporary Trench Plugs*
  - *Failure to Follow Trench Dewatering Specifications*
  - *Failure to Remove Waste from Construction Work Area (CWA)*
  - *Failure to Restore after Final Grading*
  - *Failure to Follow water-body crossing procedures*
  - *Discharge of Bentonite Drilling Fluid from Frack Out*
  - *Failure to install/Maintain Equipment Bridges Per FERC Standards*
  - *Trench Dewatering to Wetland or Water-body*
  - *Failure to Use Trench Plugs*
  - *Failure to Minimize Construction Wetland Disturbance*
  - *Failure to Mark Wetland Boundaries Prior to Clearing/Construction*
  - *Failure to Properly Address Temporary Access Roads*
  - *Failure to Properly Clear Wetlands*
  - *Failure to Properly Follow Trench De-watering Procedures*
  - *Failure to Follow Backfilling Procedures*
- Millennium was cited 642 times for the above-listed violations. Millennium's failure to implement the erosion and sediment controls are violations of the Water Quality Certification (WQC) and the General Permit.

- Millennium failed to train its environmental inspectors for the project. Inspectors lacked project-specific environmental training for conducting inspections pursuant to the General Permit.
- Millennium violated the "Upland Erosion Control, Re-vegetation and Maintenance Plan" and the WQC by failing to conduct daily inspections.
- Department staff reviewed Millennium's environmental inspections website and there were no documented inspections for the month of June 2008.
- Millennium violated the General Permit by failing to have each of its contractors sign the certification statement which identifies trained contractors that will be responsible for installing, constructing, repairing, inspecting and maintaining the erosion practices included in the SWPPP.
- Millennium violated the WQC by conducting clearing and restoration during the restriction period for cold-water streams. The specified construction timing windows are meant to minimize impact on water quality and to avoid interruption of spawning runs in water bodies.
- Millennium failed to retain a permit for storm water discharges, resulting in the disturbance of soils outside of the Construction Work Area covered by the General Permit.
- Millennium violated the States Navigation Law by discharging hydraulic oil into the East Branch of the Delaware River.
- Millennium failed to notify the department within two hours of a petroleum discharge in violation of the Navigation Law.

A civil Penalty of $7.4 million was assessed against Millennium and the company was ordered to deposit $2 million into a distinct Environmental Benefit Project (EBP) escrow account. The money would be spent on an EBP determined by the Department. However, that is not what happened. Based on the Order of Consent signed by the acting DEC Commissioner Alexander B. Grannis and Millennium's President, Richard H. Leehr: Department staff agreed to withdraw the complaint with prejudice and Millennium was assessed a civil penalty of $200,000. Millennium was ordered to hire five full-time positions by a third-party entity, for

a total EBP payment of $1 million. Four of the positions were for storm water pollution control specialists and the fifth position was a stream protection biologist. DEC agreed not to sue Millennium.

All of these violations and instances of harm were allowed under FERC's Environmental Impact Statement for the original Millennium pipeline project and in this instance of the ESU Project – an EIS is not even being required and segmentation strategies continue. Furthermore, FERC BMP practices for this current ESU proposal would be much the same practices that clearly did not work the first time around and led to hundreds of violations and impacts to New York waterbodies and violations to NY's water quality standards. To allow and permit further damage again by Millennium due to FERC's inadequate regulations and false assumptions in the EA regarding the now proposed ESU project is unacceptable. By all standards, the Millennium Pipeline was not "environmentally acceptable" and most certainly did not have "appropriate mitigation." The environmental monitoring for the project did not "ensure compliance with all mitigation measures." The Millennium ESU should not be allowed to be built.

X. <u>Induced Natural Gas Development</u>

The EA includes no analysis of impacts to the environmental that will result from induced new natural gas drilling development caused by the Project, and from the installation and operation of a new gas distribution system that will be caused by the Project.

The inducement of future gas development along the northern tier of Pennsylvania is an indirect effect of the pipeline's construction and operation that must be evaluated in the Commission's environmental review of the Project. Such development is fairly understood as being indirectly caused by the availability of infrastructure to transport the gas to market. *See, e.g., City of Davis v. Coleman*, 521 F.2d 661, 677 (9th Cir. 1975) (EIS for highway project needed to analyze impact of induced development despite uncertainty about pace and direction of development); *Natural Res. Def. Council, Inc. v. Fed. Aviation Admin.*, 564 F.3d 549 (2d Cir. 2009) (agency properly considered indirect and cumulative impacts of induced growth caused by construction of new airport); *Border Power Plant Working Grp. v. Dep't of Energy*, 260 F. Supp. 2d 997, 1012–18 (S.D. Cal. 2003) (NEPA required agency review of air emission impacts from Mexican power plants as part of EIS for transmission line project in California that indirectly caused such emissions). Such development is reasonably foreseeable given the demand for gas drilling in the Marcellus shale region. *See, e.g., Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992) (future impacts are reasonably foreseeable if they are "sufficiently likely to occur that a person of ordinary prudence would take them into account when reaching a decision."). This induced development is particularly relevant here where DRN has submitted expert reports detailing that the existing Project is necessarily designed in contemplation of future looping of Millennium's system.

XI. Public Benefits do not Outweigh the Harms

Section 7 of the NGA, 15 U.S.C. §717f, and FERC's Statement of Policy for Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC ¶ 61,227 (1999), clarified, 90 FERC ¶ 61,128 (2000), further clarified, 92 FERC ¶ 61,094 (2000) ("Certificate Policy Statement"), require the Commission to determine whether the Project facilities are "in the public interest" and whether the proposed pipeline is "required by the public convenience and necessity." Specifically, the Certificate Policy requires the Commission to balance the alleged need for a project against the adverse impacts on affected landowners and the surrounding communities. 88 FERC ¶ 61,747. Stated simply, the Commission cannot approve a project unless it concludes that the project's benefits outweigh its adverse impacts. Here it is clear that the project benefits do not outweigh its adverse impacts, and such a conclusion is supported by the findings of an expert analysis submitted here by DRN.

This expert report specifically reviewed the Project's impacts on property values, the social costs of carbon, and public health, and concludes that "[d]ue to flaws in methods, assumptions, and execution of its study, we conclude that the

benefit estimates Millennium has provided are overstated. On the cost side, the situation is worse. "[61]*See Exhibit B.*

The Commission failed to account for diminution in property values to compare with the alleged benefits of the Project. For example, the report cites a systematic review of property values impacted by pipelines which found that:

> ● 68% of Realtors believe the presence of a pipeline would decrease residential property value.
> ● Of these Realtors, 56% believe the decrease in value would be between 5% and 10%. (Kielisch does not report the magnitude of the price decrease expected by the other 44%.)
> ● 70% of Realtors believe a pipeline would cause an increase in the time it takes to sell a home. This is not merely an inconvenience, but a true economic and financial cost to the seller.
> ● More than three quarters of the Realtors view pipelines as a safety risk.
> ● In a survey of buyers presented with the prospect of buying an otherwise desirable home with a 36-inch diameter gas transmission line on the property, 62.2% stated that they would no longer buy the property at any price. Of the remainder, half (18.9%) stated that they would still buy the property, but only at a price 21%, on average, below what would otherwise be the market price. The other 18.9% said the pipeline would have no effect on the price they would offer[62]

The expert report concluded that a reduction in offer price for homes that are in close proximity to this pipeline would range from 10% to 60%. Thus, it is clear

[61] *Economic Costs of the Eastern System Upgrade: Effects on Property Value, the Social Cost of Carbon, and Public Health,* Key-Log Economics, LLC. For the Delaware Riverkeeper Network, April 2017
[62] Id. at 18.

that property values along rights-of-way for pipelines necessarily suffer significant losses.[63] This fact was not accounted for in the EA.

Additionally, the expert report also examined the impact of property values with regard to proximity to compressor stations and found that "the mounting anecdotal information suggests there is a negative relationship, and depending on the particular circumstances, the effect can be large–up to the 100% loss."[64]Specifically, the "properties within one half mile of the Highland CS would lose 25% of their value if the station is built."[65] Overall land value impacts include $2.0 million in diminished property value with the most intense effects felt by the owners of 5 parcels in the path of the right-of-way, who collectively would lose between $7,814 and $24,187 in property value. Some 196 additional parcels lie outside the ROW but are within or touching the evacuation zone. These parcels' owners would lose an estimated $753,692 (Table 5). Finally, the compressor stations would reduce the value of 43 properties by a total of $4.9 million.[66] The resulting impact would therefore drive up expenses while driving down the counties' most reliable revenue stream. However, when calculating the benefit versus the costs of this project the Commission has failed to account for any of this data. As such their decision is arbitrary.

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[63] *Economic Costs of the Eastern System Upgrade: Effects on Property Value, the Social Cost of Carbon, and Public Health,* Key-Log Economics, LLC. For the Delaware Riverkeeper Network, April 2017
[64] Id. at 24.
[65] Id.
[66] *Id*. at 26-27.

Additionally, the Project will likely dampen economic activities related to existing scenery, recreational opportunities, and quality of life factors, and therefore undermine the progress toward economic development goals related to these factors.[67] A loss of scenic and recreational amenities, the perception and the reality of physical danger, and environmental and property damage resulting from the ESU could discourage people from visiting, relocating to, or staying in the region. Workers, businesses, and retirees who might otherwise choose to locate the Project's proposed route or near the compressor stations will instead pick locations that have retained their character, their productive and healthy landscapes, and their promise for a higher quality of life.[68]

If, for example, the ESU were to cause a 5% drop in recreation and tourism spending from 2015 baselines, the project could mean $47.2 million less in travel expenditures each year (Tourism Economics, 2016a, 2016b). Those missing revenues would otherwise support roughly $3.1 million in local tax receipts, $2.6 million in state tax revenue, 745 jobs, and $22.1 million in payroll in the three-county region.[69] Again, none of these economic costs are accounted for in the EA.

Furthermore, the expert report concludes that the studies cited by Millennium for the proposition that property values are not impacted are not

[67] *Id.* at 31-32.
[68] *Id.*
[69] *Id.* at 32.

reliable because they fail to account for that "void entirely their conclusions."[70] Specifically, the expert report states:

> First, the studies fail to consider that the property price data employed in the studies do not reflect buyers' true willingness to pay for properties closer to or farther from natural gas infrastructure. For prices to reflect willingness to pay (and therefore true economic value), buyers would need full information about the subject properties, including whether the properties are near a pipeline. Second, the studies finding no difference in prices for properties closer to or farther away from pipelines are not actually comparing prices for properties that are "nearer" or "farther" by any meaningful measure. The studies compare similar properties and, not surprisingly, find that they have similar prices. Their conclusions are neither interesting nor relevant to the important question of how large an economic effect the proposed pipeline would have.[71]

The Commission also does not account for the social costs of carbon. The social cost of carbon ("SCC") is a comprehensive estimate of the economic cost of harm associated with the emission of carbon. Using U.S. EPA estimates based on the average of impacts from three assessment models and discount rates of 5% and 2.5%[72], the cost to society of the carbon transmitted through the proposed Project would total between $4.8 and $18.8 billion over 50 years. The Commission must count this significant cost among the effects of the proposed pipeline.[73] However, nowhere in the EA are these costs estimated or accounted for.

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[70] *Id. At 20.*
[71] *Id*.
[72] U.S. EPA, Climate Change Division, 2016
[73] *Id*. at 28-29.

Lastly, natural gas transmission projects such as the proposed Project are known to releases toxins, smog forming pollutants, and greenhouse gases that have a negative impact on public health. For example:

> [Compressor] stations are implicated as contributing to a long list of maladies. According to Subra (2015), individuals living within 2 miles of compressor stations and metering stations experience respiratory impacts (71% of residents), sinus problems (58%), throat irritation (55%), eye irritation (52%), nasal irritation (48%), breathing difficulties (42%), vision impairment (42%), sleep disturbances (39%), and severe headaches (39%). In addition, some 90% of individuals living within 2 miles of these facilities also reported experiencing odor events (Southwest Pennsylvania Environmental Health Project, 2015). Odors associated with compressor stations include sulfur smell, odorized natural gas, ozone, and burnt butter (Subra, 2009). Furthermore, compressors emit constant low-frequency noise, which can cause negative physical and mental health effects.[74]

The Commission has failed to assess these impacts either qualitatively or quantitatively with regard to the proposed Project.[75] In addition to the health impacts, the pollution from compressor stations can cause damage to agriculture and infrastructure. One study found that shale gas air pollution damages in Pennsylvania already amount to between $7.2 and $30 million, with compressor stations responsible for 60-75% of this total.[76] Using the low estimate of 60%, that is between $4.32 and $18 million in damages associated with compressor stations.[77]

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[74] Luckett, Buppert, & Margolis, 2015
[75] Id. at 30.
[76] Walker & Koplinka-Loehr, 2014
[77] *Id.*

As explained above, the EA fails to demonstrate that impacts on landowners and the surrounding community have been mitigated or are outweighed by any alleged public benefits of the Projects. Absent the comprehensive assessment of adverse impacts to landowners and surrounding communities that NEPA requires, the Commission is not in a position to draw a conclusion as to whether the Projects' potential public benefits outweigh the potential adverse effects. Moreover, and as discussed in detail in the Key-Log Report on the Need for the Proposed Constitution Pipeline, incorporated fully by reference herein, the Commission's assumptions that the Projects will fulfill a need is misplaced.

XII. <u>Climate Change</u>

As discussed below, the EA fails to account for the extent to which Project construction and operation will emit air pollutants and fails to present a comprehensive analysis of the direct, indirect, and cumulative effects of the Project on climate change. The EA acknowledges that construction and operation of the proposed projects will result in result in significant emissions of various air pollutants, including NOx, VOCs, carbon monoxide, particulate matter, sulfur dioxide, and GHGs, particularly methane. Methane is a potent GHG, which the Intergovernmental Panel on Climate Change ("IPCC") estimates to have 34 times the global warming potential ("GWP") of carbon dioxide ("CO2") over a 100-year period

The EA fails to undertake a meaningful analysis of the climate change impacts of the GHG emissions, including fugitive emissions of GHGs, which would result from the construction and operation of the proposed Project. The Commission acknowledges that emissions of GHGs from the operation of the Project will result in environmental impacts; however, the analysis stops there.

The proposed Project will emit GHGs equivalent to Americans driving more than 10 billion additional miles a year. This number is derived from calculating that CO2 emissions from a gallon of motor gasoline is 0.00892 metric ton, the ratio of carbon dioxide emissions to total GHG emissions is 0.985,[78] and then the average fuel economy of vehicles sold in FY 2013 was 24.7 miles per gallon.[79] Therefore, the Project's annual emissions of 4.3 million metric tons of CO2 are the equivalent of 10.1 billion miles based on average fuel economy of vehicles sold in FY 2013. However, the Commission discards this massive, and quantifiable, increase in GHGs by claiming that there is no way to specifically evaluate the incremental impact of such an increase on climate change. It appears the Commission will rely on such a dismissal of this issue until we reach a catastrophic tipping point, when it will be too late to avoid or mitigate impacts. Such an outcome is precisely what NEPA is intended to prevent.

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[78] *See* Environmental Protection Agency, Greenhouse Gas Equivalency Calculator, September 2013, www.epa.gov/cleanenergy/ energy-resources/refs.html#vehicles

[79] *See* University of Michigan, Average Sales-Weighted Fuel-Economy Rating. (Window Sticker) of Purchased New Vehicles for October 2007 Through August 2013, August 2013, www.umich.edu/~umtriswt/EDI_sales-weighted-mpg.html.

For the reasons explained above, the environmental review fails to meet the requirements of the National Environmental Policy Act ("NEPA"), 42 U.S.C. § 4321 *et seq*. (2006), and its implementing regulations, 40 C.F.R. Pts. 1500-08. The Assessment cannot serve as the basis for an adequate hard look at the Project's environmental impacts or support a finding of no significant impact ("FONSI"). Based on this flawed environmental review, the Commission cannot determine that the public benefits of the proposed Project outweigh its adverse impacts, thus violating the Natural Gas Act ("NGA"), 15 U.S.C. §§ 717f (2006) and its implementing regulations, 18 C.F.R. Part 157 (2011). Additionally, DRN requests that the Commission require Millennium submit additional information related to the interconnected nature of this project with several other of Millennium's concurrent Commission-jurisdictional projects.

Submitted,

Maya K. van Rossum
the Delaware Riverkeeper

Exhibits

A. *Observations Concerning the Millennium Eastern System Upgrade Project Proposal,* Accufacts, Inc., March 26, 2017 and Addendum, April 20, 2017

B. *Economic Costs of the Eastern System Upgrade: Effects on Property Value, the Social Cost of Carbon, and Public Health,* Key-Log Economics, LLC. For the Delaware Riverkeeper Network, April 2017

C. *Citizen Input Regarding the Proposed Eastern System Upgrade Project, Analysis of Comments to FERC,* Key-Log Economics, LLC. For Delaware Riverkeeper Network, April 2017

D. *Environmental Review of the Proposed Millennium Pipeline Eastern System Upgrade,* Prepared by Princeton Hydro, LLC. for the Delaware Riverkeeper Network, November 28, 2016

E. *Clearcutting in Forested Wetlands,* Schmid & Company, inc., Consulting Ecologists, May 1, 2017

F. *Review of INGAA Foundation Report, "Pipeline Impact to Property Value and Property Insurability",* Key-Log Economics, March 11, 2015

G. *Marcellus/Utica on Pace for Pipeline Overbuild, Says Braziel,* Natural Gas Intelligence, June 8, 2016

H. *The Potential Environmental Impact from Fracking in the Delaware River Basin*, Steven Habicht, Lars Hanson, and Paul Faeth, August 2015

I. *Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil and Shale Gas Boom,* J. David Hughes, Post Carbon Institute, October 2014

J. *A Bridge Too Far: How Appalachian Basin Gas Pipeline Expansion Will Undermine U.S. Climate Goals,* Oil International, July 2016

K. *Cumulative Land Cover Impacts of Proposed Transmission Pipelines in the Delaware River Basin,* Lars Hanson and Steven Habicht, May 2016

L. *Natural Gas Price Increase Inevitable,* Art Berman, The Petroleum Truth Report, February 21, 2016

M. *Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews,* Christina Goldfuss, Council on Environmental Quality, August 1, 2016

N. *The Effects of Converting Forest or Scrub Wetlands to Herbaceous Wetlands in Pennsylvania,* Schmid and Company, Inc., Consulting Ecologists, 2014

O. *Thermal Impacts to Exceptional Value Waterbodies in Pennsylvania Cut by Gas Pipeline Projects,* Delaware Riverkeeper Network, September 25, 2016

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March 26, 2017

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Re: Observations Concerning the Millennium Pipeline Eastern System Upgrade Project Proposal, FERC Docket No. CP-16-486

Accufacts Inc. ("Accufacts") was asked to review the above Millennium Pipeline filing and proposal to FERC identified as the Eastern System Upgrade Project Proposal ("Project"). The Project description indicates the proposal will:

1. loop the existing 24-inch Neversink 920 psig Maximum Allowable Operating Pressure, or MAOP, pipeline with approximately 7.8 miles of pipeline (approximately 0.1 miles of 30-inch and approximately 7.7 miles of 36-inch pipeline identified as the "Huguenot Loop," which will be designed for an MAOP of 1,350 psig,[1]
2. provide 38,300 additional horsepower at the existing 15,900 horsepower Hancock compressor station,
3. construct and operate a new 22,400 horsepower compressor station (Highland) installed between the Hancock and Minisink compressor stations,
4. modify the existing Wagoner Interconnect,
5. supply additional pipeline facilities at the Huguenot Meter and Westtown Metering stations including installation of various pig launchers and receivers, and
6. make modifications at the existing Ramapo Metering and Regulator Station. [2]

The stated purpose of the Project "is to permit Millennium to transport an incremental volume of 223,000 dekatherms per day of natural gas from Millennium's Corning Compressor Station to an existing interconnect with Algonquin Gas Transmission, L.L.C (Algonquin) located in Ramapo, New York."[3] The application further states that "The Project facilities have been specifically designed to provide for an additional 223,000

[1] MAOP is a term defined in federal pipeline safety regulations for gas transmission pipelines that has a specific meaning and obligation to FERC. The Millennium application/filing references the term maximum operating pressure, but this term is not defined in federal pipeline safety regulations. The bulk of the Millennium gas transmission system is designed for an MAOP of 1200 psig.
[2] Millennium Pipeline Company L.L.C application to FERC, "Eastern System Upgrade Resource Report 1 General Project Description," July 2016, pp. 1-1 & 1-10.
[3] *Ibid*., p. 1-2.

dekatherms per day of firm transportation, as well as to maintain adequate operating pressures at intermediate delivery points following the construction of the Project, to continue to meet customer demand on Millennium's system during the summer months, and to ensure continued deliveries to interconnecting pipelines."[4]

In order to obtain Project pipeline/flow/pressure data Accufacts was required to sign a Protective Agreement with Millennium, and a CEII nondisclosure agreement with FERC that prohibits public disclosure of certain information concerning this proposal. Based on a review of the CEII protected Exhibit G submissions for this project, Accufacts cannot justify the pipeline Project, especially the 1,350 psig MAOP design nor the 36-inch diameter for the new Huguenot Loop. In Accufacts' opinion this unusual proposal suggests further expansions are in Millennium's plans and such "segmented" expansion(s) should be included with this Project's proposal.

Confidential Attachments (CEII protected) Exhibits No. 1, 2, 3, and 4 developed by Accufacts.

The attached four Exhibits plot pressure and flow versus milepost between Corning compressor station, or "CS," (set as milepost zero) and the Ramapo Metering station connection to Algonquin (milepost ~ 189) for the existing and the proposed peak day expansion cases submitted to FERC for summer and winter, respectively.

The mainline pipeline length downstream of Minisink to Ramapo provided by Millennium as Exhibit Gs for the mainline transmission pipe are not modified by the proposed Project but vary by over 5 miles in length (or over 16% of the segment). Millennium needs to reconcile this error in updated filings to FERC given the importance of the Minisink CS to Ramapo mainline segment length to the validity of the Project's application. Suspecting a typographical error in the Exhibit G submissions, for purposes of the attached Confidential CEII Exhibits, I have normalized this length to the same value across all four Exhibits using the shortest mainline length given in the Exhibit Gs for the Minisink to Ramapo pipeline segment. There is another apparent error in the existing winter case pressures for the segment between the Minisink CS and the Ramapo M&E delivery point (see Exhibit 3 pressure line). The pressure slopes appear inconsistent for the flows, and pressure downstream along a pipeline does not increase with flow unless compression is added.

Based on the provided CEII information, Accufacts has the following additional detailed comments supplemented from a review of attached Exhibits:

1) **The proposed MAOP of 1,350 psig for the new pipe looping (i.e., Huguenot Loop) cannot be supported nor justified by this Project.**

   With the exception of the existing Neversink 24-inch segment restricted to an MAOP of 920 psig, the Millennium Pipeline gas transmission mainline was installed and designed to operate as a 30-inch pipeline with a MAOP of 1,200 psig (see purple dashed MAOP

[4] *Ibid*.

lines on all Exhibits).[5] Installing the 36-inch segment at an MAOP of 1,350 overbuilds the Project for its stated purpose. Millennium has not adequately explained nor justified their request to install additional large diameter 36-inch pipeline at the MAOP of 1,350 psig. Installing much larger diameter pipe rated for much higher MAOP than the current major system's design signals further expansions are being anticipated or planned as a result of this Project. Both the large diameter 36-inch pipeline and the higher pressure 1,350 psig MAOP for the looped pipe proposal are inconsistent with the remainder of Millennium's main gas transmission system of 30-inch pipe and 1,200 psig MAOP upstream and downstream of the proposed loop. There is no way, for example, that the 1,350 psig of the proposed loop can be utilized without incorporating additional compressor stations and/or mainline pipeline changes beyond the cases filed for this Project's proposal.

2) The 36-inch diameter pipe is larger than that needed for the Project.

A close review of the Exhibits, especially Exhibit No. 4, will demonstrate that the 36-inch diameter pipeline is larger than needed, even if it were to be installed at a MAOP of 1,200 psig. For example, on Exhibit 4 for the same flow rate, the approximate pressure line between the Hancock CS and Highland CS is less vertical than the pressure line between Highland CS and Huguenot Regulator. The pressure line slope between Highland CS and Huguenot Regulator should be the same or even less vertical because gas flow rate in that segment is the same or less than that for the Hancock CS to Highland CS segment, while the pressures are similar. This deviation in pressure slope or verticalness, because it can significantly affect the analysis, needs to be properly investigated and reconciled. A simple comparison analysis of the Exhibits will further demonstrate that a 30-inch pipeline for the Huguenot Loop would be suitable. Millennium has not adequately justified their proposing a 36-inch diameter pipeline for the Huguenot Loop. Installing a 36-inch pipe segment that is larger than is needed on this primarily 30-inch Millennium Pipeline system, given the current and proposed MAOPs, signals further expansions are anticipated for this Project.

3) Delivery pressures to the Algonquin Pipeline are not justified.

Based on the information provided, the delivery pressure to the Algonquin system at Ramapo can vary considerably. The delivery pressure assumption to Algonquin significantly influences the Millennium Pipeline design and operation. The delivery pressure of 750 psig to Algonquin for the additional gas claimed by the Project needs to be independently justified. Without appropriate justification, it appears as though the current proposal is anticipating additional upgrades.

4) The Neversink 24-inch pipeline segment appears destined for a different service.

It should come as no surprise that the older 24-inch, lower 920 psig MAOP, approximately 7.5 mile long segment of the Neversink portion of the Millennium

[5] PHMSA CAO

Pipeline is out of character with the design of the rest of the newer Millennium transmission pipeline that is 30-inch, 1,200 psig MAOP. The 24-inch Neversink segment has become an increasing bottleneck as gas rates have increased in recent years on the Millennium system. The serious impact of much higher gas rates and actual gas velocities, can be easily demonstrated by reviewing the steep slope (more vertical nature) of the pressure plots on Exhibit 1 and 3 for the existing Neversink segment. These steep slopes, higher pressure loss per mile, suggest that the Neversink 24-inch pipeline is destined for a different service, such as to serve as a much lower gas flow delivery supply gas line to the proposed CPV power plant. Once the Neversink is looped with a 30-inch 1,200 psig MAOP pipeline, the smaller diameter weaker MAOP Neversink pipeline segment is of little value to the mainline Millennium Pipeline system except to serve as a delivery supply line to customers on that segment, essentially the proposed CPV power plant.

5) **The Project proposal signals that Millennium Pipeline is anticipating further pipeline expansions.**

The gas rates required on the pipeline segment discharging from the Hancock compressor station (well over 1,200 Dth/d on the 30-inch 1,200 psig MAOP pipeline), results in an increase of almost 30% more gas through the Minisink Compressor station for the Peak Day Winter Expansion Case. As a result, the Project requests major horsepower addition at Hancock CS and a new compressor station addition at Highland (see Exhibit 4) to meet these higher flow rates. This additional compressor horsepower, needs further supporting analysis with appropriate flow/pressure data, given the discrepancies identified in the provided exhibit Gs, and demonstrated in the attached Exhibits. The combination of requested horsepower addition along with the much larger diameter 36-inch higher 1,350 psig MAOP needs additional supporting analysis as these changes suggest additional project expansions are expected well beyond the needs stated in the Project application.

Conclusion

Millennium's request for a larger diameter 36-inch, 1,350 psig MAOP for the Project's new pipeline segment (Huguenot Loop) is inconsistent and unwarranted. Such an unusual MAOP increase proposal over the Millennium Pipeline system's design in combination with the Project's 36-inch diameter pipe proposal, signals to me that further expansion projects are likely or already planned in the future operation of Millennium Pipeline. Such future projects, I believe, are reasonably foreseeable based on basic engineering principles and must be included in the Project's FERC application and Exhibit Gs.

s/ Richard Kuprewicz

Richard B. Kuprewicz,
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April 20, 2017

To: Maya K. Van Rossum
Delaware Riverkeeper Network
925 Canal St., Suite 3701
Bristol, PA 19007

Re: Addendum to Accufacts 3/26/17 Report Concerning the Millennium Pipeline Eastern System Upgrade Project Proposal ("Project"), FERC Docket No. CP-16-486

Since Accufacts issued its original analysis and report of March 26, 2017 on the Millennium Eastern System Upgrade Project ("ESUP") proposal, Millennium has issued a Revision #2 April 5, 2017 update to the Exhibit Gs correcting the mileage deficiency observed by Accufacts Inc. ("Accufacts"). I have subsequently updated my originally submitted four CEII Exhibits capturing these Millennium revisions. The updated and attached version of these charts can be recognized by the "Accufacts Inc. from Rev 2 data" identified in each chart's footnote. I have the following additional observations based on the revisions and further review:

1. The proposed ESUP reduces the total mainline mileage from the Hancock Compressor station to Ramapo by 0.5 miles (from 187.9 to 187.4 which is apparently associated with the proposed new Huguenot Loop being less mileage than the existing Neversink segment.
2. The justification for the new loop to be 36-inch diameter cannot be supported. An analysis of Exhibits 2 and 4 should demonstrate that a 30-inch diameter pipeline loop can supply the gas rates indicated.
3. The need for a higher MAOP for the new proposed Huguenot Loop is also not supportable as the proposed 1,350 psig MAOP is inconsistent with the Millennium 1,200 psig of the 30-inch mainline system feeding and leaving the proposed new loop segment.
4. Replacement of the proposed new Huguenot Loop with 30-inch will not lengthen or disturb additional sensitive lands, as the proposed loop is intended to bypass the weaker, lower 936 psig MAOP of the Neversink segment with higher MAOP rated pipe. The footprint of the proposed 30-inch bypass loop is essentially the same whether 30-inch or 36-inch in diameter.
5. On Exhibit 3, the gas pressures indicated for the winter pre-expansion case at approximately milepost ("MP") range 172 to 184 remain inconsistent/inappropriate, and have not been properly explained or adjusted by Millennium on the latest 4/5/2017 Exhibit Gs provided to me.

6. The mileposts on the Exhibit G-1 for the Millennium proposed 16-inch Valley Lateral project do not align with for the Millennium mainline milepost indicated for the Pipeline Eastern System Upgrade Project Proposal submitted to FERC.[1]

A further review and analysis of the Accufacts attached updated Exhibits identified as Rev 2 data capturing Millennium's recent 4/5/2017 revisions, especially Exhibits 3 and 4, will demonstrate that a 30-inch diameter pipeline for the proposed new loop around the Neversink segment should be able to supply the gas rates indicated for the proposed Project.

Millennium's request for a larger diameter 36-inch, 1,350 psig MAOP for the ESUP new pipeline segment (Huguenot Loop) remains inconsistent and unwarranted. Such an unusual MAOP increase proposal over the Millennium Pipeline mainline system's design, in combination with the Project's 36-inch diameter pipe proposal, continues to signal to me that further expansion projects are likely or already planned in the future operation of Millennium Pipeline. Such future projects, I believe, are reasonably foreseeable based on basic engineering principles and must be included in the Project's FERC application and Exhibit Gs.

Richard B. Kuprewicz,
President,
Accufacts Inc.

[1] CEII Confidential, Millennium Pipeline Company, L.L.C., "Exhibit G-1 – Valley Lateral Project, Main Transmission System as of October 9, 2015".

Economic Costs of the Eastern System Upgrade:

EFFECTS ON PROPERTY VALUE, THE SOCIAL COST OF CARBON, AND PUBLIC HEALTH

APRIL 2017

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EXECUTIVE SUMMARY

The Eastern System Upgrade project ("ESU") is a multi-part project intended to expand the capacity of the Millennium Pipeline in New York State. The project includes construction of approximately 7.8 miles of 30- and 36-inch pipeline loop in Orange County, construction and operation of a new compressor station ("the Highland Compressor Station" or "Highland CS") in Sullivan County, an additional compressor at the existing Hancock Compressor Station ("Hancock CS") in Delaware County, modifications to the existing Ramapo Meter and Regulator station in Rockland County, and additional pipeline appurtenant facilities at the existing Huguenot Meter Station and Westtown Meter Station in Orange County.

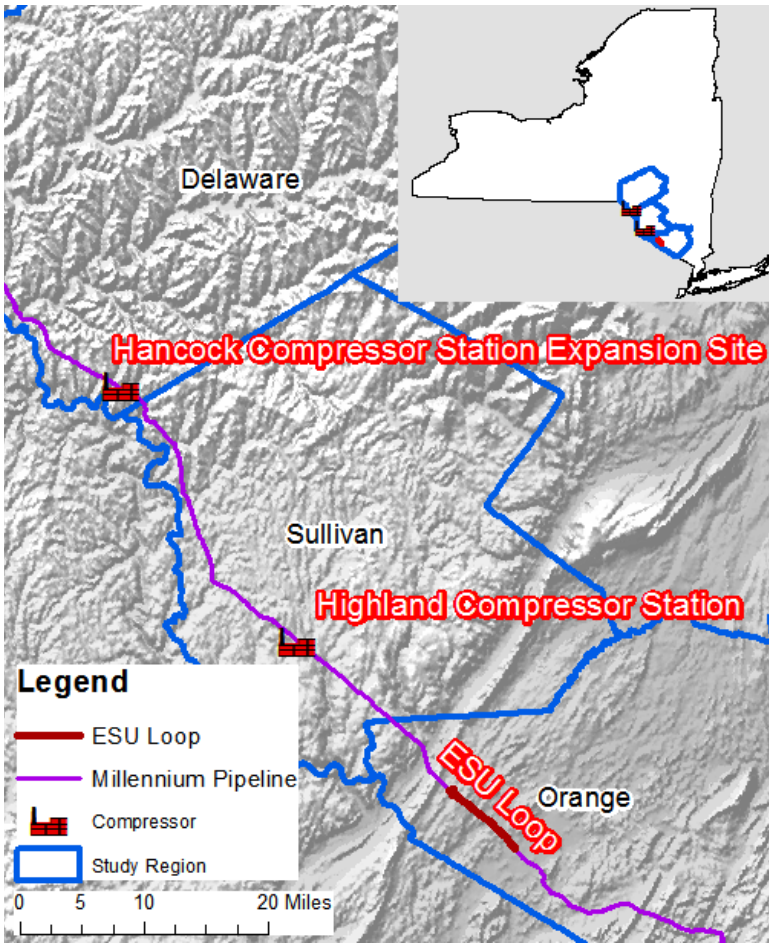

FIGURE 1: Eastern System Upgrade Project (Proposed)

Sources: Eastern System Upgrade loop obtained from Stephen Metts of the New School; Millennium Pipeline Route obtained from OpenStreetMap; Study region (counties), federal lands, and hill shade from USGS (U.S. Department of Interior & U.S. Geological Survey, 2015).

Millennium Pipeline Company, L.L.C ("Millennium LLC") would be in charge of the construction and operation of the project.

Millennium LLC is seeking authorization from the Federal Energy Regulatory Commission ("FERC"), which is responsible for reviewing, and either approving or rejecting the proposal. Under FERC's own policy and the more comprehensive requirements of the National Environmental Policy Act ("NEPA"), FERC's review must look at the economic benefits and costs, as well as the full range of environmental effects of the proposed project. The costs include, but are not limited to, the different ways in which the environmental effects of the pipeline would result in changes in human well-being—including economic benefits and costs.

Under FERC's policy, the applicant of the project provides estimates of economic benefits for review. Millennium LLC's estimates include jobs and income associated with the construction and operation of the pipeline, and additional jobs and income that could occur if the pipeline's operation results in lower net energy costs for industrial, commercial, and individual customers. Due to flaws in methods,

assumptions, and execution of its study, we conclude that the benefit estimates Millennium has provided are overstated.

On the cost side, the situation is worse. Millennium LLC and FERC have thus far discounted or ignored important environmental effects (and the economic consequences of those effects) of the proposed expansion project that would harm the human environment. In other words, Millennium LLC has not yet given serious or adequate consideration to potential negative economic effects—that is, costs—of the ESU.

Delaware Riverkeeper Network commissioned this report to fill that information gap and provide independent research into some of the ESU's principal external costs. In light of data limitations, we provide quantitative estimates of just two types of costs in this report.

First, the construction, operation, and presence of the project would reduce property values along the pipeline and around the compressor stations. Affected properties, those touched by the right-of-way ("ROW"), the 0.9-mile-wide evacuation zone, and within half a mile of the Highland and Hancock compressor stations, could lose a total of $2.0 million in property value. (See "At a Glance" for details.) This one-time reduction in property asset value will spawn a recurring loss of local property tax revenue of $36,000 per year forever.

Second, there is also the social cost of carbon ("SCC"), the additional economic cost of harm associated with the emission of carbon from the project encompassing the cost of methane transport, with the annual cost varying with the year in which the emissions would occur and the assumed rate at which future costs are discounted. Using a 5% discount rate, the social cost of carbon ranges from $50.1 to $115.0 million per year between 2019 and 2048. With a 2.5% discount rate, the annual social cost of carbon ranges from $256.5 to $420.1 million.

Putting the stream of costs into present value terms and adding the one-time costs (the initial loss of property value), the total estimated economic cost of the ESU project in the study region is $4.7 and 18.8 billion.[1] To put this in perspective, and using the (inflated) estimates of benefit provided by the applicant, the Eastern System Upgrade would impose between $2.31 and $9.24 in costs for every dollar of benefit promised.

For reasons explained fully in the body of this report, these are conservative estimates of the external costs for the proposed ESU. One reason is simply that categories of impacts exist that, due to lack of sufficient data, we could not quantify. These include public health costs to residents that would

[1] The present value of a perpetual stream of costs is the one-year cost divided by the real discount rate recommended by the Office of Management and Budget for cost-benefit and cost-effectiveness analysis of public projects and decisions (Office of Management and Budget, 2015). For our analysis, we calculated the appropriate real discount rate for each year the project is in operation for up to 50 years (until 2068), the minimum physical life of the project facilities given by Millennium (Millennium Pipeline Company, L.L.C., 2016). These discount rates were applied to the estimated annual loss in tax revenue and ecosystem service value in each of those years. The social cost of carbon calculations have discounting built in. The total present discounted value for all costs is then the one-time costs, plus the social cost of carbon for 30 years, plus the separately discounted costs due to lost property taxes and ecosystem services.

experience negative health impacts from compressor stations, the potential impact on the economic development, or other costs that may accompany construction.

Another important category of cost not counted here is "passive use value." Passive use value includes the value to people of simply knowing an unspoiled natural area exists and the value of keeping those places unspoiled for the sake of some future direct or active use. In light of this, it is important to consider the estimates of economic costs provided here as a fraction of the total economic value put at risk by the proposed ESU project.

Finally, while this report covers some of the costs that will occur if the ESU is approved, it does not include an assessment of natural resource damage and other effects that might happen during construction and operation. For example, there is a probability that erosion and resulting sedimentation of streams and rivers will occur during construction. There is also the likelihood that a leak or explosion could occur somewhere along the length of the pipeline or at the compressor station. If, when, and where these events occur, there will be clean-up and remediation costs, costs of fighting fires and reconstructing homes, businesses, and infrastructure, the cost of lost timber, wildlife habitat, and other ecosystem services, and most tragically, the cost of lost human life and health.[2]

The magnitude of these damages, multiplied by the probability of occurrence, yields additional "expected costs" which add to the certain costs estimated in this study. To be clear, the costs estimated here—the impact on land values resulting from buyers' concerns about the pipeline and compressor station, the social cost of carbon, and public health impacts associated with the compressor station—will occur with or without any discrete events like stream damage or explosions ever happening. These impacts and their monetary equivalents are simply part of what will happen in New York if the ESU is approved, built, and operates without incident.

FERC could and should thoroughly investigate all of these costs before determining whether or not the Millennium ESU project meets what the Commission describes as an "economic test"—whether the public benefits outweigh the costs—of the merits of natural gas transmission projects and before rendering its decision on the project.

[2] While no one was killed in the incident, the recent explosion of Spectra Energy's Texas Eastern gas transmission line in Pennsylvania is an example of these impacts. See, for example, "PA Pipeline Explosion: Evidence of Corrosion Found" (Phillips [Susan], 2016).

At a Glance:

The Eastern System Upgrade in New York

Delaware, Orange, and Sullivan Counties

- **Miles of pipeline loop:** 7.8
- **Additional aboveground facilities:** Highland CS, new compressor at the Hancock CS; new pig launcher/receiver, alternate interconnect, and modifications to 3 metering stations
- **Impacted acres:**
  - In the permanent right-of-way (ROW): 26.0
  - In the construction zone: 156.9
  - At the existing Hancock Compressor Station in Delaware County during construction and operation: 9.05, 5.5
  - At the new Highland Compressor Station in Sullivan County during construction and operation: 14.31, 5.4
- **Parcels in the portion of the loop not co-located with the existing Millennium Pipeline:**
  - In the ROW: 5
  - In the 1.2-mile-wide evacuation zone: 196
  - Within half a mile of the compressor stations: 32 for the Hancock CS and 11 for the Highland CS
- **Residents and housing units in the pipeline evacuation zone:** 1,092 people, 470 homes
- **Property value:**
  - Baseline—that is, in a "no ESU" scenario—property value at risk (with the expected one-time cost due to the ESU in parentheses):
    - In the ROW: $186,050 ($7,814 to $24,187)
    - In the 0.9-mile-wide evacuation zone: $19.8 million ($753,700)
    - Within half a mile of the compressor stations: $2.1 million ($519,900) for the Hancock CS and $2.9 million ($715,500) for the Highland CS
  - Total property value lost (a one-time cost): $2.0 million
  - Resulting loss in property tax revenue (annual): $36,005 to $36,298
- **The social cost of carbon (equivalent):**
  - An annual cost that varies year to year, the project would contribute to an equivalent of 3.9 million metric tons of carbon dioxide a year. Using a 5% discount rate, the social cost of carbon ranges from $50.1 to $115.0 million per year between 2019 and 2048. Using a 2.5% discount rate for the same time period, the social cost of carbon ranges between $256.5 and $420.1 million per year.
- **Other impacts for consideration:**

  Economic activity that depends on the region's scenic, recreational, and quality of life: We consider a conservative scenario in which visitor spending declines by 5% from current levels, and the rate of growth in retirement and proprietor's income slows by 5%)
    - Annual loss of recreation tourism expenditures of $47.2 million that would otherwise support 745 jobs and generate $3.1 million in local taxes and $2.6 million in state taxes
    - Annual loss of personal income of $6.3 million due to slower growth in the number of retirees
    - Annual loss of personal income of $1.2 million due to slower growth in sole proprietorships
    - The total of these losses is $82.5 million per year
- **Total estimated costs:**
  - One-time costs (property value lost during construction) would be $2.0 million
  - Annual costs (costs that recur year after year) would range from $36,005 to $36,298 PLUS the social cost of carbon, which also varies year by year, and ranges between $50.1 and $420.1 million
  - One-time costs plus the discounted value of all future annual costs: $4.7 to $18.8 billion

CONTENTS

Abbreviations and Terms

BTM: Benefit Transfer Method, a method for estimating the value of ecosystem services in a study region based on values estimated for similar resources in other places

Construction Zone: Refers to the temporary construction right-of-way, temporary work spaces (TWS), additional temporary workspace (ATWS), access roads from public roadways to the construction work areas, pipe/contractor yards, and staging areas.

EA: Environmental Assessment, a document prepared under the National Environmental Policy Act used to determine whether a proposed agency action would require an environmental impact statement of a finding of no significant impact.

EIS: Environmental Impact Statement, a document prepared under the National Environmental Policy Act analyzing the full range of environmental effects, including on the economy, of proposed federal actions.

ESU: The Eastern System Upgrade Project, generally referring to the proposed loop in Orange County and the Hancock and Highland Compressor Stations.

FERC or The Commission: Federal Energy Regulatory Commission, the agency responsible for preparing the EA or EIS and deciding whether to grant a certificate of public convenience and necessity (i.e., whether to permit the pipeline)

HCA: High Consequence Area, the area within which both the extent of property damage and the chance of serious or fatal injury would be expected to be significant in the event of a rupture failure

Millennium LLC: Millennium Pipeline Company, L.L.C., the company responsible for construction and operation of the Eastern System Upgrade; also “the applicant”

NEPA: National Environmental Policy Act of 1970, which requires the environmental review of proposed federal actions, preparation of an EIS, and, for actions taken, appropriate mitigation measures

ROW: Right-of-Way, the permanent easement in which the pipeline is buried

Author's Note

Delaware Riverkeeper Network commissioned this report to help ensure that the likely costs of the Eastern System Upgrade are not left out of the public debate. Delaware Riverkeeper Network has been working throughout the Delaware River Watershed for over 25 years. Using independent advocacy, and backed by facts, science, and law, Delaware Riverkeeper Network champions the rights of communities to a Delaware River and tributary streams that are free flowing, clean, healthy, and abundant with a diversity of life. Please visit www.delawareriverkeeper.org to learn more about their work.

Key-Log Economics is an independent consultancy that brings more than 50 years of combined experience analyzing the economic features of land and resource use and related policy. We are grateful for the assistance of Delaware Riverkeeper Network in identifying local information sources and making contacts in the study region.

Key-Log Economics remains solely responsible for the content of this report, the underlying research methods, and the conclusions drawn. We used the best available data and employed appropriate and feasible estimation methods but nevertheless make no claim regarding the extent to which these estimates will match the actual magnitude of economic effects that will be realized if the Eastern System Upgrade is approved.

Cover Photo from Mark Egan.

BACKGROUND

The Eastern System Upgrade Project proposed by Millennium Pipeline Company, L.L.C. ("Millennium LLC") is seeking a federal permit to expand capacity on parts of the Millennium Pipeline (See Table 1 for a timeline of the Millennium Pipeline and associated infrastructure). The project would transport an additional 200,000 dekatherms per day of natural gas from the Corning Compressor Station to an interconnect with Algonquin Gas Transmission, L.L.C. in Ramapo, New York (Millennium Pipeline Company, L.L.C., 2016a). The ESU includes the construction of about 0.1 miles of 30-inch and 7.7 miles of 36-inch pipeline loop in Orange County, New York, construction of a new 22,400 horsepower (hp) compressor station in Sullivan County, New York (Highland CS), adding an additional 22,400 hp to the existing 15,900 hp Hancock Compressor Station in Delaware County, New York (Hancock CS) for a total of 38,300 hp, modifications to the existing Ramapo Meter and Regulator Station in Rockland County, New York, and additional pipeline facilities at the Huguenot Meter Station and Westtown Meter Station in Orange County, New York (Millennium Pipeline Company, L.L.C., 2016).

Table 1. Brief timeline of Millennium LLC's work with Millennium Pipeline and the ESU project work.

Milestone(s)	
Date	**Description**
December 1997	Millennium LLC files an application for a certificate of public convenience and necessity authorizing the construction and operation of the Millennium Project
June 2007	FERC authorizes Millennium LLC to commence construction
December 2008	Millennium Pipeline went into service
October 2012	Construction of the Minisink Compressor Station begins
June 2013	Minisink Compressor station went into service
October 2013	Construction of the Hancock Compressor Station begins
April 2014	Hancock Compressor Station went into service
January 2016	Millennium LLC files a request for a pre-filing review with FERC for the ESU project
May 2016	FERC announces that they will prepare an environmental assessment for the ESU project
July 2016	Millennium LLC files an application requesting a certificate of public convenience and necessity authorizing the ESU project

For this report, "ESU" refers to those portions of the entire Eastern System Upgrade project that entail (a) the addition of pipeline or an increase in the amount of land consumed by pipeline right-of-way (i.e., the new pipeline and loop in Orange County), and (b) construction of the new (Highland) compressor station and addition of compression capacity at the existing (Hancock) station. We did not analyze the other components of the project because the changes would occur in areas already modified from their previous natural land cover and/or would not represent a major change from the status quo in terms of land consumption, air, noise or other direct impacts. We are not, in other words, rolling back the clock to estimate the external costs of the existing Millennium pipeline facilities in the study area: we are instead focused only on the new costs that the ESU project would impose.

According to Millennium LLC, the ESU project is necessary for meeting natural gas market demand in the region. The applicant also argues that the ESU will stimulate the local economy during the construction phase and produce long-run economic benefits due to energy cost savings for New York electric utility customers in the long run. These claims are detailed in a report prepared for Millennium LLC by Concentric Energy Advisors ("Concentric"). Concentric estimates that construction will have a total impact of $314 million and that the first ten years of operation will result in $703 million in additional economic output. These estimates include predicted consumer energy cost savings, spending on labor and materials during construction and operation, re-spending of consumer cost savings, workers' wages and firm revenues in the local economy, and property tax payments from project facilities associated with the proposed project (Concentric Energy Advisors, 2016; Millennium Pipeline Company, L.L.C., 2016b).

However, there needs to be a more thorough examination into how the permanent right-of-way, the temporary construction corridor of the pipeline, and the proposed compressor stations would impose additional external costs on local residents and businesses, including costs that accrue due to safety concerns. All natural gas pipelines present some danger of leaks and explosions that can cause substantial physical damage. Noise and air pollution from the compressor stations present risks to health and quality of life for nearby residents and businesses (Table 2) (Pipeline Safety Trust, 2015). According to the Pipeline Safety Trust (2015), these dangers are greater with pipelines installed after 2010 than with older facilities. Besides the physical dangers, pipeline incidents may require evacuation of a wide area (up to 0.9 miles across in the case of the ESU loop), a potential constant concern for the thousands of people who live or work in that zone. The economic consequences of these impacts can include diminished property value, lost natural benefits, higher healthcare costs, and dampened economic development, if the physical effects and safety concerns reduce the attractiveness of the region as a place to live, visit, retire, or do business.

TABLE 2. Pipeline Incidents, Impacts, and Costs, 1996 to 2015. Includes gas distribution, gas gathering, gas transmission, hazardous liquid, and LNG lines.
Source: Pipeline and Hazardous Materials Safety Administration (2016)

Place	Incidents	Fatalities	Injuries	Total Cost
U.S.	11,208	360	1,376	$6.9 Billion
New York	201	23	124	$ 78.2Million

To date, the negative effects mentioned above and estimates of their attendant economic costs have not received much attention in the debate surrounding the proposed ESU project. This report, commissioned by the Delaware Riverkeeper Network, is both an attempt to understand the nature and potential magnitude of the economic costs of the project in New York, as well as to provide an example for FERC as it proceeds with its process of analyzing and weighing the full effects of the proposed project.

Policy Context

Before construction can begin, the project must be approved, or "certified," by the Federal Energy Regulatory Commission (FERC). That approval, while historically granted to pipeline projects, depends on FERC's judgment that the project would meet a public "purpose and need" and that the public benefits of the project are balanced against the "potential adverse consequences" of natural gas transmission projects. Because the approval would be a federal action, FERC must also comply with the procedural and analytical requirements of the National Environmental Policy Act (NEPA). These include requirements for arranging public participation, conducting environmental impact analysis, and writing an Environmental Assessment ("EA") or Environmental Impact Statement ("EIS") that evaluates all of the relevant effects. Of particular interest here, such relevant effects include those direct, indirect, and cumulative effects on or mediated through the economy. As the NEPA regulations state,

> "Effects" includes ecological (such as the effects on natural resources and on the components, structures, and functioning of affected ecosystems), aesthetic, historic, cultural, economic, social, or health, whether direct, indirect, or cumulative. Effects may also include those resulting from actions which may have both beneficial and detrimental effects, even if on balance the agency believes that the effect will be beneficial (emphasis added, 36 CFR 1508.8; Council on Environmental Quality, 1978).

To begin its review, FERC issued a Notice of Intent to prepare an EA in May of 2016 (Federal Energy Regulatory Commission, 2016). In The Notice of Intent, FERC anticipated issues of concern regarding geology and soils, land use, water resources, fisheries, and wetlands, cultural resources, vegetation and wildlife, migratory birds, air quality and noise, endangered and threatened species, public safety, and cumulative impacts (Federal Energy Regulatory Commission, 2016). Each of these can translate into economic costs external to Millennium LLC that would be borne by individuals, businesses, and communities throughout the landscape the project would traverse and beyond.

Market Failure: External Costs and the Need for Countervailing Public Action

All market transactions involve two sets of costs and benefits. The first set includes private costs, such as the costs of constructing and operating a pipeline, and private benefits, such as the value to consumers of natural gas delivered through the pipeline. Under the certain highly restrictive preconditions that currently exist, it is possible to say that the price of gas, the amount consumed, and therefore the number of pipelines built and operated functions as the "right" number. "Right" in an economic context translates to "efficient," as in there are no other combinations of gas use/pipeline capacity that could

produce greater net societal benefits. However, the reality is that these pre-conditions do not hold and the market does not give us the right answer to the question of how many pipelines (and how much gas use) should exist. Economists call these situations "market failures." Market failures justify extra-market processes to get us to solutions that are more like the theoretical ideal.

The markets for natural gas and natural gas transmission pipelines fail in many ways. The most important, from the perspective of NEPA and FERC's certification policy, is the presence of "externalities." Externalities are costs generated by market transactions not borne by the parties to those transactions. In this case, externalities include the costs of building and operating the pipeline imposed on people other than the pipeline company and its customers (natural gas shippers and wholesale purchasers, including local distribution companies).

External costs include effects mediated through market transactions (a good example is the reduction in property value when people know a pipeline is nearby) as effects on human well-being that exceed the number of dollars that actually change hands. This "nonmarket value" includes the total value to people (reflected in their full willingness to pay for a good) over and above what they actually pay for a market good (such as a safe place to live, or clean water to drink). Nonmarket benefits and costs also include changes in human welfare from environmental effects for which there is no out of pocket payment at all. Enjoying the aesthetic quality of a view may cost nothing to experience, but the observer still values it. Whether or not there is a market component to the resulting change in value, damage to environmental goods and services caused by the construction and operation of natural gas transmission infrastructure represents a reduction in human welfare and, therefore, an economic cost.

Because these reductions are external costs, neither the pipeline company nor its customers see or consider these costs when making decisions about how much pipeline capacity or natural gas they require. The result is too much pipeline capacity and too much gas delivered at too low a price. The pure economic problem with this over-investment in pipeline capacity and over-consumption of gas stems from resources spent on excess pipeline capacity and gas that could have been more wisely invested in other infrastructure, other services, or other activities that produce higher net benefits.

From an economic point of view, compliance with the National Environmental Policy Act is one way to ensure that costs not considered by the market are nevertheless considered in resource allocation decisions. The NEPA review adds, or should add, the necessary breadth to FERC's analysis of the economics costs of proposed natural gas infrastructure. NEPA requires an evaluation of all relevant effects, but of particular interest here are the direct, indirect, and cumulative economics effects of changes in human welfare that might or might not be reflected in the market economy–i.e. the external costs.

Policy Failure: The Review and Certification of Natural Gas Transmission Projects Discounts External Costs and Inflates Social Benefits

To help address the market failure inherent in the construction and operation of natural gas transmission pipelines, additional analyses and decision making processes are required. FERC's policy on the Certification of New Interstate Natural Gas Pipeline Facilities (88 FERC, para. 61,227) is one example of an attempt to ensure consideration of at least some external costs. The policy requires that adverse

effects of new pipelines on "economic interests of landowners and communities affected by the route of the new pipeline" be weighed against "evidence of public benefits to be achieved [by the pipeline]" (88 FERC, para. 61,227, pp. 18–19). Further, "…construction projects that would have residual adverse effects would be approved only where the public benefits to be achieved from the project can be found to outweigh the adverse effects" (p. 23).

In principle, this policy—what FERC calls an "economic test"—is in line with the argument, on economic efficiency grounds, that the benefits of a project or decision should be at least equal to its cost, including external costs. However, the policy's guidance regarding what adverse effects must be considered and how they are measured is deeply flawed. The policy states, for example, "if project sponsors…are able to acquire all or substantially all, of the necessary right-of-way by negotiation prior to filing the application…it would not adversely affect any of the three interests," which are pipeline customers, competing pipelines, and "landowners and communities affected by the route of the new pipeline" (88 FERC, para. 61,227, pp. 18, 26). The Commission's policy contends that the only adverse effects that matter are those affecting owners of properties in the right-of-way. Even for a policy adopted in 1999, this contention is completely out of step with long-established understanding that development that alters the natural environment has negative economic effects at an individual, community, and broader population level.

The policy's confusion over what counts as an environmental effect (again, most of which will have economic effects) is further expressed by the following statement:

> Traditionally, the interests of the landowners and the surrounding community have been considered synonymous with the environmental impacts of a project; However, these interests can be distinct. Landowner property rights issues are different in character from other environmental issues considered under the National Environmental Policy Act of 1969 (NEPA) (88 FERC, para. 61,227, p. 24).

By the Commission's reasoning, environmental effects are a matter of the Commission's "traditions," not science, and environmental effects are deemed to be both synonymous with, and distinct from, interests of landowners and the surrounding community. This statement seems to contradict the statement one page earlier in the policy that "[there] are other interests [besides those of customers, competitors, and landowners and surrounding communities] that may need to be separately considered in a certificate proceeding, such as environmental interests (p. 23)." While it is true that separate/additional consideration of environmental "interests" must indeed be part of the Commission's review, the policy embodies such a muddle of contradictions on the question of what impacts to examine and why (tradition versus science), that it seems unlikely that any pipeline certification granted under the policy would be scientifically or economically sound.

FERC's own policies and track record, including an over-reliance on the applicants' own estimates of project benefits, make it extremely unlikely that the ESU project certification process would meet NEPA's requirement to consider all project costs and benefits, let alone produce a decision that could be

construed as generating or supporting net economic benefits.[3] The policy's stated objective "is for the applicant to develop whatever record is necessary, and for the Commission to impose whatever conditions are necessary, for the Commission to be able to find that the benefits to the public from the project outweigh the adverse impact on the relevant interests" (88 FERC, para. 61,227, p. 26). The applicant therefore has an incentive to be generous in counting the benefits and parsimonious in counting the costs of its proposal.[4]

Given the weaknesses of the policy, and as evidenced by the track record, FERC's "economic test" does not provide a robust evaluation of the public merits of natural gas transmission projects. It is a "test" in which difficult questions (such as about external costs borne by all stakeholders) are not asked, and where those taking the test (the applicants) provide the answer key. It is therefore not surprising that FERC's environmental reviews typically have not provided estimates of the magnitude of the full external costs associated with natural gas transmission pipelines. Also not surprising, pipeline applicants typically employ methods, assumptions, and a selective review of effects that result in a rosy and grossly distorted picture of the net benefits of their proposed projects.[5]

Current Economic Conditions

Our geographic focus is the three county region of Delaware, Orange, and Sullivan, containing the ESU loop, the Highland CS, and the Hancock CS. This 3,300-square-mile county region supports diverse land uses, including the headwaters of the Delaware River, thriving agri-tourism businesses, and various other attractions. These natural, cultural, and economic assets are among the reasons more than 1.8 million people call this three county region home and an even larger number visit each year for hiking, fishing, skiing, festivals, kayaking, horseback riding, weddings, and other events.

Statistics from the Center for the Study of Rural America, part of the Federal Reserve Bank of Kansas City, highlight the extent to which the region possesses the right conditions for resilience and economic success in the long run (Low, 2004). These data show that the study region has a higher human amenity index (based on scenic amenities, recreational resources, and access to health care), strong entrepreneurship, and higher agricultural land value, relative to the average for New York counties.[6]

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[3] It is important to note that NEPA does not require that federal actions–which in this case would be approving or denying the ESU certification–necessarily balance or even compare benefits and costs. NEPA is not a decision-making law, but rather a law requiring decisions be supported by an as full as possible accounting of the reasonably foreseeable effects of federal actions on the natural and human environment. It also requires that citizens have opportunities to engage in the process of analyzing and weighing those effects.

[4] Millennium LLC and Concentric published estimates of economic benefits in the form of employment and income stemming from the construction and operation of the ESU project (Concentric Energy Advisors, 2016; Millennium Pipeline Company, L.L.C., 2016b). These studies suffer from errors in the choice and application of methods and in assumptions made regarding the long-run economic stimulus represented by the project. Most significantly, the studies make no mention of likely economic costs. See Phillips & Wang (2016), and Appendix A for details on these shortcomings.

[5] See, for example, FERC's Environmental Impact Statements (Draft or Final) for the Constitution Pipeline (CP13-499), Mountain Valley Pipeline (CP16-10), Atlantic Coast Pipeline (CP15-554), PennEast Pipeline (CP-15-558), and the Atlantic Sunrise Pipeline (CP15-138).

[6] Note that the Kansas City Fed's statistics have not been updated since 2004-2006, and conditions in and outside the study region have undoubtedly changed. Some of these relative rankings may no longer hold.

More traditional measures of economic performance suggest the counties are strong and resilient, though there are some differences among the counties.[7] From 2000 through 2014, for example:[8]

- Population
  - Population in Orange County grew by 9.7%, which is more than twice the average growth rate of 4.4% increase for all of New York's metropolitan counties.
  - Population in Delaware and Sullivan Counties increased by 0.4%, compared to an average 1.7% decrease for New York's non-metro counties.
- Employment
  - Orange County employment increased by 18.0%, compared to a 14.1% increase for New York's metropolitan counties.
  - In Delaware and Sullivan Counties, job growth was 2.1%, compared to an average 0.1% decline for non-metro New York.
- Personal income
  - Personal income, which includes wages and salaries as well as income from investments and transfer payments, like Social Security, grew by 26.2% in Orange County, compared to 19.2% average growth in New York metropolitan counties.
  - Delaware and Sullivan Counties saw personal income grow by 15.0%, outpacing the New York non-metro average of 14.3%.
- Earnings per job
  - Average earnings per job increased 7.7% in Orange County, compared to a 1.6% increase for metro New York.
  - Earnings per job in Delaware and Sullivan Counties increased by just 5.8%, compared to the 9.5% increase seen in all of non-metro New York.
- Per capita personal income[9]
  - Per capita income is lower in Orange County, by about $24,700, than the average for New York's metro counties.
  - For Delaware and Sullivan Counties, per capita personal income was about $1,100 higher than the average for non-metro New York counties.
- Unemployment rate
  - The 2014 unemployment rate was 5.5% in Orange County, compared to 6.3% unemployment rate for New York's metropolitan counties.
  - The unemployment rate in Delaware and Sullivan Counties was 6.6%, the same as the unemployment rate for non-metro New York overall.

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[7] Orange County is included in the NY-NJ-PA Metropolitan Statistical Area but Delaware and Sullivan are not (Office of Management and Budget, 2015). Therefore, statistics from Orange County will be compared to the New York metro benchmark and statistics from Delaware and Sullivan Counties will be compared to New York non-metro areas.

[8] These data are from the U.S. Department of Commerce (2015a,b) as reported in Headwaters Economics' Economic Profile System.

[9] Per capita income reflects non-labor income, such as from investments and social security, in addition to the wages and salaries included in earnings per job.

In addition, several trends suggest entrepreneurs and retirees are moving to (or staying in) this region, bringing their income, expertise, and job-creating energy with them. Namely,

- In-migration contributed to 24% of population growth in Orange and 100% of population growth in Delaware and Sullivan.
- The proportion of the population 65 years and older increased from 10.3% to 11.8% in Orange and from 16.0% to 17.5% in Delaware and Sullivan.
- Proprietors' employment is up by 44.3% in Orange and 16.2% in Delaware and Sullivan.
- Non-labor income (primarily investment returns and age-related transfer payments like Social Security) is up by 37.1% in Orange and 27.5% in Delaware and Sullivan.

Temporary residents–tourists and recreationists attracted to the natural amenities of the region–and the businesses that serve them are also important parts of the region's economy. Tourists spent about $944.3 million in the study region in 2015 and the companies that directly served those tourists employed 14,907 people (Tourism Economics, 2016a & Tourism Economics, 2016b).

It is in this context that potential economic impacts of the ESU project should be weighed and the apprehension of the region's residents understood. Many believe the construction and operation of the pipeline will kill, or at least dampen, the productivity of the proverbial goose that lays its golden eggs in the region. This could result in a slower rate of growth in the region and worse economic outcomes. More dire is the prospect that businesses will not be able to maintain their current levels of employment. Just as retirees and many businesses can choose where to locate, visitors and potential visitors have practically unlimited choices for places to spend their vacation time and expendable income. If the study region loses its amenity edge, other things being equal, people will go elsewhere, and this region could contract.

The Neversink River where Millennium LLC proposes to cross.
Photo credit: Stephen Metts

Instead of a "virtuous circle" with amenities and quality of life attracting/retaining residents and visitors, who improve the quality of life, which then attracts more residents and visitors, the ESU could tip the region into a downward spiral. In that scenario, loss of amenity and risk to physical safety would translate into a diminution or outright loss of the use and enjoyment of homes, farms, and recreational and cultural experiences. Some potential in-migrants would choose other locations and some long-time residents would move away, draining the region of some of its most productive citizens. Homeowners would lose equity as housing prices follow a stagnating economy. With fewer people to create economic opportunity, fewer jobs and less income will be generated. Communities could become hollowed out, triggering a second wave of amenity loss, out-migration, and further economic stagnation.

Study Objectives

Given the policy setting and the potential for the project to impact the people and communities in the study region, Key-Log Economics has undertaken this study to provide information of three types:

1. An additional critique positive economic impacts that Millennium, LLC and their consultant, Concentric, has promoted as potential results of the project.
2. An example of the scope and type of analyses that FERC could, and should, complete as part of its assessment of the environmental (including economic) effects of the ESU project.
3. An estimate of the magnitude of key economic effects of the ESU.

The estimates presented below, however, represent less than the total of all potential costs that would attend the construction, operation, and presence of the pipeline and associated infrastructure. The reason is that there are several categories of cost for which the scope of the project or the availability of data preclude direct quantification of those costs. These categories are:

- "Passive-use value," including the value of preserving the landscape without a pipeline for future direct use.
- Probabilistic damages to natural resources, property, and human health and lives in the event of mishaps during construction and leaks/explosions during operation.

PASSIVE USE VALUE

Passive-use values include *option* value, or the value of preserving a resource unimpaired for one's potential future use; *bequest* value, which is the value to oneself of preserving the resource for the use of others, particularly future generations; and *existence* value, which is the value to individuals of simply knowing that the resource exists, absent any expectation of future use by oneself or anyone else. In the case of the ESU project, people who have not visited the Catskills, for example, or otherwise spent vacation time and dollars in the region are better off knowing that the setting for their planned activities is a beautiful, aesthetically pleasing landscape. The value that future visitors would be willing to pay to maintain that possibility would be part of the "option value" of a landscape without the ESU.

Our overall estimates, therefore, should be understood to be conservative, lower-bound estimates of the true total cost of the ESU in the region.

Millennium LLC Overestimates Economic Benefits and Discounts or Ignores Economic Costs Associated With the Project

Economic *efficiency* requires that the total societal benefits of a proposed public action (like approval of a pipeline) balance or exceed the total societal costs of the action. That efficient outcome does not require that the costs be zero, but it does require that it be at least conceptually possible to re-allocate benefits in such a way that those who bear the costs *could be* compensated for their losses. If, in other words, the gainers *could* compensate the losers, then we can declare the project to be a good idea from an economic efficiency standpoint.[10]

As noted under "Policy Failure: The Review and Certification of Natural Gas Transmission Projects Discounts External Costs and Inflates Social Benefits" (p. 4) FERC's pipeline policy states an intention that pipeline projects "would be approved only where the public benefits to be achieved from the project can be found to outweigh the adverse effects" (88 FERC, para. 61,227, p. 23). It is therefore incumbent upon FERC to ensure that estimates of both public benefits and the public costs (i.e., adverse effects) are vigorously and completely investigated. Given that FERC relies almost exclusively on information about costs and benefits provided by private companies seeking pipeline approval, it is up to FERC to ensure that the information it receives is complete and credible as the basis for a comparison of public benefits and costs.

In the case of the ESU project, an initial review of economic information presented to FERC by Millennium Pipeline LLC[11] does not meet this test. We found that the studies overestimated positive impacts (benefits) associated with construction, ongoing operation, and consumer spending of assumed savings elsewhere in local economies, while discounting or ignoring adverse effects (costs). It would therefore be impossible for FERC to conclude, given the information put forth by the applicant, that the Millennium ESU would have benefits that outweigh the costs and, therefore, that granting a certificate would be economically efficient and "good" for society.

The review was included in comments on the project filed by Delaware Riverkeeper Network.[12] Millennium LLC and Concentric Energy Advisors provided an initial and supplemental response to the review of our original critique suggesting FERC not allow our comments "to affect the normal processing of Millennium's Application" (Millennium Pipeline Company, L.L.C., 2016d, p.1; Millennium Pipeline Company, L.L.C., 2017a). We disagree with this recommendation for the simple reason that consideration of input from interested parties, such as Delaware Riverkeeper Network or Millennium

[10] Economic *justice* would require the further step of gainers actually compensating the losers.

[11] See *Estimated Savings For New York Consumers From The Millennium Pipeline Eastern System Upgrade Project* (Concentric Energy Advisors, 2016), and *Draft Resource Report 5: Socioeconomics* (Millennium Pipeline Company, LLC, 2016b).

[12] Available as submittal 20161207-5162 at https://elibrary.ferc.gov/. The review is Phillips, S., & Wang, S. Z. (2016). *Economics of the Eastern System Upgrade: Credible and Complete Estimates of Benefits and Costs are Needed* (p. 16). Charlottesville, VA: Key-Log Economics, LLC for Delaware Riverkeeper Network.

Pipeline Company, LLC is an essential—and legally mandated—part of the normal processing of a pipeline certification application. Moreover, and in light of the substance of the Millennium/Concentric responses, it remains clear that the FERC has yet to receive sufficient and reliable information from the applicant regarding the potential economic benefits and costs of the proposed ESU project. Please see Appendix A for details regarding the Millennium/Concentric responses to our earlier review.

In general, and to summarize from that initial review, Millennium LLC has still not defended its misuse of a short-term economic base model to predict long-term project impacts; it continues to cite fundamentally flawed studies to support the dubious contention that natural gas infrastructure does not affect property values; and it has not shown that the social cost of carbon and public health impacts have been considered and/or will be offset by project benefits. The reasons for caution regarding the benefit estimates are summarized below, and further details regarding the potential costs of the project comprise the remainder of this report.

Millennium LLC relies on an input-output model (specifically, IMPLAN), to estimate long-term impacts though it is well known that such models are unsuitable for estimating such impacts. Due to the underlying assumptions and structure of such models, economic actors (firms and households), at least as represented in the models, cannot respond to changing economic conditions, including new technology, changes in relative prices for goods and services, and changing consumer preferences. Input-output modeling is therefore only appropriate for estimating impacts over the short-term, during which technology, prices, and preferences might be reasonably stable.

Indeed, empirical tests have shown that input-output models have very little value as predictors of economic impacts occurring more than a year or so into the future.[13] The consequence of misapplying input-output techniques to the long-term impacts of the proposed ESU is that the estimates of economic impact presented are too high. FERC needs to understand and acknowledge these limitations, given that part of the rationale for the project is its promised regional economic benefits.

Potential overestimation of impacts occurs because Millennium LLC assumes that the entire state of New York is the proper region for analysis. Because input-output models are built to track the flow of dollars among actors in the defined study region, the bigger the region, the more times those dollars will change hands within the region before “leaking” into some other region. Thus, the bigger the region, the larger the estimated impact. We would suggest defining a more compact study region to obtain more plausible estimates of the short-term economic impact of the project’s construction. Such a region would include the counties where the construction would occur, to be sure, and possibly additional counties where significant construction-related planning, engineering, etc. would occur.

Further potential benefits of the project are assumed to result from energy savings for utility customers. Concentric Energy Advisors (2016) estimated these savings for New York consumers using a partial equilibrium model that assumes a competitive energy market. Accordingly, Key-Log recommends FERC also consider the many factors affecting energy prices–and potential savings–over time that are not considered in such a model. These include additional planned natural gas pipelines, natural gas storage, the increasing rate of growth in renewable energy sources for electricity generation, electricity imports

[13] See Robertson (2003), Haynes et al. (1997), Hoffmann and Fortmann (1996), and Krikelas (1992).

into the NYISO from other regional transmission organizations, weather variations, and state demand management programs.

Overestimates in the benefit to New York electric utility customers of increased natural gas supply could result from a failure to consider costs of the pipeline construction, including a rate of return (Phillips & Wang, 2016, pp. 8-9). Millennium states New York ratepayers will not bear the costs of the Project because none of the ESU Project shippers directly provide service to New York customers (Millennium Pipeline Company, L.L.C., 2017a, p. 4). By estimating the benefits to New York consumers as a result of increased natural gas supply without considering corresponding costs—because they are not borne by New York consumers—Millennium has provided incomplete and unbalanced information regarding the potential consequences of the ESU Project.

With regard to potential negative economic impacts of the proposed project, Millennium LLC relies on flawed analyses that purport to demonstrate that natural gas infrastructure does not affect nearby property values. The studies in question fail in two ways. First, they do not consider whether or not buyers have full information about the purchased properties' proximity to natural gas pipelines. When buyers do not know a pipeline is nearby, it is impossible to conclude from a lack of property price differences, that pipelines do not affect willingness to pay for properties near pipelines.

Second, the studies fail to compare the prices of properties that are meaningfully different with respect to their proximity to natural gas infrastructure. With few exceptions, nearly all of the properties included in the studies can be said to be "near" the pipelines in that they are within the evacuation zone, or at least within its high consequence area. There is therefore no meaningful difference in pipeline proximity between what the studies define as properties that are "near" (or on) the pipeline and "far" (or off) the pipeline. With no difference in the key feature of the subject properties, one would not expect to find any difference in price between those types of properties. To put it more simply, if one wants to know whether there is a price difference between apples and oranges, one has to consider the price of apples and the price of oranges. The studies cited by Millennium however, only consider the price of apples, which makes it impossible to say anything about the relative price of oranges. (See "Effects on Property Value" on p. 17 for more details.)

With regard to the social cost of carbon, we recognize that there is precedent in previous FERC proceedings to ignore this important external cost of natural gas infrastructure. (See "The Social Cost of Carbon: An Additional Cost of Methane Transport" on p. 28.) We make a distinction, however, between what is done by habit and by precedent, and what should be done, if we as a society are to arrive at an economically efficient level of natural gas extraction, transportation, and use. To that end, we agree with the advice of former FERC Commissioner Norman Bay where he states that "the Commission should also be open to analyzing the downstream impacts of the use of natural gas and to performing a life-cycle greenhouse gas emissions study" (Federal Energy Regulatory Commission, 2017).[14]

[14] The Trump Administration has recently rescinded guidance that requires federal agencies to use the social cost of carbon in their environmental reviews. However, this executive action does not make the cost go away; it merely increases the likelihood that agencies will make economically sound decisions.

The possible health effects of the proposed ESU project present a challenge that can only be addressed with further research beyond the scope of this study. On one hand, Millennium LLC has recently released a study that concludes that the *modeled* emissions of hazardous air pollutants associated with the Compressor Stations are "below a level of health concern" (Millennium Pipeline Company, L.L.C., 2017b, p. 2). Specifically, the model predicts an excess lifetime cancer risk for a "reasonably maximally exposed adult" living near either of the proposed compressor stations to be well below the benchmark level of one-in-a-million deemed acceptable under Clean Air Act rules. In addition, the model predicts that the risk of acute health effects is also well below legally acceptable levels.

On the other hand, evidence from other studies suggest that *actual* emissions from compressor stations may exceed allowable levels and that people living near those stations may experience higher incidence of acute health effects, such as nosebleeds, loss of sleep, and severe headaches, compared to people living farther away. A five-state study examining air pollutants around compressor stations found high concentrations of benzene and formaldehyde that exceeded federal guidelines (Macey et al., 2014). In a survey and testing study focused on Pennsylvania, Steinzor, Subra, and Sumi (2013) compared the rate of various health effects experienced by people living closer to (within 1,500 feet) and farther from natural gas facilities, including compressor stations. They found that people living closer to the facilities were more likely to experience 18 of 20 possible symptoms, with several symptoms, like throat irritation and severe headaches affecting more than half of the respondents living within 1,500 feet of the facilities.

It is important to note that further epidemiological research would be required to determine the extent to which such effects are the result of exposure to emissions from compressor stations, as opposed to wells and other facilities, and to control for other relevant factors (e.g., smoking or other behavioral factors, and exposure to other environmental hazards, such as vehicle emissions for people living in congested areas). Such research would shed light on the seeming disconnect between the results of predictive models and the experience of people living near compressor stations.

For this report, we do not include the cost of potential health effects in our estimates of the likely costs of the ESU project. Instead, we discuss those effects and associated treatment costs under the separate heading of "Public Health Effects" (p. 29) along with other possible effects where further investigation is needed.

Environmental-Economic Effects and Where They Would Occur

In the remainder of this report, we follow this potential cycle and consider three distinct types of economic consequences. For the first two of these, there are sufficient data on which to base numerical estimates of economic costs. The latter two are described qualitatively.

1. **Effects on Property Value:** Estimating the loss of private property value as owners and would-be owners choose properties farther from the pipeline's right-of-way, evacuation zone, and compressor stations.
2. **The Social Cost of Carbon:** The economic cost of harm associated with the emission of carbon.

3. **Effects on Economic Development:** More general economic effects caused by a dampening of future growth prospects or even a reversal of fortune for some industries.
4. **Public Health:** The potential for diminished human health due to the operation of compressor stations.

We begin with an exploration of the geographic area over which these various effects will most likely be felt.

Impact Zones within the Study Region

Right-of-Way and Construction Corridor

Construction of the pipeline would require clearing an area of on average about 125 feet (38.1 m or 0.02 miles) wide.[15] After construction, the permanent right-of-way ("ROW") would be an average of 50 feet (15.2 m or 0.01 miles) wide along the entire length of the pipeline.[16]

High Consequence Area

Operated at its intended pressure and due to the inherent risk of leaks and explosions, the pipeline would present the possibility of having significant human and ecological consequences within a large "High Consequence Area" and an even larger evacuation zone. A High Consequence Area ("HCA") is "the area within which both the extent of property damage and the chance of serious or fatal injury would be expected to be significant in the event of a rupture failure" (Stephens, 2000, p. 3). Using Stephens' formula, the HCA for the 30" portion of the pipeline would have a radius of 711.87 feet (216.98 m or 0.13 miles) and for the 36" portion of the pipeline, a radius of 854.25 feet (260.38 m or 0.16 miles).[17]

Evacuation Zone

The evacuation zone is defined by the distance beyond which an unprotected human could escape burn injury in the event of the ignition or explosion of leaking gas (Pipeline Association for Public Awareness, 2007, p. 29). There would be a potential evacuation zone with a radius of at least 2,369 feet (722.07 m or 0.45 miles) for the 30" portion of the pipeline and 2,843 feet (866.55 m or 0.54 miles) for the 36" portion (Figure 2).

It is reasonable to consider land value impacts within the evacuation zone. As Kielisch (2015) stresses, the value of land is determined by human perception, and property owners and would-be owners have ample reason to perceive risk to property near high-pressure natural gas transmission pipelines. Traditional and new media reports attest to the occurrence and consequences of pipeline leaks and explosions, which are even more prevalent for newer pipelines than for those installed decades ago (Smith, 2015). Information about pipeline risks translates instantly into buyers' perceptions and their

[15] Table 1A-1 in *Draft Resource Report 1: General Project Description (2016a)* gives the approximate width of the construction corridor by milepost. For our analysis, we took into account the different widths.

[16] In *Draft Resource Report 1: General Project Description (2016a)*, Millennium LLC notes that they will increase the existing 50-foot wide permanent easement of the Millennium Pipeline by 25 feet to accommodate the ESU loop in areas where the loop and existing easement co-locate. For the areas where the ESU loop and existing pipeline easement do not co-locate, a new 50- foot permanent easement will be created for the loop.

[17] The HCA calculations used the maximum allowable operating pressure of 1,200 PSIG, as noted in *Draft Resource Report 1: General Project Description (2016a)*.

FIGURE 2: Right-of-Way, Construction Corridor, High Consequence, and Evacuation Areas

Note that the overlay of the HCA (in pink) and the evacuation zone (in yellow) shows up as the salmon band in the map. The ROW covers much of the construction corridor, leaving a thin band of red/grey visible (besides for the area where a permanent ROW will not exist). The size of the ROW and construction corridor vary throughout the entire loop.

Sources: ESU loop obtained from Stephen Metts of the New School and parcels from Orange County obtained from New York State's GIS Clearinghouse.

willingness to pay for properties exposed to those risks. For would-be sellers, this dynamic reduces the price they could expect to receive for their homes and makes it harder to find a buyer in the first place. Property owners who do not wish to move would experience a loss of economic value due to diminished enjoyment of their homes (Freybote & Fruits, 2015).

Compressor Stations

The proposed compressor stations are likely to have separate effects on property value and on human health. Based on the experience of homeowners near the compressor station in Hancock, New York, the same one for which the ESU would increase horsepower, we consider the possibility of a property value effect within one half mile of both compressor stations (Catskill Citizens for Safe Energy, 2015). This zone overlaps the ROW and the evacuation zone. Because we assume that the more acute and ever present effect of proximity to the compressor station would dominate all other effects, we ignore the ROW and evacuation zone effects for the properties affected by the compressor stations.

Compressor stations have also been associated with various human health effects at distances up to two miles away from compressor stations (Subra, 2009, 2015). Further epidemiological research would allow

estimation of the costs of those effects for the two proposed stations, however, without such research, we do not include the potential public health costs in the present study.

Proposed compressor station site.
(Photo credit: George Billard)

Municipalities and Counties

If the ESU is built, there will likely be increases in the costs of community services, such as for traffic control and extra law enforcement capacity needed during construction and for emergency preparedness/emergency services during operation. As municipality and county governments, as well as volunteer fire companies meet these needs, costs for services could increase.

Millennium states that they expect the construction and operation of the project to have minor to no short-term impacts or long-term increases to public services (Millennium Pipeline Company, L.L.C., 2016b). Millennium LLC did not confirm in Resource Reports that they interviewed officials responsible for such services, therefore, FERC should not base the claim that the project will not impact public services entirely on Millennium's assurance. Rather, FERC needs to confirm and base their decision on real data, which should be collected before the final decision regarding the pipeline.

Region-Wide Effects

Beyond the loss of property value resulting from the chance of biophysical impacts (leaks and explosions), or the certainty of impacts on aesthetics, the proposed ESU would also diminish scenic amenity and passive-use value that are realized or enjoyed beyond the evacuation zone and out of sight of the pipeline corridor. The people affected include residents, businesses, and landowners throughout the study region, as well as past, current, and future visitors to the region. The impacts on human well-being would be reflected in economic decisions such as whether to stay in or migrate to the study region, whether to choose the region as a place to do business, and whether to spend scarce vacation time and dollars near the ESU project instead of in some other place.

To the extent the ESU causes such decisions to favor other areas, less spending and slower economic growth in the study region would be the result. A secondary effect of slower growth would be further reductions in land value, but in this study we consider the primary effects in terms of slower population, employment, and income growth in key sectors. Table 3 summarizes the types of economic values considered in this study and the zones in which they are estimated.

TABLE 3. Geographic Scope of Effects

A check mark indicates the zones/effects for which estimates are included in this study. The "?s" indicate cost categories for future study, but not quantified in this report.

Values/ Effects	ROW & Construction Zone	High Consequence Area & Evacuation Zone	Near Compressor Station	Entire Study Region	Beyond the Study Region
Human Health and Safety	?	?	✓	?	?
Land/ Property Value	✓[a]	✓[b]	✓[b]	?	?
Economic Development	c	c	c	c	?

Notes:

a. We estimate land value effects for the ROW but not for the construction zone.

b. Properties in the HCA are treated as though there is no additional impact on property value relative to the impact of being in the evacuation zone. Also, we exclude properties in the compressor station zone from estimates of impacts related to the ROW and the evacuation zone: while the compressor station's effects on land value may be similar (driven by health and safety concerns and possible loss of use), they are both more acute and certain. (Noise and air emissions from the compressor stations will be routine, while the probability of a major leak occurring at a given time from the pipeline is rare.) We assume that the ongoing effects of the compressor station on the use and enjoyment of properties nearby would overshadow or dominate the possibility of a high-consequence event or the need to evacuate.

c. Economic development effects related to these subsets of the study region are scenarios that are not included in the total cost estimates for the study region.

Effects on Property Value

To say the impacts and potential impacts of the ESU loop and the compressor stations on private property value are important to people along its proposed route would likely be an extreme understatement. Key-Log Economics and Delaware Riverkeeper Network are conducting an analysis of comments FERC received in regards to the report. While results from that analysis are not yet available, one can look to the nearby example of the proposed PennEast pipeline. Landowners and Realtors in the region affected by that proposal, along the proposed route of the PennEast Pipeline, a 36" high-pressure natural gas pipeline designated to transport gas through Pennsylvania and New Jersey, are already reporting lower than expected appraisals (Kohler, 2015).

While it is impossible to know precisely how large an effect the ESU project has already had on land prices, there is strong evidence from other regions that the effect would be negative. In an independent and systematic review, Kielisch (2015) presents evidence from surveys of Realtors, home buyers, and appraisers demonstrating natural gas pipelines negatively affect property values for a number of reasons.

Among his key findings relevant to the ESU project:

- 68% of Realtors believe the presence of a pipeline would decrease residential property value.
- Of these Realtors, 56% believe the decrease in value would be between 5% and 10%. (Kielisch does not report the magnitude of the price decrease expected by the other 44%.)
- 70% of Realtors believe a pipeline would cause an increase in the time it takes to sell a home. This is not merely an inconvenience, but a true economic and financial cost to the seller.
- More than three quarters of the Realtors view pipelines as a safety risk.
- In a survey of buyers presented with the prospect of buying an otherwise desirable home with a 36-inch diameter gas transmission line on the property, 62.2% stated that they would no longer buy the property at any price. Of the remainder, half (18.9%) stated that they would still buy the property, but only at a price 21%, on average, below what would otherwise be the market price. The other 18.9% said the pipeline would have no effect on the price they would offer.

Not incidentally, the survey participants were informed that the risks of "accidental explosions, terrorist threats, tampering, and the inability to detect leaks" were "extremely rare" (2015, p. 7), which shows that home buyers (and home prices) are sensitive even to low-probability threats to the safety of their families.

Considering only those buyers who are still willing to purchase the property, the expected loss in market value would be 10.5%.[18] This loss in value provides the mid-level impact in our estimates. A much greater loss (and higher estimates) would occur if one were to consider the fact that 62% of buyers are effectively reducing their offer prices by 100%, making the average reduction in offer price for <u>all</u> potential buyers 66.2%.[19] In our estimates, however, we have used the smaller effect (-10.5%) based on the assumption that sellers will eventually find one of the buyers still willing to buy the pipeline-easement-encumbered property.

- Based on five "impact studies" in which appraisals of smaller properties with and without pipelines were compared, "the average impact [on value] due to the presence of a gas transmission pipeline is -11.6%" (Kielisch, 2015, p. 11). The average rises to a range of -12% to -14% if larger parcels are considered, possibly due to the loss of subdivision capability.

These findings are consistent with economic theory about the behavior of generally risk-averse people. While would-be landowners who are informed about pipeline risks and nevertheless decide to buy property near the proposed ESU project could be said to be "coming to the nuisance," one would expect them to offer less for the pipeline-impacted property than they would offer for a property with no known risks.

Kielisch's findings demonstrate that properties on natural gas pipeline rights-of-way suffer a loss in property value. Boxall, Chan, and McMillan (2005), meanwhile, show that pipelines also decrease the value of properties lying at greater distances. In their study of property values near oil and gas wells, pipelines, and related infrastructure, the authors found that properties within the "emergency plan

[18] Half of the buyers would offer 21% less, and the other half would offer 0% less; therefore the expected loss is 0.5(-21%) + 0.5(0%) = -10.5%.

[19] This is the expected value calculated as 0.622*(-100%) + 0.189*(-21%) + 0.189*(0%).

response zone" (EPZs) of sour gas[20] wells and natural gas pipelines faced an average loss in value of 3.8%, other things being equal.

The risks posed by the ESU project would be different—it would not be carrying sour gas, for example—but there are similarities between the ESU scenario and the situation in the study that makes their finding particularly relevant. The emergency plan response zones, for example, are defined by the health and safety risks posed by the gas operations and infrastructure. Also, in contrast to Millennium-cited studies showing no price effects (see "Claims that pipelines do not harm property value are invalid," below), the Boxall study examines prices of properties for which landowners must inform prospective buyers when one or more EPZs intersect the property.

The ESU has both a high consequence area and an evacuation zone radiating from both sides of the pipeline defined by health and safety risks. Whether disclosed or not by sellers, prospective buyers are likely to become informed regarding location of the property relative to the ESU's HCA and evacuation zones or, at a minimum, regarding the presence of the ESU in the study region.

The two compressor stations would likely cause their own more severe reduction in the value of nearby properties. Around the existing Hancock compressor station, properties within half a mile of the proposed compressor station saw property devalued 25% ("Proximity of Compressor Station Devalues Homes by as much as 50%," 2015). We use the 25% devaluation to estimate the amount of property value lost within half a mile of the Highland CS and Hancock CS.[21]

The stations can also be noisy, with low-frequency noise cited as a constant nuisance ("Proximity of Compressor Station Devalues Homes by as much as 50%," 2015). These issues led some homeowners to pull-up stakes and move away and to reduced property value assessments for others (Cohen, 2015a; "Proximity of Compressor Station Devalues Homes by as much as 50%," 2015).

Existing studies suggest negative impacts on land value from various types of nuisances that impose noise, light, air, and water pollution, life safety risks, and lesser human health risks on nearby residents (Sun, 2013; Bolton & Sick, 1999; Boxall et al., 2005). In addition to the emerging body of evidence demonstrating a negative relationship between natural gas infrastructure and property value, well established analyses strongly reveal the opposite analog. Namely, amenities such as scenic vistas, access to recreational resources, proximity to protected areas, cleaner water, and others convey positive value to property.[22] The bottom line is that people derive greater value from, and are willing to pay more for, properties that are closer to positive amenities and farther from negative influences, including health and safety risks.

[20] "Sour" gas contains high concentrations of hydrogen sulfide and poses an acute risk to human health.

[21] We re-evaluate the property value lost around the Hancock CS to reflect more up to date parcel information. We believe these estimates may be conservative due to the fact that under the update, the Hancock CS would receive additional horsepower.

[22] Phillips (2004) is an example of a study that includes an extensive review of the literature on the topic.

Claims That Pipelines Do Not Harm Property Value Are Invalid

In *Draft Resource Report 5: Socioeconomics* (2016b), Millennium, LLC cites studies purporting to show that natural gas pipelines have at most an ambiguous and non-permanent effect on property values (Diskin et al. 2011; Integra Realty Resources, 2016). Millennium LLC also cites the authors of Wilde, Loos, & Williamson (2012) and their statement that there is "no credible evidence based on actual sales data that proximity to pipelines reduces property values" (p. 16). While the studies referenced differ in methods, they are similar in that they fail to take into account two factors that void entirely their conclusions that natural gas pipelines have no effect on property values.

First, the studies fail to consider that the property price data employed in the studies do not reflect buyers' true willingness to pay for properties closer to or farther from natural gas infrastructure. For prices to reflect willingness to pay (and therefore true economic value), buyers would need full information about the subject properties, including whether the properties are near a pipeline. Second, the studies finding no difference in prices for properties closer to or farther away from pipelines are not actually comparing prices for properties that are "nearer" or "farther" by any meaningful measure.[23] The studies compare similar properties and, not surprisingly, find that they have similar prices. Their conclusions are neither interesting nor relevant to the important question of how large an economic effect the proposed pipeline would have.

When the Preconditions for a Functioning Market Are Not Met, Observed Property Prices Do Not (And Cannot) Indicate the True Economic Value of the Property

Economic theory holds that for an observed market price to be considered an accurate gauge of the economic value of a good, all parties to the transaction must possess full information about the good. If, on the other hand, buyers lack important information about a good, in this case whether a property is near a potential hazard, they cannot bring their health and safety concerns to bear on their decision about how much to offer for the property. As a result, buyers' offering prices will be higher than both what they would offer if they had full information and, most importantly, the true economic value of the property to the buyer.

As Albright (2011) notes in response to the article by Disken, Friedman, Peppas, & Peppas (2011):

> "The use of the paired-sales analysis makes the assumption of a knowing purchaser, but I believe this analysis is not meaningful unless it can be determined that the purchaser had true, accurate and appropriate information concerning the nature and impact of the gas pipeline on, near or across their property… I believe that the authors' failure to confirm that the purchasers in any of the paired sales transactions had full and complete knowledge of the details concerning the gas transmission line totally undercut the authors' work product and the conclusions set forth in the article" (p.5).

[23] The Kinnard studies mentioned in Wilde, Loos, & Williamson (2012).

In some cases, however, the location and hazards of petroleum pipelines become starkly and tragically known. For example, a 1999 liquid petroleum pipeline exploded in Bellingham, Washington, killing three, injuring eight, and causing damage to property and the environment. In that case and as Hansen, Benson, and Hagen (2006) found, property values fell after the explosion, thus demonstrating that once would-be buyers become aware of the presence of a pipeline and its hazards, they can "vote with their feet" and their wallets and buy elsewhere. The authors also found that the negative effect on prices diminished over time. This makes perfect sense if, as is likely, information about the explosion dissipated once the explosion and its aftermath left the evening news and the physical damage from the explosion had been repaired.

Today's market is quite different. In contrast to Bellingham homebuyers in the months and years after the 1999 explosion, today's homebuyers can query Zillow to see the history of land prices near the pipeline and explore online maps to see what locally undesirable land uses exist near homes they might consider buying. They also have YouTube and repeated opportunities to find and view news reports, citizen's own videos, and other media describing and depicting such explosions and their aftermath. Whether or not the pre- and (in the long term) post-explosion prices in that Bellingham neighborhood reflected the presence of the pipeline, it is hard to imagine that the evident dangers of living near a fossil fuel pipeline would be so easily missed or so quickly forgotten by today's would-be homebuyers.

What Zillow and other sites do accomplish is a lowering of the effort/cost of acquiring information about properties. Potential homebuyers can easily visualize the location of properties relative to other land uses, including pipeline rights-of-way. Combined with other information, such as maps of pipeline routes and other searchable online information, real estate marketing tools do make it more likely that prospective buyers will gain and act on information about the hazard they could be buying into.

With more vocal/visible opposition to large, high-pressure natural gas pipelines and associated natural gas infrastructure it also seems likely that prospective home buyers will not have to wait for an incident involving the ESU project to learn of it and, therefore, for the project to affect willingness to pay for properties nearby. Anyone with an eye toward buying property near the proposed path of the project could quickly learn that the property is in fact near the corridor, that there is a danger the property could be adversely affected by the still pending project approval, and that fossil fuel pipelines and related infrastructure have an alarming history of negative health, safety, and environmental effects.

When people possess more complete information about a property, they are able to express their willingness to pay when it comes time to make an offer. Accordingly, the prices buyers offer for homes near the ESU upgrade will be lower than the prices offered for otherwise similar homes farther away or in another community or region.

Studies Concluding That Proximity to Pipelines Do Not Result in Different Property Values Are Not Actually Comparing Prices for Properties That Are Different

While the studies cited in *Draft Resource Report 5: Socioeconomics* purport to compare the price of properties near a pipeline to properties not near a pipeline, many or in some cases all, of the properties

counted as "not near" the pipelines are, in fact, near enough to have health and safety concerns that could influence prices. In the Interstate Natural Gas Association of America (INGAA) study, the authors compare prices for properties directly on a pipeline right-of-way to prices of properties off the right-of- way (Integra Realty Resources, 2016). However, in almost all of the case studies the geographic scope of the analysis was small enough where most or all of the properties not on the right-of-way were still within the pipelines' respective evacuation zones (Integra Realty Resources, 2016).[24]

INGAA analyzed six case studies in the 2016 study. In four of the case studies where an exact distance between the property and the pipeline was given, an average of 72.5% of the "off" properties were actually within the evacuation zone and, like the "on" properties, are therefore likely to suffer a loss in property value relative to properties farther away.[25]

For the other two case studies analyzed in the 2016 INGAA study, the study reported a simple "yes" or "no" to indicate whether the property abutted the pipeline in question. For these two case studies, we assume the author's methods, while flawed, are at least consistent from one case study to the next meaning it is likely at least 50% or more of the comparison properties (the "off" properties) are in fact within the evacuation zone.

To adequately compare the price of properties with and without a particular feature, there needs to be certainty that properties either

FINANCIAL DAMAGE ALREADY OCCURRING

Mark and Alycia Egan live 0.59 miles, directly across the street, from the proposed Highland compressor station. Upon learning about the plans for the Highland CS, the Egan's put their home on the market for fear their property value would be significantly diminished. A year later, with their home still on the market, the Egan's have had to lower the cost of their home and learned a recent buyer loved the home but declined entering an offer once they knew about the potential of the compressor station.

The Egan's contacted Millennium regarding their worries that their property may be unsellable but their only response was that buyers were "clearly misinformed." Millennium LLC and FERC continue to put industry supported studies falsely claiming property values are not impacted by pipelines and related infrastructure over the actualized harms suffered by homeowners.

Mark and Alycia walking along old route 55. (Photo credit: Mark Egan)

[24] Proximity of properties to pipelines is based on best estimate of the location of the pipelines derived from descriptions of the pipelines' locations provided in the studies and an approximation of the evacuation zone based on pipeline diameter and operating pressure (Pipeline Association for Public Awareness, 2007).
[25] We estimated the evacuation zone based on available information about the pipeline diameter and operating pressure (Pipeline Association for Public Awareness, 2007).

have or do not have said feature. The feature of interest in this case is the presence of a nearby risk to health and safety. INGAA instead relied upon case studies with little to no variation in the feature of interest (i.e., the majority of properties are within the evacuation zone), and found, unsurprisingly, that there was no systematic variation in the subsequent price of properties. By comparing apples to apples rather than comparing apples to oranges, the INGAA studies reach the obvious and not very interesting conclusion that properties that are similar in size, condition, and other features including their location within the evacuation zone of a natural gas pipeline, have similar prices.

A prime example of this problem is embodied in the 2014 study by Allen, Williford, and Seale, which is summarized in the latter INGAA study (Integra Realty Resources, 2016). The authors compare the prices of homes and lots "on" and "off" a Transco-operated pipeline in Luzerne County, Pennsylvania. In the map below (Figure 3), the green-shaded properties are those identified by the authors as "on the pipeline," because they are crossed by the 50-foot right-of-way. The orange properties are what the authors call "off the pipeline."

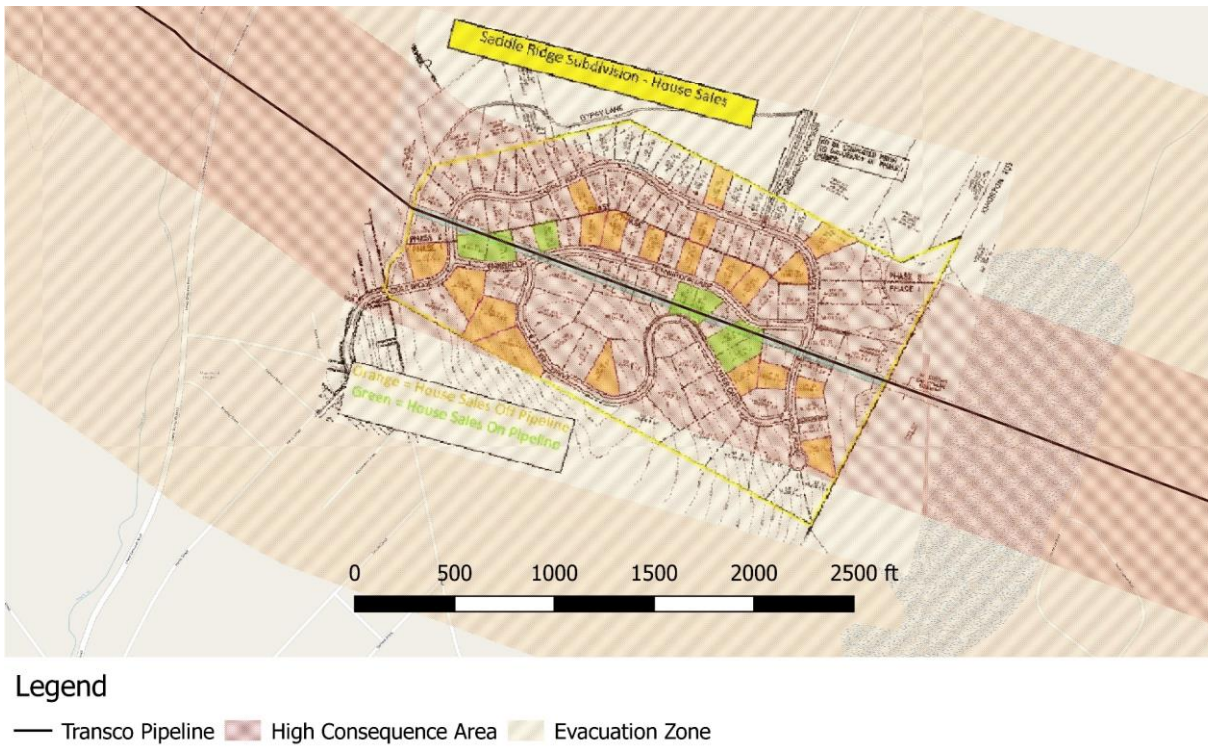

FIGURE 3. Transco Pipeline evacuation zone covers all, and the high-consequence area covers most, of properties in the Saddle Ridge case study area.

Sources: Saddle Ridge subdivision image from Allen, Williford, and Seale (2014) as reproduced in Integra Realty Resources (2016, p. 69); Transco Centerline digitized from approximated ROW shown in blue and, beyond the subdivision, from Google satellite imagery (2017).

Figure 3 also shows, in pink shading, the 1,139-foot-wide high-consequence area and, in tan, the 3,796-foot-wide evacuation zone. <u>All</u> of the properties that Allen, Williford, and Seale consider as either "on" or "off" the pipeline are well within the evacuation zone, and all of the properties are at least touched by the high-consequence area. Because perceptions of the risk to life and property in the event of an explosion or, at minimum, worry and inconvenience homeowners, living within the evacuation zone

should likely affect offer prices for all of the properties in the study area, making the authors' definitions of "on" and "off" the pipeline substantially irrelevant. As in the other cases included in INGAA's review (Integra Realty Resources, 2016), Allen, Williford, and Seale simply document the unsurprising result that similar properties have similar prices.

As economic research, their exercise is a perhaps harmless but wasted effort. As the basis for FERC's and others' contention that natural gas pipelines do not affect property values, the exercise is one of costly, and possibly dangerous, misdirection.

In short, the conclusion that pipelines do not negatively affect property values cannot be drawn from these flawed studies. To evaluate the effects of the proposed ESU project on property value, FERC and others must look to studies (e.g., Boxall et al. (2005), Kielisch (2015)) in which the buyers' willingness to pay are fully informed about the presence of nearby pipelines and in which the properties examined are truly different in terms of their exposure to pipeline-related risks.

Land Value Effects of Compressor Stations

Compressor stations can cause decreases in home values and have even forced some homeowners to move away from the noise, smells, and illnesses associated with living near the compressor stations. In one documented case from Minisink, New York, a smaller (12,600 hp) compressor station just southeast of the proposed Highland compressor station, a family of six moved to escape the effects of the compressor station operated by Millennium LLC. After two years of headaches, eye irritation, and lethargy among the children and even lost vigor in their fruit trees, the couple, unable to find a buyer for their home, moved away, leaving their $250,000 investment in the property on the table with their bank holding the balance of the mortgage (Cohen, 2015a).

Around the existing Hancock CS, three homeowners living around 15,900 hp compressor station, which would get an additional 22,400 hp upgrade under the ESU project, have had their property assessments reduced, two by 25% and one by 50%, due to the impact of truck traffic, noise, odors, and poor air quality associated with the compressor station ("Proximity of Compressor Station Devalues Homes by as Much as 50%", 2015). The larger of these reductions was for a home very close to the station and reflected physical damage that led to an increase in radon concentrations above safe levels. The two properties devalued by 25% were approximately one half mile away (Ferguson, 2015).

As of this writing, there have not been statistical studies conducted demonstrating the relationship between a property's value and its proximity to a compressor station. However, the mounting anecdotal information suggests there is a negative relationship, and depending on the particular circumstances, the effect can be large–up to the 100% loss sustained by a family in Minisink (less than whatever the bank can recover at auction). FERC must therefore count the potential loss of property value associated with the compressor stations proposed for Sullivan County and further losses associated with the existing station in Delaware County.

For our estimates, we follow the existing example of the Hancock, New York case and assume that properties within one half mile of the Highland CS would lose 25% of their value if the station is built.[26] For the analysis, we re-analyzed the potential property value loss around the Hancock CS in order to reflect up to date parcel value information. We believe our estimates are conservative in part because the horsepower proposed for the Highland CS (22,400 hp) and the upgrade for the Hancock CS (38,300 total hp) are both larger than the horsepower of the existing Hancock Station (15,900 hp), about 1.5x and 2.4x respectively. It is therefore likely that noise, odor events, and other physical effects would be experienced at a greater distance and/or with greater intensity than the existing property devaluation example.

Parcel Values

We obtained parcel data in electronic form from the New York state GIS clearinghouse as well as from county level GIS departments. The data included Geographic Information System ("GIS") layers with the valuation/assessment data for the counties. Because publicly owned conservation lands (parks, etc.[27]) are unlikely to be sold, they do not have any market value. To avoid overestimating property value effects, we set the value of any publicly owned parcels equal to zero.

Using the GIS data, we identified the five different types of parcels for which the pipeline would have an effect. In order of increasing distance from the pipeline itself, these are:

1. Parcels crossed by the right-of-way
   (5 parcels, with total baseline value (without the ESU project) of $186,050)
2. Parcels crossed by the construction corridor
   (18 parcels, with total baseline value (without the ESU project) of $6.1 million)
3. Parcels at least partially within the high consequence area (HCA)
   (20 parcels, with total baseline value (without the ESU project) of $5.9 million)
4. Parcels at least partially within the evacuation zone
   (196 parcels, with total baseline value (without the ESU project) of $19.8 million)
5. Parcels with their geographic center (centroid) within one-half mile of the parcel containing the compressor station
   (43 parcels, with total baseline value (without PE) of $4.9 million)

Note there is overlap among the zones. All ROW parcels are within the construction corridor, the HCA, and the evacuation zone. All construction corridor parcels are within the HCA and the evacuation zone. And HCA parcels are within the evacuation zone. To avoid double counting parcel values, only one land value effect is applied to a given parcel.

[26] For land value analysis of the compressor stations, we buffered a half mile radius around the workspace of the station.

[27] We used the "Protected Areas Database" from the National Gap Analysis Program to identify fee-owned conservation properties (Conservation Biology Institute, 2012).

For estimates of the ROW, we assume that the health and safety concerns associated with the compressor station dominate the effects within the ROW and the evacuation zone. Estimates of the impact of the ROW and evacuation zone exclude the compressor zone parcels, and we estimate a separate effect of the compressor station. ROW parcels are also assumed to suffer no further reduction in value due to their location within the evacuation zone.

We do not consider the construction corridor separately for the land value analysis. Even though the additional 18 parcels and $6.1 million in value (relative to parcels in the ROW) are not trivial, we do not have a basis for estimating a change in value that is separate from, or in addition to, the change due to these parcels' proximity to the ROW or their location within the evacuation zone.

TABLE 4: Summary of Marginal Property Value Effects

Values/ Effects	Right-of-Way (Low, Medium, & High Effects)	High Consequence Area & Evacuation Zone	Compressor Station Zone
Land/ Property Value	-4.2%[a] -10.5%[b] -13.0%[c]	-3.8%[d]	-25%[e]

Notes:

a. Kielisch, Realtor survey in which 56% of respondents expected an effect of between -5% and -10% (0.56*-7.5% = -4.2%).
b. Kielisch, buyer survey in which half of buyers still in the market would reduce their offer on a property with a pipeline by 21% (0.50*-0.21 = -10.5%).
c. Kielisch, appraisal/impact studies showing an average loss of between -12% and -14% (-13% is the midpoint).
d. Boxall, study in which overlap with an emergency planning zone drives, on average, a 3.8% reduction in price. We apply this reduction ONLY to those parcels in the evacuation zone that are not also in the ROW or within one half mile of the compressor station.
e. Based on examples from the town of Hancock, New York.

Furthermore, we treat parcels in the HCA and in the evacuation zone the same by applying a single land value change to all parcels in the evacuation zone. Arguably, there should be a larger effect on parcels in the HCA than those only in the evacuation zone. Living with the possibility of having to evacuate at any time day or night should have a smaller effect on property value than living with the possibility of not surviving a "high consequence" event and, therefore, not having the chance to evacuate at all. We do not have data or other study results that allow us to draw this distinction. We therefore apply the lower evacuation zone effect to all HCA and evacuation zone parcels (beyond the ROW).

To summarize, Table 4 repeats a portion of Table 3, but with the property value effects in place of check marks.

Estimated Land Value Effects

Following the procedures outlined in the previous section, our conservative estimate for costs of the proposed ESU would include $2.0 million in diminished property value with the most intense effects felt by the owners of 5 parcels in the path of the right-of-way, who collectively would lose between $7,814 and $24,187 in property value. Some 196 additional parcels lie outside the ROW but are within or

touching the evacuation zone. These parcels' owners would lose an estimated $753,692 (Table 5). Finally, the compressor stations would reduce the value of 43 properties by a total of $4.9 million.

Table 5: Summary of Land Value Effects, by Zone and County

	Delaware County	Sullivan County	Orange County	Total
Effects on ROW Properties (2015$)				
Realtor Survey (4.25%)	n/a	n/a	-7,814	**-7,814**
Buyer Survey (10.5%)	n/a	n/a	-19,535	**-19,535**
Impact Studies (13%)	n/a	n/a	-24,187	**-24,187**
Effects on Evacuation Zone Properties (2015$)				
Boxall Study (3.8%)	n/a	n/a	-753,692	**-753,692**
Effects Near Compressor Stations (2015$)				
Hancock, NY Finding (25%)	-519,888	-715,474	n/a	**-1,235,361**
All Effects (2015$)				
Low	-519,888	-715,474	-761,506	**-1,996,868**
Medium	-519,888	-715,474	-773,227	**-2,008,589**
High	-519,888	-715,474	-777,879	**-2,013,240**

Based on median property tax rates in each county, these one-time reductions in property value would result in reductions in property tax revenue of between $36,005 and $36,298 per year (Table 6). The present value of this stream of lost revenue over the 2018-2068 operating period would be $1.6 million. To keep their budgets balanced in the face of this decline in revenue, counties would need to increase tax rates, cut back on services, or both. The loss in revenue would be compounded by the likelihood that the need for local public services, such as road maintenance, water quality monitoring, law enforcement, and emergency preparedness/emergency response could increase. Thus, the ESU could drive up expenses while driving down the counties' most reliable revenue stream.

TABLE 6. Effects on Local Property Tax Revenue

Source: Property Taxes by State (propertytax101.org, 2016)

	Delaware County	Sullivan County	Orange County	Total
Median Tax Rate (% of Home Value)				
	1.62%	1.95%	1.79%	
Lost Property Tax Revenue (2015$)				
Low	-8,422	-13,952	-13,631	**-36,005**
Medium	-8,422	-13,952	-13,841	**-36,215**
High	-8,422	-13,952	-13,924	**-36,298**

The Social Cost of Carbon: An Additional Cost of Methane Transport

The social cost of carbon ("SCC") is a comprehensive estimate of the economic cost of harm associated with the emission of carbon. The SCC helps better inform regulation because it allows agencies to more accurately weigh the environmental costs and benefits of a new rule or regulation. After challenges questioning the accuracy of SCC, in April 2016, a federal court upheld the legitimacy of using the social cost of carbon as a viable statistic in climate change regulations (Brooks, 2016). Even more recently, in August 2016, The Council on Environmental Quality ("CEQ") issued its final guidance for federal agencies to consider climate change when evaluating proposed Federal actions (Council on Environmental Quality, 2016). The CEQ states "agencies should consider applying this guidance to projects in the EIS or EA preparation stage if this would inform the consideration of differences between alternatives or address comments raised through the public comment process with sufficient scientific basis that suggest the environmental analysis would be incomplete without application of the guidance, and the additional time and resources needed would be proportionate to the value of the information included" (2016, p.34).

EPA has also challenged FERC's failure to consider climate change implications in a similar application process (Westlake, 2016). Citing the CEQ guidance, EPA notes that the Final EIS for the Leach Xpress, Columbia Gulf Transmission LLC-Rayne Xpress Expansion project "perpetuates the significant omission...with respect to a proper climate change analysis to inform the decision making process" and recommends that GHG emissions from end product combustion be counted among the environmental effects of each alternative" (p. 2).

Millennium LLC estimates the ESU loop would transport 73,000,000 dekatherms annually, contributing to an equivalent of 3.9 million metric tons of CO2 emitted per year (U.S. EPA, 2016). Because the SCC assumes a ton of carbon emitted in the future will have more dire impacts than a ton emitted in the

present, we estimate the cost of carbon annually until 2068.[28] Using U.S. EPA estimates based on the average of impacts from three assessment models and discount rates of 5% and 2.5% (U.S. EPA, Climate Change Division, 2016), the cost to society of the carbon transmitted through the ESU project would total between $4.8 and $18.8 billion over 50 years. FERC must count this significant cost among the effects of the proposed pipeline.

Other Impacts for Consideration

Public Health Effects

Natural gas transmission releases toxins, smog forming pollutants, and greenhouse gases that have a negative impact on public health (Fleischman, McCabe, & Graham, 2016). Emissions from the natural gas industry have been tied to a malady of health concerns. More concrete epidemiological studies are needed to determine the extent to which natural gas transmission causes public health concerns.

More recent emerging literature is beginning to quantify just how large of an effect the industry can have on public health. For example, a study by the Clean Air Task Force estimated that in 2025, increases in ozone levels due to pollution from the oil and gas industry will cause 750,000 additional asthma attacks in children under the age of 18, add an additional 2,000 asthma-related emergency room visits and 600 respiratory related hospital admissions, cause children to miss 500,000 days of school annually, and cause adults to deal with 1.5 million days of forced rest or reduced activity due to ozone smog (Fleischman, McCabe, & Graham, 2016).

Air Pollution from the Proposed Compressor Stations

The ESU project impacts air quality by converting forests, which remove normal levels of impurities from the air, to other land uses. While there is a chance leaks could occur at any place along the proposed route, leaks and major releases of gas and other substances (lubricants, etc.) will certainly occur at the two proposed compressor stations. Leaks in seals on the moving parts of natural gas compressors produce a significant amount of VOC emissions (Fleischman, McCabe, & Graham, 2016). Also, after the compressor station in Hancock began operation, there was a 5x increase in the amount of ambient methane for roughly a one mile radius (Cohen, 2015).

The negative effects of the compressor station include noise and air pollution from everyday operations plus periodic “blowdowns,” or venting of gas in the system to reduce pressure. David Carpenter, the director of the Institute for Health and the Environment at the University at Albany, notes that compressor stations are among the worst of fracking related infrastructure (Lucas, 2015). A five-state study examining air quality near compressor stations found that levels of several volatile chemicals, including benzene and formaldehyde, exceeded federal guidelines (Macey et al., 2014). As more

[28] Based on information provided by Millennium LLC in *Draft Resource Report 1: General Project Description (*2016a), construction on the project would begin in 2017 and the first year of operation, or the first year the project would produce associated emissions, would be 2018. Millennium LLC also states that the ESU facilities “are projected to have a 50-year minimum physical life” (Millennium Pipeline Company, L.L.C., 2016, p. 1-42). Given a 50-year minimum physical life, we use 2068 as the final year of operation for the project.

> ***"I have worked on the Town of Highland's Comprehensive Management Plan and its zoning that expressly, clearly and specifically bans any and all compressor stations - as have a number of surrounding towns concerned with protecting the quiet enjoyment of our homes and rural, tourism-friendly environment."***
>
> -Debra R. Conway, Resident
> Barryville, New York

negative documented health impacts arise from other existing compressor stations, this has led the Highland Town Board to draft a unanimous resolution opposing the compressor station, citing potential health impacts as a cause of great concern (Times Herald-Record, 2016).

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While more definitive epidemiological studies are needed to determine the extent to which natural gas compressor stations add to background rates of various illnesses, these stations are implicated as contributing to a long list of maladies. According to Subra (2015), individuals living within 2 miles of compressor stations and metering stations experience respiratory impacts (71% of residents), sinus problems (58%), throat irritation (55%), eye irritation (52%), nasal irritation (48%), breathing difficulties (42%), vision impairment (42%), sleep disturbances (39%), and severe headaches (39%). In addition, some 90% of individuals living within 2 miles of these facilities also reported experiencing odor events (Southwest Pennsylvania Environmental Health Project, 2015). Odors associated with compressor stations include sulfur smell, odorized natural gas, ozone, and burnt butter (Subra, 2009). Furthermore, compressors emit constant low-frequency noise, which can cause negative physical and mental health effects (Luckett, Buppert, & Margolis, 2015).

In Sullivan County, 115 people live within 2 miles of the proposed Highland CS (U.S. Census Bureau, 2015). Applying the results of Subra (2015) to the population in Sullivan living within 2 miles, 104 people would experience odor events, 82 people would experience respiratory impacts, 67 people would experience sinus problems, and 45 people would experience sleep disturbances and/or severe headaches.

In Delaware County, 256 people live within 2 miles of the existing compressor station in Hancock (U.S. Census Bureau, 2015). Applying the results of Subra (2015) to the population in Delaware living within 2 miles, 230 people would experience odor events, 182 people would experience respiratory impacts, 148 people would experience sinus problems, and 100 people would experience sleep disturbances and/or severe headaches.

In addition to the health impacts discussed above, this pollution can cause damage to agriculture and infrastructure. One study found that shale gas air pollution damages in Pennsylvania already amount to between $7.2 and $30 million, with compressor stations responsible for 60-75% of this total (Walker & Koplinka-Loehr, 2014). Using the low estimate of 60%, that is between $4.32 and $18 million in damages associated with compressor stations.

Effects on Economic Development

In each county analyzed, county-level economic development plans recognize the importance of a high quality of life, a clean environment, and scenic and recreational amenities to the economic future of people and communities. According to the Orange County Comprehensive Plan, one of the priority goals is to "strengthen the economy in Orange County by attracting and supporting businesses that will enhance the County's economic base and provide jobs, tax revenues, and an orderly and sustainable land use pattern that accommodates the best of the County's old economy while providing the attributes necessary to build the new economy" (Orange County Planning Board, 2010). Sullivan County's Comprehensive Plan dedicates an entire section to alternative energy sources and the importance that the county supports environmentally conscious initiatives that generate economic benefits and simultaneously preserve significant natural resources (Sullivan County Planning and Environmental Management, 2005). Along similar lines, Delaware County recognizes that preserving water quality and supporting their growing agri-tourism sector go hand in hand (Delaware County Planning Department, 2008).

These intentions mirror common trends in other amenity-rich locales around the country. For example, Niemi and Whitelaw state "as in the rest of the Nation, natural-resource amenities exert an influence on the location, structure, and rate of economic growth… This influence occurs through the so-called people-first-then-jobs mechanism, in which households move to (or stay in) an area because they want to live there, thereby triggering the development of businesses seeking to take advantage of the households' labor supply and consumptive demand" (1999, p. 54). They note that decisions affecting the supply of amenities "have ripple effects throughout local and regional economies" (p. 54). Similarly, Johnson and Rasker (1995) found that quality of life is important to business owners deciding where to locate a new facility or enterprise and whether to stay in a location already chosen. This is not surprising. Business owners value safety, scenery, recreational opportunities, and quality of life factors as much as residents, vacationers, and retirees.

"This area is known for its unspoiled natural beauty, clean water and fresh air. The local economy is entirely dependent on nature tourism and vacation homes, including ours. The area is heavily forested, with a number of endangered and threatened species. There is no municipal water supply and all homeowners are dependent on the purity of the aquifer, which is replenished by our myriad of lakes and streams. Industrial use is specifically banned in The Town of Highland in order to preserve the unique natural habitat."

- John Caplan, Landowner
Highland, New York

Part of what makes tourism an important part of the study region's economy is the high aesthetic quality and environmental amenities available in the study region. In 2015 alone, tourism in the study region is a $944.3 million industry, up $61.7 million from 2010. The industry provides 14,907 jobs across the study region, contributing to $441.3 in payroll, $63.0 million in local taxes, and $52.4 in state taxes (Tourism Economics, 2016a, 2016b).

The ESU could dampen these economic activities and undermine the progress toward economic development goals. A loss of scenic and recreational amenities, the perception and the reality of physical danger, and

environmental and property damage resulting from the ESU could discourage people from visiting, relocating to, or staying in the region. Workers, businesses, and retirees who might otherwise choose to locate along the ESU's proposed route or near the compressor stations will instead pick locations that have retained their character, their productive and healthy landscapes, and their promise for a higher quality of life.

This is already occurring in the region. With the possibility of the ESU looming, business plans are stalling and the real estate market is slowing. In nearby Minisink, community members impacted by Minisink compressor station have had signs in opposition of the construction stolen from their property by other neighbors fearing if too much press highlights the negativity of the station for the town that it will harm the agricultural industry that the town depends on (Rugh, 2014).

Many of the region's residents believe the ESU will also harm the travel and tourism industry. For example, Juliette Hermant, a small business owner in Narrowsburg, an area heavily dependent on nature tourism and vacation homes has heard from clientele expressing heavy concern over the proposed project (Carazo, 2015).

It is difficult to predict just how large an effect the ESU would have on decisions about visiting, locating to, or staying in the study region. Even so, based on information provided by business owners to FERC and as part of this research, we can consider scenarios for how the ESU might affect key portions of the region's overall economy, such as tourism and recreation, retirement, and entrepreneurship.

"This whole Upper Delaware River Valley is a sacred national asset. The economy here, and the livelihood of the people who live here, are as fragile as the river valley itself. Thus, the number one economic engine here has always been, quite appropriately, the sanctity of our natural habitat. We should never, ever, ever, ever take a risk of damaging or diminishing that asset, our only real economic engine."

-Mark Righter, Community Member
Glen Spey, New York

If, for example, the ESU were to cause a 5% drop in recreation and tourism spending from 2015 baselines, the project could mean $47.2 million less in travel expenditures each year (Tourism Economics, 2016a, 2016b). Those missing revenues would otherwise support roughly $3.1 million in local tax receipts, $2.6 million in state tax revenue, 745 jobs, and $22.1 million in payroll in the three-county region. In the short run, these changes multiply through the broader economy as recreation and tourism businesses buy less from local suppliers and fewer employees spend their paychecks in the local economy. As with the reduction in local property taxes, lost tax revenue from a reduction in visitation and visitor spending would squeeze local governments trying to meet existing public service needs as well as additional demands created by the ESU.

Along similar lines, retirement income is an important economic engine that could be adversely affected by the ESU. In county-level statistics from the U.S. Department of Commerce, retirement income shows up in investment income and as age-related transfer payments, including Social Security and Medicare payments. In the study region, investment income grew by 0.6% per year from 2000 through 2014, and age-related transfer payments grew by 4.5% per year. During roughly the same time period (through

2013), the number of residents age 65 and older grew by 20.3% (1.6% per year), and this age cohort now represents 13.2% of the total population (U.S. Department of Commerce, 2015a; U.S. Department of Commerce, 2015b).

It is difficult to precisely quantify the effect of the ESU on retirement income, but given the expression of concern from residents about changes in quality of life, safety, and other factors influencing retirees' location decisions, it is important to consider that some change is likely. Here, again, we consider what a *5% reduction of the growth rate* might entail. A 5% growth reduction scenario would mean an annual decrease in investment income and age-related transfer payments of approximately $6.3 million. That loss would ripple through the economy as the missing income is not spent on groceries, health care, and other services such as restaurant meals, home and auto repairs, etc.

The same phenomenon also applies to people starting new businesses or moving existing businesses to communities in the study region. This may be particularly true of sole proprietorships and other small businesses who are most able to choose where to locate. As noted, sole proprietors account for a large and growing share of jobs in the region. If proprietors' enthusiasm for starting businesses in the study region were dampened to the same degree as retirees' enthusiasm for moving there, the 5% reduction scenario in the rate of growth would mean 74 fewer jobs and $1.2 million less in proprietor's income.

For "bottom line" reasons (e.g., cost of insurance) or due to owners' own personal concerns, businesses in addition to sole proprietorships might choose locations where living near the pipeline or a compressor station is not an issue. If so, further opportunities for local job and income growth will be missed.

These are simple, but plausible scenarios regarding the potential economic development impacts of the ESU. Other methods and assumptions would lead to different estimates, of course, and it is incumbent on FERC to complete its own evaluation of the merits of the proposal. Especially because the project is promoted by its supporters for its jobs and potential other economic benefits to the region, it is important to consider the potential for loss, as well as to take a hard look at the project applicant's claims regarding possible gains.

Conclusions

The full costs of the proposed Eastern System Upgrade to people and communities in the three-county study region and beyond are wide-ranging. The costs include one-time costs like reductions in property value during pipeline construction, which we estimate to be about $2.0 million. There are also ongoing costs like lost property tax revenue and the cost of increased carbon emissions that recur year after year for the life of the pipeline. Diminished property tax revenues would total between $36,005 and $36,298 per year. The majority of these costs would be borne by the residents, businesses, and institutions in Orange, Delaware, and Sullivan Counties.

Beyond the immediate region, the Eastern System Upgrade would also impose a cost on people worldwide due to the addition and combustion of natural gas transported through the pipeline. The social cost of carbon is an annual cost that varies by year and with the rate at which future costs are

discounted. It would total between $50.1 and $420.1 million, raising the total annual external costs to between $50.2 and $420.2 million.

Adding up all one-time recurring costs, and discounting those future costs to 2017, we estimate the total external costs of the Eastern System Upgrade to be between $4.7 and $18.8 billion in 2015 dollars.

Construction and operation of the project would produce comparatively few economic benefits. Using Millennium LLC's estimates, the construction period would produce $314 million (2015$) in economic impact (additional spending by firms and households in Millennium's study region, which is the entire state of New York). Spending on operation and maintenance of the completed project, plus assumed cost savings for energy users would, in Millennium LLC's estimation, generate $70.3 million (2015$) in output annually for 10 years (Concentric, 2016).[29] Applying the same methods to calculate the present value of the positive effects,[30] the pipeline promises a total of $2.0 billion in economic impact over 50 years of operation. This means for every dollar of benefit promised, the Eastern System Upgrade would impose between $2.31 and $9.24 in costs.

While the decision to approve or not approve the ESU does not hinge on a simple comparison of estimated benefits versus estimated costs, the difference between the external economic costs presented in this report and the potential payments to local governments and residents suggests that, from an economic perspective, the proposed project is inefficient. The scope and magnitude of the costs outlined here reflect a closer examination into important components of the full extent of the ESU's likely environmental effects that must be considered when FERC makes the certification decision. Impacts on human well-being, including but not limited to those that can be expressed in dollars-and-cents, must be taken into account by the Federal Energy Regulatory Commission and others weighing the societal value of the Eastern System Upgrade.

If these considerations and FERC's overall review result in selection of the "no-action" alternative and the ESU is never approved, most of the costs outlined in this report will be avoided. It is *most*, not *all,* costs because the cost of delayed business plans, houses languishing on the market, and the cost to individuals of the stress, time, and energy diverted to concern about the project rather than what would normally (and more productively) fill their lives has already occurred.

Another possible scenario is that FERC, considering the impacts of the ESU *as currently proposed* on property values, economic development, and climate impacts, conducts a thorough analysis of all possible alternatives. Those alternatives may include using alternative energy technologies for meeting the energy needs of the region, making better use of existing gas transmission infrastructure, and/or scaling down permitted new pipeline capacity to match regional gas transmission needs. In this case, estimates of these impacts should inform the choice of a preferred alternative that minimizes

[29] Concentric (2016) uses 2019-2028 as the operational phase, however, in Draft Resource Report 1 (2016), Millennium LLC states that the first year of operation will be in year 2018. For estimates in this report, we use 2018 as the first year of the ESU's operational period.

[30] Although Concentric (2016) only provides operational benefits for 10 years after the first year of operation, for our present discounted value calculations, we use their given average of $70.3 million per year as the annual benefit.

environmental damage and, thereby, minimizes the economic costs to individuals, businesses, and the public at large.

Adequate environmental review by FERC and, subsequently, an economically efficient outcome cannot be achieved if FERC discounts or ignores important economic costs and turns a blind eye to energy supply and transmission options that could reduce the waste of land, natural resources, and financial wealth. The analysis presented here, therefore, should be seen and used as a first step to filling a major gap in the information on which to base public decisions about the Eastern System Upgrade.

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Appendix A: Key-Log Economics Response to Millennium LLC and Concentric

In this Appendix we provide further details regarding Millennium Pipeline Company LLC's and Concentric Energy Advisors' responses to DRN's earlier review, as summarized on p. 10. We begin with arguments put forth by Millennium, followed by arguments posed by Concentric. Our replies further document the unbalanced analyses prepared to date and presented in documents which focus on purported benefits of the proposed project without adequate consideration of the possible economic costs in and beyond the region.

Millennium Pipeline Company L.L.C.

From *Answer of Millennium Pipeline Company, L.L.C. to Comments on the Eastern System Upgrade Project* (Millennium Pipeline Company, L.L.C., 2016d):

Millennium Assertion 1: "Millennium Has Demonstrated That the ESU Project's Public Benefits Outweigh Any Potential Adverse Impacts" (Millennium Pipeline Company, L.L.C., 2016d, p.1).

> Millennium LLC states that, "the Commission should apply the standard set forth in the [Natural Gas Act, or] NGA, in which the Commission determines whether a project is required by the public convenience and necessity pursuant to the criteria set forth in the Certificate Policy Statement. Under the Certificate Policy Statement, the Commission determines that a "need" for a project exists as part of its process of approving the project" (Millennium Pipeline Company, L.L.C., 2016d, p. 2).
>
> They also state, "Because Millennium has demonstrated that the ESU project will have minimal impact upon landowners and the surrounding communities, the Project satisfies the Commission's economic balancing test" (Millennium Pipeline Company, L.L.C., 2016d, p.3).
>
> Millennium is mistaken on both points.
>
> It cannot be said that current procedures are sufficient to establish a need for or public benefit from proposed pipelines. As Commissioner Norman C. Bay noted in his statement attached to *Order Granting Abandonment and Issuing Certificates* in the National Fuel Gas Supply Corporation / Empire Pipeline, Inc. case (2017), in order to respond to increasing public interest in the Commission's work, FERC needs to further explore how it establishes need when completing certificate reviews. Bay notes, "The Commission has largely relied on the extent to which potential shippers have signed precedent agreements for capacity on the proposed pipeline" (Federal Energy Regulatory Commission, 2017). However, the problem with focusing on precedent agreements is that a "variety of other considerations, including, among others: whether the capacity is needed to ensure deliverability to new or existing natural gas-fired generators, whether there is a significant reliability or resiliency benefit; whether the additional capacity promotes competitive markets; whether the precedent agreements are largely signed by affiliates; or whether there is any concern that anticipated markets may fail to materialize" (Federal Energy Regulatory Commission, 2017).

FERC's policies and procedures for evaluating pipeline costs and benefits are not sufficient to ensure a true "economic test" of the merits of any natural gas infrastructure proposal. This is primarily because they rely on applicants overinflated estimates of benefits and ignore important external costs. (Please see "Policy Failure: The Review and Certification of Natural Gas Transmission Projects Discounts External Costs and Inflates Social Benefits" on p. 4 of this report.)

On the second point, and as we have explained in the body of this report as well as in the review to which Millennium responded, the contention that natural gas pipelines and related infrastructure have no effect on landowners is not defensibly argued by Millennium, and there are entire classes of external costs that Millennium has not considered at all.

Millennium Assertion 2: That "[the] Commission should reject DRN's[31] misplaced suggestion to apply a cost-benefit analysis when evaluating the environmental impact of the Project" (Millennium Pipeline Company, L.L.C., 2016d, p. 2).

First, note that this argument is inconsistent with the first argument, which is that, at least in Millennium's view, the ESU project passes a cost-benefit test. If Millennium believes that cost-benefit analysis of its proposed project is invalid, then it should not also argue, on cost-benefit grounds, for approval of the project.

Second, note that Millennium's argument on this point is in the context of whether or not the National Environmental Policy Act requires FERC (or any agency) to balance or directly compare benefits and costs. It does not, but NEPA does require agencies to consider the effects of their actions on the human environment, and that includes economic effects (40 CFR 1508.8). As the NEPA regulations state "When an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment" (40 CFR 1508.14). To make this perfectly clear, economic effects <u>are</u> benefits and costs. So while NEPA does not require that agencies directly compare benefits to costs, or to select an alternative for which benefits outweigh costs, it does require that those economic effects be considered as part of agencies' environmental reviews.

Third, Millennium has advanced their own studies of potential benefits to argue in support of the project.[32] The reports ignore the full array of costs the project will inflict. To the extent Millennium wants to argue for a cost benefit analysis to support its project, it must consider the full picture which we help provide.

Rather than arguing, contrary to FERC and NEPA policy as well as its own past communication, that cost and benefit concerns are irrelevant, we would recommend that the applicant support

[31] Our report *Economics of the Eastern System Upgrade: Credible and Complete Estimates of Benefits and Costs are Needed* (Phillips & Wang, 2016) was filed by DRN. References to DRN should therefore be interchangeable with Key-Log Economics.

[32] See *Estimated Savings For New York Consumers From The Millennium Pipeline Eastern System Upgrade Project* (Concentric Energy Advisors, 2016), and *Draft Resource Report 5: Socioeconomics* (Millennium Pipeline Company, LLC, 2016b).

an independent, thorough, and rigorous evaluation of the full range of costs and benefits. Again, and based on our review of the information presented by the applicant to date, we do not believe that such an evaluation has previously been completed.

Our current report attempts to enumerate and quantify *some* of the key external costs likely to attend the construction and operation of the ESU project. We recommend that FERC use this information and/or expand and improve upon this effort.

Millennium Assertion 3: That DRN [Key-Log Economics] agrees that Millennium's estimated economic benefits of the ESU Project are "substantial" (Millennium Pipeline Company, L.L.C., 2016d, p. 5).

In full, Millennium states, "Despite DRN's [Key-Log Economics'] contention that the Concentric Study overestimates the Project's economic benefits, DRN's [Key-Log Economics] recognizes that the Project has substantial economic benefits"[33] (Millennium Pipeline Company, L.L.C., 2016d, p. 5). Here, Millennium seems to mistake the enumeration of the ways in which it has overstated the economic benefits of the project with agreement that the [true] benefits are "substantial". To be clear, we have not claimed that the benefits are *nonexistent*, but rather, and as we have explained previously (Phillips & Wang, 2016) as well as in the current report, there are several reasons to suspect that the benefits will be fewer or smaller than Millennium has claimed. In addition, when compared to the high level of costs the project inflicts, the benefit claims do not appear to be high enough to economically justify the project.

Millennium Assertion 4: "The Commission Should Disregard DRN's Assertions That the ESU Project Will Adversely Affect Property Values" (Millennium Pipeline Company, L.L.C., 2016d, p. 6).

Millennium states that we have not cited "credible studies or information" regarding our claim that pipelines adversely affect property values in our initial review. Estimation of land price effects was not intended to be a part of that initial review. Our evaluation of the project's external costs presented in this report however, includes such estimates and we stand behind our method—including use of credible studies and information—for estimating the extent to which the ESU project would affect nearby property values. (See the section titled "Effects on Property Value," p. 17)

Moreover, in both the initial review and in this report, we described in detail the fundamental flaws in the studies on which Millennium bases its claim that proximity to natural gas infrastructure does not affect property value. To summarize, those studies do not account for the extent to which buyers know that the property they purchased was near a pipeline, and they do not compare prices for properties that are, in any meaningful sense, nearer to, versus farther from, natural gas infrastructure. These flaws render the studies' results meaningless, and they are simply not credible as the basis for any conclusion regarding the effects of natural gas infrastructure on property value. (See the sections "Effects on Property Value"/ "Studies Concluding That Proximity to Pipelines Do Not Result in Different Property Values Are Not

[33] In the quoted passage, Millennium attributes this contention and recognition to Delaware Riverkeeper Network. They reference page 7 of DRN's submission to FERC which is in fact in the Key-Log Economics' report attached to DRN's letter.

Actually Comparing Prices for Properties That Are Different" (p. 17 and p. 21) of this report for details on the flaws in the studies in question.)

Millennium Assertion 5: That "The Commission Is Not Required to Utilize the Social Cost of Carbon to Evaluate Impacts of Greenhouse Gas Emissions Associated with the Project" (Millennium Pipeline Company, L.L.C., 2016d, p. 9).

In support of this argument, Millennium notes that "the Commission had determined that the social cost of carbon is a useful tool for considering climate benefits of rulemakings and policy alternatives, but not for considering the environmental impacts associated with individual pipeline projects" (Millennium Pipeline Company, L.L.C., 2016d, p. 9) and repeats the components of the Commission's rationale for this determination. These components and our response are as follows:

1. There is a lack of consensus on the appropriate discount rate.

   Key-Log's response: The debate of what discount rate to use for the evaluation of future effects of public projects and decisions is longstanding, and is not limited to questions about natural gas infrastructure. While it is correct to say that there is not a consensus on what particular discount rate to use, it is spurious in the extreme to suggest that the lack of consensus means that one should not consider the costs to which the (or any) discount rate is applied. The correct way to deal with this is to consider a range of different discount rates and to consider the range of estimates of impact (costs) under different discount rates.

2. The social cost of carbon does not measure actual incremental impacts of a project; and "there are no established criteria for identifying the monetized values that are to be considered significant for NEPA purposes" (Millennium Pipeline Company, L.L.C., 2016d, pp. 9-10).

   Key-Log's response: The social cost of carbon, including upstream environmental impacts of natural gas production, is an important component of the external costs of any pipeline project. The social cost of carbon, is an economically essential component of the adverse impacts that, per FERC's certification policy, must be considered.

   Norman Bay, former Commissioner, in *Order Granting Abandonment and Issuing Certificates* (2017), stated that "the Commission has never conducted a comprehensive study of the environmental consequences of increased production from that region [the Marcellus and Utica]...Even if not required by NEPA, in light of the heightened public interest and in the interests of good government, I believe the Commission should analyze the environmental effects of increased regional gas production from the Marcellus gas production and Utica" (Millennium Pipeline Company, L.L.C., 2016d, pp. 4-5).

Millennium Assertion 6: "DRN Mischaracterizes the ESU Project's Health Impacts" (Millennium Pipeline Company, L.L.C., 2016d, p. 10).

Millennium states, "DRN incorrectly applies the results of a study conducted on residents living in the vicinity of unconventional oil and gas production sites to population estimates of Sullivan and Delaware Counties" (Millennium Pipeline Company, L.L.C., 2016d, p. 10).

First, the premise of this criticism is incorrect. The studies in question were of people living near compressor stations, not oil and gas production sites. Second, we applied the rates of symptoms from those studies to a subset of the population of Sullivan and Delaware Counties, namely those persons living in Census Blocks within two miles of either the Hancock Compressor Station or the proposed Highland Station.

That said, the question of health effects has not yet been answered in a way that would allow for definitive estimates of the full range of possible health care costs that may ensue if the ESU project is approved. Millennium LLC released a report titled *Supplemental Information-Human Health Risk Assessment Report* (2017b) that uses modeling to evaluate the potential human health risks of possible exposure to air emissions during operation of the proposed compression stations. Results of the risk assessment show there are risks of cancer and other (unspecified "non-cancer") health effects. Millennium discounts the health findings by asserting that the rate of cancer and other health effects are at levels that are below EPA's acceptable risk range. For example, the adult cancer risk from exposure to potential emissions from the Hancock Compressor Station would be 6 in 100,000,000 and the EPA's acceptable risk range is 1 in 10,000 to 1 in 1,000,000 (Millennium Pipeline Company, L.L.C., 2017b, p. 14).

However, and as noted in the body of this report, statistical and anecdotal evidence from areas around operating compressor stations suggest that actual (as opposed to modeled) air emissions exceed allowable levels and that people living closer to compressor stations experience more health symptoms like severe headaches, sleep loss, and others, than people living farther away (Macey et al., 2014; Steinzor, Subra, & Sumi, 2013; Subra, 2015). It is important to note that further epidemiological research would be required to determine the extent to which such effects are the result of exposure to emissions from compressor stations, as opposed to exposure to other factors, including other environmental hazards. Until results of such research is available, however, it is prudent to consider that health effects reported in the vicinity of other natural gas compressor stations could occur in the population living near proposed new and expanded facilities.

Concentric Energy Advisors

Supplemental Answer of Millennium Pipeline Company, L.L.C. to Comments on the Eastern System Upgrade Project (Millennium Pipeline Company, L.L.C., 2017a) includes material prepared by Concentric Energy Advisors, Inc. They raise two key contentions.

Concentric Assertion 1: That "Key-Log-Log's Claim the Economic Impacts of the ESU project are Overstated is Incorrect" (Millennium Pipeline Company, L.L.C., 2017a).

1. Concentric claims that "using IMPLAN to estimate-long-term economic impacts of large projects is a widely-accepted, commonly-used approach" (Millennium Pipeline Company, L.L.C., 2017a, p. 3).

   Key-Log Economics does not disagree with the fact that IMPLAN is a widely used input-output model, but we would not agree that this use constitutes a defense of the quality of the model in general, of the applicability of the model to any particular research question, or of the value of any particular results obtained the model as a guide for public policy. To repeat, IMPLAN models a static economy, which assumes that there will be no changes in relative prices, no factor mobility, no change in products or consumers' tastes and preferences, no regional migration, no changes in technology, and no changes in state and local tax laws – to name a few – during the years of the project operation considered. However, economies are constantly in flux, affected by policies, decisions made in businesses and households, and environmental factors.

   Concentric should explicitly acknowledge the limitations associated with the use of 2014 IMPLAN data for future, multi-year impacts and the interpretation of model results. This includes stating what information would be needed to improve model predictions. For example, in order to project what a given economy will look like even five years from now, one would need to predict future demand for goods and services, the impact of new technologies on the production of goods and services, and the local availability of resources to meet that demand (Day, 2015).

2. Concentric asserts Key-Log's claim of overstated economic benefits during construction is incorrect (Millennium Pipeline Company, L.L.C., 2017a, p. 3).

   Key-Log Economics acknowledges and thanks Concentric for the clarification that they did not assume that the total cost of construction was injected into the economy four separate times over a four-year period. However, Concentric's report only indicates that construction expenses would be approximately $275 million—it does not provide a year-by-year breakdown—and it is therefore not possible for the reader to know how that figure was used within IMPLAN to estimate total constructions impacts. It would have been helpful if Concentric had included a table in their report showing annual construction activities and costs, especially as they vary from year to year (Concentric Energy Advisors, 2016). Specifically, how were the construction costs presented in Millennium's *Abbreviated Application for a Certificate of Public Convenience and Necessity* (comprising $41 million for Measuring and Regulation: $41 million, $114 million for Compressor, and $120 million for Pipeline) (Millennium Pipeline Company, L.L.C., 2016c, Exhibit K) allocated each year during the construction period?

   We remain concerned that the construction period assumed by Concentric is inconsistent with the construction period stated in documents previously filed with

FERC (which are also conflicting). In *Resource Report 1: General Project Description (2016a),* Millennium states the construction period is one year (Millennium Pipeline Company, L.L.C., 2016a). In their *Abbreviated Application for a Certificate of Public Convenience and Necessity*, Millennium, "affirms that it had begun to incur capital expenditures for the Project" in December 2015 with a targeted in-service date of September 2018 (Millennium Pipeline Company, L.L.C., 2016c, p. 11), a period of at least two years. If the activities Concentric is including in "construction" differ from those that are described as "construction" in Resource Reports, such a distinction should be clarified to allay confusion to readers of Project documents.

3. Concentric Energy Advisors, Inc., state "Key-Log's claim that Concentric's economic benefits are overestimated by using the entire state of New York as the study region is without basis" (Millennium Pipeline Company, L.L.C., 2017, p. 6).

   Concentric states that their study "analyzed the State of New York as the study area because the purpose of the study was to calculate and demonstrate the Project benefits to the State of New York" (Millennium L.L.C., 2017, p. 3). But this circular logic does not provide any reason the state is the correct level for analysis. While state-level impacts may be of interest to some, Concentric has not followed IMPLAN guidance regarding study region definition. IMPLAN documentation states, "The Study Area defines the boundaries of what will be included in the calculation of *local* impacts" (Day, 2015, p. 9; emphasis added). This geographic zone, "should include the region where the original impact occurs, the region of large suppliers whose impact should be included, and the location where most of the industry's workers live and spend their earnings" (Day, 2015, p. 8). Based on this guidance from IMPLAN itself and on information provided in ESU project documents indicate that Delaware, Sullivan, and Rockland Counties would comprise the correct study region. The following statements related to the ESU support this four county study region:

   - "...The economic benefits generated from the construction of the ESU project are largely expected to be realized in the areas where the infrastructure upgrades to the Millennium pipeline system are being undertaken (i.e., Delaware, Sullivan, Orange, and Rockland Counties), as Millennium intends to rely on local contractors, union labor, and construction materials wherever possible" (Concentric Energy Advisors, March 2016, p. 19).
   - "[T]he socioeconomic effect area for the Project focuses on Orange, Delaware, Sullivan and Rockland Counties…" (Millennium Pipeline Company, L.L.C., 2016b, p. 5-2)
   - These counties are identified as "Project Counties" and "Project Area" in *Resource Report 1: General Project Description* and *Resource Report 5: Socioeconomics* (Millennium Pipeline Company, L.L.C., 2016a and 2016b).
   - Workforce estimates presented in Table 5-A8, "Summary of Estimated Construction Workforce and Payroll for the Project" of *Resource Report 5:*

Socioeconomics for Orange, Sullivan, Delaware and Rockland Counties are described as hired "locally" (Millennium Pipeline Company, L.L.C., 2016b, p. 33).

- *Resource Report 5: Socioeconomics* states, "Approximately 60 percent of the construction workforce for the Huguenot Loop and 40 percent of the construction workforce for the aboveground facilities will be from the impacted and nearby surrounding areas" (Millennium Pipeline Company, L.L.C., 2016b, p. 5-6).

Concentric Assertion 2: That "Key-Log's Claim the Energy Market Savings may be Overstated is Incorrect" (Millennium Pipeline Company, L.L.C., 2017a, p. 7).

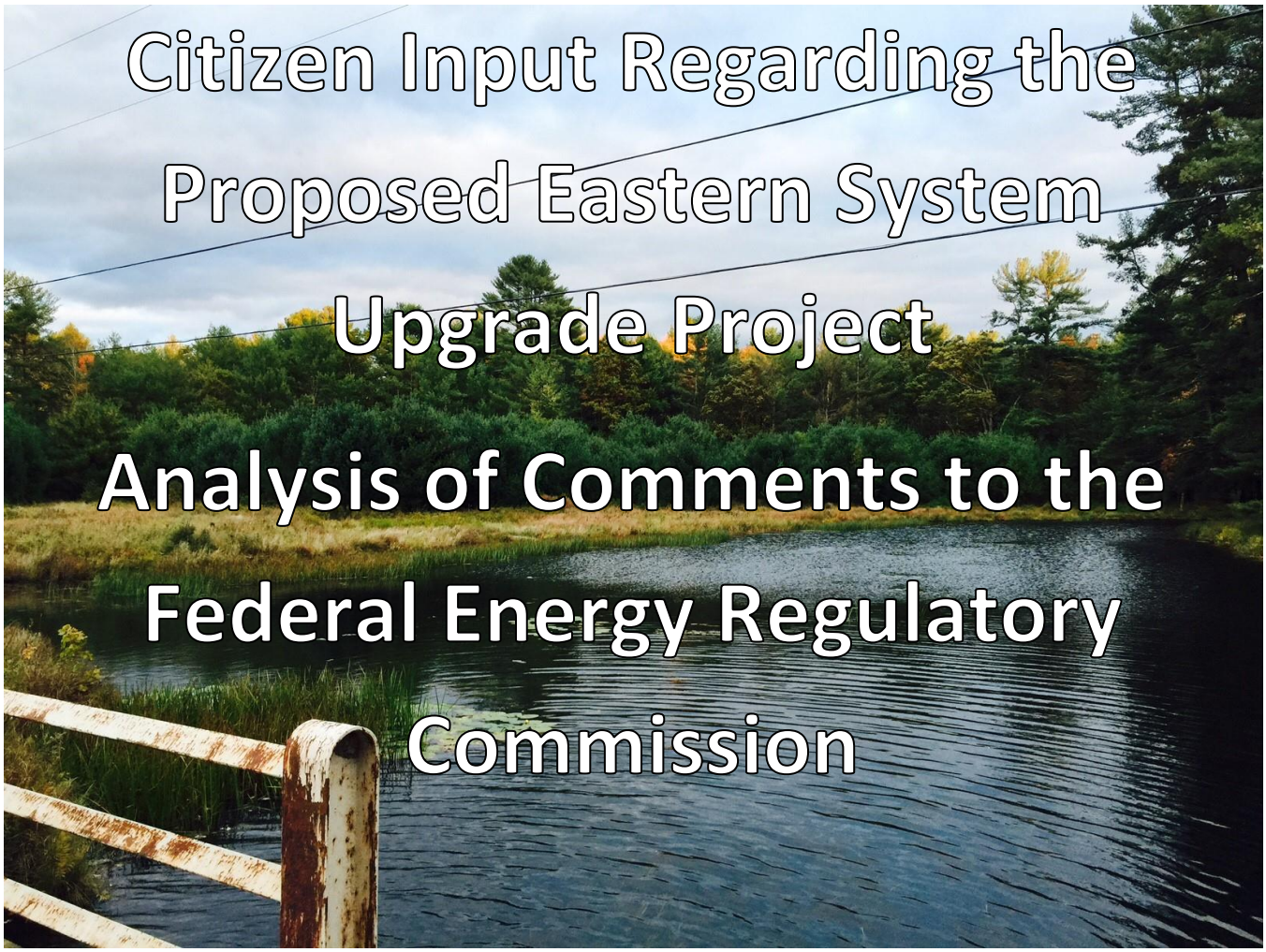
1. Concentric Energy Advisors, Inc., state "the effect of Millennium's alleged guaranteed rate of return on its investment in the ESU project is irrelevant to benefits to New York" (Millennium Pipeline Company, L.L.C., 2017, p. 7).

   Key-Log Economics expressed concern that overestimates in the estimated benefit to New York electric utility customers from increased natural gas supplies resulted from Concentric's failure to consider costs of the pipeline construction, including a rate of return. Millennium responded that New York ratepayers will not bear the costs of the Project because none of the ESU Project shippers directly provide service to New York customers (Millennium Pipeline Company, L.L.C., 2017a, p. 4). By estimating the benefits to New York consumers as a result of increased natural gas supply without considering the corresponding costs that will be borne by people other than New York consumers, Millennium has provided incomplete and unbalanced information regarding the net benefits to ALL consumers from the ESU Project.

   With regard to the rate of return, Key-Log Economics acknowledges and thanks Concentric for clarifying that, "since the ESU project shippers elected negotiated rates for transportation on the ESU project, they will not be subject to Millennium's cost-based recourse rates" (Concentric Energy Advisors, 2016, p. 7). While we understand, "there are no guarantees that Millennium, or any other natural gas pipeline, will fully recover their costs and earn a specified rate of return" (p. 8), Millennium expects its pre-tax 11.51% rate of return included in their *Abbreviated Application for a Certificate of Public Convenience and Necessity* (Millennium Pipeline L.L.C., 2016c, Exhibit N) to be realized since revenues from negotiated rates are estimated to exceed the cost of service: "As shown on Schedule 1, Line 9, the negotiated contract rates agreed to by Millennium and the Project Shippers for service on the Eastern System Upgrade Project, together with the anticipated revenues from the sale of the currently unsubscribed capacity, will generate reservation rate revenues that are greater than the Eastern System Upgrade Project cost of service by $51,524 in year 1, and sufficiently cover the cost of the project over the 15-year primary term of the contract."

2. Projected increases in renewable generation are not likely to significantly affect the energy market savings from the ESU project.

Concentric (2016, p. 12) states, "It is expected that the addition of the capacity associated with the ESU Project will result in lower natural gas prices than otherwise would be experienced…") based on their use of GPCM, a partial equilibrium model of the North American natural gas market which assumes perfect competition. There are a number of other factors influencing the natural gas market and prices however, and these should be acknowledged by Concentric in a discussion of the limitations of the modeling approach and results. These include additional sources of natural gas, such as new supplies from other natural gas pipeline expansions (U.S. Energy Information Administration, 2016); NYISO's status as a net importer of electricity from other regional transmission organizations (Hibbard, Schatzki, Aubuchon, & Wu, 2015); and factors that affect demand, such as weather, state demand management programs and federal/state incentives. Furthermore it remains likely that generation of electricity from nonconventional and renewable energy sources will increasingly affect energy prices in the future - especially given New York's commitment to achieve 50% of its electricity from renewable sources by 2030 (Morris, 2016; Kennedy, 2016). Furthermore, a recent article in *The Economist* describing the increasing growth rate of wind and solar energy notes that the more renewable energy is deployed, the more it lowers the price of power from any source (The Economist, 2017).



Citizen Input Regarding the Proposed Eastern System Upgrade Project

Analysis of Comments to the Federal Energy Regulatory Commission

April 2017

Delaware Riverkeeper Network

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Authors' Note

Key-Log Economics is grateful to have had the opportunity to conduct this independent analysis with the help of Delaware Riverkeeper Network. We owe a special thanks to the volunteers who gave their time reviewing comment letters. Without their effort this review would not have been possible.

Cover Photo from Mark Egan

Policy Setting

The Eastern System Upgrade project ("ESU") is a multi-part project intended to expand the capacity of the existing Millennium Pipeline in New York State. The project includes construction of approximately 7.8 miles of 30- and 36-inch pipeline loop in Orange County, construction and operation of a new compressor station ("the Highland Compressor Station" or "Highland CS") in Sullivan County, an additional compressor at the existing Hancock Compressor Station ("Hancock CS") in Delaware County, modifications to the existing Ramapo Meter and Regulator station in Rockland County, and additional pipeline appurtenant facilities at the existing Huguenot Meter Station and Westtown Meter Station in Orange County.

Millennium Pipeline Company, L.L.C ("Millennium LLC") would be in charge of the construction and operation of the project and is seeking authorization from the Federal Energy Regulatory Commission ("FERC"). FERC's review process for the project began when Millennium LLC requested use of FERC's National Environmental Policy Act ("NEPA") Pre-Filing Process. Under the National Environmental Policy Act, FERC must consider the environmental effects of its decision. Those effects include impacts on air and water quality, aesthetic value, wildlife, and others, as well as how changes in the physical environment are reflected in effects on people, including through changes in economic well-being.

After FERC formally approves Millennium LLC's NEPA Pre-Filing Process, project review begins. FERC participated in an open house held by Millennium LLC and then issued a Notice of Intent announcing that they would prepare an Environmental Assessment ("EA"), which determines whether or not a federal action has the potential to cause significant environmental effects.

A key part of the NEPA process is "scoping" or "a scoping period," during which any person with an interest in the proposed federal action (in this case approval or denial of the ESU project) has a chance to tell the lead agency (FERC) what concerns them about the proposed action and what they think the lead agency should include in its ensuing environmental review. FERC is obligated to consider this citizen input in its Environmental Assessment ("EA").

Before the EA was released citizens, public and private interest organizations, and experts in many fields had the opportunity to review, respond to, and comment on Millennium LLC's filing. The public provided input in the form of written letters, entries to FERC's online eComment site, and petitions circulated by groups for or against the proposed project. FERC is expected to consider this input as it revises its analysis and prepares the EA.

Between the pre-filing process, scoping period, and the release of the EA, FERC received hundreds of comments. They took the form of unique letters and eComments composed by individuals and organizations, form letters submitted with or without modification by individuals, and petitions, in the form of a single comment signed by many individuals.

Key-Log Economics, with the help of Delaware Riverkeeper Network, has completed an independent analysis of the written comments. These comments include excellent information about the economic and other effects that citizens, scientific experts, and various stakeholders expect to see, or are already seeing, as a result of the proposed Eastern System Upgrade Project.

The content of these letters is critically important for two reasons.

- First, the letters provide direct and clear information about the issues of concern to the people and communities which the project would impact as well as to people who, as visitors, downstream water users, business owners, and others, use and enjoy the directly affected landscape. Combined with our review of existing economic studies and with our analysis of primary and secondary data on property values, human

health and safety, the social cost of carbon, and economic development trends, the comment letters help FERC understand the nature and extent of the effects of the proposed project.

- Second, under the National Environmental Policy Act, FERC must consider the comments it has received as it follows the NEPA process. FERC must cover relevant issues raised in comments, and this independent review of what citizens have said in public comments will help ensure that FERC's legal obligations to consider the full range of environmental effects of the proposed project are met.

Methods

For this report, we analyzed 414 of the of the 527 publically available comments posted to both the ESU pre-filing docket, PF15-3, and the official ESU project docket, CP15-486, from January 19th, 2016 (when the pre-filing docket was established) through April 18th, 2017.[1]

In total, our analysis covers different written messages to FERC. The messages are of three types.

1. 321 individual or unique comment letters or eComments.
2. 92 copies of 16 different form letters.
   There were between 2 and 30 copies of each form letter.
3. 1 petition with a total of 8 signatures.

See also "Comment Type and Commenter Location" graph under "Results."

To review this volume of communication, we used crowdsourcing–that is, we enlisted the help of a crowd of volunteers to complete the task via the internet. Our crowd consisted of 11 volunteers recruited by Delaware Riverkeeper Network. Each of these volunteers reviewed at least one comment.

The reviewers' specific task was to read through the comment letter and log details from the comment using an online form. Concerns expressed in the comments included the economy, larger energy related questions, the environment, lifestyle factors, and systemic issues. The form also included space where volunteers could record commenters' thoughts on items not covered elsewhere on the form. (A copy of the form is included as Appendix A.) For each concern, the form asks whether the commenter views the proposed ESU project as likely to have a positive or negative effect. In addition, we asked reviewers to rate how strongly positive or negative each commenter felt the effects would be in several overarching areas: economy; U.S. energy needs; environment; and lifestyle/quality of life.

Once the form was set up, our process, in brief, consisted of the following steps:

1. Download all comment letters.
2. Send a batch of three comment letters to each volunteer along with instructions (see Appendix B) and a link to the online form.
3. Monitor the database linked to the online form and send reminders to volunteers who seemed to have missed the initial email.
4. Send new batches to volunteers who requested them via a prompt that appeared after submitting previous comments using the online form.

[1] People continued to submit comments after April 18th, however, this time frame was chosen by Delaware Riverkeeper Network as a way of managing the tasks of downloading and distributing comment letters for review. We do not think there is reason to expect that comments submitted in this (or any) window are any more or less likely to favor the proposal.

FERC received comments that varied widely in length, technicality, and the main concerns addressed. They also came from commenters residing or owning property in one of the three counties the project would impact[2], other counties in New York State, and from other states. We were therefore able to stratify the comments according to commenters' location as well as summarize the various concerns raised by people living nearer to and farther from the proposed project components.

Based on previous analysis Key-Log Economics conducted for the Atlantic Coast Pipeline and the PennEast Pipeline, we identified dozens of individual factors grouped into four broad categories of economy, energy, environment, and lifestyle. The environment category, for example, includes factors such as geologic hazards, erosion, surface water (streams/rivers/lakes), and wetlands, to name a few. For each category, the form asks [for example] "Does the commenter mention any of the following environmental factors that they say will be impacted either positively or negatively if the Eastern System Upgrade Project is permitted?" For each factor in the category the reviewer would indicate whether the comment letter writer indicated that the factor would be affected positively or negatively, or that the factor had not been mentioned at all. Some comment letters mention many issues while others mention only one.

After the economy, energy, environment, and lifestyle section, the form includes questions of the form "Overall how does the commenter think the Eastern System Upgrade Project will affect the environment? Please leave blank if they seem to have no opinion."[3] For comment letters that did indicate an opinion on the category, the reviewer registered the direction and strength of that opinion on a 1-5 Likert scale with 1 being "Extremely Negatively" and 5 being "Extremely Positively."

We also asked reviewers if the comment mentioned environmental justice positively or negatively. A further section provided space to record commenters' concerns over general or systemic issues such as cumulative impacts or the purpose and need for the project.

Additionally there was a question that asked "What is the desired outcome of the commenter?" We provided choices of "Eastern System Upgrade Project is built," "Eastern System Upgrade Project is not built," "Unstated/Unsure", and "Other." There was also a question that asked the reviewer "Overall what is the comment's attitude toward the proposed Eastern System Upgrade Project?" The reviewer was asked to again use the 1-5 Likert scale.

Reviewers aided Key-Log's broader research by answering the question "In your opinion, does this comment letter include a good personal story/testimony that illustrates one or more of the following effects?" The effects included ecosystem services, human health and safety, property values, community services, and attractiveness of the community/region. Details into the results of this research into the economic costs of the proposed Eastern System Upgrade can be found on Delaware Riverkeeper Network's website.[4]

The form concludes with space to record references to statistical or other data cited by the commenter, a free-response question for any other items not covered elsewhere in the form, and lastly, the reviewer's judgement regarding whether the comment appeared to be a form letter or a petition, as opposed to an individual letter. (Please see Appendix A for the full form.)

One final note is that some individual comment letters were particularly lengthy and/or technical. We kept that segment out of the pool for volunteer review and assigned their review to an expert reviewer.

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[2] These are Delaware, Sullivan, and Orange County in New York State.

[3] The energy question was phrased slightly differently: "Overall, does the commenter think the ESU project will help meet an identified US energy need?"

[4] Direct link: http://www.delawareriverkeeper.org/sites/default/files/EconomicCostsOfTheESU_FINAL_201704.pdf

Reviewing the Reviewers

Another important role for our team was to evaluate the volunteers' review of comment letters. To accomplish that, we selected 20 (10%) of the individual comment letters at random and assigned a team member to review those letters from scratch. We then compared the team member's review to that of the volunteer who had previously reviewed the same letter. We found that the reviews by volunteers and by our team agreed in nearly all cases and nearly all aspects.

For almost 70% of our sample, our team found either no differences or few differences compared to the review completed by a volunteer. For an additional 15% of our sample, our team found some differences, and for the last 15% we found many differences.

"Few differences" was defined as 1 to 3 differences; "some differences" was defined as 4 or 5 differences; "many differences" was defined as 6 or more differences. Our team did not count trivial differences between volunteer and team member's reviews. An example of a trivial difference would be if the volunteer reviewer had inferred a concern for "forests" from a letter that mentions environmental, habitat, or landscape impacts but where the commenter had not specifically said "forests," per se. An example of a non-trivial difference would be if the volunteer review indicated that a letter mentioned negative or positive effects on forests but our team review of the comment letter found no evidence of the same opinion.

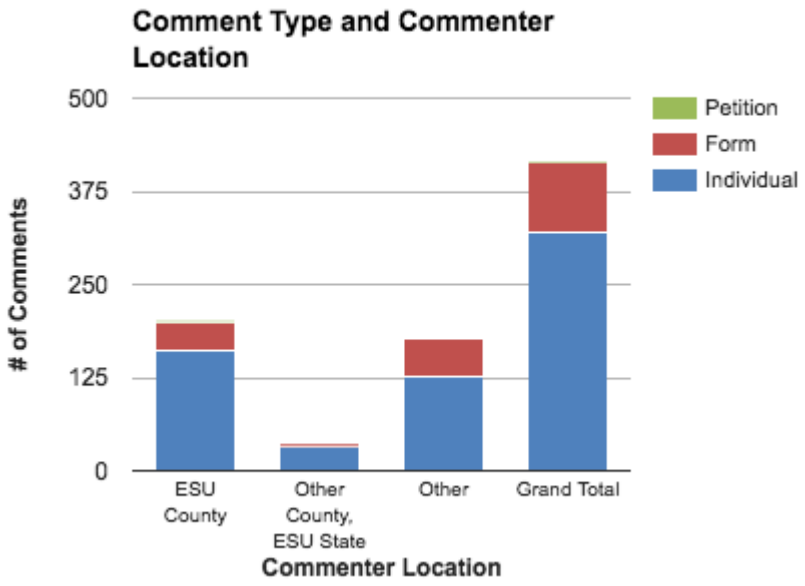
For the reviews where we found many differences between our comment analysis and that of a volunteer, our team pulled all of that volunteer's reviews and examined them for any signs of systematic bias, such as a judgement by the reviewers in question that every comment they reviewed expressed a concern that the pipeline would have either a positive or a negative effect. We found no evidence of such bias, and we are therefore confident that the volunteers' review provided information that is thorough, complete, and reliable as a characterization of commenters' concerns and opinions.

Results

Based on the information from the comment letters, we can stratify comments according to the commenters' location (or the location of their property) in an ESU county ("ESU County"), another county in New York ("Other County, New York"), and other states ("Other") (See "Comment Type and Commenter Location").

The results reported here include all types of comments submitted to FERC (i.e. individual, form, and petition).[5]

[5] A petition is counted as a single comment.



Note: Each individual letter, each form letter, and the petition is counted as one comment. However, the petition was signed by more than one person, and some of the individual and form letters were signed by more than one person (a husband and wife, or a pair of business partners, for example).

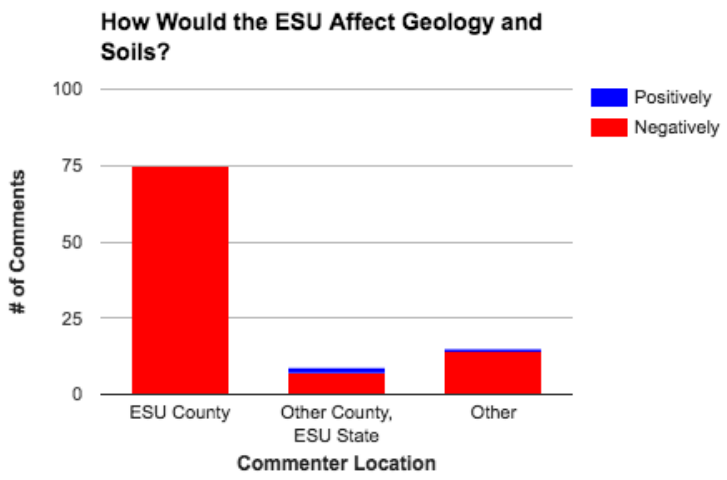
Of the comments received as individual/unique comments, some 50% came from commenters in ESU-impacted counties.

For any given issue, our analysis considers only those comments that mention the issue. Therefore, the base for all percentages of comments expressing a particular view about the effect of the Eastern System Upgrade Project in the issue area (positive or negative) is total number of comment letters that mentioned the issue. We do not, in other words, count comment letters that are silent on the issue in the percentage calculations.

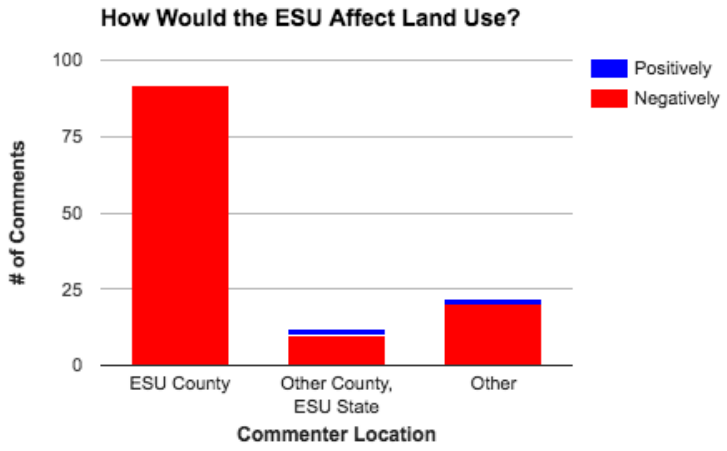
FERC's Notice of Intent to prepare an Environmental Assessment regarding the Eastern System Upgrade Project[1] includes a list of impacts that could result from the project. Not surprisingly, many commenters addressed these issues directly or indirectly. Our survey included the issues identified by FERC as well as many others. The following charts display the number of letters in which the commenter mentions a FERC/NOI-defined issue as well as whether, in the commenter's judgement, the Eastern System Upgrade project would have a positive or negative impact on the issue. Furthermore, each chart provides separate subtotals of the number of comments from residents of ESU-impacted counties, other counties in New York State, and other states.

Each chart answers a question with the same formatting as "How do citizens believe the Eastern System Upgrade Project would affect the environment" (or "...surface water," "...air quality," etc.). As the charts indicate, the vast majority of commenters that mentioned these issues believe there will be negative impacts if the Eastern System Upgrade Project is approved. Across the 12 categories, between 92.3% and 99% of the comments express a concern that the Eastern System Upgrade Project would have a negative impact on the critical issues.[6]

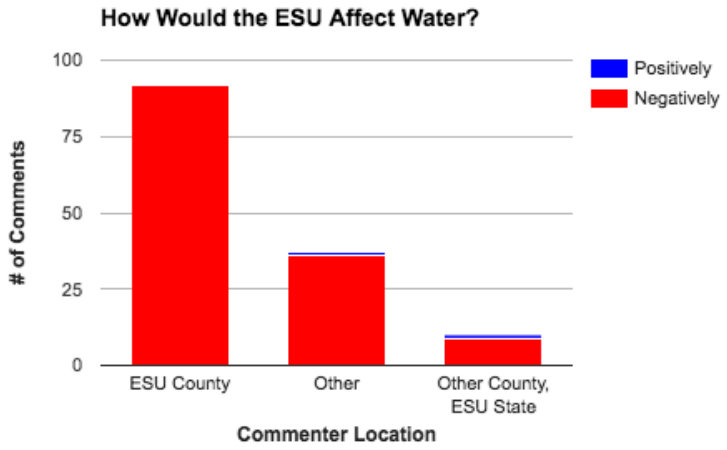
[6] The Notice of Intent also asked about "Cumulative Impacts." Only 9 out of the 414 comments mentioned this topic, and we did not collect data on whether or not the commenter believed the Eastern System Upgrade Project would have a positive or negative impact. We therefore do not include a graph of these results below.



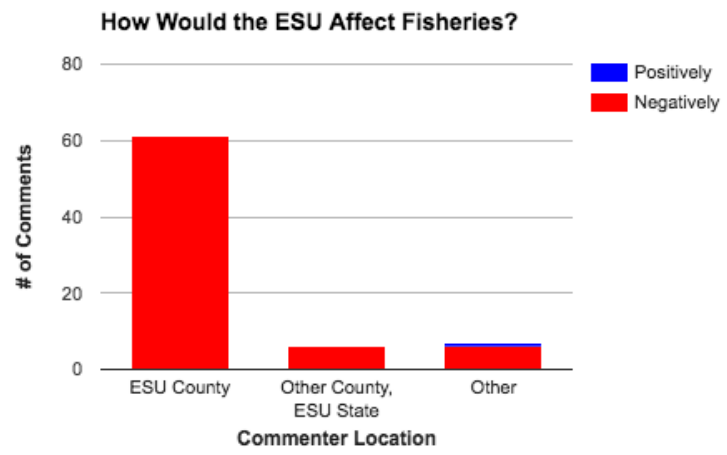
- FERC category: "Geology and Soils"
- This graph represents a combination of answers to our survey question about effects on geologic hazards and effects on soils.
- **97% mention negative impacts.**



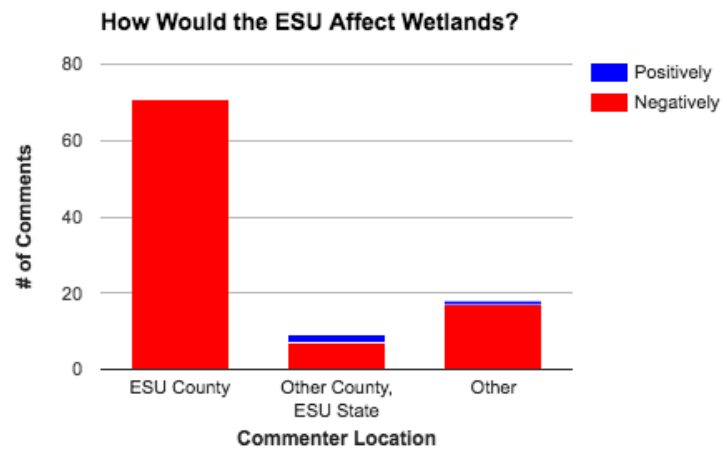
- FERC category: "Land Use"
- **96.8% mention negative impacts.**



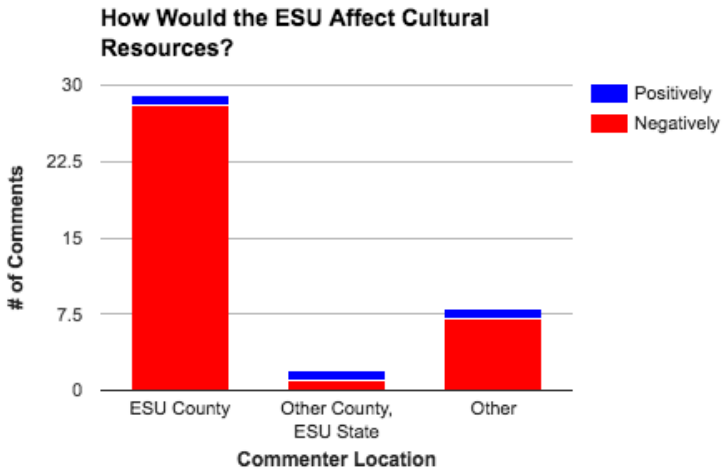
- FERC category: "Water Resources"
- This graph represents a combination of answers to our survey question about effects on surface water (streams/rivers/lakes) and groundwater (including wells and springs).
- **98.6% mention negative impacts.**



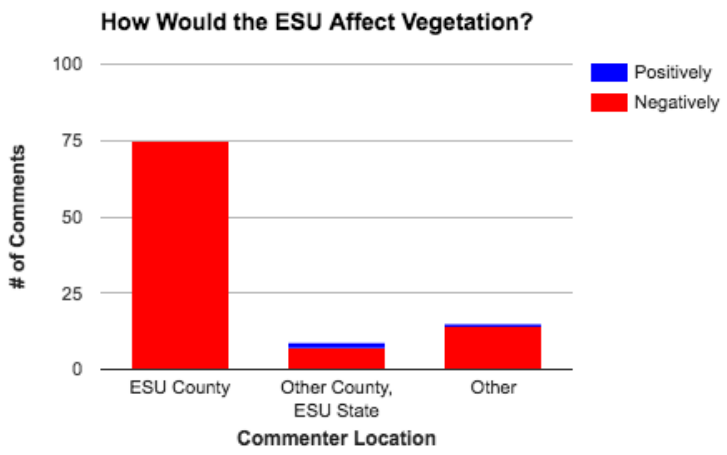
- FERC category: "Fisheries"
- **98.6% mention negative impacts.**



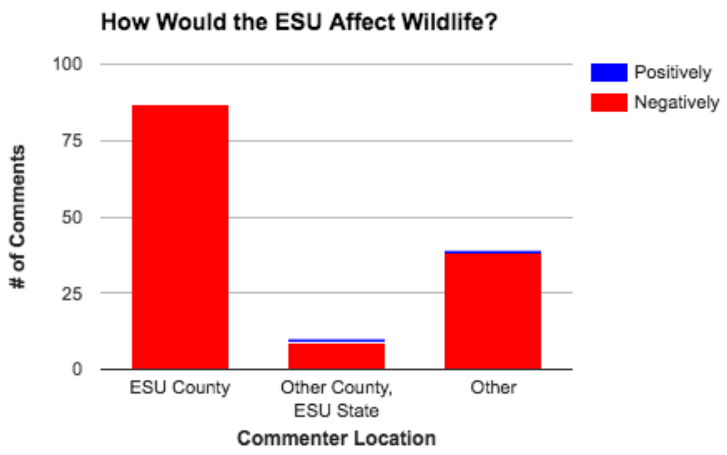
- FERC category: "Wetlands"
- **97% mention negative impacts.**



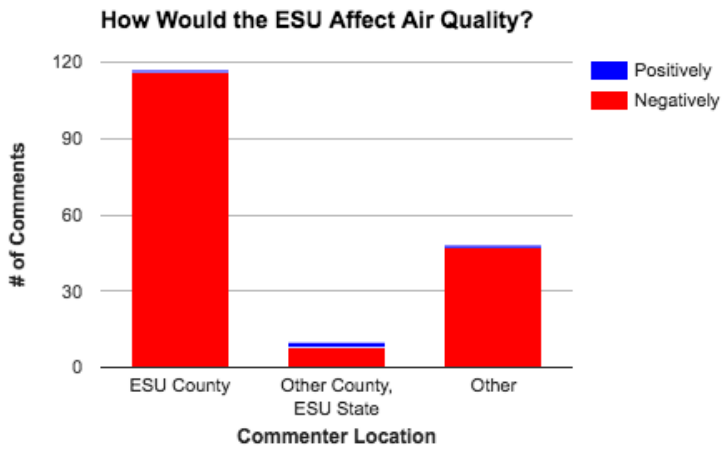
- FERC category: "Cultural Resources"
- **92.3% mention negative impacts.**



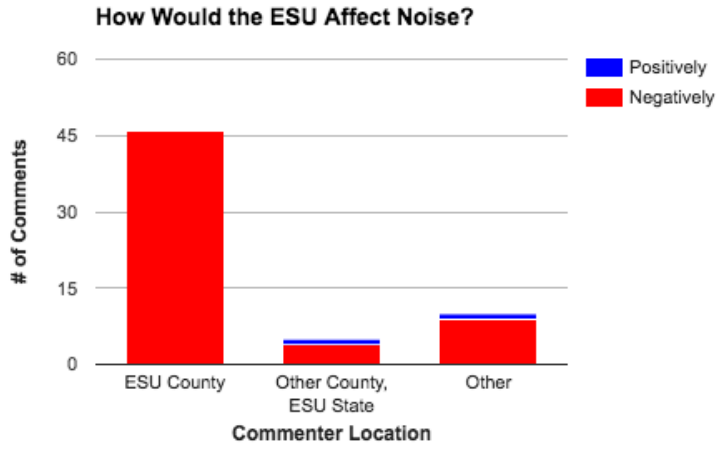
- FERC category: "Vegetation"
- **97% mention negative impacts.**



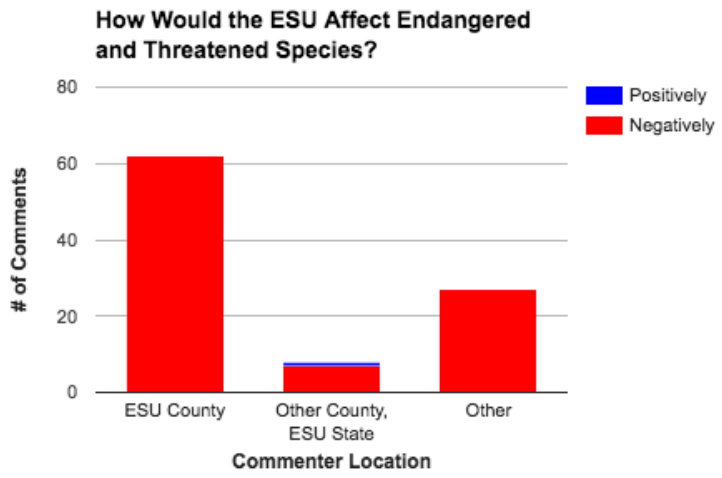
- FERC category: "Wildlife (including migratory birds)"
- **98.5% mention negative impacts.**



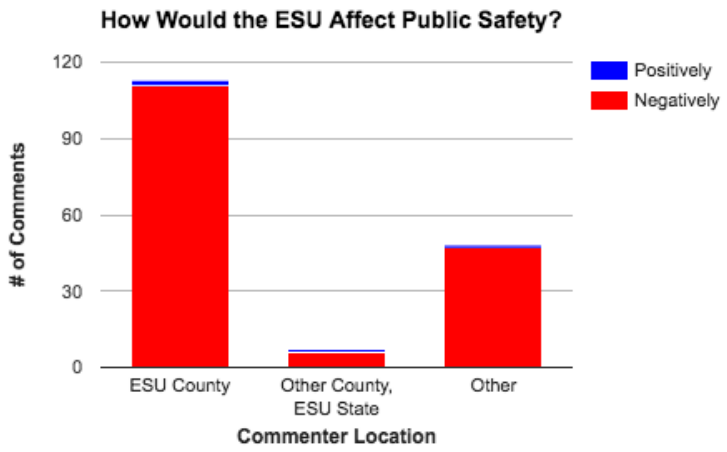
- FERC category: "Air Quality"
- **97.7% mention negative impacts.**



- FERC category: "Noise"
- **96.7% mention negative impacts.**

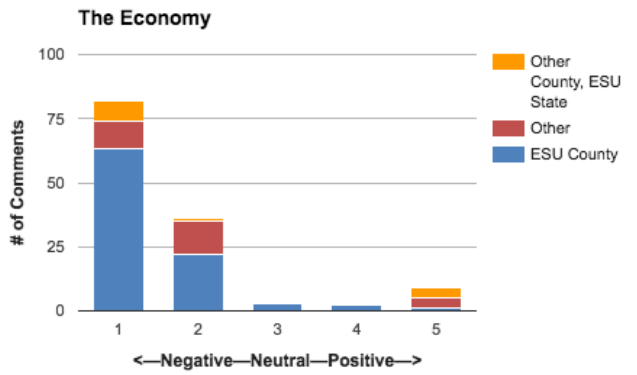


- FERC category: "Endangered and Threatened Species"
- **99% mention negative impacts.**

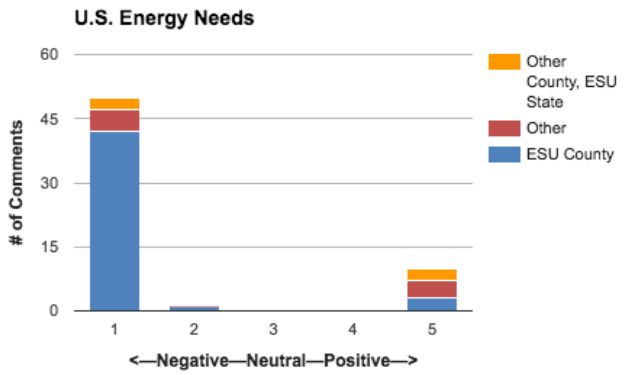


- FERC category: "Public Safety"
- **97.6% mention negative impacts.**

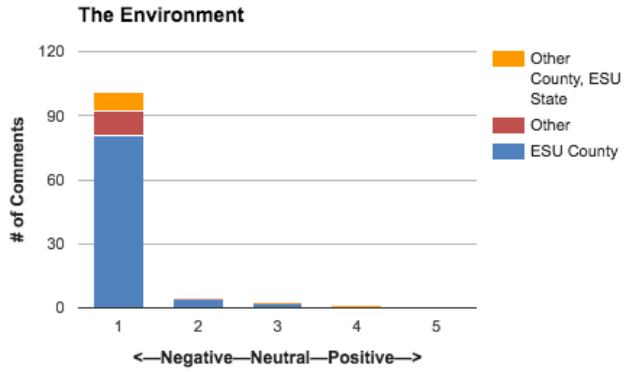
The four Likert-scale questions included in the comment review form allow us to gauge the strength of commenters' concern for four overarching issues: effects on the economy; contribution to U.S. energy needs; effects on the environment; and effects on lifestyle/quality of life. For each, the reviewer answered the question "Overall how does the commenter think the Eastern System Upgrade Project will affect the economy [for example]?" by selecting a number on a 1-5 scale, with 1 being "Extremely Negatively" and 5 being "Extremely Positively." For comment letters containing no discernable opinion on the issue, the question was left blank.



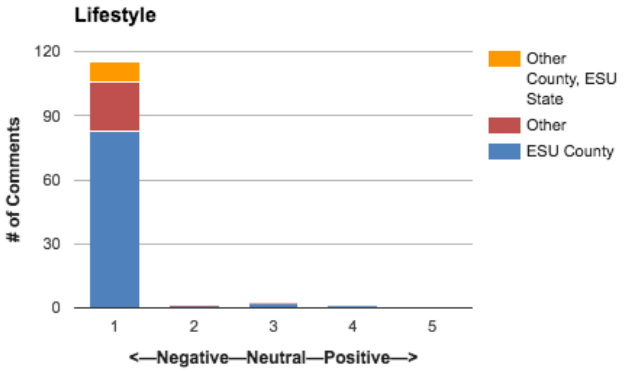
89.4% believe the Eastern System Upgrade Project will negatively affect the economy.[a]



83.6% believe the Eastern System Upgrade Project will not help meet an identified U.S. energy need.[a]



97.2% believe the Eastern System Upgrade Project will negatively affect the environment.[a]

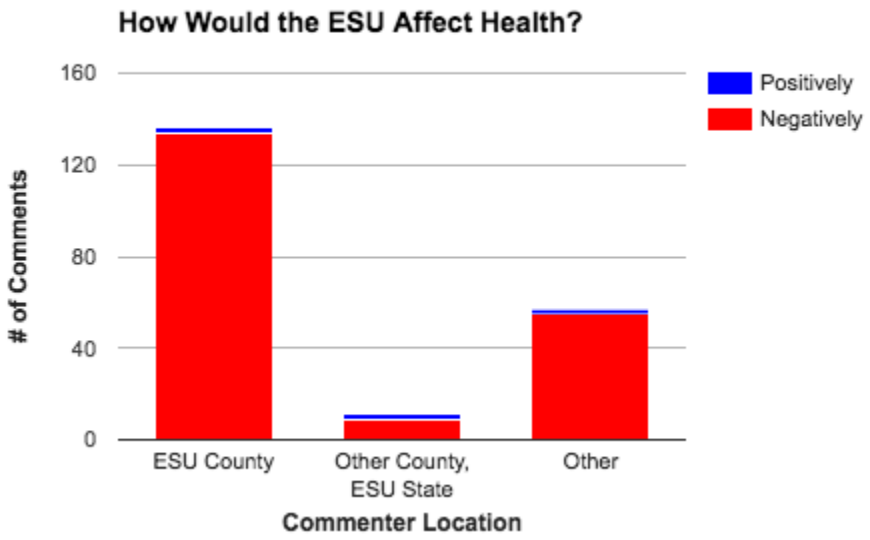


97.5% believe the Eastern System Upgrade Project will negatively affect lifestyles/the quality of life.[a]

Note: 1 corresponds to "Extremely Negatively"; 5 corresponds to "Extremely Positively."

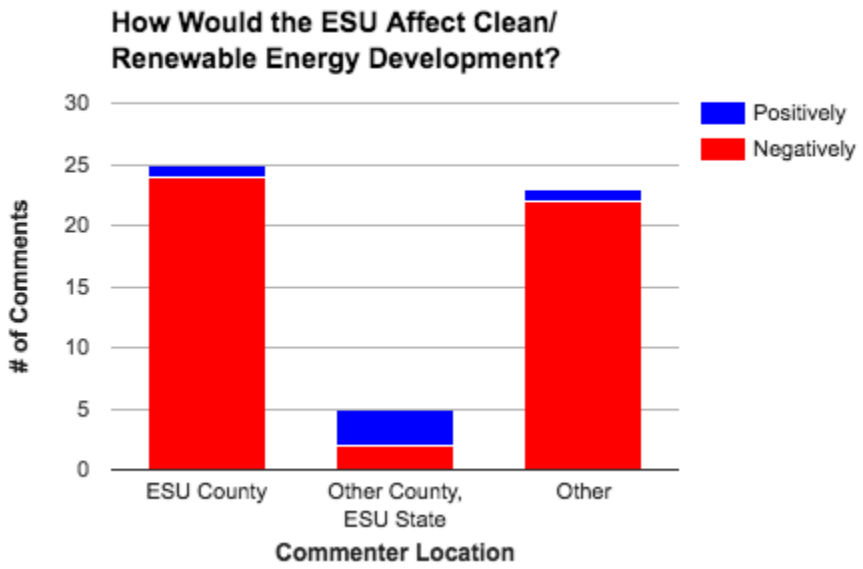
a. The percentages that believe the Eastern System Upgrade Project will affect each category negatively are defined as those commenters who ranked the category as either a 1 or 2.

The majority of commenters believe the Eastern System Upgrade Project will have an overall negative effect (1 or 2 on the scale) in four key areas. Of all commenters who mentioned the economy, 89.4% think the Eastern System Upgrade Project will harm the economy; 83.6% of those mentioning energy needs said the project would not help the U.S. meet a domestic energy need; 97.2% of those mentioning the environment said the project would have a negative impact on the environment; and 97.5% of those mentioning lifestyle/quality of life expect a negative effect. Interestingly (because it is where the impact of spending on construction and operation of the pipeline is most likely to occur[7]), commenters closest to the proposed project are least likely to believe the Eastern System Upgrade Project would help the economy or contribute to U.S. energy needs. Only 8.3% of such commenters indicated that the Eastern System Upgrade Project would be good for the economy (a score of 4 or 5), and just 16.4% thought there would be a positive contribution to U.S. energy needs.



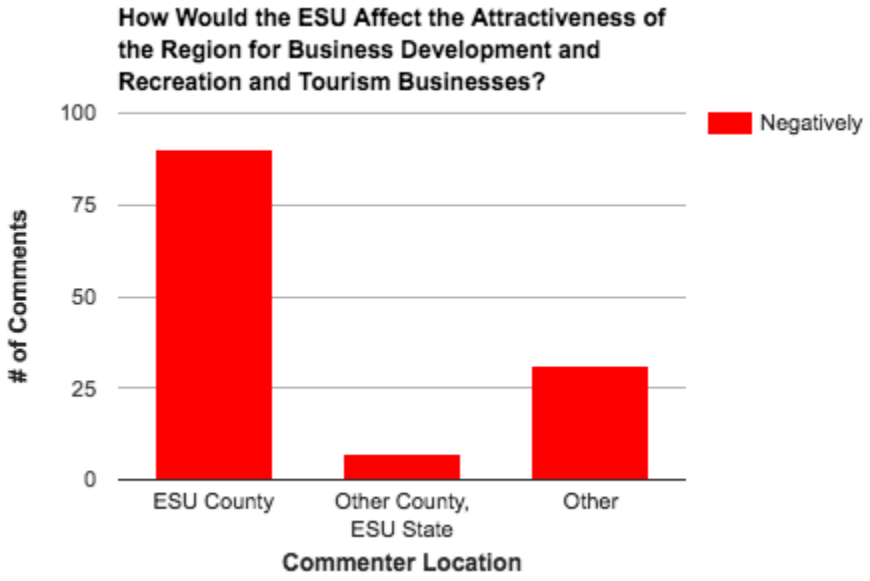
Many comments, 204, also mentioned the issue of health. 97.1% of these commenters believe the Eastern System Upgrade Project will negatively affect health. Health concerns were wide ranging, but many were worried about health effects caused by pollution from the compressor stations.

[7] As part of its application, Millennium LLC submitted a report on socioeconomics ("Resource Report 5") including an economic impact study by Concentric Energy Advisors that estimates regional job and income impacts of spending on the construction and operation of the project as well as estimated energy savings that would occur from the project (See Concentric Energy Advisors. (2016). *Estimated Savings For New York Consumers From the Millennium Pipeline Eastern System Upgrade Project* and Millennium Pipeline Company, L.L.C. (2016b). *Eastern System Upgrade, Resource Report 5:Socioeconomics (p. 32)*. Millennium Pipeline Company, L.L.C.).



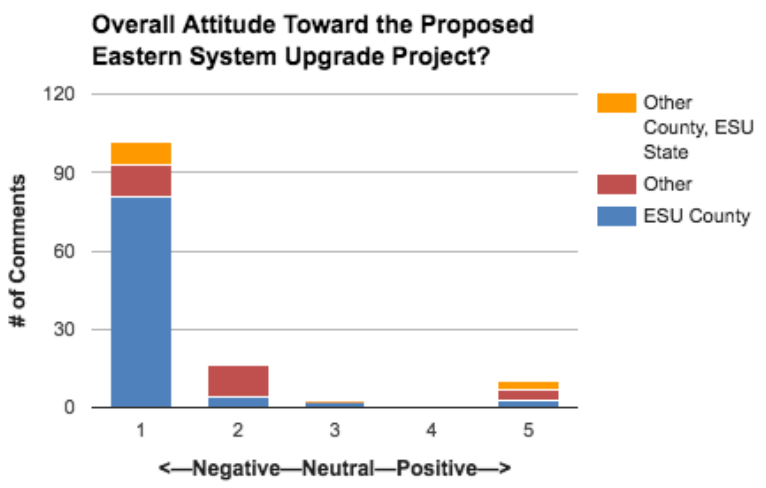
Millennium LLC claims that the project will create energy savings due to the additional capacity the project would provide. However, in our review of the costs of the Eastern System Upgrade[8], we found flaws in the claims presented by Millennium LLC and Concentric Energy Advisors in that they do not accurately assess the important role renewable energy will play in the 10 years they estimate energy saving benefits. Citizens commenting on the project also agree. Of 53 comments that mentioned clean/renewable energy, 48 believed that the project would negatively impact clean/renewable energy development.

[8] The review is Phillips, Spencer, Sonia Z. Wang, and Carolyn Alkire. "Economic Costs of the Eastern System Upgrade: Effects on Property Value, the Social Cost of Carbon, and Public Health." Key-Log Economics, LLC, April 2016.



Another important issue for citizens residing near the proposed project was how the project would impact the attractiveness of the region for business development and how the project would impact recreation and tourism businesses. Commenters noted that many homes in the area are second homes/vacation homes, with people drawn to the region for the pristine environment and ample recreation activities. Many comments also addressed concern that the project would hurt the tourism industry in the region. Out of 128 commenters that mentioned concerns over how the project would impact the attractiveness of the region or how the project would impact recreation and tourism, 100% of commenters believed the Eastern System Upgrade Project would have a negative impact.

Given the input of citizens regarding individual issues reported thus far, it will come as no surprise that most commenters have an overall negative opinion of the proposed Eastern System Upgrade Project. 90.8% have negative feelings toward the project. Among commenters who live or own property in a county potentially impacted by the ESU, the proportion of commenters opposed to the project is similar, 90%.



90.8% of all commenters expressed a negative attitude toward the proposed Eastern System Upgrade Project (ranked their attitude as either a 1, "Extremely Negative", or 2).

Conclusions

This analysis demonstrates the wealth of concerns that citizens have expressed to FERC through the NEPA process and shows the depth and breadth of those citizens' beliefs that the proposed Eastern System Upgrade Project will have negative or adverse effects on the environment, the economy, U.S. energy needs, and people's quality of life. This citizen input is what FERC is required to consider and address as it finalizes its Environmental Assessment.

The opportunity for citizen input is a core principal of the NEPA process. Citizens possess a wealth of knowledge that can be extremely helpful and enlightening for federal agencies. Moreover, these comments voice real concerns over aspects of the ESU proposal that FERC itself has flagged as important. Thus, FERC will best serve the public by carefully considering the content of the citizen input summarized here and, moreover, by addressing citizens' concerns fully in its analysis of the potential adverse effects of the Eastern System Upgrade Project.

For their part, citizens and their representatives can use this analysis and the data behind it to evaluate how well FERC succeeds in addressing the adverse effects of the proposed Eastern System Upgrade Project. Delaware Riverkeeper Network can provide interested readers with further information about the Eastern System Upgrade Project and how to become or stay involved in the review process at the federal and state levels going forward.

Appendix A: Comment Analysis Form

Note: Reads from left to right.

Eastern System Upgrade Project: FERC Comment Analysis

Thank you so much for helping to analyze the input received by the Federal Energy Regulatory Commission (FERC) regarding the proposed Eastern System Upgrade Project.

You don't have to be an expert on the issues to help out, but your help will enable detailed economic and policy analysis that will lead to better information being brought to bear on FERC's decisions regarding the ESU over the coming year.

Just as a reminder here's how to analyze your comment:

1.With your comment letter open in another window, fill out the form below to the best of your ability. Select (and sometimes type) answers to the questions on the survey using the information in the comment.
2. You may want to read or skim the comment before you begin answering questions in order to get the idea of the commenter's points first.
3. Please understand that we are trying to record as accurately as possible what the commenter is portraying in their comment, regardless of what his/her opinion might be regarding the ESU Project itself. Our goal is to have a fair and accurate accounting of what people have said to FERC.
4. When you have finished filling out this form click submit.
5. Choose "submit another response" to repeat for another comment letter.

Most of all, please accept our great thanks for your help.

Please e-mail keeper@delawareriverkeeper.org if you have any other questions about this process.

* Required

Note: The Eastern Expansion Project referred to here includes all of its components: 7.8 miles of pipeline loop in Orange County, New York, construction of a new compressor station in Sullivan County, New York, and additional horsepower for the existing Hancock compressor station in Delaware County, New York.

If the commenter specifically states, or if you know from other information they give, check off the County in which they reside (or own property/do business). *

The specific counties listed are those crossed by the proposed ESU Project.

- [ ] Delaware County, NY
- [ ] Orange County, NY
- [ ] Rockland County, NY
- [ ] Sullivan County, NY
- [ ] Other NY County
- [ ] Any Other State
- [ ] Unstated/Unsure

If the commenter lists his/her residence or other property near the proposed Eastern System Upgrade Project, please indicate, as specifically as possible, the property's location.

For example "123 main street, Delaware, NY;" "Orange;" or just "New York."

Your answer

Please enter your email. *

Your answer

Please enter the "Submittal Number" of the comment. This is the title of the PDF comment you were sent. *

It will be numbers in the form XXXXXXXX-XXXX (12 total digits).

Your answer

How does the person who submitted the comment describe him/herself?

Check all that apply

- [ ] Individual (including landowner)
- [ ] Business
- [ ] Association or Organization
- [ ] Government Official
- [ ] Expert Report
- [ ] Other: _____

Please list the name of the commenter, including any associations they list.

Association Examples: Millennium Pipeline Company, LLC, Owner/Employee of ____, Member/officer of [organization] (Homeowners Association, Delaware Riverkeeper Network, Chamber of Commerce, etc.)

Your answer

Does the commenter mention any of the following economic factors that they say will be impacted either positively or negatively if the Eastern System Upgrade Project is permitted?

Please choose a rating for all that are mentioned. Leave blank any others.

	Positively	Negatively	Did Not Mention
Economy (generally)	○	○	○
Jobs	○	○	○
Attractiveness of the Region for Business Development	○	○	○
Recreation and Tourism Businesses	○	○	○
Other Local Businesses	○	○	○
Property Values	○	○	○

Overall how does the commenter think the Eastern System Upgrade Project will affect the economy?

Please leave blank if they seem to have no opinion.

	1	2	3	4	5	
Extremely Negatively	○	○	○	○	○	Extremley Positively

Does the commenter mention any of the following energy factors that they say will be impacted either positively or negatively if the Eastern System Upgrade Project is permitted?

Please choose a rating for all that are mentioned. Leave blank any others.

	Positively	Negatively	Did Not Mention
"Clean"/Renewable Energy Supply (Solar, Wind, etc.)	○	○	○
Energy Reliability	○	○	○
Cost of Energy	○	○	○
U.S. Energy Independence	○	○	○
Shale Gas/Drilling/Fracking	○	○	○
LNG/Shale Gas Exports	○	○	○

Overall, does the commenter think the ESU project will help meet an identified US energy need?

Please leave blank if they seem to have no opinion.

	1	2	3	4	5	
Commenter believes it will not	○	○	○	○	○	Commenter believes it will

Does the commenter mention any of the following environmental factors that they say will be impacted either positively or negatively if the Eastern System Upgrade Project is permitted?

Please choose a rating for all that are mentioned. Leave blank any others.

	Positively	Negatively	Did Not Mention
Environment (generally)	○	○	○
Geologic Hazards	○	○	○
Agricultural Areas	○	○	○
Livestock	○	○	○
Soils	○	○	○
Erosion	○	○	○
Sedimentation	○	○	○
Surface Water (streams/rivers/lakes/etc)	○	○	○
Groundwater (including wells and springs)	○	○	○
Fisheries	○	○	○
Wetlands	○	○	○
Vegetation	○	○	○
Wildlife (including migratory birds)	○	○	○
Air Quality	○	○	○

Wildlife (including migratory birds)	○	○	○
Air Quality	○	○	○
Noise Pollution	○	○	○
Endangered and Threatened Species	○	○	○
Forests	○	○	○
Recreation Areas	○	○	○
Climate Change	○	○	○
Land Use	○	○	○

Does the commenter mention any of the following lifestyle factors that they say will be impacted either positively or negatively if the Eastern System Upgrade Project is permitted?

Please choose a rating for all that are mentioned. Leave blank any others.

	Positively	Negatively	Did Not Mention
Recreational Opportunities and/or Quality	○	○	○
Educational Opportunities	○	○	○
Quality of Life	○	○	○
Impacts Related to Noise During Construction and Operation	○	○	○
Local/Rural Character (including aesthetics)	○	○	○
Property Rights	○	○	○
Health	○	○	○
Public Safety	○	○	○
Cultural Resources	○	○	○

Overall how does the commenter think the Eastern System Upgrade Project will affect the environment?

Please leave blank if they seem to have no opinion.

	1	2	3	4	5	
Extremely Negatively	○	○	○	○	○	Extremley Positively

Overall how does the commenter think the Eastern System Upgrade Project will affect lifestyle?

Please leave blank if they seem to have no opinion.

	1	2	3	4	5	
Extremely Negative	○	○	○	○	○	Extremley Positive

Did the commenter mention environmental justice?
Environmental Justice is the fair treatment of all people regardless of race, color, national origin, or income when it comes to environmental impacts. Leave blank if they did not mention.

- ○ Positively
- ○ Negatively

Does the comment express concern over any of the following systemic issues?
Check all that apply.

- ☐ Purpose and Need for the Project
- ☐ Impacts on Residential Areas and Use of Eminent Domain
- ☐ Cumulative Effects of Multiple Pipeline Proposals
- ☐ Assessment of Alternative Pipeline Routes and Compressor Station Locations
- ☐ Cumulative Impacts

What is the desired outcome of the commenter?

- ○ Eastern System Upgrade Project is built
- ○ Eastern System Upgrade Project is not built
- ○ Unstated/Unsure
- ○ Other: _____

Overall what is this comment's attitude toward the proposed Eastern System Upgrade Project?

	1	2	3	4	5	
Extremely Negative	○	○	○	○	○	Extremley Positive

In your opinion, does this comment letter include a good personal story/testimony that illustrates one or more of the following effects?
Check all that apply:

- ☐ Effects on ecosystem services, or the capacity of natural systems to provide clean water, air, recreation, beauty, etc. to people
- ☐ Effects on human health and safety
- ☐ Effects on property values (including on market prices, appraisals, insurabilty, and ability to get a mortgage)
- ☐ Effects on the community services like fire, police, road maintenance, and the costs of providing them
- ☐ Effects on the attractiveness of the community/region as a place to live, work, do business, or retire

If the commenter used or referenced any statistics in their comment please list them here with the source of the statistic, if available.
Please be as specific as possible to enable our researchers to find the source data if needed.

Your answer

Please list anything else the comment said that you felt was of importance and not covered in previous questions.

Your answer

Does this comment appear to be a form letter?
A form letter is a letter written from a template, rather than being specially composed by each individual.

- ○ Yes
- ○ No
- ○ Maybe

Does this comment appear to be a petition

- ○ Yes
- ○ No
- ○ Maybe

NEXT

Appendix B: Instructions for Volunteers

Dear Volunteer,

Thank you so much for helping to analyze the input received by the Federal Energy Regulatory Commission (FERC) regarding the proposed Millennium Eastern System Upgrade. The comments you will review are part of the "scoping" phase, in which citizens, experts and interested parties are to advise FERC on what questions and issues it should consider when writing an Environmental Impact Statement for the Millennium Eastern System Upgrade. This is all part of FERC's obligations under the National Environmental Policy Act, or NEPA.

You don't have to be an expert on the issues to help out, but your help will enable detailed economic and policy analysis that will lead to better information being brought to bear on FERC's decisions regarding the pipeline over the coming year. If you'd like to learn more about the pipeline proposal and DRN's associated efforts, you can read about it at http://bit.ly/DRN-StopMillenniumESU.

Here's how your citizen-science participation works:

1. Attached to this e-mail is a "packet" of 3 comment letters for you to review.
2. For each comment letter in the packet:
    1. Open the comment letter right in your browser, or download it and open it using Adobe Acrobat Reader or a similar program.
    2. Click on this link to open a fresh copy of the review/summary form. If that link doesn't work automatically, please paste the following into the address bar of a new browser window and hit <enter>. https://docs.google.com/forms/d/e/1FAIpQLSfrmli_nV-Ex0q3dx4aLau2PsJKuOuafj64AkJOnjqXj5SZLg/viewform
    3. To the best of your ability, select (and sometimes type) answers to the questions on the survey using the information in the comment.
    You may want to read or skim the comment before you begin answering questions in order to get the idea of the commenter's points first.
    Please understand that we are trying to record as accurately as possible what the commenter is portraying in their comment, regardless of what his/her opinion might be regarding the pipeline itself. Our goal is to have a fair and accurate accounting of what people have said to FERC.
3. Repeat steps 2.1 through 2.3 for the other two comments in your packet.
4. Please be sure to answer the last questions on the survey about your progress with your packet. This step will be extremely helpful for us so that we can keep track of which of the many thousands of submitted comments have been reviewed. If you decide you don't want to participate, please email to let us know you won't be doing any of your comments or perhaps that you only did 1 or 2 of the packet. That is still helpful work and good for us to know! We'll ask a different volunteer to review the other comment(s). We ask that you finish your packet within 7 days of receiving it if possible.
5. At the end of the survey you will have an option to request more comments to review if you would like. We'll be thrilled if you do! Please feel free to spread the word and pass information about this opportunity along to anyone else you think might be interested in helping out!

Most of all, please accept our great thanks for your help. Thanks to your participation and that of many other volunteers we know we can get through the thousands of comments submitted to FERC and help ensure better decisions for the people, communities, and economies concerned about the proposed pipeline.

We are so grateful for your time. Please email molly@delawareriverkeeper.org if I have left anything out of the instructions that you need to proceed.

DELAWARE RIVERKEEPER NETWORK

November 28, 2016

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Millennium Pipeline Company, LLC Eastern System Upgrade Project, CP16-486

Dear Ms. Bose,

The Delaware Riverkeeper Network submits the attached expert analysis undertaken by Dr. Stephen J. Souza with Princeton Hydro, LLC.

Sincerely,

Maya K. van Rossum
the Delaware Riverkeeper

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

Princeton Hydro

Scientists, Engineers & Environmental Planners Designing Innovative Solutions for Water, Wetland and Soil Resource Management

28 November 28, 2016

Maya K. van Rossum
Delaware Riverkeeper Network
925 Canal Street, Suite 3701
Bristol, PA 19007

Dear Ms. van Rossum:

Princeton Hydro, LLC submits the attached report that details our findings regarding the environmental impacts associated with the proposed Millennium Pipeline Eastern System Upgrade. Our findings are largely based on the information contained in a number of reports prepared by Millennium Pipeline and submitted to the Federal Energy Regulatory Commission (FERC). Our review of these materials confirms that this project will have both short and long term impacts on environmental and water resources located within both the Delaware River Basin and the Hudson River Basin. Among the negative impacts that we expect to occur as a result of this proposed project include significant negative changes to the upland, riparian and wetland plant communities, irreversible soil compaction, increases in stormwater runoff, and both acute and long-term degradation of stream communities. As discussed herein, although the measures proposed by Millennium to mitigate these impacts may satisfy the minimum standards needed to achieve regulatory approval, they will fall far short of restoring affected areas to pre-construction conditions. As a result the proposed Eastern System Upgrade will negatively impact the ecological services and functions of the upland, wetland and stream environments traversed by and located adjacent to the pipeline right of way (ROW). Further details of the anticipated impacts and irreversible consequences of this project are provided in our report.

Should you have any questions or comments please feel free to contact me.

Sincerely,

Stephen J. Souza, Ph.D., President
Princeton Hydro, LLC

1. The Millennium Pipeline Eastern System Upgrade

The Millennium Pipeline runs for 220 miles along the southern edge of New York from Independence in Steuben County to Ramapo in Rockland County, also passing through Chemung, Tioga, Broome, Delaware, Sullivan, and Orange counties. Jointly sponsored by subsidiaries of the Columbia Pipeline Group, National Grid, and DTE Energy, the pipeline was completed in 2008 and supplies the northeast United States with 0.5 billion cubic feet per day of natural gas from the Interstate pipeline system and Appalachia (US EIA). This 30-36 inch pipeline was installed within a 50 foot wide permanently cleared right-of-way (ROW).

The proposed Eastern System Upgrade (Project) involves the construction of 7.8 miles of additional 30-36 inch pipeline partially adjacent to the existing Millennium Pipeline in Orange County, NY, known as the Huguenot Loop. Beginning in the town of Deerpark, New York, the new pipeline will pass through the town of Greenville and end in the town of Minisink. Additionally, the Project will require the construction of multiple aboveground facilities. These include a new Highland Compressor Station and access road (Sullivan County, NY), and modification of the existing Hancock Compressor Station (Delaware County, NY), the Ramapo Meter and Regulator (M&R) Station (Rockland County, NY), the Wagoner Interconnect (Orange County, NY), the Huguenot M&R Station (Orange County, NY), and the Westtown M&R Station (Orange County, NY).

The Eastern System Upgrade affects lands and water resources located within the Delaware River and the Lower Hudson River watersheds. Approximately 2.6 miles of the Huguenot Loop, as well as the Highland and Hancock Compressor Stations, the Wagoner Interconnect, and the Huguenot M&R are located within the Delaware River watershed. The remaining 5.2 miles of the Huguenot Loop along with the Westtown M&R station are located within the Lower Hudson River watershed. Figure 1 provides an overview of the subject section of the pipeline that is part of the proposed Eastern System Upgrade.

The Project is subject to review by the Federal Energy Regulatory Commission (FERC). Details of the Project's potential impacts to the environment are presented in a number of publically accessible documents. In preparing this report Princeton Hydro conducted a fairly comprehensive review of the following publically accessible documents:

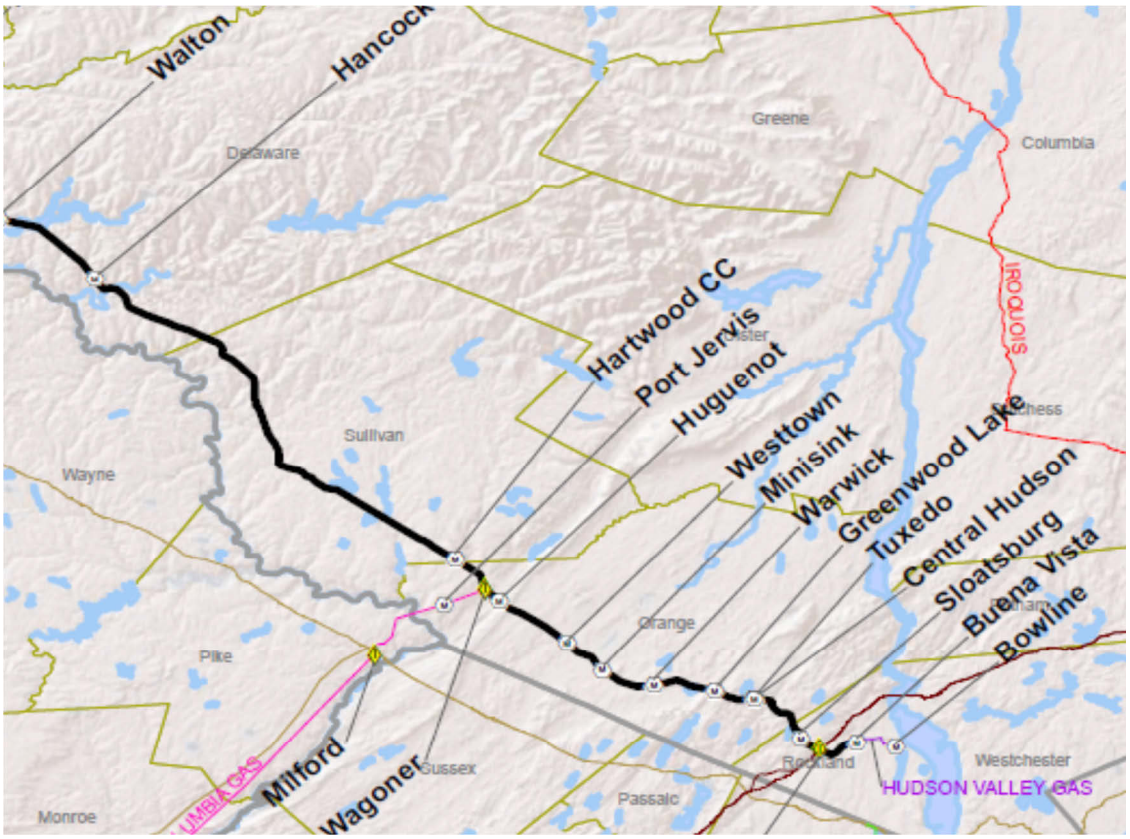
- Eastern System Upgrade, *Resource Report 1* (General Project Description*)*, July 2016
- Eastern System Upgrade, *Resource Report 2* (Water Use and Quality*)*, July 2016
- Eastern System Upgrade, *Resource Report 3* (Fisheries, Vegetation, and Wildlife), July 2016
- Eastern System Upgrade, *Resource Report 6* (Geological Resources), July 2016
- Eastern System Upgrade, *Resource Report 7* (Soils), July 2016

- Eastern System Upgrade, Final Environmental Report, Volume II-B – Appendix 1C, Maps And Figures, July 2016
- Eastern System Upgrade, Appendix C3, *Phase I Bog Turtle Habitat Survey Report,* April 2016
- TRC, Letter to the DRBC, prepared on Behalf of Millennium Pipeline Company, LLC, regarding the Eastern System Upgrade,
- 25 June Letter from the DRKN to the DRBC Commissioners and Executive Director, and
- Millennium Eastern System Upgrade Pre-filing Review Letter to FERC, 16 January 2016

Princeton Hydro's report also takes into account published literature and reports that pertain and discuss the short- and long-term impacts of gas pipelines. The additional materials that were reviewed in the preparation of this report are listed within Section 5.

FERC lists Millennium's Eastern System Upgrade as one of the major projects currently under FERC review (FERC filing date 29 July 2016). As is the case for any interstate project involving the construction and/or operation of a natural gas pipeline, FERC's review of this project is required as per Section 7(c) of the Natural Gas Act. Such reviews are also subject to the Energy Policy Act of 2005, which designates FERC as the lead agency for coordinating "all applicable Federal authorizations." The Energy Policy Act also mandates a National Environmental Policy Act (NEPA) compliance review of all interstate energy projects. On 19 January 2016 Millennium requested approval from the FERC to initiate the pre-filing NEPA review process. FERC in turn approved Millennium's pre-filing NEPA review request on 5 February 2016. The particular section of the Project that is reviewed herein is also subject to review by the New York State Department of Environmental Conservation (NYSDEC) and to the jurisdiction of the Delaware River Basin Commission (DRBC).

Figure 1 Approximate Path of Millennium Pipeline Eastern Upgrade within New York



Source: Millennium Pipeline Company, LLC

2. Overview of the Environmental Impacts of Pipelines and the Construction of the Eastern System Upgrade

Princeton Hydro's review of the proposed Eastern System Upgrade focused on the Project's potential short- and long-term environmental impacts, with the emphasis of our analysis placed on the Project's impacts to wetland, riparian and stream ecosystems traversed by the pipeline or associated with any of the above ground support facilities.

As noted above, Millennium has generated a number of reports that in part acknowledge and address the environmental consequences of the Project. The field work supporting some of these reports was conducted over an approximate 5-month period beginning in October of 2015 and concluding in early April of 2016. The field studies involved the delineation of wetlands and waterbodies, identification of threatened and endangered species (or their habitat) and surveys of cultural resources occurring within "the area of potential effect", which essentially is a 100 ft to 300 ft wide corridor. The corridor width designated by Millennium reportedly should account for disturbances attributable to pipeline construction activities, the

pipeline's permanent inspection/maintenance right-of-way (ROW), all above-ground support elements of the project, and potential "minor route realignments" that could arise due to specific site conditions. Additional analyses were conducted pertaining to the environmental impacts of construction activities and how such impacts could be mitigated. It should be noted that 27% of the area associated with the "area of potential effect" was not actually surveyed as part of the environmental assessment[1]. Summarizing the data presented in the various Resource Reports, the pipeline itself will result in a total land disturbance of 155 acres attributable to construction activities, with an additional 22 acres affected by post-construction pipeline operations and maintenance. There is an additional 73 acres of disturbance (temporary and permanent) attributable to the above ground support facilities.

2.1 Short term

The most obvious potential short-term environmental impacts are associated with the actual installation of the pipeline and the construction of the supporting infrastructure. Although the consequences of these activities are mostly viewed as triggering short-term impacts, they can elicit longer-term ecological perturbations and negative changes to the ecology of the area. Primary short term effects include vegetation removal, soil disruption and compaction, erosion, and damage to the water quality and hydrologic regime of streams and wetlands.

Vegetation must be cleared to create the pipeline ROW, as well as access roads, construction work spaces and staging areas, and is a major impact to the lands traversed by the pipeline. The clearing process involves the removal of all mature vegetation and the offsite transport of the material using heavy equipment. Collectively this results in an immediate, intense, disturbance of the work area. It also exposes the denuded soil setttig the stage for further erosion as construction activities progresses.

Pipeline construction also causes significant soil disturbance and compaction. As noted above, initially Soil disturbance occurs during the clearing of vegetation, but also results from the grading of construction areas, the operation of heavy machinery, and obviously the actual excavation of the pipeline trench. As noted the typical construction right-of-way for a 36 inch pipe is 100 feet. The pipeline trench itself has to be wide enough to not only accommodate the gasline, but to provide enough space to safely facilitate pipeline installation, construction and testing activities. The pipeline also needs to be suitably buried below the ground to prevent its exposure or damage. Typically it is buried with a soil overburden of 30-36 inches. However, the trench depth may be even greater when the pipeline runs under roads, streams, and agricultural lands.

The trenching operation therefore necessitates the removal of large amounts of soil. The soil removed to create the trench temporarily is stockpiled adjacent to the trench. This stockpiled soil is susceptible to erosion and offsite transport prior to being re-used to bury the bedded

[1] Page 1-11, *Draft Resource Report 1 – General Project Description; Eastern System Upgrade, April 2016*

pipeline. The threat of erosion and offsite transport is markedly increased on steeper sloped lands. As noted in the supporting materials submitted for the Eastern System Upgrade, the pipeline traverses a substantial amount of steep sloped lands.

Disturbing the soil also contributes to erosion and soil loss at the site, that may result in sedimentation issues down gradient of the site. Soil compaction due to machinery operation negatively impacts the soil's ability to support vegetation, reduces soil porosity, decreases infiltration, and negatively affects microbial composition. The decrease in permeability makes the disturbed sites susceptible to greater stormwater runoff both during and following construction, as less precipitation can now infiltrate into the soil.

Wetland and streams are the most sensitive ecosystems affected by pipeline crossings and associated construction activities. Vegetation clearing, excavation, and machinery operation increases the likelihood of erosion and turbidity in the waterbody, and disturbs habitat required by fish, amphibians, mollusks and aquatic insects. Hydric soils are particularly sensitive to compaction because of their higher soil moisture content. Once compressed the resulting loss in pore space negatively affects the soil's hydrologic properties. This can impact the successful re-colonization and re-establishment of wetland plants in disturbed sites. Erosion, turbidity and soil compaction issues also affect macroinvertebrate colonization, fish spawning, and feeding behaviors of various trophic groups that rely on wetland, riparian and stream habitats during any part of their life-history.

The common mitigative solution offered by the pipeline companies involves the implementation of construction-realted erosion control measures. However, the majority of these measures are designed to work in dry environments. As a result, they will either be less effective in a wetland or stream environment, or will require frequent maintenance (including dewatering), which in itself can further negatively affect the hydrology and ecology of the system. Machinery operating in riparian and aquatic settings increases the chance of fuel or lubricants leaking or spilling into streams and wetlands. Such spills, even those considered relatively minor, are detrimental to the environment.

Notably, in the materials reviewed, there is a lack of any hydrologic modeling or accounting for any local hydrologic data in the planning of the various stream crossings. This failure to model and properly plan each crossing will increase the likelihood that each crossing will to subject to disturbance and impact. Documented post-installation impacts caused by pipeline projects include stream bed and bank erosion, localized hydrologic changes, compromised habitat, and even the exposure of the bedded pipeline due to unforeseen strema hydrodynamics changes caused by the crossing. As these impacts occur they will need to be addressed and corrected. This will require once again accessing the site, resulting in further disturbance of the stream channel.

Although within the supporting documents generated by Millennium there appears an attempt to minimize the ecological significance of stream crossing, the potential environmental impacts are in fact substantial and must be viewed beyond the amount of land being disturbed. The significant disturbance associated with the project is compounded by the lack of appropriate modeling and site specific data collection.

Millennium states that the clearing process involves the removal of large obstacles (e.g., trees, boulders, rocks, and brush) and the subsequent grading of work areas to create a relatively flat, stable surface that facilitates the movement and operation of construction equipment and construction activities. They also state that all felled trees and any other brush and other vegetation removed as part of the clearing and site preparation effort may be "chipped, burned, sold, or otherwise disposed of." These actions (the removal of large obstacles, soil grading and removal and disposal of trees and brush) further add to the severity of the clearing process, especially when this occurs in steeper sloped areas, areas with shallow, highly compactable soils and within wetland and riparian areas.

It is important to note that over three (3) acres of forested wetlands and emergent wetlands will be disrupted by the pipeline's construction. The impacts arising during the clearing phase of the project will be especially acute in these areas.

As part of any disturbance activity Millennium will be required to implement certain erosion control measures. While these measures are intended to lessen or moderate the Project's unavoidable impacts to the environment or the health and safety of the affected populous, they need to be viewed as the minimum required level of protection. The Project will also require implementation of stormwater management measures used to control runoff and maintain work areas in an operational state. The reports refer to such devices as temporary flume pipes, interceptor dikes, and other flow diversion measures. The installation and maintenance of these stormwater and flow control devices add to the impacts of the project. For example, open trenches will need to be maintained in a water-free state. Whether originating as runoff, rainfall or groundwater, the water that collects in the trench will need to be pumped and removed. This affects pipe sections located not only in wetland and riparian areas, but also in upland areas.

Millennium understates the potential impacts of the dewatering process stating that "water will be pumped from the trench to a well vegetated area down-gradient of the trench and through a sediment filter" (e.g., hay bales, trench plugs or filter bags) and that this type of dewatering process will not cause any erosion or result in the transport of "heavily silt-laden water flowing into any waterbody or wetland." There are multiple examples of failed erosion and sediment control measures associated with pipeline projects. We view soil erosion (especially that related to trench de-watering activities) as one of the most significant environmental threats to the streams, wetlands, riparian areas, and even sensitive upland areas traversed by the pipeline.

Likewise soil stockpiles will need to be created along the pipeline ROW and adjacent to some of the above ground support facilities. Each of these stockpiles creates an opportunity for off-site soil transport and impact to wetlands, riparian areas and streams. With respect to any directional drilling there will be processed drilling fluids that will need to be managed before being returned to a stream or hauled off-site. The pumping of water for the drilling operation and the return of the drilling fluid all represent additional potential impacts to streams, wetlands and riparian areas.

2.2 Long term effects

Long term environmental impacts result from changes to the site that occur during the construction phase as well as changes due to the operation and maintenance of the pipeline. Though mitigation or restoration measures are taken to address construction related impacts, sites rarely return to pre-construction conditions due to irreversible changes to soil, vegetation, and hydrologic characteristics during construction.

In addition to the previously noted short-term issues, the extensive vegetation clearing associated with pipeline construction causes long-term effects. With the exception of the ROW, which is kept permanently mowed for access, cleared areas are allowed to regrow post-construction. However, it takes at least five years for grasslands and at least ten years for shrub and forest areas to attain densities and coverages similar to the pre-construction conditions. Also, complete clearing of vegetation in addition to construction activities causes changes in soil characteristics and the local environment by changing exposure to sunlight, soil moisture content, soil structure, soil compaction, and microbial composition. Additionally, in the time it takes for vegetation to grow back, cleared areas are more sensitive to erosion and soil loss. These changes may result in plant communities never recovering to the same level of complexity and ecological functioning. Forested wetlands that are cleared and become scrub-shrub or emergent wetlands are more likely to be invaded by non-native vegetation, decrease in diversity, and be affected hydrologically. Vegetation clearing also results in habitat fragmentation and the creation of edge habitat, a known ecological problem which breaks up previously continuous habitat, impacts species ability to access resources, decreases biodiversity, and increases invasive species establishment.

The hydrology and water quality of waterbodies are affected long term. Vegetation clearing and soil compaction increase runoff and associated erosion from the site, as less precipitation is intercepted or infiltrated into the soil. Along with sediment issues downstream of the site, increased runoff is associated with greater pollutant loading. Wetland and stream crossings are particularly sensitive to future erosion and water quality issues owing to their ecological importance. Increased sedimentation and pollutant loading in streams degrades in-stream habitat and causes eutrophication.

Thus, the long-term impacts associated with the Project will be realized after the completion of all construction activities. The most obvious long-term impacts will occur due to the routine, required system maintenance and operational activities. This will encompass activities within and adjacent to the ROW such as mowing, tree trimming and other mechanical vegetation removal, and the application of herbicides. There will also be the need to routinely inspect and maintain the pipeline and all its interconnections, as well as the operate and maintain the pipeline's above ground elements (compressors, PIGs, etc.). These on-going disturbances may compromise the ability of the pipeline ROW and immediately adjacent areas to become properly stabilized. It will also increase the occurrence of invasive species, especially non-native, edge species, such as Japanese knotweed, stilt grass, Canada thistle and mugwort.

However, the more serious long-term impacts are those resulting from the altered and/or lost ecological services and functions, impaired aesthetics, and reduced recreational quality of all areas disturbed by construction activities and subsequently routinely subject to the disturbances associated with the maintenance and operation of the pipeline and above ground support facilities.

The following sections of this report discusses in greater detail both the projected short- and long-term impacts of the Project, as based on the materials submitted by Millennium.

3. Specific Environmental Concerns Associated with the Proposed Eastern System Upgrade

3.1 Vegetation clearing

The construction ROW for the Huguenot Loop is 125 feet wide. This ROW accounts for the 45 feet of cleared ground that is part of the existing permanent easement, but also necessitates the clearing of an additional 80 feet (potentially 40 feet on either side of the existing ROW). Also, approximately 76 additional temporary workspaces (ATWS) are planned along the pipeline path. The actual size of each ATWS will vary, but will likely be greater in size in the more difficult to access areas to facilitate material stockpiles, etc. In total, the Huguenot Loop is expected to disturb 116 acres during construction, 86 acres of which are outside of the existing cleared easement of the Millennium pipeline. This new clearing is new disturbance and adds to total area that will need to be restored after the conclusion of construction activities.

Following the Project's completion, 36 acres will remain cleared in association with the operation and maintenance of the Huguenot Loop. Of this, 19 acres fall outside of the existing easement area and represent a new permanent impact (Resource Report 1, p. 33: Table 1.4-3).

The pipeline will cross 2,904 feet of wetland. Construction activities will permanently impact a total of 0.69 acres of forested wetland and 2.97 acres of emergent wetland. An additional 0.34 acres of forested wetland and 0.61 acres of emergent wetland will be affected by ongoing ROW clearing, with 0.16 acres of forested wetland permanently converted to emergent wetland

(Resource Report 2, p62: Table 2A-7). According to FERC standards, revegetation is considered successful if the density and cover of a restored area is similar to undisturbed land adjacent to the impacted area, excluding any colonization by invasive vegetation (Resource Report 1, p. 172). But this revegetation standard does not account for changes in the plant community or changes in overall species diversity if the disturbance results in change in the site's ecological services and functions. Such would be the case if forested wetlands are converted into emergent wetland.

The revegetation standard also does not address habitat fragmentation problems nor does it address the increased opportunity for the future colonization of the area by invasive species due to changes in the canopy cover and an increase in light penetration.

3.2 Water use

Millennium proposes to implement horizontal directional drilling (HDD) as a "non-disruptive method" of crossing the Neversink River, which is a NYSDEC Class C protected waterway supporting populations of trout and the endangered dwarf wedge mussel. Class C waters are subject to New York Protection of Waters regulations and permitting process. While HDD is less intrusive and damaging than conventional trenching methods, the operation does require 74,000 gallons of water. The water is mixed with bentonite clay and used as a drilling fluid continuously pumped into the borehole to remove cuttings (Resource Report 1). Millennium states that the water needed to support the HDD process <u>will be transported by trucks from its source at MP 4.97</u>, and discharged after use at MP 4.97, 5.4, and 2.65, all of which are located outside of the Delaware River watershed. However, a 25% water loss factor is estimated during normal drilling operations (Resource Report 2, p. 60: Table 2A-6), indicating that at least 18,500 gallons of water from the Hudson River watershed could be released into the Delaware River watershed. Another 310,000 gallons of water will be used for four additional HDD sites along the Huguenot Loop. All of these sites were confirmed to be located within the Hudson River watershed and as such do not affect the Delaware River watershed.

Another short-term impact having potential negative consequences to the streams and wetlands located within the project area pertains to the post-construction hydrostatic testing that must be conducted of the pipeline and above ground supporting structures. <u>Approximately 2.6 million gallons of water will be required for this testing</u>. Presently Millennium states that this "water will be obtained from and discharged within the Lower Hudson Watershed, [and that] no inter-basin transfer of water is anticipated." Millennium has yet to identify the <u>source of the water that will be utilized for the testing; whether commercially available or naturally sourced water.</u> <u>Additionally, Millennium has not identified where this test wastewater will be discharged</u>. Without that information there cannot be a proper or thorough assessment of potential resulting impacts.

As per the Resource Reports, spent hydrostatic test water will be discharged into "vegetated upland communities." This in itself could trigger erosion and sedimentation problems. The use

of energy dissipation devices and sediment barriers may achieve a regulatory standard of sediment control, but such devices cannot fully control all offsite soil and sediment transport. Given the proposed volume of water needed to conduct the testing and the fact that some of the testing will occur along steep sloped areas and within wetlands and riparian areas, there is a high probability that erosion and sediment migration will be experienced. Millennium has also not addressed the potential physical damage associated with trucking the water required for the testing through wetland areas or into some of the more remote or steeply sloped areas of the pipeline. This in itself could result in a significant amount of additional compaction of the construction corridor, impeding the post-construction revegetation of areas adjacent to the pipeline's permanent ROW.

Although 49 CFR Part 192, Subpart J details the procedures for the hydrostatic testing of gas pipelines, it does not speak to the composition or management of the testing fluid; even within §192.515 Environmental Protection and Safety Requirements. It is unrealistic to assume even if the spent test fluid is discharged into a well vegetated area that some of this fluid will not infiltrate into the surficial aquifer or runoff from the discharge area into a stream or wetland. Also the Resource Reports do not contain any substantive information regarding the projected chemical composition of the spent testing fluid. For example, water obtained from a potable water source could contain chlorine, chloramines or fluoride, all of which could impact the biota of a receiving stream or wetland. Similarly, additives mixed with the source water (such as some form of anti-freeze or a leak detection dye), could create an environmental threat/impact to the water quality or biota of the receiving stream or wetland. Thus, not only do we lack an understanding of the composition of the spent fluid, it is unclear how potential impacts resulting from the discharge of the spent test fluids to groundwater, surface water or wetland resources will be prevented, controlled or mitigated.

Appendix 1B of the Resource Report provides further information regarding hydrostatic testing and the mitigative measures associated with hydrostatic testing. Millennium states on page 14 of Appendix 1B, that the water required to conduct the testing will be purchased from "commercially-available" sources and if any water used in the testing is withdrawn from local surface water sources, any such withdrawals will be done in a manner consistent with FERC's Wetland And Waterbody Construction And Mitigation Procedures (Section VII.C), as well as any applicable NYSDEC or other regulatory permit limitations. Although Millennium proposes the use of commercially available water or water obtained exclusively from the Hudson River drainage, the Resource Report notes that other options are being considered and final details of the origin, volume and discharge of hydrostatic test water will be provided in the Project's final Environmental Review. That information is important for any ecological assessment.

Millennium also states within Appendix 1B that discharge of hydrostatic test water will be conducted in a manner consistent with FERC's Wetland and Waterbody Construction and Mitigation Procedures (Section VII.D), as well as any NYSDEC or other regulatory permit limitations. The mitigative measures that could be employed to decrease impacts to a receiving water beyond discharge into "well vegetated upland areas" include discharge into a transport

tank (for off-site disposal), return of the water to a stream or river, discharge into a temporary holding pond (followed by discharge into an upland area, stream or river), or discharge into some type of sediment filter or trap (followed by discharge into an upland area, stream or river). FERC notes that the Wetland and Waterbody Construction and Mitigation Procedures are baseline mitigation measures for minimizing the extent and duration of project-related disturbance on wetlands and waterbodies. Sections V11.C and V11.D of FERC's procedures are lacking with respect to the details of any of the mitigative strategies. This is especially true for water withdrawals or discharges occurring within environmentally sensitive areas (steeply sloped uplands, threatened and endangered species habitat) or high quality streams, rivers or wetlands. The general guidance provided by FERC when water is being withdrawn or discharged into high quality surface waters can be summarized as follows:

- State-designated exceptional value waters, waterbodies which provide habitat for federally listed threatened or endangered species, or waterbodies designated as public water supplies, are not to be used as source water unless appropriate federal, state, and/or local permitting agencies grant written permission.
- While water is being withdrawn, it is necessary to maintain adequate flow rates to protect aquatic life, provide for all waterbody uses, and provide for downstream withdrawals of water by existing users.
- Locate hydrostatic test manifolds outside wetlands and riparian areas to the maximum extent practicable.

Thus, stating that the withdrawal or discharge of hydrostatic test water will be conducted in a manner consistent with FERC's Wetland and Waterbody Construction and Mitigation Procedures provides very little assurance that sensitive streams, rivers and wetlands will not be impacted by hydrostatic testing activities. Nor does it address the regulatory standards of the State or the DRBC.

3.3 Waterbody crossings

The Huguenot Loop will cross a total of 20 wetlands and 15 streams. Of the 15 streams crossed, 10 are categorized as New York State protected waters. These include Rutgers Creek, Shin Hollow Brook, and an unnamed tributary of the Neversink River which are classified by the NYS DEC as C(T), a protected category with the potential to support populations of wild brown and brook trout. The Neversink River has a B classification, indicating water supporting contact recreation and fisheries. Two unnamed tributaries to the Shawangunk Kill are Class A waters that support drinking water use. Most of these waterbodies also support coldwater fisheries.

While Millennium plans to use a less disruptive boring method (HDD or conventional) to cross many of these streams, the channel of Shin Hollow Brook at MP 2.5 is expected to be crossed with a flume or dam and pump method. This stream is classified as C(T) but should be more accurately classified as a C(TS) stream with the potential to support trout spawning habitat, according to biologists at the NYS DEC [Resource Report 1, App. D p. 442]. Headwater streams

are ecologically important and have a strong influence on downstream water quality and quantity, and are very sensitive to land use change including soil disturbance and loss of riparian vegetation (Alexander et al., 2007). The headwaters of Shin Hollow Brook are already impacted by damming upstream of the pipeline location, and will be negatively affected further by pipeline construction. Likewise, Rutgers Creek at MP 7.3 and two unnamed tributaries at MP 6.3 and 7.7 are classified as C(T) and C respectively, and will be crossed using conventional stream crossing techniques which will impact these protected waterbodies.

At stream crossing sites, Millennium states that construction will occur within 24 hours and restoration in the following 24 hours, but this time limit does not include vegetation clearing, grading, or equipment installation or removal, all of which involve significant disturbance with enduring footprints and impacts. Even if not a protected waterway, each stream or wetland crossing is an opportunity for damaging sedimentation, loss of bank stability, and a disturbance to the site's soil and hydrology that may prevent complete restoration of vegetation. Multiple soils with poor revegetation potential were mapped in wetlands in the project area. Even with temporary erosion and sediment control devices, these measures are unlikely to achieve 100% efficiency (Reed, 1978). Additionally, Millennium has stated that streams will be surveyed pre-construction and monitored post-construction, and that they will address stream bed and bank stability issues at that time [Resource Report 2, p 30-31]. However, stream surveys to date as described in the submitted Resource Reports are limited to a delineation of waterbodies, with no discussion of habitat quality or ecological functioning. Likewise, plans for post-construction monitoring lack detail, with no description of what parameters will be monitored or how frequently.

No soils in the project area were described by Millennium as compaction prone, defined as soils that are clay loam or finer and have somewhat poor, poor, or very poor drainage. However, this does not mean that compaction will not be an issue. Any soil can be compacted from wheel traffic, in particular wet soils such as those found in wetlands and riparian areas. Compaction limits root growth, which will impact revegetation, and restricts infiltration leading to runoff and erosion, which will cause water quality problems during and after construction.

3.4 Erosion

Millennium claims that only 9.75 acres or 0.05 % of the total project area affects soils that are highly erodible [Resource Report 7, p.11, 24]. However, erodibility was determined by the average K-factor of each soil type, which is a problem for several reasons. The K-factor is a function of soil physical characteristics such as grain size and structure, and does not take into account the slope of the soil, which is a critical component of erosion risk. Also, Millennium calculated the overall K-factor of each soil type as an average of all the soil horizons, when most erodible soil in the construction zone, aside from the trench itself, will be the surface soil layers. Finally, the K-factor is designed to represent soils in their natural condition, and the reported K-factor is not accurate for disturbed soils (NRCS-USDA).

Millennium reports slopes of greater than 30% at 28 locations along the Huguenot Loop for a combined distance of 1 mile along the pipeline route. This is 13% of the total length of the project [Rpt. 6, p.16], and does not account for slopes less than 30% which might still be prone to significant erosion. Within these steep areas, multiple soil series were mapped that are listed both as stony and having poor revegetation potential. These include the Swartswood, Mardin, Nassau, Arnot, and Lordstown soil types. These areas are susceptible to erosion during construction due to their steep slopes, and are unlikely to be effectively mitigated due to their limitations on revegetation. In addition to the areas identified as steep (>30%), multiple soil types were mapped along the route with slopes from 8-25%. The prevalence of steep slopes in the construction area greatly increase the likelihood of short term construction related erosion in addition to long term decreased stability of these steep slopes, which will be damaging to both upland areas and nearby waterbodies. Despite Millennium's assurances that they will use sediment control measures appropriately and mitigate damages, these measures frequently are applied incorrectly, fail, or fall short. There have been multiple occasions of fines levied against pipeline construction companies for improper erosion and sediment control, equipment outside of the permit area, drilling mud spills, discharge of fluids, and failure to minimize wetland disturbance (e.g. Legere, 2014; Mayer, 2009; Phillips, 2016; Rittenbaugh, 2014; Hamill and Olson, 2012).

4. Conclusion

The Eastern System Upgrade to the Millennium Pipeline is expected to have both short and long term impacts to the affected areas and to water resources within the Delaware River Basin. The vegetation clearing associated with construction activities and maintenance of the permanent ROW will result in a loss of habitat and soil disturbance in the short term, but will cause irreversible changes in longer-term ecological services and functions of traversed areas. These impacts extend to areas adjacent to the permanent ROW due to alterations in canopy cover, plant assemblage, light penetration into core forest areas, the introduction of invasive species, and the compaction of soil.

Even with the implementation of erosion and sediment control techniques we expect significant erosion to occur as a result of soil disturbance, loss of vegetative cover, disturbance of steep slopes, and the discharge of large amounts of water in upland areas. These expectations are supported by past studies of other pipelines. Stream and wetland crossings are particularly susceptible to erosion-related damage due to their sensitivity to change and unique ecological characteristics. Measures taken to mitigate these issues to the level of regulatory approval fall short of restoring these sites to pre-construction conditions. Soil compaction is expected to increase stormwater runoff and reduce aquifer recharge.

Similarly, with respect to the discharge of hydrostatic testing fluids, concerns remain regarding the impacts that these fluids could elicit in terms of localized erosion as well as the contamination of groundwater, surface water and wetland resources.

Overall, the reports prepared by Millennium in support of the Eastern System Upgrade are lacking with respect to environmental impact prevention and mitigation. Again, even when details are provided, the proposed mitigation measures are standard techniques that are not designed to fully protect the more sensitive areas traversed by the pipeline or minimize impacts along the steeply sloped sections of the pipeline.

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1 May 2017

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In re: **Clearcutting in Forested Wetlands**

Dear Ms. Van Rossum:

This letter responds to the request of Mr. Stemplewicz that I identify the kinds of environmental damages that typically occur when forested wetlands are clearcut, with focus on aquatic and biological resources subject to legal protection. Specifically, I address the potential for clearcutting to adversely affect the quality of surface waters, one subset of which is wetlands themselves.

Introduction

The natural vegetation of much of the eastern United States consists of deciduous forests (Braun 1950). The species composition of those forests varies with climate, topography, and geology, in the combinations found locally and influenced by natural forces such as site wetness, aspect, major storms, fires, and the time available for regrowth following disturbance. Much of that forest has been cut by people at least once during historic times. The natural tendency is for forest vegetation to become reestablished following disturbance, in the absence of human activities such as plowing, mowing, and paving specifically aimed to prevent its regrowth. When the forests were vast and people few, forest cutting was uncontrolled, and the resulting damage to ecosystems larger than necessary. Modern forestry aims for sustainable growth, maximizing forest recovery after cutting, and clearcutting today is not a favored practice when harvesting timber.

Forest ecosystems perform many functions valuable to people. Forests accumulate solar energy in biomass, producing timber, fiber for paper pulp, food for animals and people, and fuel. Forests offer structural diversity in the landscape, provide habitat for wildlife, protect soils and stream banks against erosion by stormwater, keep both air and water clean by trapping pollutants, and form objects and places of aesthetic appreciation.

Wetlands are found where site conditions cause water to persist for long periods of time, giving rise to special biogeochemical conditions that distinguish wetlands from nearby uplands. Wetland soils look different and function differently from those of

uplands (Reddy *et al*. 2008), and their woody and herbaceous plants are distinctive. They provide specialized habitat for birds, amphibians, and other animals that is not available in uplands. Wetland forests occupy a small fraction of the landscape, but are recognized as contributing to water quality and wildlife diversity greatly exceeding their geographic expanse both in natural and in human-dominated settings. Forested and other wetlands typically occupy low positions in the landscape, and thus are vulnerable to damage by runoff and sediments from activities that disturb surrounding uplands. Forested wetlands adjacent to streams and other waters are recognized as especially effective buffers protecting surface water quality (Sweeney & Newbold 2014). They also serve to protect water quality in groundwater recharge areas.

Thus today the remaining wetlands are recognized as a special category of surface waters transitional between permanent open waters and the contrasting uplands that are wet only during and immediately following periods of precipitation. All wetlands, and especially forested wetlands, are protected by a variety of laws and regulations at the federal, state, and municipal levels that seek to minimize and compensate for ecosystem damage from many kinds of human activity. Activities adjacent to wetlands also are sometimes regulated, inasmuch as activities within 1,500 feet are known to affect wetland habitat adversely (Houlahan *et al*. 2006).

Regulatory protection entails several steps. First, the people seeking to alter existing conditions on a tract of land are expected to identify its significant resources. Then alternative plans are to be evaluated that could avoid or minimize potential impacts on the environment, on other landowners, and on the public at large, while meeting the applicant's objective. Third, the applicant's environmental inventory and project plans are reviewed by the public and/or its agency representatives to ascertain whether feasible protective alternatives have been selected. Supplemental information may be deemed necessary to address impacts or alternatives that initially were overlooked by the applicant. Fourth, in exchange for permit approvals, project sponsors agree to conduct their activities in specific ways and partially to restore or replace damaged ecosystems. Permittees vary in their willingness to take the time and spend the money sometimes necessary to implement environmentally protective alternatives. Monitoring and reporting, followed by changes in construction practices, may be required as conditions of approval.

To the extent that permittees fully comply with permit requirements and conscientiously use appropriate management practices, adverse impacts can be minimized. Only if the site inventory, project review, and permit conditioning steps were properly executed, and if careful monitoring is performed during and after construction, can law enforcement be undertaken if necessary to compel compliance and site restoration. In practice, wetland protection can be rendered impotent by failure at any step along the way in a regulatory process that often appears complex, bureaucratic, and insufficiently sensitive to the needs of applicants or the public. Cumulative impacts seldom are carefully analyzed by applicants or reviewers. Runoff from non-point sources, which include farmlands, forests, construction sites, and urban areas, currently supplies more than half of the nation's water quality pollution (Copeland 2012, Carlisle *et al*. 2013).

Impacts from Clearcutting

Forests consist of populations of individual large trees that change slowly when observed by humans. Individual trees die here and there, but large areas generally remain forested unless affected by major storms or fire. Small openings present opportunities for herbs, shrubs, and young trees to gain increased access to sunshine. Scientists have long worked to identify the complex biological interactions found in forests, from the ability of individual trees to exchange water and nutrients with their neighbors through their roots to interactions between species of plants and animals enabling growth, reproduction, and cycling of biogeochemical compounds. Natural ecosystems have some ability to recover from disturbances, but their ability to recover from more intense human disruption using modern equipment can readily be exceeded. Thresholds beyond which ecosystems cannot recover are not easily identified in advance, but increasingly are exceeded by ever more numerous humans using ever more powerful machines.

Site specific impacts of clear cutting on particular forested wetlands and streams will vary with the duration and severity of human disruption and the precise combination of environmental variables affected. Selective cutting is generally regarded by professional foresters as preferable to clearcutting, and the adverse impacts of clearcutting are even more severe in wetland than in upland forests.

Clearcutting a wetland forest necessarily involves intense, at least short-term damage to the wetland ecosystem. Timber harvesting followed by ongoing forest management for timber production represents a drastic change to the harvested wetland, but may lead to a recovery of many pre-harvest conditions after the passage of time measured in decades. In the short term most of the forest's accumulated biomass is removed for human use. Trapping of air and water pollutants is virtually terminated. Slash may be left behind (sometimes disrupting wildlife movement), burned, chipped, or removed entirely. Tree seedlings may or may not be replanted and successfully maintained during periods of drought or intense browsing.

The resulting exposed soil loses its cover of intervening branches and leaves that long broke the fall of rainwater, and thus the rate of soil erosion inevitably increases. Leaching of nitrate from temperate forests into streams generally increases for several years after timbering operations (Gunderson *et al*. 2006). The risk of soil erosion increases with steepness of the ground slope exposed by clearcutting. In extreme cases the loss of soil may preclude forest reestablishment for centuries. Pulses of stormwater runoff can disrupt the banks of stream channels no longer protected by tree roots. The ability of tree leaves to trap nitrates and other air pollutants is lost, along with most of the ability of the plant community to withdraw carbon dioxide from and release oxygen to the atmosphere by photosynthesis.

The water from rainfall and melting snow in streams exiting forests is generally of high quality, barring some manmade, localized or atmospheric source of toxic substances. After timbering, downstream watercourses experience increased runoff and an

increased load of sediment transported from unprotected soils and stream banks. Storms often overwhelm human efforts at sediment control, especially as global warming increases their frequency, intensity, and severity of damage. The growth of algae in streams and lakes (eutrophication) may be stimulated, leading to a decrease in dissolved oxygen in the water followed by fish kills. Stream invertebrate populations may be altered dramatically by physical damage from sediment. Unshaded soils warm, as does the runoff water passing over them, increasing stress on fish greatly valued by people. Loss of tree shade leads to increased temperature of stream water as well as the loss of detritus that supports leaf-shredding invertebrates. As much as 99% of the organic carbon in forest streams is derived from leaf litter (Stoler & Relyea 2011).

Within clearcut wetlands themselves the soil temperature increases when its shade is lost, and it dries more quickly from winds no longer broken by the forest biomass. Such resulting local changes exacerbate the ongoing effects of global warming, which are known to be pushing both plants and animals to ever higher elevations and latitudes in search of tolerable climatic conditions. Such changes may be difficult to predict for individual forest stands, and are likely to be adverse for humans as well as wild organisms.

Early-succession species that occupy clearings typically are different from those dominant in mature forest stands. Invasive, weedy herbs may thrive in the exposed soils, unless there is prompt replanting of more desirable native plants. Dominant tree species, as well as understory, may change in response to the general warming, although in the absence of clearcutting the prior species composition could have persisted indefinitely. Animals that use edges and openings may benefit, while forest interior species lose habitat for hundreds of feet beyond the edge of an actual clear-cut. Old-growth forest replacement of habitat suitable for spotted owls or Indiana bats may require centuries.

Aside from timber operations, clearcutting also occurs for other purposes, with or without subsequent restoration of vegetation. Some forested wetlands are converted permanently to roads or buildings; others, to utility corridors. Convincing justification is to be provided when such impacts are deemed unavoidable, the extent of impacts is to be minimized. Beneath powerlines trees may be cut and left on the ground, either scattered or in windrows. Pipeline rights of way and building construction sites typically have tree stumps grubbed, with the associated soil excavation greatly intensifying ecosystem disturbance. Stump piles generally are not authorized for placement as solid waste fill in recognized wetlands or other waters, but may line upland utility corridors. Grubbed pipeline rights of way are trenched, with backfill after the pipes are installed. Utility corridors usually are maintained free of trees, shrubs, and dense herbaceous cover to promote the safety of pipes and powerlines and facilitate human inspection. Chemical herbicides can damage numerous kinds of plants and animals other than those targeted for destruction. Onsite replanting of temporarily disturbed wetlands after construction is unlikely to be successful, unless pre-disturbance hydrology has been carefully investigated and effectively reestablished. Offsite creation of new wetland forest as partial compensation for wetland destruction similarly requires intensive site

investigation followed by successful modification of existing conditions of soil, hydrology, and/or vegetation. Whether onsite or remote, tree canopies require decades for reestablishment. Habitat for forest-dwelling migratory birds is missing for many years.

Unlike normal forest management activities, timbering in wetlands associated with conversions of land use theoretically is subject to regulation intended to protect water quality in consequence of the federal Clean Water Act and state laws such as the Pennsylvania Clean Streams Law and the Dam Safety and Encroachments Act. Clearcutting of wetland forests inevitably entails some placement of fill, which constitutes water pollution. Logging brings tree trunks forcibly down onto the ground, disturbing the soil surface and compacting ruts even if the trunks themselves are promptly removed. Animals can be crushed directly, even as their habitat is destroyed. Slash left behind on the ground is fill and can pose a fire hazard. The severity of direct habitat damage can vary seasonally, and can disrupt the breeding and spawning areas for amphibians and aquatic species. Only if careful pre-construction inventory has been performed can such losses be quantified, and post-construction monitoring is essential to ascertain whether any recovery of the prior ecosystem is occurring.

Branches left on the ground or chipped pose unnaturally rapid rates of deposition of cellulose to soil organisms, changing conditions for herbaceous plants. When slash materials decompose, they release constituents such as nitrates, whose increased concentrations transported by surface runoff to streams spiral down the aquatic ecosystem, contributing to eutrophication not only nearby within streams and rivers but also in distant estuaries at tidewater and out into the open ocean. Meanwhile, the natural denitrification of nitrate by wetland soil bacteria sending the molecules of inert nitrogen gas back to the atmosphere can be disrupted as a result of soil disturbance. To the extent that unshaded wetland soils dry out more rapidly, their potential for bacterial denitrification is curtailed. The measured concentration of nitrate in wetland soils typically is virtually zero, because natural denitrification is very efficient. Absent the normal supply of carbon from decaying leaves, however, the denitrifying bacteria may lack sufficient energy to complete denitrification, leading to water pollution.

Wetland forests often are surrounded by upland forests, with the wetland edge at the break in slope. Clearcutting in nearby upland forests typically poses threats to wetland forests, even if the wetland forests themselves are not clearcut. Simply exposing the outer trees to wind and sun can increase the natural blowdown of trees in a wetland forest. Erosion from soil exposed in clearcut uplands typically leads to sedimentation in the wetlands as storm and melt water carries eroded soil downslope. The potential for erosion increases sharply with slope steepness. Silt-laden runoff from upland clearcuts can flow across forested wetlands and enter streams directly, although intervening wetlands can trap some of the sediments.

In any forest mechanical equipment disturbs the ground surface, typically creating ruts more extensive than those of the falling trees themselves as the trimmed logs are dragged to collection points. Likewise, the construction of logging access roads and

work pads involves disruptive earthwork, which can in some instances be reduced by transporting logs by helicopter from remote sites. Soil erosion increases after logging as a result both of surface disturbance and the increased energy of earth-striking raindrops no longer slowed by the tree canopy within all clearcut forests, wetland or upland.

The eroded soil particles are transported by runoff and can be measured quantitatively as increases in turbidity and concentrations of solids in receiving waters. Small particles (silts and clays) can settle in streambeds following storms, filling the spaces in between gravel particles required by macroinvertebrates and by fish such as trout. The sediment particles also can directly damage the tiny gills of macroinvertebrates at the base of the aquatic food web. The consequences can be devastating for aquatic ecosystems and can severely disappoint fishermen.

Water temperatures in the streams of clearcut forests increase as a result of the increased exposure of soils and streambeds to solar energy. This is most damaging during the summer months, when higher temperatures reduce the capacity of the water to hold dissolved oxygen, placing major stress on coldwater fish.

The impacts from clear cutting of wetland forests are overwhelmingly negative and more severe than selective thinning of widely spaced individual trees, which more closely resembles natural conditions. Even relatively narrow clearcut corridors created through forests entail higher rates of wildlife predation compared to interior forest for some species. Barrier effects created by linear corridors can restrict movement by other species and alter their home ranges, decreasing gene flow and genetic diversity. Replacement forests can be technically difficult and costly to establish, and always require many decades to mature. Not only is the success of compensatory plantings uncertain, but they may be sited remote from any remaining ecosystems where the damage occurred. Agency followup to insure permit compliance is limited, and enforcement to insure successful mitigation almost nonexistent.

Clear cutting of forested wetlands is best avoided by shifting the location of construction activities or adopting measures such as horizontal directional drilling for pipelines which can pass beneath the wetlands leaving surface resources unaffected. Agency reviewers, however, often are lax when allowing applicants to reject environmentally protective alternatives based on unsubstantiated claims of infeasibility.

In sum, the clearcutting of trees in wetland forests physically impacts the plant community, both canopy trees and understory shrubs and herbs. Animals can be crushed directly or exposed to predators and climatic extremes. The soil is compacted and exposed to sunshine once shade is gone. Warmer temperatures and higher winds lead to increased drying of soil and decreased denitrification. Forest streams are deprived of natural carbon inputs from leaf detritus, warmed by the loss of shade to decrease the dissolved oxygen needed by fish, and subjected to increased concentrations of nitrogen. Invasive, nonnative herbs may invade at the expense of more desirable native vegetation. Ongoing impacts of global warming leading to

species displacement and impeding forest recovery may be exacerbated. Soil and nitrates eroded from upland clearcuts can be deposited by runoff water into downslope wetlands and into streams, damaging the aquatic ecosystem including both invertebrates and fish downstream as far as the ocean.

Yours truly,

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JAMES A. SCHMID

EDUCATION

Ph.D., Geography, University of Chicago, 1972
M.A., Geography, University of Chicago, 1969
A.B., Geography, Columbia College, Columbia University, 1966

CERTIFICATIONS

Ecological Society of America: Senior Ecologist (1983; recertified 1988, 1993, 1999, 2008)
Society of Wetland Scientists: Professional Wetland Scientist #284 (1995; recertified 2007, 2012)
US Army Corps of Engineers, Baltimore District: Wetland Delineator Program (Provisional Certification #93MD0310008A)
US Fish & Wildlife Service: Habitat Evaluation Procedures (HEP 1981)

CONTACT INFORMATION

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Schmid & Co., Inc., Consulting Ecologists 1201 Cedar Grove Road Media PA 19063-1044

SUMMARY OF EXPERIENCE

1985- **President, Schmid & Company, Inc.**, Consulting Ecologists. Dr. Schmid's current responsibilities include fieldwork, administration of contracts, writing and editing reports, regulatory analysis, client representation before agencies, expert testimony in court and at hearings, and overall management of the firm.

1981-1985 **Principal, Schmid & Company**, Consulting Ecologists. Dr. Schmid was responsible for fieldwork, project management, consultation with clients and regulatory agency personnel, the preparation and delivery of testimony in court and at public meetings, and the technical and editorial supervision of multidisciplinary reports.

1981-1982 **Principal Environmental Scientist, TERA Corporation.** Dr. Schmid provided technical supervision for a major environmental impact statement on alternative railroads in Niagara County, New York, and managed analyses of wetland fill and mitigation proposed in the New York and Philadelphia metropolitan areas and in the New Jersey Pine Barrens. He also worked on lignite mining projects in the Red River basin of western Louisiana.

1979-1981 **Principal Scientist, WAPORA, Inc.** Dr. Schmid supervised a statewide impact assessment of coal mining in Appalachia for the Environmental Protection Agency and provided technical direction for seven areawide environmental assessments of future coal mining in West Virginia. He managed impact statements for oil and coal terminals and prepared an extensive report on coastal zone management for the New Jersey Department

of Environmental Protection. He also served as senior technical advisor on projects in the Mississippi River basin, the eastern Kentucky coal fields, and the Texas Gulf Coast.

1973-1979 **Chairman of the New York office (1973-1974) and Vice President, Jack McCormick & Associates, Inc., Pennsylvania office** (1974-1979). Dr. Schmid managed environmental assessments and reports on proposed residential, industrial, and commercial developments at Brigantine, Secaucus, East Rutherford, North Bergen, Hoboken, and Camden, New Jersey; Philadelphia, Pennsylvania; and Beachville, Maryland. He directed inventories and analyses of the Fire Island National Seashore for the National Park Service and of the New York Bight for the National Oceanic and Atmospheric Administration. He designed and implemented a major analysis of environmental regulations and their effects on private industry for the US Department of Commerce and the President's Council on Environmental Quality.

1970-1973 **Assistant Professor and Instructor in the Department of Biological Sciences, Barnard College and Columbia University.** Dr. Schmid taught graduate and undergraduate courses in ecology, biogeography, environmental science, and cultural geography. His prime research interests were in the environmental effects of urbanization, the role of vegetation in cities, and the conceptualization and quality control of environmental assessments.

1968-1970 He served as **technical editor for research papers in the Department of Geography at the University of Chicago**.

Dr. Schmid has been a **guest lecturer on environmental analysis and wetlands at the University of Pennsylvania, Columbia University, Cabrini College, Clark University, West Chester State University, Rutgers University,** and the **Delaware County Community College**. He has often addressed wetland issues at the Polley Associates School of Real Estate. He has served on the Standing Committee on Environmental Education for the Association of American Geographers and has contributed reviews to the *Geographical Review* and to *Ecology*. He has served on the Board of Professional Certification of the Ecological Society of America and on the Certification Standards Committee of the Society of Wetland Scientists Professional Certification Program, Inc. For many years he served on the Environmental Advisory Board of Marple Township, Delaware County, Pennsylvania. He has peer reviewed journal articles for *Wetlands* and grant proposals submitted to the National Science Foundation, the US Department of State, and the National Geographic Society. Dr. Schmid has served as the elected president of the Chester County Beekeepers Association.

HONORS AND AWARDS

Columbia College Scholarship
Columbia College Phi Beta Kappa
A.B. cum *laude*, Columbia College, Columbia University
NDEA Title VI fellowship awards (U. Chicago, U. Wisconsin at Madison, U. Washington at Seattle, Johns Hopkins U.)
American Men of Science

PROFESSIONAL AFFILIATIONS

American Association for the Advancement of Science
Association of American Geographers
Association of State Wetland Managers
Ecological Society of America
New Jersey Academy of Science
New York State Wetlands Forum, Inc.
Society of Wetland Scientists

PROJECT EXPERIENCE

Dr. Schmid's career in environmental analysis began in the late 1960s. He has worked for all types of clients, including federal agencies, state agencies, municipalities, private developers, utilities, conservation groups, attorneys, architects, and engineering firms on many kinds of assignments.

While on the faculty of Biological Sciences at Columbia University, Dr. Schmid introduced students to the ecology of the New York-New Jersey metropolitan area and the New Jersey Pine Barrens. His scholarly research focuses on urban vegetation and historic changes in vegetation affected by human activity. His first environmental impact assessment and recommendations for minimizing impacts were prepared for a developer while he was still a graduate student and dealt with a proposed residential subdivision in the Thorn Creek Woods of suburban Will County, Illinois.

During his graduate studies in plant ecology at the University of Chicago, Dr. Schmid became familiar with the bogs and floodplain vegetation of northern Illinois, northern Indiana, and southern Michigan. While a visiting graduate student at the University of California at Los Angeles, he worked on the flora of the Mojave Desert and Santa Monica Mountains of southern California with Mildred Mathias, and he accompanied Jonathan Sauer on a flora collecting expedition to San Clemente Island. He helped Monte Lloyd collect periodic cicadas in Illinois, Ohio, and West Virginia. His master's thesis dealt with historic vegetation change in the subhumid to semi-arid limestone Edwards Plateau of southcentral Texas.

During his six years as Project Manager and Vice President at Jack McCormick & Associates, Dr. Schmid was closely associated with the late Dr. McCormick (a nationally recognized authority on wetlands and environmental assessment), both in field analyses and in project planning aimed at preserving, enhancing, restoring, or creating wetland ecosystems.

Dr. Schmid has participated in more than 100 environmental impact statements prepared using Federal, State, or local guidelines. He wrote a major analysis of the effects of the National Environmental Policy Act and Federal EISs on private industry for the US Department of Commerce, and conducted a follow-on seminar sponsored by the Council on Environmental Quality and the American Management Association. He prepared a shortened version of the report for distribution by the

Commerce Department and the Business Roundtable. As senior scientist he worked on diverse projects in Maine, West Virginia, Kentucky, Illinois, Iowa, Texas, Louisiana, Washington State, and Pacific coastal Nicaragua, not to mention the mid-Atlantic States. He participated in several wastewater treatment system EISs in suburban Philadelphia, suburban Baltimore, and at Oakwood Beach, Staten Island.

In the Hackensack Meadowlands of New Jersey, Dr. Schmid was responsible for the analyses and negotiations that led to issuance of major Federal and State permits (Clean Water Act Section 404) to fill wetlands and the Hackensack River at the Harmon Cove residential development (96 acres) and for compliance monitoring at the New Jersey Sports Complex (federal permit, 35 acres; State permit, 250 acres of tidal and non-tidal wetlands). He also was involved with assessments of a proposed new freeway (US 1 & 9), the initial Hartz Mountain Harmon Meadows Tract shopping and residential development proposal, the redevelopment of a city park (Lincoln Park West) in Jersey City, and a plan for wetlands enhancement in connection with a proposed sand and gravel operation in North Bergen. He was responsible for environmental studies, mitigation plans, and technical negotiations that led to issuance of a major Corps permit to fill 127 acres of marsh with compensation by enhancing 151 acres. He recently analyzed historic land use activities at a cemetery at the edge of the Meadowlands to ascertain the extent of wetland violations and aid the landowner in attaining compliance with NJDEP requirements.

Dr. Schmid directed a comprehensive inventory of Fire Island National Seashore in Suffolk County, New York, for the National Park Service. In New Jersey, he assisted Dr. McCormick in designing satisfactory restoration leading to permits for filling 11 acres for development in the southernmost section of Brigantine Island facing Atlantic City. In New Jersey he has worked on several analyses of beach protection and the effects of altering sand dunes, a major concern also at Fire Island National Seashore. He has participated in numerous wetland permit applications and resolution of enforcement cases in Staten Island and Brooklyn.

Dr. Schmid wrote a Federal EIS on a proposed fuel oil transfer and storage terminal in the Hudson River under contract to the New York District of the Army Corps of Engineers. Dr. Schmid also was responsible for coastal wetland projects along the Shark River, at Ocean City, and along Barnegat Bay. He supervised an analysis of the freshwater tidal marsh at Fish House Cove on the Delaware River for the Camden County Environmental Agency and a comprehensive review of proposed development in salt marshes along a barrier beach in Sussex County, Delaware, for the Delaware Department of Natural Resources and Environmental Control. Dr. Schmid supervised evaluations of several marshes along Delaware Bay in New Jersey and Delaware for National Natural Landmark status on behalf of the National Park Service.

His extensive analysis of coastal zone management in New Jersey, with a detailed account of the administration of the (Tidal) Wetlands Act and other wetland regulations, formed a major part of a four-volume Estuarine Study submitted to the

New Jersey Department of Environmental Protection in 1979. Dr. Schmid managed a residential development analysis near the mouth of the Potomac River at Beachville, Maryland, and he wrote the foreword to Dr. McCormick's monumental report on the coastal wetlands of Maryland at the request of the Maryland Department of Natural Resources.

Dr. Schmid has represented developers in regulatory negotiations concerning wetlands at Bethany Beach, Delaware; near the mouth of the Raritan River for a major new town associated with New Jersey's largest industrial park; in Gloucester City, New Jersey, where a freshwater tidal marsh was restored; at the DuPont Chambers Works, a major chemical plant adjacent to the Delaware River in Salem County, New Jersey; and in Bucks County, Pennsylvania, where a waterfront slag plant was proposed. He successfully designed mitigation for a major marine container terminal expansion, which entailed the filling of 16 acres in the Delaware River and 8 acres of freshwater tidal marsh and oversaw the restoration of a tidal marsh on the Neshaminy Creek. He has achieved full success in all of his wetland restoration and creation projects.

For the National Oceanic and Atmospheric Administration Dr. Schmid assembled a multidisciplinary panel to establish priority chemical contaminants of the New York Bight. This report formed the basis for funding by NOAA of research on chemicals in the 15,000 square miles of ocean waters off New York and New Jersey.

Dr. Schmid has worked on behalf of developers, environmental groups, and regulatory agencies in the Pinelands of southern New Jersey. Dr. Schmid's analyses enabled the New Jersey Pinelands Commission to approve development on a site with 355 acres of wetlands in Burlington County for more than 2,500 housing units under a hardship application. He assembled a review of vegetation and critical areas mapping in the Pinelands on behalf of a developer near Mays Landing. He wrote a critique of the Pinelands Commission's inventory mapping for the Sierra Club, and he defended a developer and the Pinelands Commission in a challenge to a regulatory decision approving a residential project. He represented the New Jersey Conservation Foundation, Environmental Defense Fund, and other conservation groups challenging a Pinelands Commission hardship waiver on a major residential development. He also supervised a critique of the proposed USEPA designation of a sole-source aquifer in southern New Jersey on behalf of the South Jersey Homebuilders Association. He analyzed the significance of potential impacts on wetlands and other resources by railroad construction in upstate New York under a third-party agreement to produce the major Federal EIS which preceded project approval.

Dr. Schmid assisted in an evaluation of development adjacent to the Tannersville Bog in Monroe County, Pennsylvania, on behalf of The Nature Conservancy. He demonstrated that a proposed nearby housing development posed no threat to the National Landmark bog. He has worked on other wetlands at several locations in the Poconos where delineations and permit approvals were necessary. He oversaw a

National Natural Landmarks evaluation of the Great Piece Meadows in northern New Jersey for the National Park Service and an assessment of impacts from regional sewer construction on the Great Swamp of the upper Passaic River for the US Environmental Protection Agency.

He supervised analyses of proposed development around Lake Valhalla in Morris County, and his testimony helped Montville Township zoning withstand challenge and appeal through the New Jersey court system. He managed the successful technical defense of a highway contractor, accused of polluting Lake Saginaw in Sussex County, New Jersey, with sediment, on behalf of Liberty Mutual Insurance Company. In Morris County he oversaw wetland boundary mapping on a 200+ acre tract and successfully defended the mapping through agency review and intervenor challenge. His project work has taken him to most of the major wetlands in the Passaic River Basin of northern New Jersey: Great Piece Meadows, Troy Meadows, Bog and Vly Meadows, Black Meadow, and Hatfield Swamp.

In Pennsylvania Dr. Schmid has supervised permitting for numerous residential, industrial, and commercial developments including landfills and shopping malls. He analyzed impacts and prepared reports and expert testimony on the impacts of coal mines, surface mines, fiber-optic cables, water wells, and residential subdivisions for various clients including the Izaak Walton League of New Jersey, the Raymond Proffitt Foundation, the Delaware Riverkeeper, the Center for Coalfield Justice, the Mountain Watershed Association, and the Green Valleys Association. He prepared the wetland-related sections of the Crum Creek Rivers Conservation Plan for the Department of Conservation and Natural Resources. He has examined a number of sites for rare species such as bog turtle and beach plum.

Dr. Schmid's principal expertise and professional interest lie in the analysis of urban vegetation and in the design and establishment of functioning ecosystems in the form of new wetlands, reclaimed landfills, mined areas, and other vegetated spaces in the increasingly human-dominated environment. Under his supervision, Schmid & Company has participated in many hundreds of wetland projects throughout New Jersey, Pennsylvania, and New York State, as well as projects in other States.

When the US Fish & Wildlife Service Pleasantville Office evaluated actual compliance with approval conditions by all the Clean Water Act Section 404 fill permits issued by the Corps of Engineers in the State of New Jersey during the period 1985-1992, every Schmid & Company mitigation project was judged in the field to exhibit full compliance with all requirements and mitigation goals. Schmid & Company mitigation projects represented 21% of all the mitigation projects judged fully successful in New Jersey by USFWS in its written report to USEPA.

PUBLICATIONS

ACADEMIC RESEARCH

Doctoral Dissertation: Urban vegetation, a review and Chicago case study. University of Chicago, Department of Geography (published in full; see below).

Masters Thesis: The wild landscape of the Edwards Plateau of southcentral Texas: a study of developing livelihood patterns and ecological change. University of Chicago, Department of Geography. 1969. 144 p.

BOOKS

Schmid, James A. 2003. Checklist and synonymy of Maryland higher plants, with special reference to their rarity, protected, and wetland indicator status. First edition. Schmid & Company, Inc. Media PA. 406 p.

Schmid, James A. 2003. Checklist and synonymy of Delaware higher plants, with special reference to their rarity and wetland indicator status. First edition. Schmid & Company, Inc. Media PA. 302 p.

Schmid, James A. 2003. Checklist and synonymy of New York higher plants, with special reference to their protective, rarity, and wetland indicator status. First edition. Schmid & Company, Inc. Media PA. 460 p.

Schmid, James A. 2001. Checklist and synonymy of New Jersey higher plants, with special reference to their rarity and wetland indicator status. Third edition. Schmid & Company, Inc. Media PA. 325 p.

Schmid, James A. 2001. Checklist and synonymy of Pennsylvania higher plants, with special reference to their rarity and wetland indicator status. Second edition. Schmid & Company, Inc. Media PA. 365 p.

Schmid, James A. 1994. Checklist and synonymy of New Jersey higher plants with special reference to their rarity and wetland indicator status: Volume I field manual. Second edition. Schmid & Company, Inc. Media, PA. 17O p.

Schmid, James A., and John T. Kartesz. 1994. Checklist and synonymy of New Jersey and Pennsylvania higher plants with special reference to their rarity and wetland indicator status: Volume II desk manual. First edition. Schmid & Company, Inc. Media, PA. 443 p. (Reviewed by: Kraus, M. 1995. Wetland Journal 7(1):21.)

Schmid, James A. 1994. Checklist and synonymy of Pennsylvania higher plants with special reference to their rarity and wetland indicator status: Volume I field manual. First edition. Schmid & Company, Inc. Media, PA. 182 p.

Schmid, James A. 1990. Checklist and synonymy of New Jersey higher plants with special reference to their rarity and wetland indicator status. First edition. Schmid & Company, Inc. Media, PA. 2 vols. (247 + 177 p.)

Schmid, James A. 1975. Urban Vegetation: a review and Chicago case study. Department of Geography, University of Chicago, Research Paper 161. Chicago IL., 266 p.
REVIEWED BY:
Küchler, A.W. 1976. Bioscience 26(7):454.

de Laubenfels, D.B. 1976. Geographical Review 66(3):370-71.
Barkham, J.P. 1976. Journal of Ecology 64(3):1113.
Haefner, H. 1977. Geographica Helvetica, p.53.
Wagner, P.L. 1977. Annals of the Association of American Geographers 67(1):171-73.
Levenson, J.B. 1977. Ecology 58(2):465.
Gutte, P. 1978. Petermanns Geographische Mitteilungen (1):56.
T., J. 1978. Annales de Géographie (481):382.

PROFESSIONAL PAPERS AND BOOK CHAPTERS

Schmid, James A. 2007. Draft Atlantic and Gulf coastal plain regional supplement to the 1987 Wetland Delineation Manual. The Forum 14(1):5, 8, 11. New York State Wetlands Forum, Inc.

Schmid, James A. 2005-2006. Introduced, non-native, and invasive plants in mid Atlantic woods and wetlands: is there a problem in the human habitat? The Forum 11(2) and 12(1). New York State Wetlands Forum, Inc.

Schmid, James A. 2003. Evaluating created wetlands in New Jersey: how credible is NJDEP? (Abstract). New Jersey Academy of Science Bulletin 48 (1): 28.

Schmid,James A. 2001. So you think you have hydrophytic vegetation? Wetland Journal 13(2):29-31.

Schmid, James A. 2000. Wetlands as conserved landscapes in the United States. In A. B. Murphy and D. L. Johnson, eds. Cultural Encounters with the Environment: Enduring and Evolving Geographic Themes. Rowman & Littlefield. Lanham MD. p. 133-155.

Schmid, James A. 1997. Wetland mitigation case studies. Chapter 9 in Mark S. Dennison. Wetland Mitigation. Rockville MD. Government Institutes Press. p. 157-182.

Schmid, James A. 1996. More on fire sales. National Wetlands Newsletter 18(5):4

Schmid, James A. 1996. Fire sale in Pennsylvania. National Wetlands Newsletter 18(1):4-5.

Schmid, James A. 1994. Wetlands in the urban landscape of the United States. In R. H. Platt, R. A. Rowntree, and P. C. Muick (eds.). The Ecological City: Preserving and Restoring Urban Biodiversity. University of Massachusetts Press. Amherst MA. p. 106-133.

Schmid, James A. 1994. Wetland creation using native plants. "A Preference for Natives". Proceedings of the symposium, 22 March 1991. Longwood Graduate Program, University of Delaware, Longwood Gardens. Kennett Square PA. p. 30-47.

Schmid, James A. 1989. Mitigation for fills in wetlands: the promise and some recent experience in New Jersey. (Abstract) Bulletin of the New Jersey Academy of Science 34(2):34.

Schmid, James A. 1989. Aboveground primary productivity in marshes of the Raritan River estuary, Middlesex County, NJ. (Abstract) Bulletin of the New Jersey Academy of Science 34(2):34.

Schmid, James A. 1989. Dune destruction at Normandy Shores, Dover Township, Ocean County: is NJDEP minding the shore? (Abstract) Bulletin of the New Jersey Academy of Science 34(2):34.

Schmid, James A. 1985. Atlantic whitecedar in the Hackensack Meadowlands, New Jersey: its historic extirpation and future reestablishment. In A. D. Laderman (ed.). Atlantic White Cedar Wetlands. Westview Press. Boulder CO. p. 317-322.

Schmid, James A. 1984. What and where are New Jersey's inland wetlands? (Abstract) Bulletin of the New Jersey Academy of Science 29(1):31.

Jurka, Valdis, and James A. Schmid. 1981. Contaminants in runoff from a parking structure in Northern New Jersey. (Abstract) Bulletin of the New Jersey Academy of Science 26(2):74.

Munro, John W., and James A. Schmid. 1981. Primary productivity in a backbarrier tidal marsh, northern Sussex County, Delaware. (Abstract) Bulletin of the New Jersey Academy of Science 26(2):69.

Schmid, James A. 1981. New Jersey's coastal wetlands: will they be protected? (Abstract) Bulletin of the New Jersey Academy of Science 26(2):64.

Schmid, James A. 1980. The effects of the National Environment Policy Act on corporate decision making. Early Corporate Environmental Assessment: Selected Papers. U.S.Department of Commerce, Office of Environmental Affairs. Washington DC. p. 1-9.

Schmid, James A., and David H. Dike. 1979. Biological resource information and coal mine assessment in the Gauley and Monongahela river basins, West Virginia. In Duane G. Nichols, R. A. Servais, and E. J. Ralinski (eds.). Proceedings of the Sixth National Conference on Energy and the Environment. Dayton Section, American Institute of Chemical Engineers. Dayton OH. p. 177-181.

Schmid, James A. 1979. Biological resource information and coal mine assessments in the Gauley and Monongahela river basins. Surface Mining and Fish/Wildlife Needs in the Eastern United States. U.S. Fish and Wildlife Service Publication FWS/OBS-78/81A. Washington DC. p. 87-90.

Schmid, James A. 1979. Vegetation types, functions, and constraints in metropolitan environments. Chapter 21. Planning the Uses and Management of Land. American Society of Agronomy. Madison WI. p. 499-528.

Schmid, James A. 1978. The urban habitat. In G. W. Frankie and C. S. Kohler (eds.). Perspectives in Urban Entomology. Academic Press. New York NY. p. ix-xiii.

Schmid, James A. 1977. Research and management: The case of Fire Island National Seashore. In J. H. Noyes and E. H. Zube (eds.). Coastal recreation resources in an urbanizing environment. Cooperative Extensive Service, University of Massachusetts. Amherst MA. p. 119-127.

Schmid, James A., D. Pennington, and J. McCormick. 1975. Ecological impact of the disposal of municipal sludge onto the land. Proceedings of the 1975 National Conference on Municipal Sludge Management and Disposal. Information Transfer, Inc. Rockville MD. p. 156-168.

Schmid, James A. 1974. The environmental impact of urbanization. In I. R. Manners and M. W. Mikesell (eds.). Perspectives on Environment. Association of American Geographers, Commission of College Geography Publication 13. Washington DC. p. 213-251.

Schmid, James A. 1974. The environmental impact of plants and animals. Ekistics 37(218):53-61.

LECTURES

Schmid, James A. 2015. Powerlines, pipelines, wetlands, and streams: data are critical for decisionmaking. Schuylkill Watershed Congress. Pottstown PA.

Schmid, James A. 2015. How not to design and regulate onlot residential sewage systems---someone might be paying attention. American Water Resources Association, Philadelphia Metropolitan Area Section. Philadelphia PA.

Schmid, James A. 2014. Water quality protection: a "wicked" problem in Pennsylvania. Cabrini College. Radnor PA.

Schmid, James A. 2014. To keep New York green, learn from Pennsylvania's mistakes. New York State Wetlands Forum, Inc. Annual Meeting, Rochester NY.

Schmid, James A. 2014. Shale gas, pipelines, and rural water supplies. Pennsylvania Rural Watershed Association Annual Meeting. Harrisburg PA.

Schmid, James A. 2014. How precarious is environmental protection in Pennsylvania? Precarious Alliance Energy in Transition Symposium. Doylestown PA.

Schmid, James A. 2013. How not to protect streams and wetlands, Pennsylvania-style. Ecological Society of America Mid-Atlantic Chapter Annual Meeting. Dover DE.

Schmid, James A. 2013. Natural gas extraction and its impacts in the landscape. Fourth Annual Choose Clean Water Conference. Baltimore MD.

Schmid, James A. 2012. Wetland science versus wetland regulation: observations of a practicing ecologist. Society of Wetland Scientists Mid-Atlantic Chapter Annual Conference. New Brunswick NJ.

Schmid, James A. 2012. Let mother nature clean up our mess: an attempted misuse of science to avoid protecting streams and wetlands. Society of Wetland Scientists Mid-Atlantic Chapter Annual Conference. New Brunswick NJ.

Schmid, James A. 2012. When sorcerers' apprentices fail to protect streams and wetlands. New York State Wetlands Forum, Inc. Annual Meeting, Utica NY.

Schmid, James A. 2011. Marcellus shale gas impacts on Pennsylvania wetlands and streams. Ecological Society of America Mid-Atlantic Chapter and New Jersey Academy of Sciences Annual Meeting. Montclair NJ.

Schmid, James A. 2011. Marcellus shale gas impacts on Pennsylvania wetlands and streams. New York State Wetlands Forum, Inc. Annual Meeting, Lake Placid NY.

Schmid, James A. 2010. Marcellus shal gas: what, where, whence, why now, so what? One ecologist's observations. Cabrini College. Radnor PA.

Schmid, James A. 2009. Regulatory gaps in Pennsylvania headwaters stream protection. Association of American Geographers Annual Meeting. Las Vegas NV.

Schmid, James A. 2009. Searching for bog turtles in southeastern Pennsylvania. Greater Philadelphia Herpetological Society and Marple Township Environmental Advisory Board. Broomall PA.

Schmid, James A. 2009. Protecting significant headwaters in Pennsylvania: Lessons from real projects in five counties, southeast and southwest. Schuylkill Watershed Congress. Pottstown PA.

Schmid, James A. 2009. Clean coal? Impacts of longwall mining in Pennsylvania. PennEnvironment and Sierra Club of Southeastern Pennsylvania. Free Library of Philadelphia. Philadelphia PA.

Schmid, James A. 2008. Ecological and soil regions along the Atlantic coastal plain---rules for Clean Water Act wetland delineation. Association of American Geographers Annual Meeting. Boston MA.

Schmid, James A. 2007. The missing geography of wetlands in the United States. Association of American Geographers Annual Meeting. San Francisco CA.

Schmid, James A. 2006. A consulting ecologist's observations on environmental regulation in the real world---focus on the National Environmental Policy Act and wetlands protection. Columbia University, Department of Ecology, Evolution, and Environmental Biology. New York NY.

Schmid, James A. 2003. Multiple wetland boundaries on a single tract of land: when different levels of government undermine credible regulation. New York State Wetland Forum, Inc., Annual Meeting. Saratoga Springs NY.

Schmid, James A. 2002. NWI wetland indicator status---are there any significant differences between 1988 and 1997 indicators for plants in the mid Atlantic states? US Environmental Protection Agency Wetlands Workshop. Atlantic City NJ.

Schmid, James A. 2002. Rare plants, protected plants, native plants, and wetlands in the mid Atlantic states. New York State Wetlands Forum, Inc., Annual Meeting. Syracuse NY.

Schmid, James A. 2001. So you think you have hydrophytic vegetation? US Environmental Protection Agency Wetlands Workshop. Atlantic City NJ.

Schmid, James A. 2001. Calculating hydrophytic vegetation: select the method that gives you the result you want? Society of Wetland Scientists Annual Meeting. Lake Placid NY.

Schmid, James A. 2001. Assembling the plant list for New Jersey: sources of wetland indicator status information. US Environmental Protection Agency Wetlands Workshop. Atlantic City NJ.

REVIEWS

Schmid, James A. 2007. City trees: A historical geography from the Renaissance through the nineteenth century, by Henry W. Lawrence. Geographical Review 97(4):572-574.

Schmid, James A. 2001. My, how much we need to learn about wetlands! Wetland ecology: principles and conservation, by Paul A. Keddy. Ecology 82(7): 2085

Schmid, James A. 1999. Days afield: exploring wetlands in the Chesapeake Bay region, by William S. Sipple. Wetland Journal 11(4):21.

Schmid, James A. 1998. Discovering the unknown landscape: a history of America's wetlands, by Ann Vileisis. Wetland Journal 10(2): 30.

Schmid, James A. 1977. Worldwide human modification of ecosystems. Ecology 58(1):221-222.

Schmid, James A. 1977. Politics of shore erosion: Westhampton Beach, by J. M. Heikoff. Geographical Review 67(4):491-93.

SELECTED CONTRACT REPORTS

- Principal Authorship

JMA. 1974. Environmental impact assessment on the construction and operation of a residential and commercial development, Specially Planned Area I, Town of Secaucus, Hudson County, New Jersey. Submitted to the State of New Jersey, Hackensack Meadowlands Development Commission, Lyndhurst NJ, by Hartz Mountain Industries, Inc. Devon PA. 241 p.

JMA. 1975. Draft environmental impact statement on construction permits for a proposed fuel storage terminal in the Hudson River, Weehawken Cove, Hudson County, New Jersey. Prepared for the United States Army Engineer District, New York City. Devon PA. 217 plus 103 p.

JMA. 1975. Environmental inventory of the Fire Island National Seashore and the William Floyd Estate, Suffolk County, New York. Submitted to the National Park Service, Denver CO. Devon PA. 461 p. plus map folio.

JMA. 1975. The potential impact of urbanization on the fringe of megalopolis. Prepared for the Committee for the Preservation of Northern Montville, Montville NJ. Devon PA. 36 p.

JMA. 1976. Community development block grant program environmental assessment report on the Gateway Project. Prepared for the City of Camden NJ. Berwyn PA. 70 p.

JMA. 1977. Final report on environmental aspects of the new source NPDES permit program for the West Virginia surface coal mining industry, 1977-1980. Prepared for the US Environmental Protection Agency Region III, Philadelphia PA. Berwyn PA. 219 p.

JMA. 1977. Supplemental socioeconomic environmental impact assessment on the construction and operation of an Island Residential development on Specially Planned Area I, Town of Secaucus, Hudson County, New Jersey. Submitted to the State of New Jersey, Hackensack Meadowlands Development Commission, Lyndhurst NJ, by Hartz Mountain Industries, Inc. Berwyn PA. 201 p.

JMA. 1977. Effects of the National Environment Policy Act on corporate decisionmaking: A draft report for review. Prepared for the United States Department of Commerce, Washington DC. Berwyn PA. 268 p.

JMA. 1978. Draft environmental impact statement for the proposed Ravenscliff Subdivision, Radnor and Newtown Townships, Delaware County, Pennsylvania. Prepared on behalf of Ravenscliff Land Co., Devon PA, for submission to Radnor Township. Berwyn PA. 85 p.

JMA. 1979. New source NPDES permits and environmental impacts of the coal mining industry in the Monongahela and Gauley River Basins, West Virginia. Prepared for US Environmental Protection Agency Region III, Philadelphia, PA. Berwyn PA.

WAPORA. 1979. The estuarine study, Volume I, Part 3, management report and recommendations. Prepared for the New Jersey Department of Environmental Protection, Trenton NJ. Chevy Chase MD. 220 p.

WAPORA. 1979. Potential environmental impacts of energy facilities and other development on Fish House Cove, Delaware River. Prepared for Camden County Environmental Agency, Camden NJ. 78 p. plus folio map.

WAPORA. 1979. Analysis of sole source designation pursuant to Section 1424(e) of the Safe Drinking Water Act and the proposed coastal New Jersey designation. Prepared for Homebuilders League of South Jersey, Cherry Hill NJ. Berwyn PA. 39 p.

WAPORA. 1979-1980. New Jersey Sports Complex monitoring reports 59 through 66. Prepared for submission to regulatory agencies by the New Jersey Sports and Exposition Authority. Berwyn PA. (combined) 353 p.

WAPORA. 1979-1980. Quarterly reports 2 through 6 updating the 1978 Hearing Officers' Report on the construction and operation of the New Jersey Sports Complex. Prepared on behalf of the New Jersey Sports and Exposition Authority for presentation to the Environmental Liaison Committee. Berwyn PA. (combined) 68 p.

WAPORA. 1979-1980. Monthly official minutes of the Environmental Liaison Committee pertaining to the construction and operation of the New Jersey Sports Complex, East Rutherford, New Jersey. Meetings 57 through 71. Berwyn PA. (combined) 110 p. exclusive of attachments.

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TERA. 1981. Report on environmental conditions at Leisure Towne, Southampton Township, Burlington County, New Jersey. Prepared for Leisure Technology Inc., Lakewood NJ. King of Prussia PA. 16 p.

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TERA. 1981. Specifications for site work and revegetation, terminal expansion, and park site mitigation, Camden County, New Jersey. Prepared for Holt Hauling & Warehousing System, Inc., Gloucester NJ. King of Prussia PA. 16 p.

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TERA. 1982. Proposed mitigation plan and environmental assessment, Hartz Mountain permit application, Public Notice 112255-82-391-J2. For submission to Army Engineer District, New York City. King of Prussia PA. 21 p. plus appendixes.
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Schmid & Co. 1984. Preliminary feasibility analysis of hybrid poplar sylviculture using municipal sludge on dredged spoil disposal areas, Logan Township, Gloucester County, New Jersey. Prepared for S. T. Hudson Engineers, Inc. Media PA. 10 p.
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Schmid & Co. 1985. Wildlife habitat values on the Laurel Harbor proposed resubdivision project site, Lacey Township, Ocean County, New Jersey. Prepared on behalf of Charles H. Mackie Associates for submission to New Jersey Department of Environmental Protection (CAFRA Permit Application 85-0716-5). Media PA. 11 p.
Schmid & Co. 1985. Wetlands on the site of the proposed Quadrant 3 urban renewal site, Wayne Township, Passaic County, New Jersey. Prepared on behalf of Farcal Realty, Inc., for submission to the Army Corps of Engineers. Media PA. 22 p.
Schmid & Co. 1985. Wetlands, fill, and mitigation at the Summit Corporate Research Center, Edison Township, Middlesex County, New Jersey. Prepared on behalf of Summit Associates, Inc., for submission to Army Corps of Engineers. Media PA. 25 p.
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Schmid & Co. 1985. Wetlands on the Washington Greene project site, Washington Township, Mercer County, New Jersey. Prepared on behalf of Toll Brothers for submission to the Army Corps of Engineers. Media PA. 21 p.
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Schmid & Co., Inc. 1987. Draft analysis of ocean dune destruction project proposed by Normandy Shores Beach Association, Long Beach Island, Dover Township, Ocean County, New Jersey. Media PA. 8 p.
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Schmid & Co., Inc. 1990. Wetland creation concept in mitigation for the proposed expansion of the Meadville Mall, Vernon Township, Crawford County, Pennsylvania. Prepared for George D. Zamias, Johnstown PA. Media PA. 14 p.

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Schmid & Company, Inc. 1993. Alternatives for restoration of intertidal shallows and marsh creation, Mallard View subdivision, Brick Township, Ocean County, New Jersey. Prepared for Yardville National Bank, Morrisville NJ. Media PA. 17 p.

Schmid & Company, Inc. 1994. Ecological assessment of a forested wetland swale at the American Nickeloid Company's Walnutport facility, Northampton County, Pennsylvania. Prepared for American Nickeloid Company, Peru IL. Media PA. 22 p.
Schmid & Company, Inc., and ACT Engineers, Inc. 1994. Statement of compliance with NJDEPE Coastal Resource and Development Rules for a Waterfront Development Permit application. Prepared for Yardville National Bank, Trenton NJ. Media PA. 8 p.
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Schmid & Company, Inc. 1997. Environmental conditions at a site on Manhattan Street near Surf Avenue, Tottenville, Borough of Staten Island, Richmond County, New York. Prepared for Calvanico Associates, Inc. Media PA. 40 p.

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Schmid & Company, Inc. 1997. Update on planning prior to application for final approval of the Salem River Corridor wetland mitigation bank. Prepared for DuPont Chambers Works. Media PA. 12 p.
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Schmid & Company., Inc. 2000. Description of site conditions for a jurisdictional determination and plan to provide wetland mitigation for a property along East Ridley Avenue, Ridley Park Borough, Delaware County, Pennsylvania. Prepared for Harper Associates, Ridley Park PA. Media PA. 50 p.
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- **Substantial Input**

JMA. 1973. Environmental impact statement on the construction and operation of Ocean Harbor, a residential and commercial development in the City of Brigantine, Atlantic County, New Jersey. Prepared for Brigantine Harbour, Inc., for submission to the New Jersey Department of Environmental Protection. Devon PA. 206 p.

JMA. 1975. The existing water quality of Lake Valhalla, Morris County, New Jersey, and an assessment of potential impacts on water quality of development in the watershed. Prepared for the Committee for the Preservation of Northern Montville. Devon PA. 22 p.

JMA. 1975. Natural resource inventory of the Middle Run study area, New Castle County, Delaware. Prepared for the New Castle County Department of Parks and Recreation. Devon PA. 129 plus 32 p.

JMA. 1975. Environmental assessment for the feasibility study for the land reclamation project, complementary urban development, City of Corinto, Nicaragua. Prepared for submission to the Autoridad Portuaria de Corinto and US-AID by Boswell-Amman & Whitney-Lamsa, Ingenieros Consultores. Devon PA. 116 p. plus folio maps.

JMA. 1975. Waterfowl in the Meadowlands Freeway (US Routes 1 & 9) study area, Hackensack Meadowlands District, Hudson and Bergen Counties, New Jersey. Submitted to the New Jersey Department of Transportation by Louis Berger & Associates, Inc. Berwyn PA. 25 p.

JMA. 1975. Inventory reports for Legislative Route 202 project area, Chester County, Pennsylvania. Prepared on behalf of Pennsylvania Department of Transportation, District 6-0. Berwyn PA. Variously paged, 377 p.

JMA. 1975. Request for the determination of eligibility for listing on the National Register of Historic Places of six historic sites in the corridor for the proposed improvements to Legislative Route 202, Charlestown Township and Schuylkill Township, Pennsylvania. Submitted to the Pennsylvania Historic and Museum Commission by the Pennsylvania Department of Transportation, District 6-0. Berwyn PA. 63 p.

JMA. 1976. Draft environmental impact statement, L.R. 202 (Phoenixville Pike), Pennsylvania Turnpike to City Line Avenue, Borough of Phoenixville, Chester County, Pennsylvania. Prepared for the Pennsylvania Department of Transportation, District 6-O, and the Federal Highway Administration. Berwyn PA. 170 p.

JMA. 1976. Application for the construction and operation of a residential development in Ocean County, Cape May County, New Jersey. Prepared on behalf of EVED Enterprises, Inc. for submission to the New Jersey Department of Environmental Protection. Berwyn PA. 26 p.

JMA. 1976. An assessment of beach erosion, with recommendations for the Borough of Ocean City, Cape May County, New Jersey. Berwyn PA. 102 p.

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JMA. 1976. Quick response environmental impact assessment of dredging and filling at Harmon Cove, Specially Planned Area I, Secaucus, New Jersey. Submitted to the State of New Jersey, Hackensack Meadowlands Development Commission, by Hartz Mountain Industries, Inc. Berwyn PA. 10 p.

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Schmid & Co., Inc. 1988. Wetland evaluation of the Shadow Oaks at Cranbury site, Block 21, Lot 8, Cranbury Township, Middlesex County, New Jersey. Prepared for Garden State Land Group, Cranbury NJ. Media PA. 31 p.

Schmid & Co., Inc. 1988. Wetland evaluation of the Cushetunk Lake site, Readington Township, Hunterdon County, New Jersey. Prepared for Trammell Crow Company, Princeton NJ. Media PA. 35 p.

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Schmid & Co., Inc. 1990. Wetland identification at the Floodgate Road site, Logan Township, Gloucester County, New Jersey. Prepared for American Dredging Co., Camden NJ. Media PA. 34 p.
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Schmid & Co., Inc. 1990. Wetlands at Block 195, Lots 6, 7, and 8, Brick Township, Ocean County, New Jersey, and regulatory implications. Prepared for the Trust for Public Lands, New York NY. Media PA. 29 p.

Schmid & Co., Inc. 1991. Wetland identification, Wings Field tract, Whitpain Township, Montgomery County, Pennsylvania. Prepared for LHC Realty/Wings Field Associates. Plymouth Meeting PA. Media PA 40 p.
Schmid & Co., Inc. 1991. Wetland investigations at Block 1DD, Lots 2-4, and Block 1BB, Lots 26-30, Pine Hill Borough, Camden County, New Jersey. Prepared for Richard B. Heller, Newtown Square PA. Media PA. 17 p.
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Schmid & Co., Inc. 1991. Wetland investigation at the Suttmeier Tract, West Windsor Township, Mercer County, New Jersey. Prepared for Garden State Land Group. Media PA. 38 p.
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Schmid & Co., Inc. 1995. Wetland conditions at a site along Morton Avenue and MacDade Boulevard, Ridley Township, Delaware County, Pennsylvania. Prepared for Harper Associates, Ridley Park PA. Media PA. 44 p.

Schmid & Co., Inc. 1995. Wetland conditions at a site along George Dye Road and Klockner Road, Hamilton Township, Mercer County, New Jersey. Prepared for Stanley Neuman. Media PA. 72 p.
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Schmid & Company, Inc. 1995. Wetland conditions at a site along Cardiff Lane, Hamilton Township, Mercer County, New Jersey. Prepared for Mercer Capital Management, Inc., L.P. Hamilton, New Jersey. Media PA. 35 p.
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Schmid & Co., Inc. 1997. Wetland conditions at the Yardville National Bank site, Section 96, Lot 359, Hamilton Township, Mercer County, New Jersey. Prepared for Yardville National Bank. Media PA. 39 p.
Schmid & Co., Inc. 1997. Wetland conditions at the Oak Meadow Lane site, Easttown Township, Chester County, Pennsylvania. Prepared for Durkin Associates, Inc. Media PA. 32 p.
Schmid & Co., Inc. 1997. Wetland conditions at Culligan Water Conditioning site, Sunfield Avenue, Raritan Center, Edison Township, Middlesex County, New Jersey. Prepared for Culligan Water Conditioning, Inc. Media PA. 30 p.
Schmid & Co., Inc. 1997. Wetland conditions at a property along Barclay and Brunswick Avenues, City of Margate, Atlantic County, New Jersey. Prepared for A. Silverstein. Media PA. 33 p.
Schmid & Co., Inc. 1997. Wetland conditions at a site along Patterson Avenue, Hamilton Township, Mercer County, New Jersey. Prepared for W. Matisa. Media PA. 31 p.
Schmid & Co., Inc. 1997. Preliminary site assessment for a site along Hobson and Emeline Avenues, Hamilton Township, Mercer County, New Jersey. Prepared for Hamilton Township Division of Planning. Media PA. 62 p.
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Schmid & Co., Inc. 1997. Preliminary site assessment for a site along Paxson Avenue, Hamilton Township, Mercer County, New Jersey. Prepared for Hamilton Township Division of Planning. Media PA. 51 p.
Schmid & Co., Inc. 1997. Wetland conditions at a site along Melrich Road, South Brunswick Township, Middlesex County, New Jersey. Prepared for Summit/Greene Associates. Media PA. 40 p.

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Schmid & Co., Inc. 1998. Wetland conditions along Pascack Road, Lot 2, Block 7706, Paramus Borough, Bergen County, New Jersey. Prepared for the Borough of Paramus. Media PA. 35 p.

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Schmid & Co., Inc. 2000. Site conditions at a property along Domorah Drive, Montgomeryville Industrial Park, Montgomery Township, Montgomery County, Pennsylvania. Prepared for Nappen & Associates, Montgomeryville PA. Media PA. 35 p.
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Schmid & Co., Inc. 2000. Existing conditions and potential impacts of proposed development at the Pitcher Property along French Creek Road, West Vincent Township, Chester County, Pennsylvania. Prepared for French and Pickering Creeks Conservation Trust, Pottstown PA. Media PA. 20 p.

Schmid & Co., Inc. 2000. Site conditions at a property along Sherwood Avenue, Block 6784, Lots 73, 75, 79, and 81, Borough of Staten Island, Richmond County, New York. Prepared for Robert Kelly, Staten Island NY. Media PA. 31 p.

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Schmid & Co., Inc. 2002. Site conditions at a property along Jefferson Avenue, Lots 114 and 116, Block 3864, Staten Island, Richmond County, New York. Prepared for V. Grinberg, Staten Island, New York. Media PA. 43 p.
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Schmid & Co., Inc. 2002. Wetland conditions, Reed Sod Farm, Lots 22 and 22.02, Block 43, Upper Freehold Township, Monmouth County, New Jersey. Prepared for MGD Development Group, LLC, Hopewell, New Jersey. Media PA. 43 p.
Schmid & Co., Inc. 2002. Site conditions at Tax Parcels 101 and 102, Tinicum Township, Delaware County, Pennsylvania. Prepared for Tinicum LandVest, LLC, Chester Heights, Pennsylvania. Media PA. 40 p.
Schmid & Co., Inc. 2002. Wetland conditions at a site along Fellowship Road and Church Road, Mount Laurel Township, Burlington County, New Jersey. Prepared for M. Rourke, Fairfax Station, Virginia. Media PA. 39 p.
Schmid & Co., Inc. 2002. Site conditions at a property along Slater Boulevard, Lots 4, 7, 11, and 33, Block 3830, Staten Island, Richmond County, New York. Prepared for S. Krebushevski, Staten Island, New York. Media PA. 37 p.
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Schmid & Co., Inc. Site conditions at Hamanassett, Chester Heights Borough, Delaware County, Pennsylvania. Prepared for Hamanassett at Darlington LLC, Media, Pennsylvania. Media PA. 37 p.
Schmid & Co., Inc. 2002. Wetland conditions at a site along Blueball Avenue and Interstate 95, Upper Chichester Township, Delaware County, Pennsylvania. Prepared for Moser-Knauer Associates, Boothwyn, Pennsylvania. Media PA. 59 p.
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Research and strategy for the land community.

To: Interested Parties
From: Sonia Wang and Spencer Phillips, Ph.D.
Date: 3/11/2015
Subject: Review of INGAA Foundation Report, "Pipeline Impact to Property Value and Property Insurability"

The Interstate Natural Gas Association of America (INGAA) Foundation, Inc., has released another report on the impacts of pipelines on property values and property insurability.[1] Like a previous report using the same methods, the report claims that pipelines have no measurable impact on property values of homes of any type, regardless of the age or size of the transmission line. The report quantitatively analyzes two pipelines in Ohio, plus one each in Virginia, New Jersey, Pennsylvania, and Mississippi.

Like its similar 2001 study,[2] this new study has many flaws in methods and uses the same, incorrect assumptions.[3] The authors attempt to compare prices for properties "adjacent to" a pipeline with the price of properties "off" the pipeline. The trouble in each of their case studies, however, is that the definition of "adjacent to" ignores the potential impact of health and safety risks that may be depressing property values for a majority (and in some cases, all) of the properties considered. Specifically, and for most of the properties, the authors fail to account for the fact that many of the "off" properties analyzed are in fact included in the evacuation zone of the pipeline, which would mean the study is not truly distinguishing between properties potentially affected by the pipeline and those beyond the danger zone.

- For the Texas Gas Transmission in Ohio, based on the lowest estimated pressure (PSI) for a 26" pipeline, 25 of the 31 (81%) "off" properties are actually located in the evacuation zone (615.5 feet). [4,5]

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[1] Integra Realty Resources. 2016. "Pipeline Impact to Property Value and Property Insurability." 2016.01. Interstate Natural Gas Association of America (INGAA) Foundation, Inc. http://www.ingaa.org/PropertyValues.aspx.

[2] Allen, Williford & Seale Inc. 2001. "Natural Gas Pipeline Impact Study." F-2001-02. Interstate Natural Gas Association of America (INGAA) Foundation, Inc.

[3] The flaws in the 2001 study are described in Phillips, Bottorff and Wang, 2016, Economic Costs of the Atlantic Coast Pipeline: Effects on Property Value, Ecosystem Services, and Economic Development in Western and Central Virginia, Charlottesville, VA: Key-Log Economics available at keylogeconomics.com.

[4] In most cases, we were able to estimate the evacuation zone based on the diameter and operating pressure given for the pipeline. The Pipeline Association for Public Awareness provides a lookup table with these evacuation zones. For pipelines that fall between the sizes or pressures given,, we interpolated the evacuation zone from the available information. (See Appendix C of "Pipeline Emergency Response Guidelines," Pipeline Association for Public Awareness, 2007, www.pipelineawareness.org.)

[5] For this pipeline, we used the lowest estimated pressure because the exact PSI was not noted in the study or available from other sources. This estimate is the most conservative and it is likely the evacuation is actually larger, meaning even more of the "off" properties listed are, in effect, near the pipeline.

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- For the REX-EAST pipeline in Ohio, based on a max operating PSI of 1480 for a 42" pipeline, 5 of the 9 (56%) "off" properties are actually located in the EVAC zone (3683.8 feet).
- For the Transcontinental Gas Pipeline in New Jersey, based on the max operating PSI of 1480 for a 42" pipeline, ALL "off" properties are actually located in the EVAC zone (3683.8 ft).
- For the Gulf South Transmission Pipeline in Mississippi, based on the lowest estimated operating PSI of 100 for a 30" pipeline, 9 out of the 17 (53%) "off" properties are actually located in the EVAC zone (684 ft).[4]
- For the Transco (Williams) Pipeline in Virginia and the Williams Natural Gas Pipelines in Pennsylvania, the authors do not report the distance away from the pipeline, rather there is just a yes or no regarding whether or not the property is abutting the right of way. Assuming the authors methods, while flawed, are at least consistent from one case study to the next within the paper, it is likely that 50% or more of the comparison properties (those not abutting the right-of way) are in fact within the evacuation zone and, therefore, are not materially different from those abutting the right-of-way from the perspective of health and safety effects on property value.

In summary, while any econometric evaluation of differences in market prices requires comparing observed prices of things that are different in some way, the INGAA study is merely reporting that there is little difference in the price of things that are not materially different. The authors should be comparing apples to oranges, but instead they compare oranges to oranges.

In addition, the INGAA study suffers from a more serious flaw in that the authors do not state whether or not the purchasers of any of the properties analyzed were aware of the properties' proximity to a pipeline. If a market price is to be taken as a signal of economic value, then the price must arise from a transaction in which both buyers and sellers have full information about the property being sold. But proximity to natural gas pipelines is not typically something that sellers and realtors are required to disclose. If buyers in the study were unaware that they were buying a property near a natural gas pipeline, then one cannot legitimately conclude that their offer prices reflect the effect of the presence or absence of a pipeline on property value.

As a result of these flaws, it is impossible to conclude from INGAA's study that a property value effect does not exist. Other, more appropriate/robust studies, like the study by Hansen, Benson, and Hagen (2006)[6] actually reinforce the conclusion that when buyers do know about a nearby pipeline, market prices drop. These authors found that property values fell after a deadly 1999 liquid petroleum pipeline explosion in Bellingham, Washington. They also found that the negative effect on prices diminished over time. This makes perfect sense if, as is likely, information about the explosion dissipated once the explosion and its aftermath left the evening news and the physical damage from the explosion had been repaired.

Similarly, Kielisch (2015) concludes that when buyers are aware that a property is near a pipeline, their willingness to buy the property and their average offer prices drop significantly.[7] In his systematic

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[6] Hansen, Julia L., Earl D. Benson, and Daniel A. Hagen. 2006. "Environmental Hazards and Residential Property Values: Evidence from a Major Pipeline Event." Land Economics 82 (4): 529–41.

[7] Kielisch, Kurt. 2015. "Study on the Impact of Natural Gas Transmission Pipelines." Forensic Appraisal Group, Ltd.

review of studies were buyers, Realtors, or appraisers were aware of properties' proximity to natural gas pipelines, He found, in brief, that

- 68% of Realtors believe the presence of a pipeline would decrease residential property value, with 56% of Realtors estimating a decrease in value between 5% and 10%.
- 70% of Realtors believe a pipeline would cause an increase in the time it takes to sell a home.
- 62.2% of buyers in a different study stated that they would no longer buy a property with/on a pipeline ROW at any price. Of the remainder, half (18.9%) stated that they would still buy the property, but only at a price 21% below what would otherwise be the market price. The other 18.9% said the pipeline would have no effect on the price they would offer. Not incidentally, the survey participants were informed that the risks of "accidental explosions, terrorist threats, tampering, and the inability to detect leaks" were "extremely rare" (2015, p. 7).

  This translates into a reduction in expected value of 10.5% for those who proceed to buy the home. If you consider that the 62% of buyers who drop out are effectively reducing their offer prices by 100%, the expected reduction in offer price for <u>all</u> potential buyers 66.2%.
- Based on five "impact studies" in which appraisals of smaller properties with and without pipelines were compared, "the average impact [on value] due to the presence of a gas transmission pipeline is -11.6%" (p. 11).

Clearly when one considers property transactions in which one's eyes are open to the presence or or proximity to a pipeline, market prices fall because the properties are less attractive and valuable to their would-be or actual new owners.

In conclusion, the recent INGAA study does not provide conceptually or empirically valid results regarding the effect of natural gas pipelines on property value. Citizens local government officials and FERC should be looking to the best available information from studies such as those referenced here.

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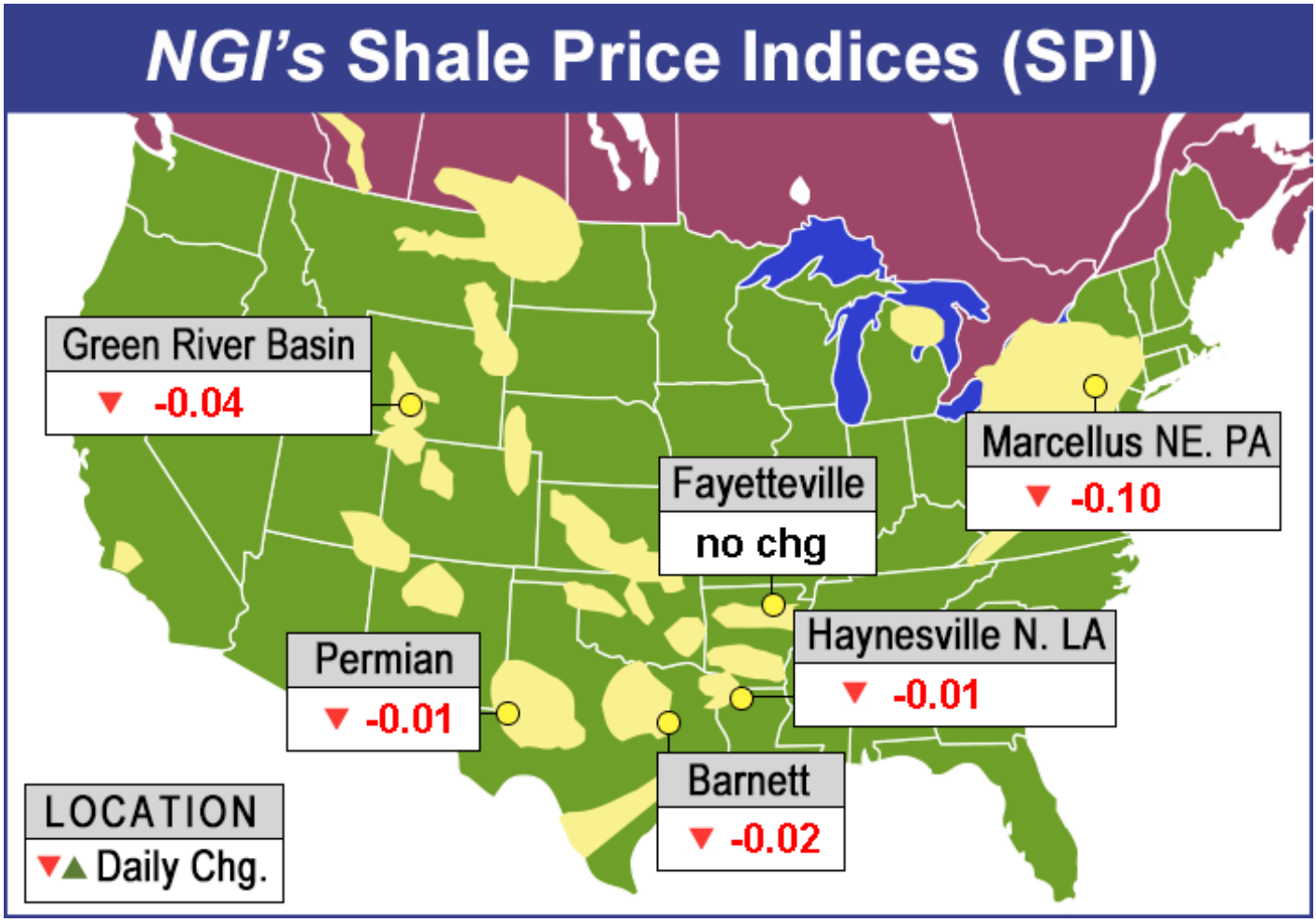

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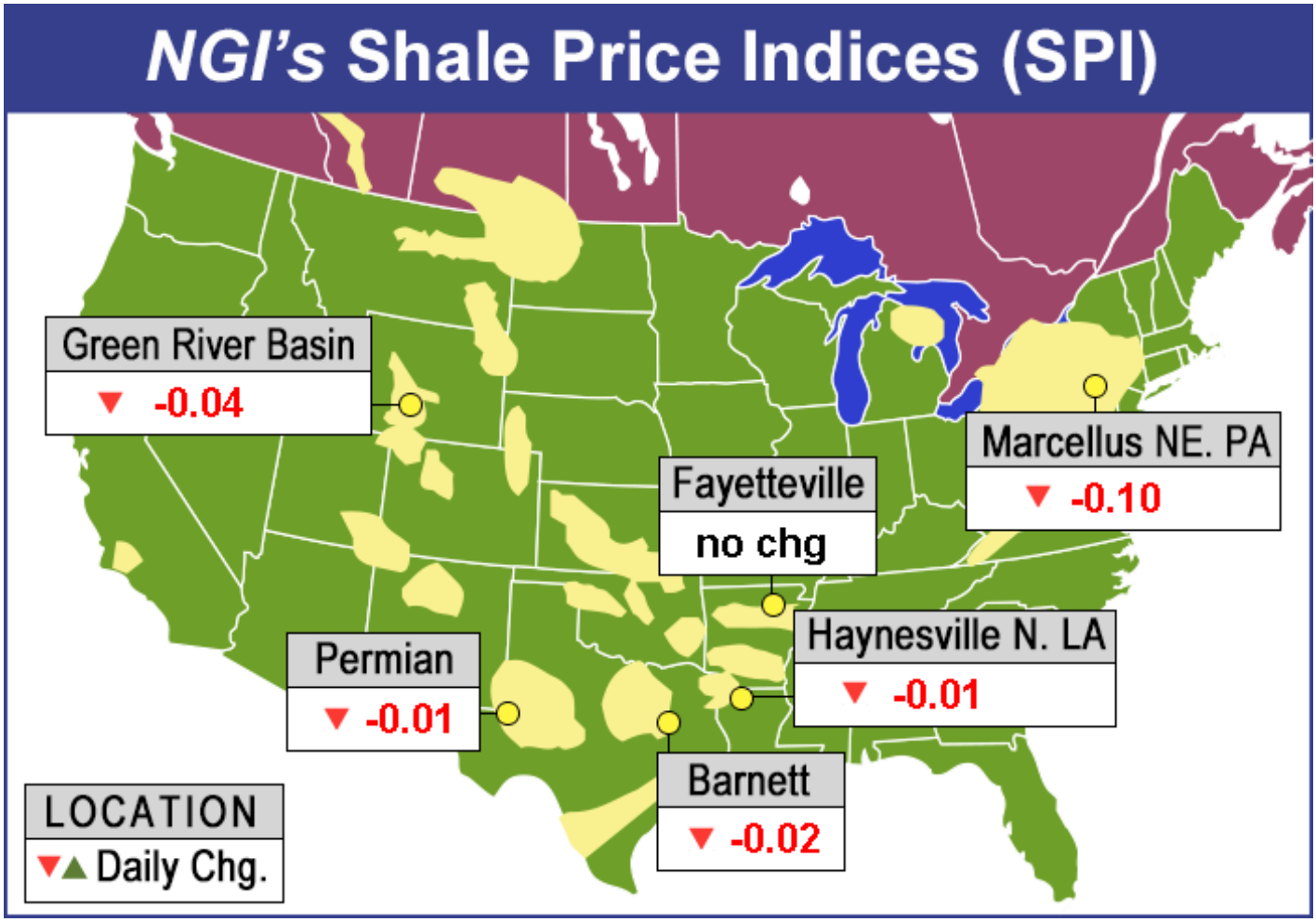

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NGI's NatGas Prices - Biggest Movers		
Daily	Iroquois Zone 2	-0.40
Weekly	Kingsgate	+0.53
Bidweek	Algonquin Citygate	-0.41
Shale	Marcellus - NE PA: Tenn	-0.12

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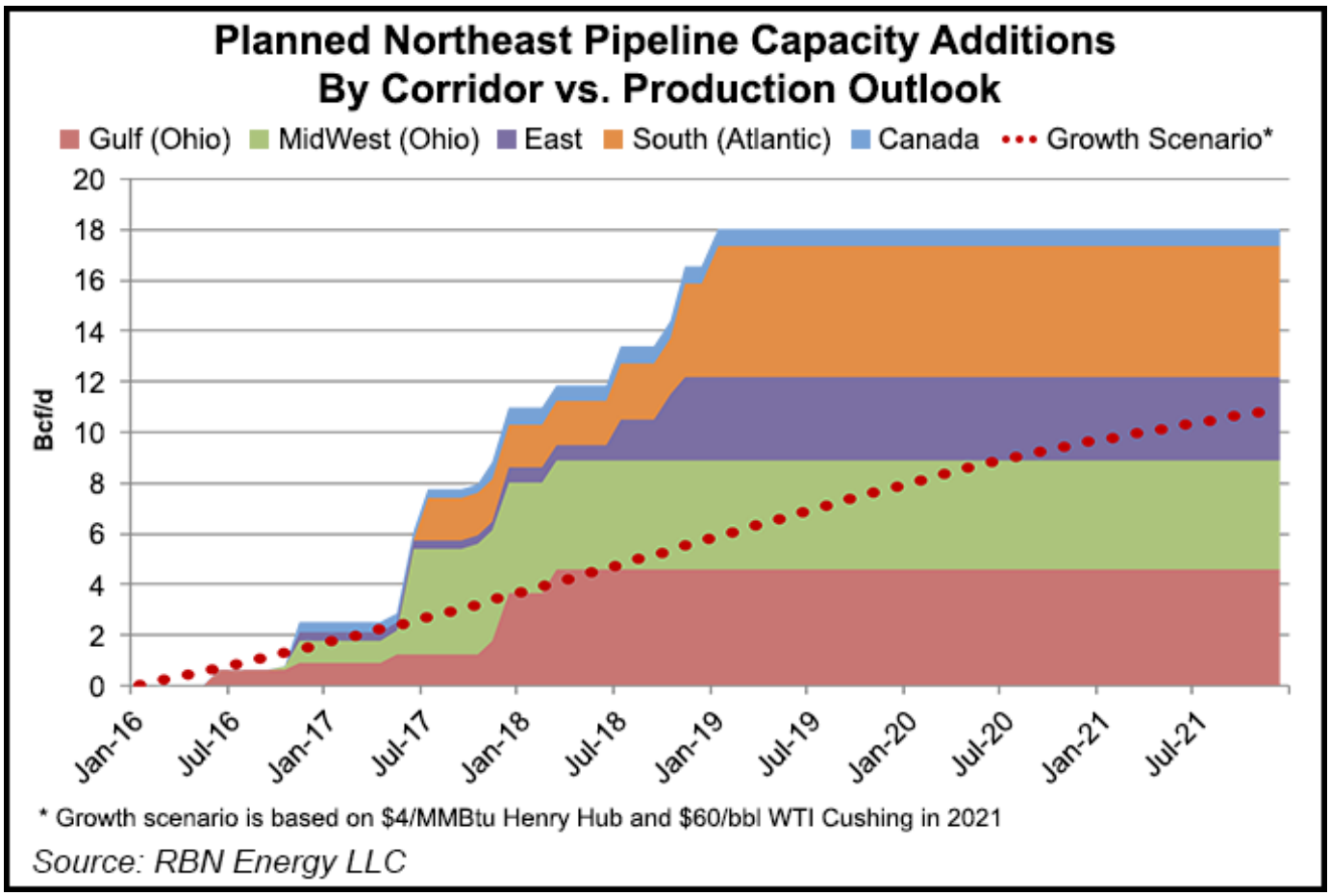

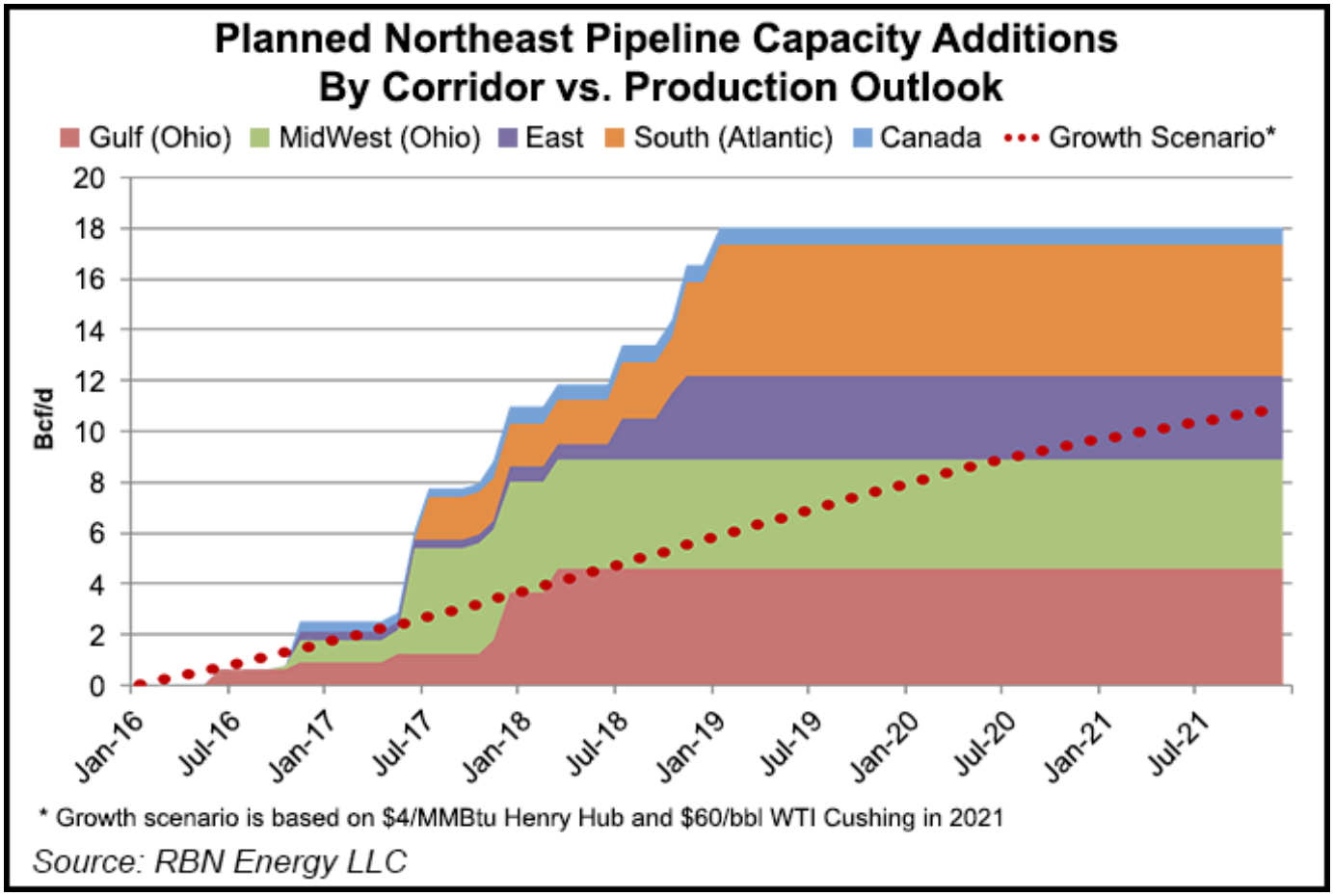

The need for more takeaway capacity out of the Marcellus and Utica shales has become a common refrain, but with a long list of projects on tap the Northeast could be headed for a pipeline overbuild, according to RBN Energy LLC President Rusty Braziel.

Speaking to attendees at the 21st Annual LDC Gas Forums Northeast conference in Boston Tuesday, Braziel said an evaluation of price and production scenarios through 2021 suggests the industry is planning too many pipelines to relieve the region's current capacity constraints.

"Is it possible that we could build too much takeaway capacity out of the" Marcellus and Utica? "It's certainly happened in about every other segment of the energy business over the last few years," Braziel said.

Braziel said his firm estimated Northeast production through 2021 by taking a range of price scenarios and determining what producers would be likely to drill and how many drilled but uncompleted (DUC) wells they would put into service.

RBN's most aggressive growth scenario, based on 2021 prices of $4/MMBtu Henry Hub and $60/bbl West Texas Intermediate, would see the Marcellus and Utica increase production by 11 Bcf/d over the next five years.

Meanwhile, add up all the major proposed Marcellus/Utica takeaway projects headed to the East (3.3 Bcf/d), to the Midwest (4.3 Bcf/d), to the Gulf of Mexico (4.5 Bcf/d), to the South along the Atlantic Coast (5.2 Bcf/d) and to Canada (.65 Bcf/d) and it equals 18 Bcf/d of new capacity by 2019.

"Could prices be higher, and could [the growth scenario] be higher because prices are higher? Yes, it could. Could pipes be delayed? Absolutely," Braziel said. Ultimately the discrepancy between the growth projections and planned capacity "means that there are a lot of things that could go right or wrong depending on your perspective on all of this...If you're looking at this from the standpoint of a company committing or considering commitments to any pipelines, firm pipeline capacity, 20-year deals, you just might want to think long and hard about whether [an overbuild] could happen."

Braziel drew parallels between the current state of shale hydrocarbon commodities markets and the housing market crash during the Great Recession.

"What we're really seeing is the tail end of a bubble, and what's actually happened is that bubble attracted billions of dollars worth of infrastructure investment that now has to be worked off," he said. "It's entirely possible that that could be the world that we're into now, that it's this world of infrastructure investment that we're dealing with right now and that this has a lot to do with what we're seeing happening up in the Northeast."

Basis differentials at Appalachian Basin trading points still point to a need for more pipelines, Braziel said. It may come down to which projects pull from the remaining active areas within the basin, he said.

"Due to localized transportation or capacity constraints, that means a lot of these pipes are going to be needed anyway. Growth is in very narrow pockets, so we're going to need some of these pipes," Braziel said. "That means if you're looking at one of those pipes that is not in one of these narrow pockets, then that pipeline might be at risk."

Of the 15 counties responsible "for the vast majority" of drilling activity in Pennsylvania, Ohio and West Virginia, "there's only been nine of those counties that have anything going on today...It's a very concentrated market with not much drilling going on. Of course, there are the DUCs. So there are certainly DUCs coming back, but the majority of the DUCs, guess what? The good DUCs are coming back in those very same counties...There's a lot of other DUCs that are scattered about in those other counties that were drilled quite some time ago. They're probably not coming back. The economics are not so good. We like to call them the dead DUCs."

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Jeremiah Shelor joined NGI in October of 2015 after two years covering business and politics for The Exponent Telegram in Clarksburg, WV. He holds a Bachelor of Arts in Creative Writing from Virginia Tech.
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The Potential Environmental Impact from Fracking in the Delaware River Basin

Steven Habicht, Lars Hanson and Paul Faeth

August 2015

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Authors: Steven Habicht, Lars Hanson and Paul Faeth

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Approved by: **August 2015**

David J. Kaufman, Vice President and Director
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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.

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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.

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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

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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.

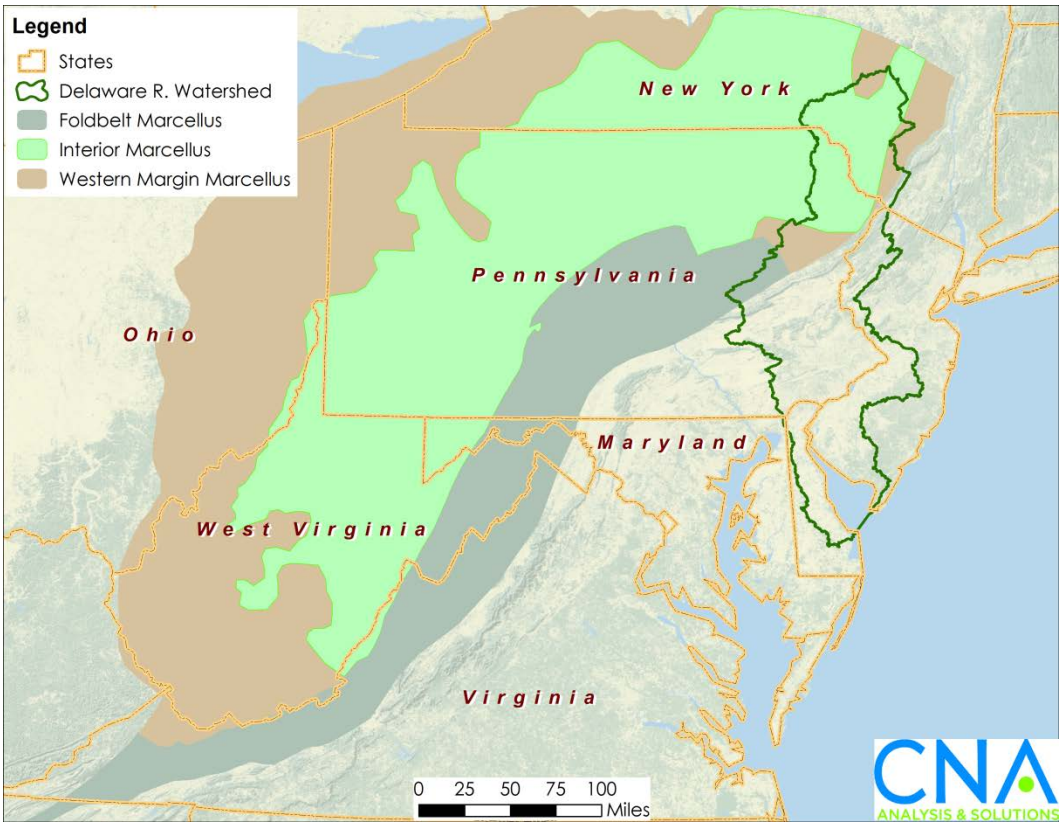
One of the primary barriers to conducting this type of research is the difficulty in predicting where future natural gas wells will be located. For example, in a recent report to Congress, the U.S. Government Accountability Office stated, "The risks identified in the studies and publications we reviewed 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

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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.

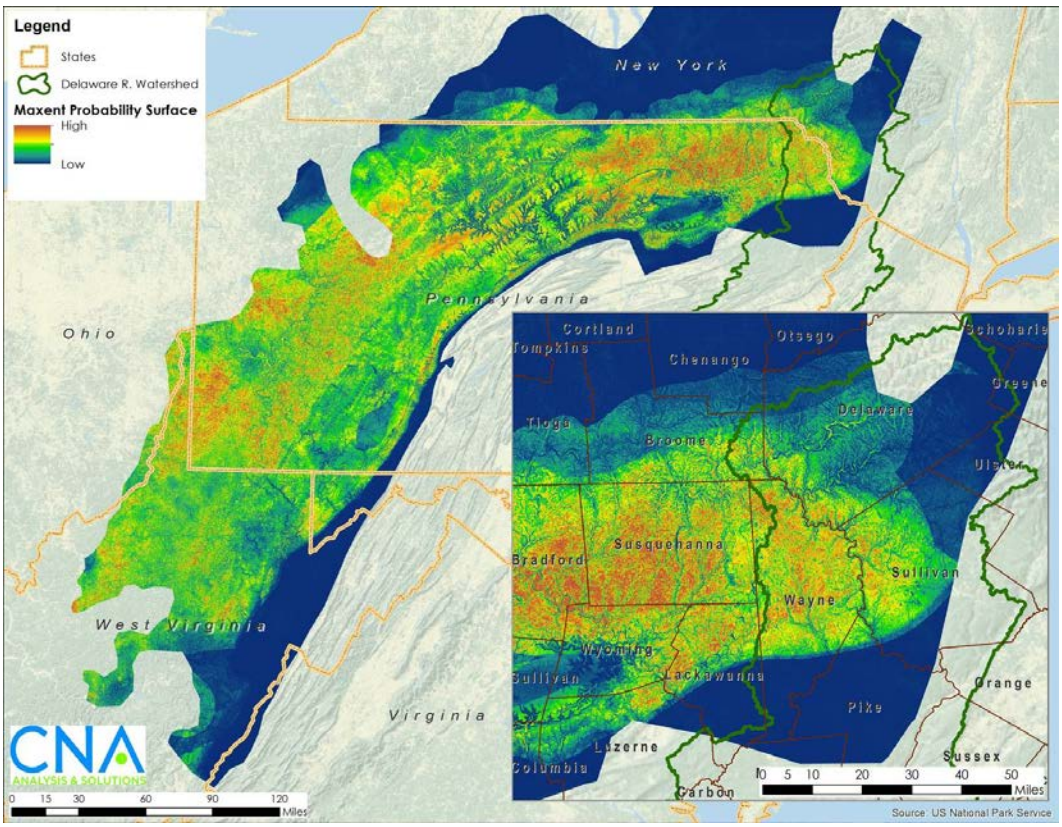
Well-Location Modeling

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.

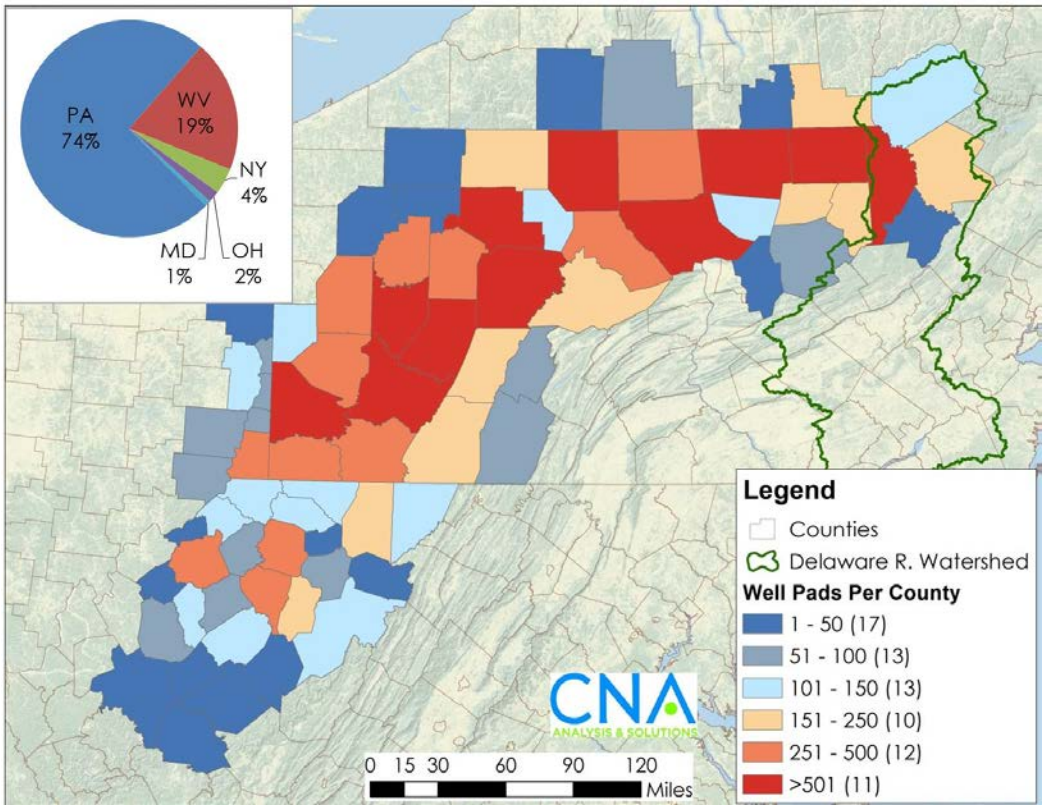
After developing the probability surface and scenarios, we devised a methodology to analyze the probability surface and choose the most likely locations for natural gas well pads. First, we used GIS tools to exclude areas in the probability map that would most likely be prohibited from development (e.g., 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

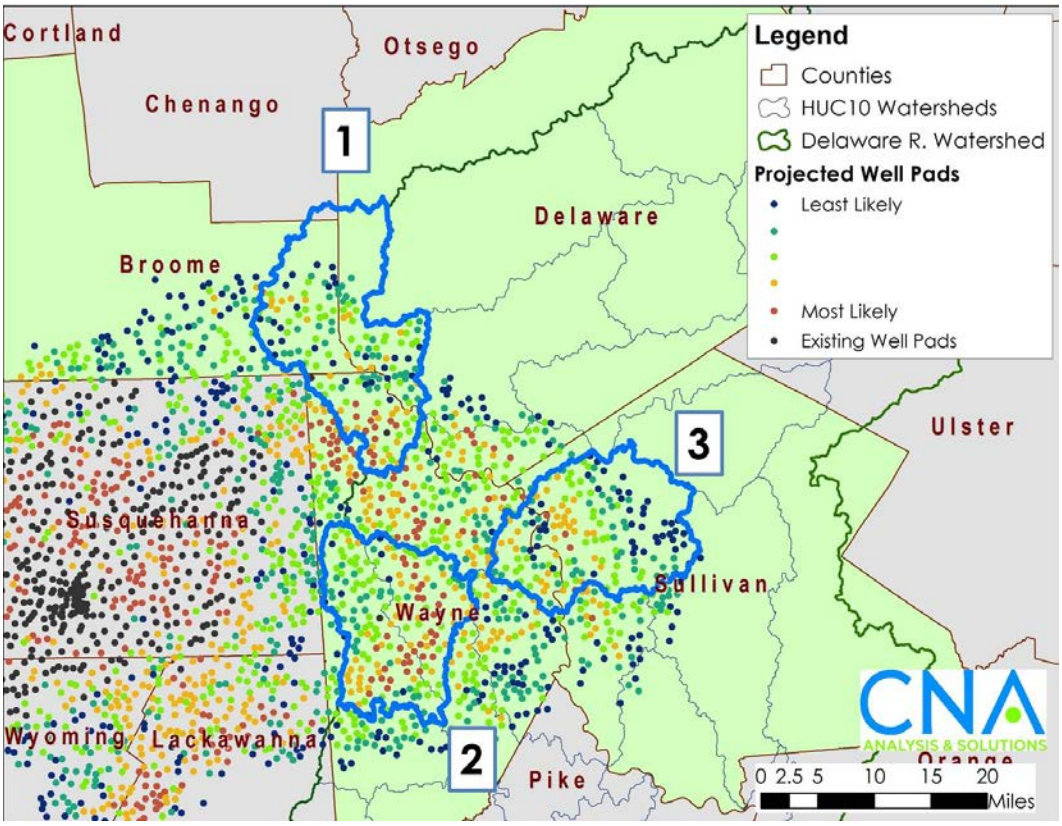
Figure 4 shows an expanded view of the potential landscape of natural gas development in the DRB, based on our development projection using the "dispersed" scenario. The well pads are color-coded according to their potential for development, again using the warm-to-cool scale to indicate most to least 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

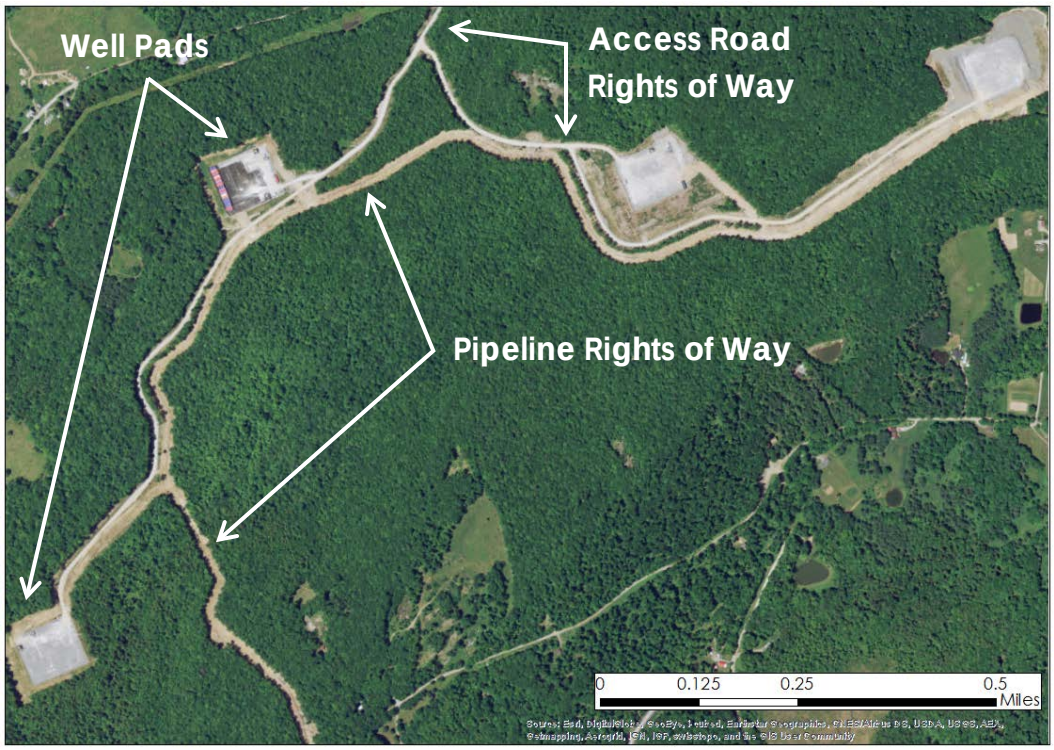
Key Findings

- 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.

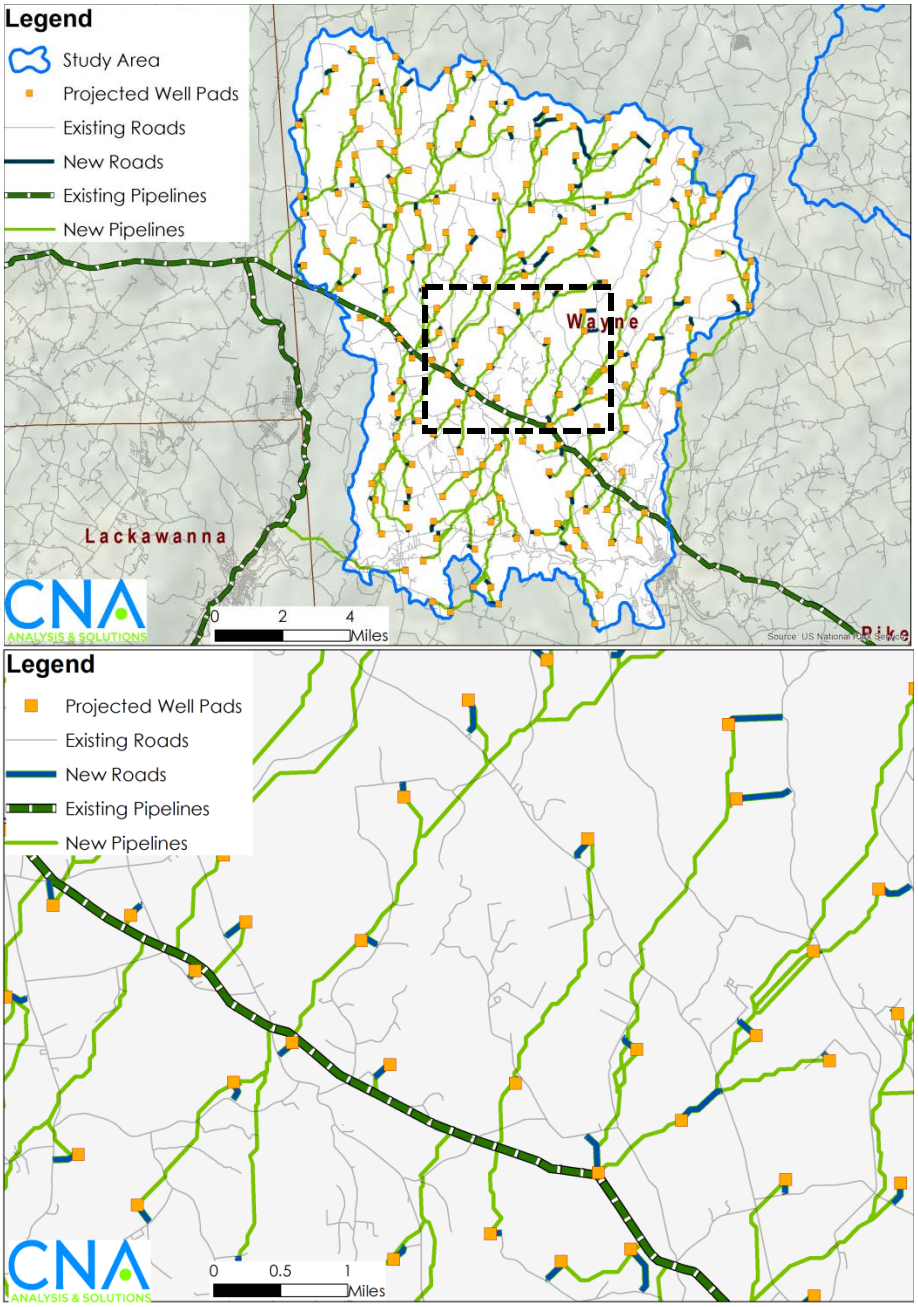
Given the prevalence of forest cover in the DRB and the potential for impact, we extended our land cover analysis to focus on the extent of forest fragmentation caused by this disturbance. To assess this impact, we calculated the baseline total area of forest in each study area through GIS analysis of 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

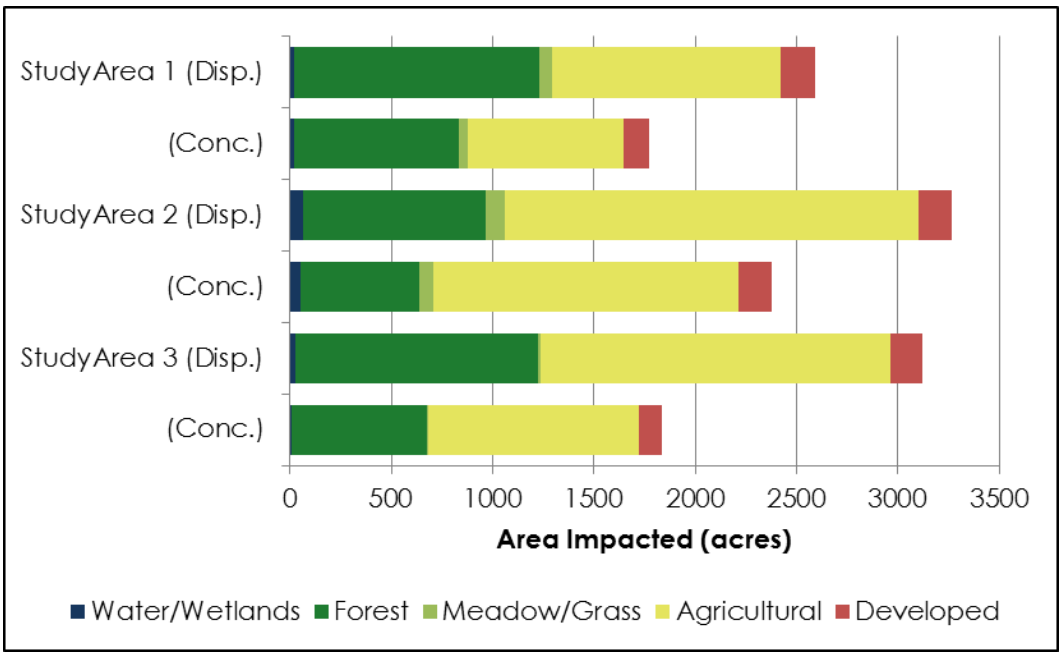
Our infrastructure modeling results compare favorably to recent retrospective studies on Marcellus Shale infrastructure development in Bradford County, PA [29-30]. For pipelines, the average length to support a well pad dropped by 26 percent from the "concentrated" to "dispersed" scenarios, which may 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.

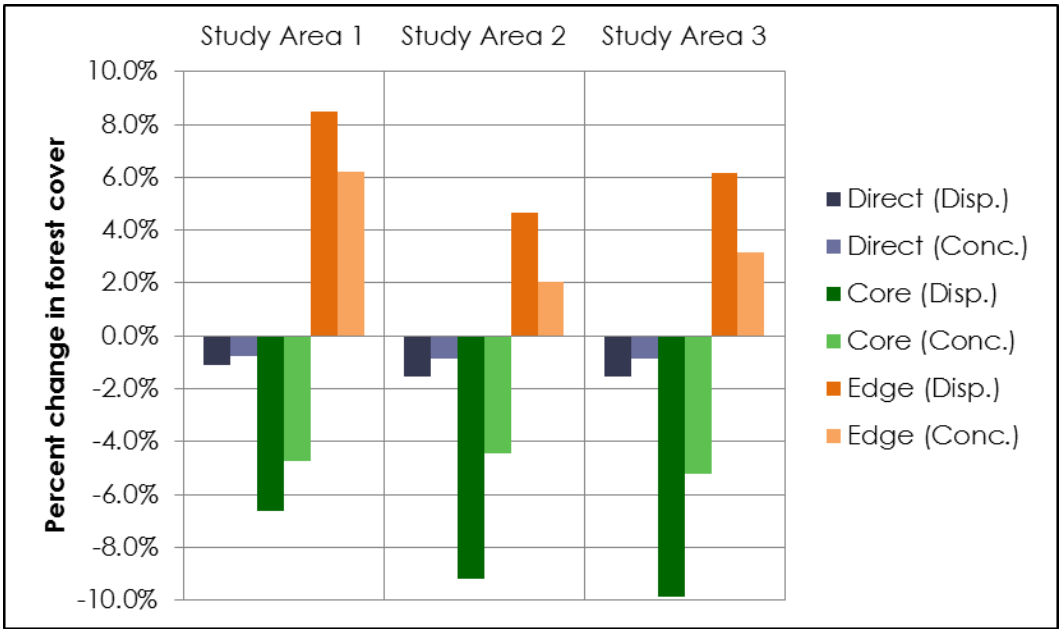
We also determined the number of stream and wetland crossings that could be encountered from development of supporting infrastructure. From our GIS analysis, we found an average of 115 stream crossings and 130 wetland crossings from new pipelines in each study area, and an average of 12 stream and 10 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

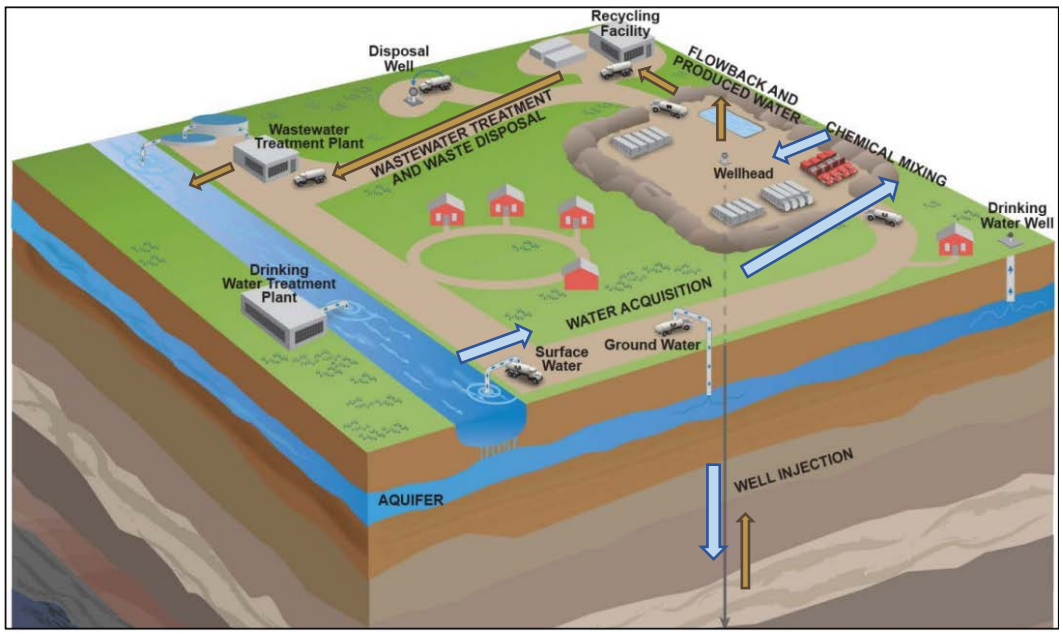
Key Findings

- 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.

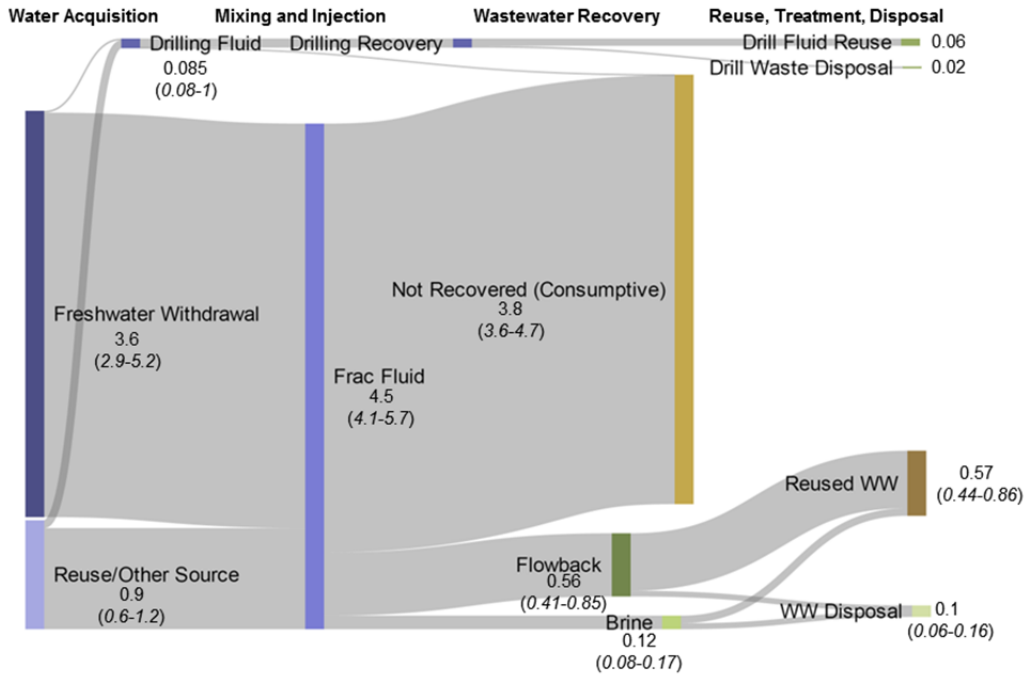


Figure by CNA via *SankeyMATIC*

[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).

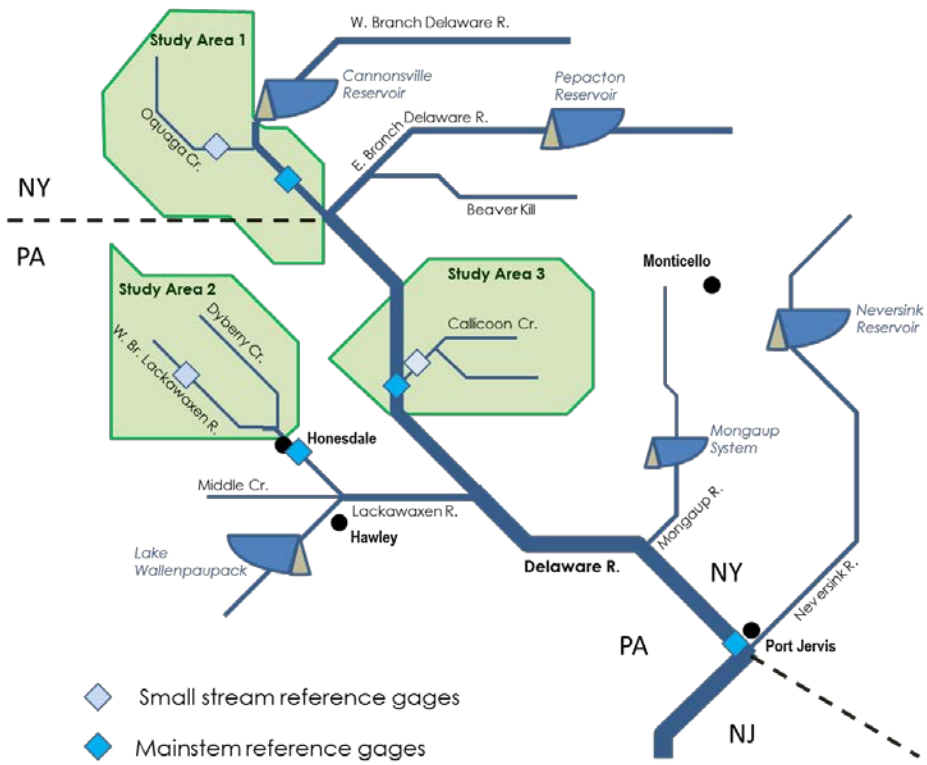
Impacts from Water Withdrawal

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.



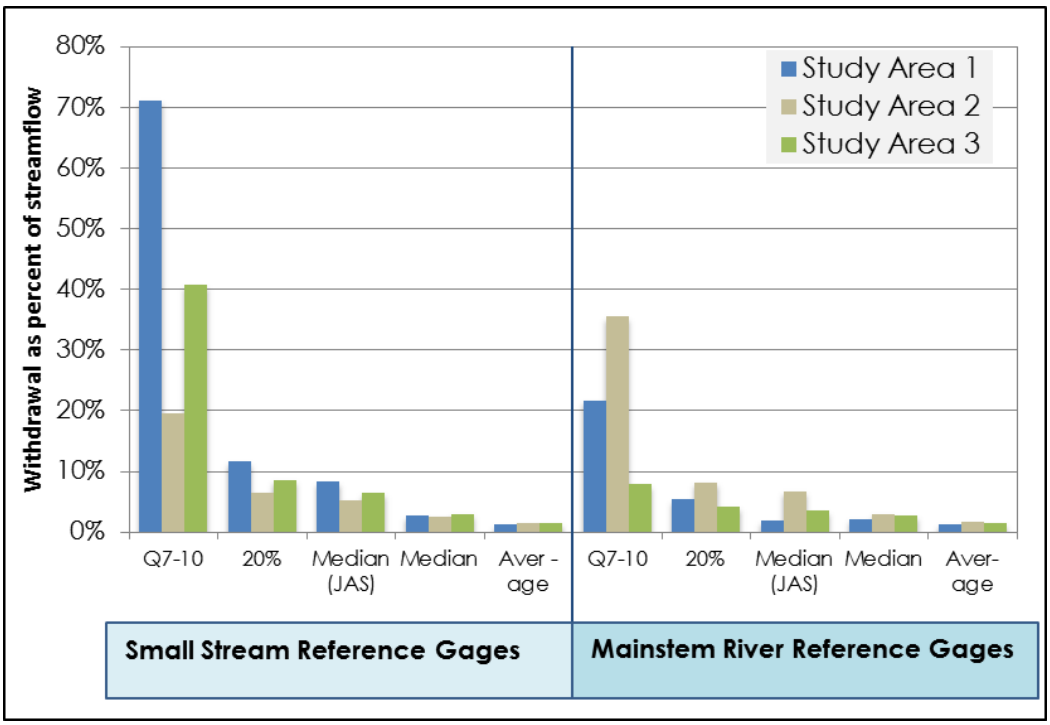
Note: The schematic is not to scale. Source: CNA.

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.

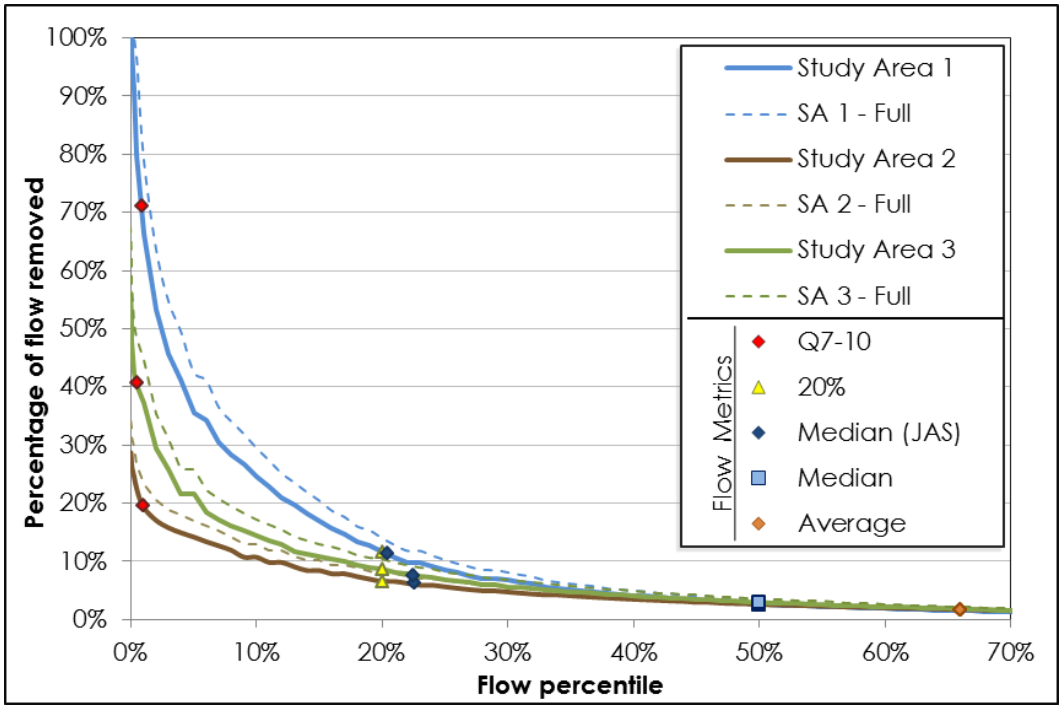
Figure 12. Withdrawals as percent of available streamflow for maximum-year development scenario. Shown for several flow metrics for both the small stream and mainstem gages. Withdrawals can take a high percentage of flow during low flow, when taken from small streams, and a lower percentage during average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

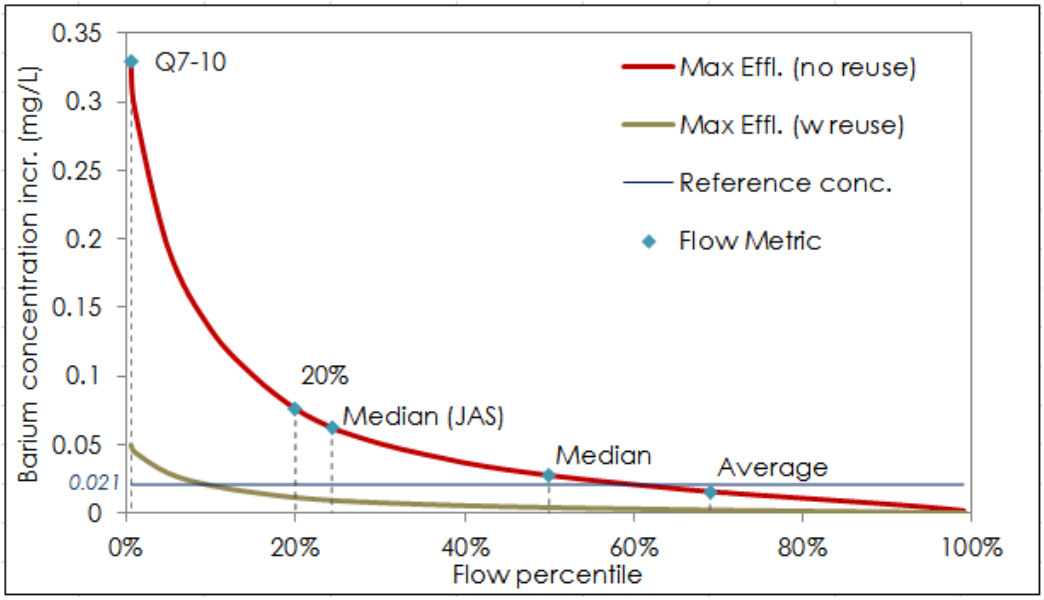
Note: TDS – Total dissolved solids, Cl – Chloride, SO_4 – Sulfate, Ba – Barium, Sr - Strontium

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

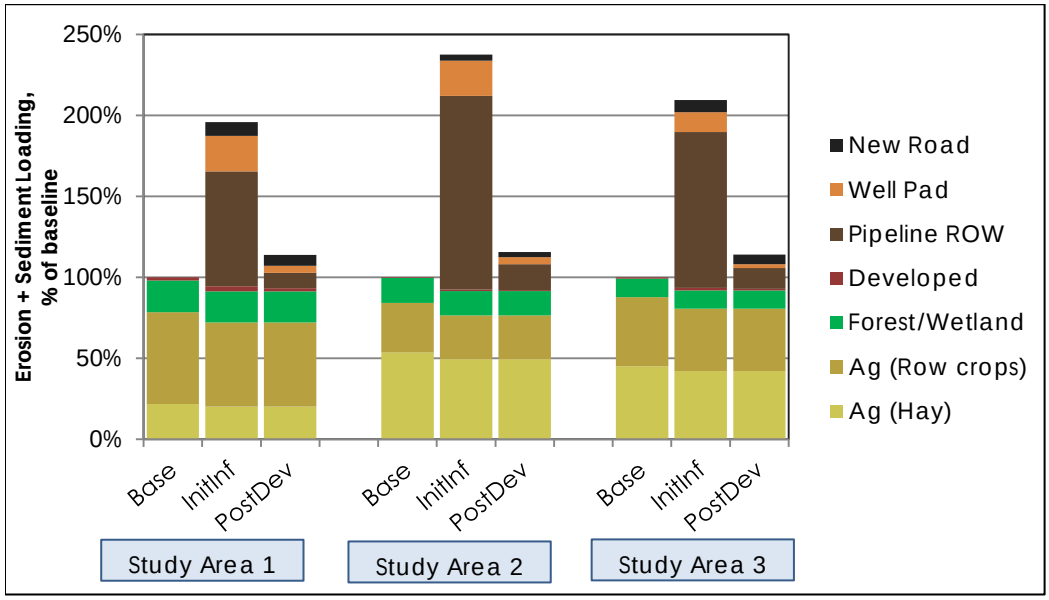
The hydrologic changes show increases in runoff of 1–3 percent, with reductions in groundwater recharge of a few tenths of a percent. On a volume basis, however, these changes are nearly equal, so average yearly streamflow is nearly unchanged, but flow distribution changes. The flows increase (roughly 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.

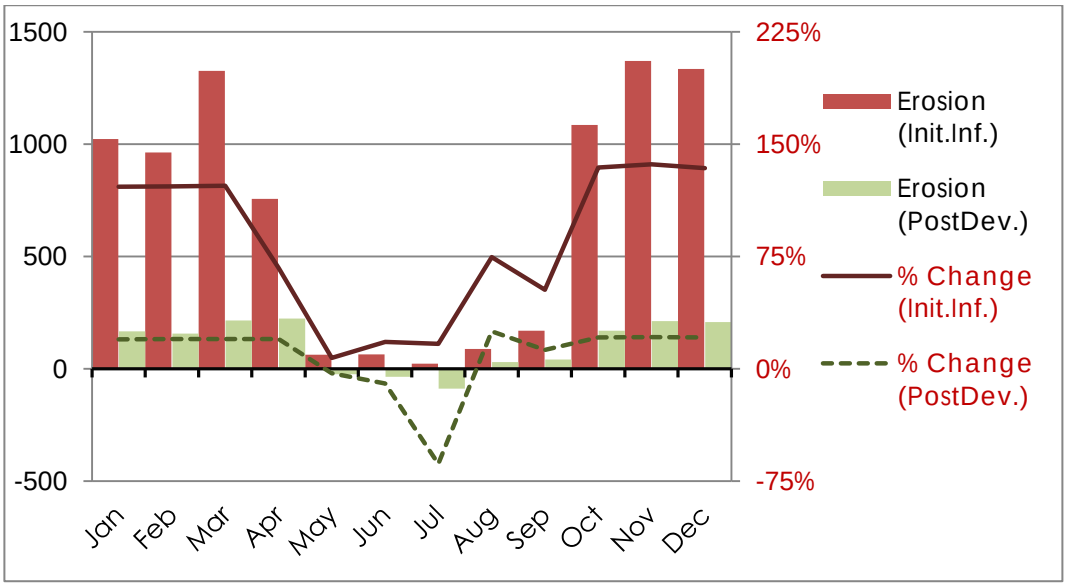
Figure 15. Total upland erosion plus sediment loading, as percent of the baseline loading. Increases in erosion and sedimentation are caused mainly by the pipeline rights-of-way and are more severe in the Initial Infrastructure ("InitInf") condition than the Post-Development ("PostDev") condition. Units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

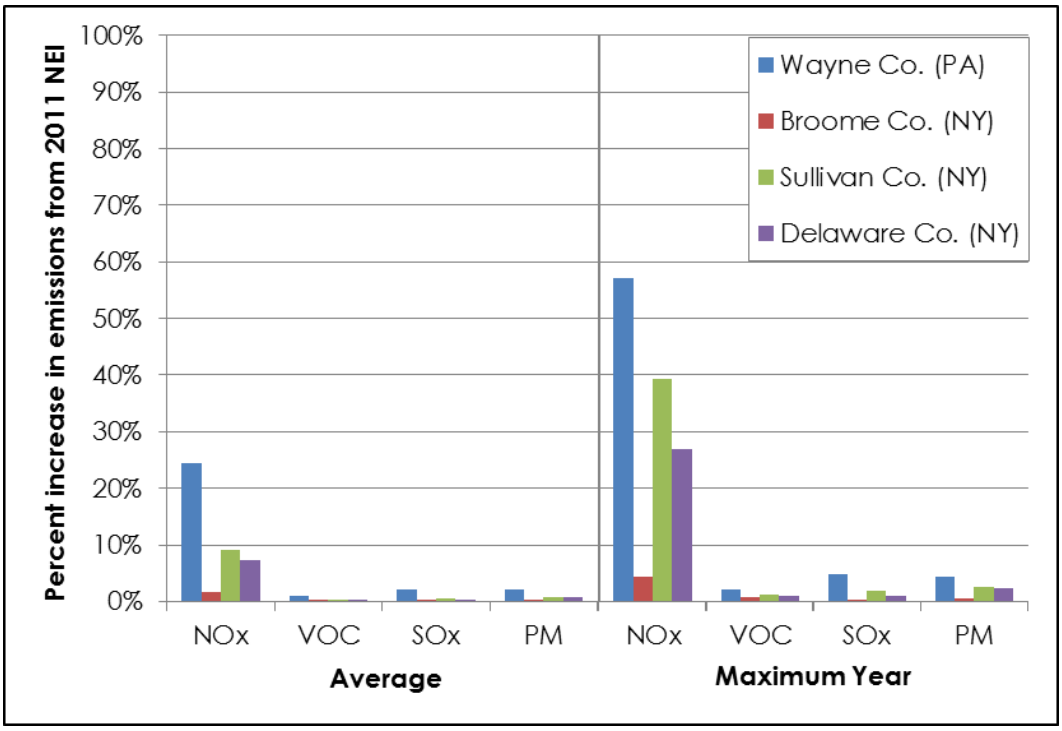
Table 10. Annual emissions estimates for projected natural gas development by county (and for one compressor station) in the DRB. NO_x emissions would be the largest contributor to air pollution by weight. Units = metric tons, unless noted otherwise.

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.



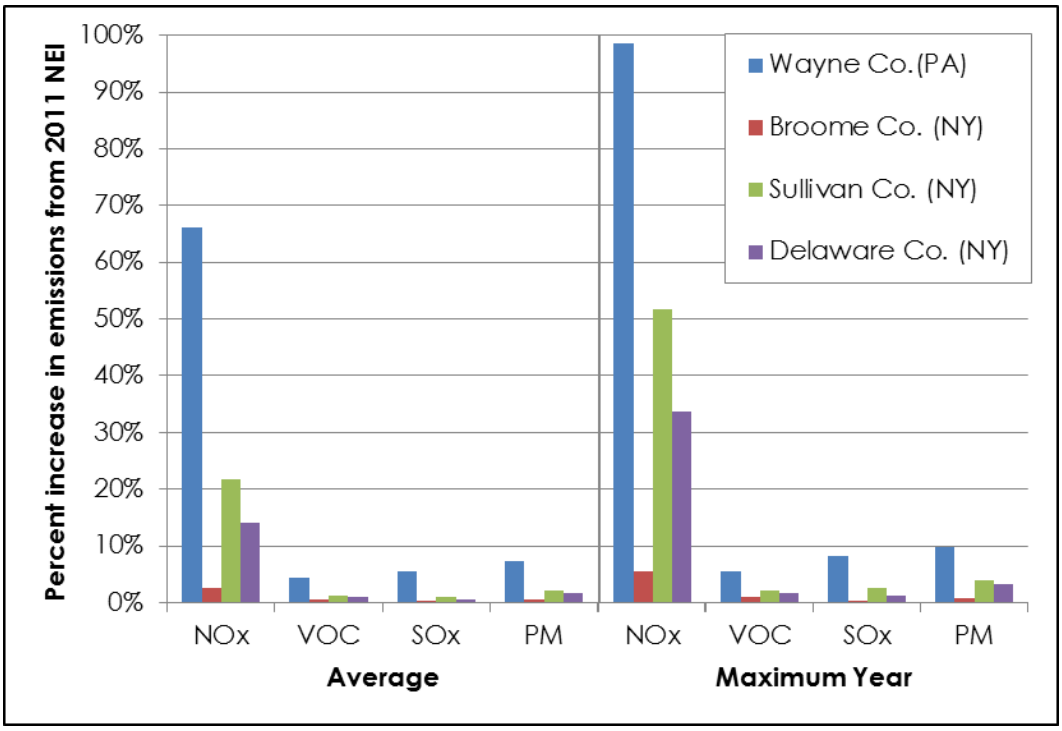
We see noticeable potential increases in NO_x emissions for three of the four counties: Wayne County (PA) and Sullivan and Delaware Counties (NY) could all see greater than a 27-percent increase in NO_x emissions under the maximum annual-development scenario. Under the average annual-development scenario, 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].

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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

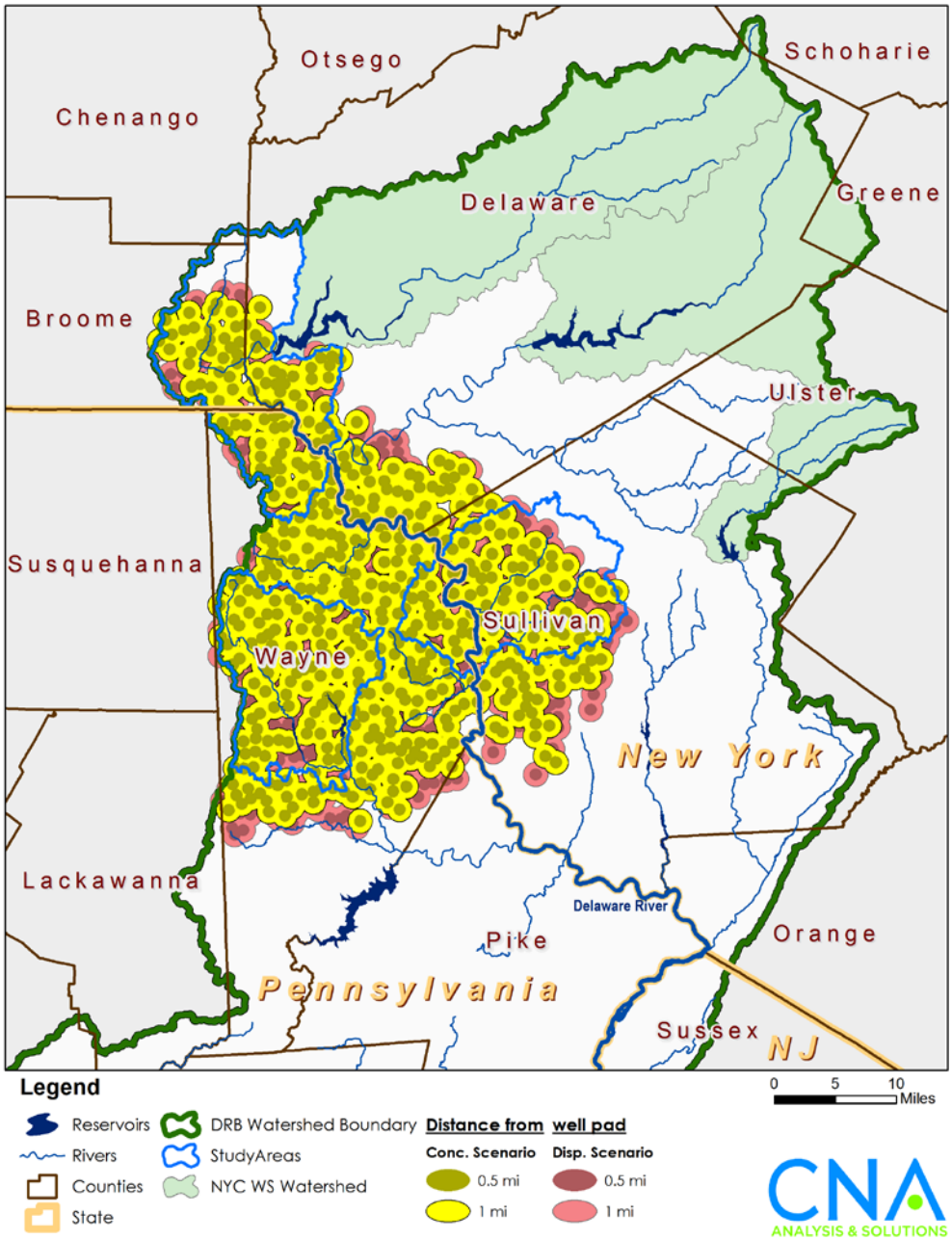
Until more rigorous data on health outcomes, exposure pathways, risk of exposure, and expected dosages become available, it is difficult to perform a detailed assessment of health impact, especially in a prospective analysis. Furthermore, actual risks of exposure depend strongly on both industry practices 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

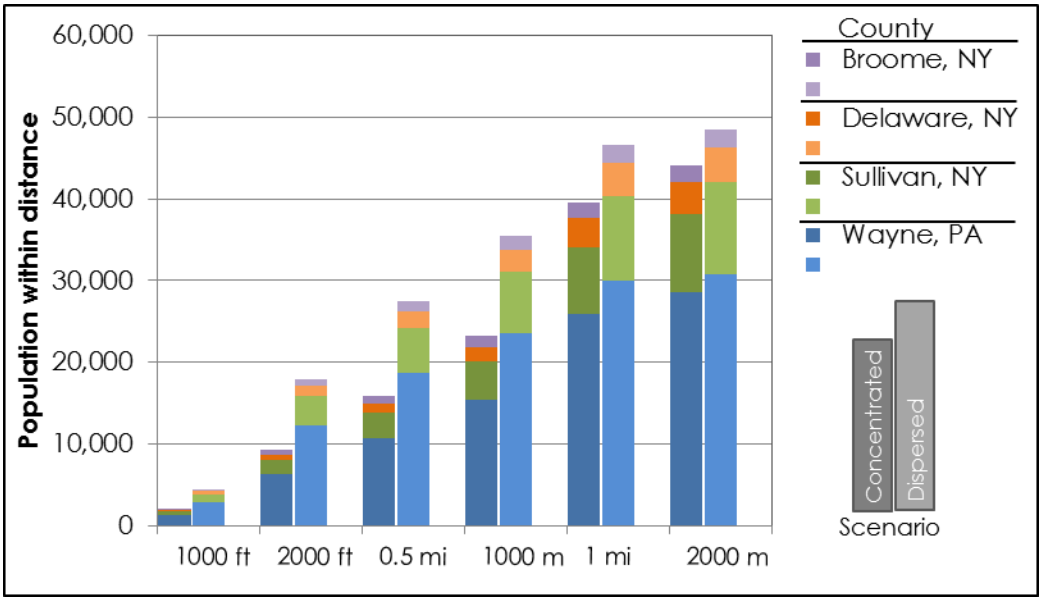
Hydraulic fracturing gas development with multiple wells per pad results in reasonably low overall well pad density, but fairly even distribution across the landscape. This even spacing results in large areas within reasonably short distances of the nearest wells. Figure 19 (previous page) illustrates 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.

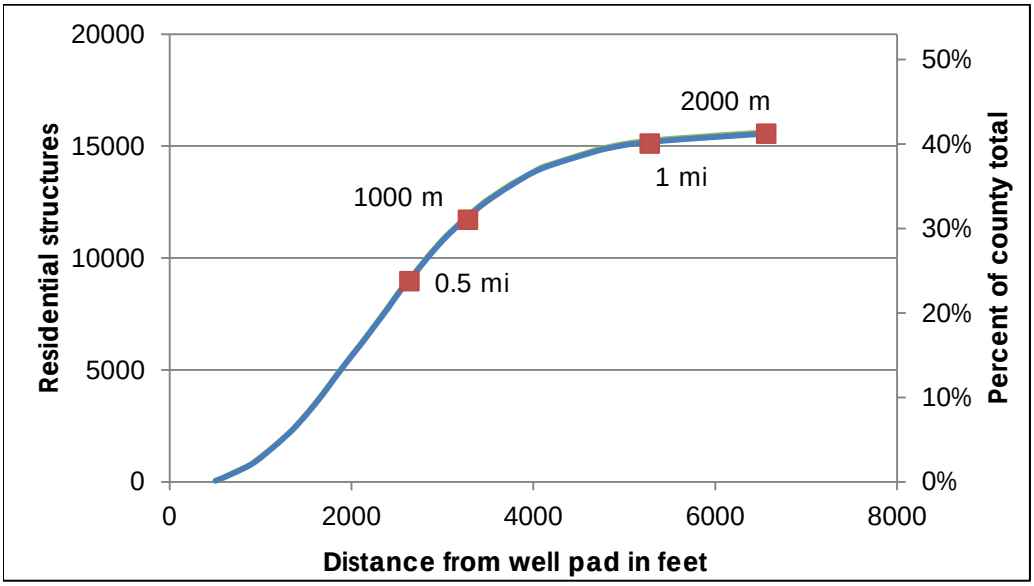
Figure 20. Population within several radii common to health-assessment literature. The population living within several distances (cited in health risk literature) of well pads depends on development scenario. At smaller distances, more people are affected with the "dispersed" scenario. Most of the population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

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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

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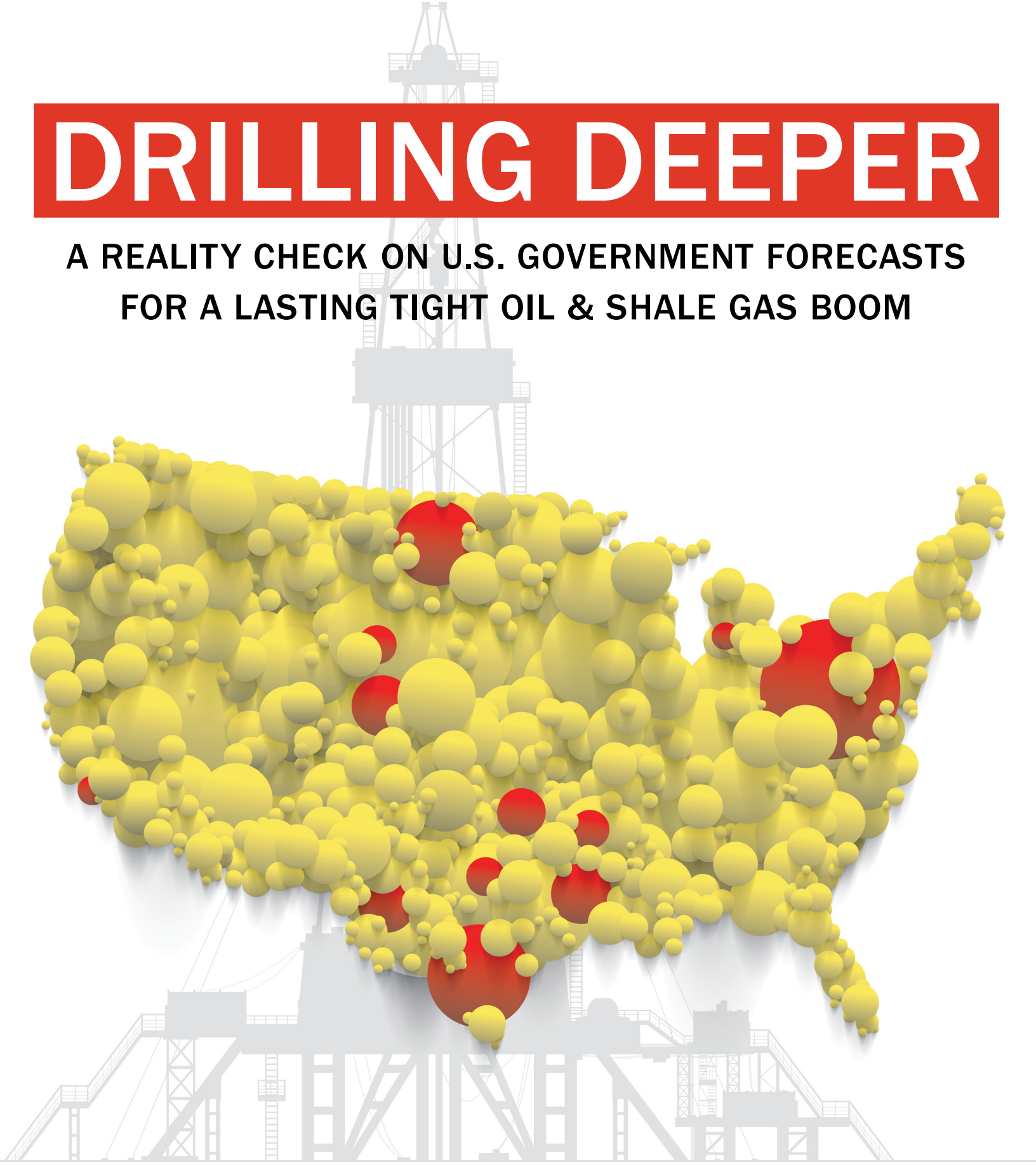

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Drilling Deeper

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By J. David Hughes

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About the Author

David Hughes is a geoscientist who has studied the energy resources of Canada for four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He developed the National Coal Inventory to determine the availability and environmental constraints associated with Canada's coal resources. As Team Leader for Unconventional Gas on the Canadian Gas Potential Committee, he coordinated the publication of a comprehensive assessment of Canada's unconventional natural gas potential. Over the past decade, Hughes has researched, published, and lectured widely on global energy and sustainability issues in North America and internationally.

In 2011, Hughes authored a series of papers on the production potential and environmental impacts of U.S. natural gas. In early 2013, he authored *Drill, Baby, Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*, which took a far-ranging and painstakingly researched look at the prospects for various unconventional fuels to provide energy abundance for the United States in the 21st century. In late 2013 he authored *Drilling California: A Reality Check on the Monterey Shale*, which critically examined the U.S. Energy Information Administration's (EIA) estimates of technically recoverable tight oil in the Monterey Shale, which the EIA claimed constituted two-thirds of U.S. tight oil; the EIA subsequently wrote down its resource estimate for the Monterey by 96%. In early 2014 he authored *BC LNG: A Reality Check*, which examined the issues surrounding the proposed massive scale up of shale gas production in British Columbia for LNG export.

Hughes is president of Global Sustainability Research, a consultancy dedicated to research on energy and sustainability issues. He is also a board member of Physicians, Scientists & Engineers for Healthy Energy (PSE Healthy Energy) and is a Fellow of Post Carbon Institute. Hughes contributed to *Carbon Shift*, an anthology edited by Thomas Homer-Dixon on the twin issues of peak energy and climate change, and his work has been featured in *Nature*, *Canadian Business*, *Bloomberg, USA Today*, as well as other popular press, radio, and television.

About Post Carbon Institute

Post Carbon Institute's mission is to lead the transition to a more resilient, equitable, and sustainable world by providing individuals and communities with the resources needed to understand and respond to the interrelated economic, energy, and ecological crises of the 21st century.

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Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Tight Oil & Shale Gas Boom
By J. David Hughes
In association with Post Carbon Institute

For reprint requests and other inquiries, contact:
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Abstract

Drilling Deeper reviews the twelve shale plays that account for 82% of the tight oil production and 88% of the shale gas production in the U.S. Department of Energy's Energy Information Administration (EIA) reference case forecasts through 2040. It utilizes all available production data for the plays analyzed, and assesses historical production, well- and field-decline rates, available drilling locations, and well-quality trends for each play, as well as counties within plays. Projections of future production rates are then made based on forecast drilling rates (and, by implication, capital expenditures). Tight oil (shale oil) and shale gas production is found to be unsustainable in the medium- and longer-term at the rates forecast by the EIA, which are extremely optimistic.

This report finds that tight oil production from major plays will peak before 2020. Barring major new discoveries on the scale of the Bakken or Eagle Ford, production will be far below the EIA's forecast by 2040. Tight oil production from the two top plays, the Bakken and Eagle Ford, will underperform the EIA's reference case oil recovery by 28% from 2013 to 2040, and more of this production will be front-loaded than the EIA estimates. By 2040, production rates from the Bakken and Eagle Ford will be less than a tenth of that projected by the EIA. Tight oil production forecast by the EIA from plays other than the Bakken and Eagle Ford is in most cases highly optimistic and unlikely to be realized at the medium- and long-term rates projected.

Shale gas production from the top seven plays will also likely peak before 2020. Barring major new discoveries on the scale of the Marcellus, production will be far below the EIA's forecast by 2040. Shale gas production from the top seven plays will underperform the EIA's reference case forecast by 39% from 2014 to 2040, and more of this production will be front-loaded than the EIA estimates. By 2040, production rates from these plays will be about one-third that of the EIA forecast. Production from shale gas plays other than the top seven will need to be four times that estimated by the EIA in order to meet its reference case forecast.

Over the short term, U.S. production of both shale gas and tight oil is projected to be robust—but a thorough review of production data from the major plays indicates that this will not be sustainable in the long term. These findings have clear implications for medium and long term supply, and hence current domestic and foreign policy discussions, which generally assume decades of U.S. oil and gas abundance.

Even as we've become less hooked on crude, we've become more addicted to drilling.

— Randy Udall (1951-2013)

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PART 1: EXECUTIVE SUMMARY

By Asher Miller, Executive Director, Post Carbon Institute

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PART 1: EXECUTIVE SUMMARY - FIGURES

1.1 Introduction

In recent years Americans have been hearing that the United States is poised to regain its role as the world's premier oil and natural gas producer, thanks to the widespread use of horizontal drilling and hydraulic fracturing ("fracking"). This "shale revolution," we're told, will fundamentally change the U.S. energy picture for decades to come—leading to energy independence, a rebirth of U.S. manufacturing, and a surplus supply of both oil and natural gas that can be exported to allies around the world. This promise of oil and natural gas abundance is influencing climate policy, foreign policy, and investments in alternative energy sources.

The primary source for these rosy expectations of future production is the U.S. Department of Energy (DOE). Each year the DOE's Energy Information Administration (EIA) releases its *Annual Energy Outlook* (AEO)[1], which provides a range of forecasts for energy production, consumption, and prices.

The 2014 AEO reference case projects U.S. crude oil production to rise to 9.6 million barrels of oil per day (MMbbl/d) in 2019 and slowly decline to 7.5 MMbbl/d by 2040, while natural gas production is projected to grow for at least the next 25 years and hit 37.5 trillion cubic feet per year in 2040. Tight oil (shale oil) and shale gas serve as the foundation for these optimistic forecasts.

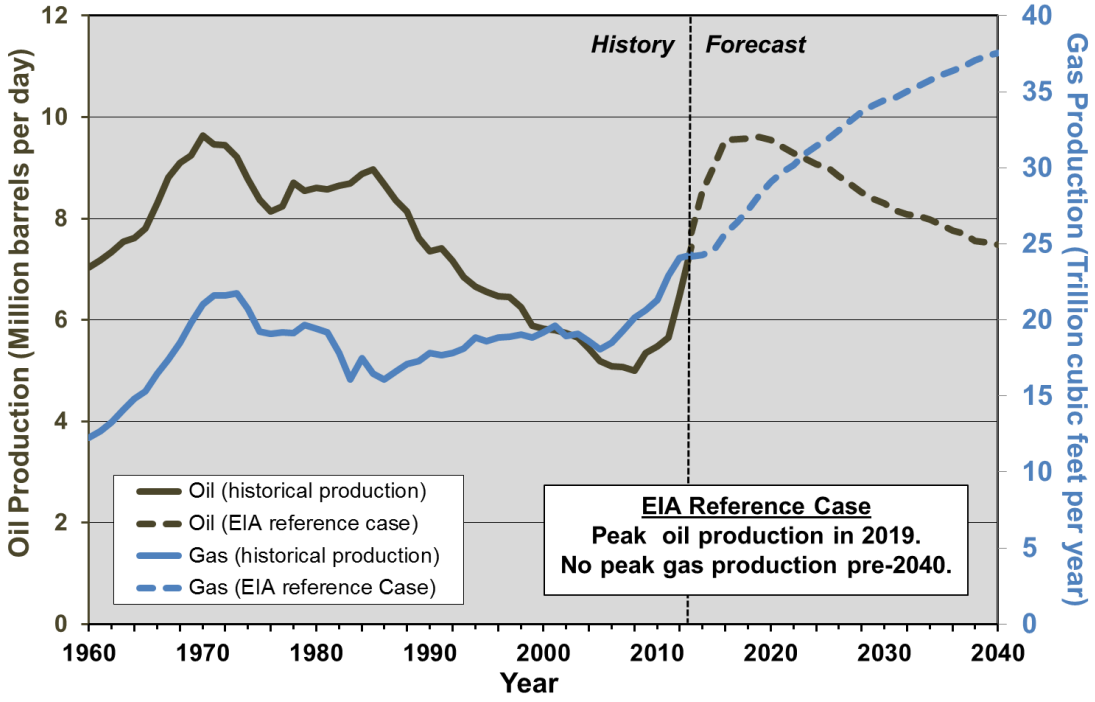


Figure 1-1. History and EIA reference case forecast of U.S. oil and natural gas production, 1960 to 2040.[2]

[1] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/.
[2] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/.

This report provides an extensive analysis of actual production data from the top seven tight oil and seven shale gas plays in the U.S. (These plays account for 89% of current tight oil production and 88% of current shale gas production, and serve as the primary sources of future production in the EIA's forecasts—82% of forecast tight oil and 88% of forecast shale gas production through 2040.) It concludes that the current boom in domestic oil and gas production is unsustainable at the rates projected by the EIA, and that the EIA's tight oil and shale gas forecasts to 2040 are extremely optimistic. What this means is that the country's current energy policy—which is largely based on the expectation of domestic oil and natural gas abundance far into the future—is badly misguided and is setting the country up for a painful, costly, and unexpected shock when the boom ends.

1.2 About the Report

Drilling Deeper: A Reality Check on U.S. Government Forecasts for a Lasting Shale Boom was authored by J. David Hughes on behalf of Post Carbon Institute. The report investigates whether the EIA's expectation of long-term domestic oil and natural gas abundance is founded. It aims to gauge the likely future of U.S. tight oil and shale gas production based on an in-depth assessment of actual well production data from the major shale plays. The primary source of data for this analysis is Drillinginfo, a commercial database of well production data widely used by industry and government, including the EIA.[3] Drillinginfo also provides a variety of analytical tools which proved essential for the analysis.

This analysis is based on all drilling and production data available through early- to mid-2014. The report determined future production profiles given assumed rates of drilling, average well quality by area, well- and field-decline rates, and the estimated number of available drilling locations. The plays analyzed (which collectively account for 89% of current tight oil production and 88% of current shale gas production) are as follows:

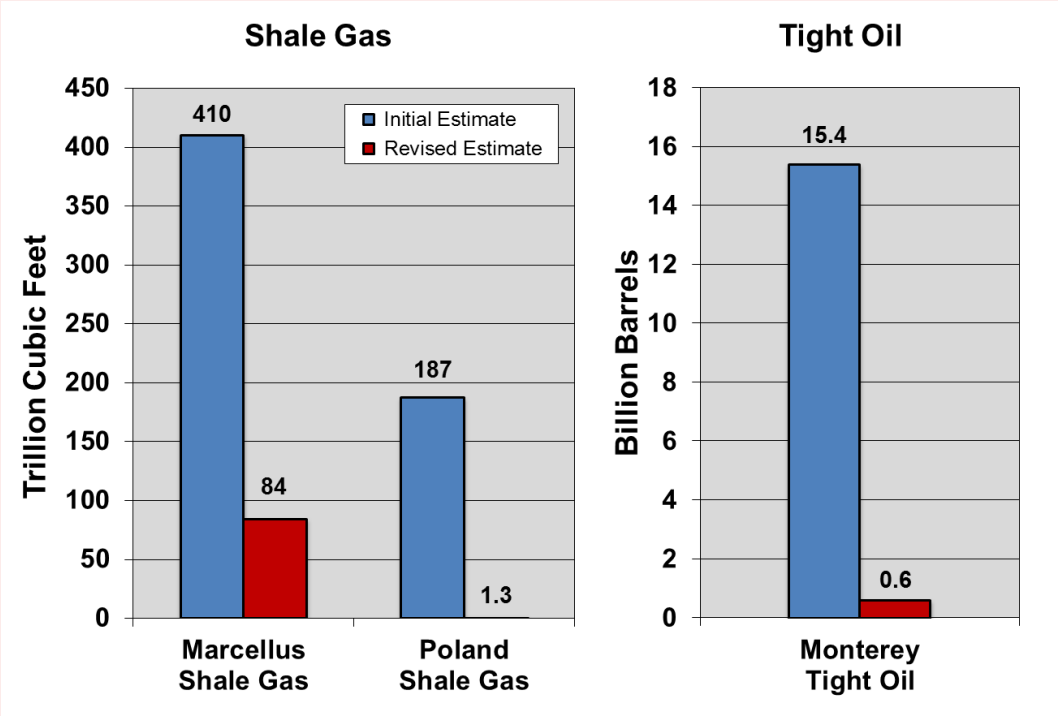
Tight Oil Plays[4]	Shale Gas Plays
Bakken (North Dakota and Montana)	Barnett (Texas)
Eagle Ford (Texas)	Haynesville (Louisiana and Texas)
Spraberry (Texas)	Fayetteville (Arkansas)
Wolfcamp (Texas and New Mexico)	Woodford (Oklahoma)
Bone Spring (Texas and New Mexico)	Marcellus (Pennsylvania and West Virginia)
Austin Chalk (Gulf Coast Region)	Bakken (North Dakota and Montana; associated gas)
Niobrara (Colorado and Wyoming)	Eagle Ford (Texas; associated gas)

[3] See http://info.drillinginfo.com.

[4] The Monterey tight oil play in California was assessed in a previous report by this same author: J. David Hughes, *Drilling California: A Reality Check on the Monterey Shale*, Post Carbon Institute, 2013, http://www.postcarbon.org/publications/drilling-california.

The EIA's Poor Track Record

Policymakers, media, investors, and the general public typically receive the Department of Energy's EIA forecasts with little to no circumspection, despite their poor track record. In 2011, the EIA was forced to cut its estimates of technically recoverable shale gas in the Marcellus play by 80%[1] and in Poland by 99%[2] after the United States Geological Survey came out with much lower numbers. At the time of the Marcellus downgrade, an EIA spokesperson said, "We consider the USGS to be the experts in this matter... They're geologists, we're not. We're going to be taking this number and using it in our model."[3] In early 2014, the EIA slashed its estimate of technically recoverable tight oil from California's Monterey Formation by a whopping 96%.[4] Just three years previously, the agency had estimated it held fully two-thirds of all U.S. tight oil. The author of the original EIA estimate, INTEK Inc., admitted that it had been derived from oil company presentations rather than hard data.[5] The EIA's downgrade occurred after this report's author, J. David Hughes, published an analysis six months earlier that showed—using actual production data from the Monterey Formation—that the EIA's estimates were wildly optimistic.[6]



Initial EIA estimates of shale resources vs. revised estimates.

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[1] Efstathiou, J. and Klimasinska, K., 23 August 2011, *Bloomberg* "U.S. to Slash Marcellus Shale Gas Estimate 80%," http://www.bloomberg.com/news/2011-08-23/u-s-to-slash-marcellus-shale-gas-estimate-80-.html.
[2] Blake, M., September/October 2014, *Mother Jones*, "How Hillary Clinton's State Department Sold Fracking to the World," http://www.motherjones.com/environment/2014/09/hillary-clinton-fracking-shale-state-department-chevron.
[3] Efstathiou, J. and Klimasinska, K., "U.S. to Slash Marcellus Shale Gas Estimate 80%."
[4] Sahagun, L., 20 May 2014, *Los Angeles Times*, "U.S. officials cut estimate of recoverable Monterey Shale oil by 96%," http://www.latimes.com/business/la-fi-oil-20140521-story.html.
[5] Kern Golden Empire, 3 December 2013, "Report: Monterey Shale production 'wildly optimistic'," http://www.kerngoldenempire.com/story/report-monterey-shale-production-wildly-optimistic/d/story/VdOYdQZ-4UKgp7qNwqq8Xg
[6] Hughes, J.D., 2013, *Drilling California: A Reality Check on the Monterey Shale*, Post Carbon Institute, http://www.postcarbon.org/publications/drilling-california.

1.3 Key Findings

The seven tight oil plays and seven shale gas plays analyzed in this report account for 82% of projected tight oil production and 88% of projected shale gas production through 2040 in the EIA's *Annual Energy Outlook 2014* reference case forecast. A detailed analysis of well production data from these plays resulted in these key findings:

1) Tight oil production from major plays will peak before 2020. Barring major new discoveries on the scale of the Bakken or Eagle Ford, production will be far below EIA's forecast by 2040.

    a) Tight oil production from the two top plays, the Bakken and Eagle Ford, will underperform EIA's reference case oil recovery by 28% from 2013 to 2040, and more of this production will be front-loaded than the EIA estimates.

    b) By 2040, production rates from the Bakken and Eagle Ford will be less than a tenth of that projected by EIA.

    c) Tight oil production forecast by the EIA from plays other than the Bakken and Eagle Ford is in most cases highly optimistic and unlikely to be realized at the rates projected.

2) Shale gas production from the top seven plays will likely peak before 2020. Barring major new discoveries on the scale of the Marcellus, production will be far below EIA's forecast by 2040.

    a) Shale gas production from the top seven plays will underperform EIA's reference case forecast by 39% from 2014 to 2040 period, and more of this production will be front-loaded than EIA estimates.

    b) By 2040, production rates from these plays will be about one-third that of the EIA forecast.

    c) Production from shale gas plays other than the top seven will need to be four times that estimated by EIA in order to meet its reference case forecast.

3) Over the short term, U.S. production of both shale gas and tight oil is projected to be robust—but a thorough review of the production data indicate that this will be unsustainable in the longer term. These findings have clear implications for current domestic and foreign policy discussions, which generally assume decades of U.S. oil and gas abundance.

Other factors that could limit production are public pushback as a result of health and environmental concerns, and capital constraints that could result from lower oil or gas prices or higher interest rates. As such factors have not been included in this analysis, the findings of this report represent a "best case" scenario for market, capital, and political conditions.

1.3.1 Tight Oil

The analysis shows that U.S. tight oil production cannot be maintained at the levels assumed by the EIA beyond 2020. The top two plays—Bakken and Eagle Ford—which account for more than 60% of current production, are likely to peak by 2017 and the remaining plays will make up considerably less of future production than has been forecast by the EIA. Rather than a peak in 2021 followed by a gradual decline to slightly below today's levels by 2040, total U.S. tight oil production is likely to peak before 2020 and decline to a small fraction of today's production levels by 2040.

1.3.1.1 General Findings

- The 3-year average well decline rates in the seven plays analyzed for this report (which collectively provide 89% of current U.S. tight oil production) range from 60% to 91%.

- The high decline rates of tight oil wells in these plays means that 43% to 64% of their estimated ultimate recovery (EUR) is recovered in the first three years.

- Field declines from the Bakken and Eagle Ford are 45% and 38% per year, respectively (this compares to 5% per year for large conventional fields). This is the amount of production that must be replaced each year with more drilling in order to maintain production at current levels (field decline is made up of all wells in a play—old and new—and hence is lower than first-year well declines).

- Based on production history, drilling locations, and declining well quality, this report found that 98% of the EIA's projected production from these seven plays has a "high" or "very high" optimism bias.

Play	Average 3-Year Well Decline Rate	Optimism Bias Rating of EIA's Forecast
Bakken	85%	High
Eagle Ford	79%	High
Spraberry	60%	Very High
Wolfcamp	81%	High
Bone Spring	91%	Low
Austin Chalk	85%	Very High
Niobrara	90%	High

- The EIA assumes that the equivalent of 100% of proved reserves and between 65% and 85% of its "unproved technically recoverable tight oil resources" will be recovered by 2040 for the plays analyzed. Considering that unproved, technically recoverable resources have no price constraints and only loose geological constraints, this is highly speculative.

- The EIA assumes that the U.S. will exit 2040 with tight oil production at levels only marginally less than today, at 3.2 MMbbl/d. A thorough analysis of the well production data suggests this is highly optimistic.

1.3.1.2 Forecasts for Bakken & Eagle Ford Tight Oil Plays

- The EIA's forecast of the timing of peak production in the Bakken and Eagle Ford is similar to this report, as is the rate of peak production.
- The EIA forecasts a much higher tail after peak production, with recovery of 19.2 billion barrels between 2012 and 2040, as opposed to 13.9 billion barrels forecast in this report.
- The EIA forecasts collective production from the Bakken and Eagle Ford to be a little over 1 million barrels per day in 2040. In contrast, the "Most Likely" drilling rate scenario presented in this report forecasts that production will fall to about 73,000 barrels per day by 2040.

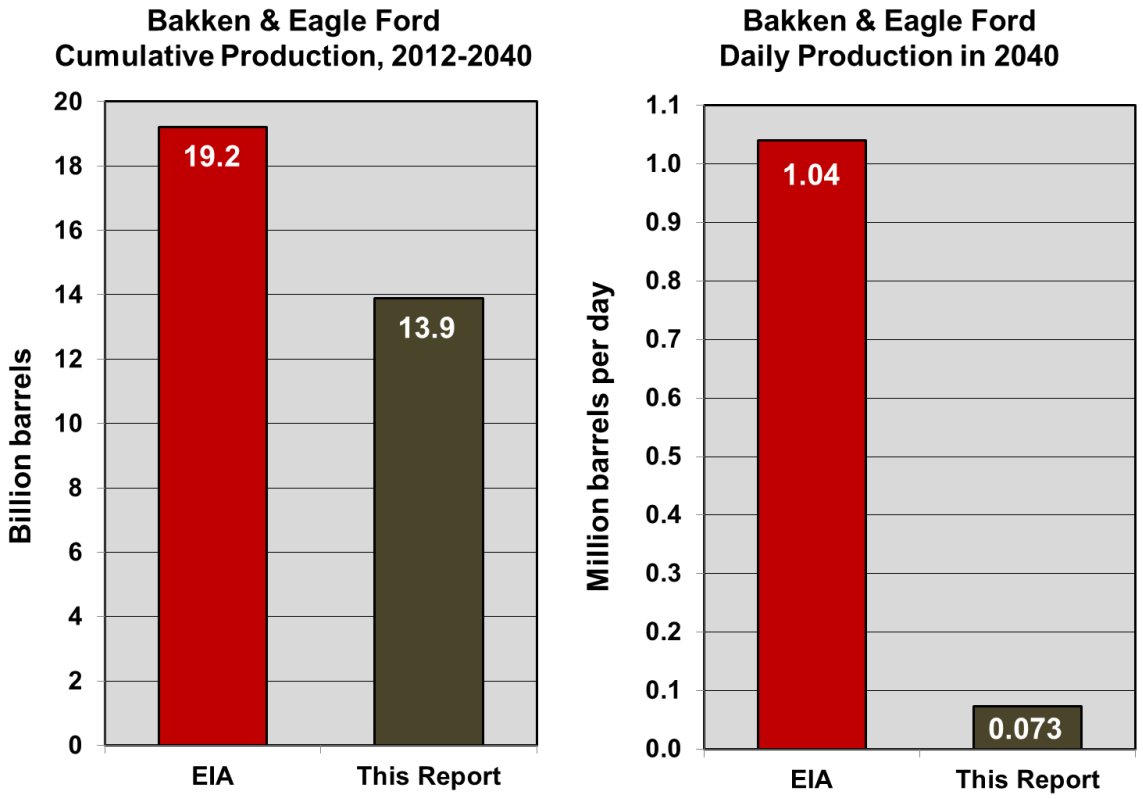

Figure 1-2. Bakken and Eagle Ford plays projected cumulative oil production from 2012 to 2040 and daily oil production in 2040, EIA projection[5] versus this report's projection.

[5] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

1.3.1.3 Forecasts for Other Tight Oil Plays

- To meet the EIA's forecasts, all other plays together would need to produce over twice as much through 2040 as what is projected for the Bakken and Eagle Ford.

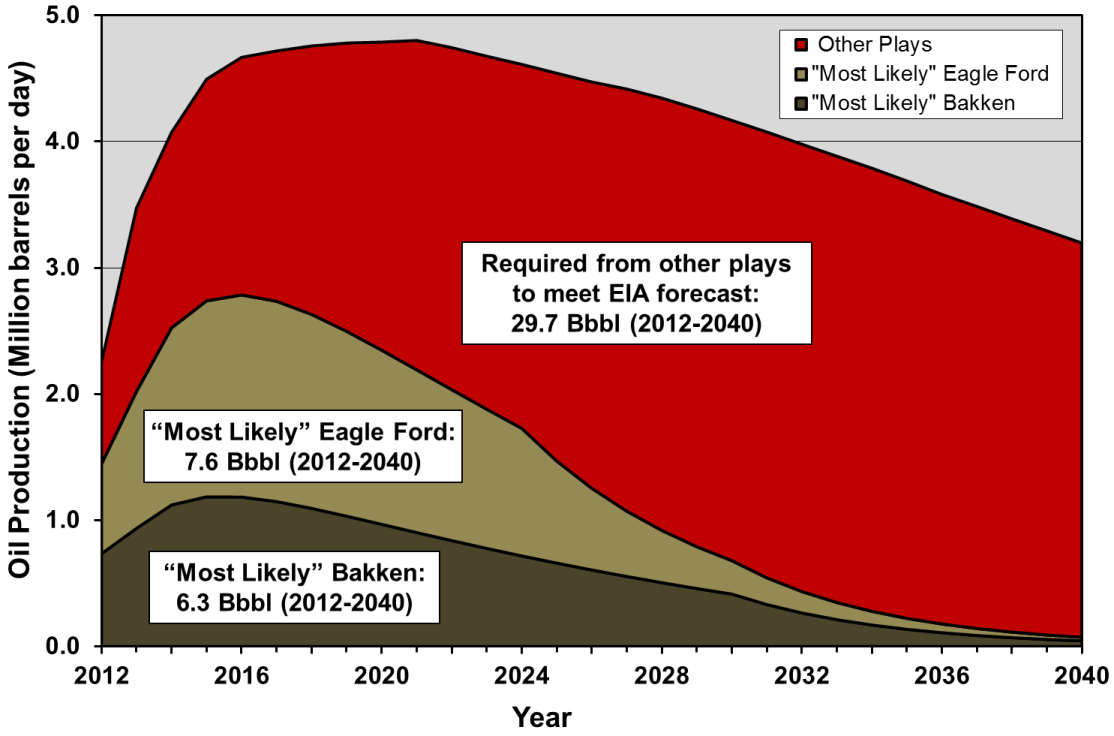

Figure 1-3. "Most Likely" scenario projections of oil production for the Bakken and Eagle Ford plays[6] with the remaining amount of production that would be required from other plays to meet the EIA's total reference case forecast.[7]

The EIA forecasts 43.6 billion barrels of U.S. tight oil will be recovered from 2012 to 2040. After subtracting the 13.9 billion barrels projected by this report for the Bakken and Eagle Ford, 29.7 billion barrels would remain to be produced from all other tight oil plays—5.3 billion barrels more than the EIA's already optimistic forecast for these plays.

[6] Data from Drillinginfo retrieved July 2014.
[7] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

- The major remaining tight oil plays are the three Permian Basin plays—Spraberry, Wolfcamp, and Avalon/Bone Spring—plus the Austin Chalk and the Niobrara. EIA forecasts expect these plays to produce four to five times their historical production in the next 26 years, but this is highly questionable, considering that:
  - These plays are already 40-60 years old, with tens of thousands of wells already drilled.
  - The Permian Basin plays' average initial well productivities are half or less the average of core counties in the Bakken or Eagle Ford.
  - The Bakken and Eagle Ford's average estimated ultimate recovery (EUR) per well is two to more than six times higher than that of these other plays.

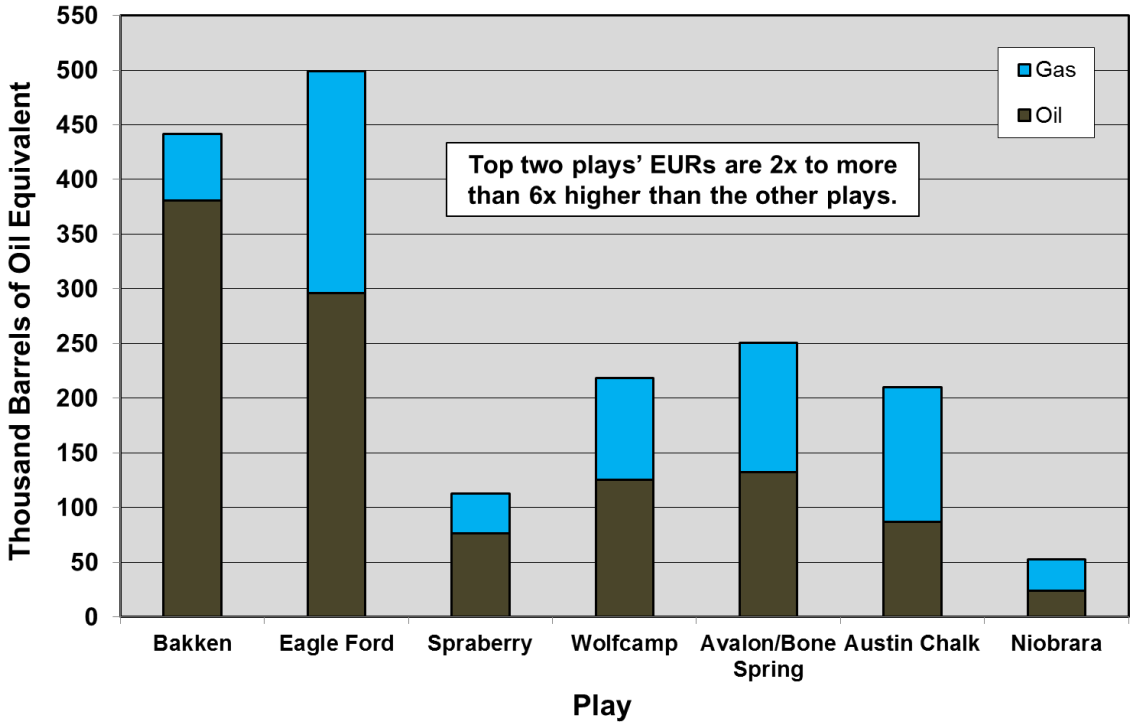

Figure 1-4. Estimated ultimate recovery (EUR) of oil and gas per well of reviewed plays, on a "barrels of oil equivalent" basis.[8]

The Bakken's and Eagle Ford's EURs per well are two to more than six times the EURs per well of the other five plays. If only horizontal wells are considered, the Bakken and Eagle Ford EURs per well are 39% to 141% higher than those of the other five plays (see discussion in Section 2).

[8] Based on data from Drillinginfo retrieved May-July 2014.

1.3.2 Shale Gas

The EIA now projects domestic gas production to reach nearly 38 trillion cubic feet per year by 2040, which is 55% above 2013 levels. The bulk of this production growth would come from shale gas.

This analysis shows that simply maintaining U.S. shale gas production in the medium term—let alone increasing production at rates forecast by the EIA through 2040—will be problematic. Four of the top seven shale gas plays are already in decline. Of the major plays, only the Marcellus, Eagle Ford, and Bakken (the latter two are tight oil plays producing associated gas) are growing; and yet, the EIA reference case gas forecast calls for plays currently in decline to grow to new production highs, at moderate future prices. Although significantly higher gas prices needed to justify higher drilling rates could temporarily reverse decline in some of these plays, the EIA forecast is unlikely to be realized.

1.3.2.1 General Findings

- The 3-year average well decline rates in the seven plays analyzed for this report (which collectively provide 88% of U.S. shale gas production) ranges between 74% and 82%.

- The average field decline rates for these plays ranges between 23% and 49%, meaning that between one-quarter and one-half of all production in each play must be replaced each year in order to simply maintain current production.

- Although the EIA forecast for the Marcellus play is rated as "reasonable" and its forecast for the Bakken play is rated "conservative," the deficit left by being "very highly optimistic" on some of the other plays makes finding and developing the gas required to meet the overall forecast unlikely.

Play	Average 3-Year Well Decline Rate	Average First-Year Field Decline Rate	Optimism Bias Rating of EIA's Forecast
Barnett	75%	23%	Very High
Haynesville	88%	49%	Very High
Fayetteville	79%	34%	Very High
Woodford	74%	34%	High
Marcellus	74-82%	32%	Reasonable
Eagle Ford	80%	47%	Very high
Bakken	81%	41%	Conservative

- Because productivity of shale wells declines rapidly, many new wells must be drilled just to maintain existing production levels. Of the top shale gas plays, only the Marcellus, Eagle Ford, and Bakken are currently seeing enough drilling to maintain and grow production.

- Major shale gas plays are variable in well quality. The Marcellus and Haynesville are much more productive on average than the other plays analyzed in this report. Even within plays, well quality varies considerably.

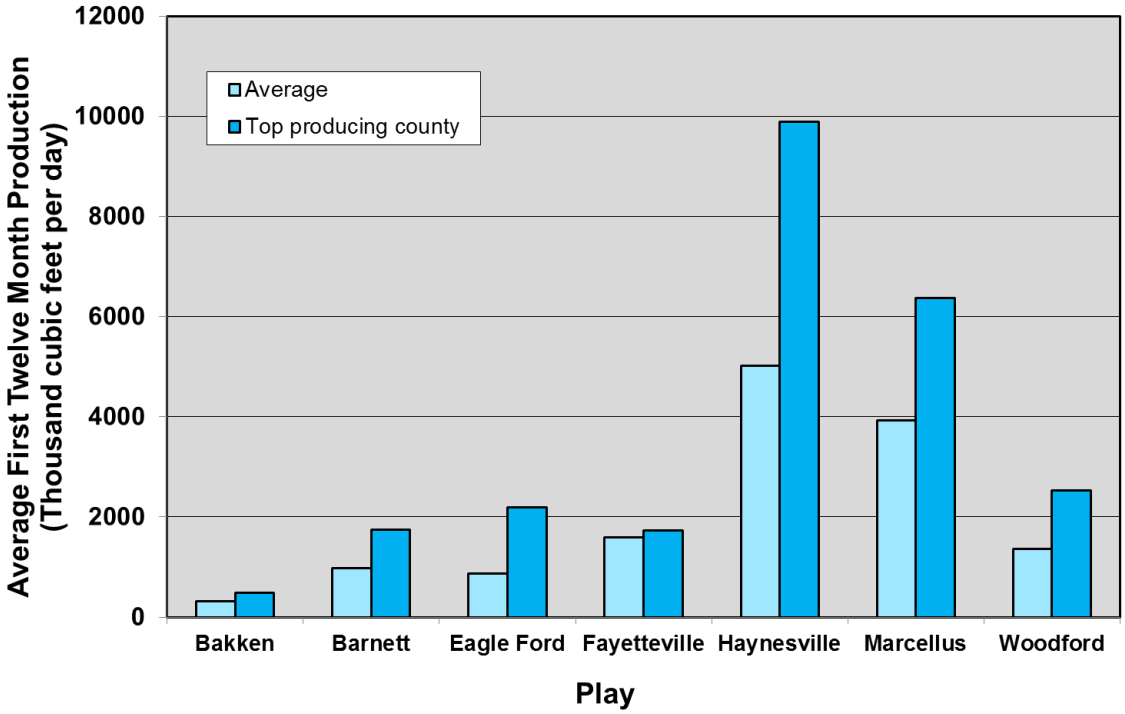

Figure 1-5. Average first-year gas production per well in 2013 from horizontal wells both play-wide and in the top-producing county for the plays analyzed in this report.[9]

[9] Data from Drillinginfo retrieved August to September 2014.

- Despite years of concerted efforts and claims that technological innovation can overcome steep well decline rates and the move from "sweet spots" to lower quality parts of plays, average well productivity has gone flat in all major shale gas plays except the Marcellus.

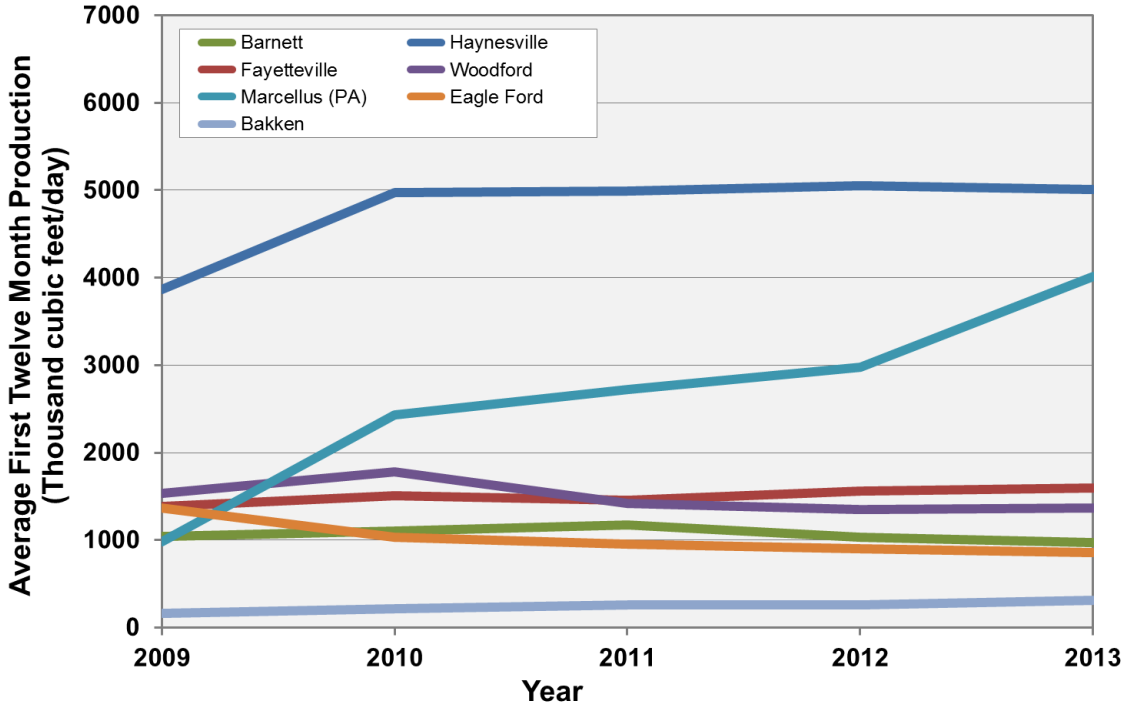

Figure 1-6. Average production over first twelve months per well for major U.S. shale gas plays.[10]

- Approximately 130,000 additional shale gas wells will need to be drilled by 2040 to meet the projections of this report, on top of the 50,000 wells drilled in these plays through 2013. Assuming an average well cost of $7 million, this would require $910 billion of additional capital input by 2040, not including leasing, operating, and other ancillary costs.

[10] Data from Drillinginfo retrieved August 2014.

1.3.2.2 Forecasts for Shale Gas Plays

- The EIA assumes that 74% to 110% of its "unproved technically recoverable resources" plus "proved reserves" will be recovered by 2040 for the seven major plays analyzed. Considering that unproved, technically recoverable resources have no price constraints and only loose geological constraints, this is highly speculative.

- This analysis found that the EIA reference case forecast for the top seven shale gas plays overestimates cumulative production through 2040 in this report's "Most Likely" scenario by 64%.

- The EIA further estimates that in 2040, shale gas production from the seven plays analyzed will be 182% higher (nearly 3 times) than estimated in this report—and that by 2040, another 49.6 Tcf will have been recovered from other plays not analyzed in this report.

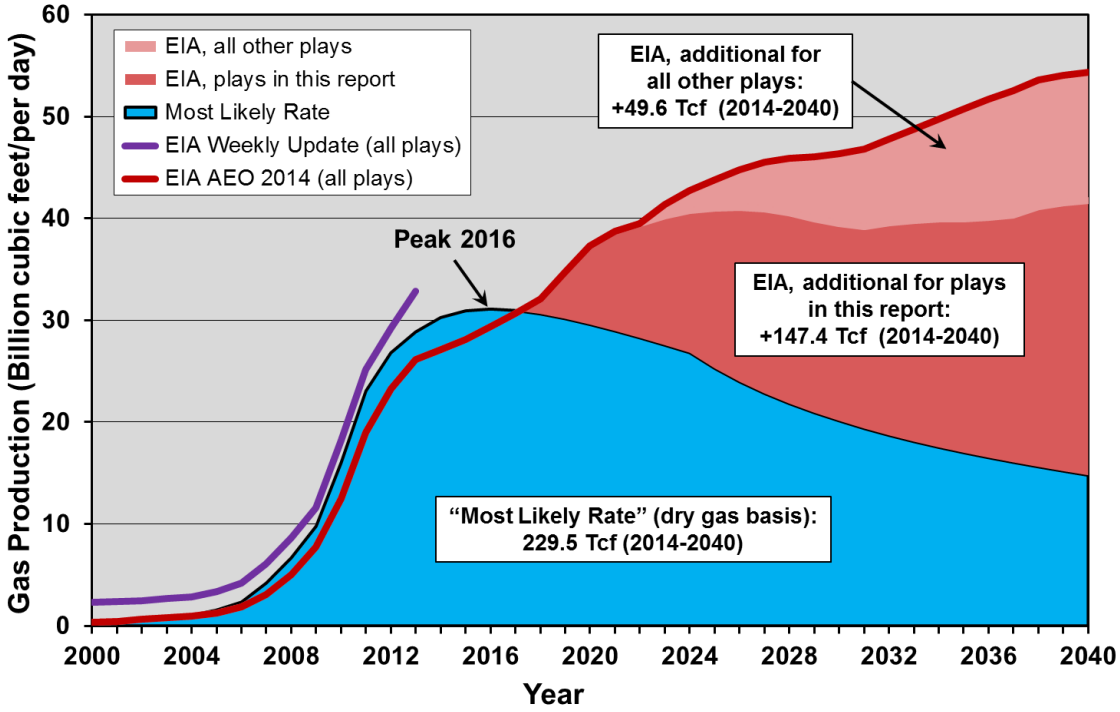

Figure 1-7. Totaled "Most Likely Rate" scenarios for the seven plays analyzed in this report, compared to the EIA's reference case forecast for these plays and for all plays.[11,12]

The "Most Likely Rate" scenario projections here are made on a "dry gas" basis. Also shown are the EIA's gas production statistics from its *Natural Gas Weekly Update*,[13] which contradict the early years of its AEO 2014 forecast.

[11] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[12] EIA, *Annual Energy Outlook 2014*, reference case forecast, Table 14, oil and gas supply, http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx.
[13] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly.

- In this report's "Most Likely" scenario, cumulative dry shale gas production over the 2014-2040 period is 229.5 trillion cubic feet (Tcf)—46% lower than the EIA Reference Case (377 Tcf).

- In this report's "Most Likely" scenario, shale gas production from the seven plays analyzed peaks in the 2016-2017 timeframe and declines by more than half, to 14.8 billion cubic feet per day (Bcf/d) by 2040. In contrast, the EIA expects production from these plays to keep growing through 2040, with shale gas production in that year at 41.8 Bcf/d—nearly three times higher than this report finds justifiable.

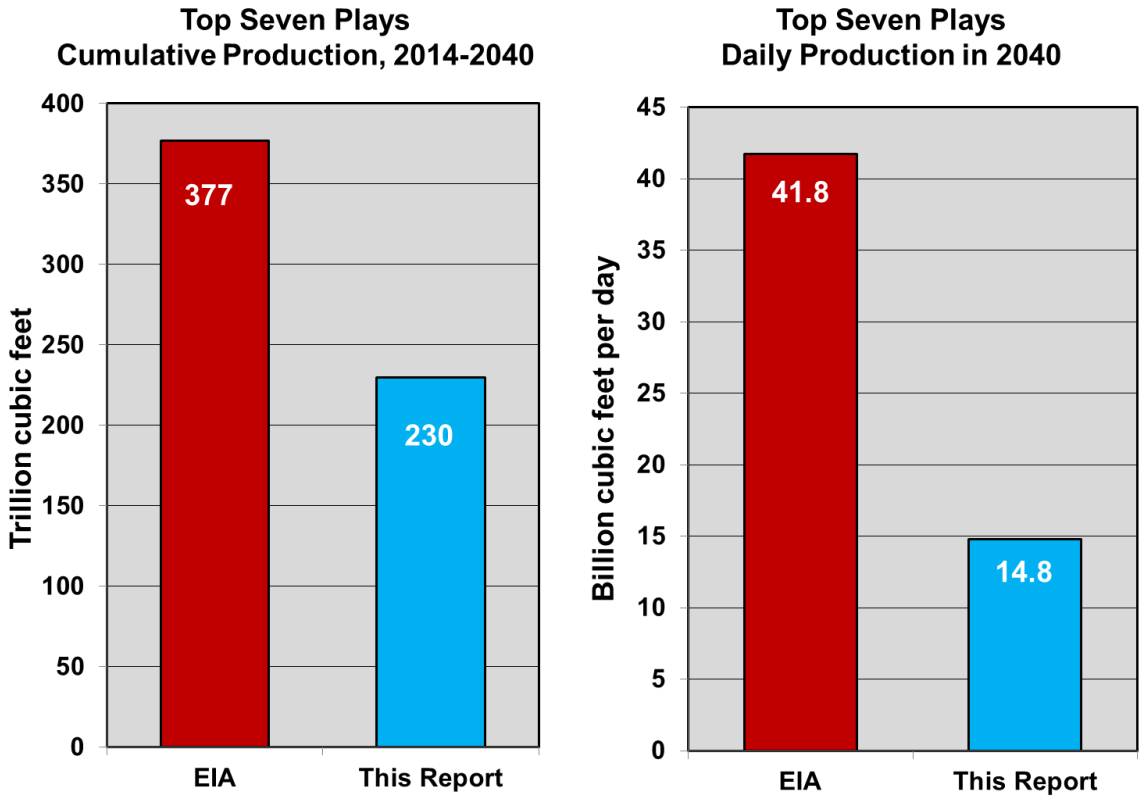

Figure 1-8. Projected cumulative gas production to 2040 and daily gas production in 2040, EIA projection[14] versus this report's projection.

The values given here are for the seven plays analyzed in this report. These plays constitute 88% of cumulative U.S. shale gas production from 2014 to 2040 in the EIA's reference case forecast.

[14] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

1.4 IMPLICATIONS

This report shows that the EIA's optimistic forecasts for future U.S. tight oil and shale gas production are based on a set of ***false premises***, namely that:

- High-quality shale plays are ubiquitous, and there will be always be new discoveries and production from emerging plays to fill the gap left by declining production from major existing plays.
- Technological advances can overcome steep decline rates and declining well quality as drilling moves from sweet spots to poorer quality rock, in order to maintain high production rates.
- Large estimated resources underground imply high and durable rates of extraction over decades.

Actual production data from the past decade of shale gas and tight oil drilling clearly do not support these assumptions. Unfortunately, the EIA's rosy forecasts have led policymakers and the American public to believe a number of ***false promises***:

- That cheap and abundant natural gas supplies can create a domestic manufacturing resurgence and millions of new jobs over the long term.[15]
- That abundant domestic oil and natural gas resources justify lifting the oil export ban (imposed 40 years ago after the Arab oil embargo)[16] and fast-tracking approval of liquefied natural gas (LNG) export terminals.[17]
- That the U.S. can use its newfound energy strength to shift geopolitical trends in our long-term favor.[18]
- That we can easily limit carbon dioxide emissions from power plants as a result of natural gas replacing coal as the primary source of electricity production.[19]

The promises associated with the expectation of robust and relatively cheap shale gas and high-cost but rising tight oil production have also led to a tempering of investments in renewable energy and nuclear power.[20] If, as this report shows, these premises and promises are indeed false, the implications are profound. It calls into question plans for LNG and crude oil exports and the benefits of the shale boom in light of the amount of drilling and capital investment that would be required, along with the environmental and health impacts associated with it. Conventional wisdom holds that the shale boom will last for decades, leaving the U.S. woefully unprepared for a painful, costly, and unexpected shock when the shale boom winds down sooner than expected. Rather than planning for a future where domestic oil and natural gas production is maintained at current or higher levels, we would be wise to harness this temporary fossil fuel bounty to quickly develop a truly sustainable energy policy—one that is based on conservation, efficiency, and a rapid transition to distributed renewable energy production.

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[15] Nelson Schwartz, "Boom in Energy Spurs Industry in the Rust Belt," *New York Times*, September 8, 2014, http://nyti.ms/1qHoxXz.
[16] Jay Fitzgerald, "Pressure builds to allow US exports of crude," *Boston Globe*, September 21, 2014, http://bit.ly/1uDI0sP.
[17] Amy Harder, "House Passes Bill Speeding Up Liquefied Natural-Gas Exports," *Wall Street Journal,* June 25, 2014, http://on.wsj.com/1lsgKqN.
[18] Robert Blackwill and Meghan O'Sullivan, "America's Energy Edge: The Geopolitical Consequences of the Shale Revolution," *Foreign Affairs,* March/April 2014, http://www.foreignaffairs.com/articles/140750/robert-d-blackwill-and-meghan-l-osullivan/americas-energy-edge.
[19] Isaac Arnsdorf, "Fracking Sucks Money From Wind While China Eclipses U.S.," Bloomberg, May 29, 2014, http://bloom.bg/1iu9Y3m.
[20] Ibid.

Part 2: Tight Oil

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PART 2: TIGHT OIL - TABLES

2.1 INTRODUCTION

2.1.1 Overview

The widespread adoption of hydraulic fracturing ("fracking") and horizontal drilling in the United States to extract oil and natural gas from previously inaccessible shale formations has been termed the "shale revolution." In just the last few years, U.S. oil production—universally held to be in terminal decline a mere decade ago—has grown rapidly and significantly thanks to oil produced from shales ("tight oil"). The U.S. Energy Information Administration (EIA) now projects domestic oil production to reach the previous 1970 peak of 9.6 million barrels per day (MMbbl/d) by 2019 and decline gradually to 7.5 MMbbl/d by 2040.[1]

The environmental, health, and quality of life impacts of shale development have stoked controversy across the country. In contrast, the expectation of long-term domestic oil abundance—driven by optimistic forecasts from industry and government—has been widely reported and little questioned, despite the myriad economic and policy consequences.

This report investigates whether the EIA's expectation of long-term domestic oil abundance is founded. It aims to gauge the likely future production of U.S. tight oil, based on an in-depth assessment of actual well production data from the major shale plays. It determines future production profiles given assumed rates of drilling, average well quality by area, well- and field-decline rates, and the estimated number of available drilling locations. This analysis is based on all drilling and production data available through early- to mid-2014.

The analysis shows that U.S. tight oil production cannot be maintained at the levels assumed by the EIA beyond 2020. The top two plays, which account for more than 60% of production, are likely to peak by 2017 and the remaining plays will make up considerably less of future production than has been forecast by the EIA. Rather than a peak in 2021 followed by a gradual decline to slightly below today's levels by 2040, U.S. tight oil is likely to peak before 2020 and decline to a small fraction of today's production levels by 2040. The analysis also underscores the amount of drilling, the amount of capital investment, and the associated scale of environmental and community impacts that will be required to meet these projections. These findings call into question plans for crude oil exports and highlight the real risks to long-term U.S. energy security.

[1] Per the EIA's "reference case" in *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

2.1.2 Methodology

This report analyzes the top two U.S. tight oil plays—the Bakken and the Eagle Ford—in depth, followed by an assessment of five additional tight oil plays that make up most of the balance of the EIA's tight oil forecasts in its 2014 Annual Energy Outlook (AEO 2014).

The Bakken and Eagle Ford are investigated in depth as they account for nearly two-thirds of U.S. tight oil production and now have an extensive drilling history with which to assess key parameters; the report develops projections of their likely production levels given various scenarios of drilling and investment. The other tight oil plays are assessed based on their drilling and production history in comparison to the EIA forecasts of future production; they differ from the Bakken and Eagle Ford in that most of them have a long history of conventional oil and gas production stretching back decades. In total, all these plays account for 82% of the 2014-2040 tight oil production in the EIA's reference case forecast, and hence provide a solid basis for assessing its credibility. The remaining 18% comes from a number of smaller plays whose ultimate contribution remains highly speculative.

The primary source of data for this analysis is Drillinginfo, a commercial database of well production data widely used by industry and government, including the EIA.[2] Drillinginfo also provides a variety of analytical tools which proved essential for the analysis.

A detailed analysis of well production data for the major tight oil plays reveals several fundamental characteristics that will determine future production levels:

1. **Rate of well production decline:** Tight oil plays have high well production decline rates, typically in the range of 80-85% in the first three years.

2. **Rate of field production decline:** Tight oil plays have high field production declines, typically in the range of 40-45% per year, which must be replaced with more drilling to maintain production levels. This compares to field declines in the range of 5-6% per year in major conventional oil fields.[3]

3. **Average well quality:** All tight oil plays invariably have "core" areas or "sweet spots", where individual well production is highest and hence the economics are best. Sweet spots are targeted and drilled off early in a play's lifecycle, leaving lesser quality rock to be drilled as the play matures (requiring higher oil prices to be economic); thus the number of wells required to offset field decline inevitably increases with time. Although technological innovations including longer horizontal laterals, more fracturing stages, more effective additives and higher-volume frack treatments have increased well productivity in the early stages of the development of all plays, they have provided diminishing returns over time, and cannot compensate for poor quality reservoir rock.

4. **Number of potential wells:** Plays are limited in area and therefore have a finite number of locations to be drilled. Once the locations run out, production goes into terminal decline.

5. **Rate of drilling:** The rate of production is directly correlated with the rate of drilling, which is determined by the level of capital investment.

[2] See http://info.drillinginfo.com.
[3] IEA, *World Energy Outlook 2008*, http://www.worldenergyoutlook.org/media/weowebsite/2008-1994/weo2008.pdf.

The basic methodology used is as follows:

- Historical production, number of currently producing- and total-wells drilled, the split between horizontal- and vertical/directional-wells, and the overall play area were determined for all plays. Average well production decline for both horizontal and vertical/directional wells, and the average estimated ultimate recovery (EUR), were also assessed for all plays. For the Bakken and Eagle Ford, these parameters were assessed at the county- as well as at the play-level (the top counties in terms of the number of producing wells were analyzed individually, whereas counties with few wells were aggregated).

- Field decline rates and the number of available drilling locations were determined at the county- and play-level for the Bakken and Eagle Ford.

- First-year average production was established from type decline curves (i.e., average well decline profiles) constructed for all wells drilled in the year in question; 2013 was the year used as representative of future average first-year production levels per well. Average first-year production is used to determine the number of wells needed to offset field decline each year, and to determine the production trajectory over time given various drilling rates. In determining future production rates, the current trends in well productivity over time were considered; for example if recent well quality trends were increasing, it was assumed for plays in early stages of development that well quality would increase somewhat in the future before declining as drilling moves into lower quality outlying portions of plays.

- Projections of future production profiles were made for the Bakken and Eagle Ford based on various drilling rate scenarios. These projections assume a gradation over time from the well quality observed in the current top counties of a play to the well quality observed in the outlying counties as available drilling locations are used up. The different drilling rate scenarios were prepared so that the effect of a high drilling rate, presumably due to favorable economic conditions, compared to a low or a “most likely” drilling rate, could be assessed, both in terms of production over time and cumulative oil recovery from the play by 2040.

- Production history for all plays and production projections (in the case of the Bakken and Eagle Ford) were then compared to the EIA forecasts to assess the likelihood that these forecasts could be met.

- All plays were then compared to each other in terms of well quality and other parameters and an overall assessment of the likely long-term sustainability of tight oil production was determined.

Although public pushback against fracking due to health and environmental concerns has limited access to drilling locations in states like New York and Maryland and several municipalities, as well as triggered lawsuits, this report assumes there will be no restrictions to access due to environmental concerns. It also assumes there will be no restrictions on access to the capital required to meet the various drilling rate scenarios. In these respects, it presents a “best case,” as any restrictions on access to drilling locations or to the capital needed to drill wells would reduce forecast production levels.

2.2 THE CONTEXT OF U.S. OIL PRODUCTION

2.2.1 U.S. Oil Production Forecasts

The EIA's *Annual Energy Outlook 2014* provides various scenarios of future U.S. oil production, as well as price projections and stated assumptions in terms of available technically recoverable reserves and resources, play areas, well productivity, and so forth.

Figure 2-1 illustrates the range of the EIA's oil production forecasts through 2040 compared to historical production. Most scenarios project the U.S. to meet or exceed its all-time peak production, which occurred in 1970. These scenarios assume cumulative production of between 77 and 123 billion barrels of oil between 2013 and 2040, which is 2.7-4.2 times the *proved reserves* (i.e., economically recoverable with current technology) that were thought to exist as of 2012.[4] Adding in *unproved resources*, which are uncertain estimates without price constraints, between a third and a half of remaining potentially recoverable oil in the U.S. will be consumed over the next 26 years according to the EIA projection. This amounts to the equivalent of 54-84% of all the oil produced over the 54 years between 1960 and 2013.

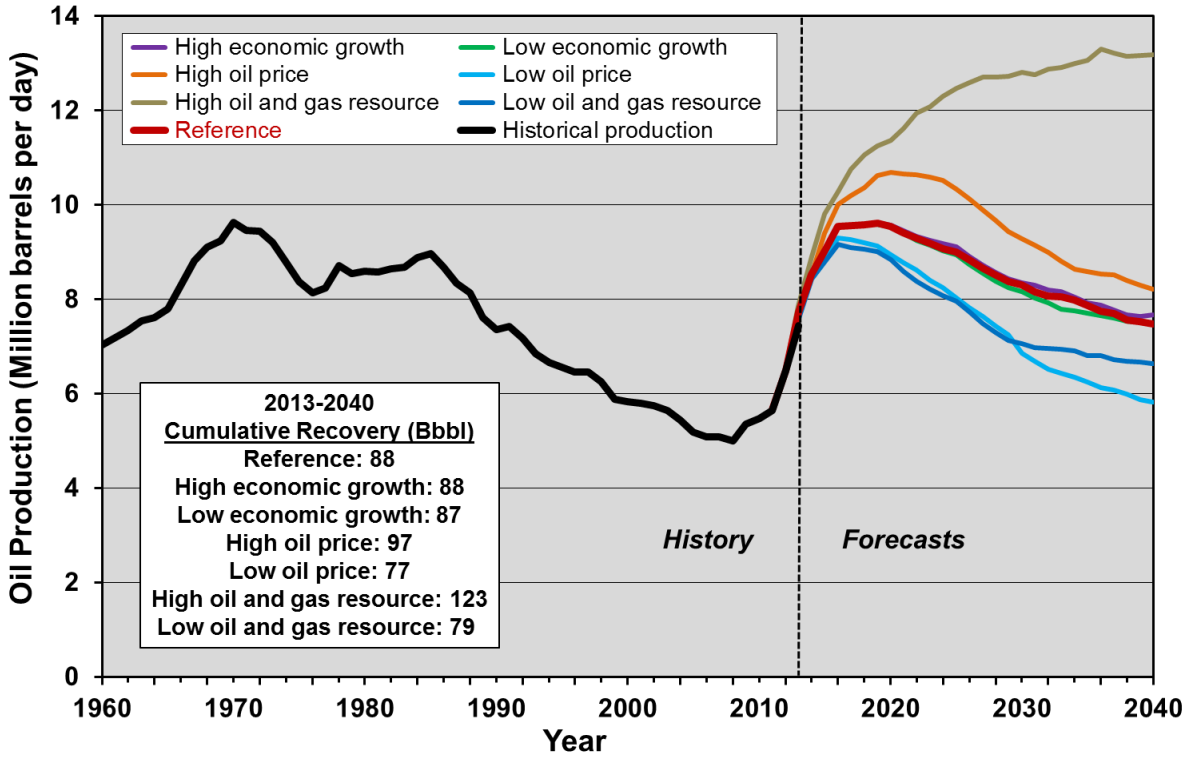


Figure 2-1. Scenarios of U.S. oil production through 2040 from the EIA's *Annual Energy Outlook 2014*,[5] compared to historical production from 1960.

Oil production includes both crude oil and lease condensates.

[4] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[5] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

The source of this optimism in future oil production is the application of high-volume, multi-stage, hydraulic fracturing technology in horizontal wells, which has unlocked previously inaccessible oil trapped in highly impermeable shales and tight source rocks. Figure 2-2 illustrates the EIA's reference case projection for oil production by source through 2040. Although conventional production is forecast to be flat or declining over the period, tight oil production increases rapidly to a peak early in the next decade, amounting to roughly half of all U.S. oil production. Oil prices in this reference case are forecast to remain below $140 per barrel over the period. Notwithstanding talk of U.S. energy independence, this scenario implies that U.S. oil production, even with tight oil, will amount to only 40% of projected 2040 demand.

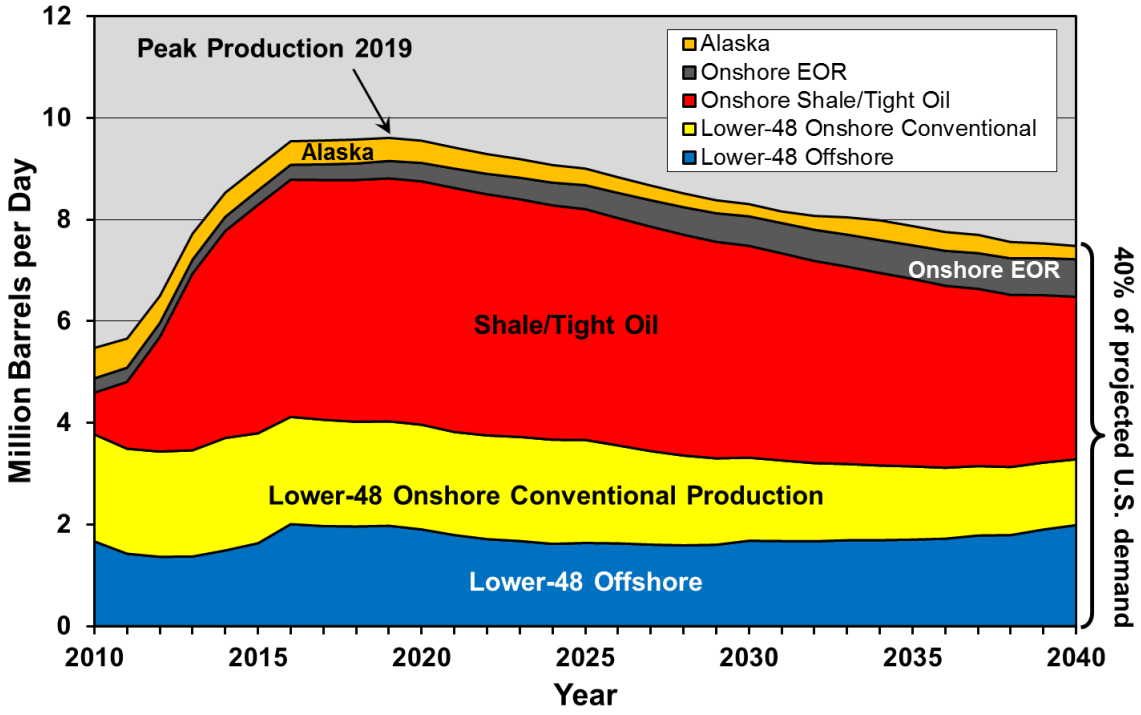


Figure 2-2. EIA reference case projection of U.S. oil production by source through 2040.[6]

[6] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo

Figure 2-3 illustrates EIA's projections for tight oil production in several cases. These assume the extraction of between 37 (low oil price case) and 47 billion barrels (high oil price case) by 2040. This amounts to all of the 7.15 billion barrels of proved tight oil reserves and between 50% and 67% of the EIA's estimated 59.2 billion barrels of unproved tight oil resources (unproved resources have no implied price required for extraction and are highly uncertain, as evidenced by the EIA's recent 96% downgrade of resources in the Monterey Shale of California[7]).

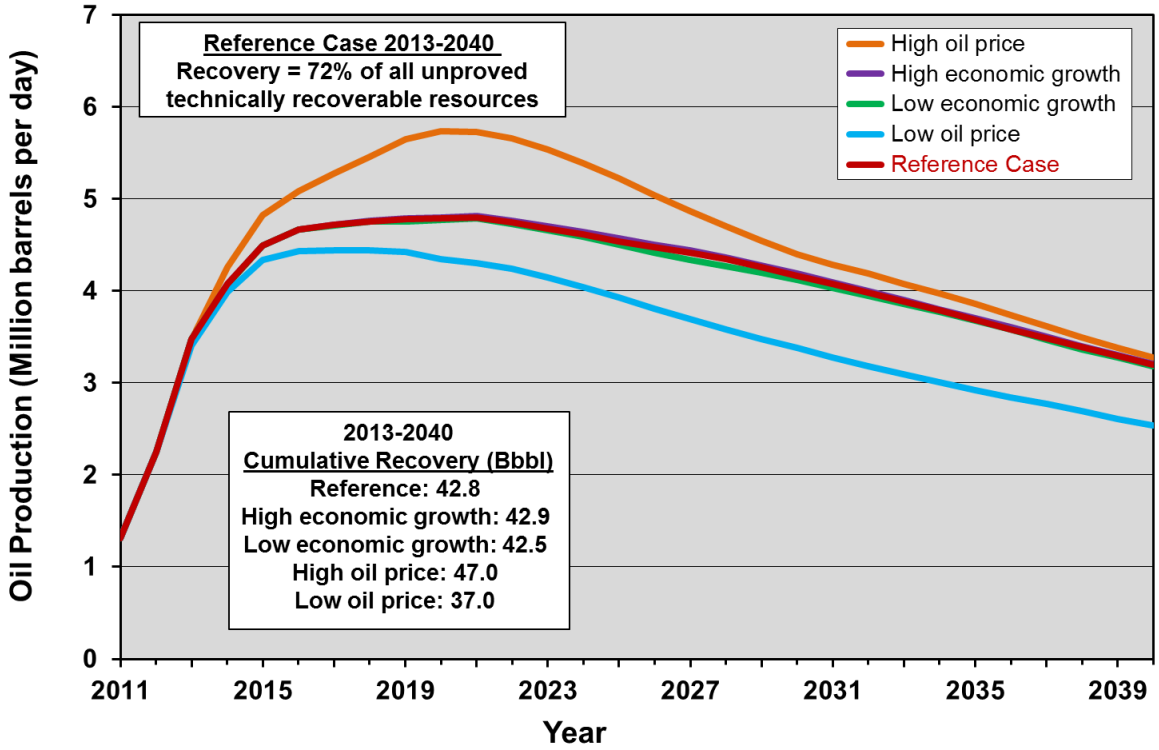


Figure 2-3. EIA scenarios of U.S. tight oil production through 2040.[8]

According to the EIA, proved reserves of tight oil are 7.15 billion barrels and unproved technically recoverable resources are estimated at 59.2 billion barrels, as of January 1, 2012.[9]

[7] Louis Sahagun, "U.S. officials cut estimate of recoverable Monterey Shale oil by 96%," *Los Angeles Times*, May 20, 2014, http://www.latimes.com/business/la-fi-oil-20140521-story.html.
[8] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.
[9] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf

Figure 2-4 illustrates how the EIA reference case projections for tight oil production are divided between the Bakken, the Eagle Ford, and all other plays.

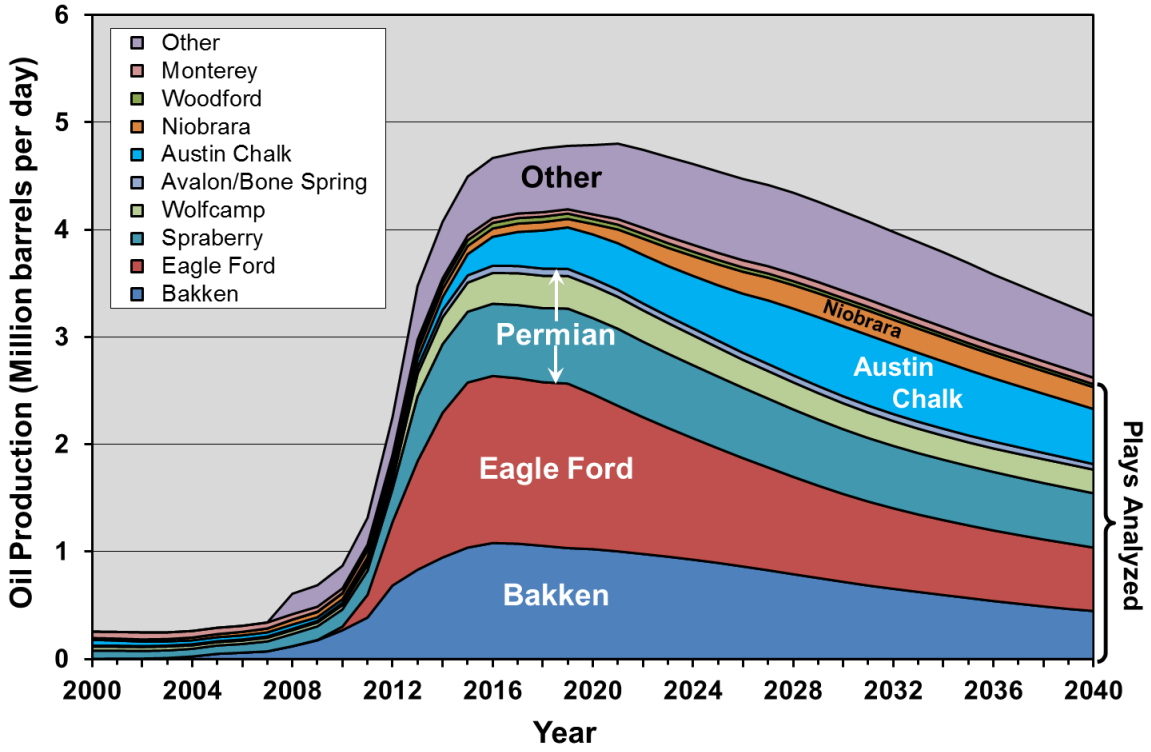


Figure 2-4. EIA reference case projection of tight oil production divided among Bakken, Eagle Ford, and all other plays, 2011-2040.[10]

This report analyzed the seven most productive plays, which account for 82% of EIA's tight oil production forecast to 2040.

The EIA reference case clearly expects the Bakken and Eagle Ford to provide a slowly declining but significant foundation of tight oil production for the next few decades. The Bakken and Eagle Ford are relatively new plays, with substantial tight oil resources that have only recently been unlocked by directional drilling and hydraulic fracturing.

Tight oil production in all these plays has risen quickly due to rapid increases in drilling rates and sustained high levels of capital input. However, high well- and field-decline rates, coupled with a finite number of drilling locations, suggest that production will drop off sharply when sweet spots are depleted; therefore, the projected long slow production decline of these plays warrants further scrutiny. Section 3 of this report explores the realistic production potential for the Bakken and Eagle Ford in depth.

[10] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

The remainder of tight oil production is expected to come from seven major plays as well as numerous emerging plays, as illustrated in Figure 2-5.

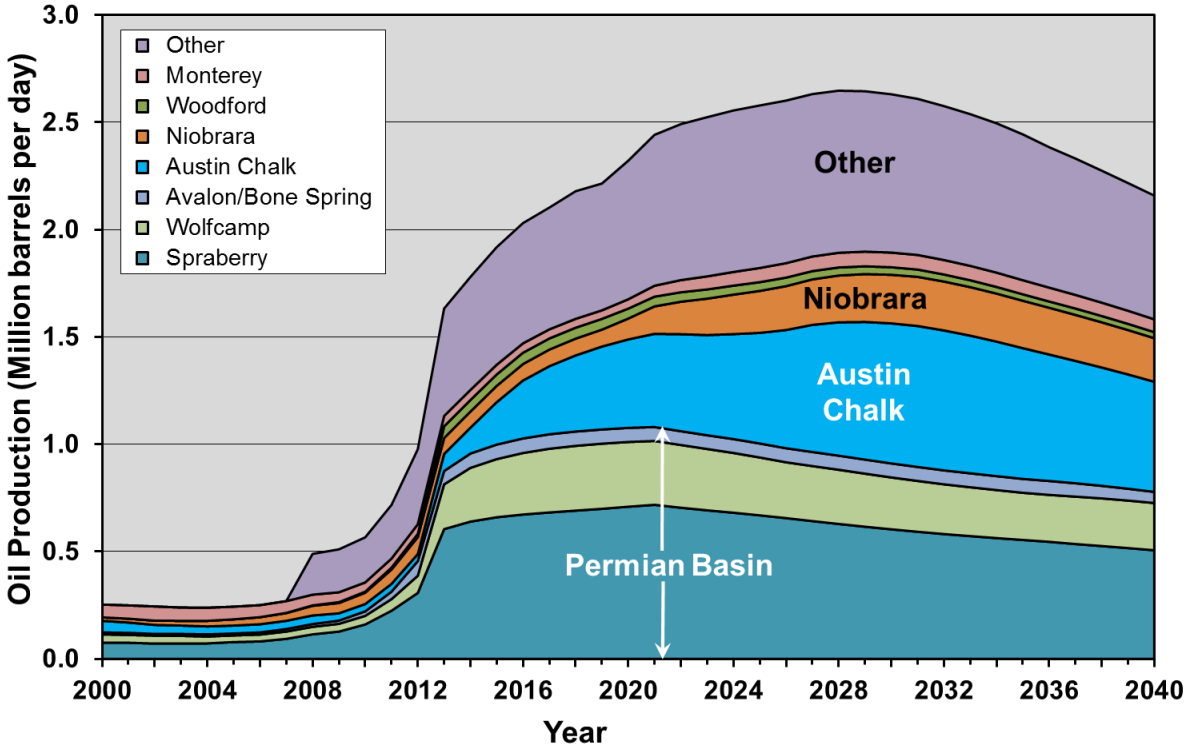


Figure 2-5. EIA reference case projections of tight oil production from plays other than the Bakken and Eagle Ford, through 2040.[11]

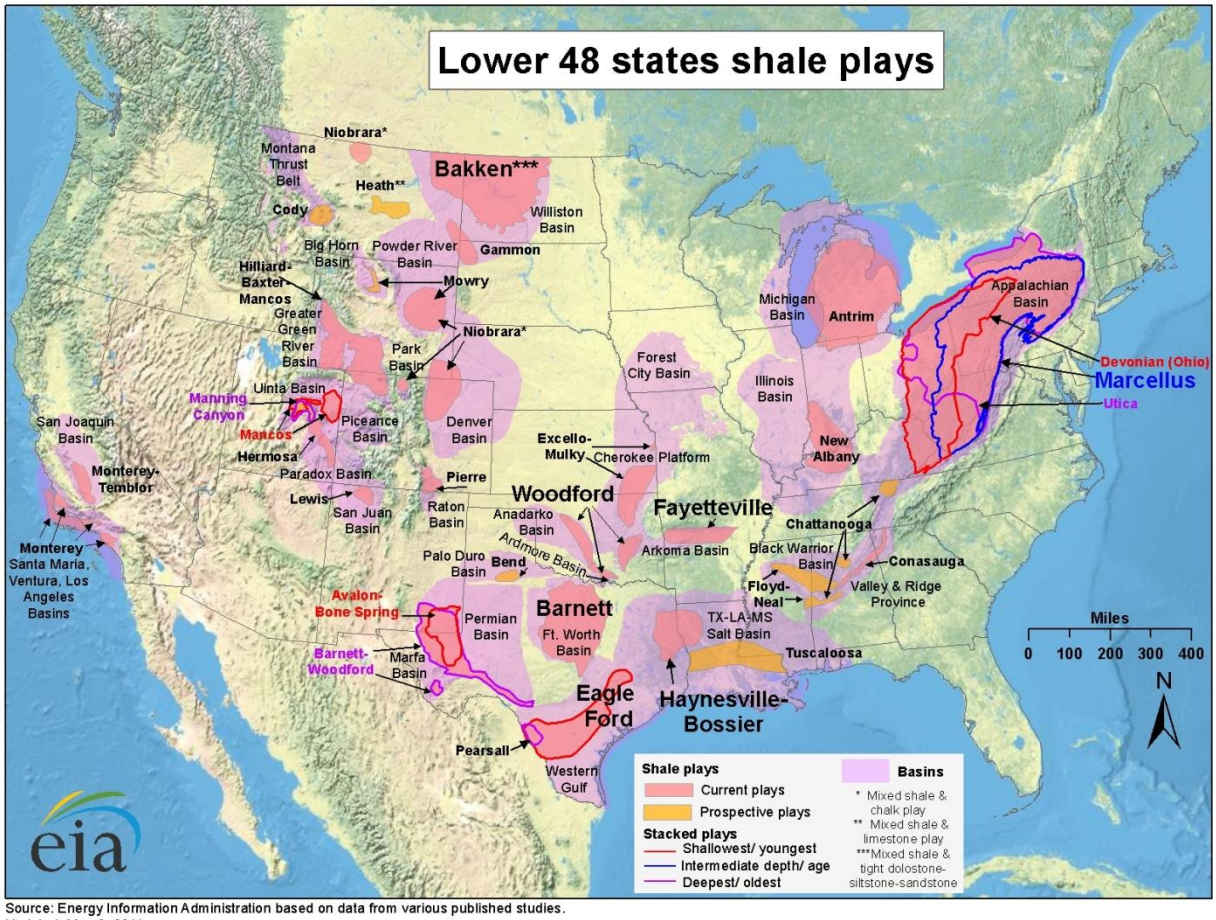
Of the Permian Basin plays, only the top three are labeled here; the remaining are minor plays included in "Other."

Unlike the Bakken and Eagle Ford, most of these plays have been known for a long time; their growing production reflects the successful application of new technology to extract additional resources. They are projected by the EIA to account for two-thirds of tight oil production in 2040; therefore, sustained production projected from these mature plays warrants further scrutiny. Sections 2.4 and 2.5 of this report explore the realistic production potential of these plays in depth.

[11] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

2.2.2 Current U.S. Tight Oil Production

Production of tight oil began in the Bakken Field of Montana and North Dakota in the early 2000s. With the widespread application of horizontal drilling and hydraulic fracturing beginning in 2005, production grew rapidly. The Eagle Ford Field of southern Texas was unknown as recently at 2007, and now is the single largest producer of tight oil in the U.S. The distribution of tight oil and shale gas plays in the lower 48 states is illustrated in Figure 2-6.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 2-6. Distribution of lower 48 states shale gas and oil plays.[12]

[12] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/.

Current production from U.S. tight oil plays is estimated by the EIA at 3.7 MMbbl/d. Despite the apparent widespread nature of shale plays as shown in Figure 4, 62% of this production comes from just the top two plays: the Bakken and Eagle Ford. A further 25% comes from the five plays of the Permian Basin in Texas and New Mexico. Figure 2-7 illustrates tight oil production by play from 2000 through May, 2014, according to the EIA.

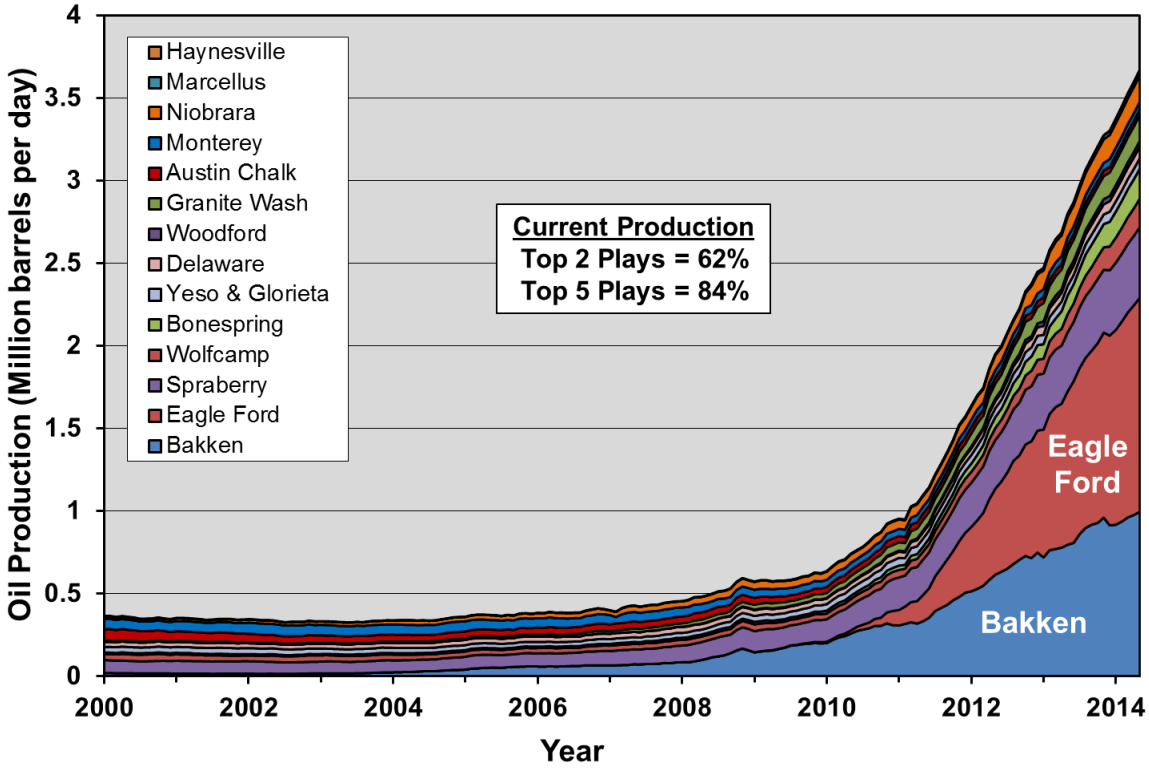


Figure 2-7. U.S. tight oil production by play, 2000 through May 2014.[13]

The Permian Basin, which is made up of several plays (the largest of which are noted), is the third largest projected source of tight oil.

[13] EIA estimates obtained in June 2014 from http://www.eia.gov/naturalgas/weekly, where it appears to have been mistakenly posted; no longer available at this location.

2.3 The Bakken and Eagle Ford Plays

This report investigates the Bakken play and Eagle Ford play in depth because they are the foundation of the U.S. tight oil "shale revolution." They are the two most productive U.S. tight oil plays, accounting for 62% of current production, and are projected to account for over half of total tight oil production well into the next decade.

Moreover, the Bakken and Eagle Ford are new tight oil plays, having only recently been unlocked by directional drilling and fracking. In comparison, most of the other major U.S. tight oil plays are decades old with tens of thousands of conventional wells. Thus, the Bakken and Eagle Ford are the best representatives of what may be expected from future tight oil discoveries.

2.3.1 Bakken Play

The EIA forecasts recovery of 8.8 billion barrels of oil from the Bakken play by 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Bakken play is where tight oil production got its start—first in the Elm Coulee Field of Montana, then in the western counties of North Dakota. The Bakken Formation is underlain by the Three Forks Formation, which is also productive and is separated from the Bakken by as little as 30 feet. The analysis herein encompasses both the Bakken and Three Forks.

The U.S. Geological Survey (USGS) produced a new assessment of the Bakken and Three Forks in 2013 in which they estimated a mean technically recoverable resource of 7.4 billion barrels.[14] They broke the play into six "assessment units" (AUs) as illustrated in Figure 2-8. The EIA has apparently used this breakdown in its estimates of the play area used to calculate an unproved recoverable resource of 9.2 billion barrels (54% of which are in the Three Forks Formation) in its 2014 reference case; however, it does not provide an updated map showing the areas it has included.[15] In the EIA's analysis, the Bakken play is comprised of five contiguous units totaling 14,594 square miles plus a single underlying Three Forks unit totaling 17,652 square miles (USGS areas for these units, shown in Figure 2-8, are somewhat larger).

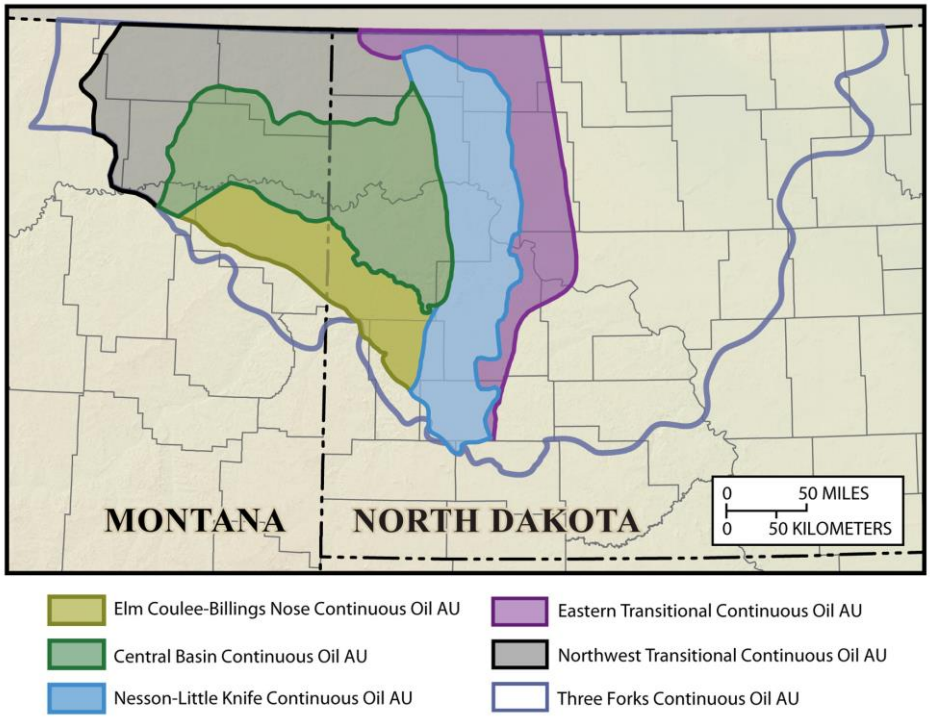


Figure 2-8. USGS demarcation of Bakken and Three Forks tight oil assessment units.[16]
The USGS demarcates five contiguous Bakken units and one underlying, much larger, Three Forks unit.

[14] USGS, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, 2013, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.
[15] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf. At publication, the most recent shapefile for the EIA play area was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm.
[16] Map by Post Carbon Institute, using data from USGS, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, 2013, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.

Figure 2-9 illustrates the distribution of wells in the Bakken as of early 2014. Over 9,200 wells have been drilled to date, of which 8,534 were producing oil at the time of writing. Although the play covers parts of 15 counties, most drilling is concentrated in McKenzie, Mountrail, Dunn, Williams, and Divide counties in North Dakota and Richland County in Montana. The functional prospective limits of the play are well defined by wells with little or no productivity, and encompass approximately 12,700 square miles; this is a markedly smaller area than the play area demarcated by the EIA.

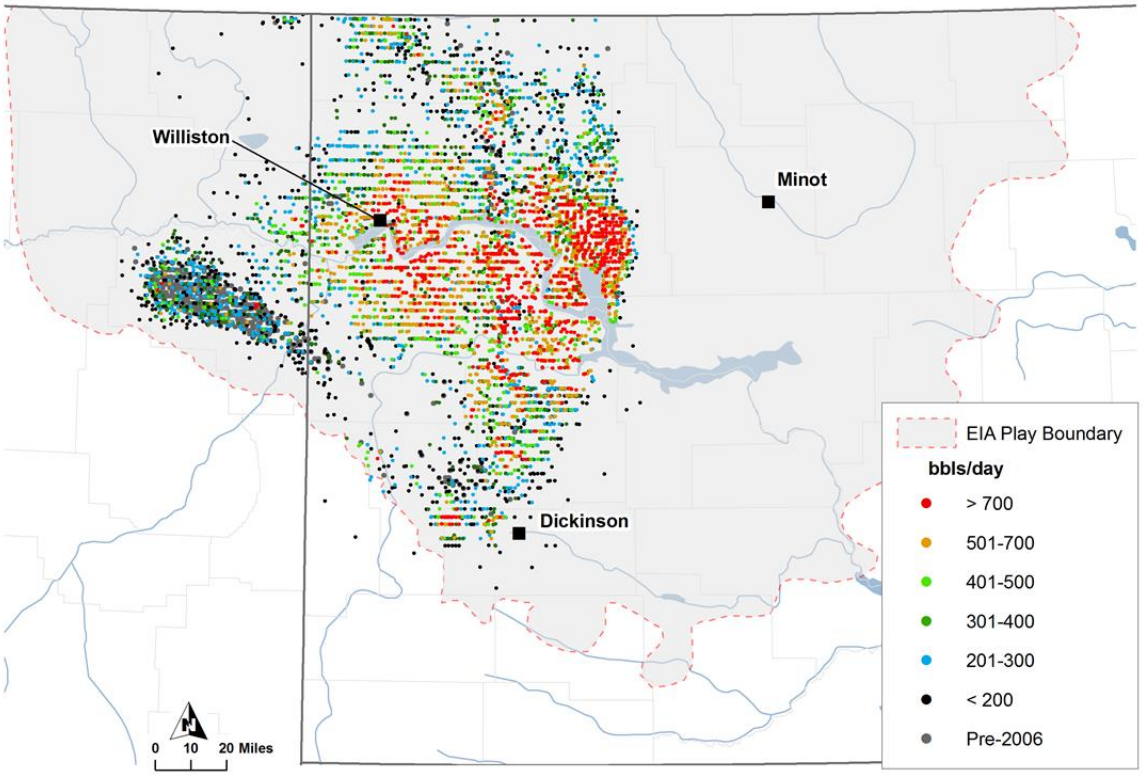


Figure 2-9. Distribution of wells in the Bakken play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP),[17] with EIA play boundary.[18]

The size of the Bakken play as defined by the extent of where productive drilling has actually occurred is approximately 12,700 square miles, in contrast to the much larger area designated as the play by the EIA (2011). Well IPs are categorized approximately by percentile; see Appendix.

The case for such a smaller Bakken play area than what the EIA and USGS claim is further underlain by observing where operators actually have acreage and where drilling is occurring. For example, the leaseholdings of Continental Resources, one of the largest operators in the Bakken, are notably concentrated in the productive area of the play.[19]

[17] Data from Drillinginfo retrieved September 2014.
[18] At publication, the most recent shapefile for the EIA's play area for the Bakken was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.
[19] Continental Resources, September 2014 investor presentation, http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NTU0MDg2fENoaWxkSUQ9MjUwMTQyfFR5cGU9MQ==&t=1.

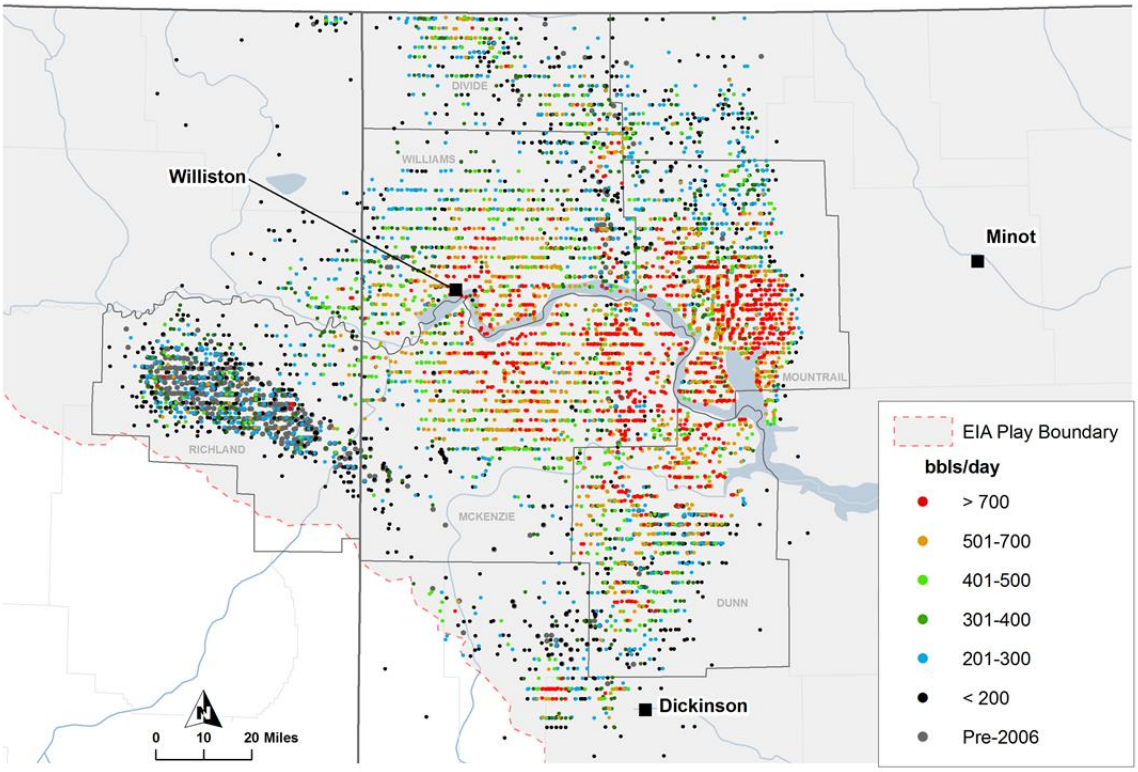


Figure 2-10. Detail of Bakken play showing distribution of wells as of early 2014, and illustrating highest one-month oil production (initial productivity, IP),[20] with EIA play boundary.[21]

The top six producing counties are indicated. Well IPs are categorized approximately by percentile; see Appendix.

[20] Data from Drillinginfo retrieved August 2014.
[21] At publication, the most recent shapefile for the EIA's play area for the Bakken was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.

Production in the Bakken was nearly one million barrels of oil per day and 1.1 billion cubic feet of gas per day at the time of writing, as illustrated in Figure 2-11.[22] Gas production is expressed in Figure 2-11 as barrels of oil equivalent (6,000 cubic feet of gas equals approximately one barrel of oil on an energy equivalent basis). Ninety-eight percent of this production is from horizontally drilled, hydraulically fractured ("fracked") wells. The rate of drilling has grown from about 500 wells per year in 2009 to about 2,000 wells per year in mid-2012, where it has remained.

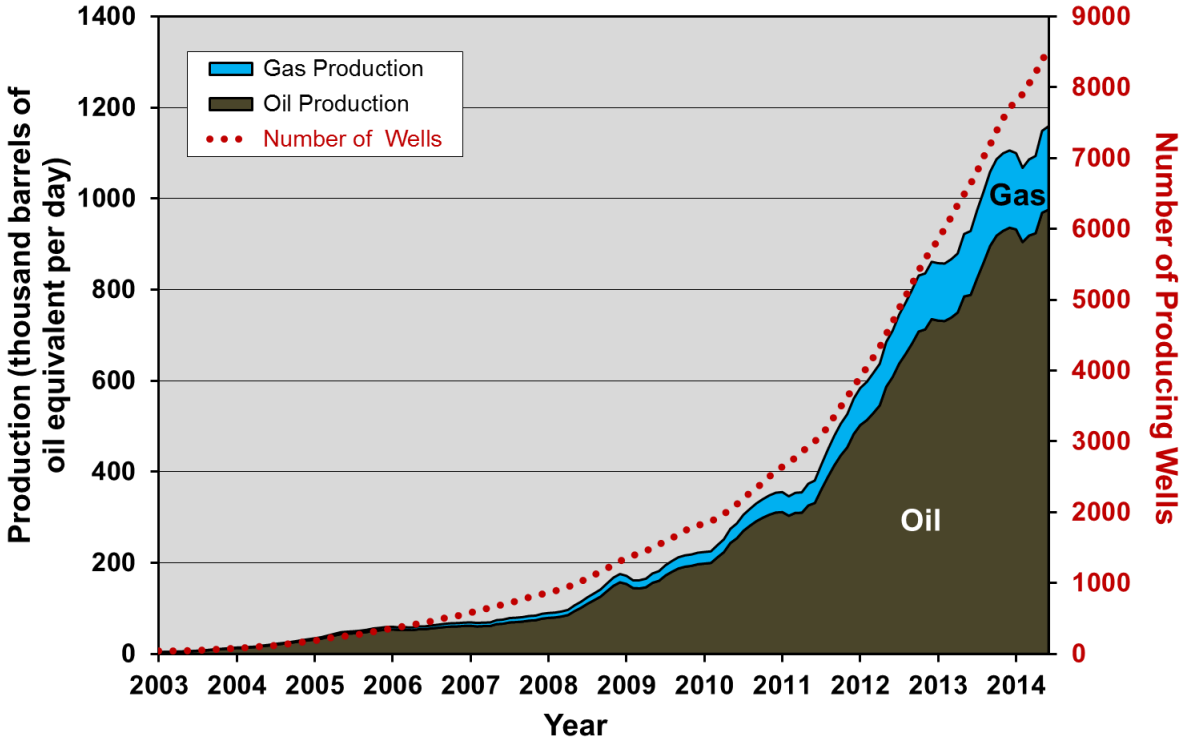


Figure 2-11. Bakken play tight oil and gas production and number of producing wells, 2003 to 2014.[23]

[22] Although the EIA's widely cited Drilling Productivity Report (DPR) states as of September 2014 that Bakken has produced over 1 million barrels per day of oil since February 2014, it must be noted that the DPR's figures for the Bakken seem to overstate production and recent months are based on estimates. See http://www.pphb.com/images/pdfs/musings2014/Musings040114.pdf.

[23] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The amount of oil added to total play production by each new well has been declining since early 2012 as illustrated in Figure 2-12.This is due to the fact that the higher production grows, the more intrinsic decline must be offset by new wells.

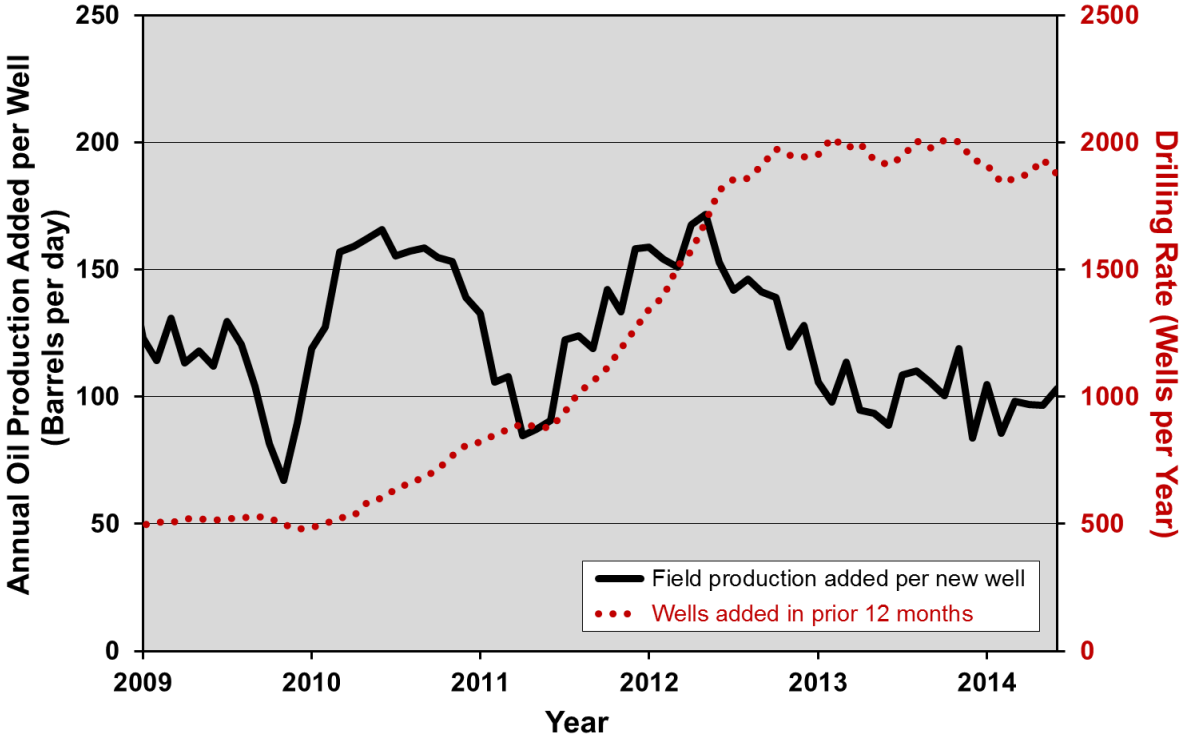


Figure 2-12. Annual oil production added per new well and annual drilling rate in the Bakken play, 2009 through 2014.[24]

[24] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

2.3.1.1 Well Decline

The first key fundamental in determining the life cycle of Bakken production is the *well decline rate*. Bakken wells exhibit high decline rates in common with all shale plays. Figure 2-13 illustrates the average decline profile of Bakken horizontal wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life is 85%.

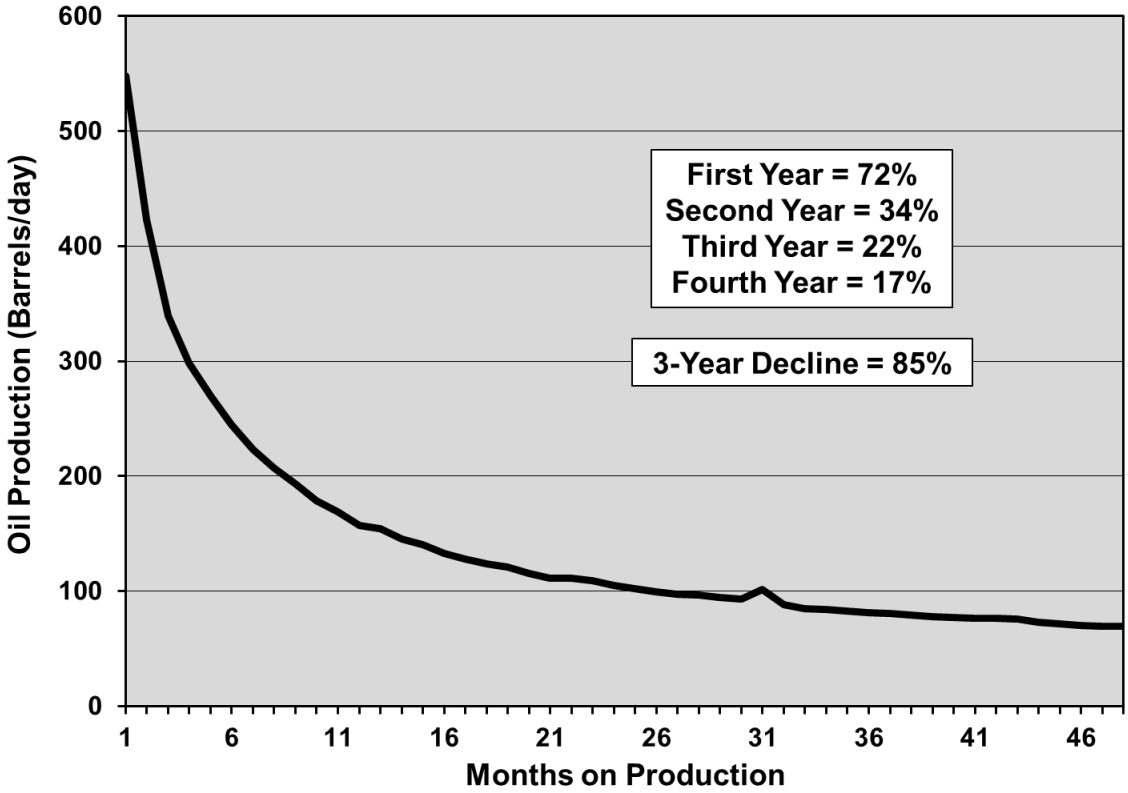


Figure 2-13. Average decline profile for horizontal tight oil wells in the Bakken play.[25]
Decline profile is based on all horizontal tight oil wells drilled since 2009.

[25] Data from Drillinginfo retrieved April 2014.

2.3.1.2 Field Decline

The second key fundamental is the overall *field decline rate*, which is the total amount of production in a given play that would be lost in a year without more drilling. Figure 2-14 illustrates production from the 5,300 wells drilled in the Bakken prior to 2013. The field decline rate of the first year without new drilling is 45%. This is lower than the well decline rate as the field decline is made up of new wells, declining at high rates, and older wells, declining at lesser rates. The field decline has been relatively constant at 45% for the past three years in the Bakken. Assuming new wells will produce in their first year at the first-year rates observed for wells drilled in 2013, 1,470 new wells would need to be drilled each year to offset field decline at current production levels. At an average cost of $8 million per well,[26] this would represent a capital input of about $11.8 billion per year, exclusive of leasing, operating, and other infrastructure costs, just to keep production flat at 2013 levels.

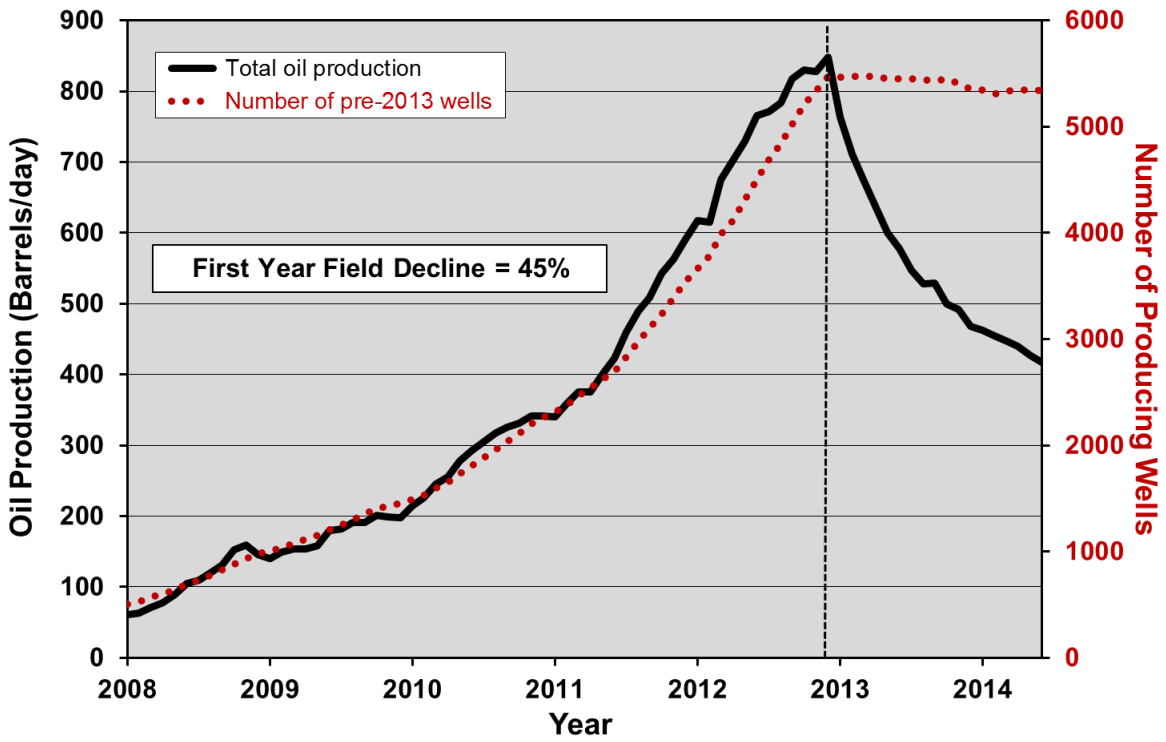


Figure 2-14. Production rate and number of horizontal tight oil wells in the Bakken play prior to 2013.[27]

In order to offset the 45% field decline rate, 1,470 new wells per year producing at 2013 levels would be required.

[26] Ingrid Pan, "Most operators are seeing declining well costs in the Bakken," *Market Realist*, December 12, 2013, http://marketrealist.com/2013/12/operators-seeing-declining-well-costs-bakken.
[27] Data from Drillinginfo retrieved September 2014.

2.3.1.3 Well Quality

The third key fundamental is the trend of *average well quality* over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, which, along with multi-well pad drilling, has reduced well costs. In the Bakken, however, technological improvements appear to be approaching the limits of diminishing returns: improvements in average well quality are flat to slightly increasing at best. The average first-year production rate of Bakken wells is only 7% above its last-highest point, in 2011, as illustrated in Figure 2-15. Moreover, it is likely that this slight rise in average well quality is in part a result of concentrating drilling in the sweet spots, as discussed in the following section, rather than significant technology improvements.

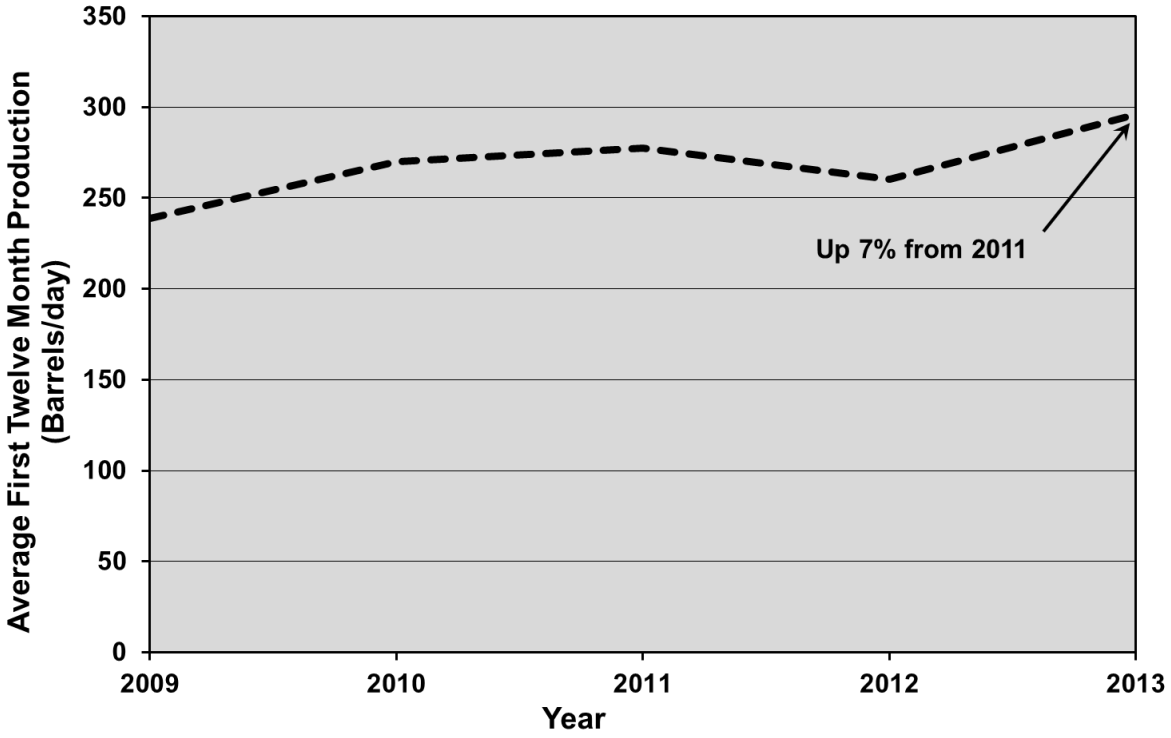


Figure 2-15. Average first-year production rates for Bakken tight oil wells, 2009 to 2013.[28]

The slight improvement over 2011 is likely as much a result of focusing drilling in sweet spots as significant technology improvements.

[28] Data from Drillinginfo retrieved September 2014.

Another measure of well quality is cumulative production and well life. Figure 2-16 illustrates the cumulative production of all wells that were producing in the Bakken as of March 2014. Eighty-two percent of these wells are less than 5 years old, and knowing that production will be down more than 90% after 5 years, their economic lifespan is uncertain. Although it can be seen that there are a few very good wells that recovered more than 600,000 barrels of oil in the first few years, and undoubtedly were great economic successes, the average well has produced just 127,765 barrels over a lifespan averaging 35 months. Only 1% of these wells are more than 10 years old. The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer—this is conjectural at this point given the lack of long-term well-performance data.

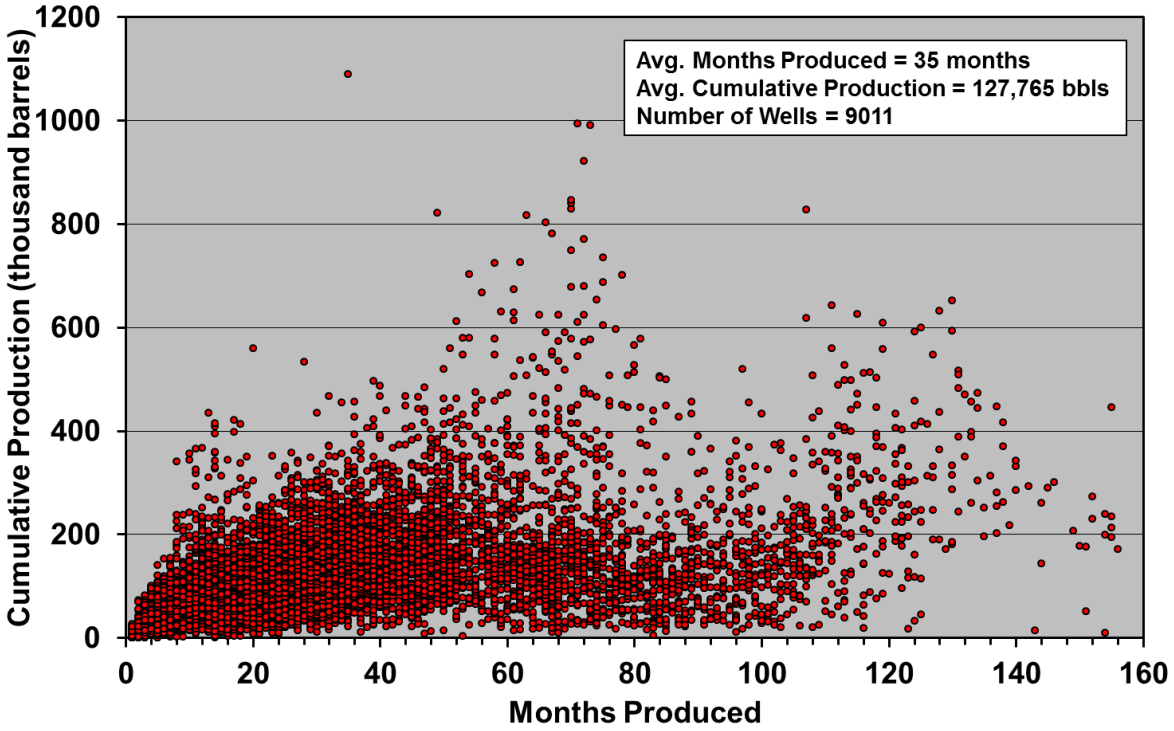


Figure 2-16. Cumulative oil production and length of time produced for Bakken wells that were producing as of March 2014.[29]

Very few wells are greater than ten years old, with a mean age of 35 months and a mean cumulative recovery of 127,765 barrels.

[29] Data from Drillinginfo retrieved September 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much oil these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP), which is often focused on by operators. Figure 2-17 illustrates the average daily output over the first six months of production (six-month IP) for all wells in the Bakken play. Again, as with cumulative production, there are a few exceptional wells—4% of wells produced more than 600 barrels per day over the first six months—but the average for all wells drilled between 2008 and 2014 is just 262 barrels per day. The trend line on Figure 2-17 shows the average over time, which is declining as of the first half of 2014 as drilling moves into lower-quality areas. Figure 2-9 and Figure 2-10 illustrate the distribution of IPs in map form.

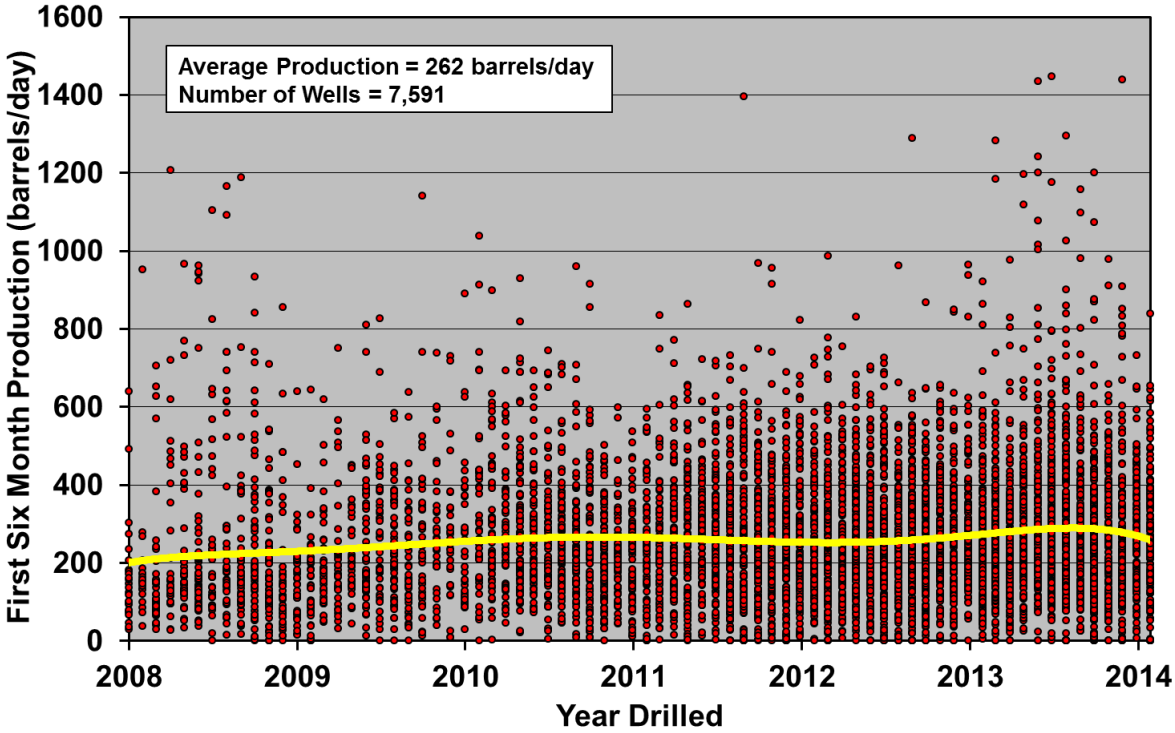


Figure 2-17. Average oil production over the first six months for all wells drilled in the Bakken play, 2008-2014.[30]

Although there are a few exceptional wells, the average well produced 262 barrels per day over this period.

[30] Data from Drillinginfo retrieved September 2014.

Different counties in the Bakken display markedly different well production rate characteristics, which are critical in determining the most likely production profile in the future. Figure 2-18, which illustrates production over time by county, shows that the top two counties produce 55% of the total, the top four produce 87%, and the remaining eleven produce just 13%. Clearly, years of widespread drilling (see Figure 2-19 for number of wells drilled per county) have not resulted in significant production increases outside the top four counties.

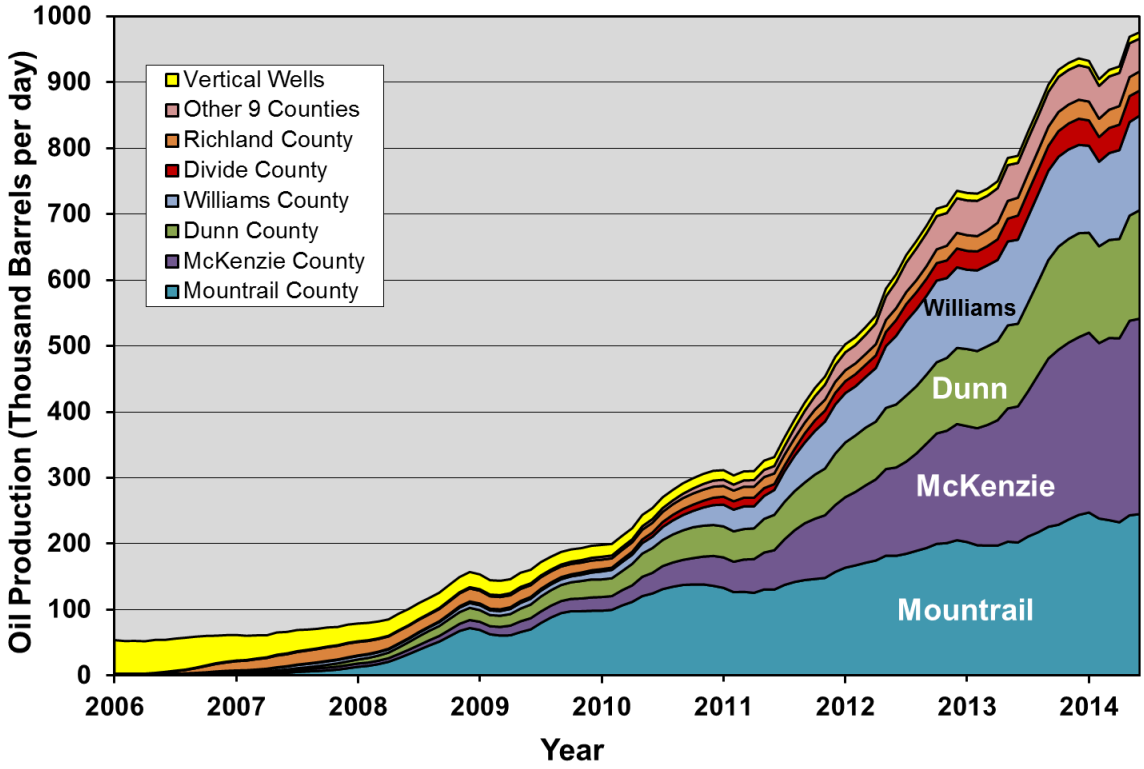


Figure 2-18. Oil production by county in the Bakken play, 2006 through 2014.[31]

The top four counties produced 87% of production in 2014.

[31] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 2-19, the top two counties have produced half of the oil and the top four more than three-quarters. This trend will likely become even more pronounced given that the production rate share from these counties is increasing as noted above.

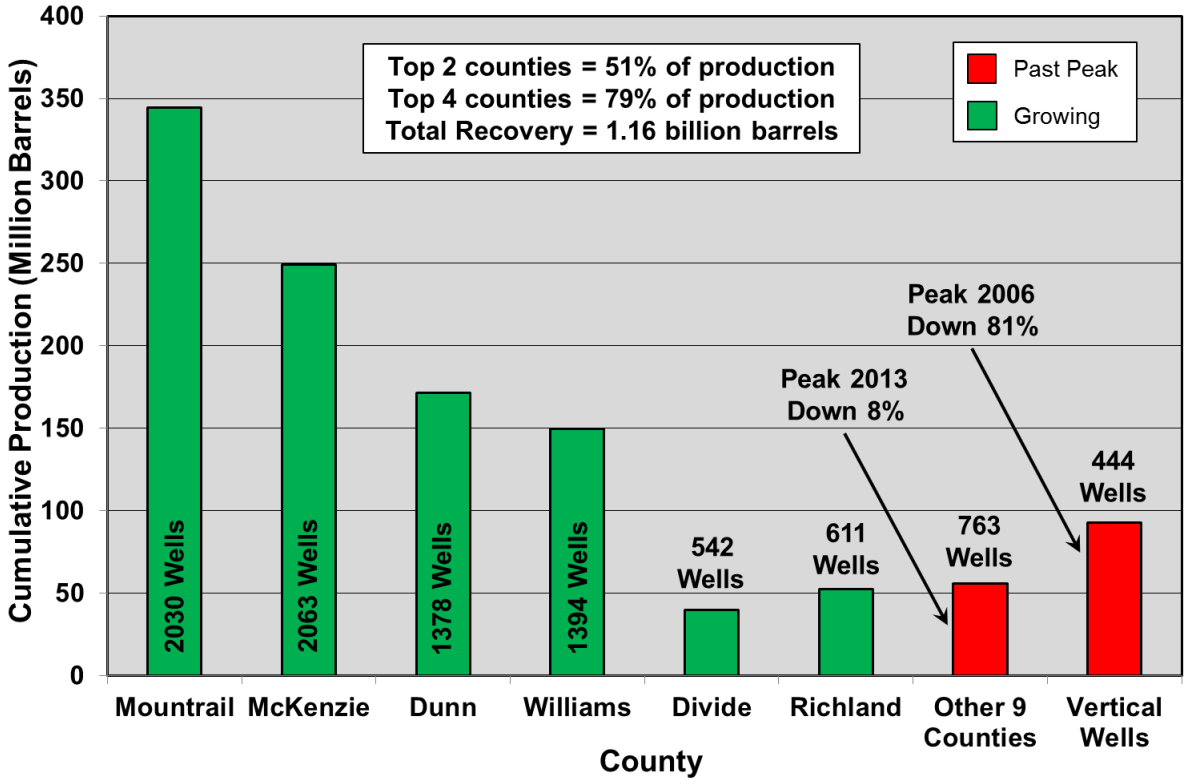


Figure 2-19. Cumulative oil production by county in the Bakken play through 2014.[32]

The top four counties have produced 79% of the 1.16 billion barrels produced to date. Note that production from vertical wells in all counties is grouped at right; the cumulative tallies by county are for horizontal wells only.

[32] Data from Drillinginfo retrieved September 2014.

The Bakken also produces significant amounts of natural gas (see the Bakken section in *Part3: Shale Gas* of this report for a full discussion). As with oil, cumulative production of natural gas is concentrated in the top four counties as illustrated in Figure 2-20. Although natural gas does add value for operators and amounts to 18% of the energy produced from the play, the high discount of natural gas price compared to the price of oil and the lack of gathering infrastructure (particularly in remote regions) have resulted in the flaring of some 30% of production. This has attracted considerable attention, including the enactment of new regulations.[33] The Bakken currently produces about 1.1 billion cubic feet per day and has produced more than one trillion cubic feet since 2006.

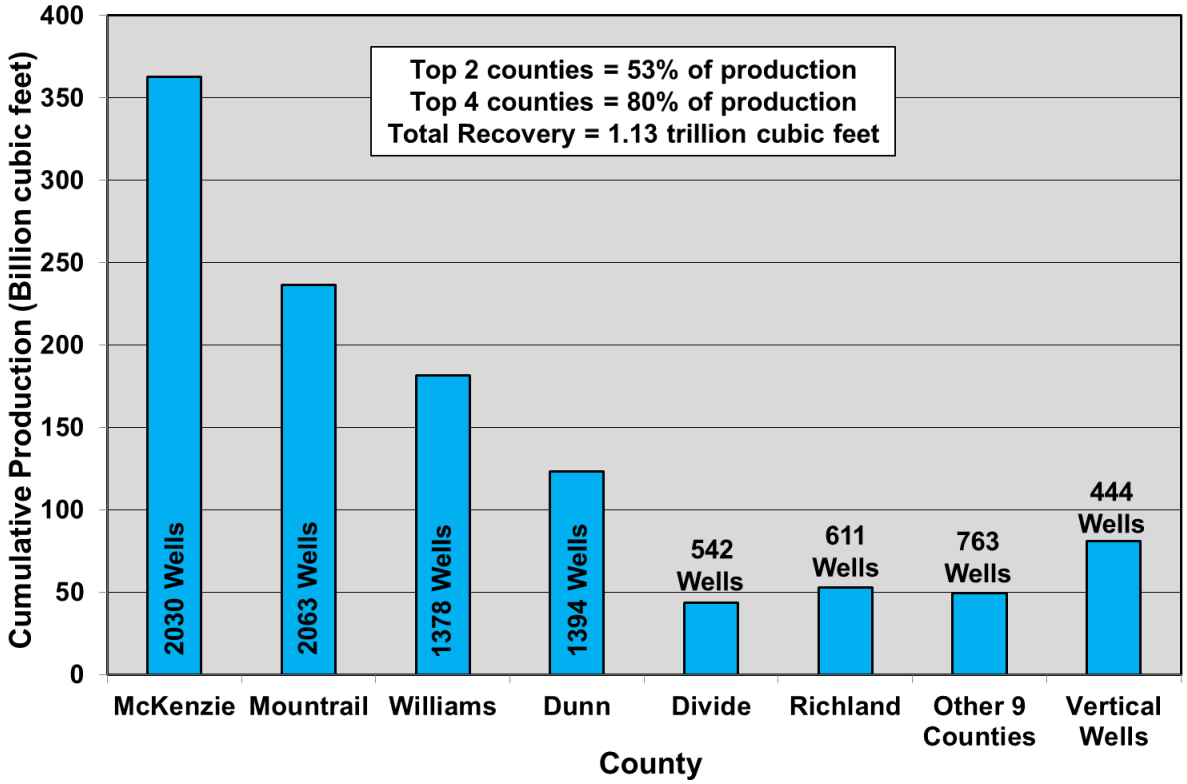


Figure 2-20. Cumulative gas production by county in the Bakken play through 2014.[34]
The top four counties have produced 80% of the 1.13 trillion cubic feet produced to June 2014.

[33] Anna Driver and Ernest Scheyder, "North Dakota flaring crackdown may slow oil field growth," Reuters, June 5, 2014, http://www.reuters.com/article/2014/06/05/bakken-flaring-idUSL1N0OK2AI20140605.
[34] Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost in the order of $8 million or more each, not including leasing costs and other expenses. The areas of highest quality—the "core" or "sweet spots"—have now been well defined. Figure 2-21 illustrates average well decline profiles by county; these can be seen as a measure of well quality. The well decline profiles from the top three counties are all above the Bakken average, hence these counties are attracting the bulk of the drilling and investment.

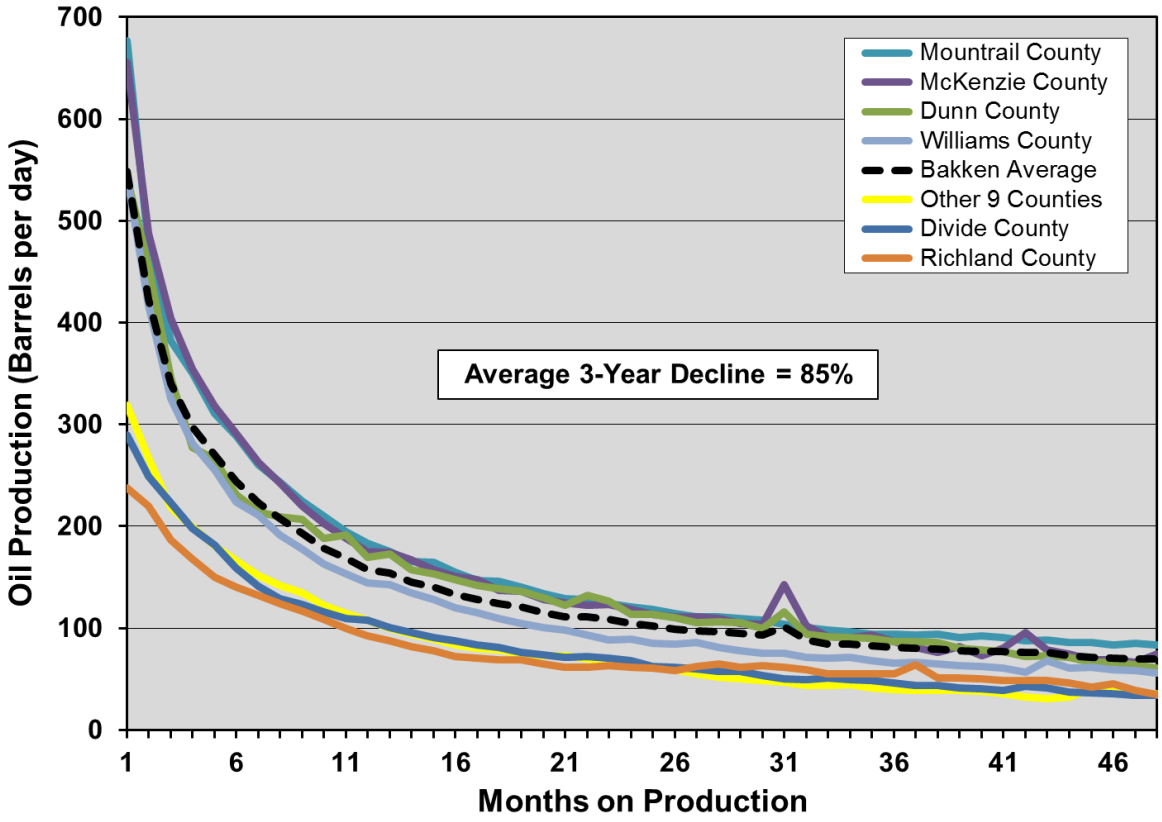


Figure 2-21. Average tight oil well decline profiles by county for the Bakken play.[35]

The top four counties which have produced most of the oil and gas in the Bakken are clearly superior. If natural gas is included, on a "barrels of oil equivalent basis," average initial production in counties like Mountrail and McKenzie is over 800 barrels per day. Well decline profiles are based on horizontal wells drilled since 2009.

Another measure of well quality is "estimated ultimate recovery" (EUR), the amount of oil a well will recover over its lifetime. To be clear, no one knows what the lifespan of a Bakken well is, given that few of them are more than seven years old. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 2-21, assuming well life spans of 30-50 years (as is typical for conventional oil wells), but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Bakken. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 2-21, which show that wells exhibit steep initial decline rates with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

[35] Data from Drillinginfo retrieved April 2014.

Figure 2-22 illustrates theoretical EURs for horizontal wells by county for the Bakken, for comparative purposes of well quality; these range from 203,000 to 442,000 barrels per well. This compares to EURs of 13,000 to 340,000 barrels per well assumed by the EIA (the EIA weighted mean EUR—based on potential number of wells—is 146,000 barrels).[36] EURs in the top four counties are 50% to more than 100% higher than in the remaining parts of the play. The steep well production declines mean that well payout (if it is achieved) comes in the first few years of production, as between 52% and 62% of an average well's lifetime production occurs in the first four years.

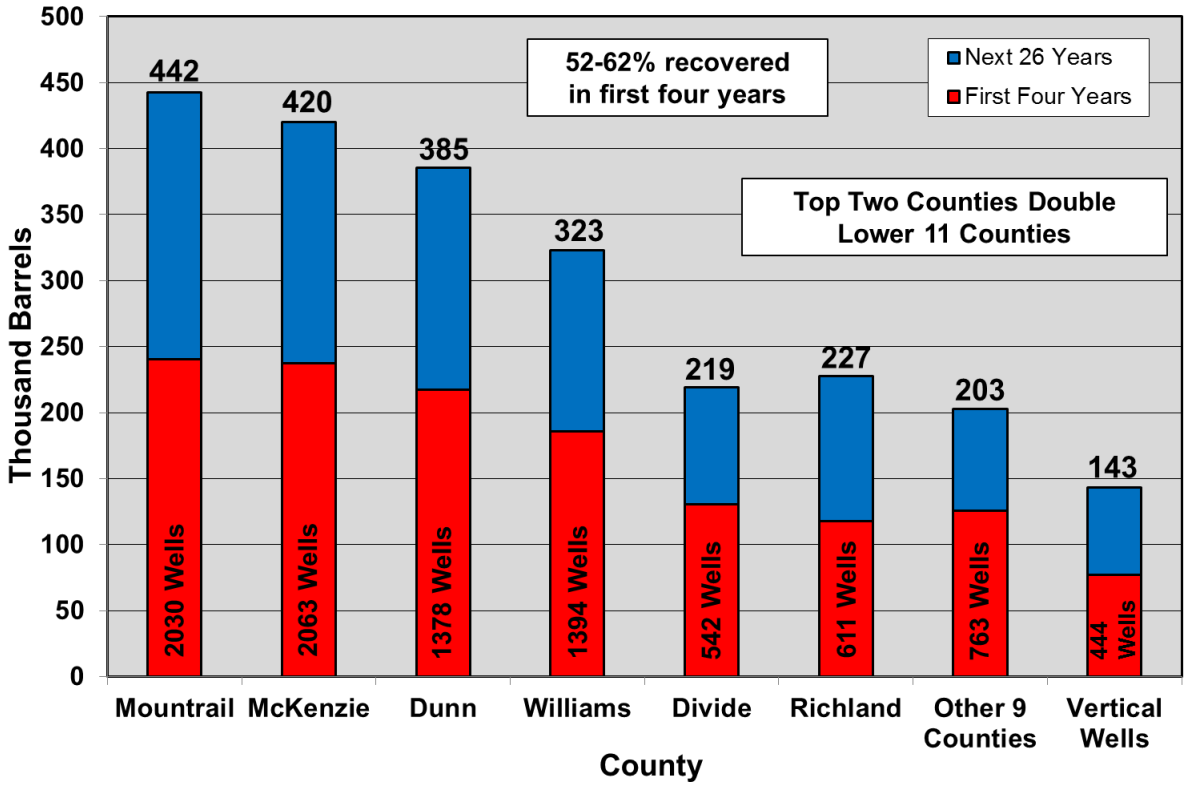


Figure 2-22. Estimated ultimate recovery of oil per well by county for the Bakken play.[37]

EURs are based on average well decline profiles (Figure 2-21) and a terminal decline rate of 13%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years, as are the decline rates at the end of well life. The EURs by county are for horizontal wells only; the EUR for vertical wells is shown at right. The steep decline rates mean that most production occurs early in well life.

[36] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[37] Data from Drillinginfo retrieved September 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the field's decline rate and the average well's first-year production rate, we can calculate the number of wells that need to be drilled each year in order to offset field decline and maintain production. Given that drilling is currently focused on the highest-quality counties, the average first-year production rate per well will necessarily fall as drilling moves into lower-quality counties over time (i.e., as the best locations are drilled off). As average well quality falls, the number of wells that must be drilled to offset field decline must rise, until the drilling rate can no longer offset decline and the field peaks.

Figure 2-23 illustrates the average first-year oil production rate of wells by county. Notwithstanding modest gains in the top four counties, which are also those that are most densely drilled, future technology improvements are unlikely to postpone for long the inevitable decline in average overall well quality as drilling moves into lower quality counties.

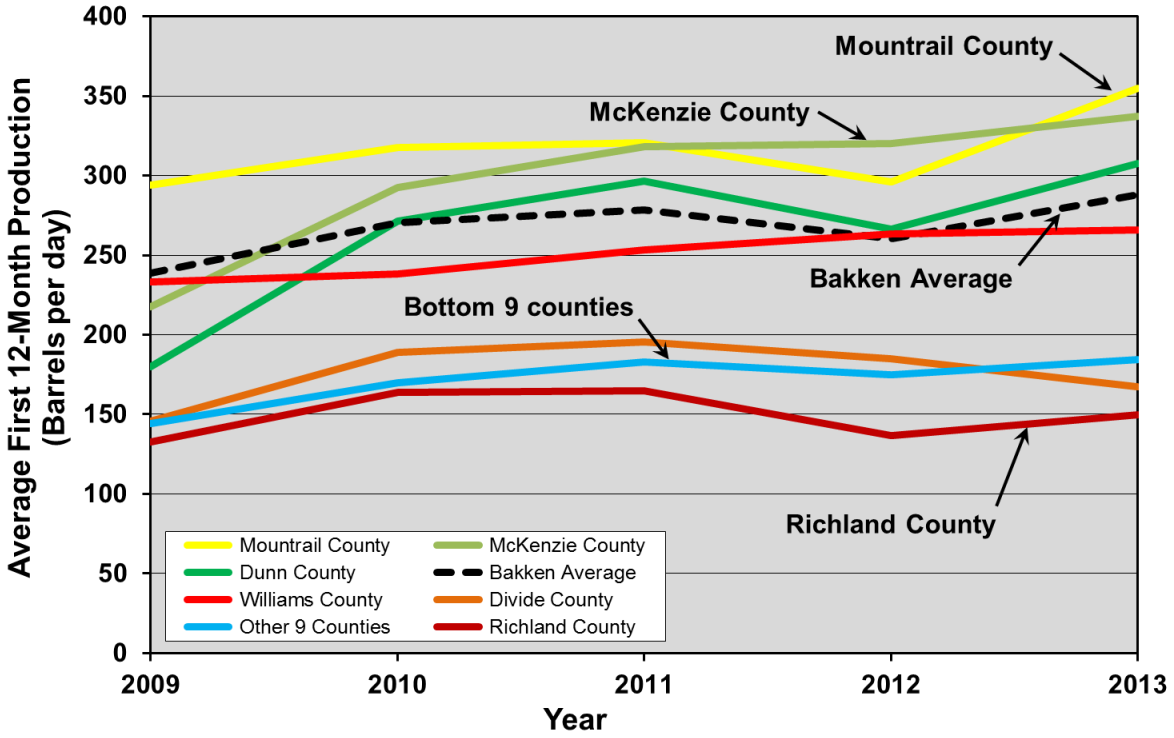


Figure 2-23. Average first-year oil production rates of wells in the Bakken play by county, 2009 to 2013.[38]

Well quality is rising most rapidly in Mountrail County, which is also the county with the current highest well density. First year production rate in the lowest-producing 11 counties, where the bulk of remaining drilling locations are, is flat. The top four counties have roughly double the well quality of the lowest 11.

[38] Data from Drillinginfo retrieved April 2014.

2.3.1.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Bakken, a function of (a) the size of the area worth drilling and (b) the density of drilling that will likely occur. This issue is hotly debated in investor presentations. One of the most optimistic views comes from Continental Resources, one of the first companies to drill in the Bakken, whose CEO claims 100,000 wells may ultimately be drilled.[39] The North Dakota Industrial Commission is bullish, but less so, at 40,000 wells[40] in addition to the 9,225 already drilled. In contrast, the EIA estimates 73,697 wells, 29,186 of which are in the Bakken with the remainder in the Three Forks (obtained from the product of well density and play area in the EIA assumptions[41]).

Determining the likely density at which operators will drill wells requires consideration of both the geology of the play and the mechanics of hydraulic fracturing. Typical wells in the Bakken have horizontal laterals of 10,000 feet in length with 25 or more frack stages. The EIA suggests that the Bakken may be drilled at a density of 2 wells per square mile[42] which would space horizontal laterals 1,320 feet from each other. One operator, Enerplus, suggests (based on a drilling pilot in one of the best areas) that 3.5 wells can be drilled per square mile, including both the Bakken and Three Forks.[43] Continental is testing downspacing of horizontal laterals to just 660 feet apart on four layers of the Bakken and Three Forks, which, if successful, could be up to a staggering 16 wells per square mile.[44] There is no confirmation if this actually worked over a period of time long enough to assess the degree of interference between wells, which would only become apparent after 6-12 or more months of production history.

Wells spaced less than 2,000 feet apart in the Bakken may undergo interference, meaning that wells cannibalize each other's oil over time, as noted by Thuot, based on an empirical analysis of Bakken data.[45] This means that although oil can be produced more quickly by spacing wells closer together than 2,000 feet, the ultimate amount of oil produced per well will be reduced, and the total amount of oil recovered per unit area will not be substantially increased. Thuot concludes:

1. *Well interference in the Bakken appears to occur for hydraulically fractured horizontal wellbores spaced closer than roughly 2,000 feet.*

2. *The magnitude of well interference on production appears to increase over time.*

3. *The full impact of well interference in the analysis above is likely somewhat masked since operators become more proficient in drilling and completion techniques over time. As we saw, secondary wells over-perform when spaced wider than 2,000 feet.*

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[39] Christopher Helman, "Harold Hamm: The Billionaire Oilman Fueling America's Recovery," *Forbes*, April 16, 2014, http://www.forbes.com/sites/christopherhelman/2014/04/16/harold-hamm-billionaire-fueling-americas-recovery.
[40] North Dakota Industrial Commission, *Development of the Bakken Resource*, June 11, 2014, https://www.dmr.nd.gov/oilgas/presentations/ActivityUpdate2014-06-11NCSLBismarck.pdf.
[41] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[42] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[43] Enerplus, "A Deeper Look into the Williston Basin" investor presentation, June 18, 2014, http://www.enerplus.com/files/pdf/investor-relations/Williston%20Basin%20Deck_June%2018_FINAL%202.pdf.
[44] Continental Resources, July 2014 Investor presentation, retrieved August 2014 from http://investors.clr.com/phoenix.zhtml?c=197380&p=irol-presentations.
[45] Kevin Thuot, "There Will Be Blood: Well Spacing & The Bakken Shale Oil Milkshake," Drillinginfo, November 26, 2013, http://info.drillinginfo.com/well-spacing-bakken-shale-oil.

This implies that fractures propagated from a wellbore drain in the order of 1,000 feet from the well. Given that 2 wells per square mile places 10,000 foot laterals 1,320 feet apart, a 2,000-foot spacing would require considerably lower well densities.

Given that the four layers ("benches") of the Three Forks lie between 80 and 250 feet below the middle Bakken target zone, it is likely that wells drilled in the middle Bakken are also draining oil from at least some of the underlying Three Forks benches, ultimately limiting the number of wells needed to effectively recover the oil. Therefore, there are practical limits to well downspacing..

Determining the area actually conducive to drilling is comparatively straightforward. After years of exploration and thousands of wells drilled, operators have delineated the limits of the play and focused their efforts on those areas with proven potential; thus by identifying the farthest-lying wells with little to no production as the likely edge of the play, and estimating the size of the area within that edge which is clearly attracting industry interest, the functional area of the Bakken play can be calculated. By this method, the area likely to be conducive to drilling is approximately 12,700 square miles (see Figure 2-9).

Based on the above parameters, and given the fact that much of the area covered by the Bakken is of much lower quality than the top four counties, an estimate of two wells per square mile may be reasonable for the whole area, with an estimate of three wells per square mile being on the optimistic upside. This translates to approximately 25,400 wells if drilled at a density of two wells per square mile, and 38,100 wells locations if drilled at a density of three wells per square mile. Allowing three wells per square mile on average over the whole region would provide for greater density in the best quality parts of the play and lower density in the outlying lower quality areas.

Of course, these estimates assume that the entire area designated as the Bakken play is available for drilling—failing to account for parks, towns, rivers, reservoirs, and other areas not conducive to drilling. A slightly more conservative but possibly more realistic calculation would include a "risk" that 20% of the play's remaining area will be undrillable. After accounting for wells already drilled, this risk would reduce the total number of potential wells to approximately 21,400 and 31,500 for the two- and three-well per section cases, respectively. Either way, the Bakken play could experience somewhere between three and four times the number of wells drilled to date.

2.3.1.5 Rate of Drilling

The fifth key fundamental is the *rate of drilling*. As noted earlier, the Bakken play has a field decline of 45% per year, meaning that 45% of production has to be replaced with new wells each year to keep production flat. As the amount of oil produced from an average well in its first year of production is known from the data, the number of wells needed to offset field production decline each year at a given production level can be easily calculated. For the Bakken, at current production levels, some 1,470 wells must be drilled each year just to keep production flat. Since drilling rates in the Bakken are now at about 2,000 wells per year, production will keep growing as long as these rates are sustained. However, the higher production grows, the more wells are needed to offset the 45% field decline. And as drilling moves into lower quality parts of the play, even more wells will be needed, for as illustrated above (Figure 2-23), well quality in 11 of the 15 counties is at least 40% lower than in the best four.

2.3.1.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Bakken play were developed to illustrate the effects of changing the rate of drilling and the number of drilling locations. These production projections intentionally ignore questions of economics (e.g., the amount of capital required and whether oil prices would support drilling in less productive areas) or politics (e.g., community opposition, new government regulation) in order to analyze what is technically possible.

The projections are given in three cases, differentiated by the number of drilling locations:

1. A "Low Well Density Case" of 100% of the play area being drillable, at 2 wells per square mile. (The EIA assumes that 2 wells can be drilled per square mile in the Bakken and 2.5 wells per square mile can be drilled in the underlying Three Forks.)

2. An "Optimistic Case" of 100% of the play area being drillable at 3 wells per square mile.

3. A "Realistic Case" of 80% of the remaining play area being drillable (i.e., the remaining play area is "risked" at 80% to account for undrillable areas like parks, towns, rivers, etc.), at 3 wells per section.

Each case includes three scenarios, differentiated by the rate of drilling:

1. MOST LIKELY RATE scenario: Drilling continues at the current rate of 2,000 wells per year and then declines to 1,000 wells per year as drilling moves into the lower quality counties.

2. EXPANDED RATE scenario: Drilling increases to 2,500 wells per year and then declines to 1,500 wells per year as drilling moves into the lower quality counties.

3. FASTEST RATE scenario: Drilling is increased 50% over the current rate to 3,000 wells per year, and held constant until locations run out.

The critical parameters used for determining production rates in these scenarios are given in Table 2-1.

Parameters	Counties							Total
	Divide	Dunn	McKenzie	Mountrail	Richland	Williams	Other 9	
Production Jan 2014 (Kbbl/d)	38	165	296	245	29	143	50	966
% of Field Production	4	17	31	25	3	15	5	100
Cumulative Oil (million bbls)	40	172	249	344	52	150	56	1063
Cumulative Gas (Bcf)	44	123	363	237	53	182	49	1050
Number of Wells	542	1378	2063	2030	611	1394	763	8781
Number of Horizontal Producing Wells	524	1282	1875	1896	565	1318	693	8153
Average EUR per well (Kbbls)	219	385	420	443	227	323	203	378
Field Decline (%)	51	38	49	40	30	50	54	45
3-Year Well Decline (%)	85	84	88	86	73	88	88	85
Average First Year Production in 2013 (bbl/d)	169	308	344	376	148	271	180	296
New Wells Needed to Offset Field Decline	115	202	418	258	60	266	150	1468
Area in square miles	1259	2010	2742	1824	2084	2071	18000	29990
% Prospective	60	60	75	65	55	90	25	39
Net square miles	755	1206	2057	1186	1146	1864	4500	12714
Well Density per square mile	0.72	1.14	1.00	1.71	0.53	0.75	0.17	0.75
Additional locations to 2/sq. Mile	969	1034	2050	341	1681	2334	8237	16646
Additional locations to 3/sq. Mile	1724	2240	4107	1527	2828	4198	12737	29360
Population	2071	3536	6360	7673	9667	22398	N/A	N/A
Total Wells 2/sq. Mile	1511	2412	4113	2371	2292	3728	9000	25427
Total Wells 3/sq. Mile	2266	3618	6170	3557	3439	5592	13500	38141
Total Wells 2/sq. Mile Risked at 80%	1317	2205	3703	2303	1956	3261	7353	22098
Total Wells 3/sq. Mile Risked at 80%	1921	3170	5348	3251	2873	4752	10953	32269

Table 2-1. Parameters for projecting Bakken tight oil production, by county

Area in square miles under "Other" is estimated.

Low Well Density Case

In the "Low Well Density Case" (Figure 2-24), assuming 100% of the area is drillable, approximately 17,700 wells remain to be drilled on top of the more than 8,500 wells currently producing, for a total of 25,500 wells (including wells no longer producing).

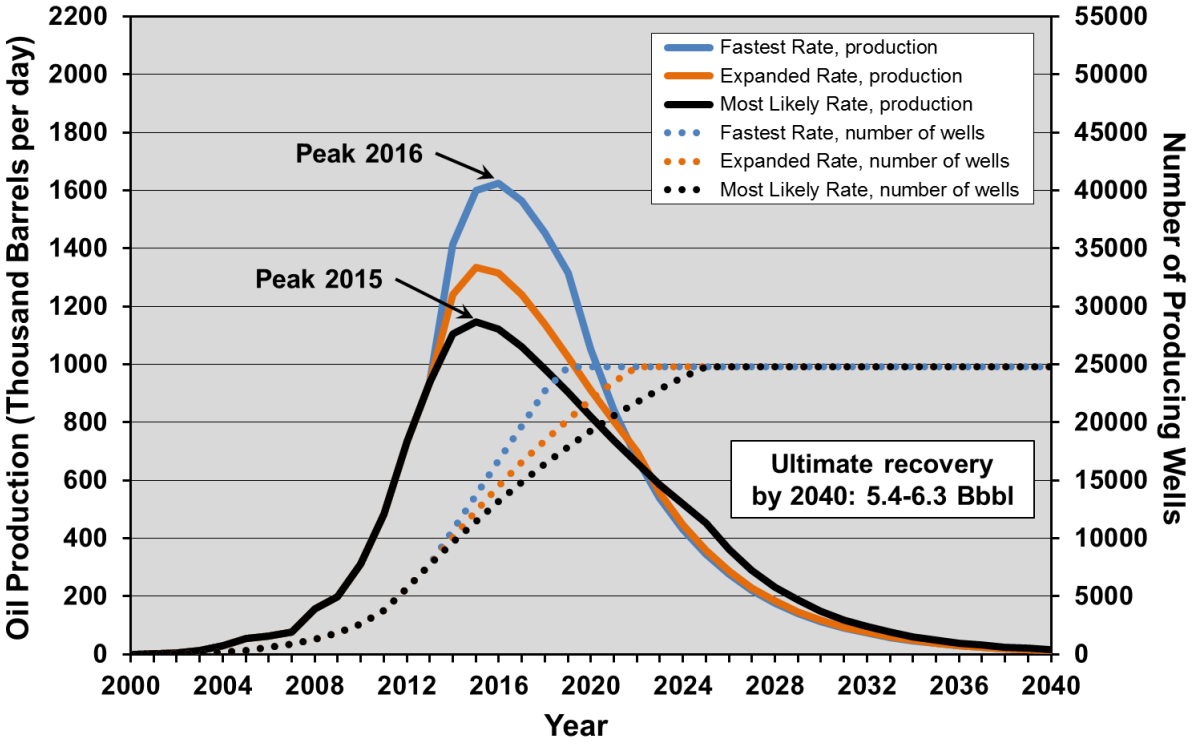

Figure 2-24. Three drilling rate scenarios of Bakken tight oil production, in the "Low Well Density Case" (100% of play area is drillable at two wells per square mile).[46]

"Most Likely Rate" scenario: drilling continues at 2,000 wells/year, declining to 1,000 wells/year; "Expanded Rate" scenario: drilling increases to 2,500 wells/year, declining to 1,500 wells/year; "Fastest Rate" scenario: drilling increases to 3,000 wells/year, holding constant.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2015 at 1.15 MMbbl/d. Drilling continues until 2025, and total oil recovery by 2040 is 5.4 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2015 at 1.33 MMbbl/d. Drilling continues until 2022, and total oil recovery by 2040 is 5.7 billion barrels. Production would be lower after 2023 than in the "Most Likely Rate" case as faster drilling would recover the oil sooner.

3. FASTEST RATE scenario: Peak production occurs in 2016 at 1.63 MMbbl/d. Drilling continues until 2019, and total oil recovery by 2040 is 6.3 billion barrels. As in the "Expanded Rate" scenario, production would be lower after 2023 than in the "Most Likely Rate" case.

[46] Data from Drillinginfo retrieved September 2014.

Optimistic Case

If technological advances allow for a denser drilling footprint of three wells per section, ultimate recovery increases somewhat—but the timing of production peaks remain virtually the same (pushed back by only a year). This case would see the drilling of 29,400 wells on top of the more than 8,500 currently producing wells for a total of 38,100 wells (including wells no longer producing). Figure 2-25 illustrates this "Optimistic Case."

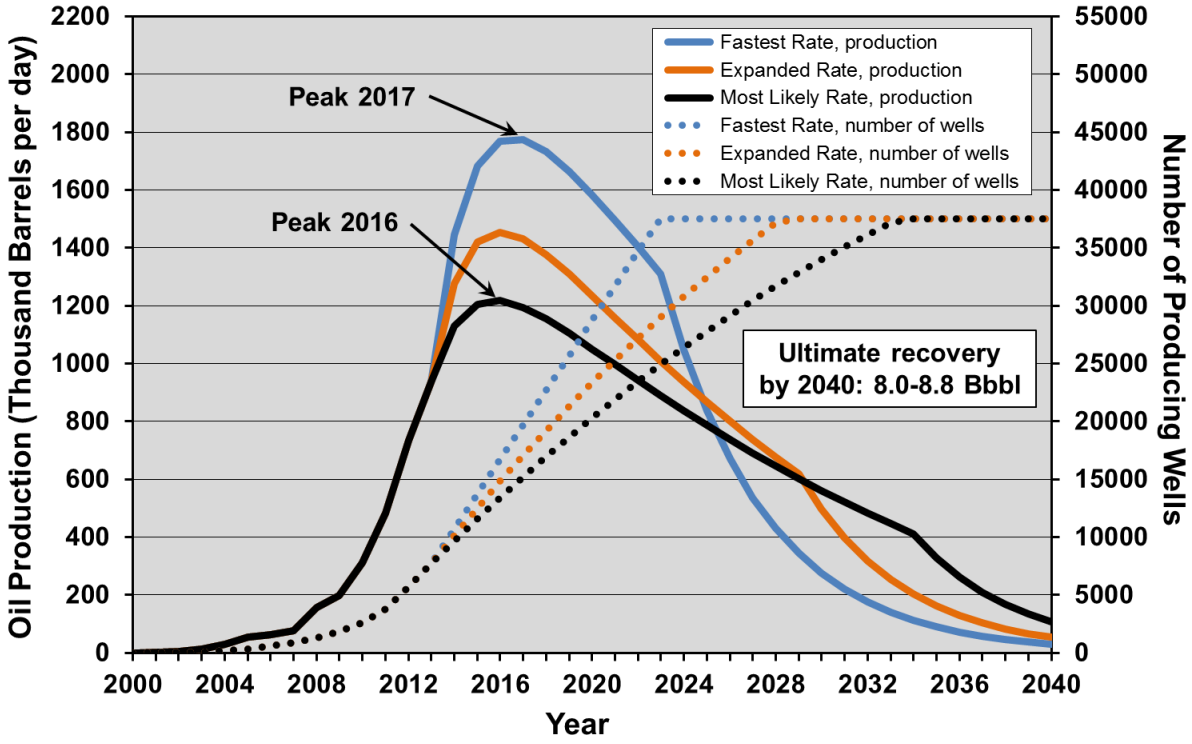

Figure 2-25. Three drilling rate scenarios of Bakken tight oil production, in the "Optimistic Case" (100% of play area is drillable at three wells per square mile).[47]

"Most Likely Rate" scenario: drilling continues at 2,000 wells/year, declining to 1,000 wells/year; "Expanded Rate" scenario: drilling increases to 2,500 wells/year, declining to 1,500 wells/year; "Fastest Rate" scenario: drilling increases to 3,000 wells/year, holding constant.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2016 at 1.22 MMbbl/d. Drilling continues until 2034, and total oil recovery by 2040 is 8.0 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2016 at 1.45 MMbbl/d. Drilling continues until 2029, and total oil recovery by 2040 is 8.3 billion barrels.

3. FASTEST RATE scenario: Peak production occurs in 2017 at 1.77 MMbbl/d. Drilling continues until 2023, and total oil recovery by 2040 is 8.8 billion barrels. In this scenario, production would be considerably lower after 2026 than in the "Most Likely Rate" scenario.

[47] Data from Drillinginfo retrieved September 2014.

Realistic Case

A more realistic case (Figure 2-26) is that 80% of the remaining play area will be drillable at three wells per square mile (i.e., the case includes a "risk" that 20% of the play remaining area will be undrillable). This allows for surface features that preclude drilling, such as towns, rivers, reservoirs, parks and other surface features which may limit access for drilling. This scenario would see the drilling of 23,500 wells on top of the more than 8,500 currently producing wells for a total of 32,300 wells (including wells no longer producing).

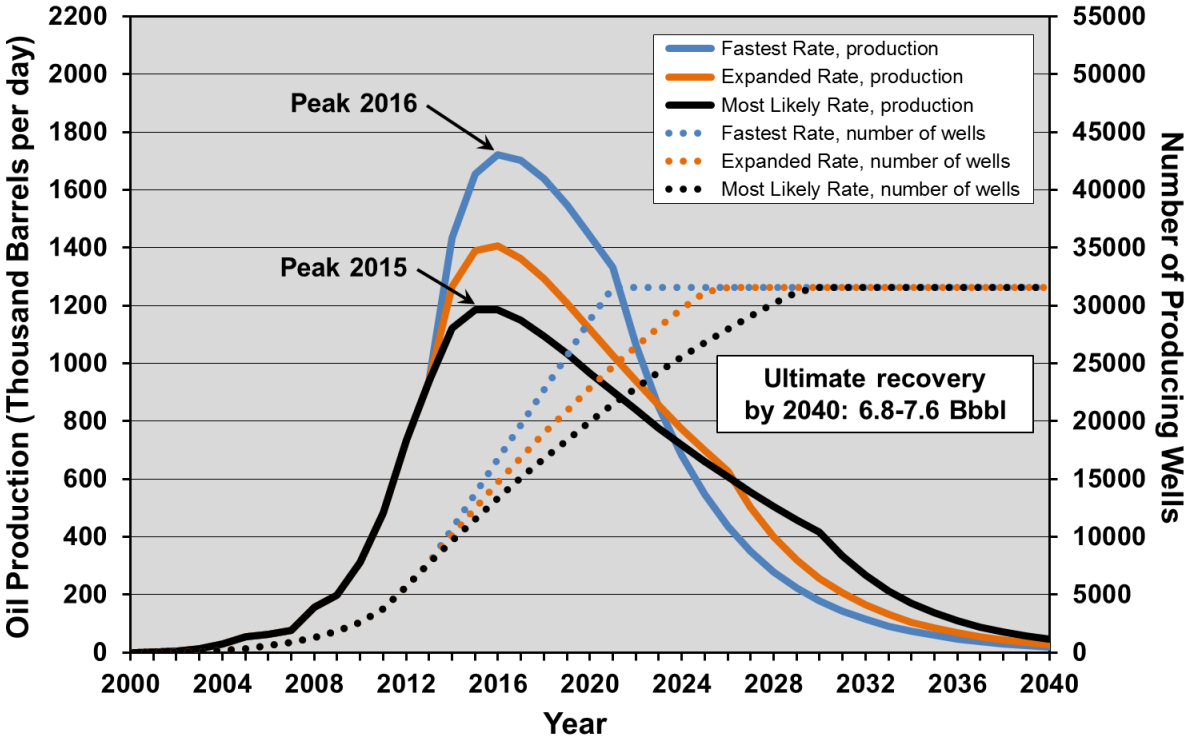

Figure 2-26. Three drilling rate scenarios of Bakken tight oil production, in the "Realistic Case" (80% of the remaining play area is drillable at three wells per square mile).[48]

"Most Likely Rate" scenario: drilling continues at 2,000 wells/year, declining to 1,000 wells/year; "Expanded Rate" scenario: drilling increases to 2,500 wells/year, declining to 1,500 wells/year; "Fastest Rate" scenario: drilling increases to 3,000 wells/year, holding constant.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2015 at 1.19 MMbbl/d. Drilling continues until 2030, and total oil recovery by 2040 is 6.8 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2016 at 1.41 MMbbl/d. Drilling continues until 2026, and total oil recovery by 2040 is 7.1 billion barrels.

3. FASTEST RATE scenario: Peak production occurs in 2016 at 1.72 MMbbl/d. Drilling continues until 2021, and total oil recovery by 2040 is 7.6 billion barrels. In this scenario, production would be considerably lower after 2024 than in the "Most Likely Rate" scenario.

[48] Data from Drillinginfo retrieved September 2014.

2.3.1.7 Comparison to EIA Forecast

Figure 2-27 compares the EIA's reference case projection for Bakken tight oil production to the "Most Likely Rate" scenario of the "Realistic" case presented above.

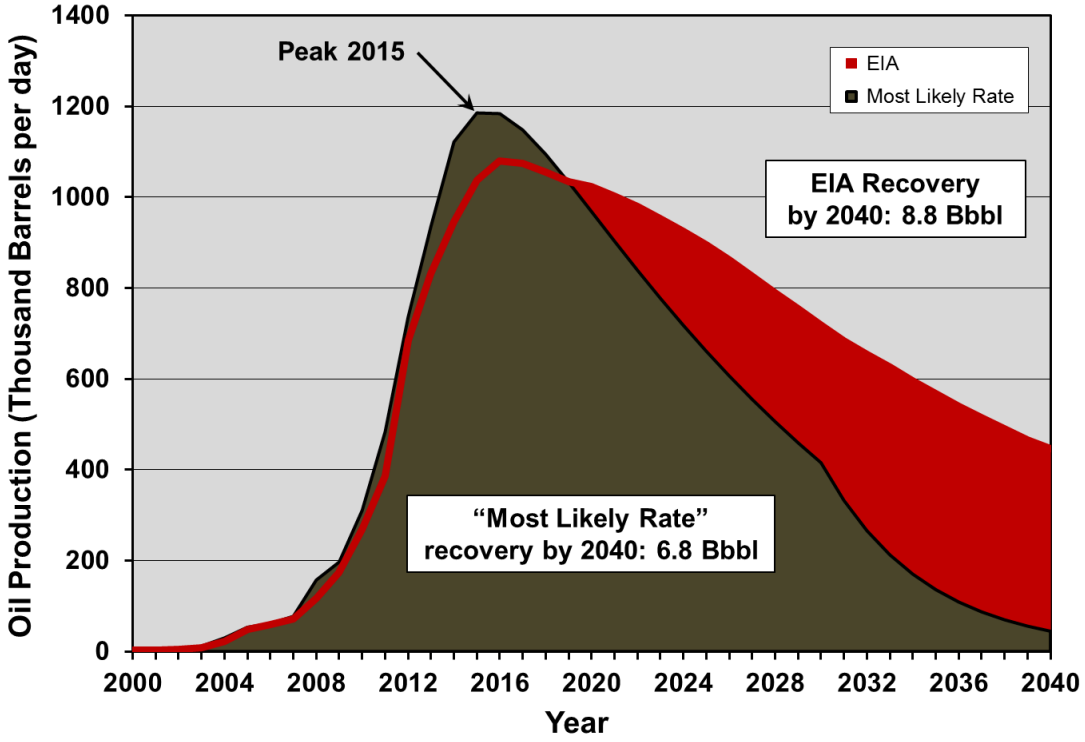

Figure 2-27. "Most Likely Rate" scenario ("Realistic" case) of Bakken tight oil production compared to the EIA reference case, 2000 to 2040.[49]

In this "Most Likely Rate" scenario, drilling continues at 2,000 wells/year, declining to 1,000 wells/year.

This comparison reveals:

- The EIA's forecast of the timing of peak production (2016) in the Bakken is similar to the projection of this report.
- The EIA's forecast of the production rate at peak (1.08 million bpd) is lower than the projection of this report (1.19 million bpd), but only slightly.
- The EIA projects a higher tail of production after peak, with estimated ultimate recovery (EUR) of 8.8 billion barrels by 2040 (7.9 billion for 2014-2040) as opposed this report's projection of 6.8 billion barrels by 2040 (5.7 billion for 2014-2040).

In short, the EIA is forecasting 2.2 billion additional barrels of future Bakken production than this report finds substantiated.

[49] EIA, *Annual Energy Outlook 2014.*

2.3.1.8 Bakken Play Analysis Summary

Several conclusions can be made from the foregoing analysis of the Bakken play:

1. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. The observed 45% per year field decline rate requires the drilling of 1,470 wells per year just to maintain current production levels.

2. The production profile is most dependent on drilling rate and to a lesser extent the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Drilling rate is determined by capital input, which currently is about $16 billion per year to drill 2,000 wells, not including leasing and other ancillary costs.

3. Peak production is highly likely to occur in the 2015 to 2017 timeframe and will occur at between 1.15 and 1.77 MMbbl/d. The most likely peak is between 1.15 and 1.22 MMbbl/d in the 2015 to 2016 timeframe.

4. Increased drilling rates will raise the level of peak production and move it forward a few months but do not appreciably increase cumulative oil recovery through 2040. Increased drilling rates effectively recover the oil sooner, making the supply situation worse later.

5. The projected recovery of 6.8 billion barrels by 2040 in the "Most Likely Rate" scenario (2,000 wells/year declining to 1,000 wells/year) of the "Realistic" case (80% of play drillable, at 3 wells per square mile), agrees fairly well with the mean estimate of latest USGS assessment of the Bakken (including the Three Forks) of 7.4 billion barrels.[50]

6. These projections are optimistic in that they assume the capital will be available for the drilling "treadmill" that must be maintained (roughly $188 billion is needed to drill more than 23,500 wells, exclusive of leasing and ancillary costs). This is not a sure thing as drilling in the poorer-quality parts of the play will require much higher oil prices to be economic. Failure to maintain drilling rates will result in a steeper drop-off in production.

7. Nearly four times the current number of wells will be required to recover 6.8 billion barrels by 2040 in the "Realistic" case.

8. Projections that the Bakken will continue to grow and then maintain a plateau followed by a gentle decline for the foreseeable future[51] are unlikely to be realized.

[50] USGS, *Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota*, 2013, http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.
[51] North Dakota Industrial Commission, *Development of the Bakken Resource*, June 11, 2014, https://www.dmr.nd.gov/oilgas/presentations/ActivityUpdate2014-06-11NCSLBismarck.pdf.

2.3.2 Eagle Ford Play

The EIA forecasts recovery of 10.8 billion barrels of oil from the Eagle Ford play by 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Eagle Ford play of southern Texas is now the largest tight oil play in the U.S; it was unknown prior to 2007. In the EIA's analysis, the Eagle Ford play totals 11,165 square miles.[52] This report considers a surface area for the Eagle Ford defined by where productive drilling has actually occurred; after years of exploration, Eagle Ford producers have presumably focused their efforts on those areas with proven potential. By identifying the farthest-lying wells with little to no production as the likely edge of the play, and estimating the size of the area within that edge that is clearly attracting industry interest, the functional prospective area of the Eagle Ford play is calculated at approximately 7,200 square miles. Forecasts of production outside this area cannot substantiated by currently available drilling information. Figure 2-28 illustrates the distribution of tight oil wells as of mid- 2014 as well as the significantly larger EIA play boundary. More than 10,500 wells have been drilled to date, of which 10,088 were producing oil at the time of writing.

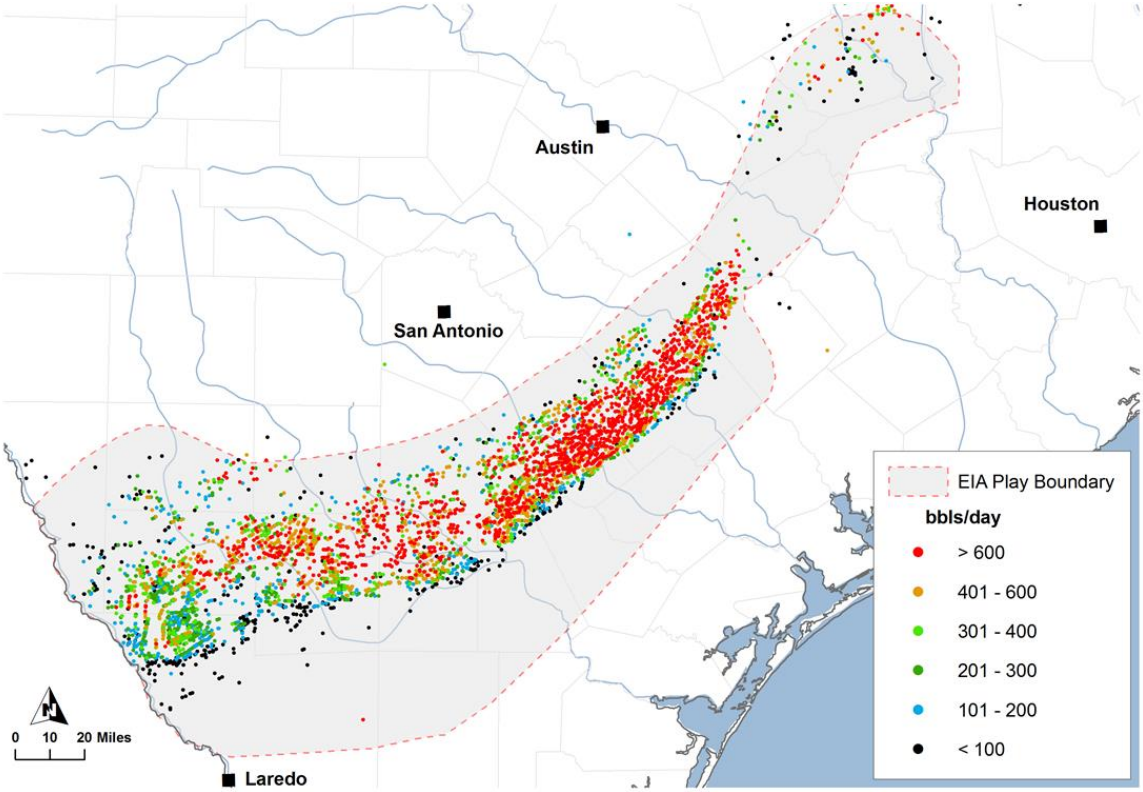

Figure 2-28. Distribution of wells in the Eagle Ford as of mid-2014 illustrating highest one-month oil production (initial productivity, IP),[53] with EIA play boundary.[54]

The size of the Eagle Ford play as defined by the extent of where productive drilling has actually occurred is approximately 7,200 square miles, in contrast to the much larger area designated as the play by the EIA. Well IPs are categorized approximately by percentile; see Appendix.

[52] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf .
[53] Data from Drillinginfo retrieved August 2014.
[54] At publication, the most recent shapefile for the EIA's play area for the Eagle Ford was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.

The play covers parts of 28 counties although most drilling is concentrated in six counties which account for 81% of production.

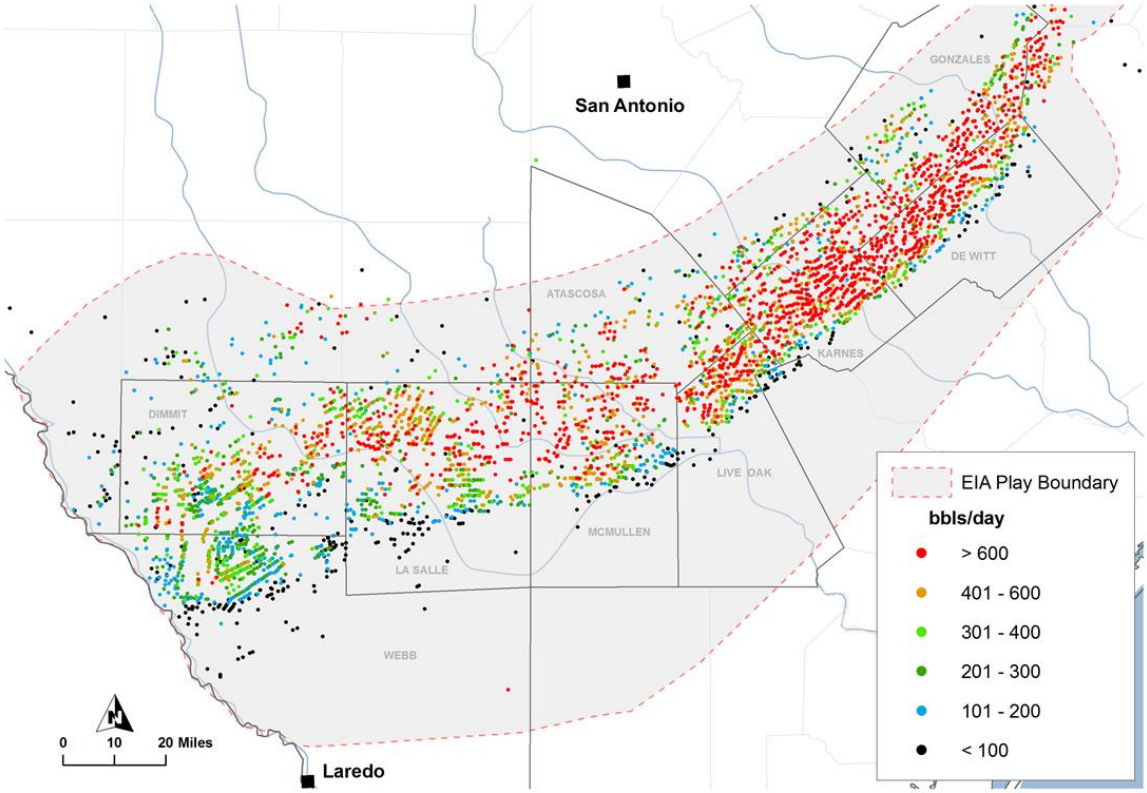

Figure 2-29. Detail of Eagle Ford play showing distribution of wells as of mid-2014 illustrating highest one-month oil production (initial productivity, IP),[55] with EIA play boundary.[56]

The top six producing counties are indicated. Well IPs are categorized approximately by percentile; see Appendix.

[55] Data from Drillinginfo retrieved August 2014.
[56] At publication, the most recent shapefile for the EIA's play area for the Eagle Ford was dated May 2011, available at http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm#geodata.

The Eagle Ford is both a prolific oil producer and a natural gas producer. It has oil, wet gas and dry gas windows, with oil being produced up dip (i.e., in the shallower part of the formation) along the northwestern portion of the field and gas in the down dip (i.e., in the deeper part of the formation) southeastern portion. Figure 2-30 illustrates the distribution of wells classified as "oil" and "gas" in the main part of the field stretching northeast from the Mexican border.

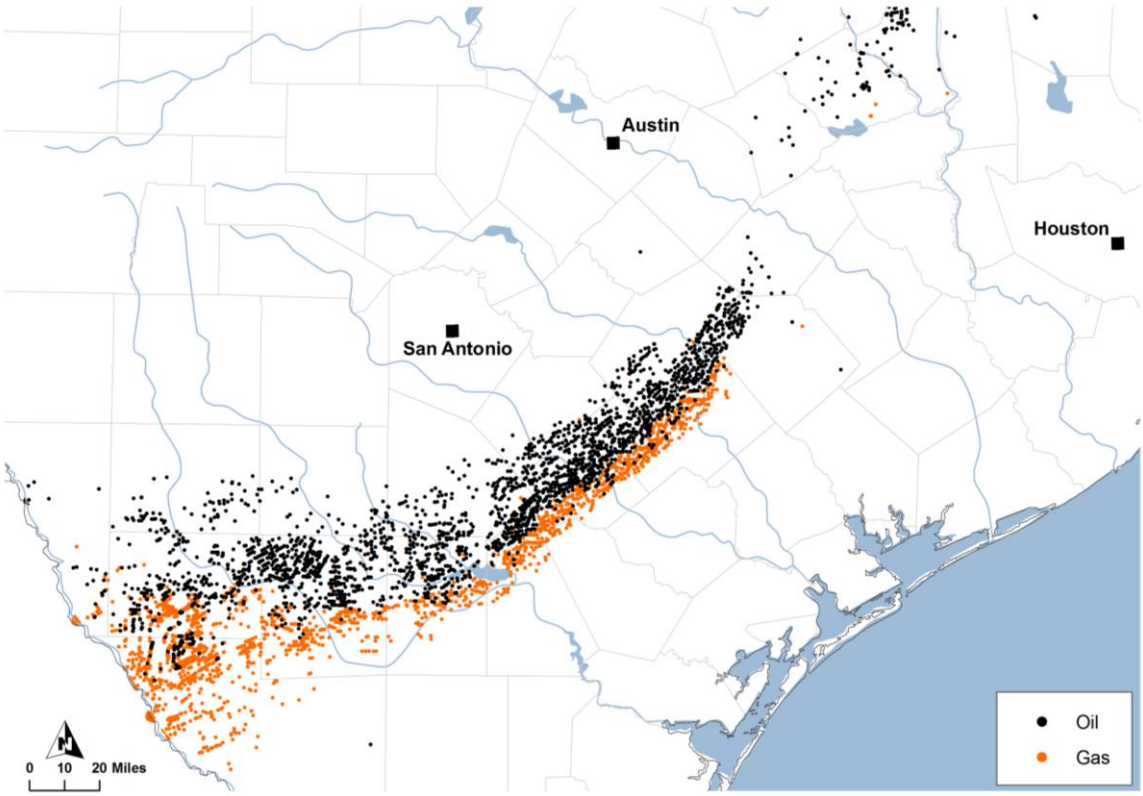

Figure 2-30. Distribution of oil and gas wells in the main portion of the Eagle Ford play as of early 2014.[57]

The Mexican border is on the left. Orange wells are classified as "gas" and black wells are classified as "oil".

[57] Data from Drillinginfo retrieved August 2014.

Production in the Eagle Ford was nearly 1.3 million barrels of oil and 4.9 billion cubic feet of gas per day at the time of writing, as illustrated in Figure 23. Gas production is expressed in Figure 2-31 as barrels of oil equivalent (6,000 cubic feet of gas equals approximately one barrel of oil on an energy equivalent basis). Ninety-eight percent of this production is from horizontal fracked wells. The rate of drilling has grown from about 500 wells per year in early 2011 to about 3,500 wells per year in 2014.

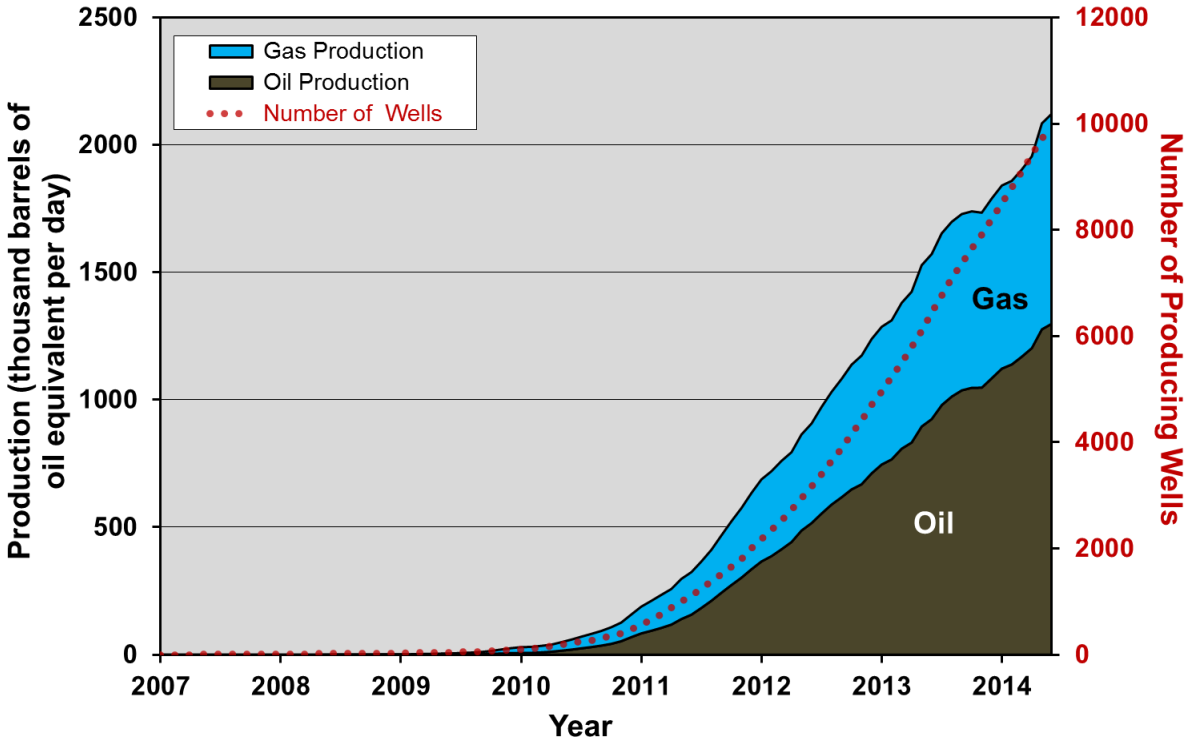

Figure 2-31. Eagle Ford play tight oil and gas production and number of producing wells, 2007 to 2014.[58]

Gas production is expressed as "barrels of oil equivalent" (6,000 cubic feet of gas is approximately equivalent to one barrel of oil on an energy basis).

[58] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The amount of oil added to total play production by each new well has been declining since mid-2011 as illustrated in Figure 2-32.

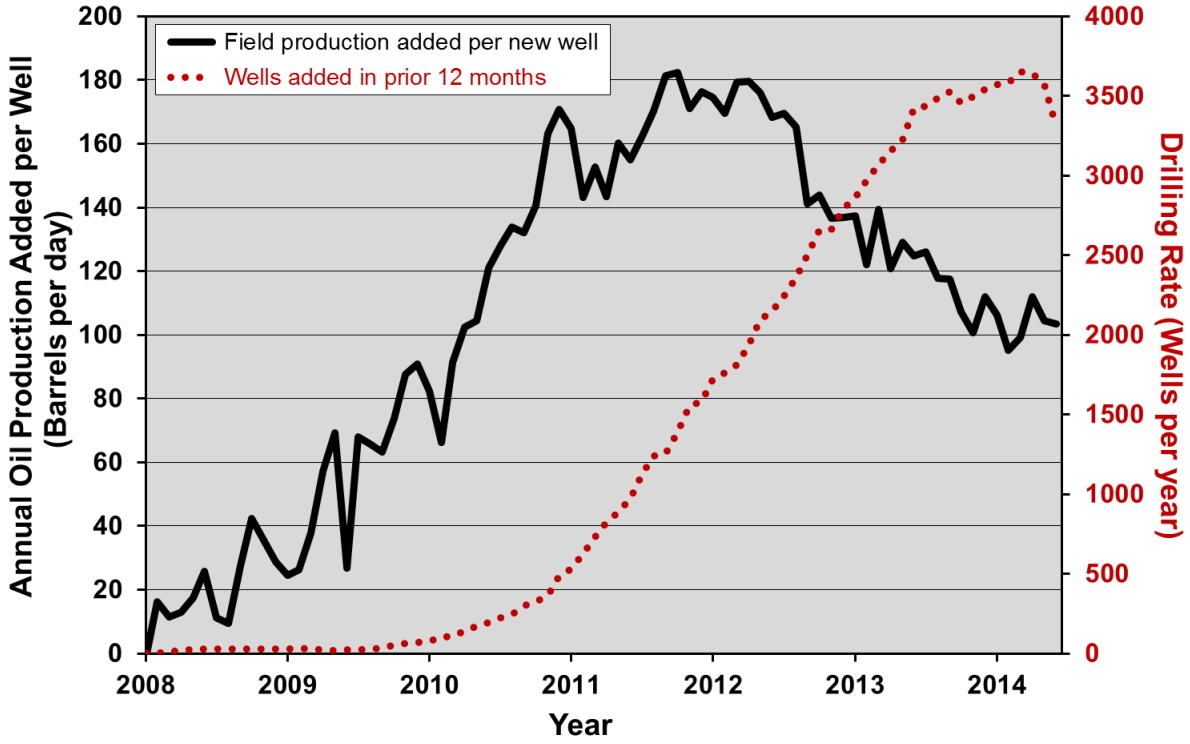

Figure 2-32. Annual oil production added per new well and annual drilling rate in the Eagle Ford play, 2008 through 2014, 2008 to 2014.[59]

[59] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

2.3.2.1 Well Decline

The first key fundamental in determining the life cycle of Eagle Ford production is the *well decline rate*. Eagle Ford wells exhibit high decline rates in common with all shale plays. Figure 2-33 illustrates the average decline profile of Eagle Ford horizontal wells, both for oil alone and for oil and gas on a "barrels of oil equivalent" basis. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life for oil and gas is 79% and 80%, respectively.

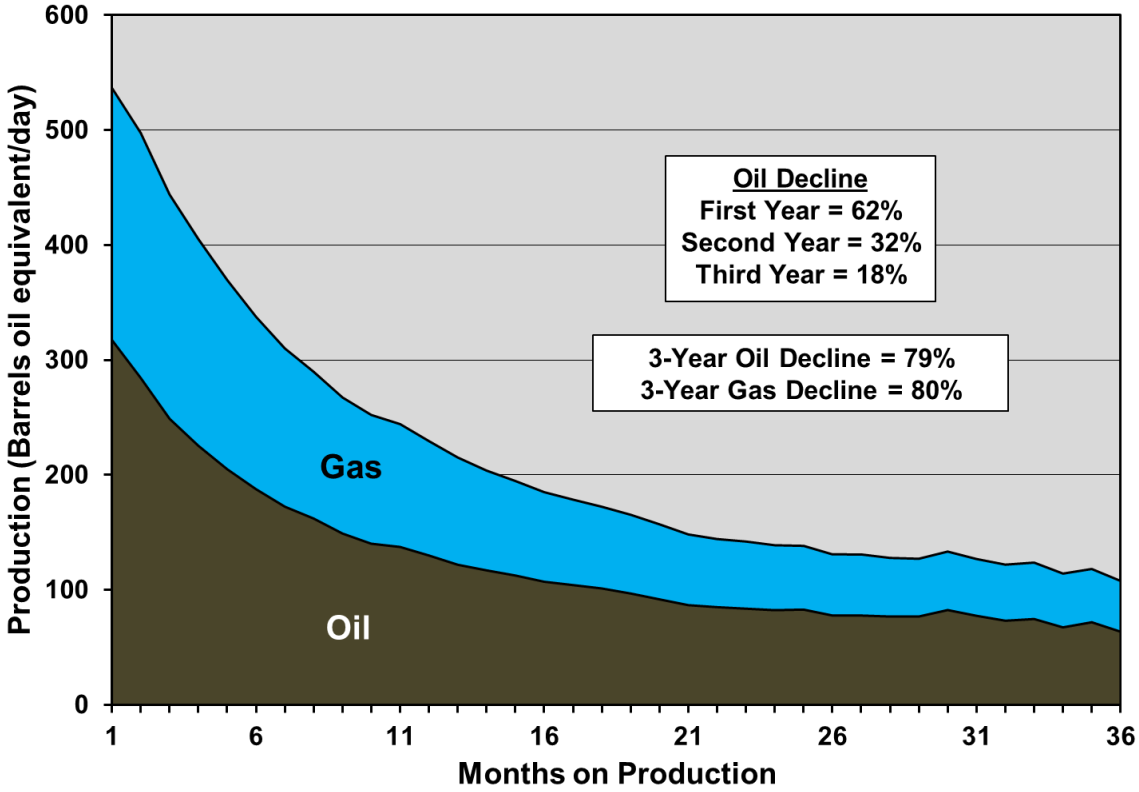

Figure 2-33. Average decline profile for horizontal tight oil and shale gas wells in the Eagle Ford play.[60]

Gas has been converted to barrels of oil on an energy equivalent basis. Decline profile is based on all horizontal wells drilled since 2009.

[60] Data from Drillinginfo retrieved May 2014.

2.3.2.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in a year without more drilling. Figure 2-34 illustrates oil production from the 5,800 horizontal wells spudded (i.e., drilling was started) prior to 2013, and the 4,964 wells actually producing prior to 2013 (wells are being drilled at such a high rate that many wells drilled prior to 2013 were not connected and producing until well into 2013). The first-year decline for producing wells is 38%. This is lower than the well decline rate as the field decline is made up of new wells, declining at high rates, and older wells, declining at lesser rates. As will be shown later, a field decline of 38% requires 2,285 wells to offset at current production levels, representing capital input of $18.3 billion assuming an average well cost of $8 million.

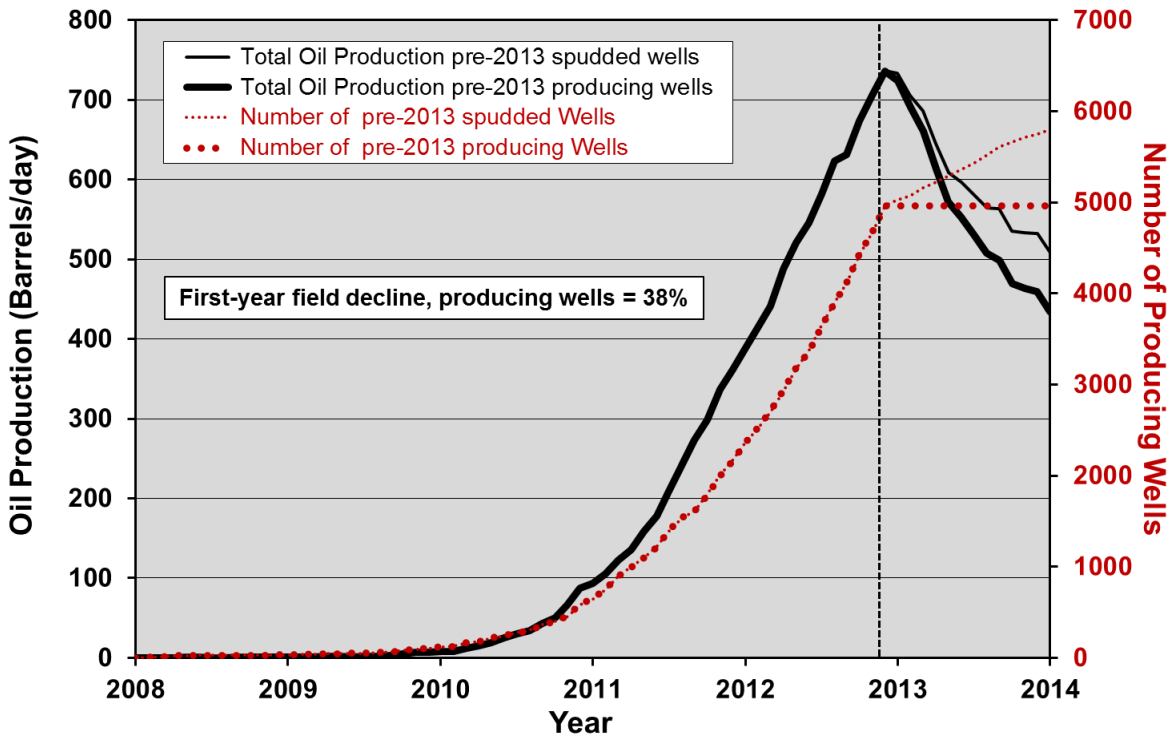

Figure 2-34. Production rate and number of horizontal tight oil wells in the Eagle Ford spudded or producing prior to 2013.[61]

Many of the spudded wells were not connected and producing until well into 2013. In order to offset the 38% field decline rate, 2,285 new wells per year producing at 2013 levels would be required.

[61] Data from Drillinginfo retrieved May 2014.

Figure 2-35 illustrates the same analysis on a "barrels of oil equivalent" basis to account for the large amounts of gas also produced. Field decline for wells producing prior to 2013 is 42% in the first year on a barrels oil equivalent basis, and for gas on a standalone basis is 47%.

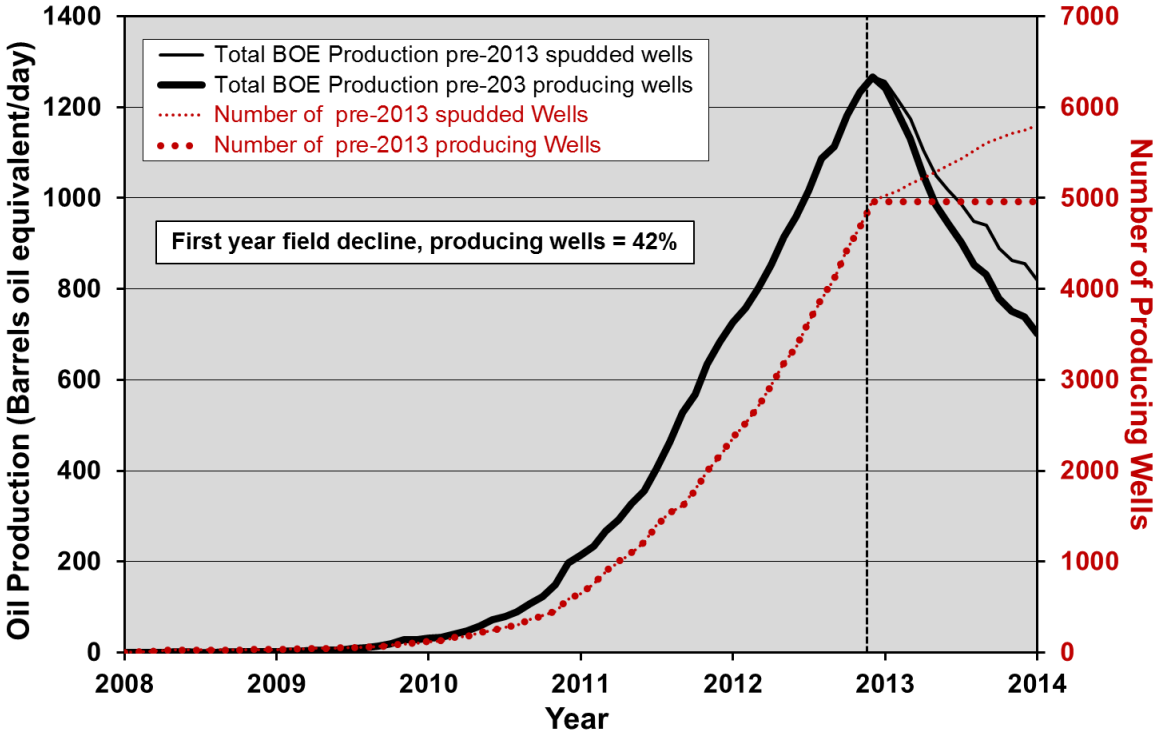

Figure 2-35. Production rate and number of horizontal tight oil wells in the Eagle Ford spudded or producing prior to 2013, including gas on a "barrels of oil equivalent" basis.[62]

Field decline is 42% per year for oil and gas on a "barrels of oil equivalent" basis, and for gas on a standalone basis is 47%.

[62] Data from Drillinginfo retrieved May 2014.

2.3.2.3 Well Quality

The third key fundamental is the trend of *average well quality* over time. As noted earlier, petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, which along with multi-well pad drilling has reduced well costs. It is, however, approaching the limits of diminishing returns and improvements in average well quality are flat to very slightly increasing at best.

Figure 2-36 illustrates production rate trends in oil, gas and "barrels of oil equivalent" from 2009 to 2013 based on the average first year production of wells. On a barrels of oil equivalent basis (BOE) there has been no improvement since 2012, whereas there has been a 4% improvement in oil productivity and a decrease in gas productivity. These trends reflect the shift in operator emphasis to liquids production with the low price of gas, focusing drilling in the oil window of the Eagle Ford, as well as concentrating on the sweet spots defined in the initial wave of drilling. The lack of improvement on a BOE basis suggests better technology is having a very limited, if any, effect; there appears to still be room for significant numbers of new wells in sweet spots, so operators have not yet been forced to move into lower quality parts of the play.

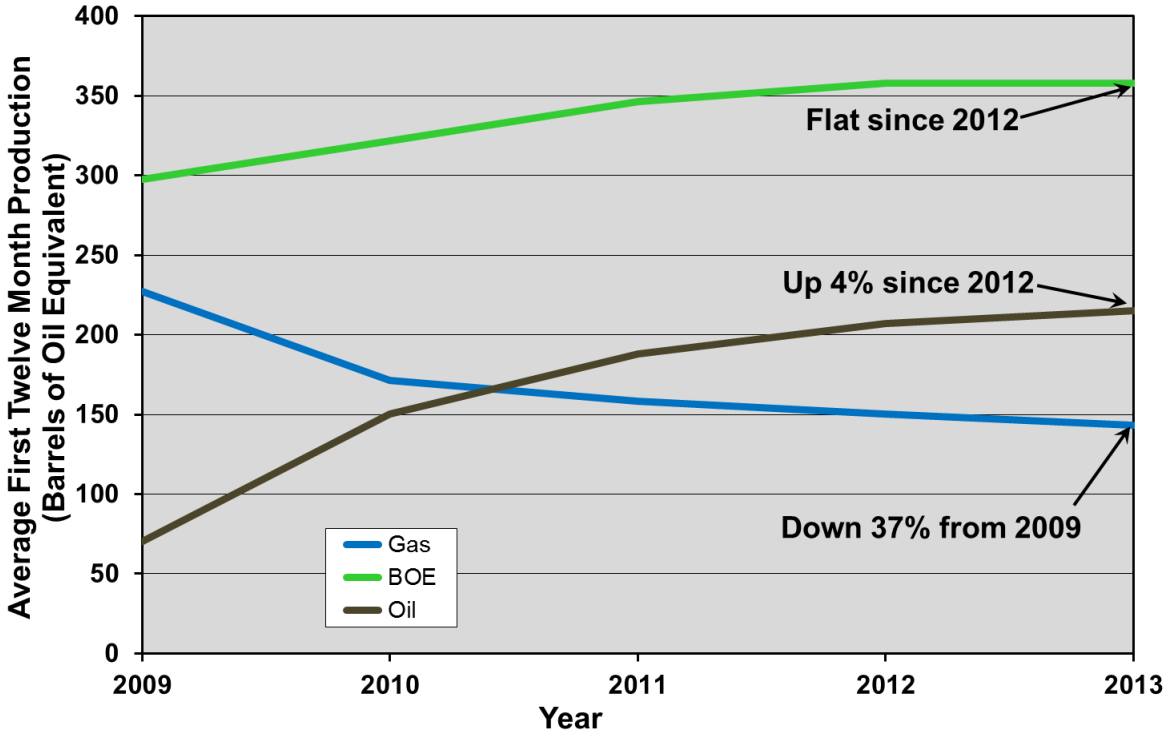

Figure 2-36. Average first year production rates for Eagle Ford wells from 2009 to 2013.[63]

Total production on a "barrels of oil equivalent" basis is unchanged since 2012, whereas oil has risen slightly and gas has fallen. This reflects the focus on liquids production over gas and the concentration of drilling in the oil window of the field, as well as the focus on proven sweet spots, along with likely limited gains from technological improvements in the most recent year.

[63] Data from Drillinginfo retrieved May 2014.

Another measure of well quality is cumulative production and well life. Figure 2-37 illustrates the cumulative production of all oil wells that were producing in the Eagle Ford as of March 2014. Eighty-nine percent of these wells are less than 3 years old, and knowing that production will be down nearly 80% after 3 years, their economic lifespan is uncertain. Although it can be seen that there are a few very good wells that recovered more than 400,000 barrels of oil in the first few years, and undoubtedly were great economic successes, the average well has produced just 72,145 barrels over a lifespan averaging 20 months. Less than 1% of these wells are more than 5 years old. The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer—this is conjectural at this point given the lack of long-term well-performance data.

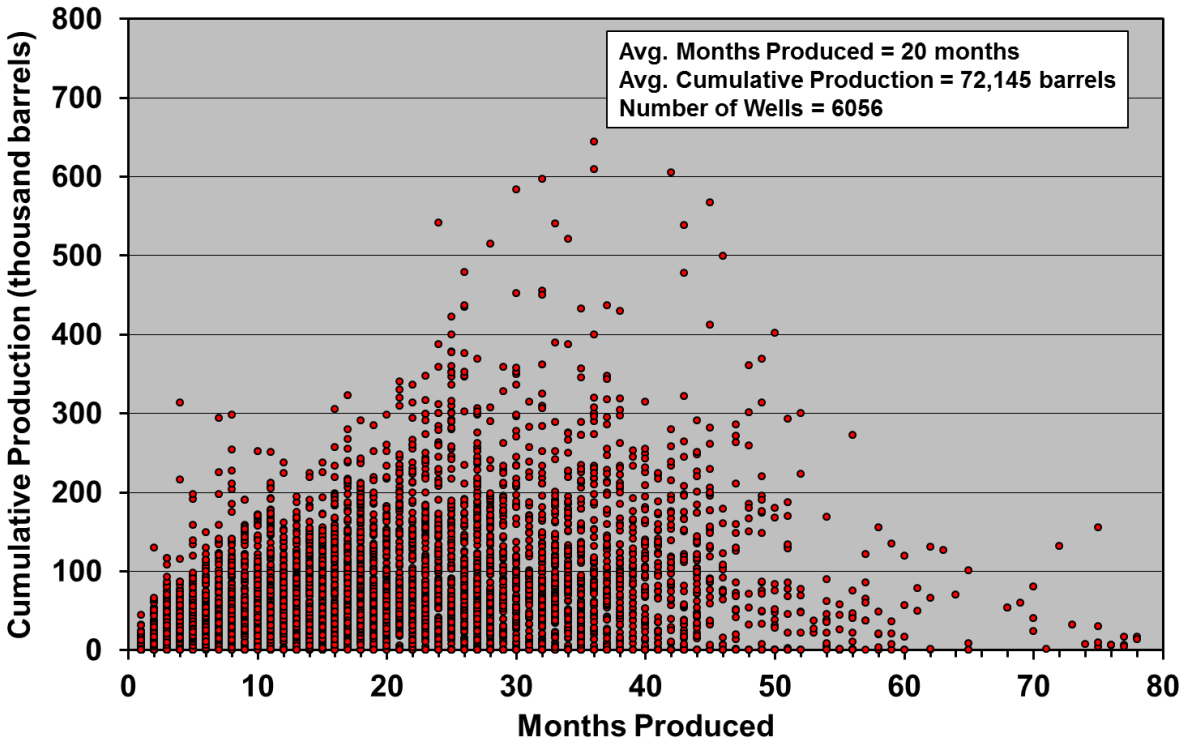

Figure 2-37. Cumulative oil production and months produced for Eagle Ford wells that were producing as of March 2014.[64]

Very few wells are greater than five years old, with a mean age of 20 months and a mean cumulative recovery of 72,145 barrels.

[64] Data from Drillinginfo retrieved September 2014. Note that only leases with one well and individual wells are included in this figure (Texas has a practice of lumping production from multi-well leases with production from individual wells).

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much oil these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP) which is often focused on by operators. Figure 2-38 illustrates the average daily output over the first six months of production (six-month IP) for all oil wells in the Eagle Ford play. Again, as with cumulative production, there are a few exceptional wells—4% of wells produced more than 600 barrels per day over the first six months—but the average for all wells drilled between 2008 and 2014 is just 262 barrels per day. The trend line on Figure 2-38 shows the average over time, which has been increasing slightly over the period, owing to both better technology and the focus of drilling on sweet spots. Figure 2-28 and Figure 2-29 illustrate the distribution of IPs in map form.

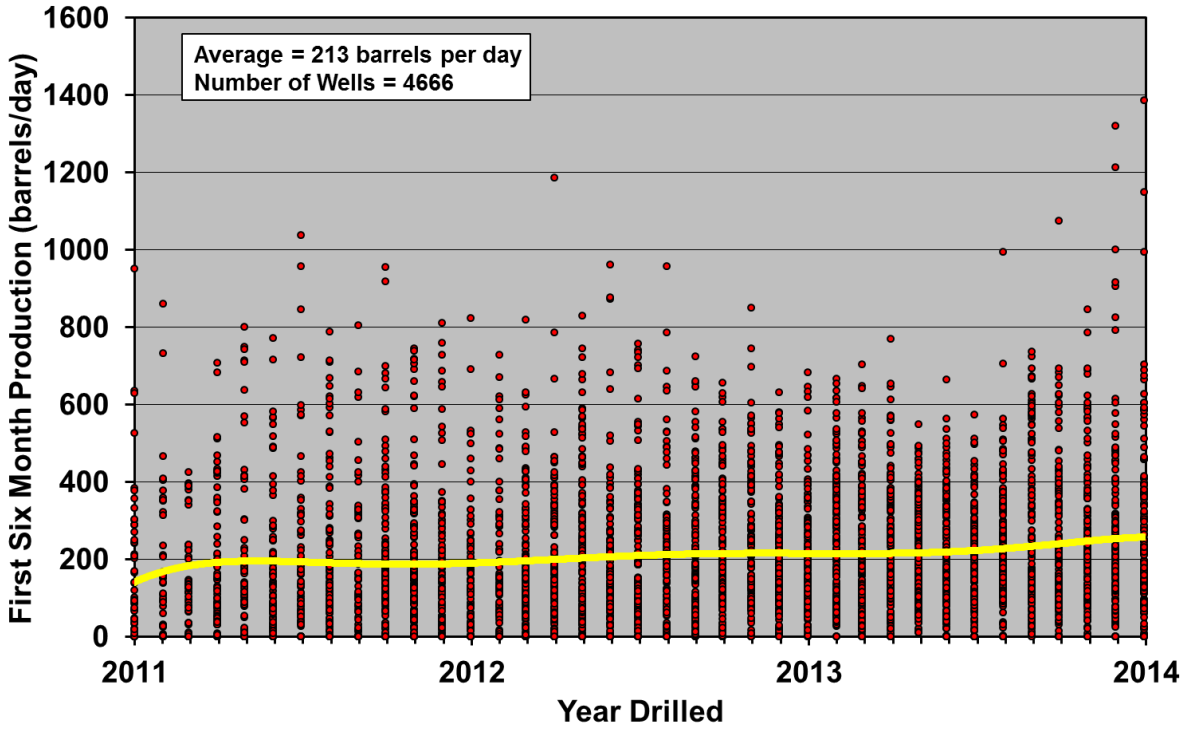

Figure 2-38. Average oil production over the first six months for all wells drilled in the Eagle Ford play.[65]

Although there are a few exceptional wells, the average well produced 213 barrels per day over this period. The trend line indicates variation in mean productivity over time.

[65] Data from Drillinginfo retrieved September 2014. Note that only leases with one well and individual wells are included in this figure (Texas has a practice of lumping production from multi-well leases with production from individual wells).

Drilling has focused on liquids-rich parts of the play given the low price of gas in recent years, however the Eagle Ford still produces large amounts of gas which adds to the economic viability of wells. Figure 2-39 illustrates the average production of wells over the first six months on a "barrels of oil equivalent" basis (converting natural gas to its oil equivalent on an energy basis—6000 cubic feet of natural gas equals one barrel of oil). The trend line in this case, combining oil and gas, is essentially flat over the 2011 through 2014 period, indicating technological improvements are not improving well productivity.

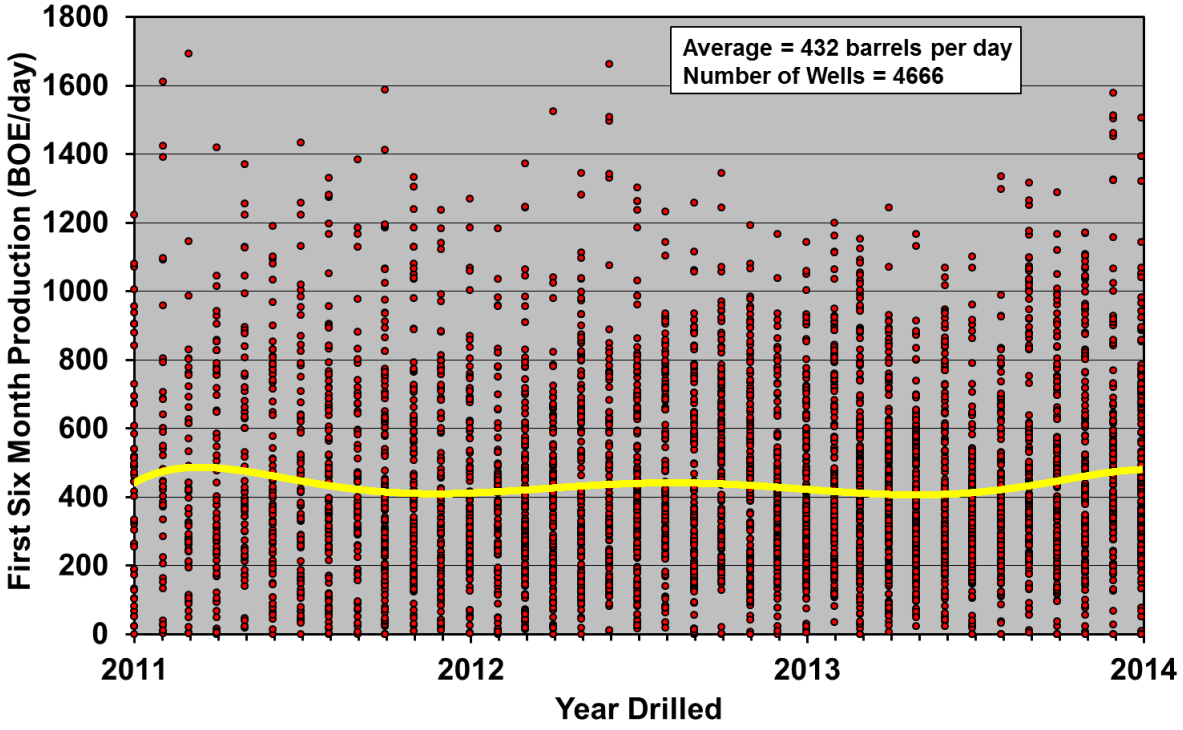

Figure 2-39. Average oil and gas production over the first six months for all wells drilled in the Eagle Ford play on a barrels of oil equivalent basis.[66]

Although there are a few exceptional wells, the average well produced 432 barrels of oil equivalent per day over this period.

[66] Data from Drillinginfo retrieved September 2014. Note that only leases with one well and individual wells are included in this figure (Texas has a practice of lumping production from multi-well leases with production from individual wells).

Different counties in the Eagle Ford display markedly different well production rate characteristics which are critical in determining the most likely production profile in the future. Figure 2-40, which illustrates oil production over time by county, shows that the top three counties produce 51% of the total, the top six produce 81% and the remaining 22 counties produce just 19%. Three years of widespread drilling (see Figure 2-41 for number of wells drilled per county) have not resulted in significant production increases outside the top six counties.

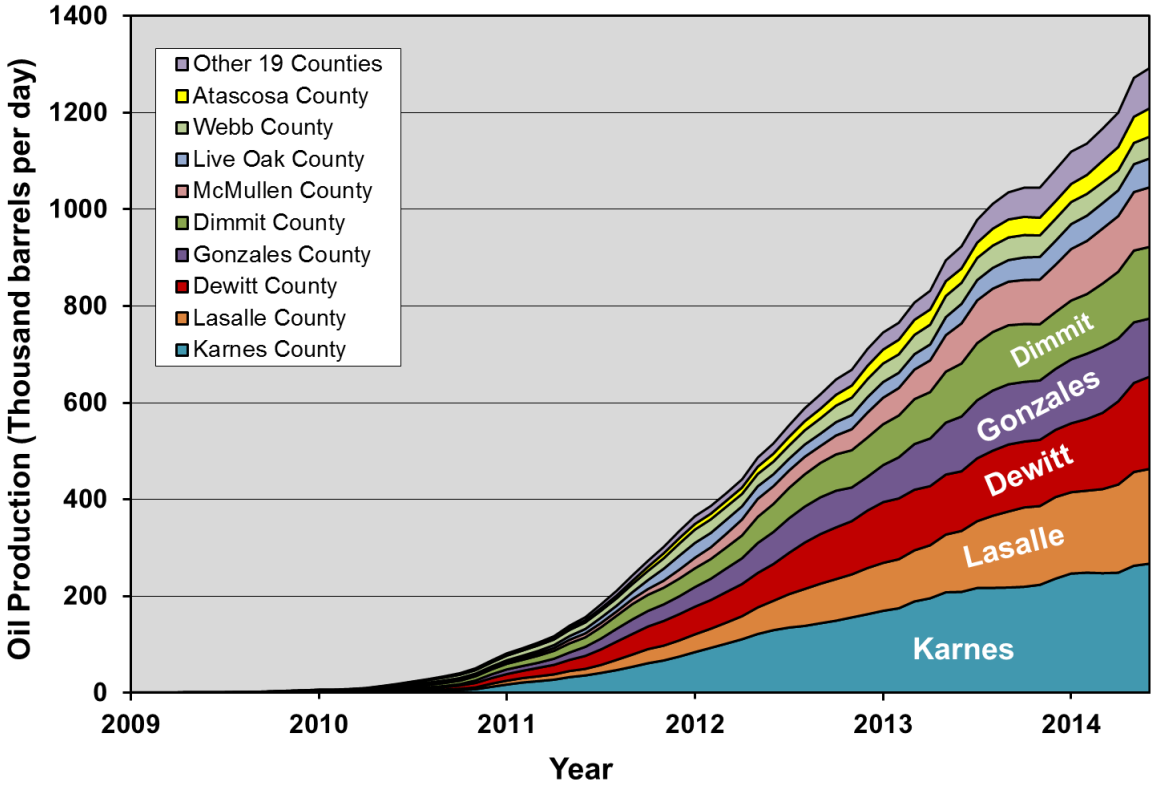

Figure 2-40. Oil production by county in the Eagle Ford play, 2009 through 2014.[67]
Eighty-one percent of production came from just six counties in mid-2014.

[67] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 2-41, the top three counties have produced 51% of the oil and the top six have produced 81%.

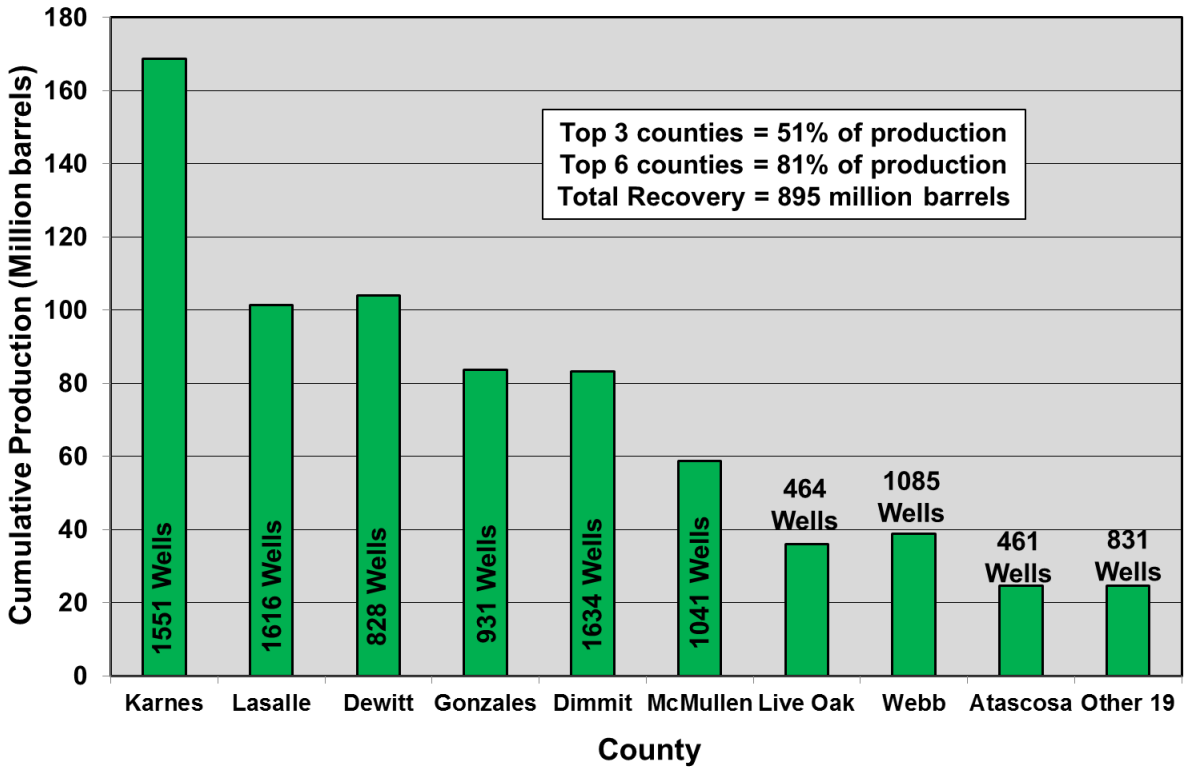

Figure 2-41. Cumulative oil production by county in the Eagle Ford play through 2014.[68]

The top six counties have produced 81% of the 895 million barrels produced to date. Production is growing in all counties.

[68] Data from Drillinginfo retrieved September 2014.

Approximately 39% of the energy produced from the Eagle Ford is in the form of natural gas, making the field one of the nation's top five gas fields (see the Eagle Ford section in *Part3: Shale Gas* of this report for a full discussion). The Eagle Ford currently produces 4.9 billion cubic feet per day and has produced nearly four trillion cubic feet since 2009. As with oil, gas production is concentrated in a few counties, but these tend to be different counties than for oil given the segregation of the play into oil and gas windows. Webb County, for example, produces less than 4% of the play's oil but produces 25% of its gas. Figure 2-42 illustrates gas production from the play since 2009 by county. In 2014, the top three counties produced 54% of the gas and the top six produced 87%.

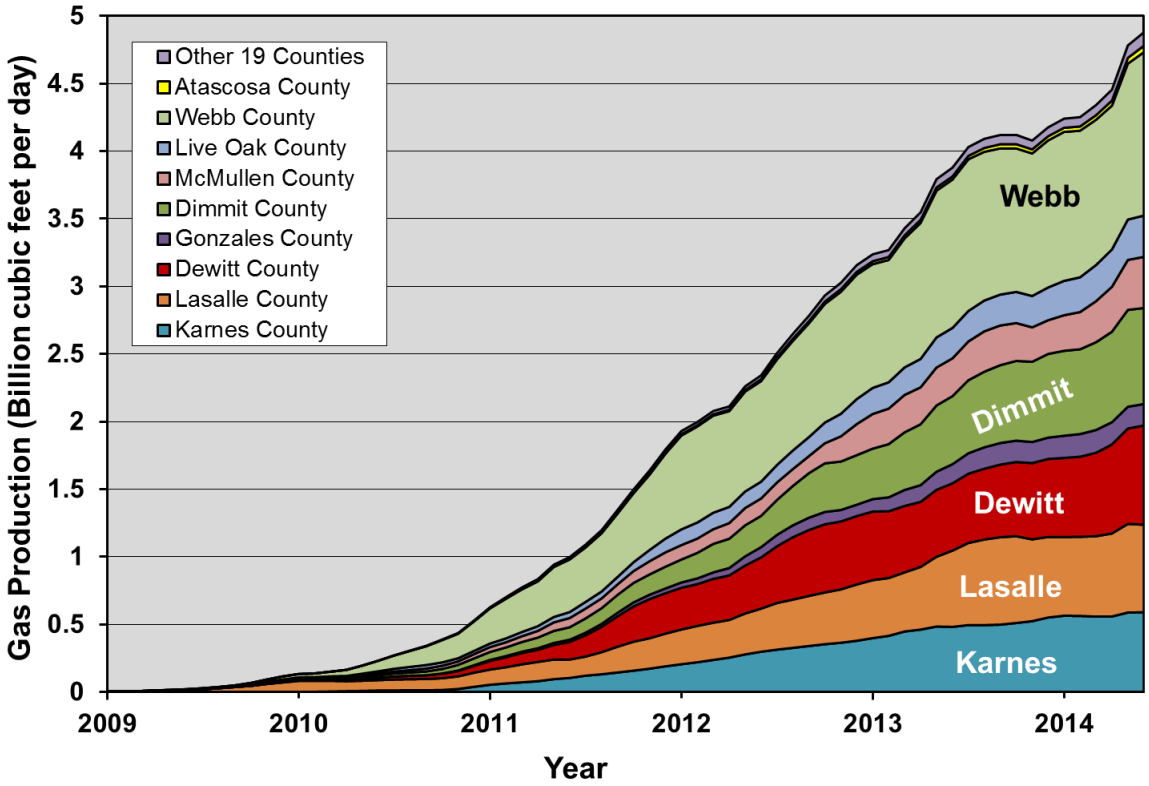

Figure 2-42. Gas production by county in the Eagle Ford play, 2009 through 2014.[69]

Eighty-seven percent of production came from just six counties as of mid-2014. For ease of comparison, the counties in this figure are sorted in the same order as in Figure 2-40, i.e., by *oil* production.

[69] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

Figure 2-43 illustrates cumulative gas production from the play as of mid-2014. The top three counties have produced 58% of the gas and the top six have produced 89%.

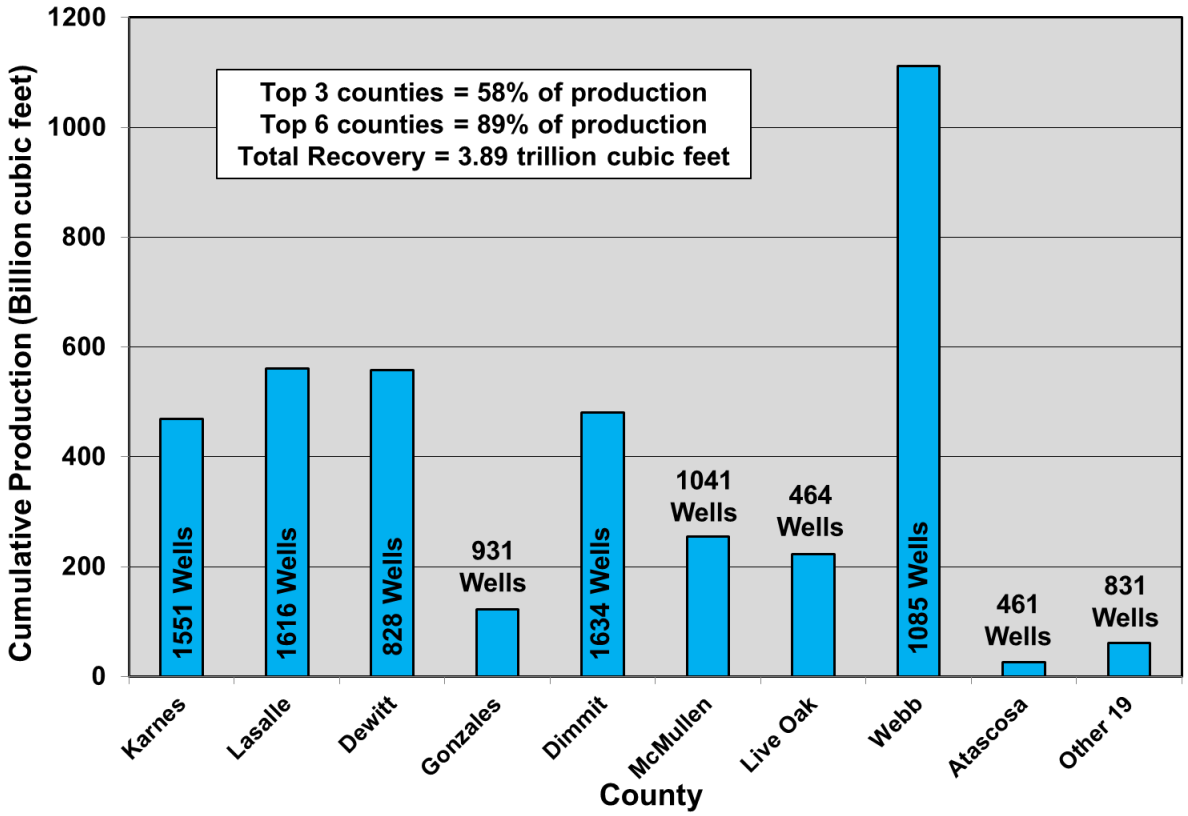

Figure 2-43. Cumulative gas production by county in the Eagle Ford play through 2014.[70]

The top six counties have produced 89% of the 3.89 trillion cubic feet produced to June 2014.

[70] Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost in the order of $8 million each,[71] not including leasing costs and other expenses. The areas of highest quality—the "core" or "sweet spots"—have now been well defined, both for oil and gas. Figure 2-44 illustrates average well decline profiles by county which are a measure of well quality. As can be seen, the decline profiles from the top four counties are all above the Eagle Ford average, hence these counties are attracting the bulk of the drilling and investment.

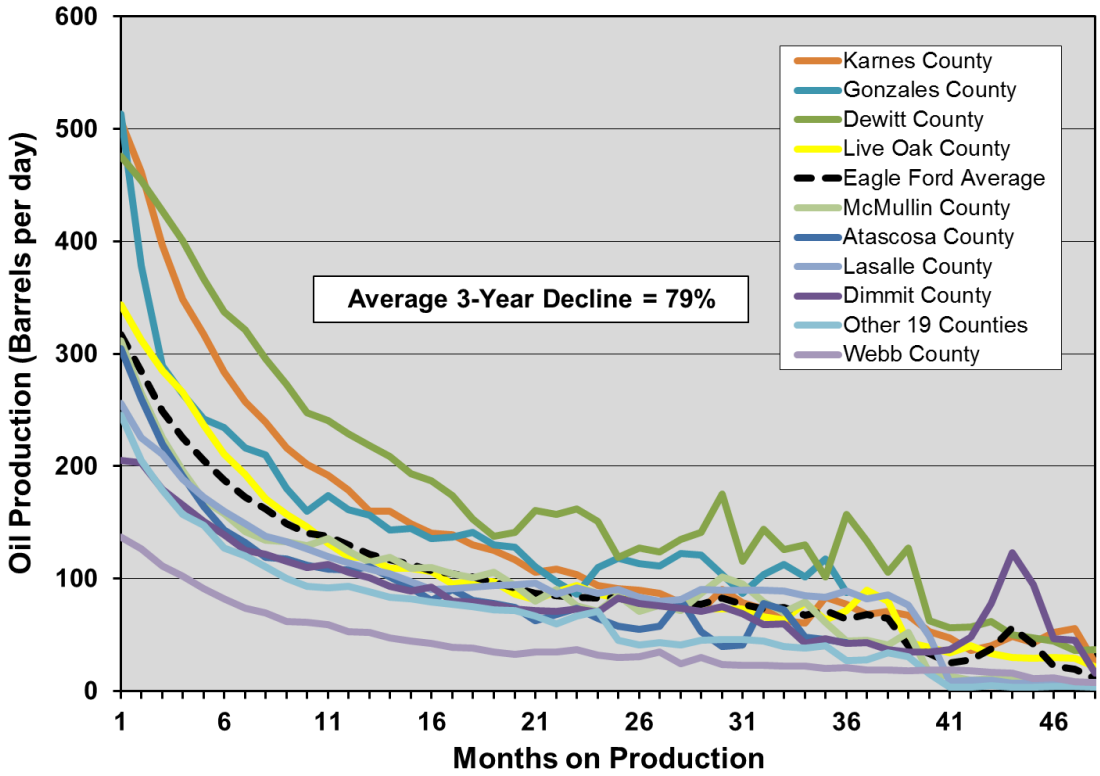

Figure 2-44. Average oil well decline profiles by county for the Eagle Ford play.[72]

The top four counties, which have produced much of the oil in the Eagle Ford, are clearly superior compared the play average and the other 23 counties. Well decline profiles are based on horizontal wells drilled since 2009.

[71] Trey Cowan, "Costs for Drilling The Eagle Ford," *Rigzone*, June 20, 2011, https://www.rigzone.com/news/article.asp?a_id=108179.
[72] Data from Drillinginfo retrieved May 2014.

Figure 2-45 illustrates average well decline profiles on a "barrels of oil equivalent" basis which includes the energy value of natural gas. Five counties are above the Eagle Ford average. Although four of these five are also the top four for oil production, Webb County is the second highest county on an energy output basis due to its prolific natural gas output, whereas is it ranks at the bottom for oil output.

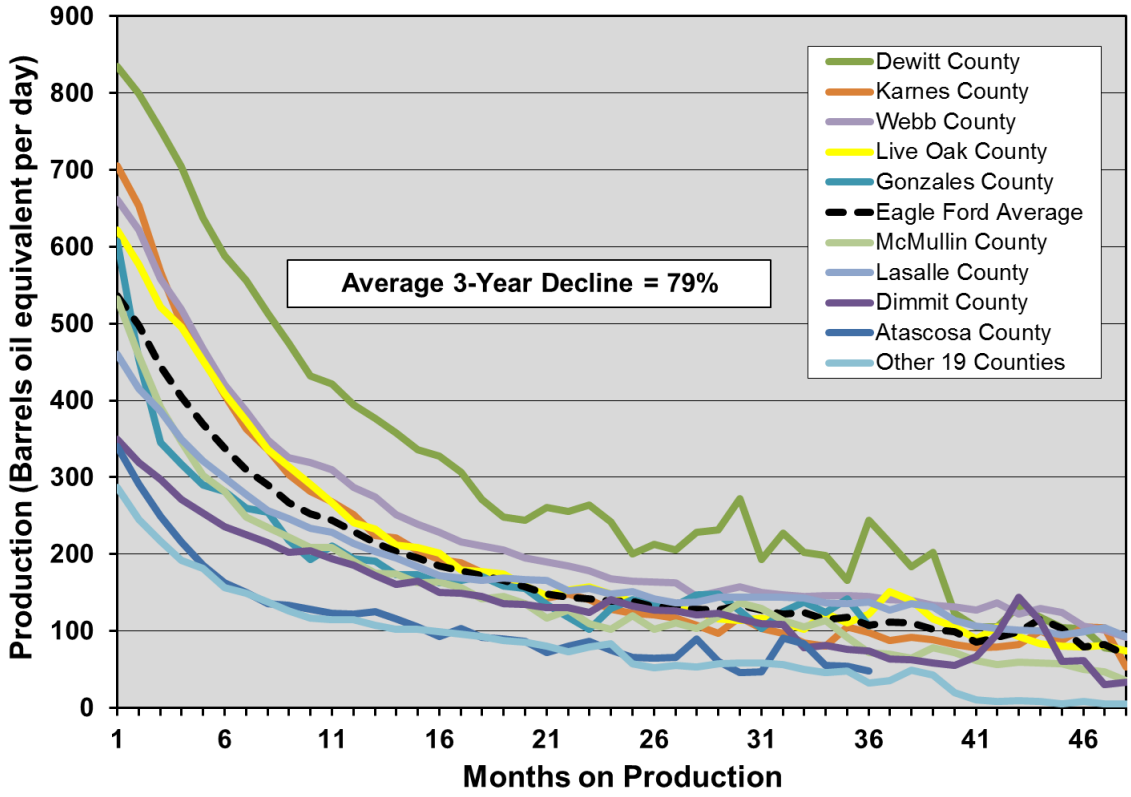

Figure 2-45. Average well decline profiles on a "barrels of oil equivalent" basis including the energy of natural gas produced by county for the Eagle Ford play.[73]

Although the top five counties include the top four for oil, Webb County has moved up to number two on an energy output basis, whereas it ranks at the bottom for oil production. Well decline profiles are based on horizontal wells drilled since 2009.

Another measure of well quality is "estimated ultimate recovery" (EUR), the amount of oil a well will recover over its lifetime. To be clear, no one knows what the lifespan of an Eagle Ford well is, given that few of them are more than five years old. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 2-44 and Figure 2-45, assuming well life spans of 30-50 years by comparison to conventional wells, but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Eagle Ford. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 2-44 and Figure 2-45, which show that wells exhibit steep initial decline rates with progressively more gradual decline rates over the first three years, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

[73] Data from Drillinginfo retrieved May 2014.

Figure 2-46 illustrates theoretical EURs per well by county for the Eagle Ford; these range from 101,000 to 531,000 barrels per well. This compares to EURs of 97,000 to 223,000 barrels per well assumed by the EIA (the EIA EURs are not broken down by county and include large areas of limited prospectivity).[74] EURs in the top three counties are nearly 100% higher than in the lowest 22 counties of the play. The steep well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 46% and 56% of an average well's lifetime production occurs in the first three years.

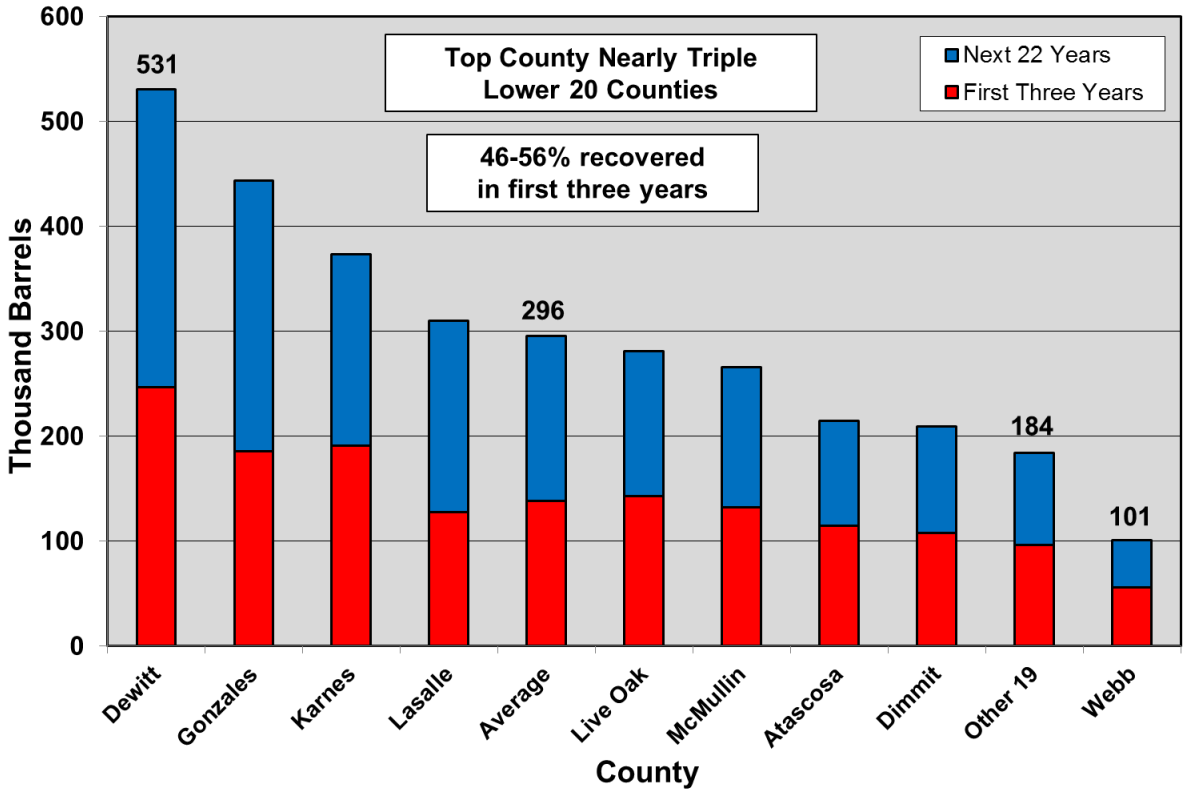

Figure 2-46. Estimated ultimate recovery of oil per horizontal well by county for the Eagle Ford play.[75]

EURs are based on average well decline profiles (Figure 2-44) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 25 years, as are the decline rates at the end of well life. The steep decline rates mean that most production occurs early in well life.

[74] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[75] Data from Drillinginfo retrieved May 2014.

Figure 2-47 illustrates theoretical EURs by county on a "barrels of oil equivalent" basis showing the split between oil and gas by county. The average well has an EUR of nearly 500,000 barrels oil equivalent, with Dewitt, the top county, more than triple the lowest 20 counties.

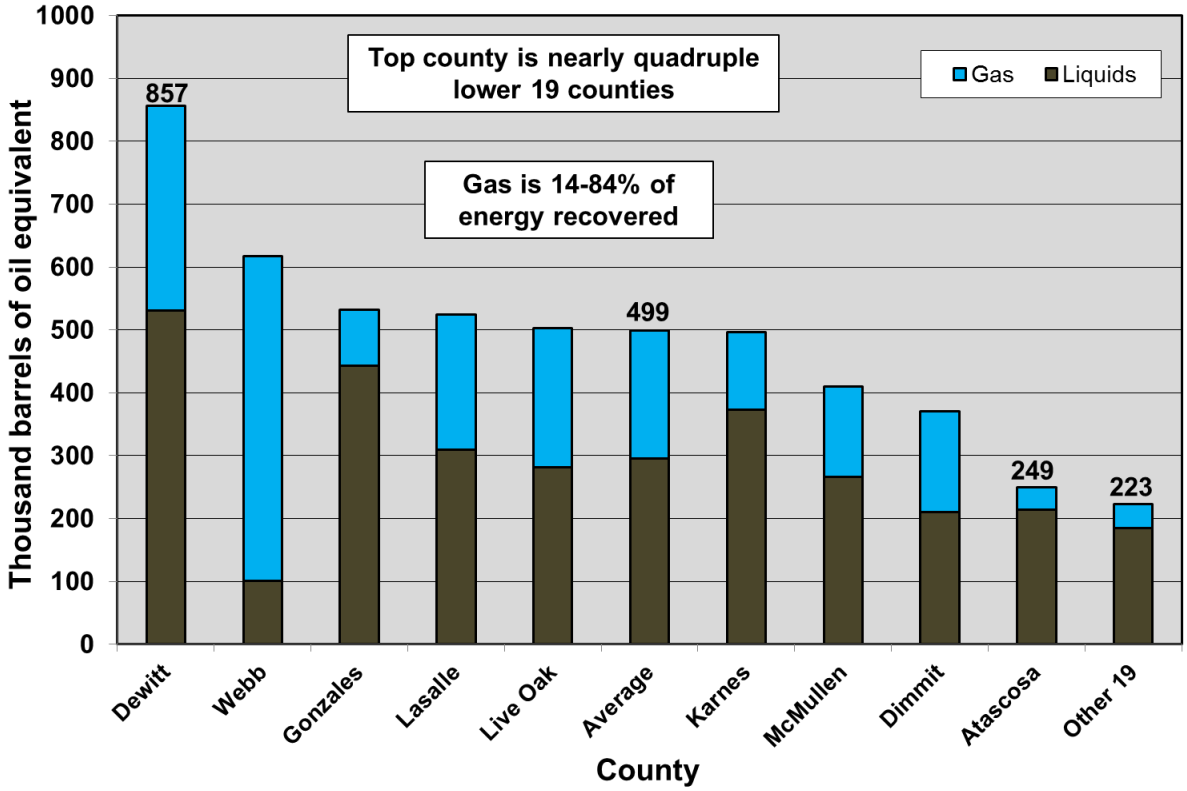

Figure 2-47. Estimated ultimate recovery on a "barrels of oil equivalent" basis, including the energy value of gas, by county for the Eagle Ford play.[76]

EURs are based on average well decline profiles (Figure 2-45) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 25 years, as are the decline rates at the end of well life. Gas comprises 14% to 84% of the energy produced with an average of about 39%.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the field decline rate and the average well's first-year production rate, we can calculate the number of wells that need to be drilled each year in order to offset field decline and maintain production. Given that drilling is currently focused on the highest quality counties, the average first-year production rate per well will fall as drilling moves into lower quality counties over time as the best locations are drilled off. As average well quality falls, the number of wells that must be drilled to offset field decline must rise, until the drilling rate can no longer offset decline and the field peaks.

[76] Data from Drillinginfo retrieved May 2014.

Figure 2-48 illustrates the average first year oil production rate of wells by county over the 2009 to 2013 period. Gains are evident in several counties although Dewitt, the most productive county, is in decline. Only three counties exceed the play average. The average increase in productivity for the play as a whole is just 4% over 2012, suggesting that technological improvements are approaching the limits of diminishing returns. Much of the observed improvement is likely from the shift of drilling from gas prone to oil prone portions of counties. Future technology improvements are unlikely to postpone for long the inevitable decline in average overall well quality as drilling moves into lower quality counties.

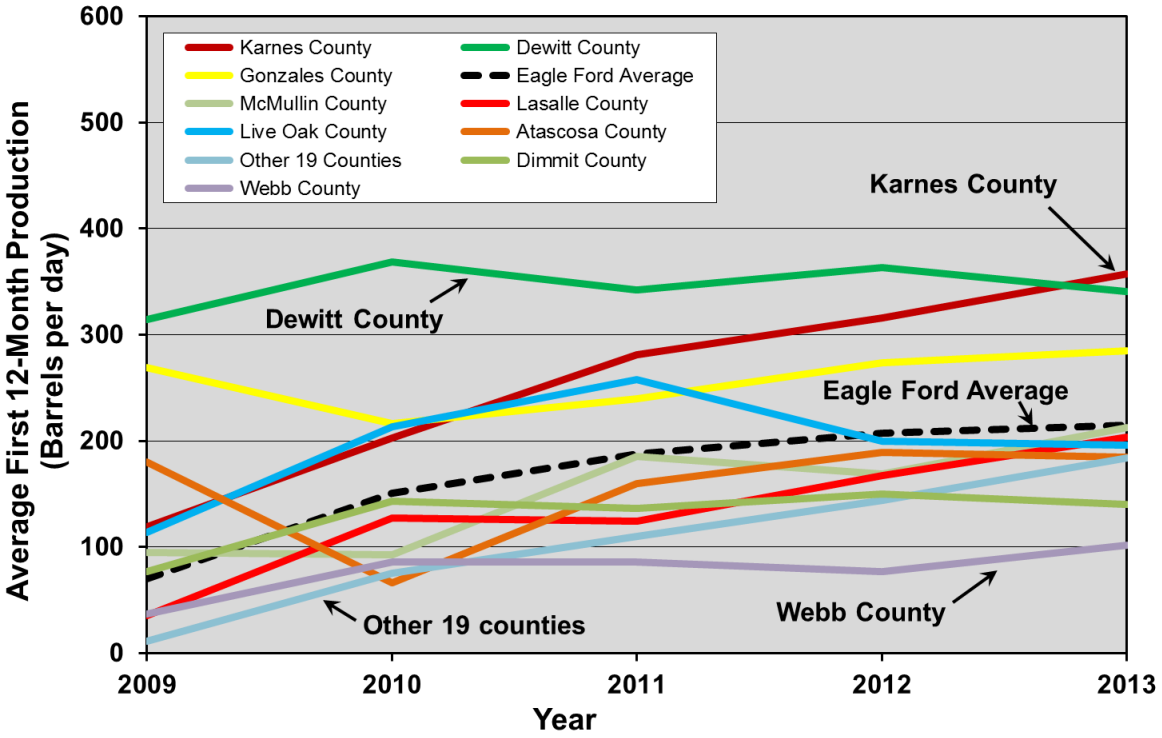

Figure 2-48. Average first-year oil production rates of wells by county for the Eagle Ford play, 2009 to 2013.[77]

Well quality is rising most rapidly in Karnes County, which has the second highest well count. Average first year oil production rates rose 4% over 2012.

[77] Data from Drillinginfo retrieved May 2014.

Figure 2-49 illustrates the average first year oil and gas production rate of wells by county on a "barrels of oil equivalent" basis over the 2009 to 2013 period. Gains are evident in several counties although Dewitt, the most productive county, is in decline, and the overall average for the play is unchanged over 2012, suggesting technological improvements are not making much difference overall.

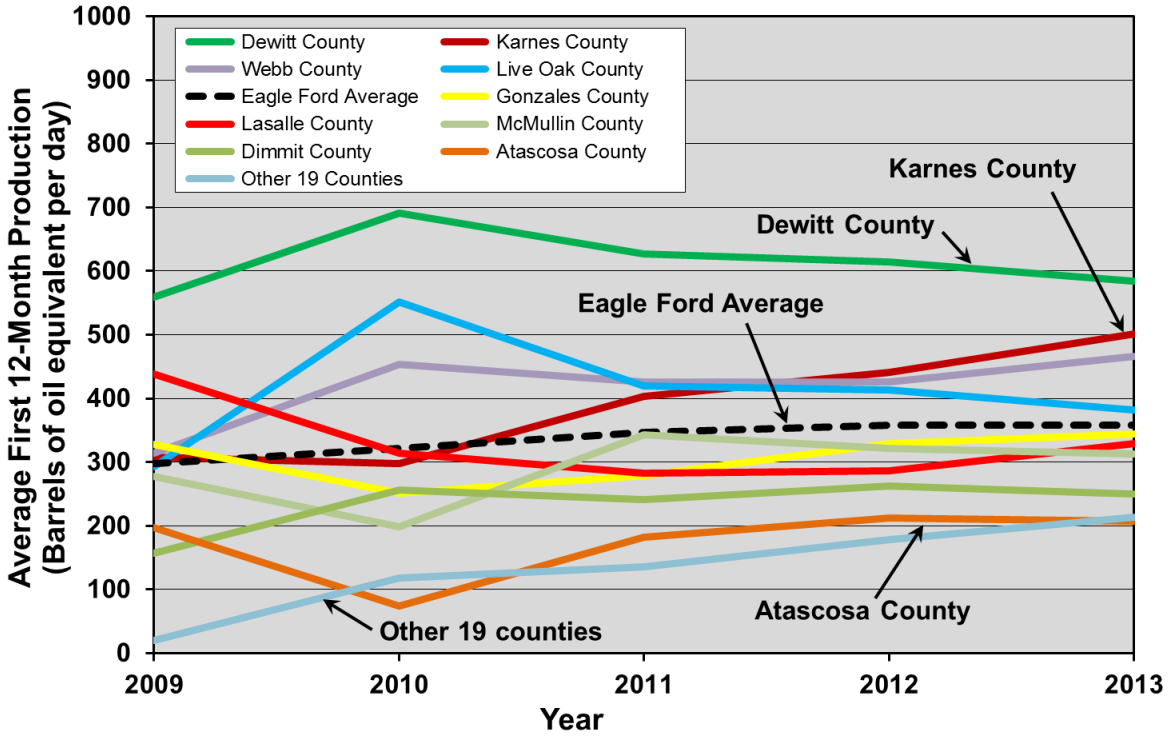

Figure 2-49. Average first-year oil and gas production rates of wells on a "barrels of oil equivalent" basis by county for the Eagle Ford play, 2009 to 2013.[78]

Average first-year production rates were unchanged in 2013 compared to 2012.

[78] Data from Drillinginfo retrieved May 2014.

2.3.2.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Eagle Ford, a function of (a) the size of the area worth drilling and (b) the density of drilling that will likely occur. As in the Bakken, this is hotly debated in investor presentations.

Determining the likely density at which operators will drill wells requires consideration of both the geology of the play and the mechanics of hydraulic fracturing. Typical wells in the Eagle Ford have horizontal laterals of 5,000-7,000 feet in length with 20 or more frack stages. The EIA suggests that the area may be drilled at a density of 6 wells per square mile,[79] which would space horizontal laterals at 880 feet from each other. Companies like Marathon claim that spacing in core areas can be reduced to 16 wells per square mile in its pilots (40-acre spacing).[80] This would place horizontal laterals 350 feet apart, implying that frack jobs on wells only effectively drain less than 200 feet from a well.

This seems very optimistic given studies on well interference discussed earlier (section 2.3.1.4) showing that interference may occur with wells separated by less than 2,000 feet in the Bakken.[81] There has been no compelling evidence presented to suggest that 40-acre spacings in the Eagle Ford will not cannibalize production from adjacent wells, meaning that such attempts will not increase ultimate oil and gas recovery, although they may temporarily increase production.

Determining the area actually conducive to drilling is comparatively straightforward. After years of exploration and thousands of wells drilled, operators have delineated the limits of the play and focused their efforts on those areas with proven potential; thus by identifying the farthest-lying wells with little to no production as the likely edge of the play, and estimating the size of the area within that edge which is clearly attracting industry interest, the functional area of the Eagle Ford play can be calculated. By this method, the area likely to be conducive to drilling is approximately 7,200 square miles (see Figure 2-28).

Based on the above parameters, and given the fact that much of the area covered by the Eagle Ford is of considerably lower quality than the top few counties, an estimate of 6 wells per square mile may be reasonable for the whole area, allowing for a higher density in core areas and a lower density in outlying lower quality areas. This translates to approximately 43,200 potential wells if drilled at a density of 6 wells per square mile (compared to EIA's estimated 66,987 locations, determined from the product of the EIA's play area and well density). As more than 10,500 wells have been drilled to date, this means that approximately 32,800 wells remain to be drilled. Of course, these estimates assume that the entire designated area is available, and do not account for parks, towns, rivers, reservoirs, and other areas not conducive to drilling. A more conservative but possibly more realistic calculation would include a "risk" that 20% of the remaining play area will be undrillable. This reduces the remaining number of potential wells to approximately 26,200 which, coupled with wells already drilled, puts the total well count when the play is completely finished at 35,900. Either way, the Eagle Ford play could experience somewhere between three and four times the number of wells drilled to date.

[79] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[80] Marathon Investor Presentation, December 11, 2013, http://files.shareholder.com/downloads/AMDA-DZ30I/2909841818x0x713050/bf6626c0-3865-4e94-a4d4-6d47103dcc6d/Analyst_Day_Final_without_notes_v2.pdf.
[81] Kevin Thuot, "There Will Be Blood: Well Spacing & The Bakken Shale Oil Milkshake," DrillingInfo, November 26, 2013, http://info.drillinginfo.com/well-spacing-bakken-shale-oil.

2.3.2.5 Rate of Drilling

The fifth key fundamental is the *rate of drilling*. As noted earlier, the Eagle Ford play has a field decline of 38% per year (for oil), meaning that 38% of production has to be replaced with new wells each year to keep production flat. As the amount of oil produced from an average well in its first year of production is known from the data, the number of wells needed to offset field production decline each year at a given production level can be easily calculated. For the Eagle Ford at current production levels some 2,285 wells must be drilled each year to keep production flat. Since drilling rates in the Eagle Ford are now at about 3,550 wells per year, production will keep growing as long as these rates are sustained—until drilling locations run out. However, the higher production grows, the more wells are needed to offset the field decline. And as drilling moves into lower quality parts of the play, even more wells will be needed, for as illustrated above (Figure 2-48), well quality in most counties is significantly lower than in the best three.

2.3.2.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Eagle Ford play were developed to illustrate the effects of changing the rate of drilling.

The projections are given in two cases, differentiated by the number of drilling locations:

1. An “Optimistic Case” of 100% of the play area being drillable, at 6 wells per square mile.

2. A “Realistic Case” of 80% of the remaining play area being drillable (i.e., the play is “risked” at 80% to account for undrillable areas like parks, towns, rivers, etc.), at 6 wells per square mile.

Each case includes three scenarios, differentiated by the rate of drilling:

1. MOST LIKELY RATE scenario: Drilling continues at the current rate of 3,550 wells per year and then declines to 2,000 wells per year as drilling moves into the lower quality counties.

2. EXPANDED RATE scenario: Drilling continues at the current rate of 3,550 wells per year and held constant until locations run out.

3. FASTEST RATE scenario: Drilling is increased to 4,000 wells per year and held constant until locations run out.

The critical parameters used for determining production rates in these scenarios are given in Table 2-2.

Parameters	Counties										Total
	Atascosa	Dewitt	Dimmit	Gonzales	Karnes	Lasalle	Live Oak	McMullen	Webb	Other 19	
Oil Production Jan 2014 (Kbbl/d)	58.6	190.8	148.3	120.3	267.1	196.0	59.7	123.2	45.2	83.2	1292.2
Gas Production Jan 2014 (Kbbl/d)	7.9	122.3	118.3	26.5	98.3	107.9	50.8	63.0	201.5	16.5	813.1
Gas Production Jan 2014 (Bcf/d)	0.0	0.7	0.7	0.2	0.6	0.6	0.3	0.4	1.2	0.1	4.9
Oil % of Field Production	4.5	14.8	11.5	9.3	20.7	15.2	4.6	9.5	3.5	6.4	100.0
BOE % of Field Production	3.2	14.9	12.7	7.0	17.4	14.4	5.3	8.8	11.7	4.7	100.0
Gas % of Field Production	1.0	15.0	14.6	3.3	12.1	13.3	6.3	7.7	24.8	2.0	100.0
Cumulative Oil (million bbls)	32.4	130.3	102.7	101.6	200.0	122.8	43.1	72.5	43.7	46.4	895.5
Cumulative Gas (Bcf)	25.8	557.5	480.1	122.7	468.9	560.3	223.5	254.6	1112.0	60.6	3866.0
Number of Wells	461	828	1634	931	1551	1616	464	1041	1085	831	10442
Number of Producing Wells	441	797	1576	895	1506	1580	458	990	1023	759	10025
Avg. Oil EUR per well (Kbbls)	215	531	210	443	373	310	281	266	101	184	296
Avg. BOE EUR per well (Kbbls)	249	857	371	532	496	524	503	410	618	223	499
Avg. Gas EUR per well (Bcf)	0.2	2.0	1.0	0.5	0.7	1.3	1.3	0.9	3.1	0.2	1.2
Oil Field Decline (%)	50	41	37	33	40	34	40	30	48	27	38
BOE Field Decline (%)	49	44	36	33	42	37	47	45	46	30	42
Gas Field Decline (%)	43	47	34	26	47	41	54	64	46	43	47
Oil 3-Year Well Decline (%)	88	72	79	81	87	68	74	86	86	89	79
BOE 3-Year Well Decline (%)	88	74	82	81	86	72	76	87	79	88	79
Gas 3-Year Well Decline (%)	86	77	82	80	90	78	78	89	77	81	80
Average First Year Oil Production in 2013 (bbl/d)	184.6	340.9	140.0	284.9	357.5	203.3	195.8	212.8	101.4	183.7	214.9
Average First Year BOE Production in 2013 (bbl/d)	207.6	584.0	249.5	344.6	500.9	328.8	381.5	312.4	466.4	213.6	357.9
Average First Year Gas Production in 2013 (mcf/d)	138.4	1459.1	656.9	358.0	860.8	752.9	1113.9	597.3	2190.2	179.7	858.2
Oil New Wells Needed to Offset Field Decline	159	229	392	139	299	328	122	174	214	122	2285
BOE New Wells Needed to Offset Field Decline	157	236	385	141	306	342	136	268	243	140	2470
Gas New Wells Needed to Offset Field Decline	147	236	368	115	322	353	148	405	254	236	2672
Area in square miles	1232	909	1331	1068	750	1489	1036	1113	3357	20000	32285
% Prospective	50	30	90	40	75	80	25	60	30	5	22
Net square miles	616	273	1198	427	563	1191	259	668	1007	1000	7201
Well Density per square mile	0.75	3.04	1.36	2.18	2.76	1.36	1.79	1.56	1.08	0.83	1.45
Additional locations to 6/sq. Mile	3235	808	5553	1632	1824	5531	1090	2966	4958	5169	11162
Population	44911	20097	9996	19807	14824	6886	11531	707	250304	N/A	N/A
Total Wells 6/sq. Mile	3696	1636	7187	2563	3375	7147	1554	4007	6043	6000	43208
Producing Wells 6/sq. Mile	3676	1605	7129	2527	3330	7111	1548	3956	5981	5928	42791

Table 2-2. Parameters for projecting Eagle Ford tight oil production, by county

Optimistic Case

Figure 2-50 illustrates the production profiles of the three drilling rate scenarios in the "Optimistic Case," where 100% of the play area is drillable at six wells per square mile.

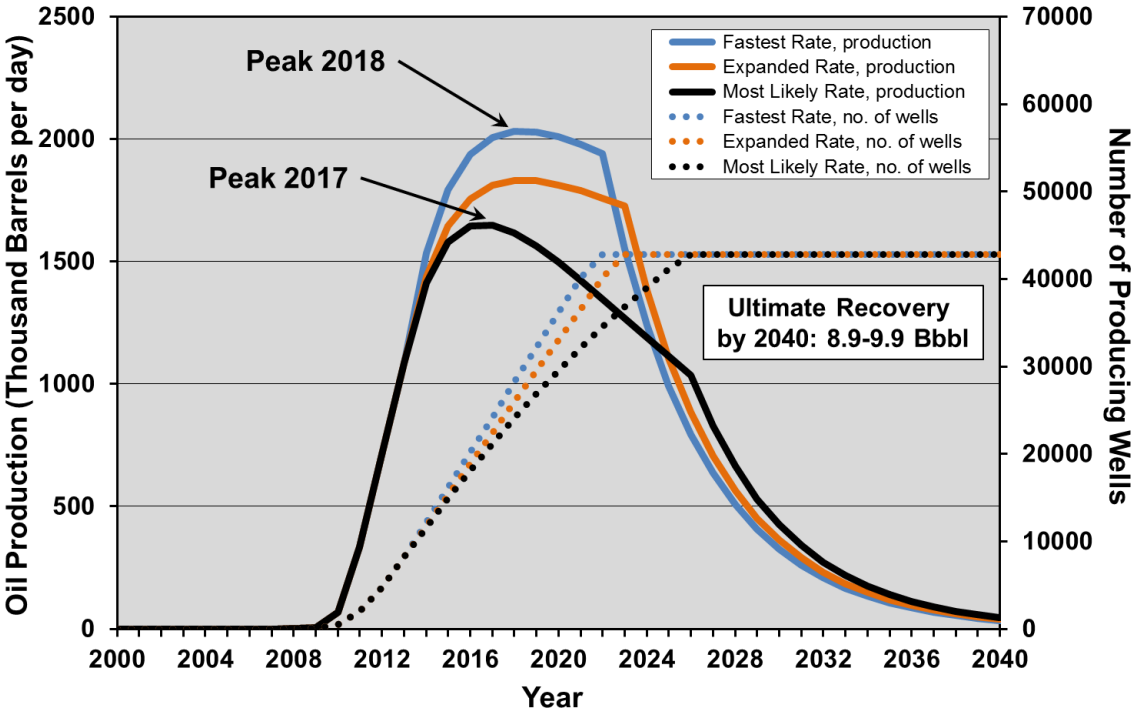

Figure 2-50. Three drilling rate scenarios of Eagle Ford tight oil production, in the "Optimistic Case" (100% of the play area is drillable at six wells per square mile).[82]

"Most Likely Rate" scenario: drilling continues at 3,550 wells/year, declining to 2,000 wells/year.
"Expanded Rate" scenario: drilling continues at 3,550 wells/year, holding constant until locations run out.
"Fastest Rate" scenario: drilling is increased to 4,000 wells/year, holding constant until locations run out.

The drilling rate scenarios in this case have the following results:

1. MOST LIKELY RATE scenario: Peak production occurs in 2017 at 1.65 MMbbl/d. Drilling continues until 2026, and total oil recovery by 2040 is 8.9 billion barrels.

2. EXPANDED RATE scenario: Peak production occurs in 2018 at 1.83 MMbbl/d. Drilling continues until 2023, and total oil recovery by 2040 is 9.6 billion barrels. In this scenario, however, production would be lower after 2026 than in the most likely case; in essence faster drilling recovers the oil sooner but makes future supply more problematic.

3. FASTEST RATE scenario: Peak production occurs in 2018 at 2.03 MMbbl/d. Drilling continues until 2022, and total oil recovery by 2040 is 9.9 billion barrels. In this scenario, however, production would be lower after 2025 than in the most likely case; in essence faster drilling recovers the oil sooner but makes future supply more problematic.

[82] Data from Drillinginfo retrieved September 2014.

The following two figures add natural gas, as oil equivalent energy, and differentiate oil from condensate production for the "Most Likely Rate" scenario (the Texas Railroad Commission reports that approximately 20% of liquids production is condensate,[83] which is generally of lower value than oil).

Figure 2-51 illustrates oil, condensate and gas production for the "Most Likely Rate" scenario in the "Optimistic Case" (100% of the prospective area is drillable at six wells per square mile).

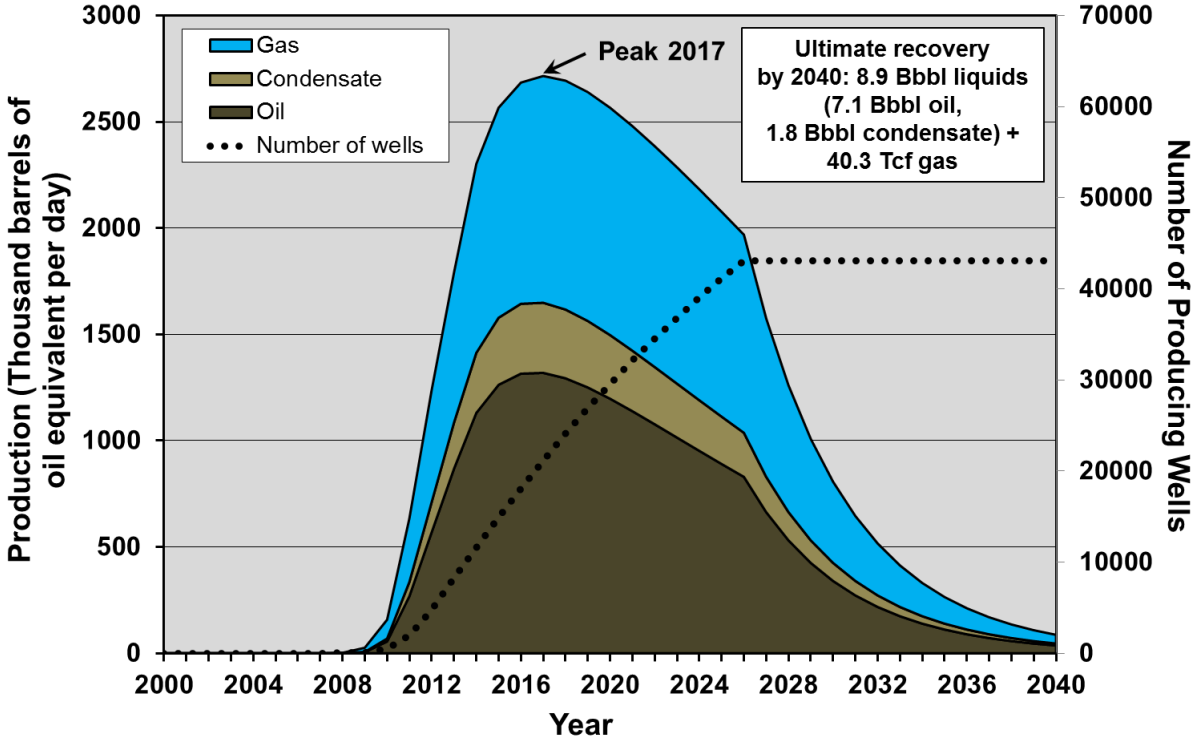

Figure 2-51. "Most Likely Rate" scenario of Eagle Ford production for oil, condensate and gas in the "Optimistic" case (100% of the play area is drillable at six wells per square mile).[84]

In this "Most Likely Rate" scenario, drilling continues at 3,550 wells/year, declining to 2,000 wells/year.

In this case, peak production occurs in 2017 at 2.7 MMbbl/d of oil equivalent. Drilling continues until 2026, total liquids recovery is 8.9 billion barrels (7.1 billion barrels of oil and 1.8 billion barrels of condensate), and total gas recovery is 40.3 trillion cubic feet.

[83] Texas Railroad Commission, "Eagle Ford Shale Information," July 2014, http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale.
[84] Data from Drillinginfo retrieved September 2014.

Realistic Case

Figure 2-52 illustrates oil, condensate and gas production in the "Most Likely Rate" scenario in the "Realistic Case" (only 80% of the remaining prospective area is drillable, at six wells per square mile).

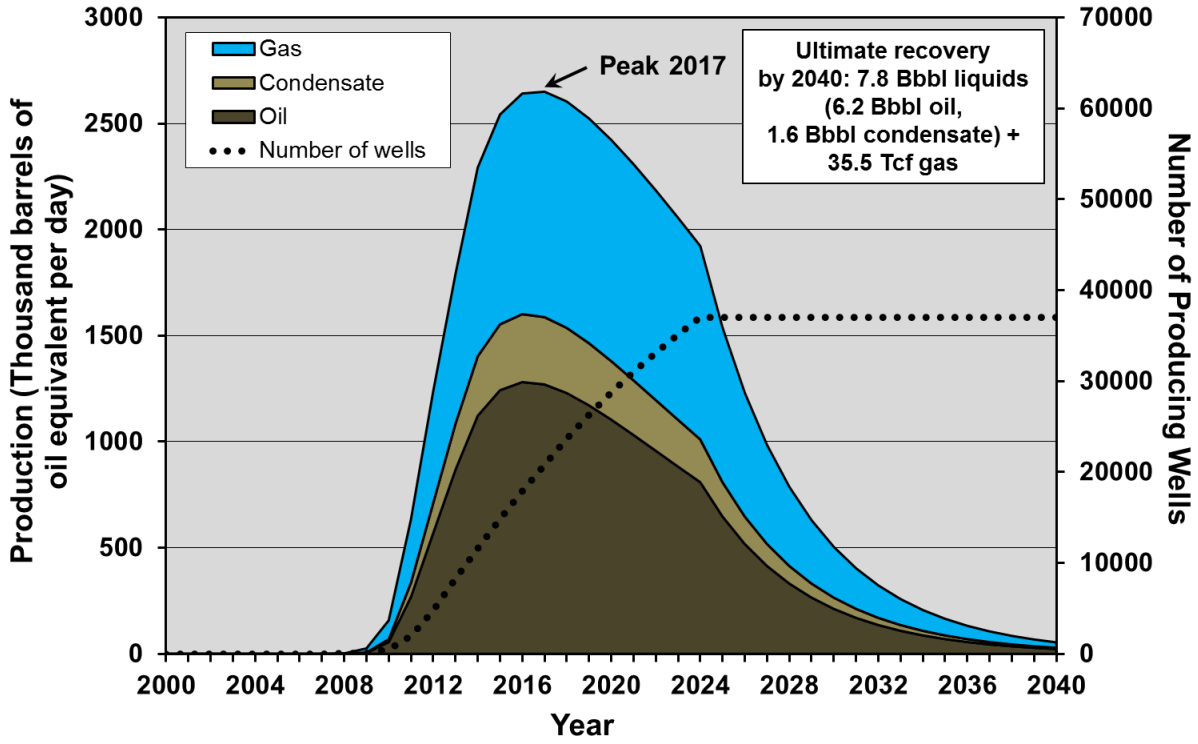

Figure 2-52. "Most Likely Rate" scenario of Eagle Ford production for oil, condensate and gas in the "Realistic Case" (80% of the remaining area is drillable at six wells per square mile).[85]

In this "Most Likely Rate" scenario, drilling continues at 3,550 wells/year, declining to 2,000 wells/year.

In this case, peak production occurs in 2017 at 2.65 MMbbl/d of oil equivalent. Drilling continues until 2024, total liquids recovery by 2040 is 7.8 billion barrels (6.2 billion barrels of oil and 1.6 billion barrels of condensate), and total gas recovery is 35.5 trillion cubic feet.

[85] Data from Drillinginfo retrieved September 2014.

2.3.2.7 Comparison to EIA Forecast

Figure 2-53 compares the EIA's reference case projection for Eagle Ford tight oil production to the "Most Likely Rate" scenario of the "Realistic" Case presented above.

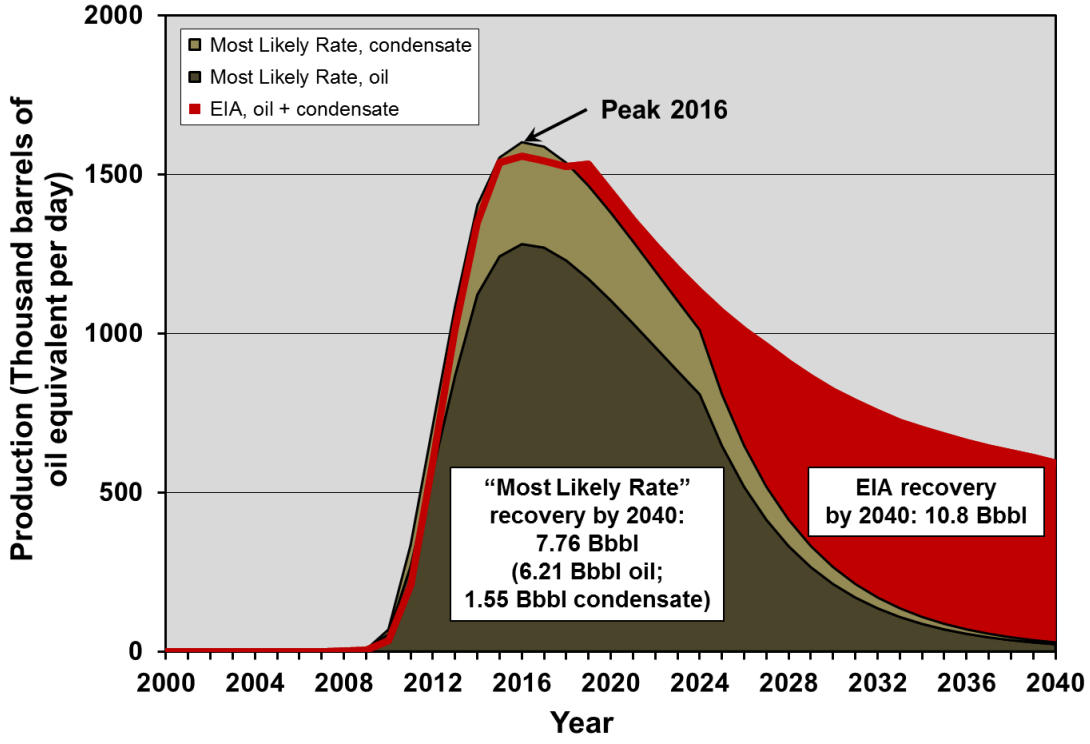

Figure 2-53. "Most Likely Rate" scenario ("Realistic" case) of Eagle Ford tight oil production compared to the EIA reference case, 2000 to 2040.[86]

This "Most Likely Rate" scenario sees 3,550 wells/year, declining to 2,000 wells/year. By 2040, 7.76 billion barrels of liquids would be recovered: 6.21 Bbbls of oil and 1.55 Bbbls of condensate.

This comparison reveals:

- The EIA's forecast of the timing of peak production (2016) in the Eagle Ford is the same as the projection of this report.
- The EIA's forecast of the production rate at peak (1.56 million bpd) is lower than the projection of this report (1.60 million bpd), but only slightly.
- The EIA projects a higher tail of production after peak, with estimated ultimate recovery (EUR) of 10.8 billion barrels by 2040 (10.2 billion for 2014-2040) as opposed this report's projection of 7.8 billion barrels by 2040 (7 billion for 2014-2040).

In short, the EIA is forecasting 3.2 billion additional barrels of future Eagle Ford production than this report finds substantiated. The EIA's assumption that production will be nearly 600,000 barrels per day in 2040 implies that much additional oil will be recovered.

[86] EIA, *Annual Energy Outlook 2014.*

2.3.2.8 Eagle Ford Play Analysis Summary

As with the Bakken, several things are clear from this analysis:

1. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Approximately 2,285 wells must be drilled each year to keep production flat at current levels.

2. The production profile is most dependent on drilling rate and to a lesser extent on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Drilling rate is determined by capital input, which currently is about $28 billion per year to drill 3,550 wells, not including leasing and other ancillary costs.

3. Peak production is highly likely to occur in the 2016 to 2018 timeframe and will occur at between 1.6 and 2.0 MMbbl/d. The most likely peak is about 1.6 MMbbl/d in 2016.

4. Increased drilling rates would raise the level of peak production and move it forward a few months but would not appreciably increase cumulative oil recovery through 2040. Increased drilling rates effectively recover the oil sooner making the supply situation worse later.

5. The projected recovery of 7.8 billion barrels by 2040 in the "Most Likely Rate" scenario of the "Realistic" case (i.e., six wells per square mile "risked" at 80%) is considerably less than the 10.8 billion barrels forecast by the EIA to be recovered by 2040.[87]

6. These projections are optimistic in that they assume the capital will be available for the drilling "treadmill" that must be maintained (roughly $210 billion is needed to drill more than 26,200 wells excluding leasing and ancillary costs). This is not a sure thing as drilling in the poorer-quality parts of the play will require much higher oil prices to be economic. Failure to maintain drilling rates will result in a steeper drop off in production.

7. Nearly four times the current number of wells will be required to recover 7.8 billion barrels by 2040 in the "Realistic" case assuming six wells per square mile "risked" at 80%.

8. The concept that the Eagle Ford will maintain a production plateau beyond its peak is unwarranted, even with extremely large capital inputs.

[87] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.4 THE PERMIAN BASIN PLAYS

The Permian Basin is the third largest source of tight oil production growth in the U.S. after the Bakken and Eagle Ford. The Permian Basin has been a prolific conventional oil and gas producer for nearly 100 years. Some 400,000 wells have been drilled there, producing more than 30 billion barrels of oil and 108 trillion cubic feet of gas.

Figure 2-54 illustrates the distribution of wells drilled since 1970 in the basin in Texas and southeastern New Mexico. The basin contains five major plays and several smaller ones that have collectively allowed oil production to grow by more than 500,000 barrels per day since 2005.[88] Three of these, the Spraberry, Wolfcamp, and Avalon/Bone Spring, are projected by the EIA to be major contributors to future production (see Figure 2-5).

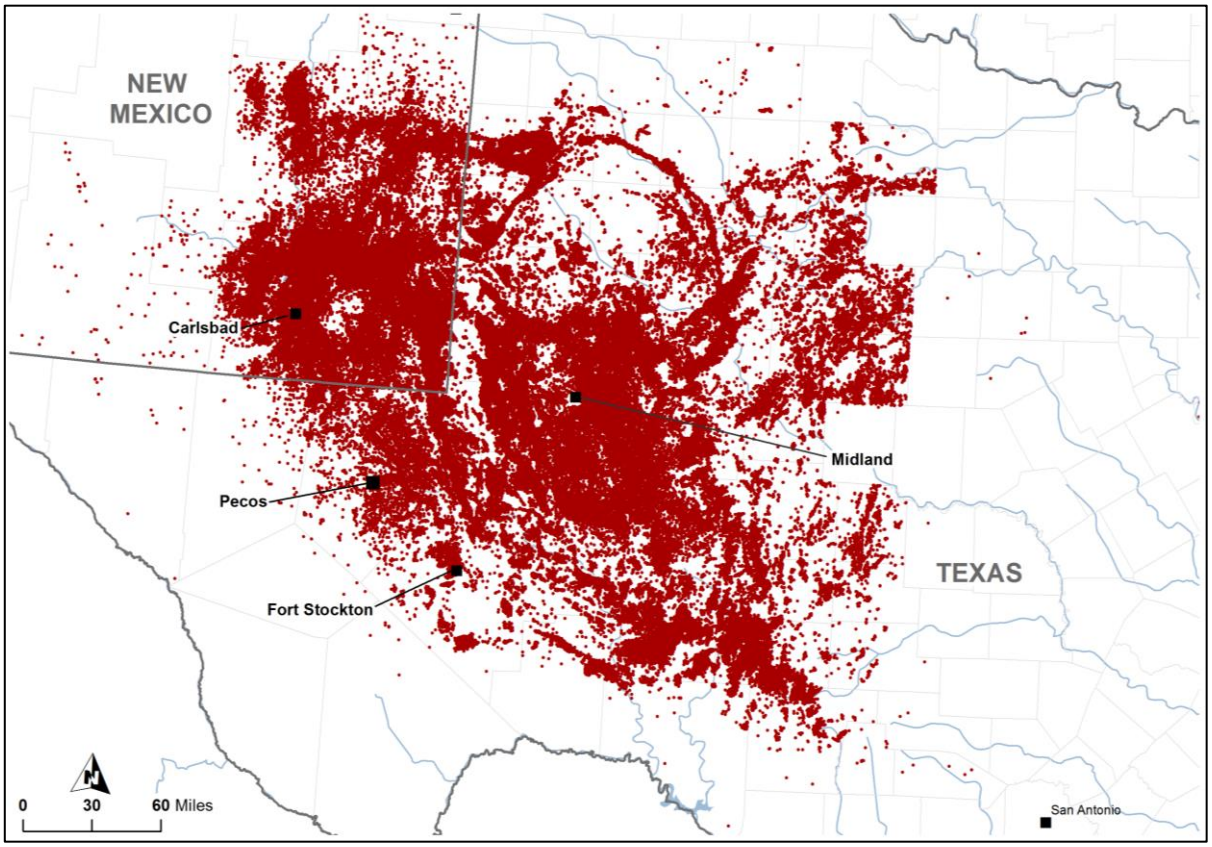

Figure 2-54. Distribution of wells drilled since 1970 in the Permian Basin of Texas and southeastern New Mexico.[89]

[88] EIA, "Six formations are responsible for surge in Permian Basin crude oil production," *Today in Energy*, July 9, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=17031.
[89] Data from Drillinginfo retrieved July 2014.

Production of oil and gas from the Permian Basin peaked in 1973 but has undergone a renaissance since 2010, with the application of new technology to old reservoirs. Figure 2-55 illustrates oil and gas production in the basin since 1960.

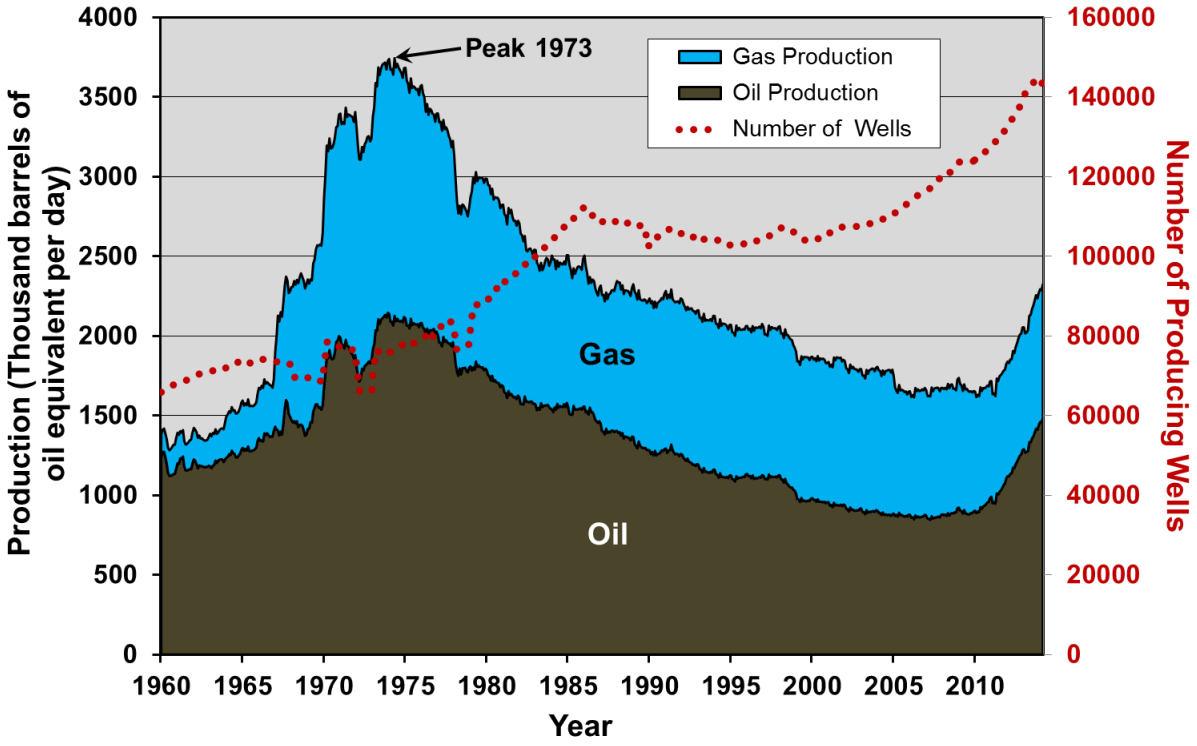

Figure 2-55. Permian Basin oil and gas production and number of producing wells, 1960 to 2014.[90]

Gas production is expressed as "barrels of oil equivalent" (6,000 cubic feet of gas is approximately equivalent to one barrel of oil on an energy basis).

[90] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

Unlike the Bakken and Eagle Ford shale plays, tight oil production in the Permian Basin is from both horizontal and vertical fracked wells. Coupled with the fact that the Permian Basin has been producing for nearly a century, this makes it difficult to separate truly new "tight oil" production from conventional production. Figure 2-56 illustrates production from vertical and horizontal wells in the Permian Basin. Production growth has occurred from both well types, although horizontal wells appear to contribute a larger proportion of the growth.

As mentioned above, the three plays that the EIA is counting on to meet a significant proportion of its tight oil forecasts from the Permian Basin are the Spraberry, Wolfcamp, and Avalon/Bone Spring. These plays are reviewed below with respect to production characteristics and future growth potential in the light of the EIA projections for them.

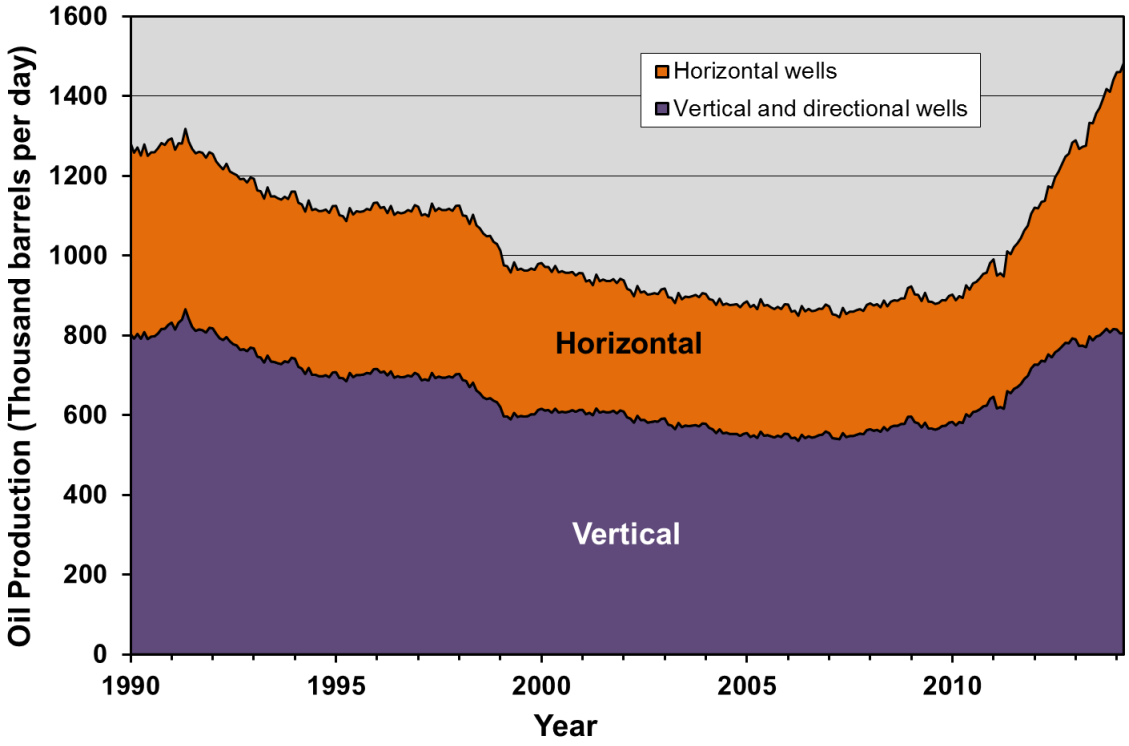

Figure 2-56. Oil production by well type in the Permian Basin, 1990 to 2014.[91]
Recent production growth is a function of both horizontal and vertical wells.

[91] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.1 Spraberry Play

The EIA forecasts recovery of 6.5 billion barrels of oil from the Spraberry play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Spraberry play has been producing oil and gas for decades. Nearly 37,000 wells have been drilled of which more than 25,000 are currently producing. The play has produced over 1.8 billion barrels of oil and more than 4.2 trillion cubic feet of natural gas over its lifetime. Production comes from the Spraberry reservoir proper, and an equivalent reservoir termed "Trend Area", which together make up the Spraberry play. Figure 2-57 illustrates well distribution within the play.

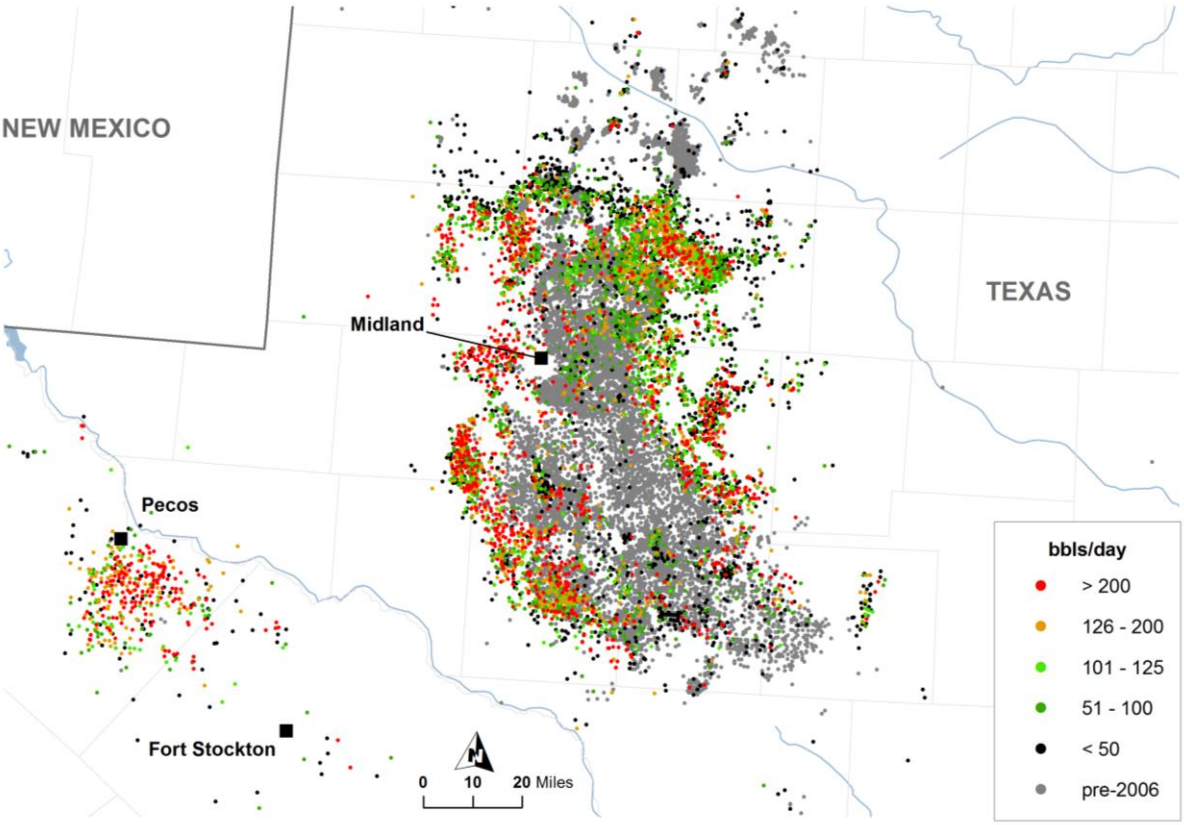

Figure 2-57. Distribution of wells in the Spraberry play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[92]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[92] Data from Drillinginfo retrieved July 2014.

2.4.1.1 Production History

Production of oil in the Spraberry has more than tripled since 2005 and including natural gas (on an energy equivalent basis) is up four-fold as illustrated in Figure 2-58. The number of producing wells has also more than doubled over this period.

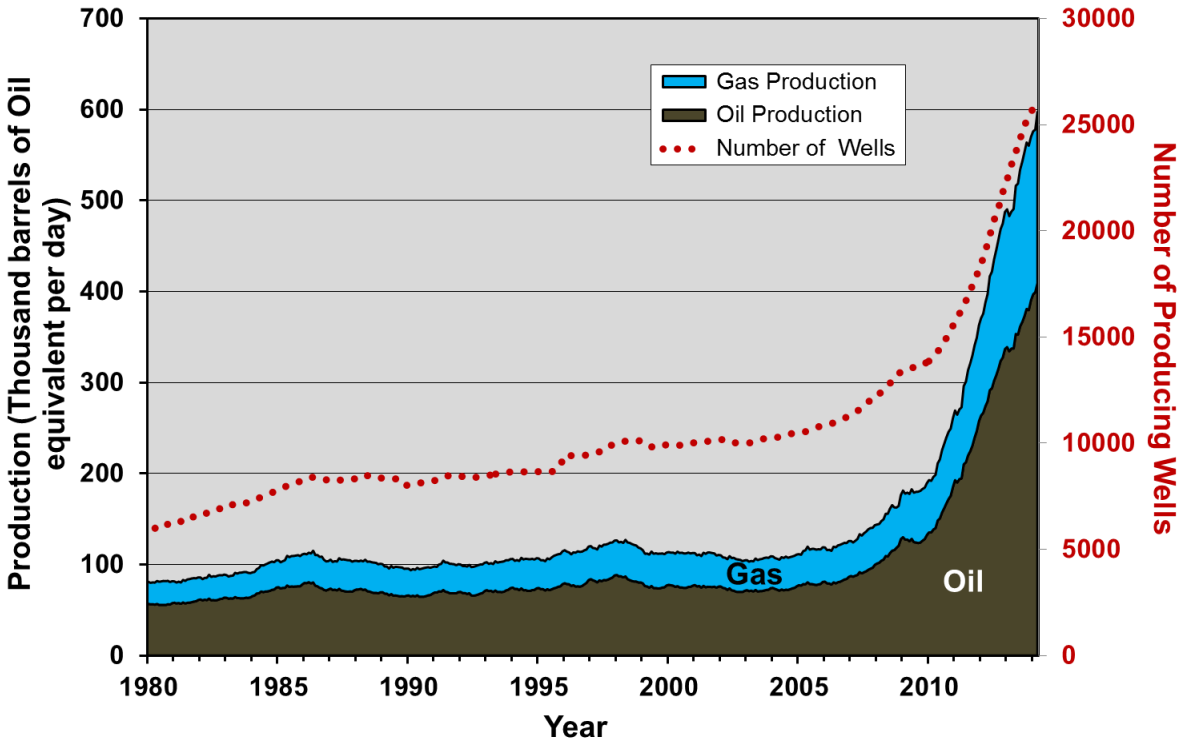

Figure 2-58. Spraberry play oil and gas production and number of producing wells, 1980 to 2014.[93]

Producing well count is now above 25,000.

[93] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

A look at the split in production by well type reveals that much of this growth is attributable to vertical wells, although horizontal wells are becoming increasingly important (Figure 2-59). New completion technology in both well types is obviously paying dividends.

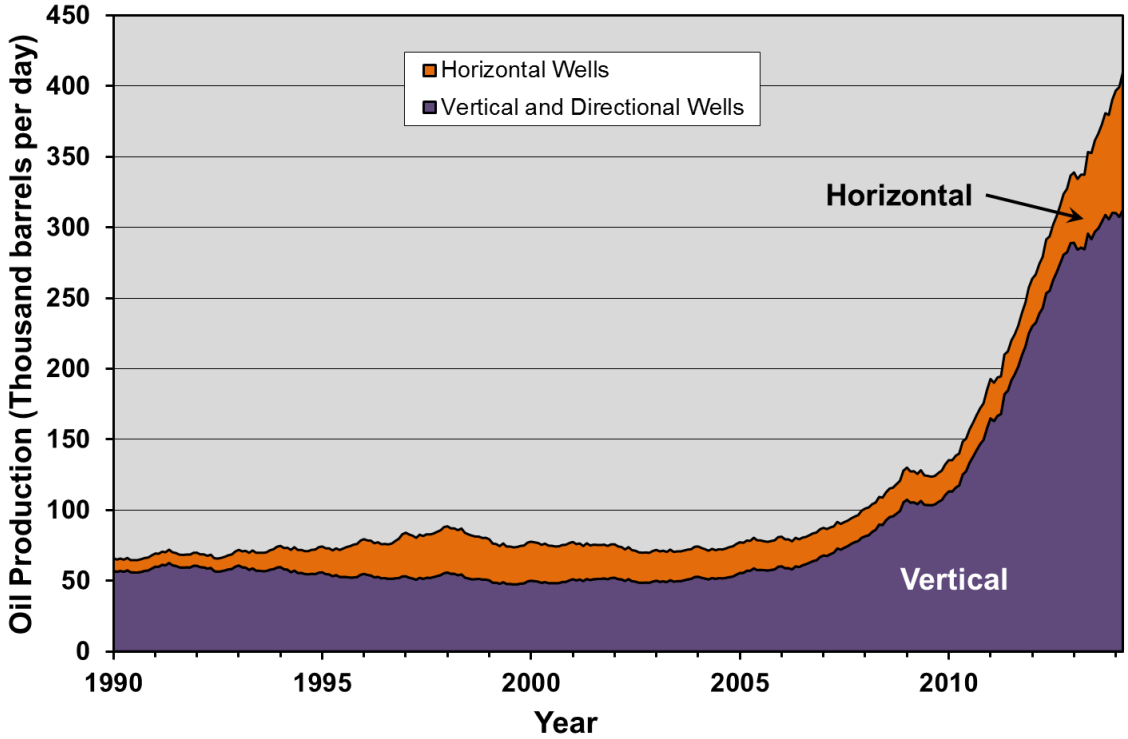

Figure 2-59. Oil production from the Spraberry play by well type.[94]

Although vertical wells have accounted for much of the recent production growth, horizontal wells now appear to be the most important contributors.

[94] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.1.2 Well Quality

A look at well quality reveals that the Spraberry is unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-60 illustrates the average well decline profile for all wells; Figure 2-61 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are just a tenth of the initial production of an average Bakken well in a top county. Horizontal wells are more than double the initial productivity of the average well but still pale by comparison to a Bakken or Eagle Ford well. The average three-year decline of Spraberry wells is, however, somewhat lower than the Bakken at 60% and 72% for all wells and horizontal wells, respectively.

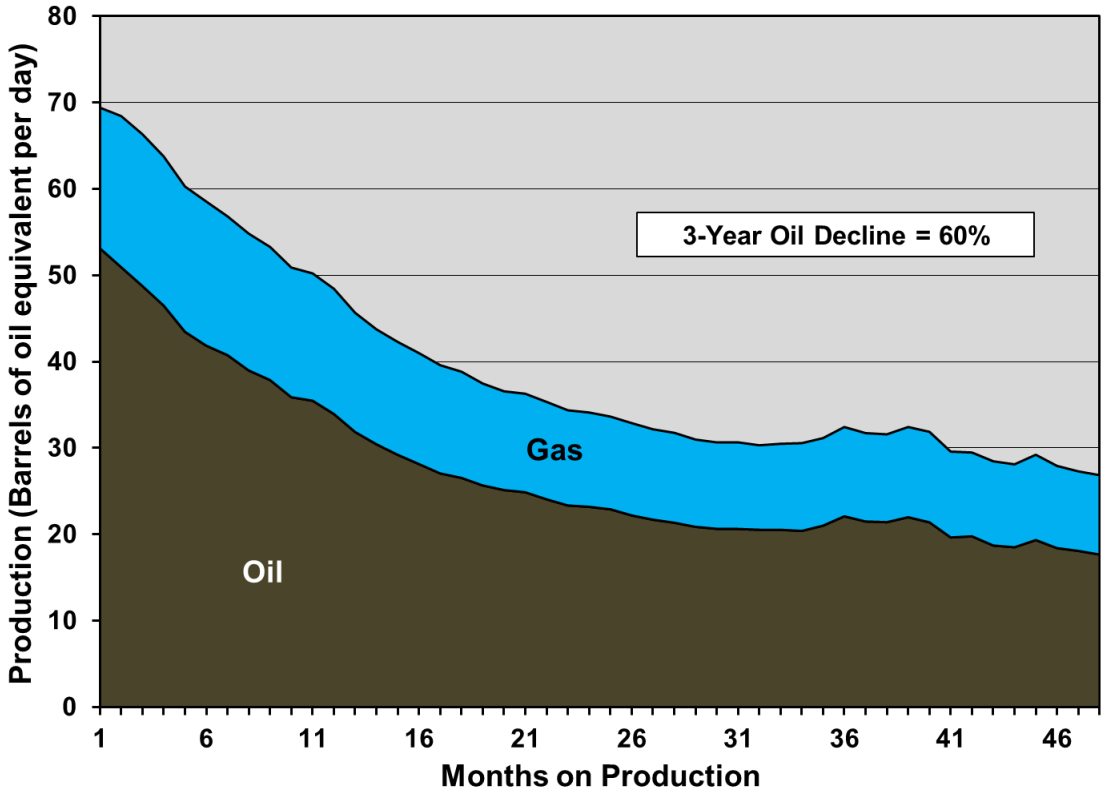

Figure 2-60. Oil and gas average well decline profile for all wells in the Spraberry play.[95]

On an energy equivalent basis these wells have an initial productivity of less than a tenth that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[95] Data from Drillinginfo retrieved July 2014.

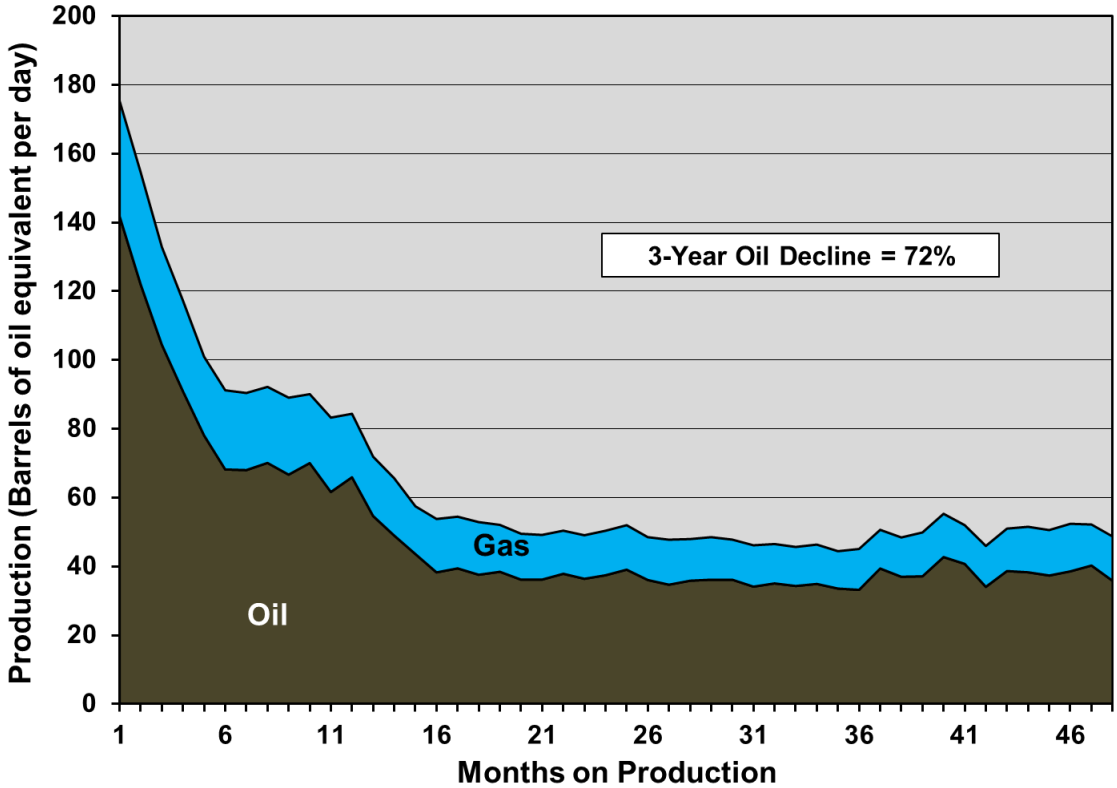

Figure 2-61. Oil and gas average well decline profile for horizontal wells in the Spraberry play.[96]

On an energy equivalent basis these wells have an initial productivity of less than a third that of the average well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[96] Data from Drillinginfo retrieved July 2014.

2.4.1.3 EIA Forecast

The EIA's projection for Spraberry play production through 2040 in its reference case is illustrated in Figure 2-62. Total recovery between 2012 and 2040 is forecast to be 6.5 billion barrels; this amounts to 15% of the EIA's reference case forecast for U.S. tight oil production through 2040. Cumulative production by 2040 amounts to 80% of the "unproved technically recoverable resources" the EIA estimated for the Spraberry as of January 1, 2012.

Given that this is a redevelopment of an old play which is already extensively drilled, the fact that the wells are of relatively low quality, and the nature of likely production profiles from shale plays like the Bakken, this would seem to be a highly optimistic forecast. It is already overestimating actual production by 55% in year one, as actual production for 2013 amounted to 390,000 barrels per day compared to an estimate of 604,000 barrels by the EIA. Furthermore, the EIA is projecting that production will be 505,000 barrels per day in 2040, which is 30% above current levels. High field decline rates make it very likely that production decline after its projected peak in 2021 will be much steeper than projected. Given what is known, this EIA forecast would seem to have a very high optimist bias.

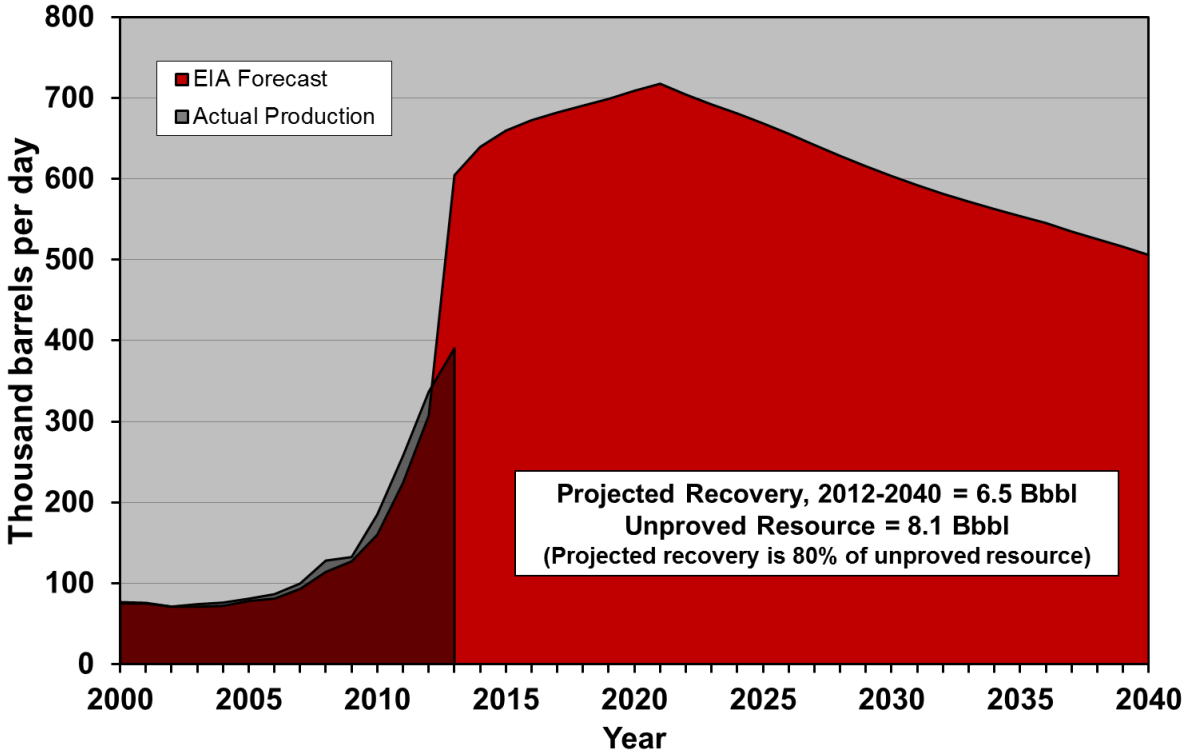

Figure 2-62. EIA reference case projection of oil production from the Spraberry play through 2040, with actual production to 2013.[97]

The forecast total recovery of 6.5 billion barrels over the 2012-2040 period amounts to 80% of the 8.1 billion barrels of "unproved technically recoverable resources as of January 1, 2012".[98]

[97] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[98] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.4.2 Wolfcamp Play

The EIA forecasts recovery of 2.64 billion barrels of oil from the Wolfcamp play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Wolfcamp play has also been producing oil and gas for decades. Over 12,800 wells have been drilled of which more than 6,000 are currently producing. The play has produced over 870 million barrels of oil and nearly 4.8 trillion cubic feet of natural gas over its lifetime. Figure 2-63 illustrates well distribution within the Wolfcamp play.

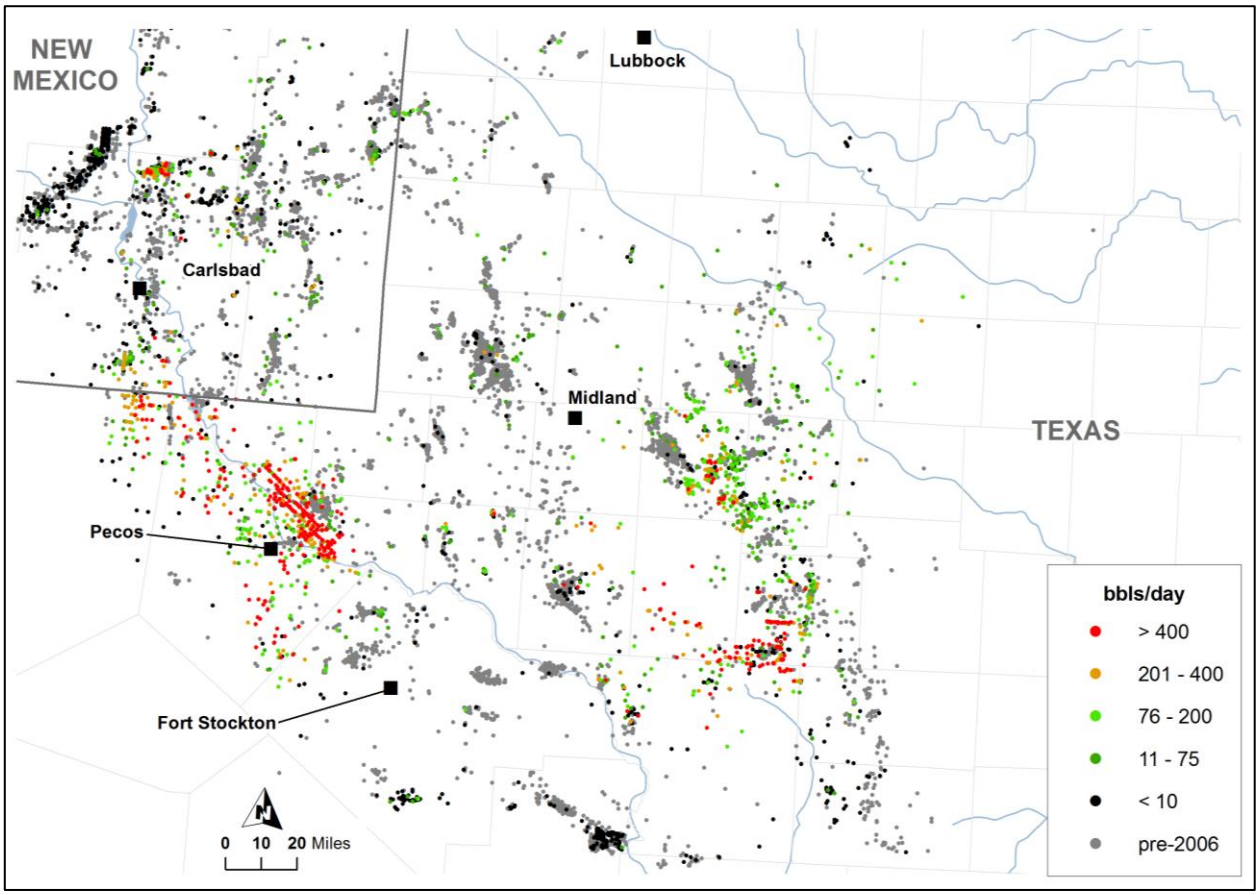

Figure 2-63. Distribution of wells in the Wolfcamp play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[99]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[99] Data from Drillinginfo retrieved July 2014.

2.4.2.1 Production History

Production of oil in the Wolfcamp has quadrupled since 2005, and including natural gas (on an energy equivalent basis) is up three-fold as illustrated in Figure 2-64.

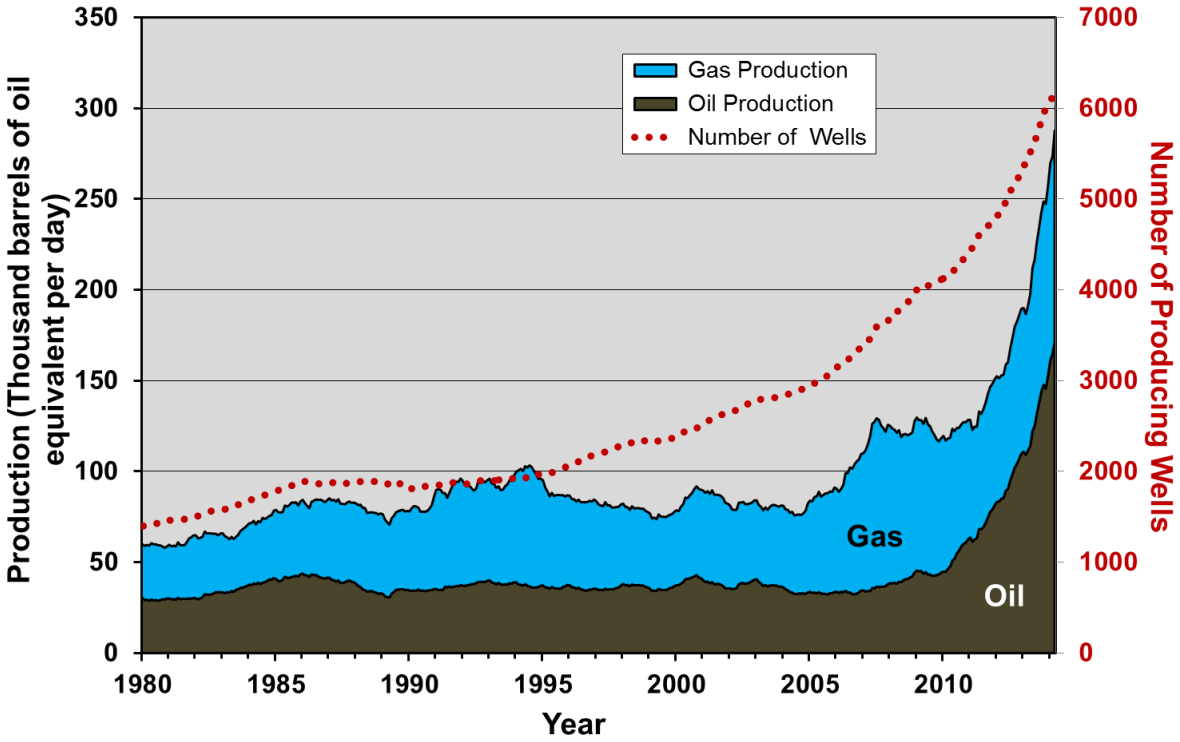

Figure 2-64. Wolfcamp play oil and gas production and number of producing wells, 1980 to 2014.[100]

Producing well count is now over 6,000.

[100] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

The number of producing wells has also doubled over this period. A look at the split in production by well type reveals that virtually all of this growth is attributable to horizontal wells (Figure 2-65). Horizontal fracking technology is obviously paying dividends.

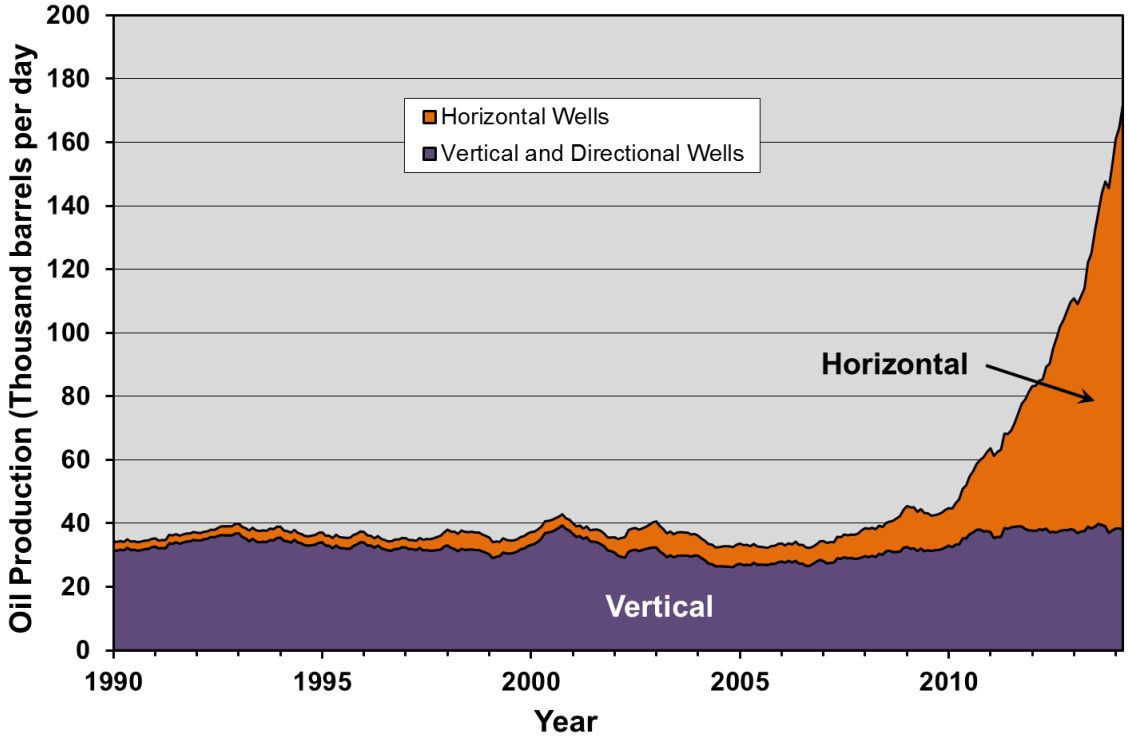

Figure 2-65. Oil production from the Wolfcamp play by well type.[101]

Horizontal wells are now accounting for most of the production growth.

[101] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.2.2 Well Quality

A look at well quality reveals that the Wolfcamp, although considerably better than the Spraberry, is unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-66 illustrates the average well decline profile for all wells; Figure 2-67 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are just a quarter of the initial production of an average Bakken well in a top county. Horizontal wells are nearly double the initial productivity of the average well but still pale by comparison to a Bakken or Eagle Ford well. The average three-year decline of Wolfcamp wells is comparable to the Bakken at 81% and 85% for all wells and horizontal wells, respectively.

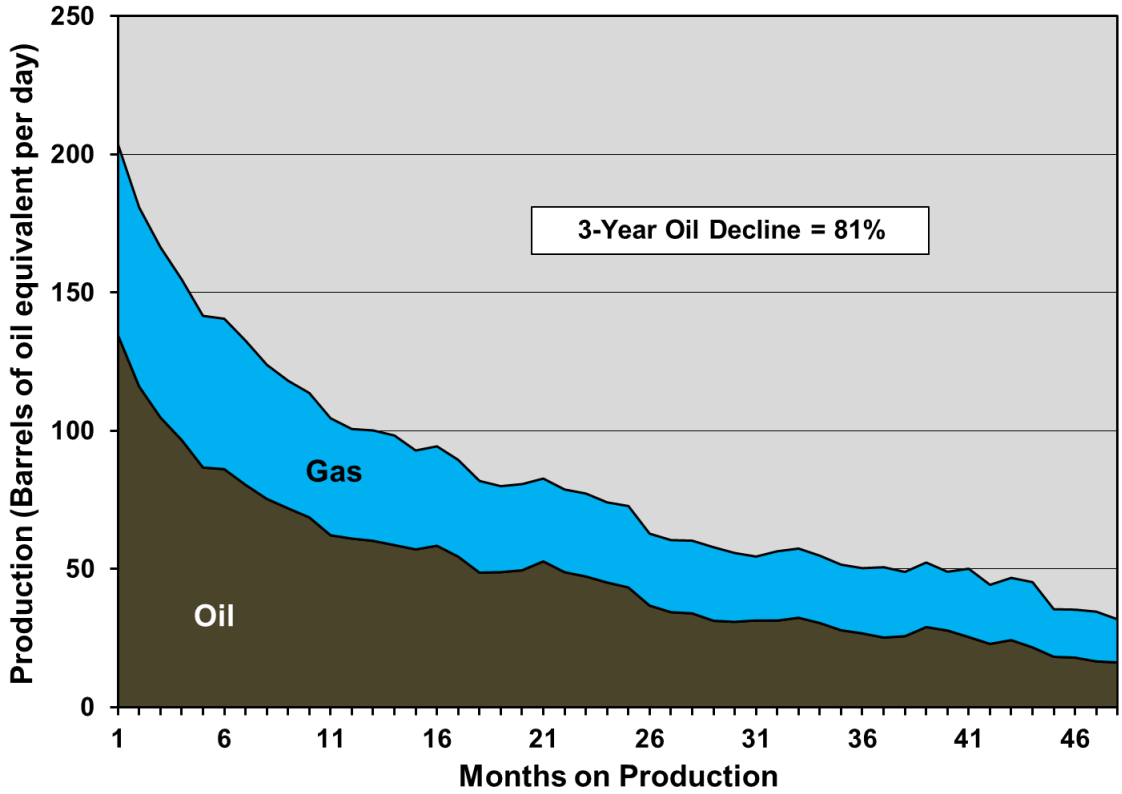

Figure 2-66. Oil and gas average well decline profile for all wells in the Wolfcamp play.[102]

On an energy equivalent basis these wells have an initial productivity of less than a quarter that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[102] Data from Drillinginfo retrieved July 2014.

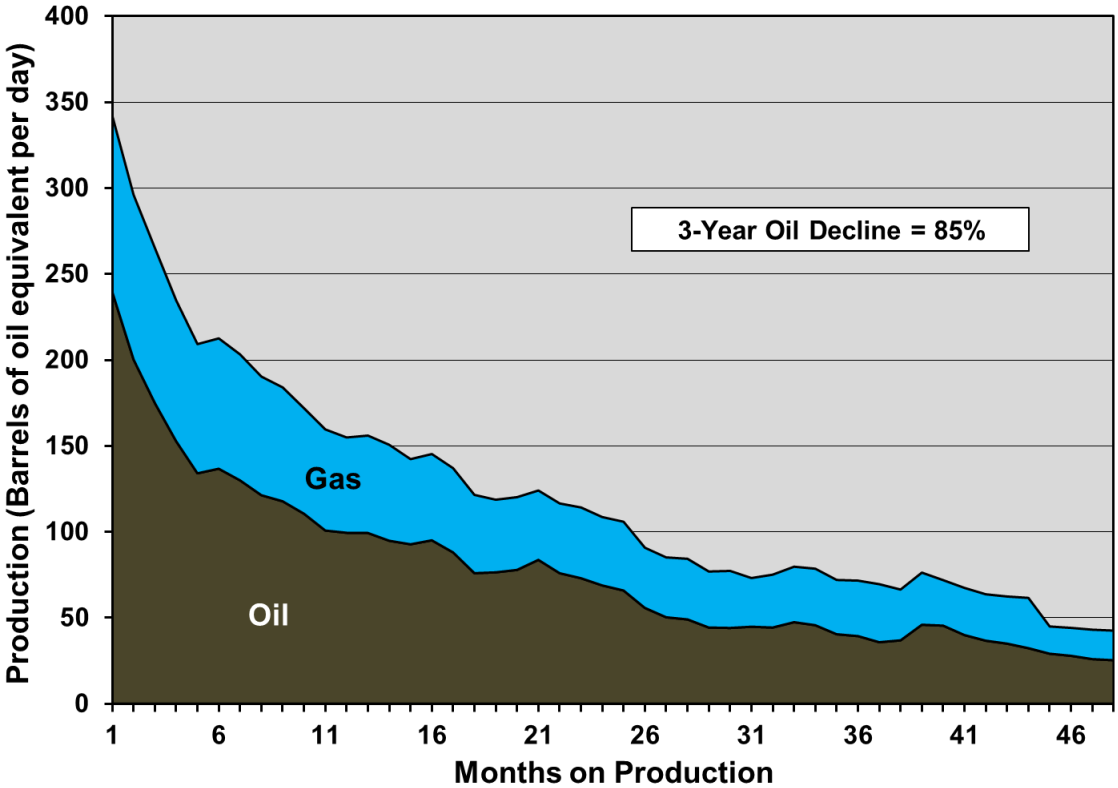

Figure 2-67. Oil and gas average well decline profile for horizontal wells in the Wolfcamp play.[103]

On an energy equivalent basis these wells have an initial productivity of about a third of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[103] Data from Drillinginfo retrieved July 2014.

2.4.2.3 EIA Forecast

The EIA's projection for Wolfcamp play production through 2040 in its reference case is illustrated in Figure 2-68. Total recovery between 2012 and 2040 is forecast to be 2.64 billion barrels. This amounts to 6.1% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 amounts to 78% of the "unproved technically recoverable resources" the EIA estimated for the Wolfcamp as at January 1, 2012.

Given that this is a redevelopment of an old play which is already extensively drilled, the fact that the wells are of relatively low quality, and the nature of likely production profiles from shale plays like the Bakken, this would seem to be an optimistic forecast. It is already off by 36% on the high side in year one, as actual production for 2013 amounted to 153,000 barrels per day compared to an estimate of 209,000 barrels by the EIA. Furthermore, the EIA is projecting that production will be 220,000 barrels per day in 2040, which is 44% above current levels. High field decline rates make it likely that production decline after its projected peak in 2019 will be much steeper than forecast. Given what is known, this EIA forecast would seem to have a high optimist bias.

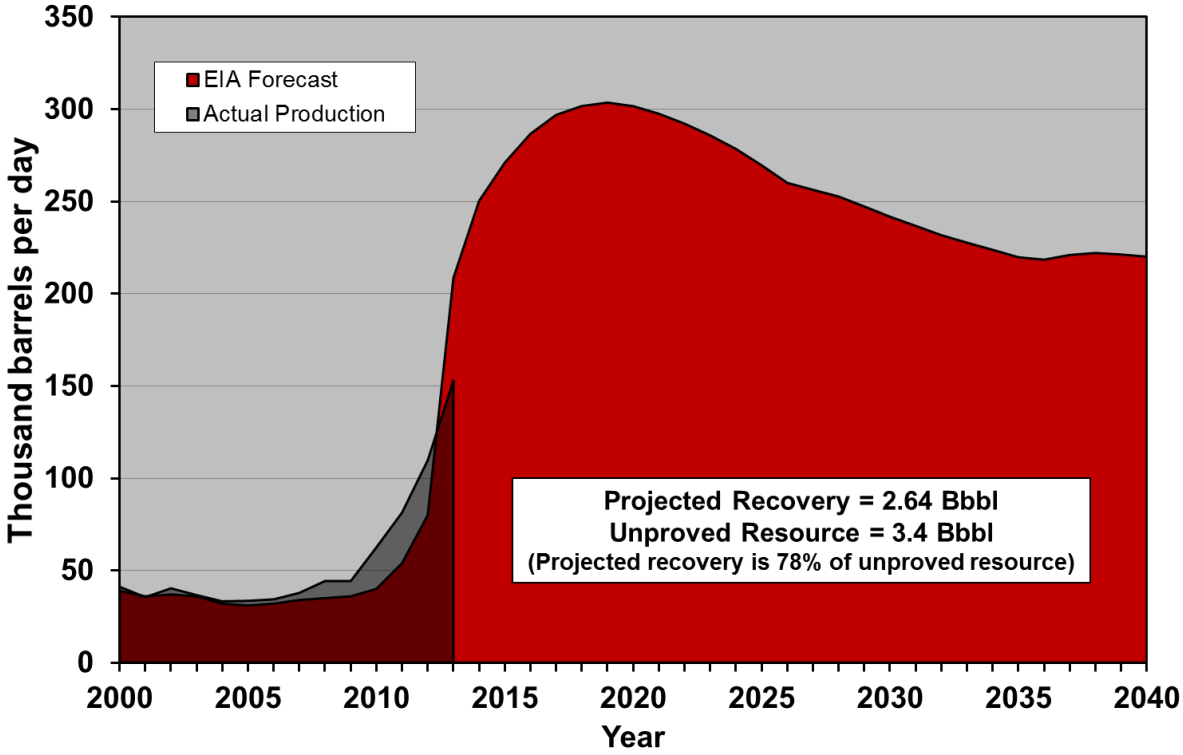

Figure 2-68. EIA reference case projection of oil production from the Wolfcamp play through 2040, with actual production to 2013.[104]

The forecast total recovery of 2.64 billion barrels over the 2012-2040 period amounts to 78% of the 3.4 billion barrels of "unproved technically recoverable resources as of January 1, 2012".[105]

[104] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[105] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.4.3 Bone Spring Play

The EIA forecasts recovery of 0.68 billion barrels of oil from the Bone Spring play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is reasonable and may be on the low end of future production.

The Bone Spring play has, like the Spraberry and Wolfcamp, been producing oil and gas for decades. Over 5,200 wells have been drilled of which 2,500 are currently producing. The play has produced 208 million barrels of oil and 730 billion cubic feet of natural gas over its lifetime. Figure 2-69 illustrates well distribution within the Bone Spring play.

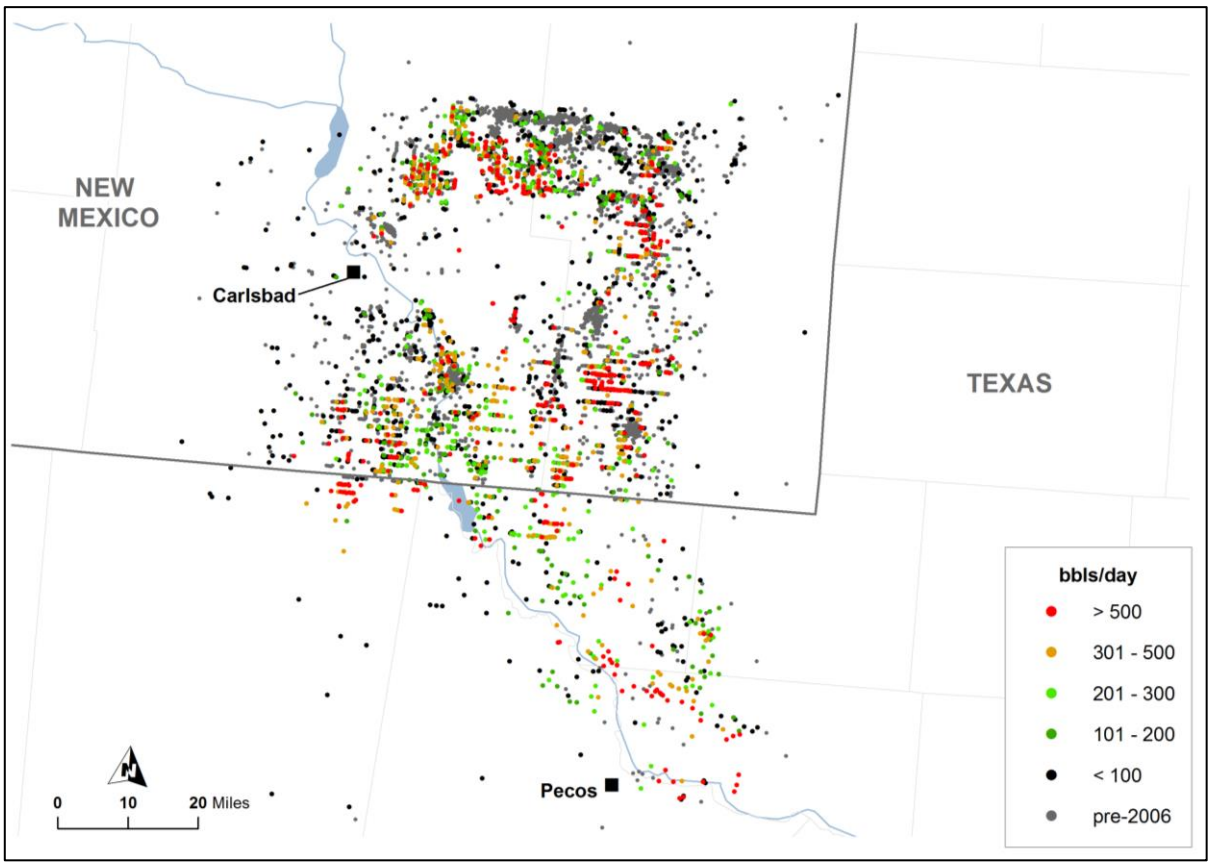

Figure 2-69. Distribution of wells in the Bone Spring play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[106]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[106] Data from Drillinginfo retrieved July 2014.

2.4.3.1 Production History

Production of oil in the Bone Spring has increased more than 10 fold since 2005 and on an energy equivalent basis, including natural gas, is up more than 15-fold as illustrated in Figure 2-70.

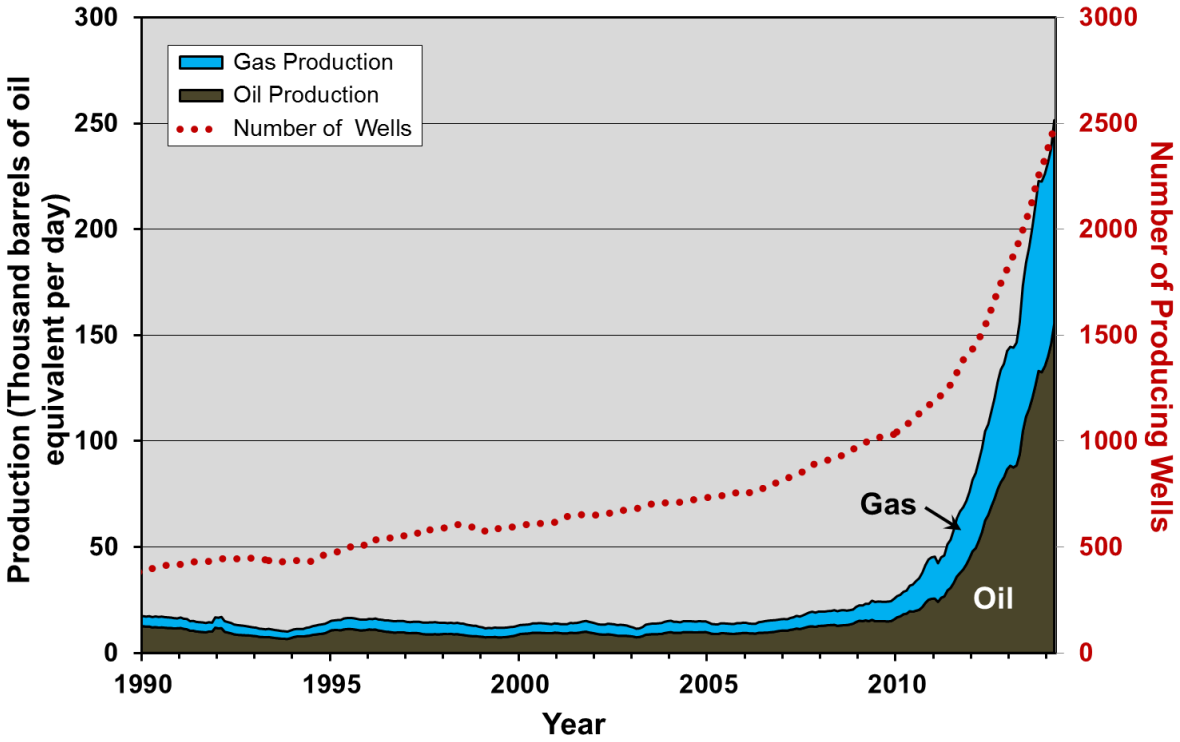

Figure 2-70. Bone Spring play oil and gas production and number of producing wells, 1990 to 2014.[107]

Producing well count is now about 2,500.

[107] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

The number of producing wells has also more than tripled over this period. A look at the split in production by well type reveals that virtually all of this growth is attributable to horizontal wells (Figure 2-71). Horizontal fracking technology is obviously paying dividends.

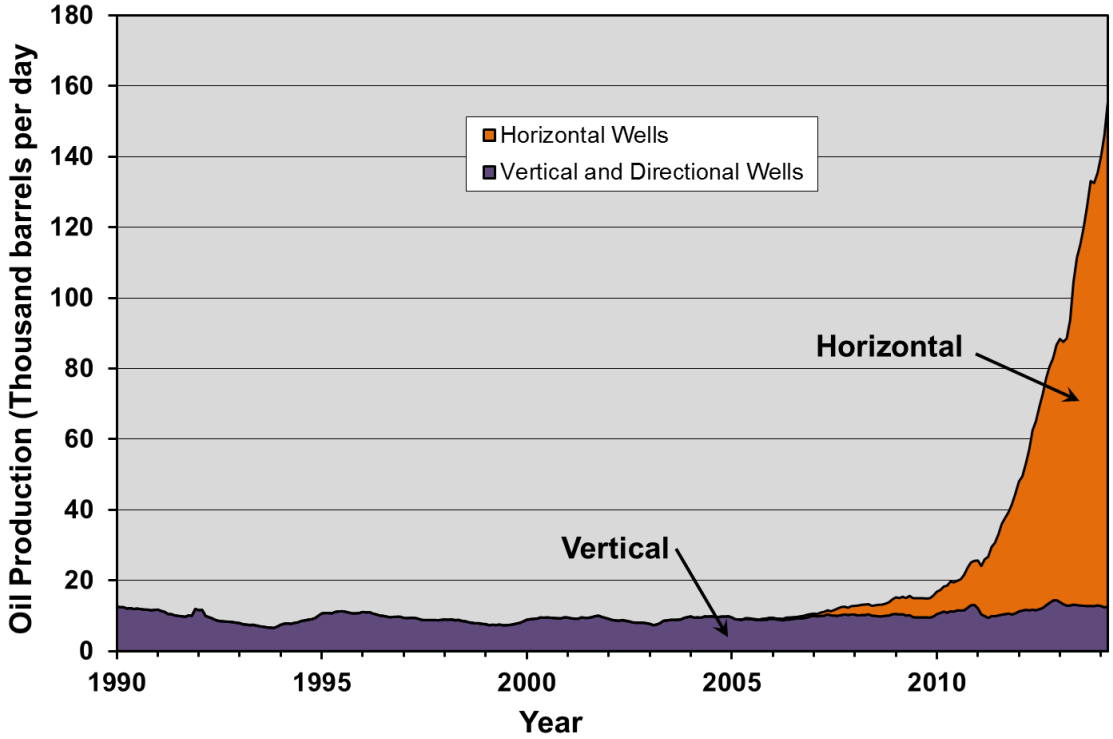

Figure 2-71. Oil production from the Bone Spring play by well type.[108]

Horizontal wells are now accounting for most of the production growth.

[108] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.4.3.2 Well Quality

A look at well quality reveals that the Bone Spring, although considerably better than either the Spraberry or Wolfcamp, is still unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-72 illustrates the average well decline profile for all wells; Figure 2-73 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are about half of the initial production of an average Bakken well in a top county. Horizontal wells are slightly better; the average initial productivity is about two-thirds of an average Bakken well. The average three-year decline of Bone Spring wells is greater that the Bakken at 91% for all wells and for horizontal wells, and is the steepest observed for any shale play.

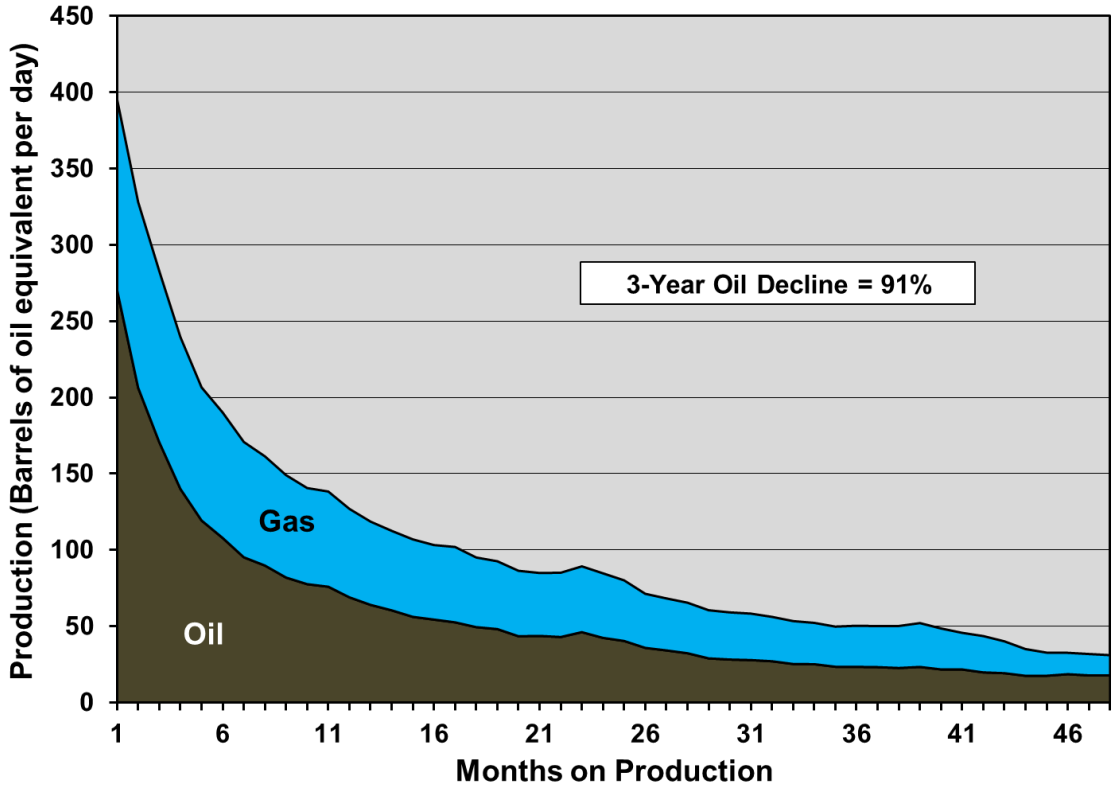

Figure 2-72. Oil and gas average well decline profile for all wells in the Bone Spring play.[109]

On an energy equivalent basis these wells have an initial productivity of about half that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[109] Data from Drillinginfo retrieved July 2014.

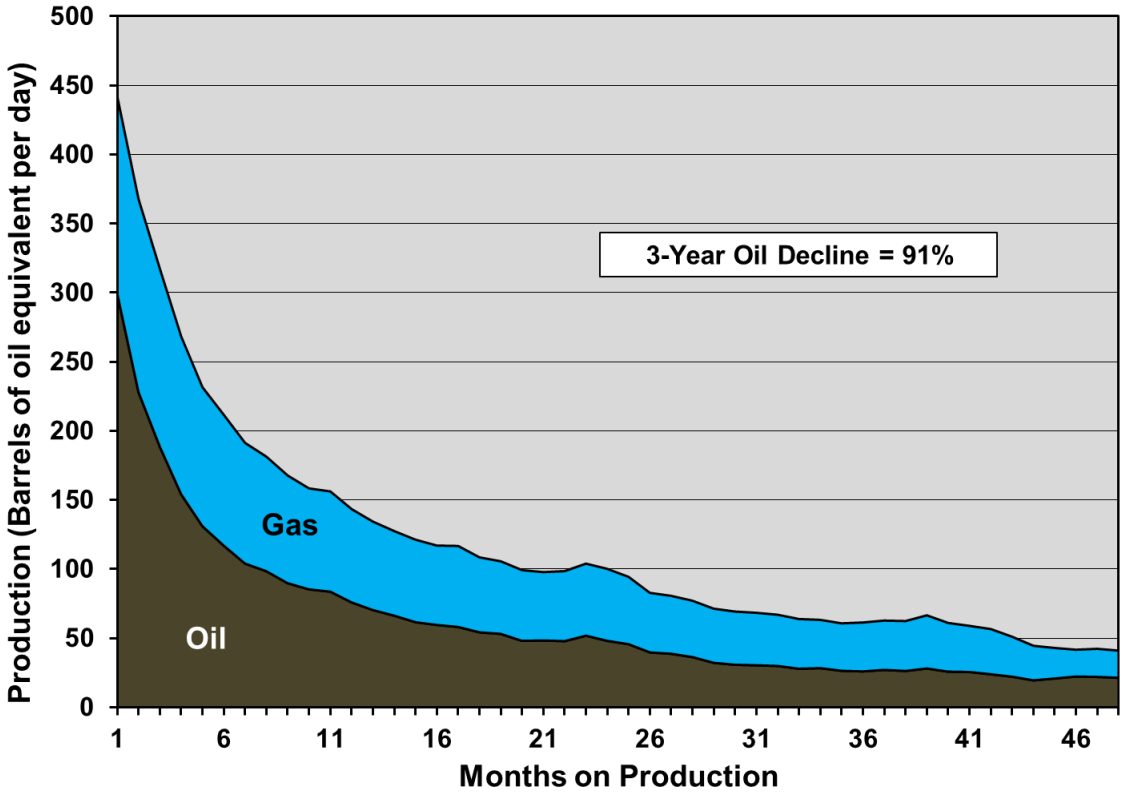

Figure 2-73. Oil and gas average well decline profile for horizontal wells in the Bone Spring play.[110]

On an energy equivalent basis these wells have an initial productivity of about half of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[110] Data from Drillinginfo retrieved July 2014.

2.4.3.3 EIA Forecast

The EIA's projection for Bone Spring play production through 2040 in its reference case is illustrated in Figure 64. Total recovery between 2012 and 2040 is forecast to be 0.68 billion barrels. This amounts to just 1.6% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 amounts to 34% of the "unproved technically recoverable resources" the EIA estimated for the Bone Spring as at January 1, 2012.

In this case the EIA's forecast looks conservative, as production is already considerably higher in year one than projected. One could argue with the long extended tail of production but it appears likely that Bone Spring production may rise considerably higher. The very high well- and field-declines noted, which are considerably higher than the other Permian plays examined above, will likely make decline on the far side of peak production much steeper than depicted in the EIA projection. Given what is known, this EIA forecast would seem to have a low optimist bias.

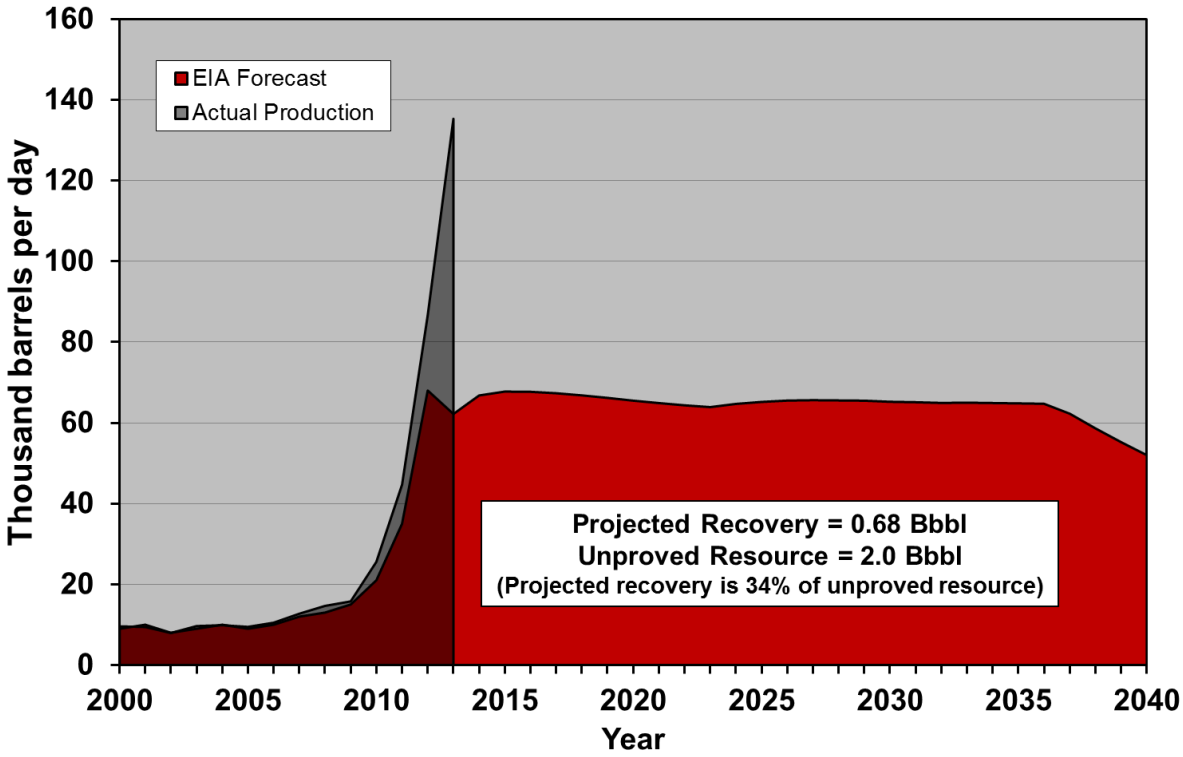

Figure 2-74. EIA reference case projection of oil production from the Bone Spring through 2040, with actual production to 2013.[111]

The forecast total recovery of .68 billion barrels over the 2012-2040 period amounts to 34% of the 2.0 billion barrels of "unproved technically recoverable resources as of January 1, 2012".[112]

[111] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[112] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.4.4 Key Characteristics of the Permian Basin Plays

As mentioned, the Permian Basin is the third largest source of tight oil in the U.S., and the three plays reviewed above constitute 23% of the oil the EIA projects will be recovered by 2040 in its reference tight oil case. In addition to these plays, two smaller Permian plays are listed by the EIA in Figure 2-7 above: the Glorieta-Yeso (actually two separate formations) and the Delaware. These latter two plays display the same characteristics as the first three: they are old plays which have been producing for decades, and although they are increasing somewhat in production, well quality is unremarkable compared to the Bakken and Eagle Ford.

Figure 2-75 illustrates total Permian Basin production, highlighting these five plays which now make up 56% of the total production of the basin.

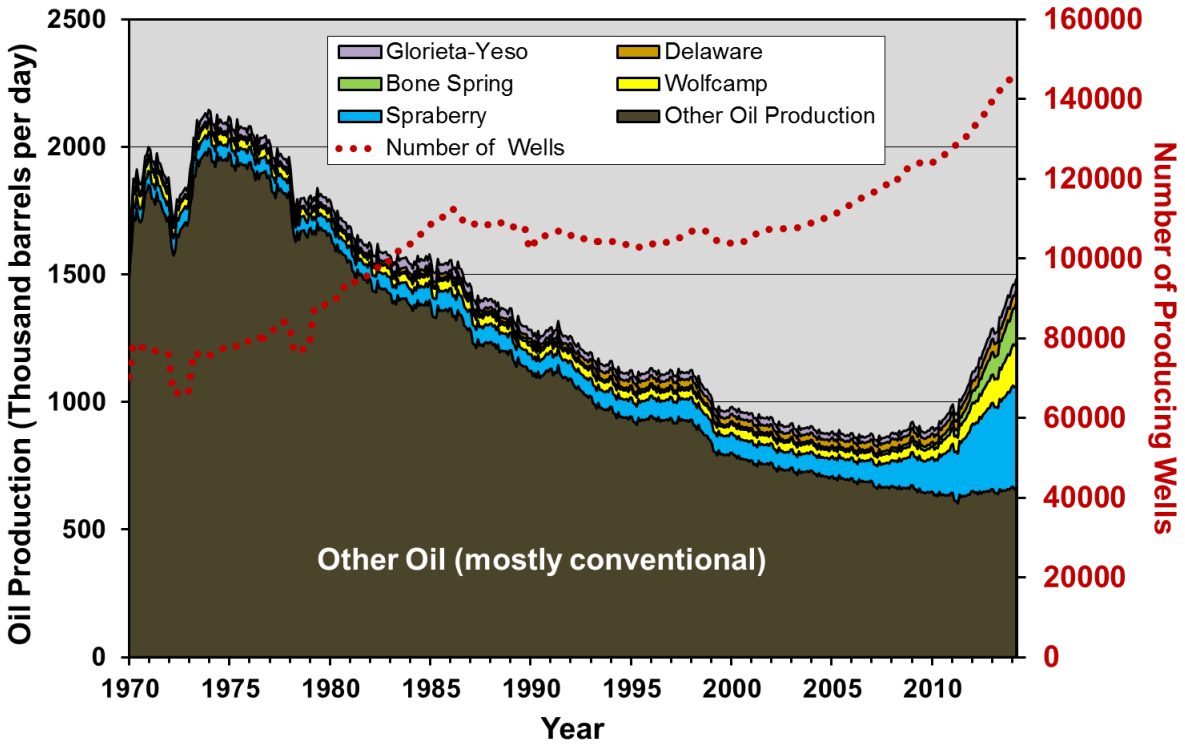

Figure 2-75. Oil production and number of producing wells in the Permian Basin to 2014.[113]

Production from the five tight oil plays the EIA includes in the Permian Basin (see Figure 2-7) is highlighted. As of March 2014, these plays made up 56% of total Permian Basin production.

[113] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

The EIA only provided projections used in its reference case tight oil forecast for the three Permian plays reviewed in detail above.[114] The aggregate production of these plays compared to the collective forecast of the EIA for them is illustrated in Figure 2-76. The EIA forecast suggests these plays will collectively produce 9.25 billion barrels between 2014 and 2040, which is nearly five times as much oil as they produced in the previous 34 years. Production is projected to rise to a peak in 2021 followed by a gradual decline through 2040, when these plays are forecast to be producing 770,000 barrels per day, or 6% above current levels. This is a very aggressive forecast considering their age and extensive drilling and production history, their relatively low quality wells, and their observed steep well- and field-declines.

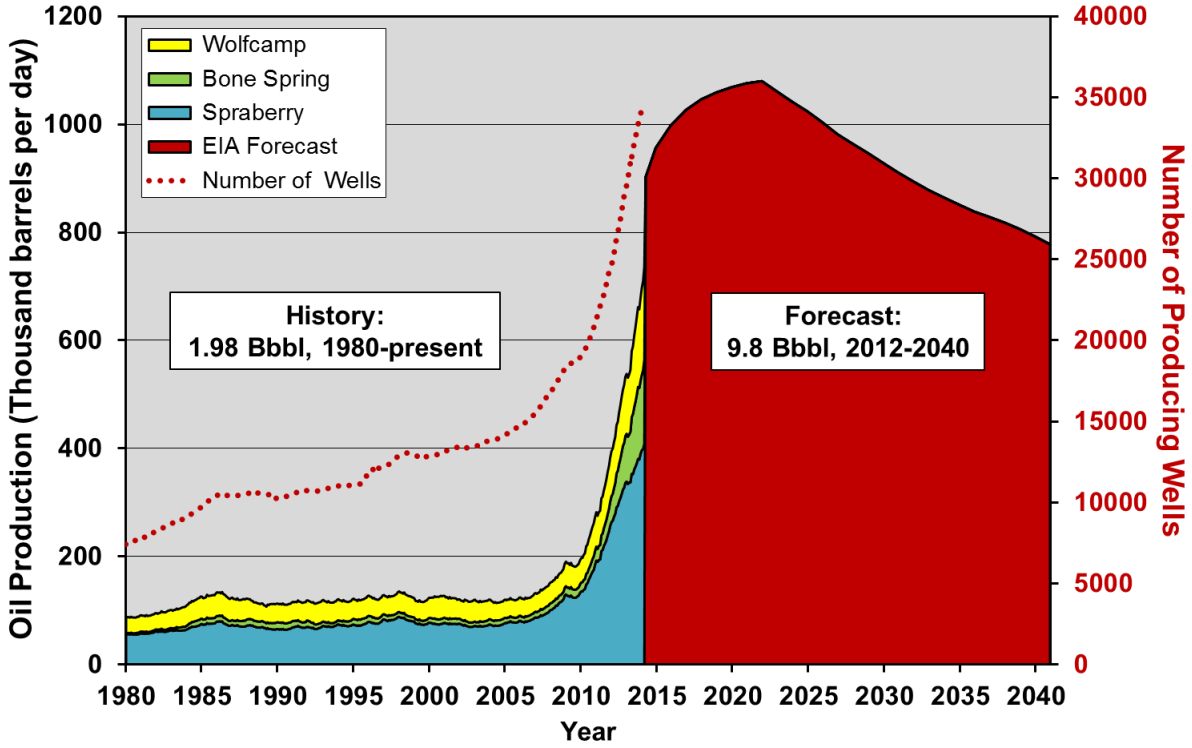

Figure 2-76. Oil production and number of producing wells in the Spraberry, Wolfcamp, and Bone Spring plays to 2014, with EIA reference case projection for these plays through 2040.[115]

The forecast total recovery of 9.8 billion barrels over the 2012-2040 period amounts to nearly five times the 1.98 billion barrels recovered from 1980 to the present, and 73% of the plays "unproved technically recoverable resources as of January 1, 2012.[116]

[114] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[115] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[116] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Growth in the Permian Basin plays is largely a result of redevelopment of long-established plays with better technology, including horizontal drilling and fracking, rather than the new discoveries represented by the Bakken and Eagle Ford. Most of the Permian plays first began to produce significant amounts of oil and gas back in the 1950s. More than 70,000 wells have been drilled of which 43,000 are currently producing. As such they are not analogues to the Bakken and Eagle Ford, from which significant production is just twelve and six years old, respectively. The Bakken and Eagle Ford currently produce 62% of all U.S. tight oil (Figure 5), compared to 25% for the Permian plays. At least some of the oil produced from these so-called Permian "tight oil" plays is conventional, as is most of the rest of Permian Basin production. Table 2-3 summarizes the long history of development of these Permian Basin plays and contrasts that with the EIA's tight oil forecast.

Play	Years Produced	Wells Drilled	Wells Producing	Production to Date (Bbbls)	EIA Recovery 2012-2040 (Bbbls)	EIA Unproved Resources as of January 1, 2012 (Bbbls)	EIA Production in 2040 (MMbbl/d)
Spraberry	60+	36756	25939	1.83	6.5	8.1	0.51
Avalon / Bone Spring	40+	5287	2473	0.21	0.7	2.0	0.05
Wolfcamp	60+	12837	6124	0.87	2.6	3.4	0.22
Delaware	60+	8468	3995	0.43	Not Stated	Not Stated	Not Stated
Glorieta-Yeso	60+	9365	4492	0.59	Not Stated	Not Stated	Not Stated
Total		72713	43023	3.93	9.8+	13.5+	0.78+

Table 2-3. Age, wells, production[117], EIA unproved technically recoverable resources[118] and EIA reference case forecast for Permian Basin tight oil plays.[119]

[117] Data from Drillinginfo retrieved July 2014.
[118] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[119] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.4.5 Permian Basin Plays Analysis Summary

Several conclusions can be made from the foregoing analysis of the Permian Basin plays:

1. Growth in Permian Basin production is largely a result of application of new technologies to old plays, rather than significant new discoveries such as represented by the Bakken and Eagle Ford, although there are some emerging Permian plays lumped by the EIA into "other" in its reference case tight oil forecast.[120]

2. Productivity of wells in Permian tight oil plays is generally much lower on average than in the Bakken and Eagle Ford. Well costs are also lower with both vertical and horizontal development possible, and extensive infrastructure is in place, hence improving the economics of drilling despite the lower well productivity.

3. These plays exhibit steep well- and field-declines mandating continuous high levels of drilling and capital input to maintain production, although in the Spraberry declines are somewhat lower than in the other Permian plays.

4. The EIA is projecting aggressive continued growth in production from these plays with a peak in 2021 followed by a gradual decline, and the recovery of nearly five times as much oil by 2040 as these plays have produced in the past 34 years. This forecast is highly optimistic given the number of wells that would have to be drilled and the amount of capital required.

5. Although these plays were not reviewed on a detailed county-by-county basis, they are highly likely to exhibit "sweet spots" or "core areas" which are being targeted first, hence the number of wells and capital input will need to increase later in the EIA's forecast to moderate production decline.

[120] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA. Note that the EIA did not provide play specific projections for the Glorieta-Yeso and Delaware plays.

2.5 Other Major Plays

Two other plays with significant production were singled out by the EIA[121] in its reference case tight oil forecast: the Austin Chalk in the Gulf Coast region and the Niobrara-Codell, in Colorado and Wyoming (a projection for the Monterey was also provided by the EIA but has been dealt with in a previous report[122], and the Woodford Shale, which was also provided, has relatively insignificant oil production). These are reviewed below.

[121] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[122] J. David Hughes, *Drilling California: A Reality Check on the Monterey Shale*, Post Carbon Institute, 2013, http://www.postcarbon.org/publications/drilling-california.

2.5.1 Austin Chalk Play

The EIA forecasts recovery of 4.9 billion barrels of oil from the Austin Chalk play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is highly unlikely to be realized.

The Austin Chalk play has, like the Permian plays, been producing oil and gas for decades. Over 15,000 wells have been drilled of which 5,000 are currently producing. The play has produced 1.17 billion barrels of oil and 6.1 trillion cubic feet of natural gas over its lifetime. Figure 2-77 illustrates well distribution within the Austin Chalk play. The play has seen the application of horizontal drilling for many years. Figure 2-78 illustrates the distribution of horizontal wells in the play which tend to be concentrated within certain areas.

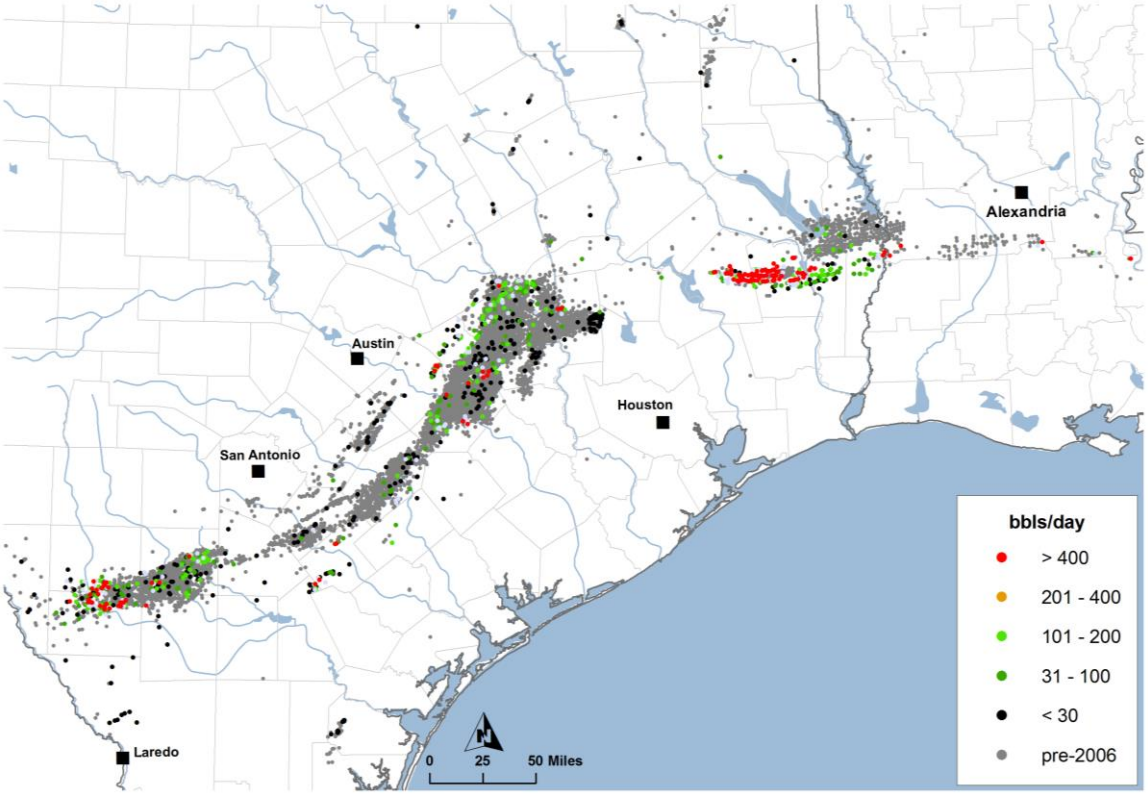

Figure 2-77. Distribution of wells in the Austin Chalk play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[123]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[123] Data from Drillinginfo retrieved July 2014.

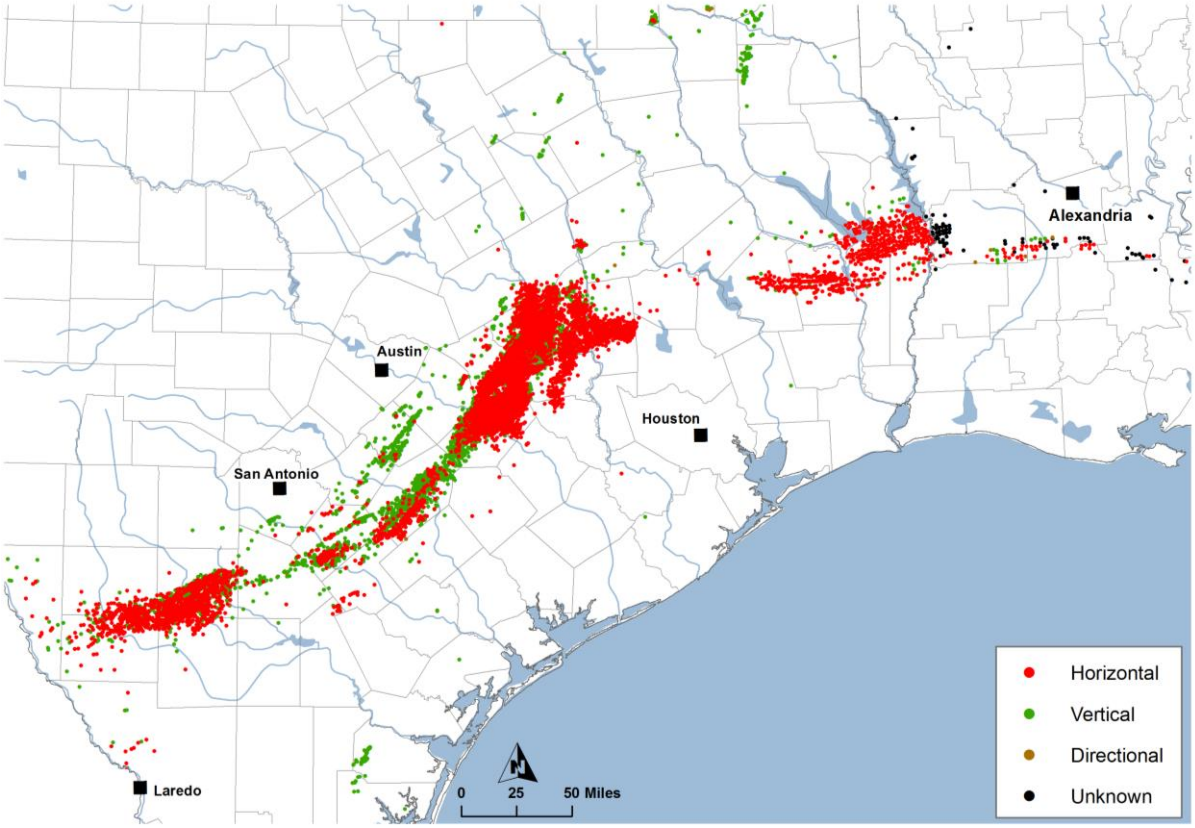

Figure 2-78. Distribution of wells in the Austin Chalk play categorized by drilling type, as of early 2014.[124]

[124] Data from Drillinginfo retrieved July 2014.

2.5.1.1 Production History

Production of oil in the Austin Chalk has been declining and the number of producing wells is also falling as illustrated in Figure 2-79. Oil production has declined by 83% since its peak in 1991.

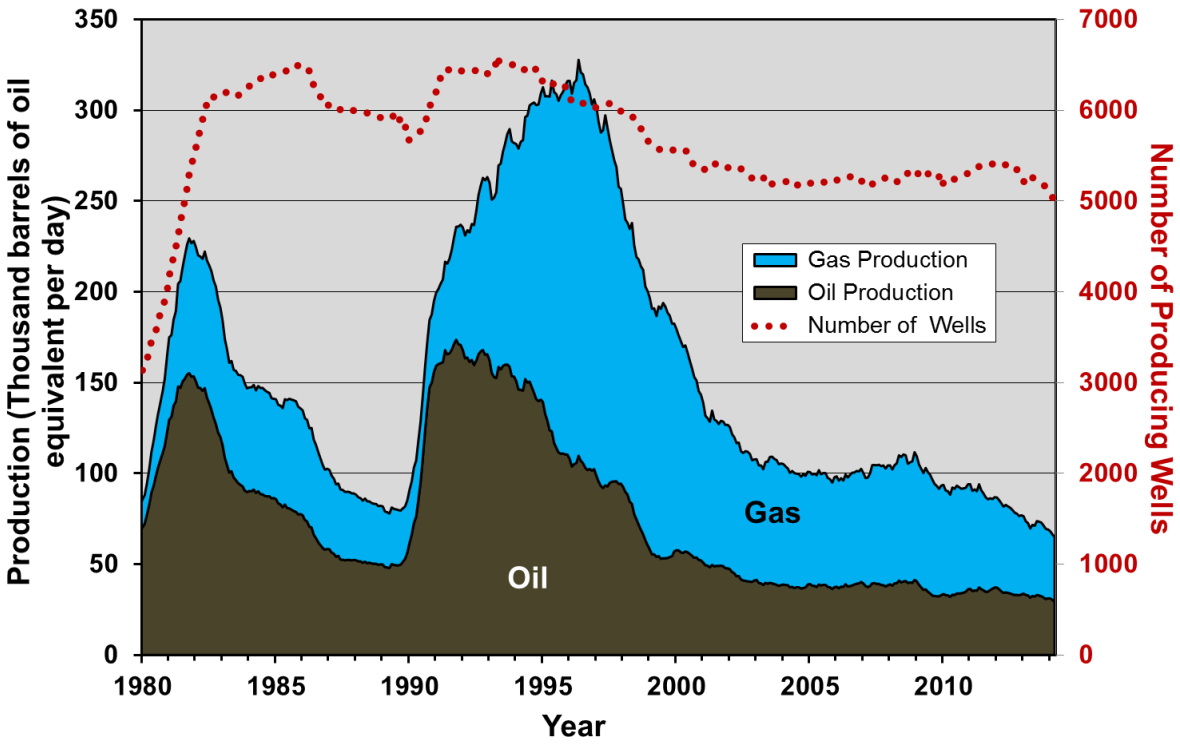

Figure 2-79. Austin Chalk play oil and gas production and number of producing wells, 1980 to 2014.[125]

Producing well count is now about 5,000.

[125] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

A look at the split in production by well type reveals that horizontal wells have contributed the bulk of oil production over the past 25 years and currently provide 90% of production (Figure 2-80).

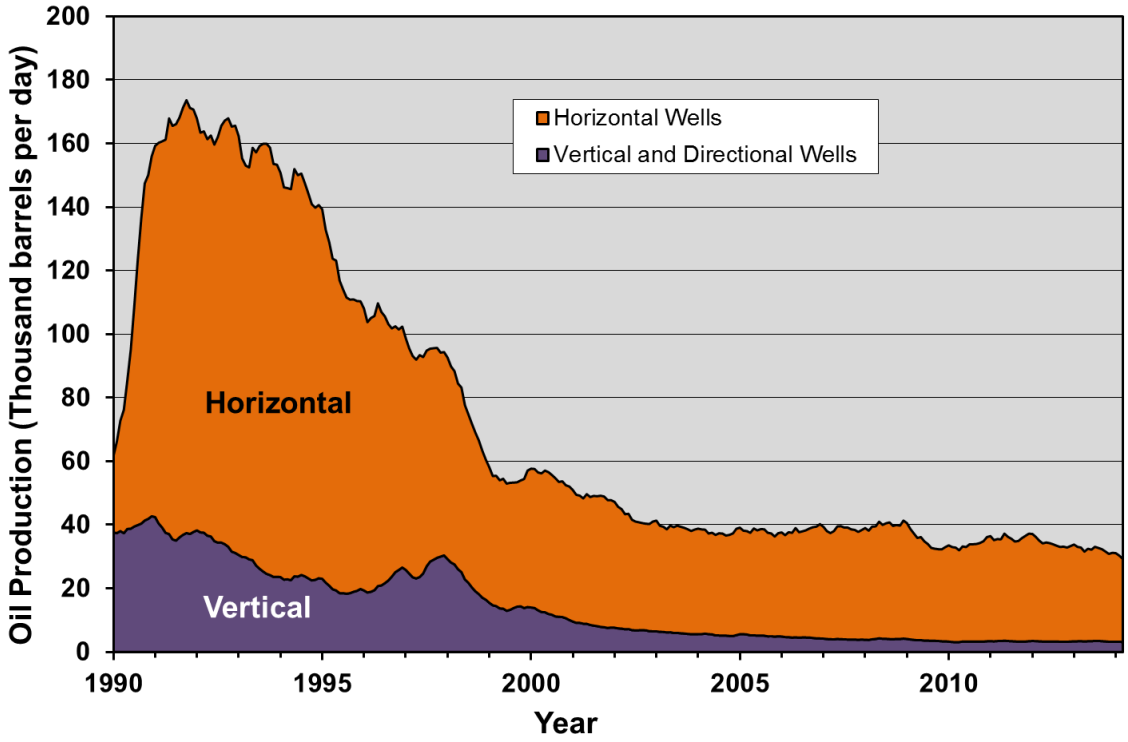

Figure 2-80. Oil production from the Austin Chalk play by well type.[126]

Horizontal wells have been the major contributors since the early 1990s.

[126] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.5.1.2 Well Quality

A look at well quality reveals that the Austin Chalk is, like the Permian Basin plays, unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-81 illustrates the average well decline profile for all wells; Figure 2-82 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are about one third of the initial production of an average Bakken well in a top county. Horizontal wells are slightly better (although 90% of "all" wells are horizontal so the only slight improvement is not surprising), although the initial productivity of the average well still pales by comparison to a Bakken or Eagle Ford well. The average three-year decline in oil production of Austin Chalk wells is comparable to the Bakken at 85% for all wells and for horizontal wells.

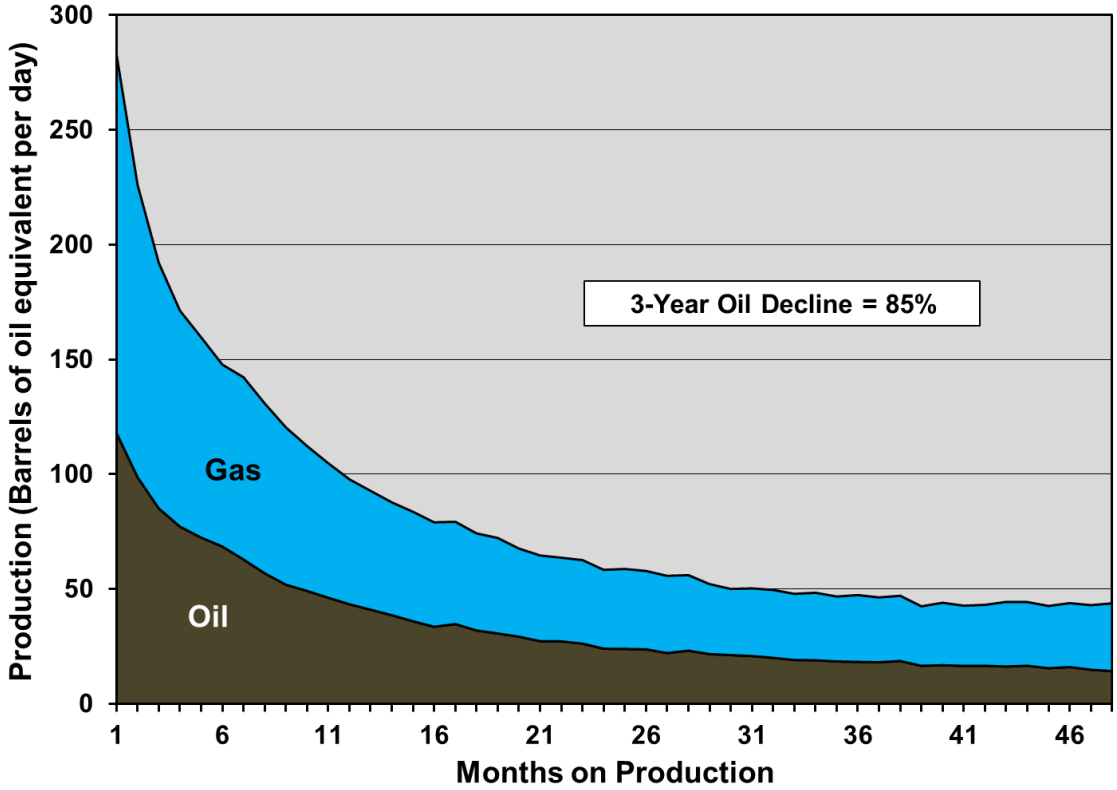

Figure 2-81. Oil and gas average well decline profile for all wells in the Austin Chalk play.[127]

On an energy equivalent basis these wells have an initial productivity of about one third that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[127] Data from Drillinginfo retrieved July 2014.

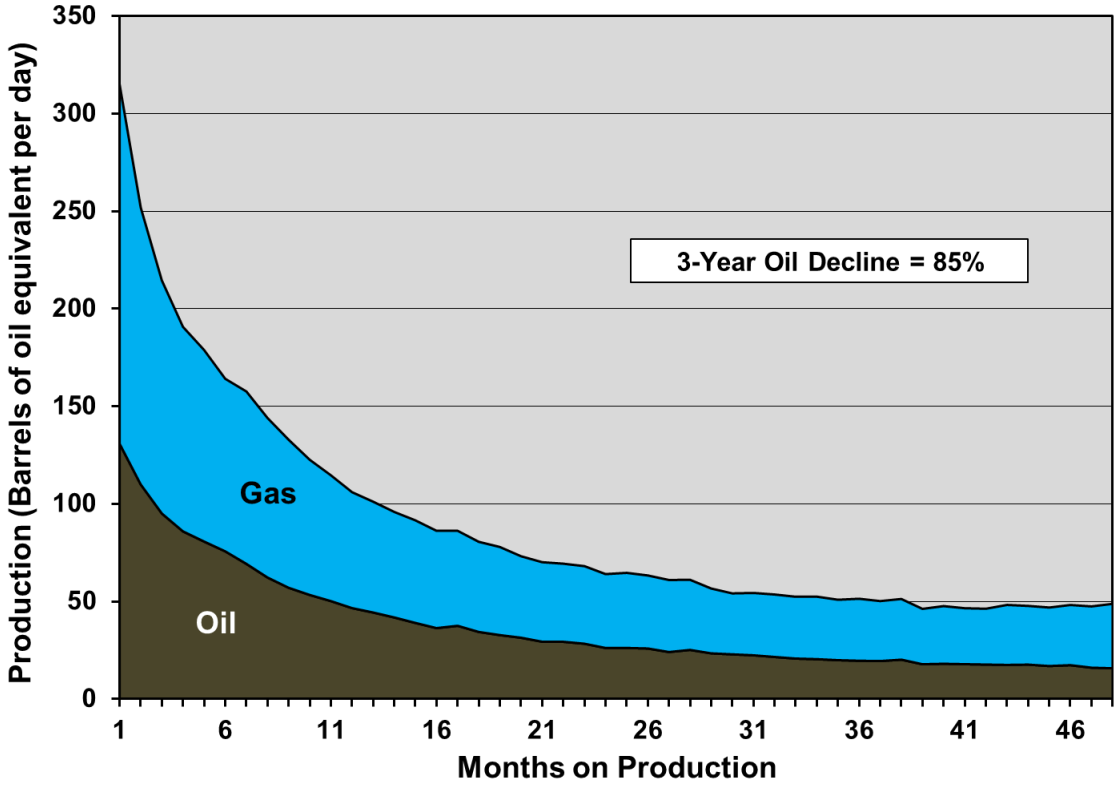

Figure 2-82. Oil and gas average well decline profile for horizontal wells in the Austin Chalk play.[128]

On an energy equivalent basis these wells have an initial productivity of about one third of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[128] Data from Drillinginfo retrieved July 2014.

2.5.1.3 EIA Forecast

The EIA's projection for Austin Chalk play production through 2040 in its reference case is illustrated in Figure 2-83. Total recovery between 2012 and 2040 is forecast to be 4.9 billion barrels. This amounts to 11.3% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 amounts to 65% of the "unproved technically recoverable resources" the EIA estimated for the Austin Chalk as at January 1, 2012.

In this case the EIA's forecast looks extremely optimistic. They are projecting a production rise to a peak in 2031, at 656,830 barrels per day, which is 20 times current production, followed by a gradual decline to 513,000 barrels per day in 2040—16 times current production. As noted earlier, production in this play along with well count is falling, and well- and field-decline rates are high. In year one this forecast is already off by 145% on the high side. Given what is known, this EIA forecast would seem to have a very high optimist bias.

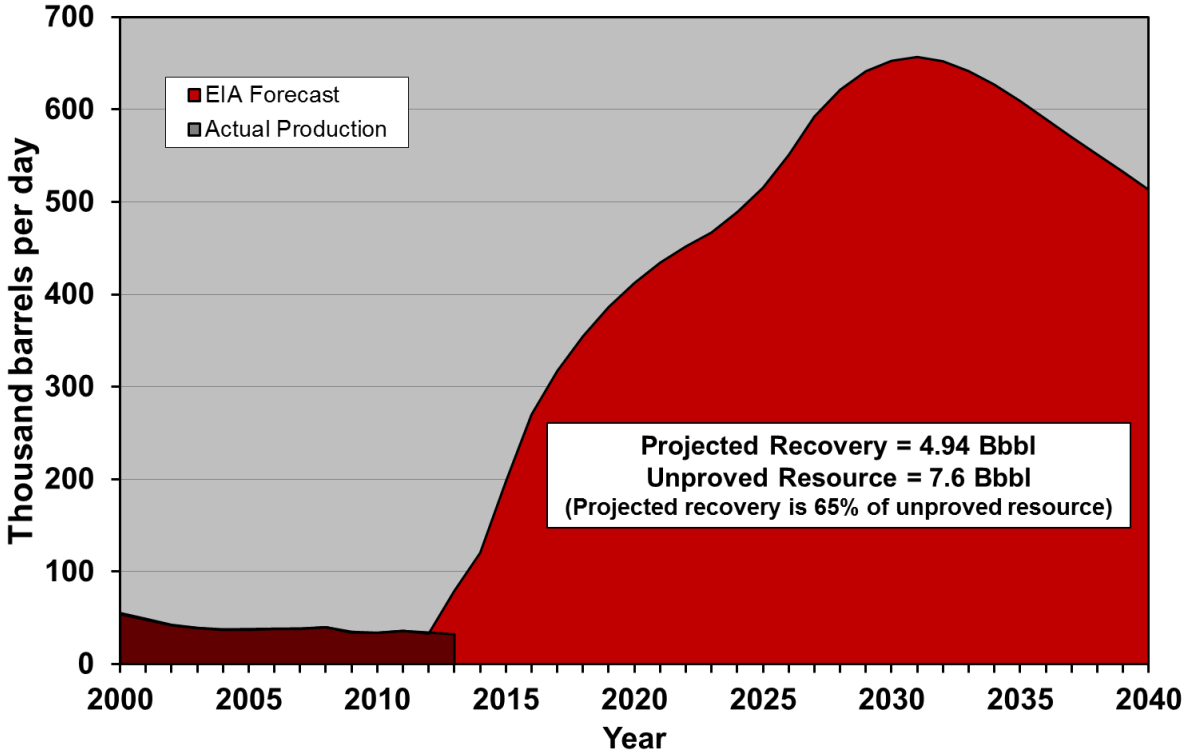

Figure 2-83. EIA reference case projection of oil production from the Austin Chalk through 2040, with actual production to 2013.[129]

The forecast total recovery of 4.94 billion barrels over the 2012-2040 period amounts to 65% of the 7.6 billion barrels of the EIA's "unproved technically recoverable resources as of January 1, 2012.[130]

[129] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[130] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.5.2 Niobrara-Codell Play

The EIA forecasts recovery of 4.9 billion barrels of oil from the Niobrara-Codell play between 2012 and 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Niobrara-Codell play, like the Permian Basin plays and the Austin Chalk play, has been producing oil and gas for decades. Over 30,800 wells have been drilled of which 13,900 are currently producing. The play has produced 357 million barrels of oil and 3.8 trillion cubic feet of natural gas over its lifetime. Figure 2-84 illustrates well distribution within the Niobrara-Codell play. Figure 2-85 illustrates the distribution of wells in the Wattenberg Field located mainly in Weld County of Colorado, where much of the drilling has occurred.

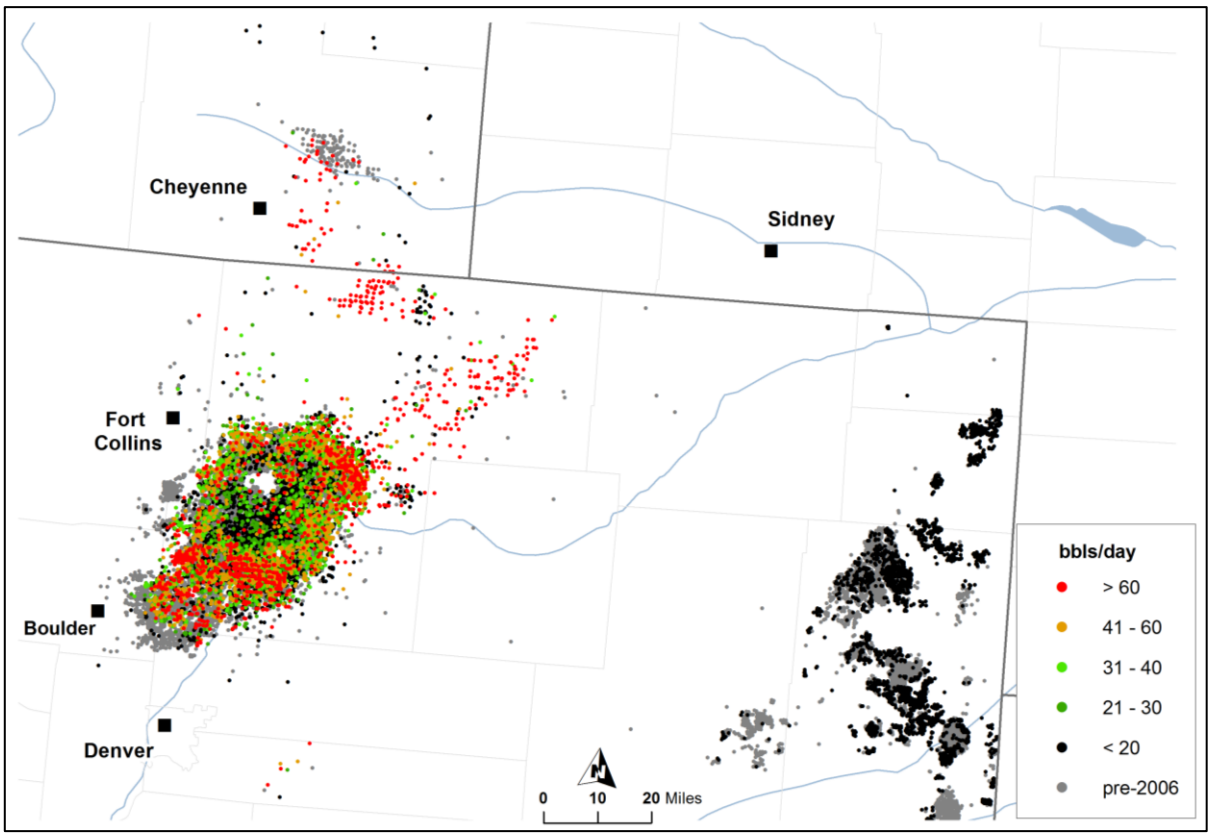

Figure 2-84. Distribution of wells in the Niobrara-Codell play as of mid-2014 illustrating highest one-month oil production (initial productivity, IP).[131]

Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[131] Data from Drillinginfo retrieved July 2014.

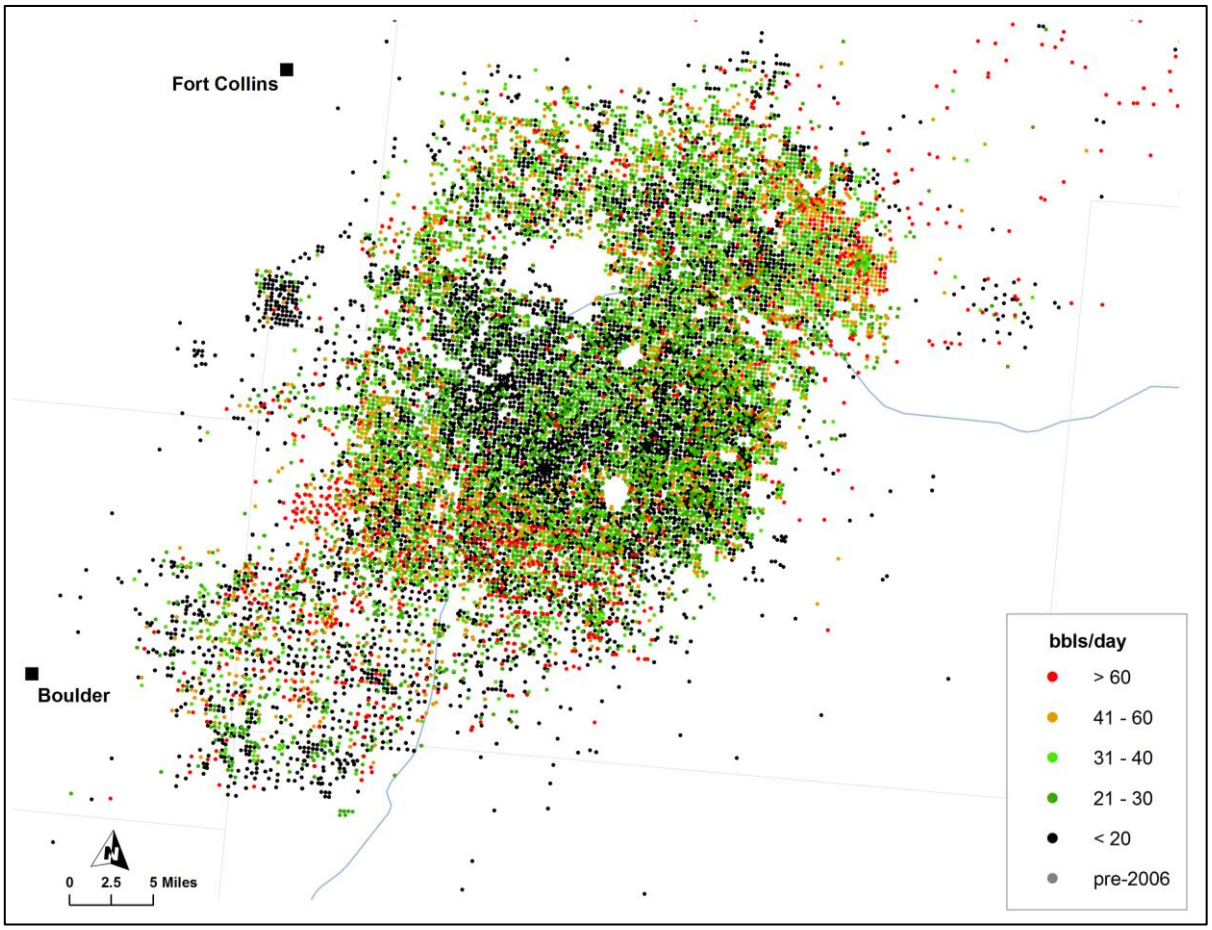

Figure 2-85. Detail of Niobrara-Codell play showing distribution of wells as of mid-2014, illustrating highest one-month oil production (initial productivity, IP).[132]

Map shows the Wattenberg Field of Weld County, Colorado, where much of the drilling has occurred. Only wells drilled in 2006 and later are considered as possible "tight oil" production and colored by IP; wells drilled prior to 2006 are predominantly conventional production. Well IPs are categorized approximately by percentile; see Appendix.

[132] Data from Drillinginfo retrieved July 2014.

2.5.2.1 Production History

Production of oil in the Niobrara-Codell has been growing although the number of producing wells has been falling recently as illustrated in Figure 2-86 (this may in part be related to flooding that occurred in Colorado in late 2013). Oil production hit an all-time high in December 2013, but has declined by 18% since then (again possibly related to the flooding).

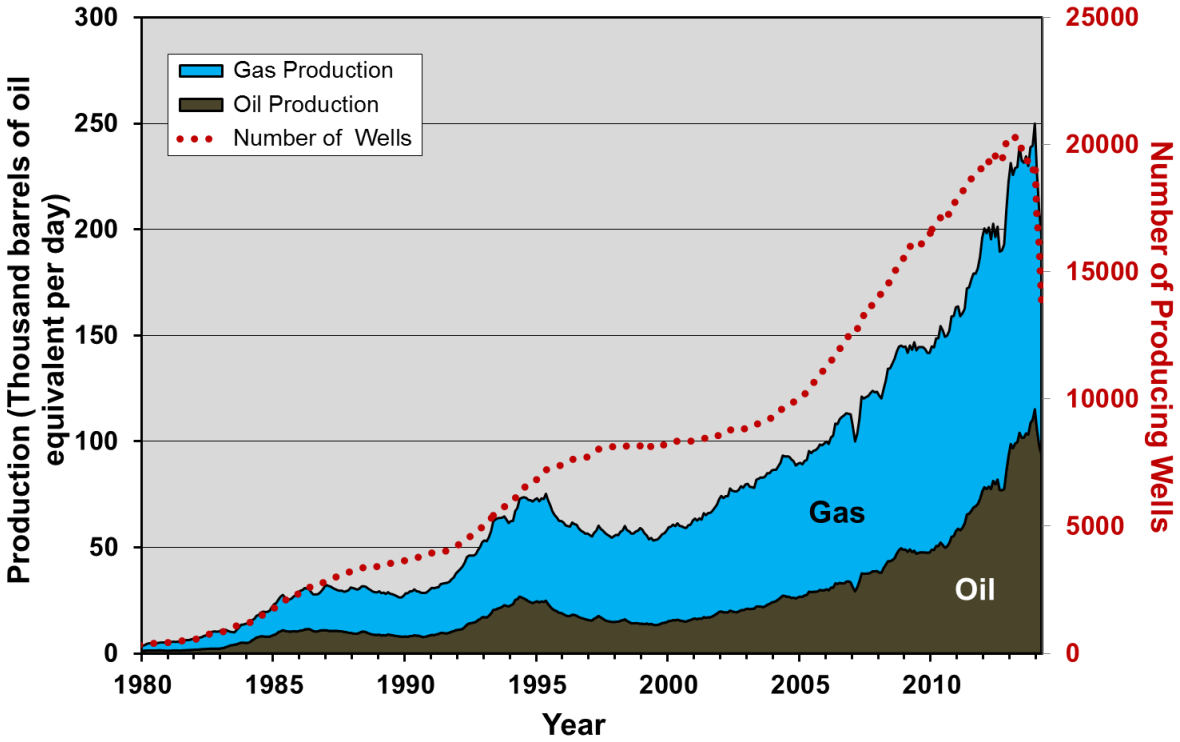

Figure 2-86. Niobrara-Codell play oil and gas production and number of producing wells, 1980 to 2014.[133]

Producing well count is now about 13,900.

[133] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

A look at the split in production by well type reveals that horizontal wells now account for 77% of oil production (Figure 2-87).

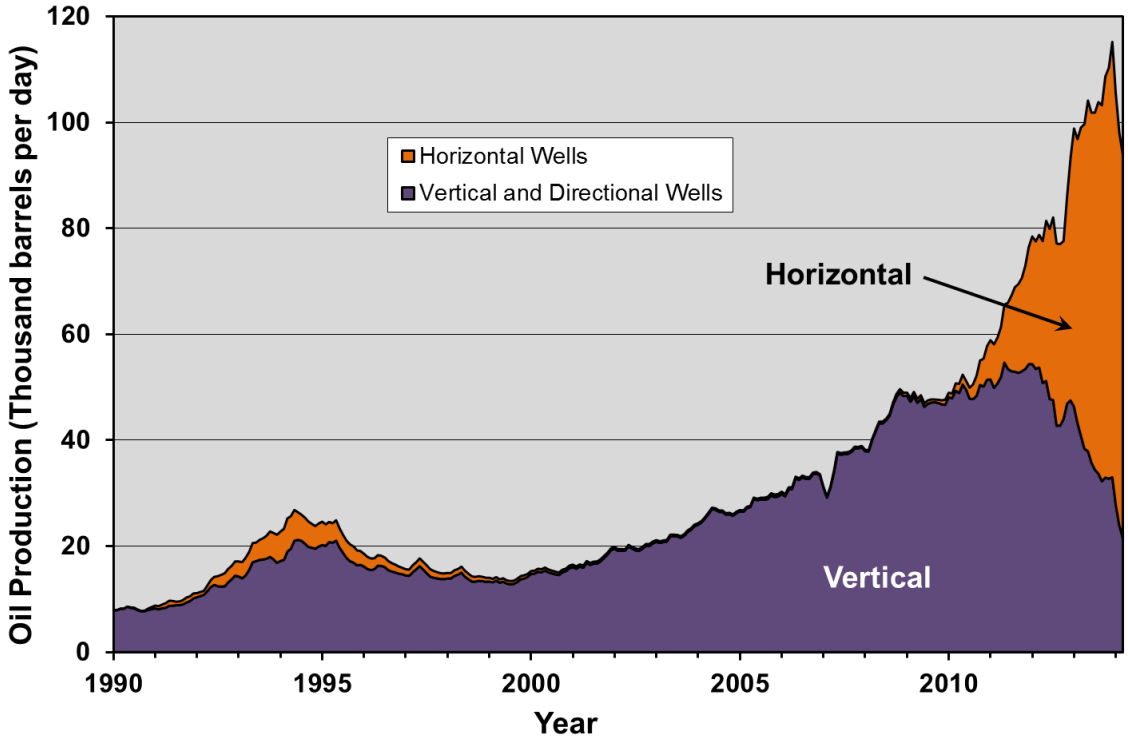

Figure 2-87. Oil production from the Niobrara-Codell play by well type.
Horizontal wells now produce 77% of the oil.[134]

[134] Data from Drillinginfo retrieved July 2014. Three-month trailing moving average.

2.5.2.2 Well Quality

A look at well quality reveals that the Niobrara-Codell is unremarkable by comparison to the Bakken or Eagle Ford. Figure 2-88 illustrates the average well decline profile for all wells; Figure 2-89 illustrates the average well decline profile for horizontal wells only. All wells on an energy equivalent basis are about a tenth of the initial production of an average Bakken well in a top county. Horizontal wells are much better (hence the fact that they now make up 77% of production), although the initial productivity of the average well still pales by comparison to a Bakken or Eagle Ford well. The average three-year decline of Niobrara-Codell wells is higher than that of the Bakken at 93% for all wells and 90% for horizontal wells.

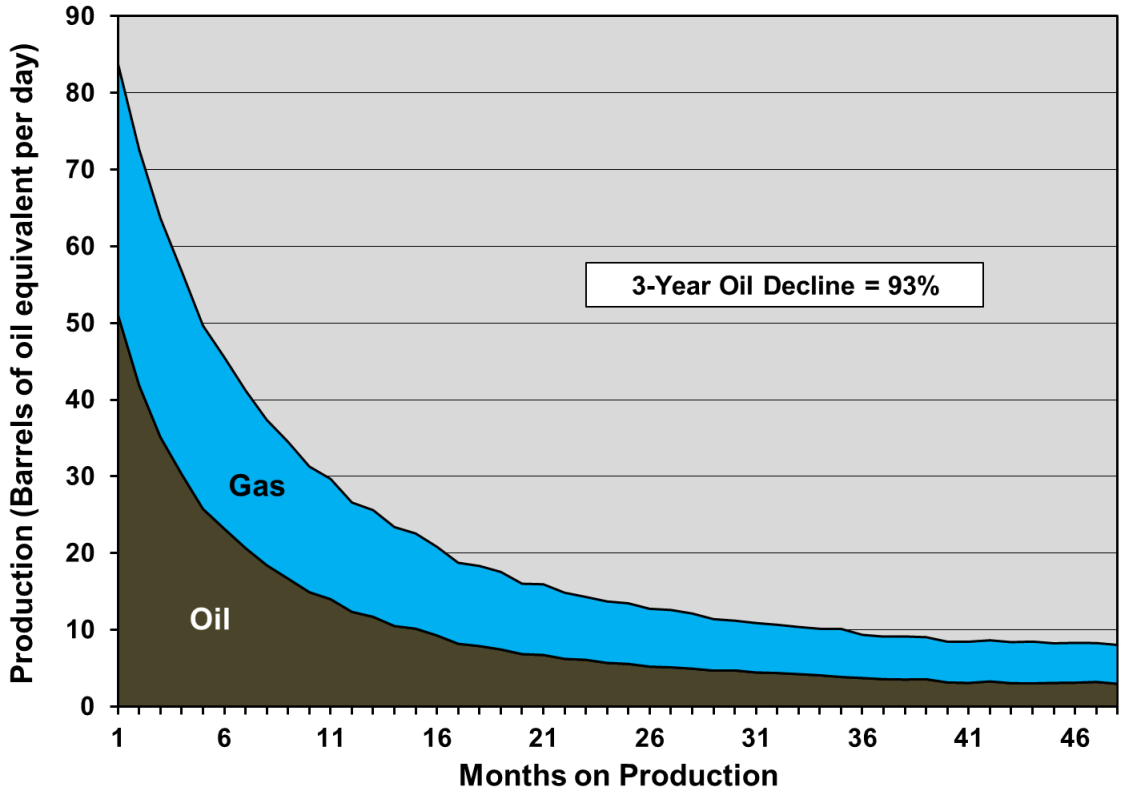

Figure 2-88. Oil and gas average well decline profile for all wells in the Niobrara-Codell play.[135]

On an energy equivalent basis these wells have an initial productivity of about a tenth that of the average well in the top counties of the Bakken play. Decline profile is based on all wells drilled since 2009.

[135] Data from Drillinginfo retrieved July 2014.

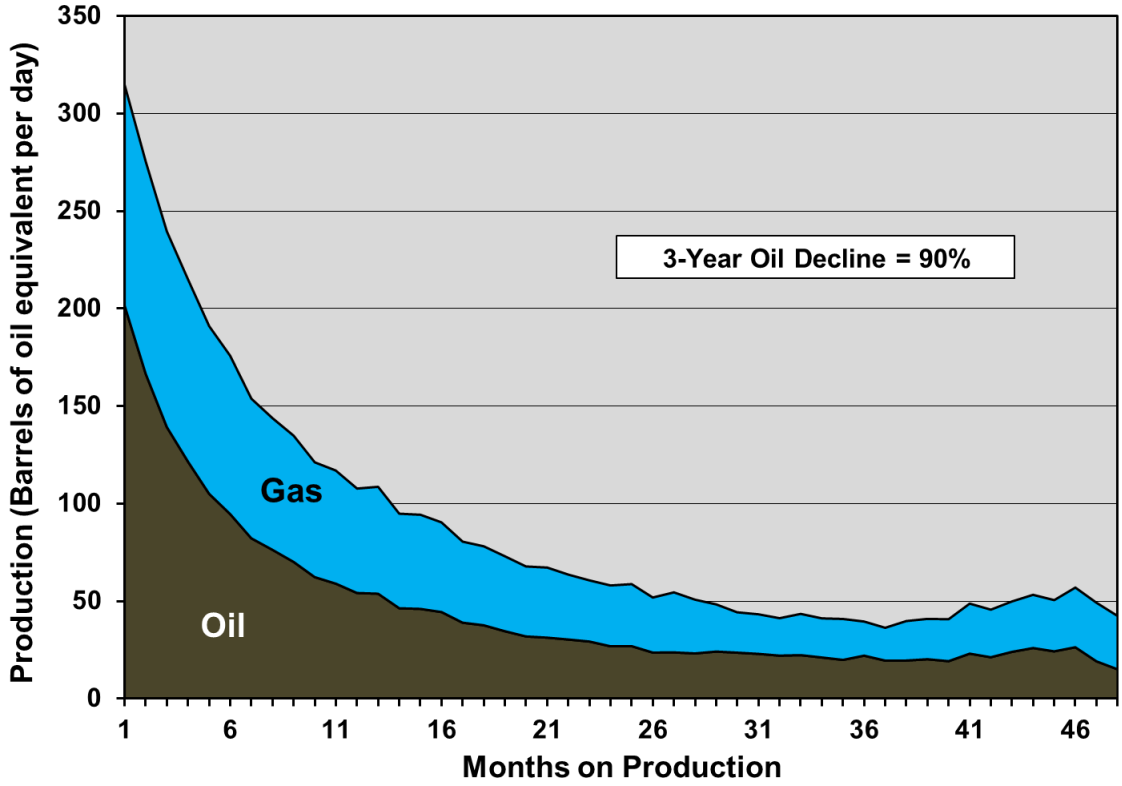

Figure 2-89. Oil and gas average well decline profile for horizontal wells in the Niobrara-Codell play.[136]

On an energy equivalent basis these wells have an initial productivity of about one third of the average horizontal well in the top counties of the Bakken play. Decline profile is based on all horizontal wells drilled since 2009.

[136] Data from Drillinginfo retrieved July 2014.

2.5.2.3 EIA Forecast

The EIA's projection for Niobrara-Codell play production through 2040 in its reference case is illustrated in Figure 2-90. Total recovery between 2012 and 2040 is forecast to be 4.9 billion barrels. This amounts to 4% of its U.S. reference case tight oil production through 2040. Cumulative production by 2040 is much higher than the resource estimate, amounting to 423% of the "unproved technically recoverable resources" the EIA estimated for the Niobrara-Codell as at January 1, 2012.

Notwithstanding the apparent overestimate of the EIA's production forecast compared to resources, the forecast has already been exceeded by production in year one. Nonetheless, the EIA projects that production will be double current levels in 2031 followed by a gradual decline to 76% above current levels in 2040. Given the very high well and field declines, among the highest of any play examined to date, this EIA forecast would seem to have a high optimist bias.

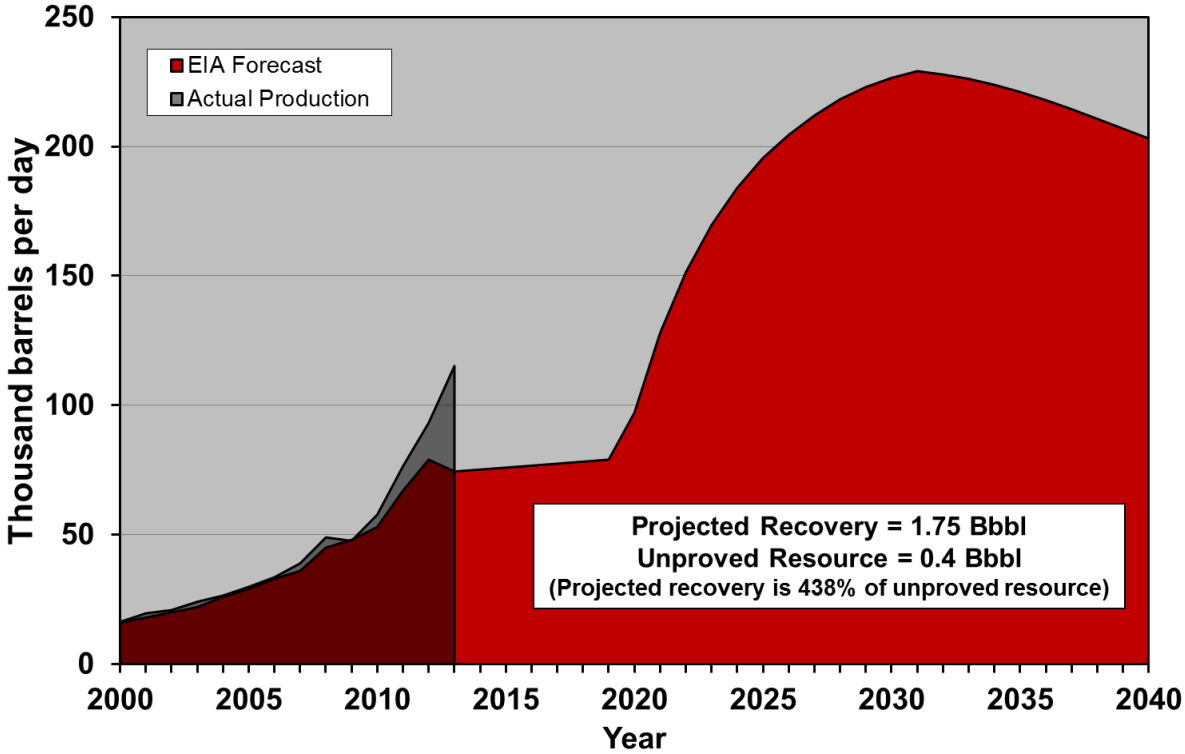

Figure 2-90. EIA reference case projection of oil production from the Niobrara-Codell through 2040, with actual production to 2013.[137]

The forecast total recovery of 1.75 billion barrels over the 2012-2040 period amounts to 438% of the 0.4 billion barrels of the EIA's "unproved technically recoverable resources as of January 1, 2012."[138]

[137] Production data from DrillingInfo, July 2014. Forecast from EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[138] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.5.3 Key Characteristics of the Austin Chalk and Niobrara-Codell Plays

The Austin Chalk and Niobrara-Codell plays are together projected to account for 15.3% of the tight oil production in the EIA's reference case tight oil forecast[139] (the two other plays for which the EIA provided individual play projections, the Woodford and Monterey, contribute only 2.4%). The EIA suggests these plays will collectively produce 6.6 billion barrels between 2014 and 2040, which is more than four times as much oil as they produced since their discoveries more than 40 years ago. Production is projected to rise to a peak in 2031 at 890,000 barrels per day followed by a gradual decline through 2040, when these plays are forecast to still be producing 720,000 barrels per day, which is nearly five times current levels (current combined production is 147,000 barrels per day[140]). This is a very aggressive forecast considering their age and extensive drilling and production history, their relatively low quality wells, and their observed steep well- and field-declines.

Production growth in the Austin Chalk and Niobrara-Codell plays is largely a result of redevelopment of long established plays with better technology, including horizontal drilling and fracking, rather than the new discoveries represented by the Bakken and Eagle Ford. The Austin Chalk began production in the 1950s and the Niobrara-Codell in the 1970s. More than 46,000 wells have been drilled of which 18,800 are currently producing. As such they are not analogues to the Bakken and Eagle Ford, from which significant production is just twelve and six years old, respectively. The Bakken and Eagle Ford currently produce 62% of all U.S. tight oil (Figure 5), compared to 5.3% for the Austin Chalk and Niobrara-Codell. At least some of the oil produced from these so-called "tight oil" plays is conventional. Table 2-4 summarizes the long history of development of these plays and contrasts that with the expectations for them in EIA's tight oil forecast.

Play	Years Produced	Wells Drilled	Wells Producing	Production to Date (Bbbls)	EIA Recovery 2012-2040 (Bbbls)	EIA Unproved Resources as of January 1, 2012 (Bbbls)	EIA Production in 2040 (MMbbl/d)
Austin Chalk	60+	15308	4988	1.17	4.9	7.6	0.51
Niobrara-Codell	40+	30871	13888	0.36	1.8	0.4	0.20
Total		46179	18876	1.53	6.7	8.0	0.72

Table 2-4. Age, wells, production[141], EIA unproved technically recoverable resources[142] and EIA reference case forecast for the Austin Chalk and Niobrara-Codell plays.[143]

Numbers may not add due to rounding.

[139] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[140] Data from Drillinginfo retrieved July 2014.
[141] Data from Drillinginfo retrieved July 2014.
[142] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[143] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.5.4 Austin Chalk and Niobrara-Codell Plays Analysis Summary

Several conclusions can be made from the foregoing analysis of the Austin Chalk and Niobrara-Codell plays:

1. Oil production in the Austin Chalk and Niobrara-Codell plays is largely a result of application of new technologies to old plays, rather than significant new discoveries such as represented by the Bakken and Eagle Ford. Despite the application of new technology oil production in the Austin Chalk is falling, and the Niobrara-Codell may have peaked.

2. Productivity of wells in the Austin Chalk and Niobrara-Codell plays is generally much lower on average than in the Bakken and Eagle Ford. Well costs may also be somewhat lower, although most new production utilizes horizontal drilling, and extensive infrastructure is in place, hence improving the economics of drilling despite the lower well productivity.

3. These plays exhibit steep well- and field-declines mandating continuous high levels of drilling and capital input to maintain production.

4. The EIA is projecting aggressive growth in production from these plays with a peak in 2031 followed by a gradual decline, and the recovery of more than four times as much oil by 2040 as they have produced since their discoveries more than 40 years ago. This forecast is extremely optimistic given the number of wells that would have to be drilled and the amount of capital required.

5. Although these plays were not reviewed on a detailed county-by-county basis, they are highly likely to exhibit “sweet spots” or “core areas” which are being targeted first, hence the number of wells and capital input will need to increase later in the EIA’s forecast to moderate production decline.

2.6 All-Plays Analysis

The foregoing analysis has reviewed—on a play-by-play basis—82% of the projected U.S. tight oil production in the EIA reference case forecast through 2040. Eighty percent of this projected production has a "high" or "very high" optimism bias, suggesting that actual production is likely to be far less than that projected by the EIA over the long term. Moreover, the analysis suggests that the Bakken and Eagle Ford plays will remain the foundation of the U.S. tight oil "shale revolution." The plays outside of the Bakken and Eagle Ford are mainly redevelopments of old plays, with tens of thousands of wells drilled over the preceding 40 to 60 years. Despite the EIA's assertion, for example, that Permian Basin plays such as the Spraberry, Wolfcamp, and Bone Spring "have initial well production rates comparable to those found in the Bakken and Eagle Ford shale formations"[144], this is belied by the actual data. Average initial oil well productivities of these plays are a half or less of the average initial production of a high quality county in the Bakken or Eagle Ford.

This section will further explore the outlook for overall U.S. tight oil production with a summary analysis of the plays' EIA forecasts, estimated ultimate recovery per well, associated natural gas production, and production prospects to 2040.

[144] EIA, "Six formations are responsible for surge in Permian Basin crude oil production," *Today in Energy*, July 9, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=17031.

2.6.1 Summary of EIA Forecasts

Table 2-5 summarizes the salient details of the EIA's tight oil production projections and estimates of "unproved technically recoverable resources" and "proved reserves"; it also includes historical production for context, and an "optimism bias" rating.

Play	EIA Projected Recovery 2012-2040 (Bbbls)	Production to Date (Bbbls)[145]	EIA Unproved Resources as of January 1, 2012 (Bbbls)	EIA Proved Reserves as of 2012 (Bbbls)	EIA Total Proved and Unproved Technically Recoverable (Bbbls)	Percent of Unproved Resources and Proved Reserves Recovered by 2040 in EIA Forecast	Play's Share of Total Recovery (%)	EIA Production in 2040 (MMbbl/d)	Optimism Bias
Bakken	8.4	1.16	9.2	3.12	12.32	68.3	19.3	0.45	High
Eagle Ford	10.7	0.90	9.3	3.37	12.67	84.8	24.6	0.59	High
Woodford	0.4	0.03	0.2	--	0.20	207.4	1.0	0.03	Very High
Austin Chalk	4.9	1.17	7.6	--	7.60	65.0	11.3	0.51	Very High
Spraberry	6.5	1.83	8.1	--	8.10	80.0	14.9	0.51	Very High
Niobrara	1.8	0.36	0.4	0.01	0.41	423.8	4.0	0.20	High
Avalon/Bone Spring	0.7	0.21	2.0	--	2.00	34.1	1.6	0.05	Low
Monterey	0.6	--	0.6	--	0.60	102.3	1.4	0.06	High
Wolfcamp	2.6	0.87	3.4	--	3.40	77.6	6.1	0.22	High
Other	6.9	1.50	18.4	0.65	19.05	36.3	15.8	0.58	Unknown
Total	43.6	8.03	59.2	7.15	66.35	65.7	100.0	3.20	High to Very High

Table 2-5. Summary of EIA reference case tight oil forecast and assumptions[146] and stated unproved technically recoverable resources[147] and proved reserves[148], with historical production and "optimism bias" rating.[149]

The "optimism bias" rating is based on the analysis in this report.

[145] "Other" category estimated: Delaware and Glorieta-Yeso plays have cumulative production of 1.02 Bbbls over the last 40+ years and 0.48 Bbbl is estimated for other plays, which include the Utica, Tuscaloosa Marine Shale, Albany and others including liquids produced from shale gas plays.
[146] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[147] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[148] EIA, http://www.eia.gov/naturalgas/crudeoilreserves/index.cfm.
[149] Data from Drillinginfo retrieved May-July 2014.

2.6.2 Estimated Ultimate Recovery per Well

Average per-well estimated ultimate recovery (EUR) for each of the analyzed plays is illustrated in Figure 2-91. These EURs are offered for comparative purposes only; each play is treated the same, with the average well decline data used in the first three years followed by an exponential decline at a terminal decline rate (the jury is out on the actual long term oil recovery of tight oil wells). This comparison highlights that the Bakken's and Eagle Ford's per-well EURs are two to more than four times higher than that of the other plays. For all plays, high decline rates of tight oil wells mean that 43% to 64% of the EUR is recovered in the first three years.

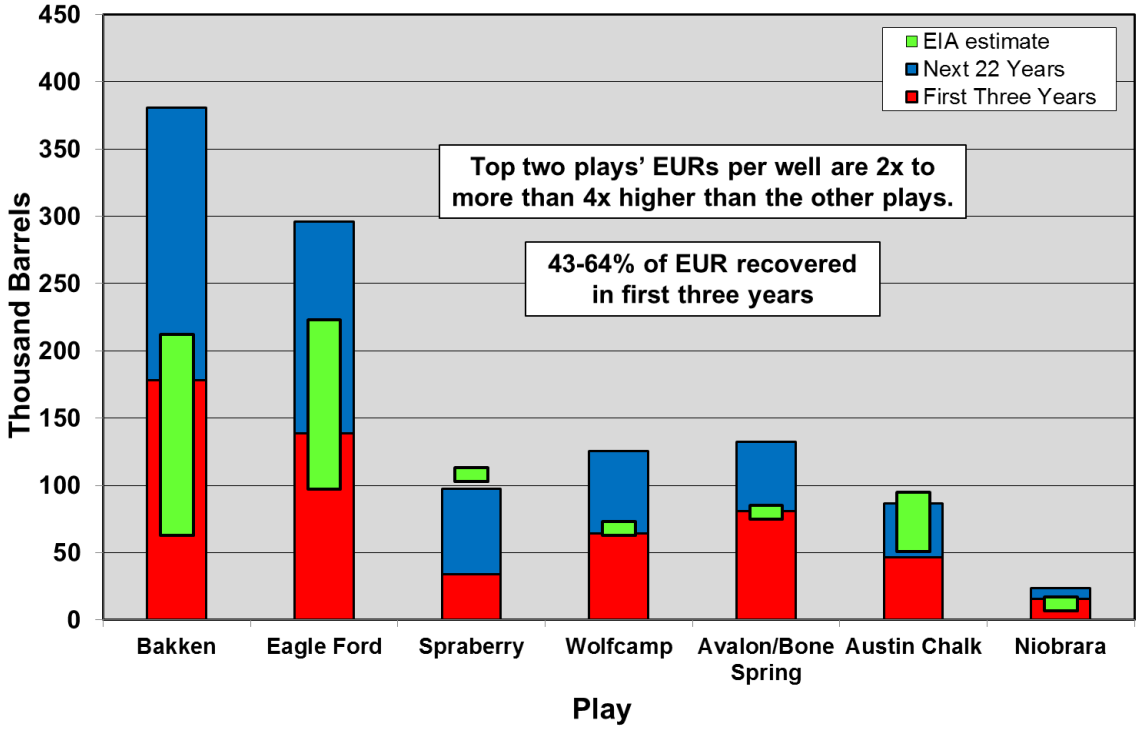

Figure 2-91. Estimated ultimate recovery (EUR) of oil per well of reviewed plays.[150]

Roughly half of the EUR is recovered in the first three years due to steep decline rates. These estimates of EUR per well are generally higher than those provided by the EIA[151] which are (in Kbbls): Bakken, 63-212; Eagle Ford, 97-223; Spraberry, 108; Wolfcamp, 68; Avalon/Bone Spring, 80; Austin Chalk, 51-95; Niobrara, 12.

[150] Based on data from Drillinginfo retrieved May-July 2014.
[151] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Horizontal wells generally improve the per-well EURs somewhat. Figure 2-92 illustrates the same comparison for horizontal wells only. Although looking at only horizontal wells markedly improves plays like the Niobrara-Codell, illustrating the difference that new technology is making, the Bakken's and Eagle Ford's EURs per well are still nearly double to triple the average well performance of the other plays.

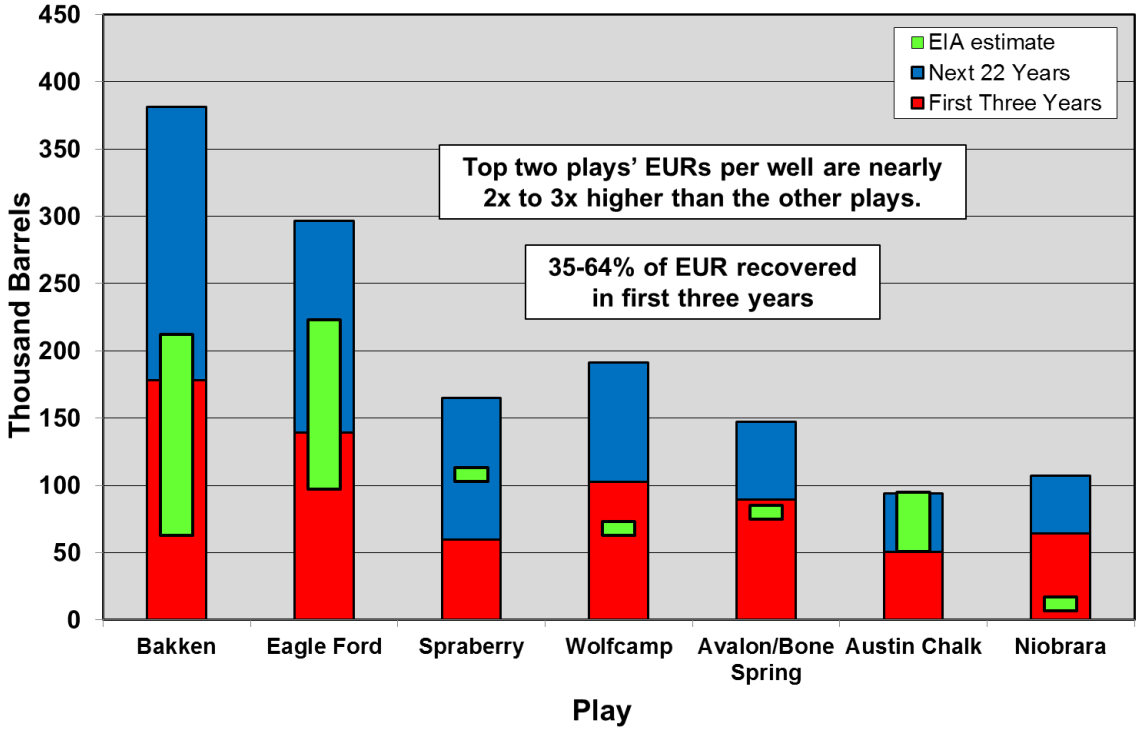

Figure 2-92. Estimated ultimate recovery (EUR) of oil per horizontal well for reviewed plays.[152]

Roughly half of the EUR is recovered in the first three years due to steep decline rates. These estimates of EUR per well are generally higher than those provided by the EIA[153] which are (in kbbls): Bakken, 63-212; Eagle Ford, 97-223; Spraberry, 108; Wolfcamp, 68; Avalon/Bone Spring, 80; Austin Chalk, 51-95; Niobrara, 12.

[152] Based on data from Drillinginfo retrieved May-July 2014.
[153] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

2.6.3 Natural Gas Production Component

The natural gas production component of many of these plays is also an important contributor to energy production and economics (all these plays produce both oil and gas). Natural gas can be converted to its oil energy equivalent at a ratio of 6,000 cubic feet of gas to one barrel of oil. On a price basis, however, oil is far more valuable, so whereas 1,000 cubic feet of gas is equivalent to one sixth of a barrel of oil on an energy equivalent basis, it is only equivalent to one twentieth or less of the value of a barrel of oil at current prices. Figure 2-93 illustrates the EUR comparison between plays on a "barrels of oil equivalent" basis. The same pattern holds: the Bakken's and Eagle Ford's EURs per well are two to more than six times higher than the EURs per well of the other plays.

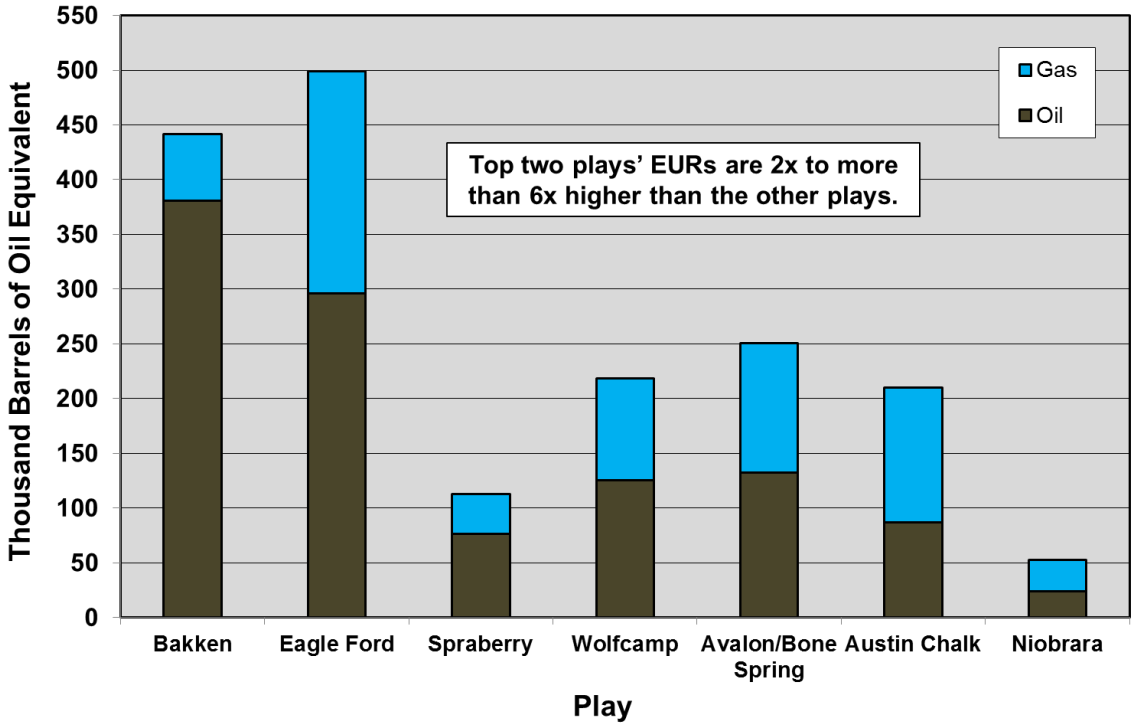

Figure 2-93. Estimated ultimate recovery (EUR) of oil and gas per well of reviewed plays, on a "barrels of oil equivalent" basis.[154]

The Bakken's and Eagle Ford's EURs per well are two to more than six times the EURs per well of the other five plays.

[154] Based on data from Drillinginfo retrieved May-July 2014.

Looking at horizontal wells only on an oil and gas EUR energy equivalency basis, production from some of these plays is considerably higher—and in plays like the Austin Chalk, Bone Spring, and Niobrara-Codell, natural gas is half or more of total energy production. Nonetheless, the Bakken's and Eagle Ford's EURs per well remain 39% to 141% higher than the other plays on an energy equivalency basis.

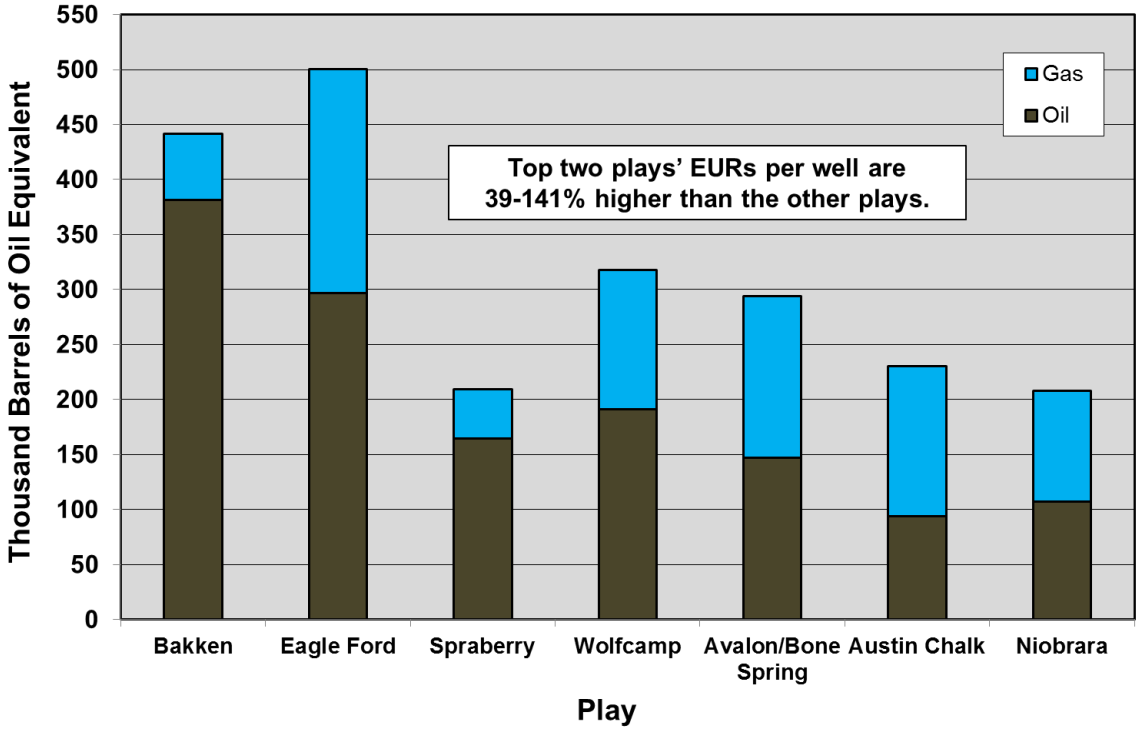

Figure 2-94. Estimated ultimate recovery (EUR) of oil and gas per horizontal well of reviewed plays, on a "barrels of oil equivalent" basis.[155]

The Bakken's and Eagle Ford's EURs per well are 34% to 141% higher than the other plays.

[155] Based on data from Drillinginfo retrieved May-July 2014.

2.6.4 Production Through 2040

This report provides tight oil production projections for the Bakken and Eagle Ford plays—which account for 62% of current production—and production history, well quality and other factors controlling future production for additional major plays which comprise a further 27% of tight oil production. The Bakken and Eagle Ford are particularly important as they are projected to account for over half of total production well into the next decade. This analysis reveals that more than two times the projected production from the Bakken and Eagle Ford will have to be produced from other plays to meet the EIA reference case forecast by 2040: a tall order which is unlikely to be realized given the fundamentals of these plays as outlined in this report.

Figure 2-95 compares the EIA's reference case projection through 2040 for tight oil production[156] to the most likely of the Bakken and Eagle Ford scenarios presented in sections 2.3.1.6 and 2.3.2.6, respectively (the "Most Likely Rate" scenarios of the "Realistic" cases of the respective plays).

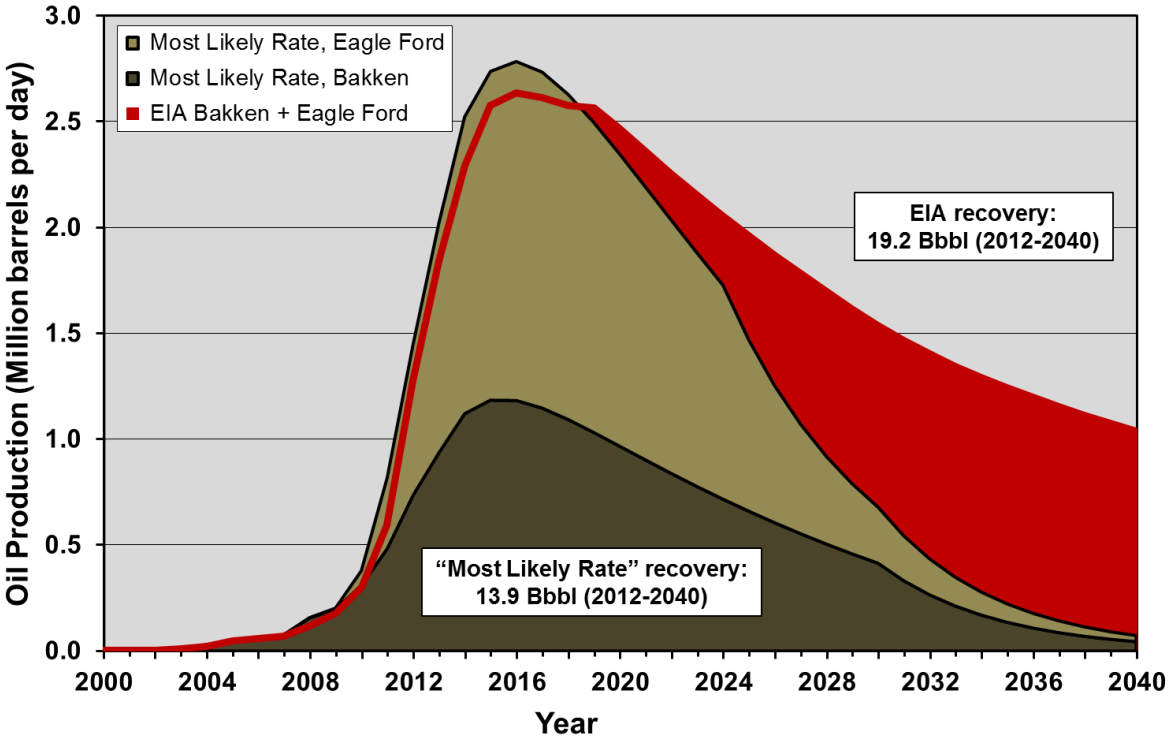

Figure 2-95. "Most Likely Rate" scenarios ("Realistic" cases) of Bakken and Eagle Ford tight oil production compared to the EIA reference case, 2000 to 2040.[157]

Total oil recovery forecast by the EIA from these plays is 19.2 billion barrels from 2012-2040 versus 13.7 billion barrels in this report.

[156] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.
[157] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

This comparison reveals:

- The EIA's forecast of the timing of peak production in the Bakken and Eagle Ford is similar to this report.
- The EIA's forecast of the rate at peak production is lower than this report, but only slightly.
- The EIA projects a much higher tail after peak production, with recovery of 19.2 billion barrels between 2012 and 2040, as opposed to 13.9 billion barrels forecast in this report.
- The EIA forecasts collective production from these plays to be 1 million barrels per day in 2040, suggesting considerably more oil will be recovered after that date; in contrast, the "Most Likely" drilling rate scenario presented in this report forecasts that production will fall to about 73,000 barrels per day by 2040.

The EIA's reference case projections for the Bakken and Eagle Ford require the recovery of 19.2 billion barrels by 2040. This amounts to 77% of the sum of proved reserves (6.49 billion barrels)[158] and estimated "unproved technically recoverable resources" (18.5 billion barrels)[159] claimed for these two plays. Unproved technically recoverable resources have no price constraints applied and are loosely constrained by geological parameters; to assume the recovery of 77% of proved reserves plus unproved resources by 2040 is extremely optimistic.

Moreover, the EIA's Bakken and Eagle Ford forecast amounts to the recovery of 40% more oil than this report's analysis suggests those plays can produce by 2040 (assuming capital will even be available to drill more than 51,000 additional wells in these plays at a cost of some $410 billion). The EIA's assumption that production from the Bakken and Eagle Ford will still be at more than one million barrels per day in 2040, after producing over 19.6 billion barrels since 2000, strains credibility to the limit.

The large difference between this report's projections and the EIA's forecasts for the Bakken and Eagle Ford, coupled with the high to very high optimism bias in the EIA's forecast for most of the other plays analyzed, suggests that the EIA's total U.S. tight oil forecast is likely to be seriously overstated, and hence very difficult or impossible to achieve. Figure 2-96 illustrates the production that would be required from all other tight oil plays to meet the EIA's reference case tight oil forecast from 2012 through 2040 (43.6 billion barrels), after accounting for this report's "Most Likely" scenario forecasts for the Bakken and Eagle Ford (which are 5.3 billion barrels less than the EIA's through 2040). The result is 29.7 billion barrels that must be made up from other tight oil plays, or two times the projected recovery from the Bakken and Eagle Ford by 2040 (13.9 billion barrels), over this period.

[158] EIA, "U.S. Crude Oil and Natural Gas Proved Reserves," April 2014, http://www.eia.gov/naturalgas/crudeoilreserves/index.cfm.
[159] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

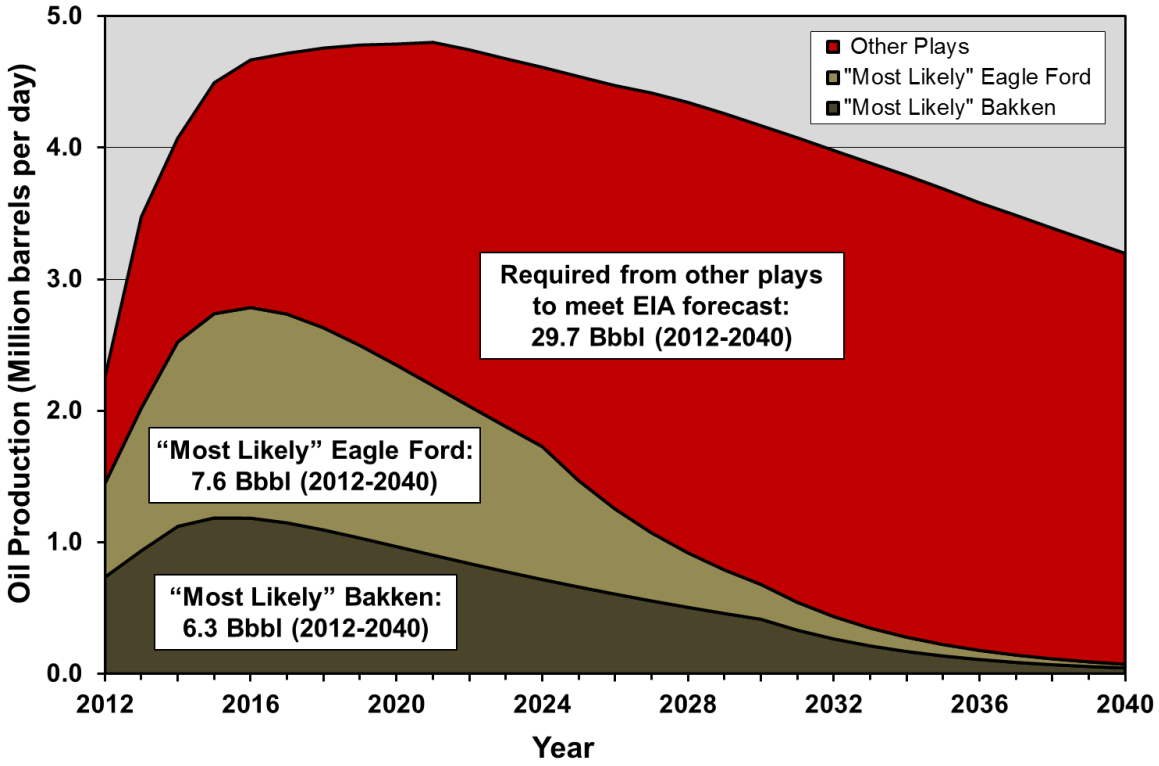

Figure 2-96. "Most Likely" scenario projections of oil production for the Bakken and Eagle Ford plays[160] with the remaining amount of production that would be required from other plays to meet the EIA's total reference case forecast.[161]

The EIA forecasts 43.6 billion barrels of U.S. tight oil will be recovered from 2012 to 2040. After subtracting the 13.9 billion barrels projected by this report for the Bakken and Eagle Ford, 29.7 billion barrels would remain to be produced from all other tight oil plays—5.3 billion barrels more than the EIA's already optimistic forecast for these plays.

[160] Data from Drillinginfo retrieved May 2014.
[161] EIA, *Annual Energy Outlook 2014*, Unpublished tables from AEO 2014 provided by the EIA.

2.7 Summary and Implications

The growth of U.S. tight oil production is one of the few bright spots contributing to global oil production growth. Geopolitical turmoil in parts of the Middle East and northern and western Africa, coupled with production declines in other major producers such as Russia[162], has kept oil prices persistently near historic highs. Investments by oil majors in upstream oil and gas production have increased three-fold since 2000 yet production is up just 14%.[163] Economist Mark Lewis points out that "the damage has been masked so far as big oil companies draw down on their cheap legacy reserves", but that "they are having to look for oil in the deepwater fields off Africa and Brazil, or in the Arctic, where it is much more difficult. The marginal cost for many shale plays is now $85 to $90 a barrel."[164]

Given these factors it is important to understand the long term supply limitations of U.S. tight oil. The analysis presented herein, which is based on one of the best commercial databases of well production information available[165], finds that the longevity of U.S. tight oil production at meaningful rates is highly questionable. Certainly production will rise in the short term, but with the very likely peaking of the Bakken and Eagle Ford plays (which provide 62% of current U.S. tight oil output) in the 2016-2017 timeframe, maintaining production or even stemming the decline will require ever greater amounts of drilling, along with the capital input to sustain it. This will require higher prices, for the nature of shale plays is that the sweet spots get drilled first and progressively lower quality rock gets drilled last.

Furthermore, much of the purported "tight oil" production outside of the Bakken and Eagle Ford comes from long-established plays benefiting from the application of new technology, not new discoveries. Tens of thousands of wells have been drilled in these plays over the past 40 or more years and they have produced much oil and gas, yet the EIA forecast expects them to produce 4-5 times their historical production in the next 26 years. These plays have well qualities as defined by initial productivity and EUR of less than half of the Bakken and Eagle Ford on average. The concept that high quality tight oil plays like the Bakken and Eagle Ford are widespread is false.

The EIA, which is viewed as perhaps the most authoritative source of U.S. energy production forecasts, has consistently overestimated future production.[166] The analysis presented herein suggests that this is the case with respect to tight oil. A play-by-play analysis of the data with respect to the EIA forecasts reveals a high to very high "optimism bias". The EIA assumes that 65% to 85% of its "proved reserves and unproved technically recoverable resources as of January 1, 2012" will be recovered by 2040 for most plays. Unproved resources have no price constraints applied and are loosely constrained compared to "reserves" which are proven to be recoverable with existing technology and economic conditions. Not only do the EIA's projections demonstrate a high or very high optimism bias, they also assume that the U.S. will exit 2040 with tight oil production comparable to today, at 3.2 MMbbl/d. This is highly unlikely given a thorough analysis of the data.

The Bakken and the Eagle Ford have produced just under 2 billion barrels of oil to date and will continue to produce much more oil, assuming drilling rates and the capital input to sustain them will be maintained. This report projects that they will produce 13.9 billion barrels from 2012 to 2040, with marginal production under

[162] Reuters, "UPDATE 1-Russian oil output down for fourth month in a row," May 2, 2014, http://uk.reuters.com/article/2014/05/02/russia-energy-production-idUKL6N0N00UL20140502.
[163] Mark Lewis of Kepler Cheuvreux cited in Ambrose Evans-Pritchard, "Fossil industry is the subprime danger of this cycle", Telegraph, July 9, 2014, http://www.telegraph.co.uk/finance/comment/ambroseevans_pritchard/10957292/Fossil-industry-is-the-subprime-danger-of-this-cycle.html.
[164] Ambrose Evans-Pritchard, "Fossil industry is the subprime danger of this cycle", Telegraph, July 9, 2014.
[165] DI Desktop (formerly HDPI), produced by Drillinginfo.
[166] See Figure 25 in J. David Hughes, *Drill Baby Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*, Post Carbon Institute, 2013, http://www.postcarbon.org/publications/drill-baby-drill.

0.08 MMbbl/d in 2040, given unconstrained capital input. In contrast, the EIA forecasts 19.2 billion barrels of cumulative production from these plays over the same period, with production of just over 1 MMbbl/d in 2040. Figure 2-97 illustrates the stark difference between the EIA's projections and this report's projections of Bakken and Eagle Ford tight oil production.

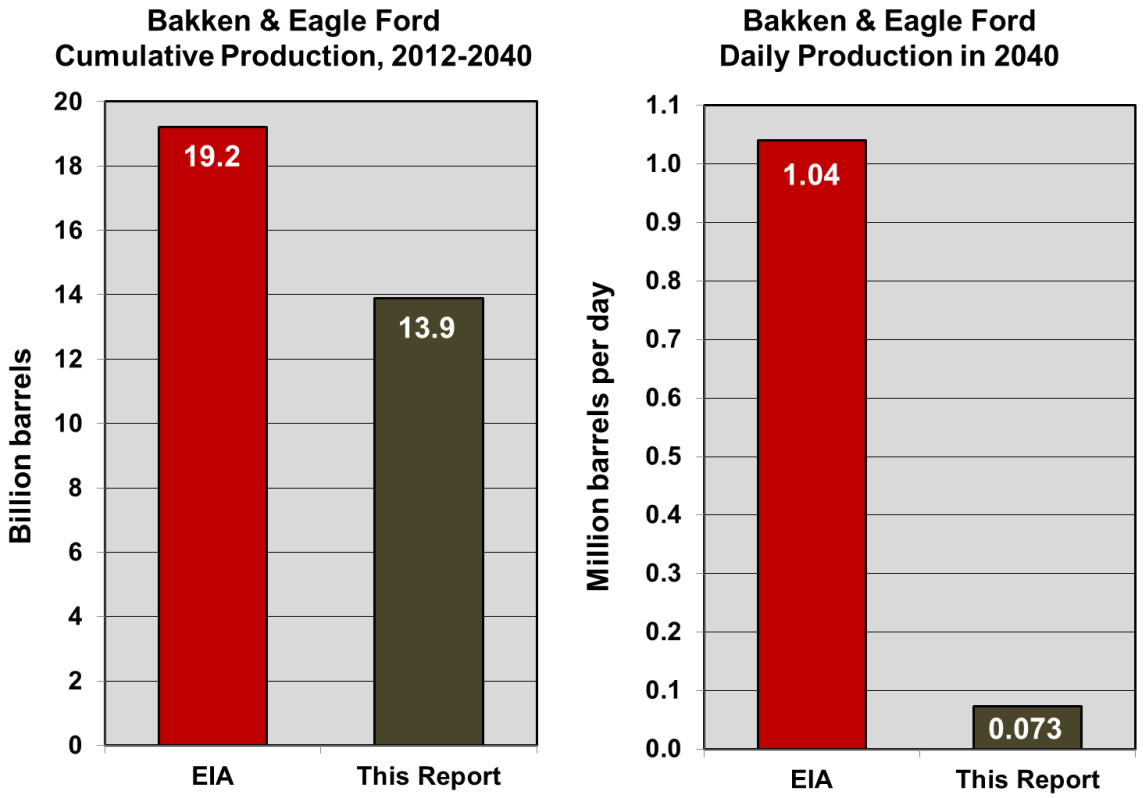

Figure 2-97. Bakken and Eagle Ford plays projected cumulative oil production from 2012 to 2040 and daily oil production in 2040, EIA projection[167] versus this report's projection.

The EIA's forecast strains credibility, given the known decline rates, well quality by area, available drilling locations, and the number of wells that would need to be drilled to make that happen. Given this report's "Most Likely" scenario estimate for the Bakken and Eagle Ford based on the analysis in this report, the remaining significant U.S. tight oil plays would need to produce 29.7 billion barrels of oil between 2012 and 2040 to meet the EIA's forecast—more than twice as much as the Bakken and Eagle Ford combined (see Figure 2-96). However, the EIA projects that these plays will produce just 23.5 billion barrels between 2014 and 2040. A more realistic best-case estimate, assuming capital inputs are not a constraint, is for these plays to produce about ten billion barrels over this period, which, coupled with 12.7 billion barrels from the Eagle Ford and Bakken, is just over half of the EIA's forecast by 2040—if everything goes right. Producing this much oil from these plays will require much higher oil prices than today's in the latter part of the 2014-2040 period. Most troubling from an energy security point of view is that much of the tight oil production will occur in the early years of this period, making supply ever more problematic later on.

[167] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

The consequences of getting it wrong on future tight oil production are immense. The EIA projects that the U.S. will be a significant oil importer in 2040 (Figure 2-2). Although the flush of tight oil production is likely to peak before 2020 and decline thereafter at much more rapid rates than projected by the EIA, there is increasing pressure by industry to allow crude oil exports.[168] The longer term geopolitical complications certain to arise given increased competition for available oil exports in a shrinking export market should be obvious. Rather than viewing tight oil as an unlimited bounty, it should be viewed for what it is—a short term reprieve from the inexorable decline in U.S. oil production. A sensible energy policy would be based on this prospect.

[168] IHS, "U.S. Crude Oil Export Decision," *Crude Oil Export Report*, 2014, http://www.ihs.com/info/0514/crude-oil.aspx.

PART 3: SHALE GAS

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3.1 INTRODUCTION

3.1.1 Overview

The widespread adoption of hydraulic fracturing ("fracking") and horizontal drilling in the United States to extract oil and natural gas from previously inaccessible shale formations has been termed the "shale revolution." U.S. natural gas production, thought to be in terminal decline as recently as 2005, has exceeded its all-time 1973 peak. The U.S. Energy Information Administration (EIA) now projects domestic gas production to reach nearly 38 trillion cubic feet per year by 2040, which is 55% above 2013 levels.

Although the U.S. is still a net importer of gas from Canada, there is now a rush to export natural gas overseas. Four liquefied natural gas (LNG) export terminals have been approved—one of which is under construction at Sabine Pass in Louisiana—with a further 13 "proposed" and an additional 13 under consideration as "potential".[1] The enthusiasm for LNG exports is based on the assumption that the North American gas supply will continue to grow for the foreseeable future and prices will remain low, resulting in an attractive differential with much higher gas prices in Europe and Asia.

The environmental, health, and quality of life impacts of shale development have stoked controversy across the country. In contrast, the expectation of long-term domestic natural gas abundance—driven by optimistic forecasts from industry and government—has been widely reported and little questioned, despite the myriad economic and policy consequences. There is no question that the development of shale gas has created a surge in production. However, a look at the fundamentals of shale plays reveals that they come with serious drawbacks, both in terms of environmental impact and the sustainability of long term production.

This report investigates whether the EIA's expectation of long-term domestic gas abundance is founded. It aims to gauge the likely future production of U.S. shale gas, based on an in-depth assessment of actual well production data from the major shale plays. It determines future production profiles given assumed rates of drilling, average well quality by area, well- and field-decline rates, and the estimated number of available drilling locations. This analysis is based on all drilling and production data available through early- to mid-2014.

The analysis shows that maintaining U.S. shale gas production, let alone increasing production at rates forecast by the EIA through 2040, will be problematic. Four of the top seven shale gas plays are already in decline. Of the major plays, only the Marcellus, along with associated gas from the Eagle Ford and Bakken tight oil plays, are increasing—and yet, the EIA reference gas forecast calls for plays currently in decline to grow to new production highs, at moderate future prices. Lesser plays like the Utica and others are also counted on for strong growth. Although significantly higher gas prices needed to justify higher drilling rates could temporarily reverse decline in some of these plays, the EIA forecast is unlikely to be realized.

The analysis also underscores the amount of drilling, the amount of capital investment, and the associated scale of environmental and community impacts that will be required to meet these projections. These findings call into question plans for LNG exports and highlight the real risks to long-term U.S. energy security.

[1] FERC, July 18, 2014, "LNG," http://www.ferc.gov/industries/gas/indus-act/lng.asp.

3.1.2 Methodology

This report analyzes the top five U.S. shale gas plays—the Barnett, Haynesville, Fayetteville, Woodford and Marcellus—as well as associated gas production from the top two tight oil plays, the Bakken and Eagle Ford. Together these plays make up 88% of shale gas production through 2040 in the EIA's 2014 Annual Energy Outlook (AEO 2014).

The primary source of data for this analysis is Drillinginfo, a commercial database of well production data widely used by industry and government, including the EIA.[2] Drillinginfo also provides a variety of analytical tools which proved essential for the analysis.

A detailed analysis of well production data for the major shale gas plays reveals several fundamental characteristics that will determine future production levels:

1. **Rate of well production decline:** Shale gas plays have high well production decline rates, typically in the range of 75-85% in the first three years.

2. **Rate of field production decline:** Shale gas plays have high field production declines, typically in the range of 30-45% per year, which must be replaced with more drilling to maintain production levels.

3. **Average well quality:** All shale gas plays invariably have "core" areas or "sweet spots", where individual well production is highest and hence the economics are best. Sweet spots are targeted and drilled off early in a play's lifecycle, leaving lesser quality rock to be drilled as the play matures (requiring higher gas prices to be economic); thus the number of wells required to offset field decline inevitably increases with time. Although technological innovations including longer horizontal laterals, more fracturing stages, more effective additives and higher-volume frack treatments have increased well productivity in the early stages of the development of all plays, they have provided diminishing returns over time, and cannot compensate for poor quality reservoir rock.

4. **Number of potential wells:** Plays are limited in area and therefore have a finite number of locations to be drilled. Once the locations run out, production goes into terminal decline.

5. **Rate of drilling:** The rate of production is directly correlated with the rate of drilling, which is determined by the level of capital investment.

The basic methodology used is as follows:

- Historical production, number of currently producing wells and total wells drilled, the split between horizontal and vertical/directional wells, and the overall play area were determined for all plays. Average well decline for wells, both horizontal and vertical/directional, and the average estimated ultimate recovery (EUR), were also assessed for all plays. These parameters were assessed at both the play level and at the county level (the top counties in terms of the number of producing wells were analyzed individually, whereas counties with few wells were aggregated).

- Field decline rates and the number of available drilling locations were determined at the county- and play-level for all plays.

[2] See http://info.drillinginfo.com.

- First-year average production was established from type decline curves (i.e., average well decline profiles) constructed for all wells drilled in the year in question; 2013 was the year used as representative of future average first-year production levels per well. Average first-year production is used to determine the number of wells needed to offset field decline each year, and to determine the production trajectory over time given various drilling rates. In determining future production rates, the current trends in well productivity over time were considered; for example if recent well quality trends were increasing, it was assumed for plays in early stages of development that well quality would increase somewhat in the future before declining as drilling moves into lower quality outlying portions of plays.

- Projections of future production profiles were made for all plays based on various drilling rate scenarios. These projections assume a gradation over time from the well quality observed in the current top counties of a play to the well quality observed in the outlying counties as available drilling locations are used up. The different drilling rate scenarios were prepared so that the effect of a high drilling rate, presumably due to favorable economic conditions, compared to a low or a "Most Likely" drilling rate, could be assessed, both in terms of production over time and cumulative gas recovery from the play by 2040.

- Production projections and the production history and cumulative production for all plays were then compared to the EIA forecasts to assess the likelihood that these forecasts could be met.

- All plays were then compared to each other in terms of well quality and other parameters and an overall assessment of the likely long-term sustainability of shale gas production was determined.

Although public pushback against hydraulic fracturing ("fracking") due to health and environmental concerns has limited access to drilling locations in states like New York and Maryland and several municipalities, as well as triggered lawsuits, this report assumes there will be no restrictions to access due to environmental concerns. It also assumes there will be no restrictions on access to the capital required to meet the various drilling rate scenarios. In these respects, it presents a "best case," as any restrictions on access to drilling locations or to the capital needed to drill wells would reduce forecast production levels.

3.2 THE CONTEXT OF U.S. GAS PRODUCTION

3.2.1 U.S. Gas Production Forecasts

The EIA's Annual Energy Outlook 2014 provides various scenarios of future U.S. gas production, as well as price projections and stated assumptions in terms of available technically recoverable reserves and resources, play areas, well productivity, and so forth.

Figure 3-1 illustrates the range of the EIA's gas production forecasts through 2040 compared to historical production. These scenarios project U.S. gas production to rise anywhere from 37% to 71% above 2013 levels by 2040 and recover between 856 and 971 trillion cubic feet of gas over the 2013-2040 period. This amounts to 2.5-2.9 times the proved reserves that existed as of 2012[3] (proved reserves are generally considered to be economically recoverable with current technology). Adding in unproved resources, which are uncertain estimates without price constraints, between 37% and 42% of remaining potentially recoverable gas in the U.S. will be consumed over the next 26 years according to the EIA projections. This amounts to the equivalent of 85% to 99% of all the gas produced over the 54 years between 1960 and 2013.

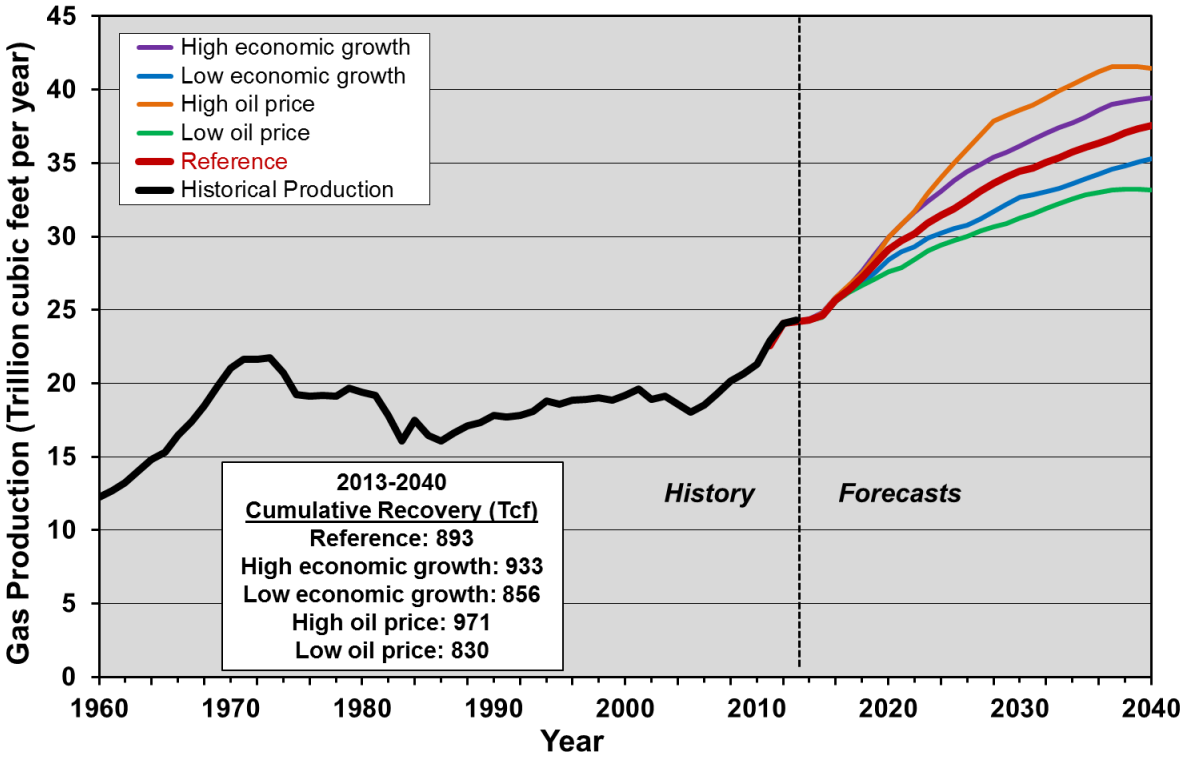

Figure 3-1. Scenarios of U.S. gas production through 2040 from the EIA's Annual Energy Outlook 2014[4] compared to historical production from 1960.

[3] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[4] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

The source of this optimism in future gas production is the application of high-volume, multi-stage, hydraulic fracturing technology ("fracking") in horizontal wells, which has unlocked previously inaccessible gas trapped in highly impermeable shales. Figure 3-2 illustrates the EIA's reference case gas production projection by source through 2040. Although conventional production is forecast to be flat or grow only slightly over the period, shale gas is forecast to more than double from 2013 levels and be 53% of a much expanded supply by 2040. Gas prices in this reference case are forecast to remain below $5 per million Btu (MMBtu) (2012 dollars) through 2024 and $6/MMBtu through 2030. Some 15% of production is forecast to be available for LNG and other exports in 2040, and net imports from Canada will cease by 2018.

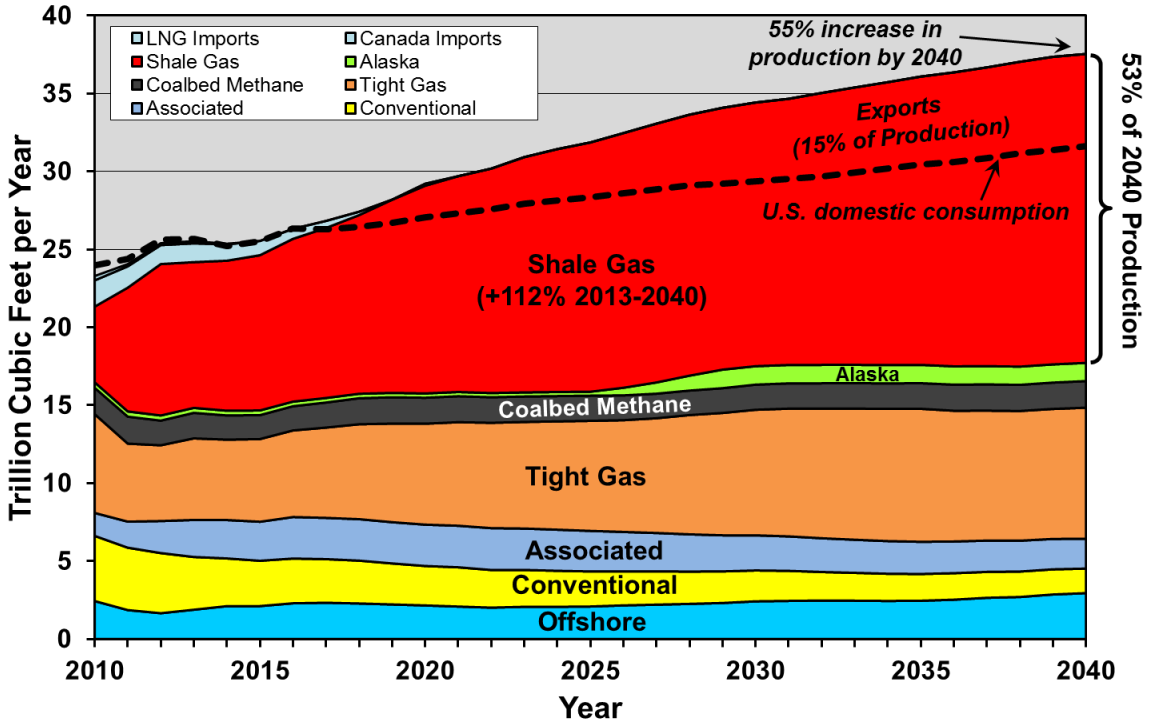

Figure 3-2. EIA reference case forecast of U.S. natural gas production by source through 2040.[5]

Overall production increases 55% from 2013 to 2040, whereas shale gas increases 112% over the same period.

[5] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

Figure 3-3 illustrates EIA forecasts for shale gas production in several cases. These assume the extraction of between 66% and 79% of the EIA's estimated 611 trillion cubic feet of proved shale gas reserves and unproved resources by 2040[6] (unproved resources have no implied price required for extraction and are highly uncertain compared to proved reserves which are recoverable with current technology under current economic conditions).

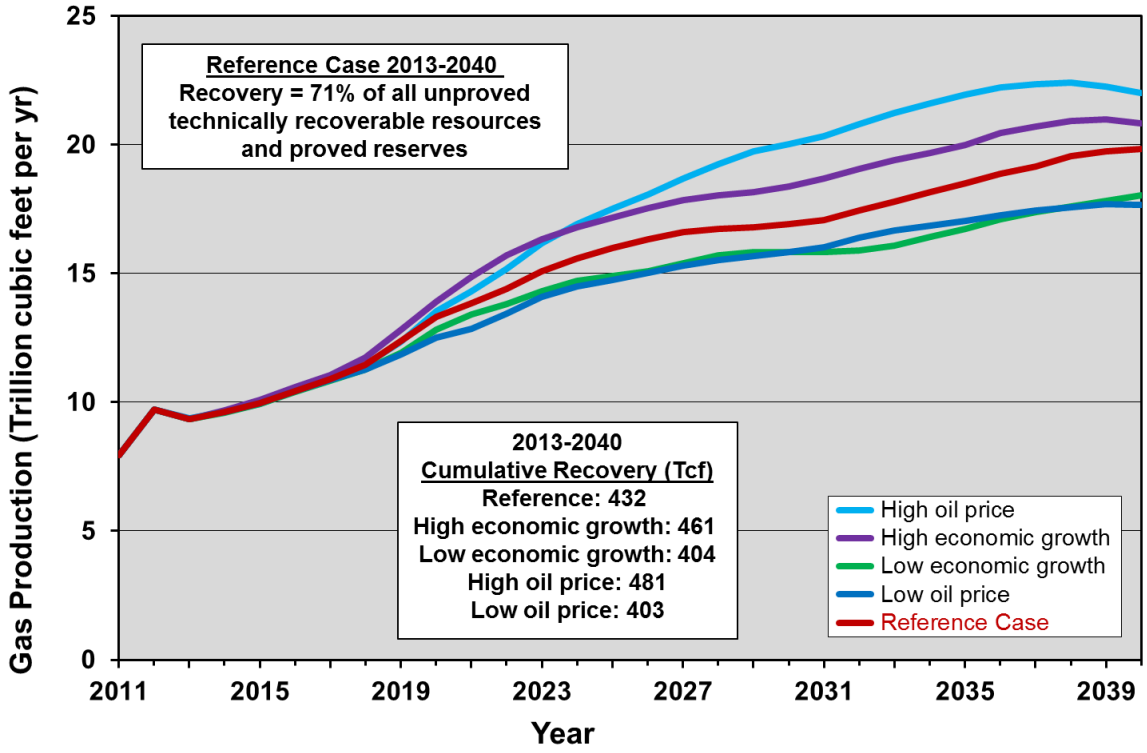

Figure 3-3. EIA scenarios of U.S. shale gas production through 2040.[7]

Unproved technically recoverable resources are estimated by the EIA at 489 trillion cubic feet and proved reserves at 122 trillion cubic feet[8], so these scenarios amount to the recovery of 66% to 79% of all proved reserves and unproved resources by 2040.

[6] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.
[7] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.
[8] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Figure 3-4 illustrates how the EIA reference case projections for shale gas production are divided between plays.

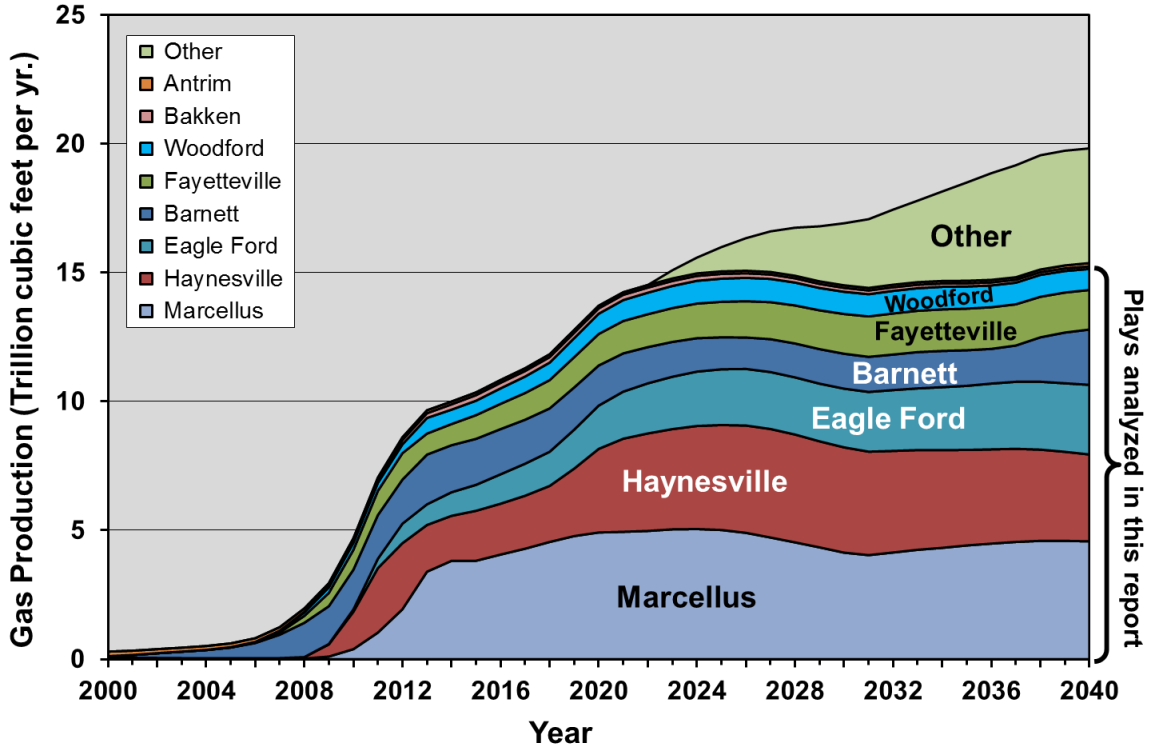

Figure 3-4. EIA reference case forecast of shale gas production divided by play through 2040.[9]

This report analyzed the seven most productive plays, which account for 88% of EIA's reference case shale gas production forecast to 2040.

The EIA reference case clearly expects the seven shale gas plays analyzed in this report to provide the bulk of production through 2040, with "other" plays increasing significantly after 2020. Shale gas production in all these plays has risen quickly due to rapid increases in drilling rates and sustained high levels of capital input; however, four of them are now in decline. High well- and field-decline rates, coupled with a finite number of drilling locations, suggest that production will be problematic to sustain, let alone grow at these forecast rates. Section 3 of this report explores the realistic production potential for these plays in depth.

[9] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

3.2.2 Current U.S. Shale Gas Production

Production of shale gas began in the Barnett play of eastern Texas in the late 1990s and early 2000s. With the widespread application of horizontal drilling and hydraulic fracturing ("fracking") beginning in 2003, production grew rapidly. The Haynesville play of Louisiana and east Texas was unknown as recently at 2007, and became the largest shale play in the U.S. at its peak in late 2011—although production has subsequently declined by 46%. The distribution of shale plays in the U.S. lower 48 states is illustrated in Figure 3-5.

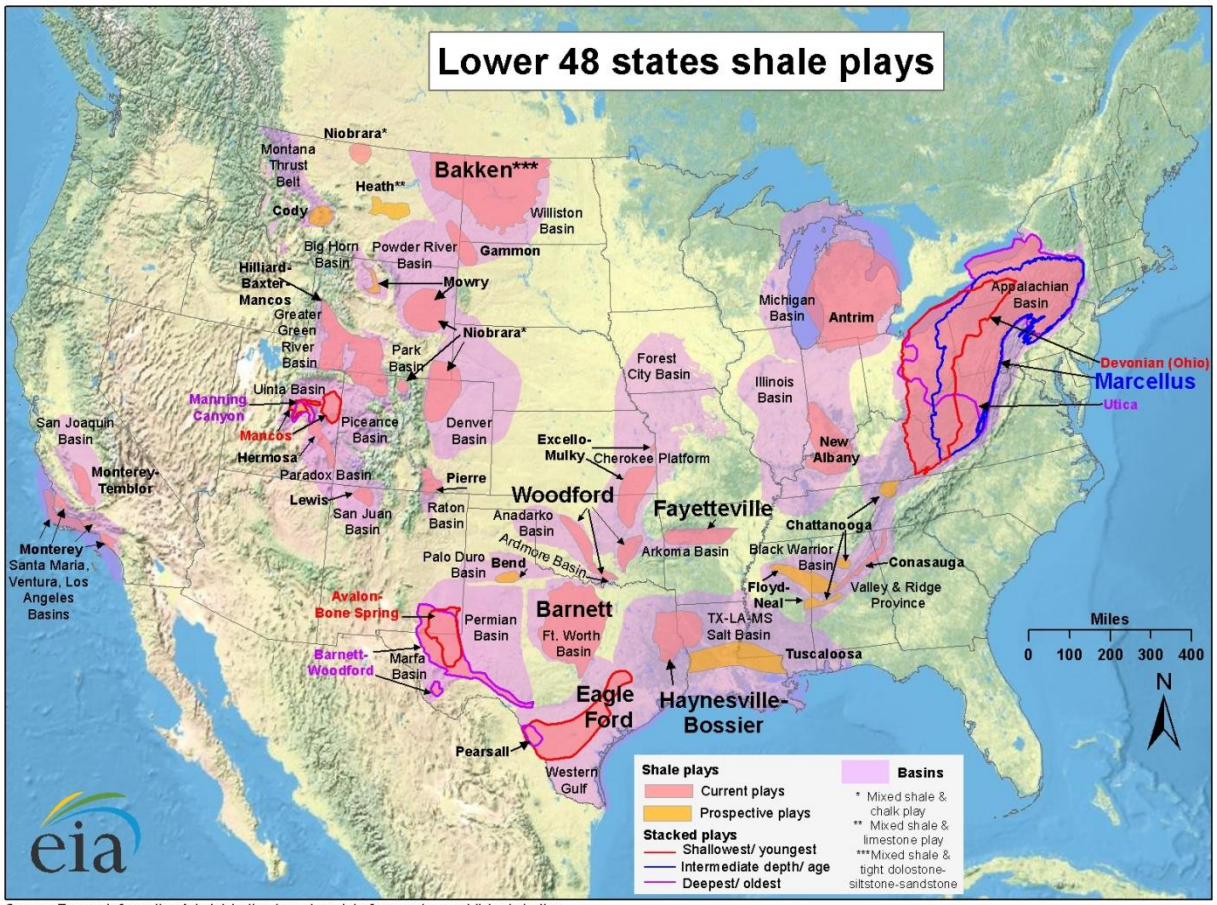

Figure 3-5. Distribution of lower 48 states shale gas and oil plays.[10]

[10] EIA, "Shale Gas and Oil Plays, Lower 48 States," http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm.

Current production from U.S. shale gas plays is estimated by the EIA at 37 billion cubic feet per day. Despite the apparent widespread nature of shale plays in Figure 3-5, nearly half of this production comes from just two plays—the Barnett and the Marcellus—and 78% comes from just five plays. Figure 3-6 illustrates shale gas production by play from 2000 through August 2014 according to the EIA.

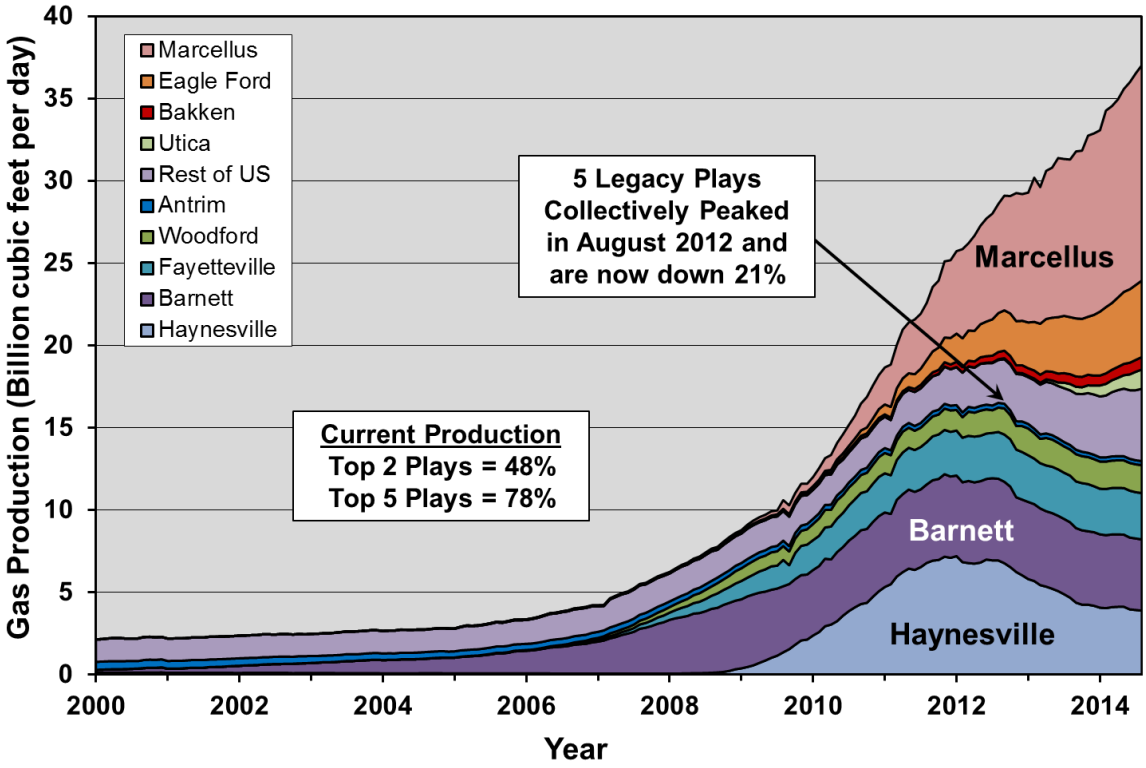

Figure 3-6. U.S. shale gas production by play from 2000 through July 2014, according to the EIA.[11]

[11] EIA estimates obtained in October 2014 from http://www.eia.gov/naturalgas/weekly.

3.3 MAJOR U.S. SHALE GAS PLAYS

3.3.1 Barnett Play

The EIA forecasts recovery of 53 Tcf of gas from the Barnett play by 2040. The analysis of actual production data presented below suggests that this forecast is unlikely to be realized.

The Barnett play is where shale gas production got its start in the late 1990s and the combination of horizontal drilling with multi-stage hydraulic fracturing ("fracking") was first applied at scale. Shale fracking was commercialized here by Mitchell Energy, a company headed by the late George Mitchell, "the father of fracking."[12] Figure 3-7 illustrates the distribution of wells as of early 2014. Over 19,600 wells have been drilled to date of which 15,906 were producing at the time of writing. The play covers parts of 24 counties although most of the drilling is concentrated in five counties in east Texas surrounding the city of Dallas/Fort Worth.

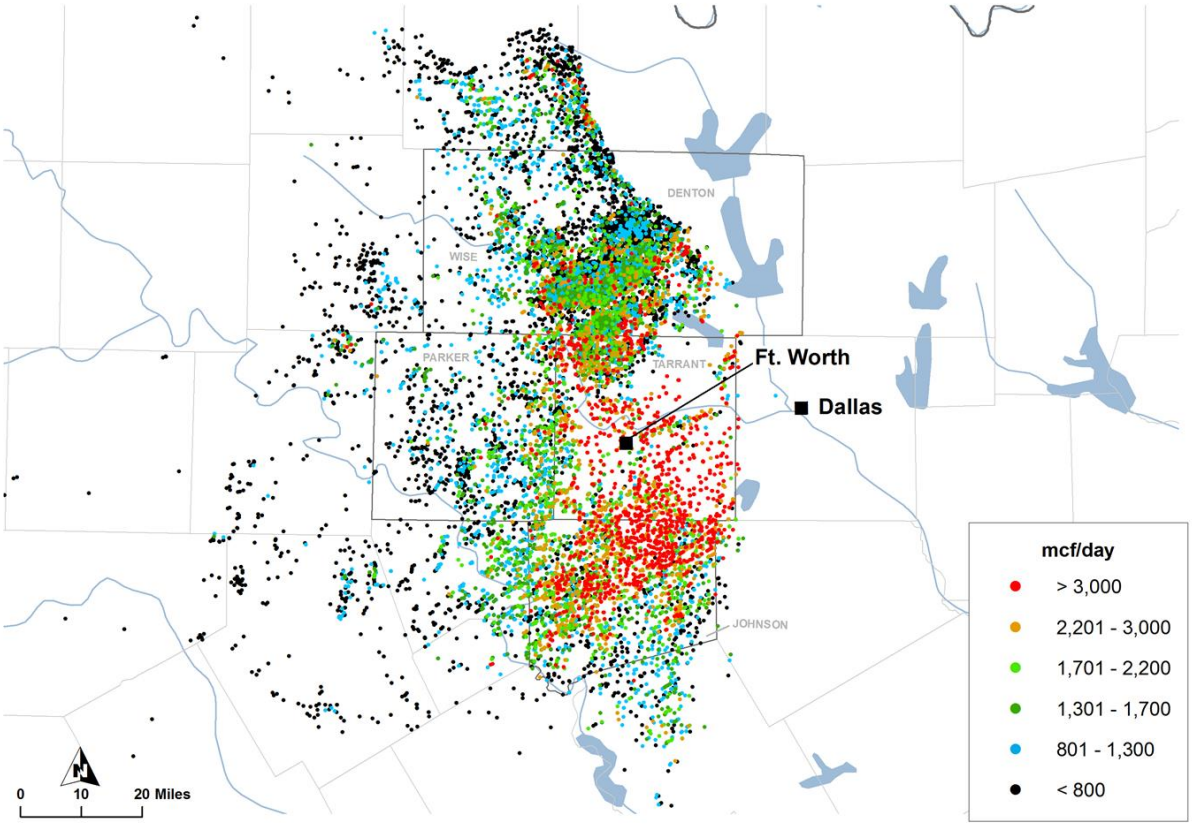

Figure 3-7. Distribution of wells in the Barnett play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).[13]

Well IPs are categorized approximately by percentile; see Appendix.

[12] *The Economist*, August 3, 2013, "The father of fracking," http://www.economist.com/news/business/21582482-few-businesspeople-have-done-much-change-world-george-mitchell-father.
[13] Data from Drillinginfo retrieved August 2014.

Production in the Barnett peaked at nearly six billion cubic feet per day in December 2011 as illustrated in Figure 3-8. Ninety-four percent of current production is from horizontal fracked wells. The rate of drilling grew from about 500 (mainly vertical) wells per year in 2002 to a peak of over 2,800 (mainly horizontal) wells per year in 2008. It has since fallen to about 400 wells per year which is insufficient to offset field decline. Drilling rates required to keep production flat at current production levels are about 1,161 wells per year.

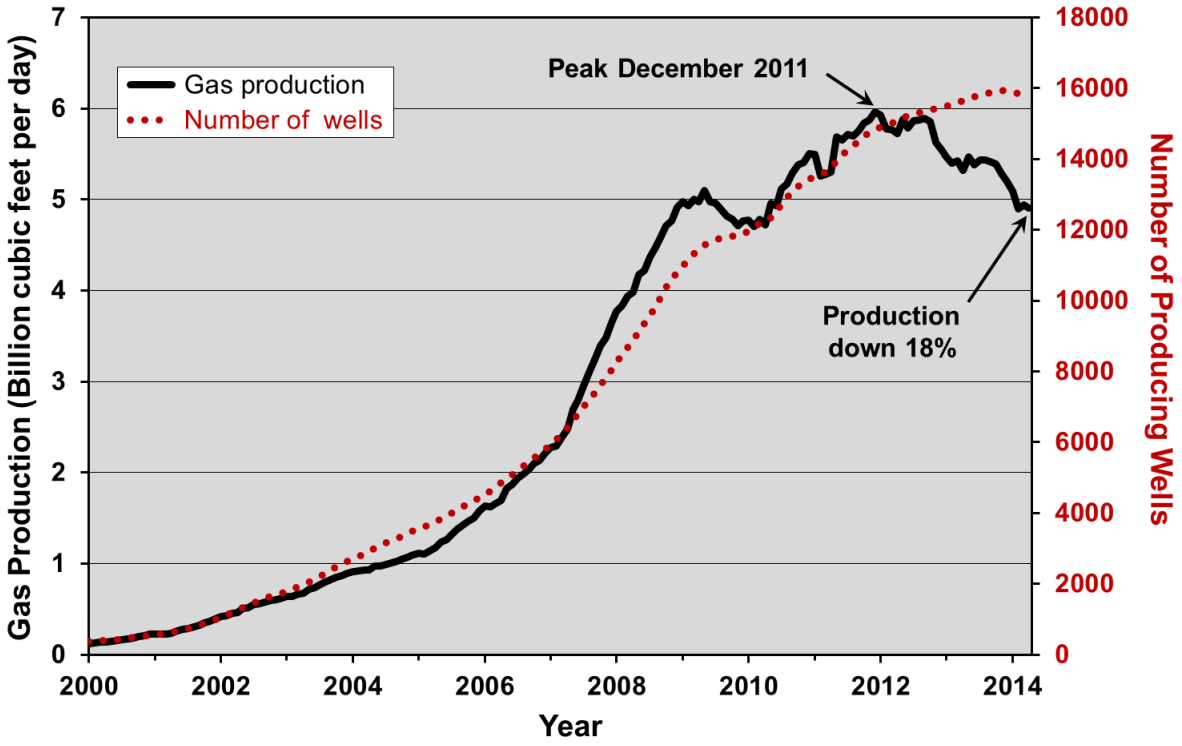

Figure 3-8. Barnett play shale gas production and number of producing wells, 2000 to 2014.[14]

Gas production data are provided on a "raw gas" basis.

[14] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

Vertical wells played a significant role in the early development of the Barnett play and still produce some oil and gas, although new wells are predominantly horizontal. The evolution of the Barnett began in Denton and adjacent counties with vertical and directional wells before moving to horizontal wells as the limits of the play were defined, as illustrated in Figure 3-9.

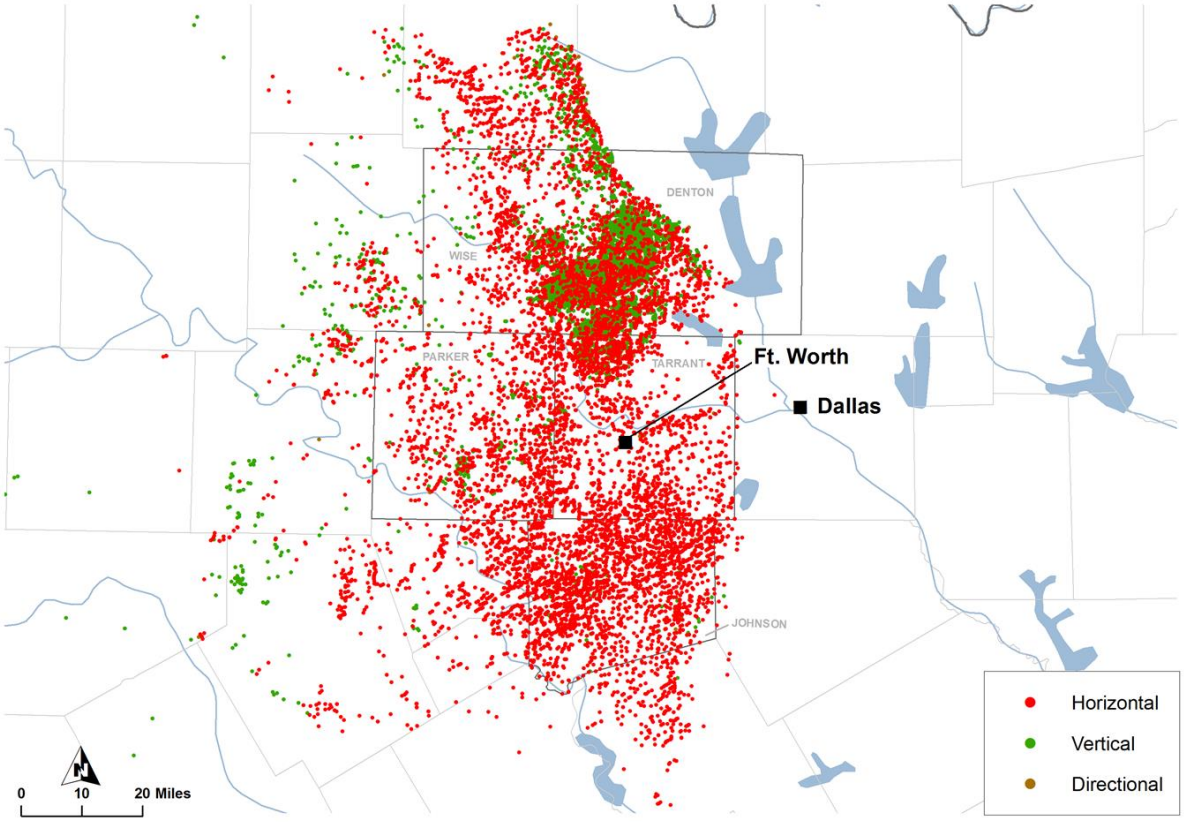

Figure 3-9. Distribution of gas wells in Barnett play categorized by drilling type, as of early 2014.[15]

Development began with vertical and directional wells in Denton County before expanding to largely horizontal drilling as the play's limits were defined.

[15] Data from Drillinginfo retrieved August 2014.

Production by well type is illustrated in Figure 3-10. There were still 3,366 producing vertical or directional wells, or 21% of the 15,906 producing wells in the play at the time of writing—yet these now produce less than 6% of total gas output. Very few vertical/directional wells are being drilled today; the future of the play lies in horizontal fracked wells. The dramatic growth in production from horizontal wells is noted in Figure 3-10.

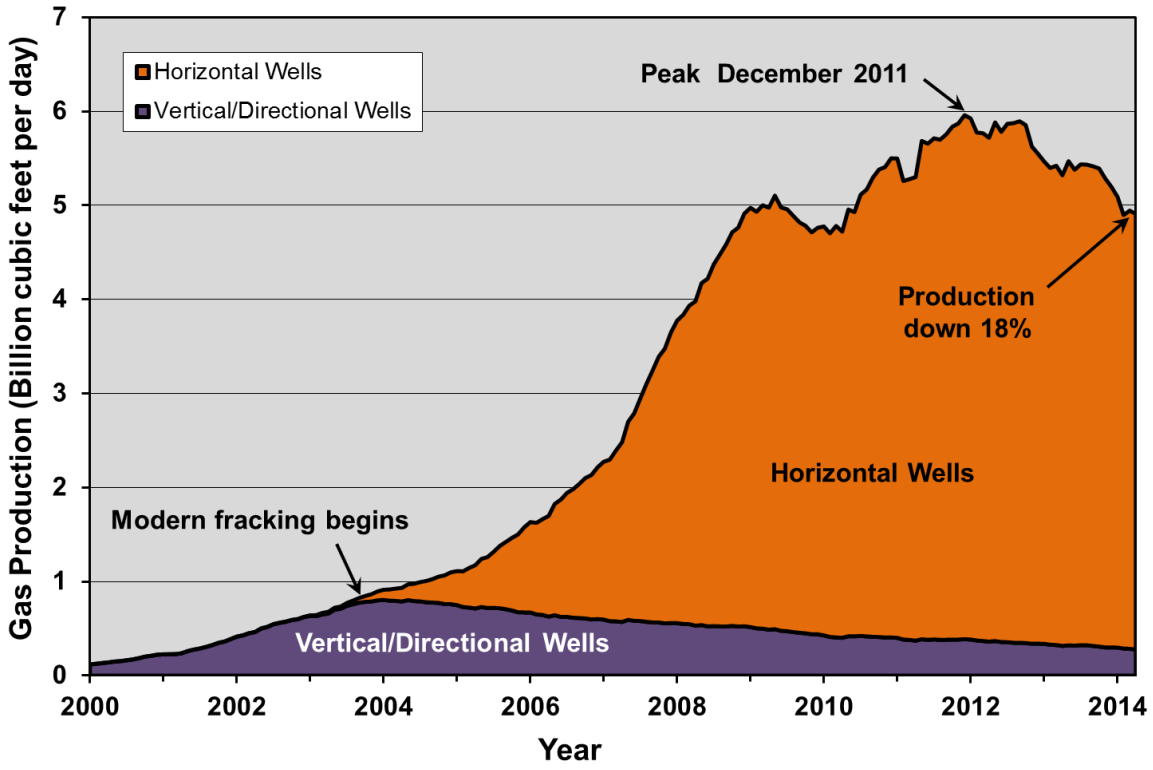

Figure 3-10. Gas production from the Barnett play by well type, 2000 to 2014.[16]

Fracking of horizontal wells at scale got underway in the Barnett in 2003.

[16] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

3.3.1.1 Well Decline

The first key fundamental in determining the life cycle of Barnett production is the *well decline rate*. Barnett wells exhibit high decline rates in common with all shale plays. Figure 3-11 illustrates the average decline rate of Barnett horizontal and vertical/directional wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The decline rate over the first three years of average well life is 75%, which is considerably higher than most conventional wells. As can be seen, vertical/directional wells have much lower productivity than horizontal wells and hence are being phased out.

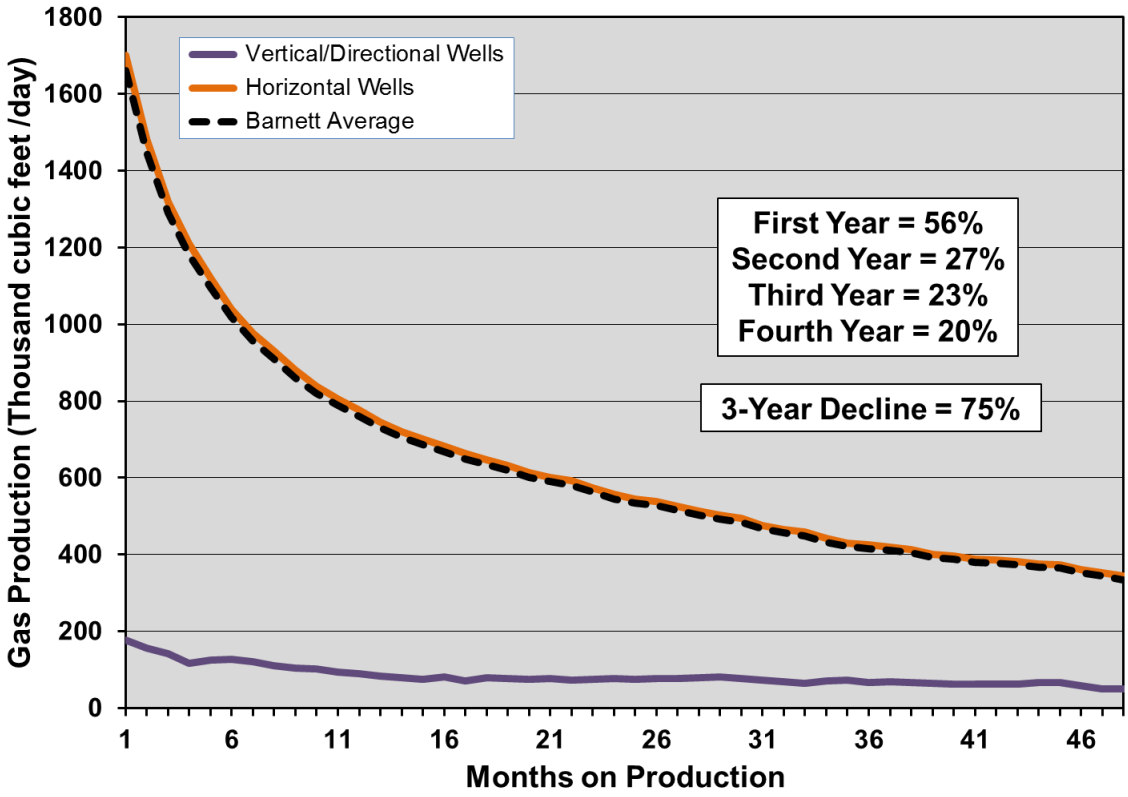

Figure 3-11. Average decline profile for gas wells in the Barnett play.[17]

Decline profile is based on all shale gas wells drilled since 2009.

[17] Data from Drillinginfo retrieved August 2014.

3.3.1.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost for the entire play in a year without more drilling. Figure 3-12 illustrates production from the 12,000 horizontal wells drilled prior to 2013. The first-year decline rate is 23%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. It is also one of the lowest field decline rates observed in any shale field. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, 1,161 new wells each year would be required to offset field decline at current production levels. At an average cost of $3.5 million per well,[18] this would represent a capital input of about $4 billion per year, exclusive of leasing and other ancillary costs, just to keep production flat at 2013 levels.

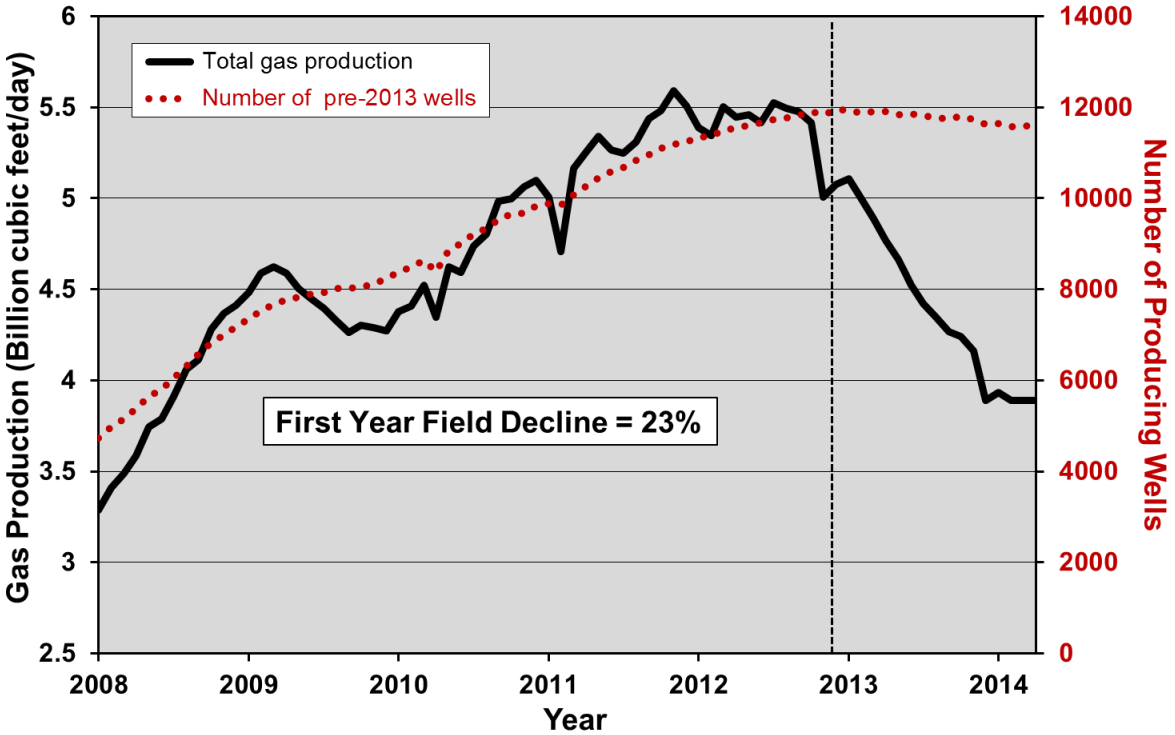

Figure 3-12. Production rate and number of horizontal shale gas wells drilled in the Barnett play prior to 2013, 2008 to 2014.[19]

This defines the field decline for the Barnett play, which is 23% per year (only production from horizontal wells is analyzed as few vertical/directional wells are likely to be drilled in the future).

[18] Browning et al., 2013, Barnett Gas Production Outlook, http://www.searchanddiscovery.com/pdfz/documents/2013/10541browning/ndx_browning.pdf.html.
[19] Data from Drillinginfo retrieved August 2014.

3.3.1.3 Well Quality

The third key fundamental is the *average well quality* by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, and improvements in average well quality are non-existent in the Barnett. The average first-year production rate of Barnett wells is down 17%from what it was in 2011, as illustrated in Figure 3-13. This is clear evidence that geology is winning out over technology, as drilling moves into lower-quality locations as investigated further below.

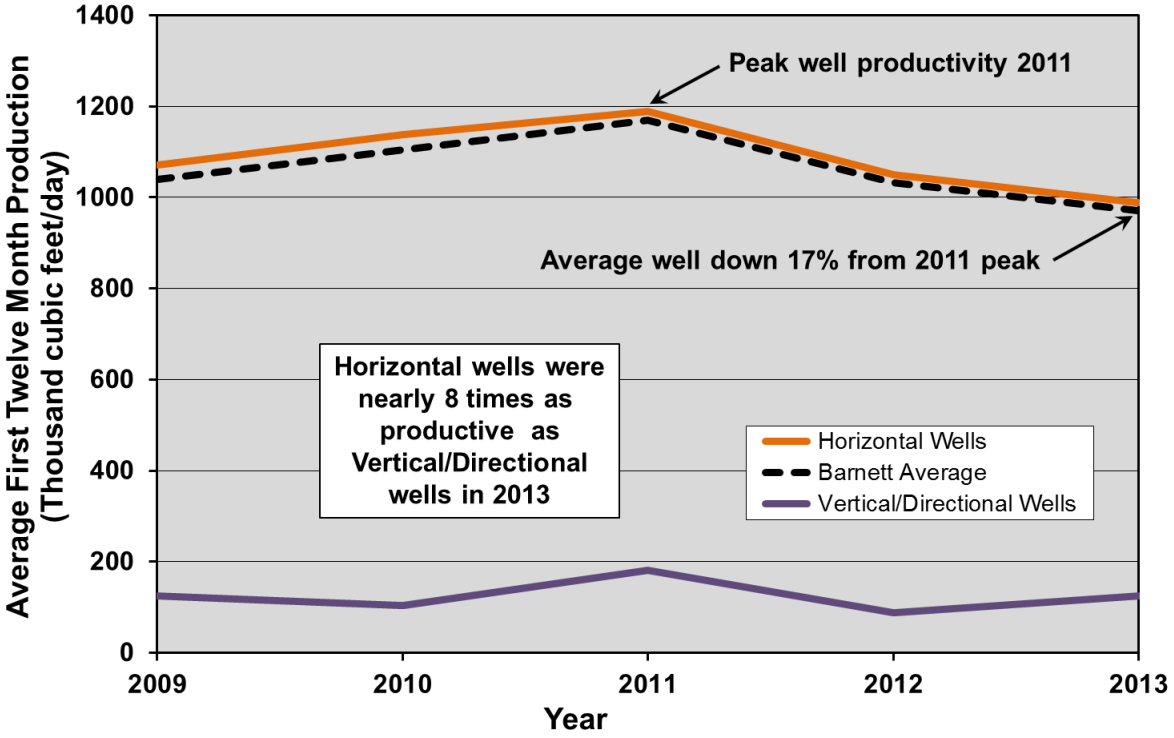

Figure 3-13. Average first-year production rates for Barnett horizontal and vertical/directional gas wells, 2009 to 2013.[20]

Average well quality has fallen by 17% from 2011, a clear indication that geology is trumping technology in this mature shale play.

[20] Data from Drillinginfo retrieved August 2014.

Another measure of well quality is cumulative production and well life. More than 14% of the horizontal wells that have been drilled in the Barnett are no longer productive. Figure 3-14 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 37 months and a mean cumulative production of 0.38 billion cubic feet, these wells would in large part be economic losers.

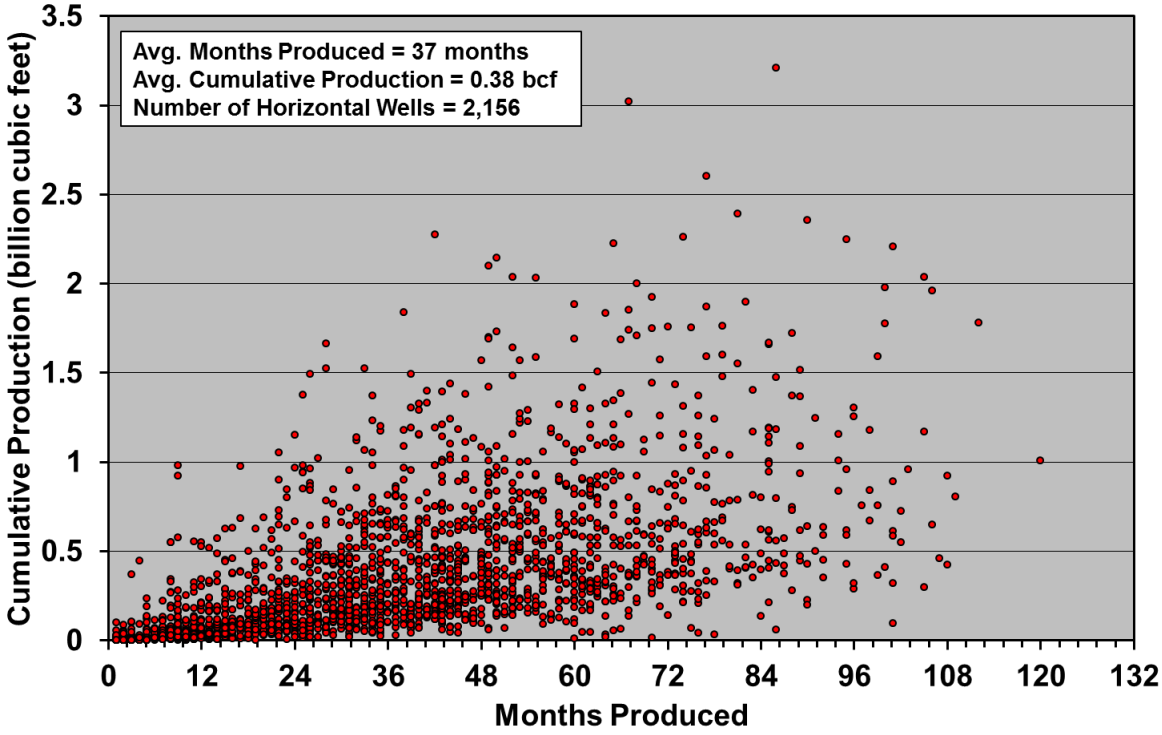

Figure 3-14. Cumulative gas production and length of time produced for Barnett horizontal wells that were not producing as of February 2014.[21]

These well constitute more than 14% of all horizontal wells drilled; most would be economic failures, given the mean life of 37 months and average cumulative production of 0.38 billion cubic feet when production ended.

[21] Data from Drillinginfo retrieved August 2014.

Figure 3-15 illustrates the cumulative production of all horizontal wells that were producing in the Barnett as of March 2014. Although it can be seen that there are a few very good wells that recovered large amounts of gas in the first few years, and undoubtedly were great economic successes, the average well had produced just 0.95 billion cubic feet over a lifespan averaging 58 months. Just 1% of these wells are more than 10 years old.

The lifespan of wells is another key parameter as many operators assume a minimum well life of 30 years and longer; this is conjectural given the lack of data and the large numbers of wells that have been shut down after less than 10 years.

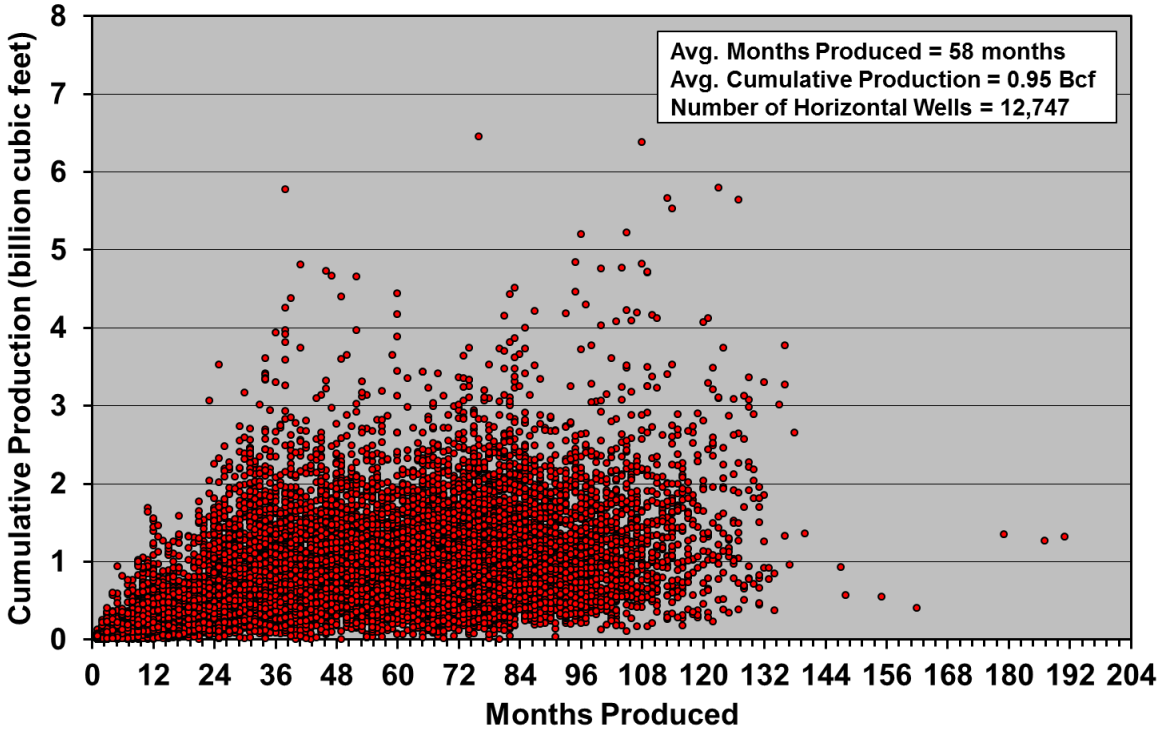

Figure 3-15. Cumulative gas production and length of time produced for Barnett horizontal wells that were producing as of March 2014.

These well constitute 86% of all horizontal wells drilled. Very few wells are greater than ten years old, with a mean age of 58 months and a mean cumulative recovery of 0.95 billion cubic feet.[22]

[22] Data from Drillinginfo retrieved August 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP), which is often focused on by operators. Figure 3-16 illustrates the average daily output over the first six months of production for all wells in the Barnett play (six-month IP). Again, as with cumulative production, there are a few exceptional wells—one percent produced more than 4 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 1995 is just 1.04 MMcf/d. Figure 3-7 illustrates the distribution of IPs in map form.

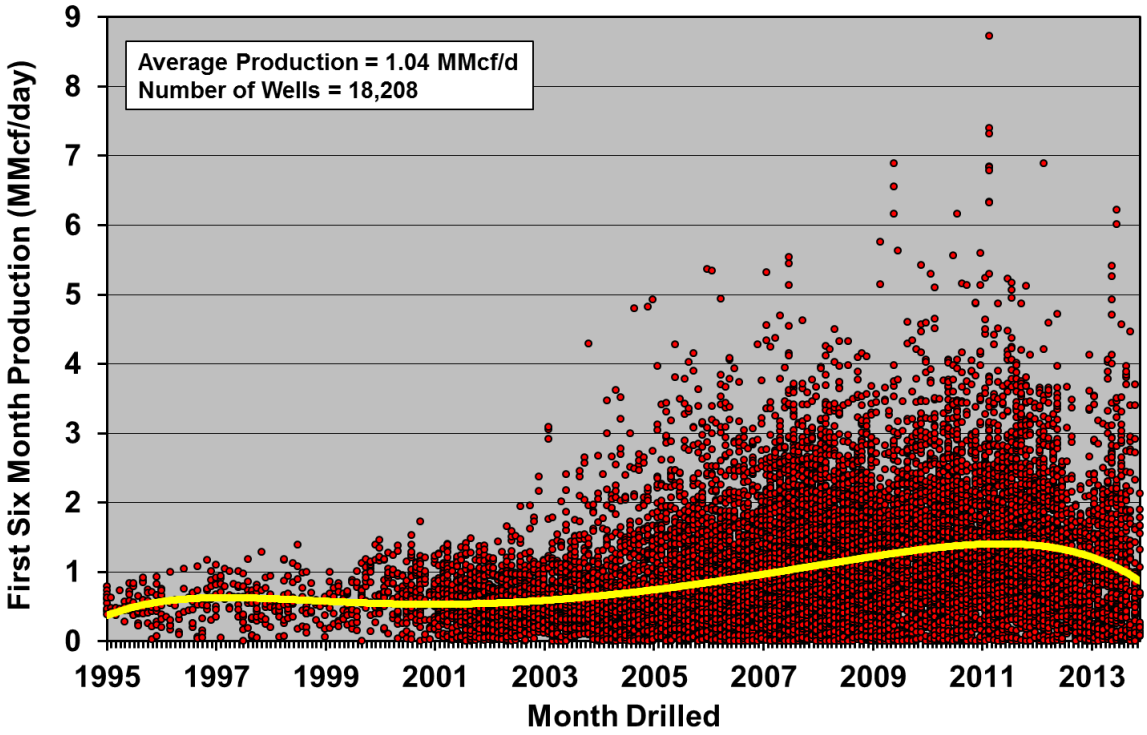

Figure 3-16. Average gas production over the first six months for all wells drilled in the Barnett play, 1995 to 2014.

Although there are a few exceptional wells, the average well produced 1.04 million cubic feet per day over this period.[23] The trend line indicates mean productivity over time.

[23] Data from Drillinginfo retrieved August 2014.

Different counties in the Barnett display markedly different well quality characteristics which are critical in determining the most likely production profile in the future. Figure 3-17, which illustrates production over time by county, shows that as of April 2014, the top two counties produced 57% of the total, the top five produced 88%, and the remaining 19 counties produced just 12%.

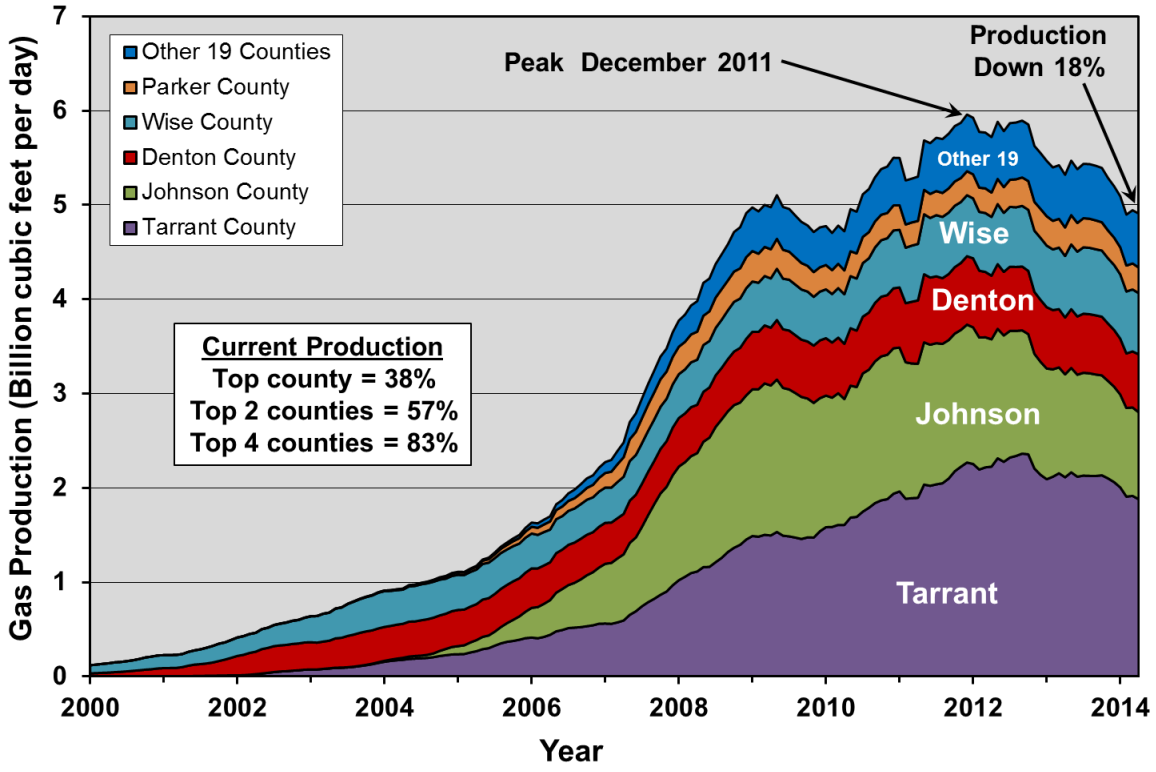

Figure 3-17. Gas production by county in the Barnett play, 2000 through 2014.[24]

The top five counties produced 88% of production in April 2014.

[24] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-18, the top two counties have produced 56% of the gas and the top five have produced 92%. All of the counties have peaked, although with increased drilling rates some could conceivably resume production growth.

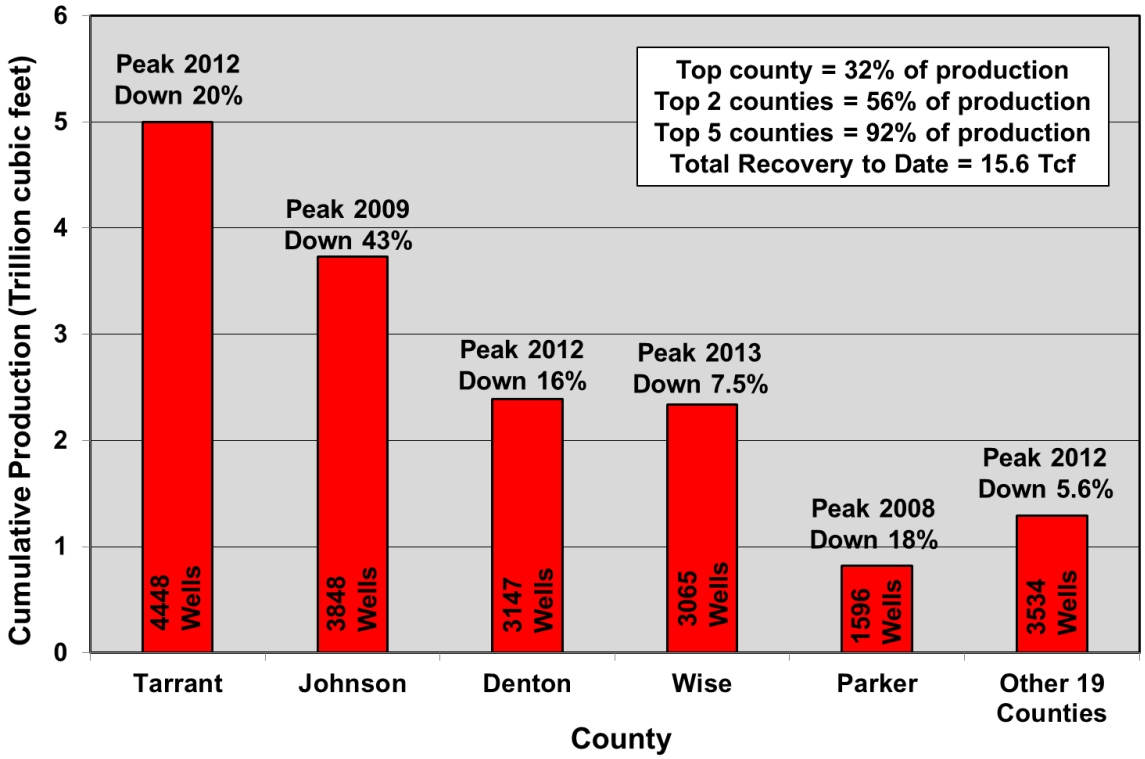

Figure 3-18. Cumulative gas production by county in the Barnett play through 2014.[25]

The top five counties have produced 92% of the 15.6 trillion cubic feet of gas produced to date.

[25] Data from Drillinginfo retrieved August 2014.

The Barnett also produces limited amounts of natural gas liquids and oil. Most liquids production is not within the top five counties but is located in the northern and western extremities of the play as illustrated in Figure 3-19. Some 59 million barrels of liquids have been produced since 2000, and although it has somewhat improved economics in marginal counties for gas production, in the big picture liquids production from the Barnett is relatively insignificant (Figure 3-20).

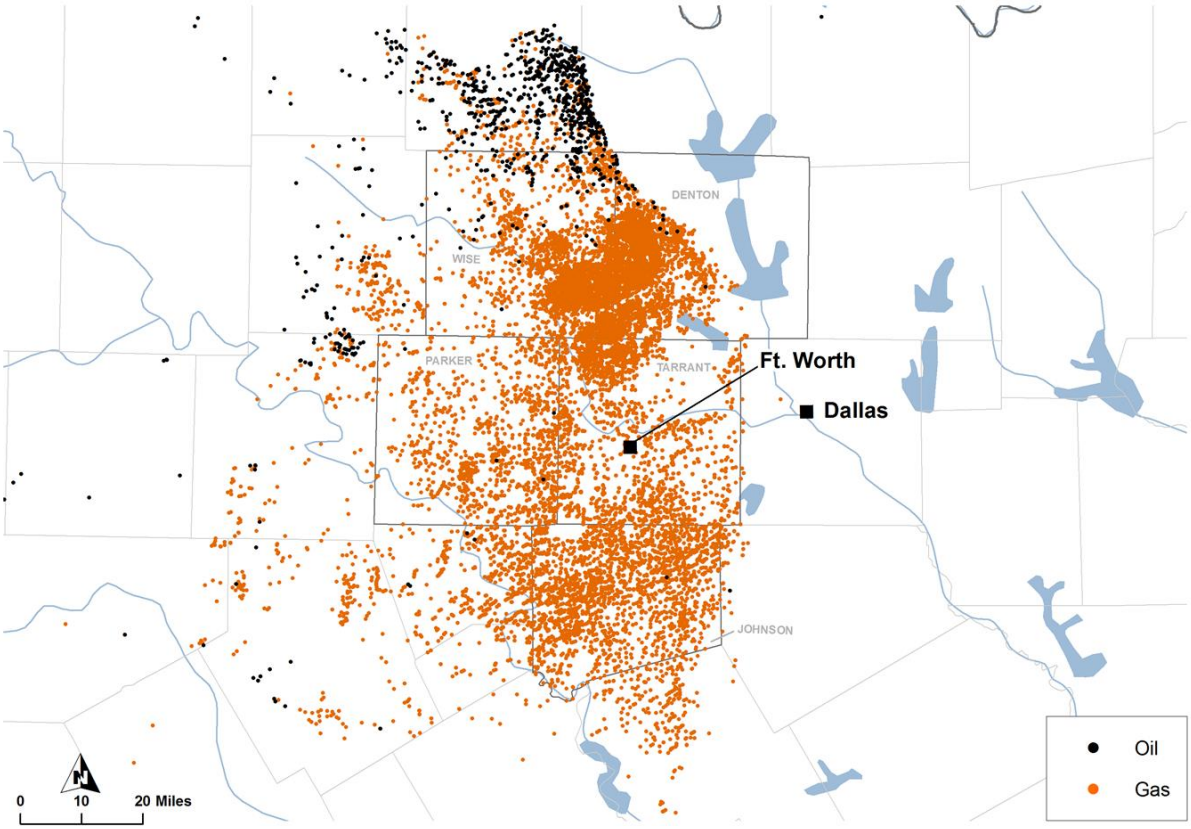

Figure 3-19. Distribution of gas and oil wells in the Barnett play as of early 2014.[26]

Liquids production from wells classified as "oil" occurs mainly in the northern and western extremities of the play.

[26] Data from Drillinginfo retrieved August 2014.

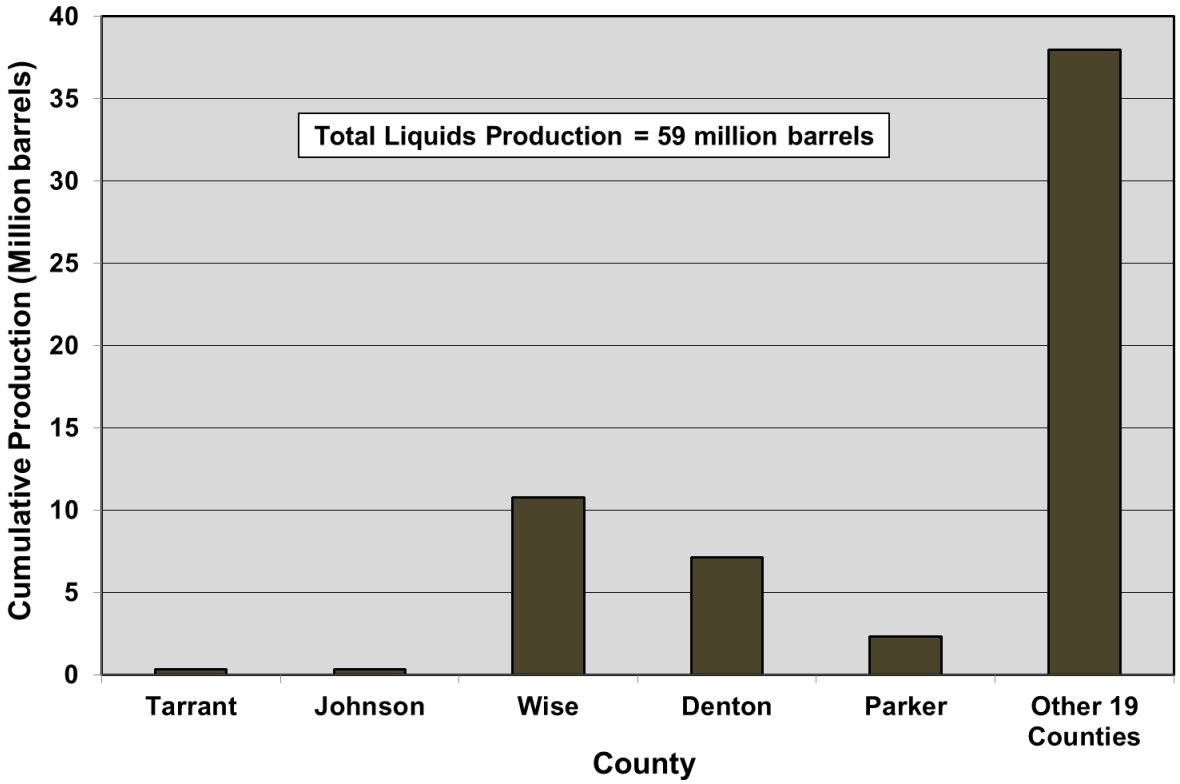

Figure 3-20. Cumulative liquids production by county in the Barnett play through 2014.[27]

The "other 19" counties account for 65% of the 59 million barrels produced to date.

[27] Data from Drillinginfo retrieved August 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of $3.5 million or more each in the Barnett, not including leasing costs and other expenses. The areas of highest quality—the "core" or "sweet spots"—have now been well defined. Figure 3-21 illustrates average horizontal well decline curves by county, which are a measure of well quality (recognizing that future gas production from the Barnett will be from horizontal, not vertical, wells). Initial well productivities (IPs) from Tarrant and Johnson counties are double those of Wise and Parker counties and quadruple those of the outlying 19 counties. The decline curves from the top three counties are all above the Barnett average, hence these counties are attracting the bulk of the drilling and investment—but they are nearly saturated with wells. Future drilling will have to focus more and more on lesser-quality counties.

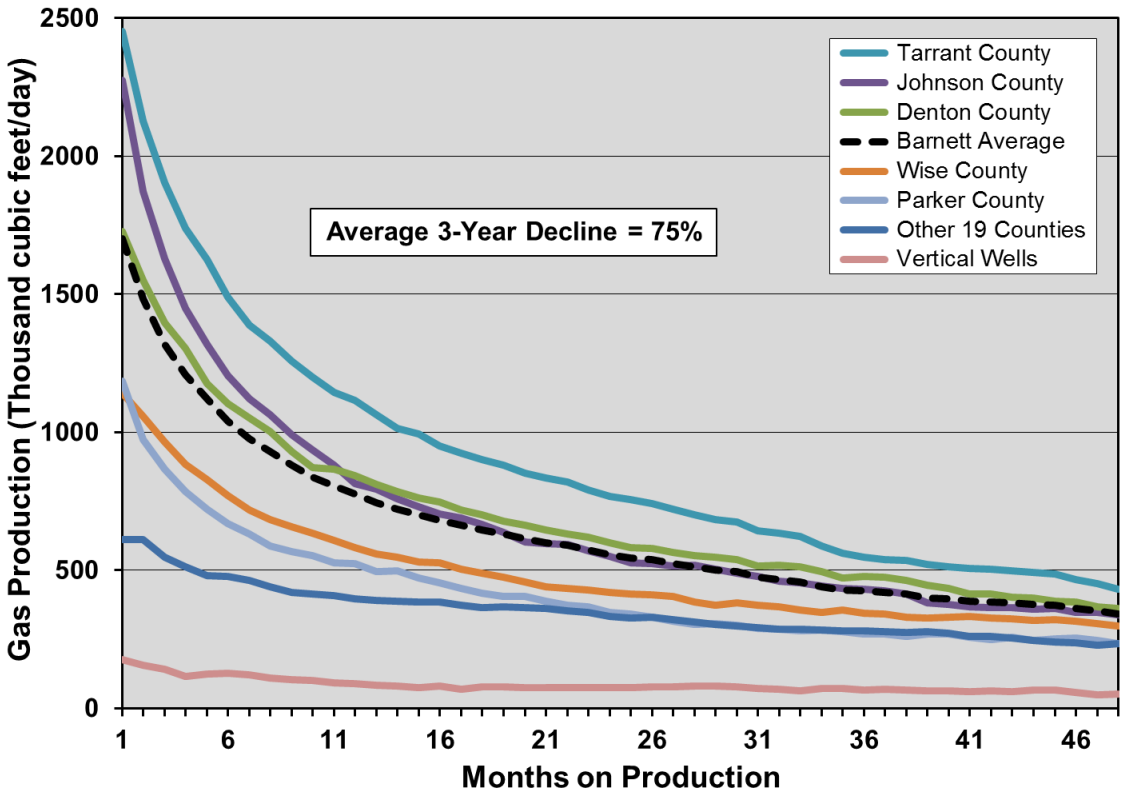

Figure 3-21. Average horizontal gas well decline profiles by county for the Barnett play.[28]

The top three counties, which have produced much of the gas in the Barnett, are clearly superior.

Another measure of well quality is "estimated ultimate recovery" or EUR—the amount of gas a well will recover over its lifetime. To be clear, no one knows what the lifespan of an average Barnett well is, given that few of them are more than ten years old (see Figure 3-14 and Figure 3-15), and some 14% of horizontal wells drilled have ceased production at an average age of just over three years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-21, assuming well life spans of 30-50 years (as is typical for conventional wells), but so far this is speculation, given the nature of the extremely low permeability reservoirs and the completion technologies used in the Barnett. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-21, which exhibits steep initial decline with

[28] Data from Drillinginfo retrieved August 2014.

progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-22 illustrates theoretical EURs by county for the Barnett for comparative purposes of well quality. These range from 1.01 to 2.34 billion cubic feet per well, which are somewhat higher than the 0.19 to 1.62 billion cubic feet assumed by the EIA.[29] The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 51% and 58% of an average well's lifetime production occurs in the first four years.

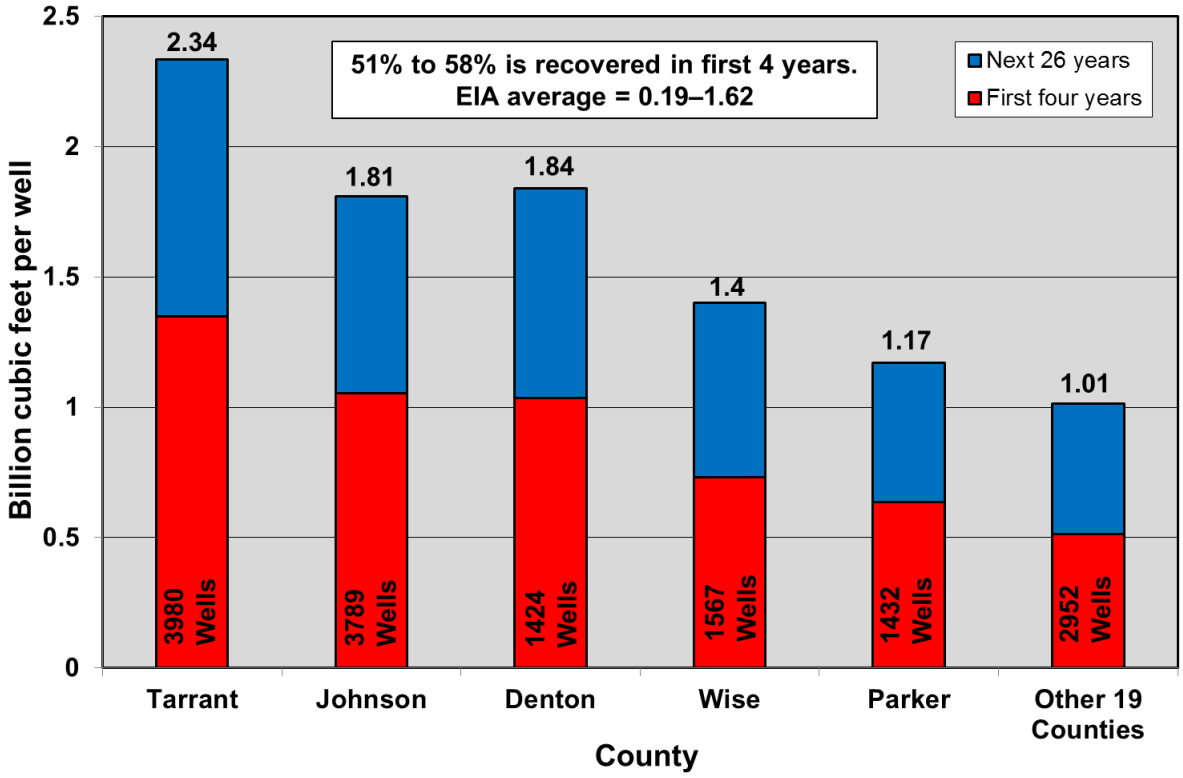

Figure 3-22. Estimated ultimate recovery of gas per well by county for the Barnett play.[30]

EURs are based on average well decline profiles (Figure 3-21) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

[29] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[30] Data from Drillinginfo retrieved August 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Given that drilling is currently focused on the highest quality counties, the average first-year production rate per well will fall as drilling moves into lower-quality counties as the best locations are drilled off. As average well quality falls, the number of wells that must be drilled to offset field decline must rise, until the drilling rate can no longer offset decline and the field peaks.

Figure 3-23 illustrates the average first year production rate of wells by county. Notwithstanding modest recent gains in the top two counties—which are also those that are most densely drilled—the average well quality is flat or falling, as progressively more wells are drilled in lower quality parts of individual counties and in the play overall.

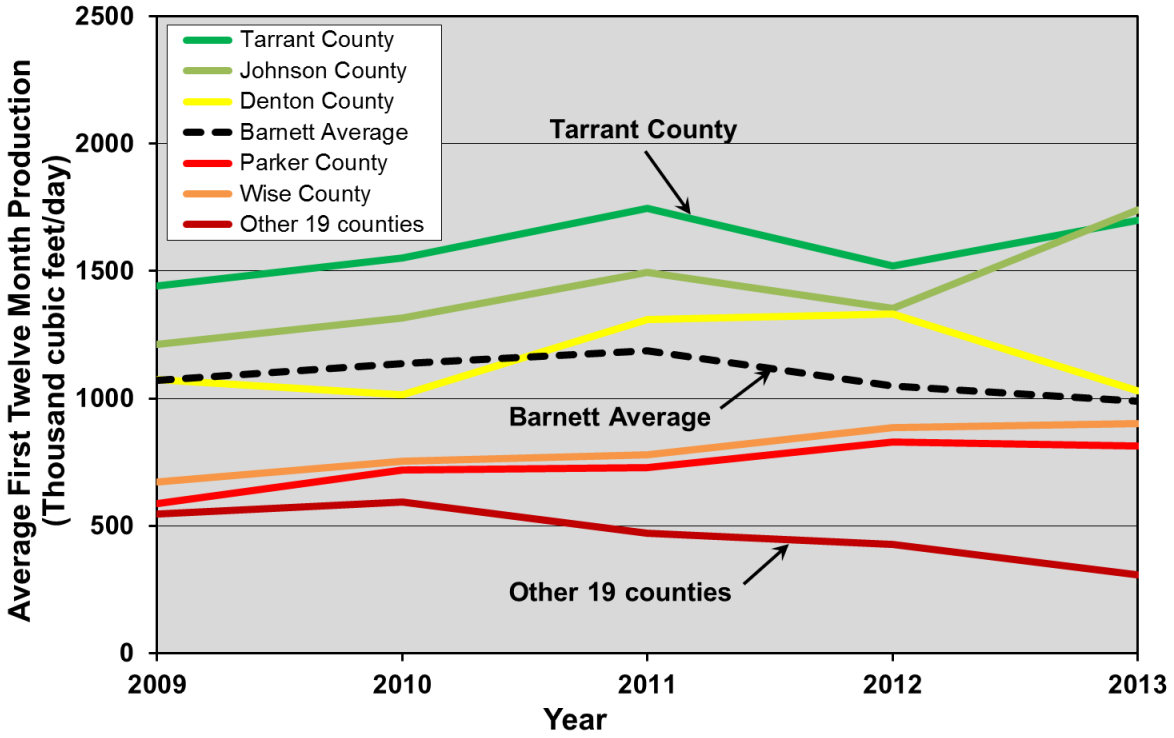

Figure 3-23. Average first-year gas production rates of wells by county for the Barnett play, 2009 to 2013.[31]

Well quality is rising modestly in Tarrant and Johnson counties and falling or flat in other counties. First year production rate in the lowest 19 counties, where the bulk of remaining drilling locations are, is less than a quarter of the top two counties, and is falling.

[31] Data from Drillinginfo retrieved August 2014.

3.3.1.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled. The Bureau of Economic Geology at the University of Texas at Austin has done a detailed analysis of the Barnett in which they suggest a total of 29,217 wells will be drilled by 2030 in its base case (including 15,144 wells drilled through 2010 and 14,073 new wells to be drilled through 2030).[32] The range of total estimated wells in the University of Texas study was from 20,636 for its low case to 40,267 for its high case. The EIA, on the other hand, suggests that there are 6,725 square miles that can be drilled at a density of 8 wells per square mile for a total of 53,797 wells.[33] However, more than two-thirds of the EIA's estimated wells occur in counties with very low production potential (EUR estimated by the EIA of just 0.19 Bcf per well)—hence it is questionable if many of these wells would ever be drilled. It is also not clear if the EIA's drillable area excludes areas already drilled, which, if so, would increase the total area of the play and the number of wells that ultimately would be drilled.

A careful review of the drilling production levels by well in Figure 3-7 reveals that the limits of the Barnett play are quite well defined. Total play area is about 5,140 square miles, which translates to 41,121 locations if drilled at a density of eight wells per square mile. Given that prospective parts of Denton County now exceed eight wells per square mile (averaging 8.86 per square mile) the ultimate total well count would be 41,426 (i.e., 305 more wells than the 8 per square mile limit given the Denton County overshoot), which includes 3,732 wells drilled since 1995 that are no longer producing. This is considerably higher than the University of Texas base case estimate of wells drilled by 2030 and lower than the EIA estimate (although the Browning et al. study does not state the number of wells to be drilled beyond 2030 in any of its cases). It assumes that 21,788 wells remain to be drilled in the Barnett play, so that the well count will more than double from current levels assuming that capital input is not a constraint in drilling marginal wells. It also assumes that drilling will not be constrained by surface features such as towns, parks etc. and thus is a best case estimate.

Table 3-1 lists the critical parameters used for determining the future production rates of the Barnett play.

[32] Browning et al., 2014, *Oil and Gas Journal*, "BARNETT SHALE MODEL-2 (Conclusion): Barnett study determines full-field reserves, production forecast," http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html.
[33] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Parameter	County						Total
	Denton	Johnson	Parker	Tarrant	Wise	Other 19	
Production April 2014 (Bcf/d)	0.61	0.92	0.27	1.88	0.65	0.57	4.91
% of Field Production	13	19	6	38	13	12	100
Cumulative Gas (Tcf)	2.39	3.73	0.82	5	2.34	1.29	15.57
Cumulative Liquids (MMBBL)	7.14	0.32	2.31	0.31	10.76	37.99	58.85
Number of Wells	3147	3848	1596	4448	3065	3534	19638
Number of Producing Wells	2678	3028	1135	3735	2608	2722	15906
Average EUR per well (Bcf)	1.84	1.81	1.17	2.34	1.4	1.01	1.70
Field Decline (%)	19.05	23.81	25.75	24.86	22.56	20.58	23.37
3-Year Well Decline (%)	72	81	77	78	70	55	75
Peak Year	Jan-12	May-09	Dec-08	Sep-12	Oct-13	May-12	Dec-11
% Below Peak	16	43	18	20	7.5	5.6	18
Average First Year Production in 2013 (Mcf/d)	1032	1740	812	1701	900	308	988
New Wells Needed to Offset Field Decline	113	126	86	275	163	382	1161
Area in square miles	888	729	904	864	905	19000	23290
% Prospective	40	90	90	80	80	10	22
Net Square Miles	355.2	656.1	813.6	691.2	724	1900	5140
Well Density per square mile	8.86	5.86	1.96	6.44	4.23	1.86	3.82
Additional locations to 8/sq. Mile	0	1401	4913	1082	2727	11666	21788
Population	584238	126811	88495	1446219	48793	N/A	N/A
Total Wells 8/sq. Mile	3147	5249	6509	5530	5792	15200	41426
Total Producing Wells 8/sq. Mile	2678	4429	6048	4817	5335	14388	37694

Table 3-1. Parameters for projecting Barnett production, by county.

Area in square miles under "Other" is estimated.

3.3.1.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-24 illustrates the historical drilling rates in the Barnett. Horizontal drilling rates peaked in 2008 at 2,707 wells per year and have fallen to current levels of less than 400 wells per year. Current drilling rates are far less than the 1,161 wells per year required to maintain production at current levels, hence each new well drilled now serves only to slow the overall production decline of the play.

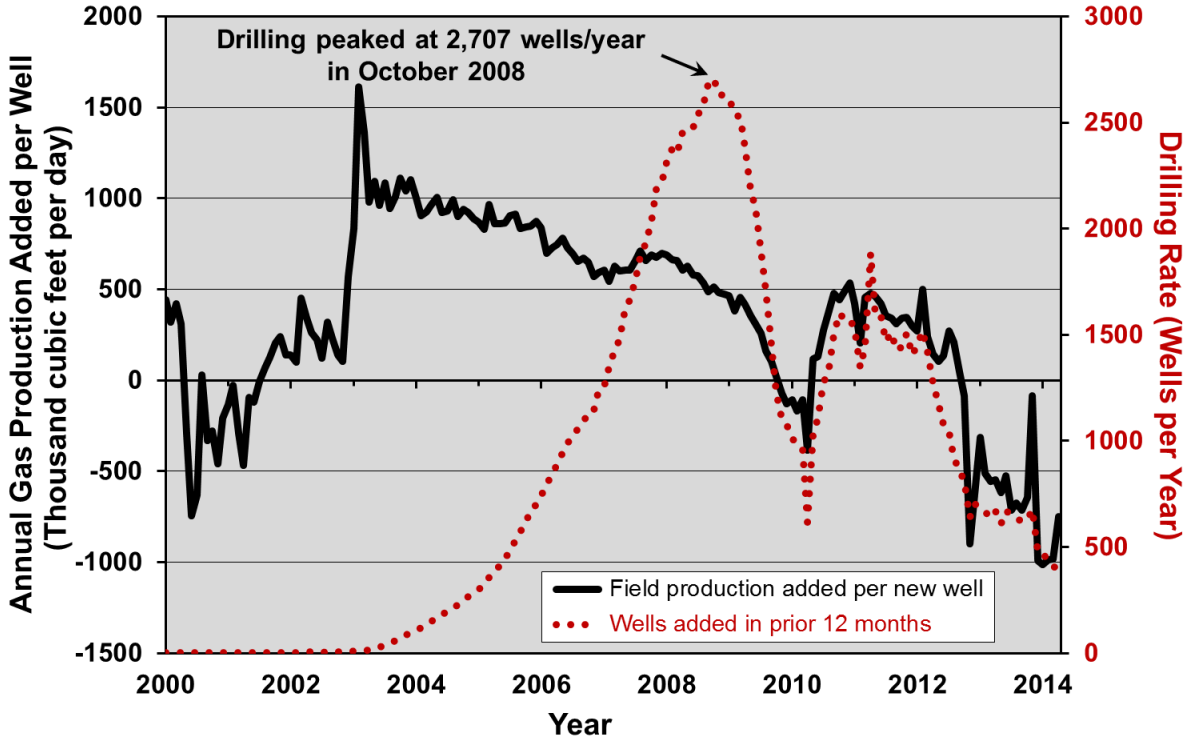

Figure 3-24. Annual gas production added per new horizontal well and annual drilling rate in the Barnett play, 2000 through 2014.[34]

Drilling rate peaked in 2008 and is now far below the level needed to keep production flat, hence each new well now only serves to slow the overall production decline of the play.

[34] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

3.3.1.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Barnett play were developed to illustrate the effects of changing the rate of drilling. Figure 3-25 illustrates the production profiles of four drilling rate scenarios if 100% of the prospective play area is drillable at eight wells per square mile. These scenarios are:

1. MOST LIKELY RATE scenario: Drilling increases from the current rate to 600 wells per year, then gradually declines to 500 wells per year

2. LOW RATE scenario: Drilling continues at current level of 400 wells per year, holding constant.

3. TRIPLE RATE scenario: Drilling increases to 1,200 wells per year, then gradually declines to 600 wells per year.

4. QUINTUPLE RATE scenario: Drilling increases to 2,000 per year, then gradually declines to 1,000 wells per year.

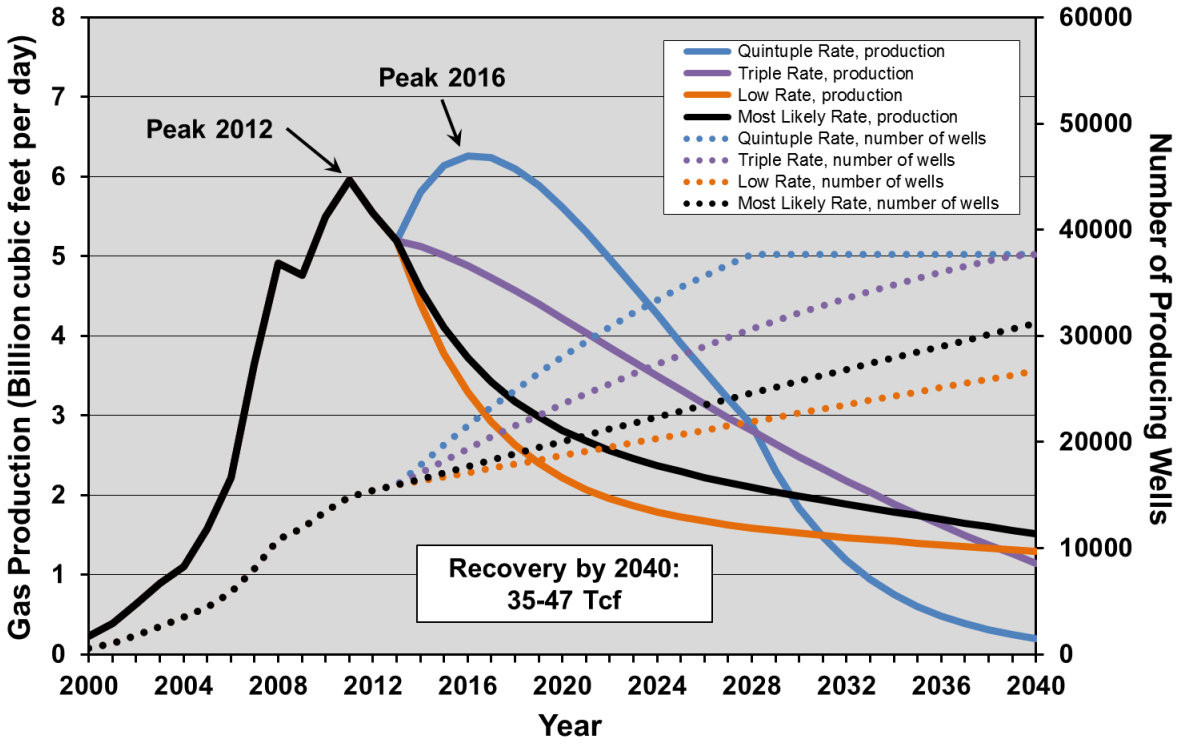

Figure 3-25. Four drilling rate scenarios of Barnett gas production (assuming 100% of the area is drillable at eight wells per square mile).[35]

"Most Likely Rate" scenario: drilling increases to 600 wells/year, declining to 500 wells/year.
"Low Rate" scenario: drilling continues at 400 wells/year, holding constant.
"Triple Rate" scenario: drilling increases to 1,200 wells/year, declining to 600 wells/year.
"Quintuple Rate" scenario: drilling increases to 2,000 wells/year, declining to 1,000 wells/year.
Although the peak month was December 2011, on a total year production basis the peak year is 2012.

[35] Data from Drillinginfo retrieved August 2014.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: The drilling rate declines after its initial increase as drilling moves into poorer quality locations. Total gas recovery by 2040 would be 39.2 trillion cubic feet, and drilling would continue beyond 2040.

2. LOW RATE scenario: Total gas recovery by 2040 would be 34.8 trillion cubic feet, and drilling would continue beyond 2040.

3. TRIPLE RATE scenario: Total gas recovery by 2040 would be 45.6 trillion cubic feet, and drilling would end by 2039.

4. QUINTUPLE RATE scenario: The current production decline would be reversed and grow to a new peak in 2016; however, drilling locations would run out by 2028 followed by a steep production decline, making the supply situation much worse in later years than in the "Most Likely Rate" scenario. Total gas recovery by 2040 would be 46.7trillion cubic feet.

Both the recovery of 39.2 trillion cubic feet by 2040 in the "Most Likely Rate" scenario and the recovery of 46.7 trillion cubic feet in the "Quintuple Rate" scenario agree well with the University of Texas study, which calculates an ultimate recovery of 45 Tcf for the Barnett.[36] (They continue their analysis through 2050 for their ultimate recovery estimate, hence there is almost perfect agreement with the "Most Likely Rate" scenario given that considerably more gas would be recovered after 2040).

[36] Browning et al., 2014, *Oil and Gas Journal*, "BARNETT SHALE MODEL-2 (Conclusion): Barnett study determines full-field reserves, production forecast," http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html.

3.3.1.7 Comparison to EIA Forecast

Figure 3-26 illustrates the EIA's projection for Barnett production through 2040 compared to the "Most Likely Rate" scenario. The EIA projects a recovery by 2040 of 53.3 Tcf to meet its reference case forecast (44.4 Tcf between 2012 and 2040). Not only is this far higher than the projections of this report and the University of Texas study, it *projects a new high in production in 2040*, which implies very considerable future production after 2040. Furthermore, this amounts to *the complete recovery* of all of the EIA's estimated 20.3 Tcf of proved reserves by 2040[37] plus 23.7 Tcf of unproved resources (44 Tcf in total).[38] This strains credibility to the limit; how can all the proved and unproved resources and reserves be extracted and still have production at all-time highs in 2040?

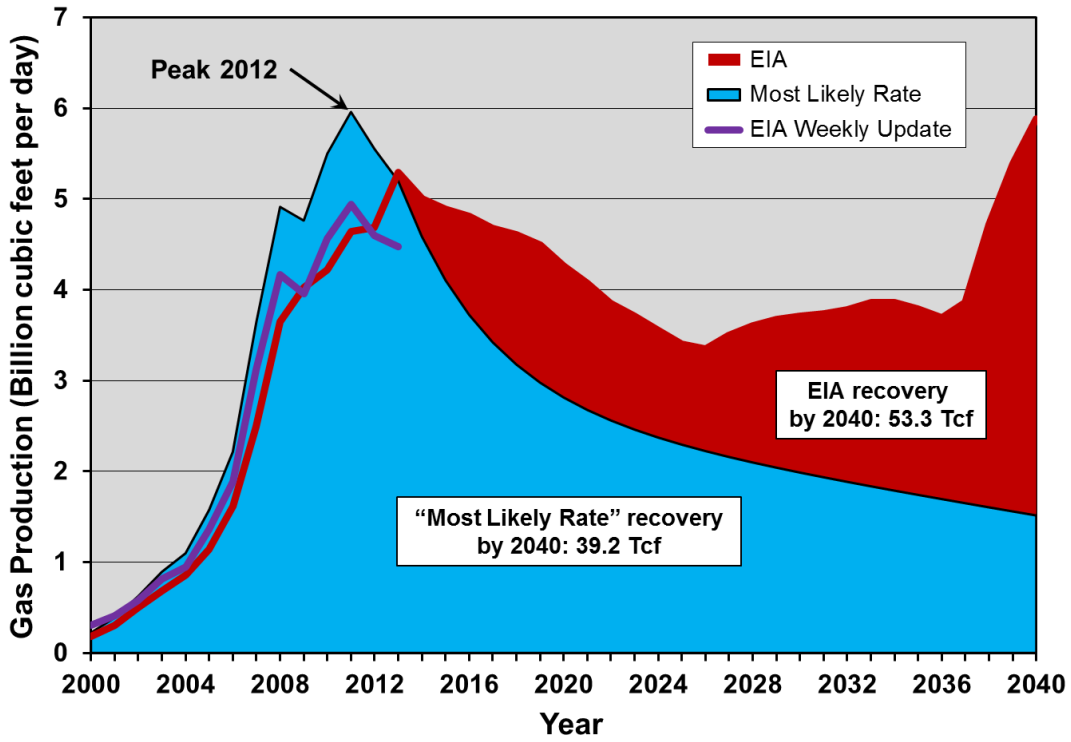

Figure 3-26. "Most Likely Rate" scenario of Barnett gas production compared to the EIA reference case, 2000 to 2040.[39]

The EIA assumes the Barnett will reach a new all-time high by 2040 after producing all proved reserves and unproved resources, and presumably produce a great deal more gas in the post-2040 period. Note that although the peak month was December 2011, on a total year production basis the peak year is 2012. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis. The EIA production data are also shown on a dry basis; the difference between the EIA's data and the Drillinginfo data used in this report may be due to the shrinkage factor between "raw" and "dry" gas.[40]

[37] EIA, 2014, Principal shale gas plays: natural gas production and proved reserves, 2011-12, http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls.
[38] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[39] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[40] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly

3.3.1.8 Barnett Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen markedly in the Barnett due to gas prices and to saturation of sweet spots with wells.

2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of 384 wells per year are far below the level of 1,161 wells per year required to maintain production, which would require the investment of $4 billion per year for drilling (assuming $3.5 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Maintaining or growing production in the Barnett would require much higher gas prices to justify higher drilling rates.

3. Quintupling current drilling rates could reverse the current production decline and raise production to a new peak in the 2016 timeframe, but would increase cumulative recovery only by 19% by 2040 and wouldn't change the ultimate recovery of the play. Increasing drilling rates effectively recovers the gas sooner, making the supply situation worse later.

4. The projected recovery of 39.2 Tcf by 2040 in this report's "Most Likely Rate" scenario is comparable to the University of Texas study's ultimate recovery of 45 Tcf (given that considerable gas would be recovered in the "Most Likely Rate" scenario after 2040).[41] Both are significantly less than the EIA's reference case projection of 53.3 Tcf by 2040.

5. This report's projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require much higher gas prices to be economic. Failure to maintain drilling rates will result in a steeper drop off in production.

6. More than double the current number of producing wells will need to be drilled to meet the production projection of the "Most Likely Rate" scenario over the next several decades.

7. The EIA projection for future Barnett gas production included in its reference case forecast for AEO 2014[42] strains credibility to the limit. It is highly unlikely to be realized, especially at the gas prices the EIA forecasts.[43]

[41] Browning et al., 2014, *Oil and Gas Journal*, "BARNETT SHALE MODEL-2 (Conclusion): Barnett study determines full-field reserves, production forecast," http://www.ogj.com/articles/print/volume-111/issue-9/drilling-production/barnett-study-determines-full-field-reserves.html.
[42] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[43] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/.

3.3.2 Haynesville Play

The EIA forecasts recovery of 102 Tcf of gas from the Haynesville play by 2040. The analysis of actual production data presented below suggests that this forecast is highly unlikely to be realized.

The Haynesville play was discovered in 2007 and production rapidly increased until it became the largest shale gas play in the U.S. at its peak in early 2012. Figure 3-27 illustrates the distribution of wells as of early 2014. Over 3,500 wells have been drilled to date, of which 3,274 were producing at the time of writing. The play covers parts of 16 counties although most of the drilling is concentrated in Caddo, DeSoto, and Red River parishes in Louisiana and Panola County in east Texas.

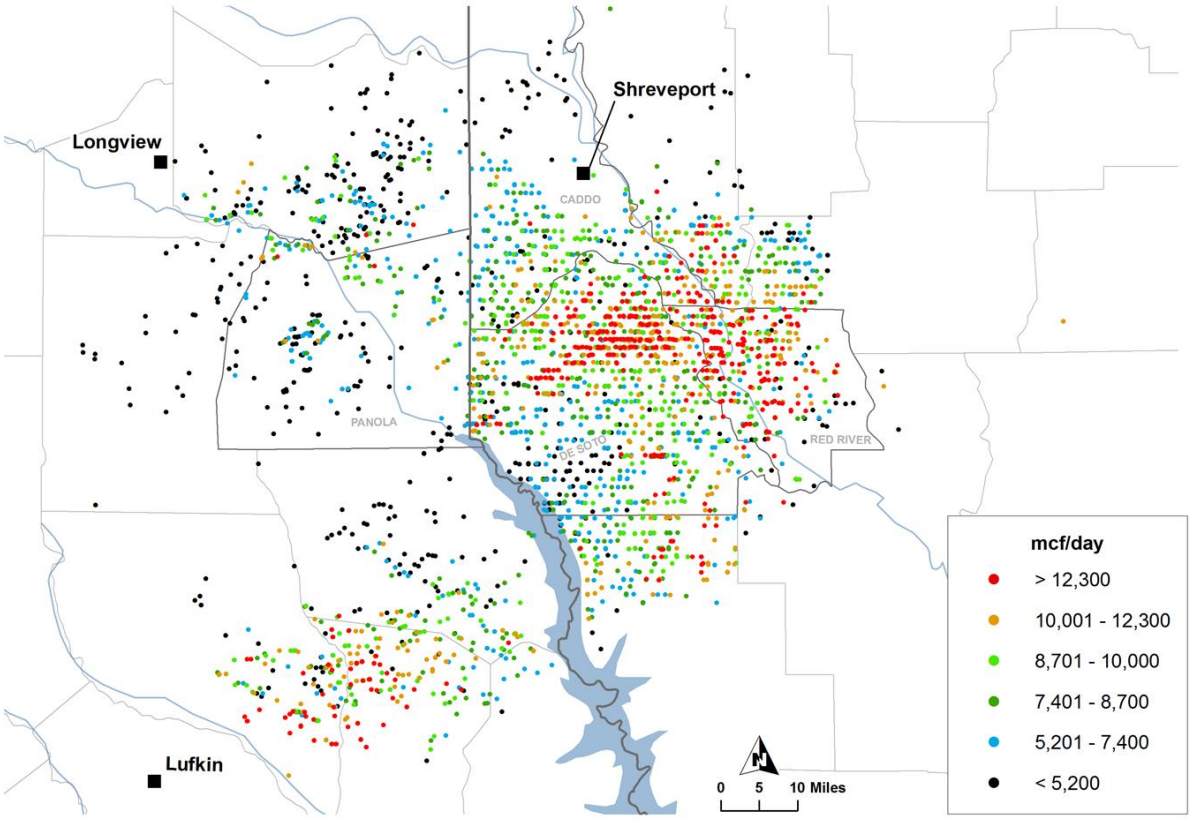

Figure 3-27. Distribution of wells in the Haynesville play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).[44]

Well IPs are categorized approximately by percentile; see Appendix.

[44] Data from Drillinginfo retrieved April 2014.

Production in the Haynesville peaked at more than 7 billion cubic feet per day in January 2012 as illustrated in Figure 3-28. Ninety-five percent of current production is from horizontal fracked wells. Horizontal drilling grew from virtually nothing in 2008 to a peak rate of 1,050 wells per year in mid-2011. It has since fallen to 215 wells per year, which is insufficient to offset field decline. Drilling rates required to keep production flat at current production levels are about 400 wells per year.

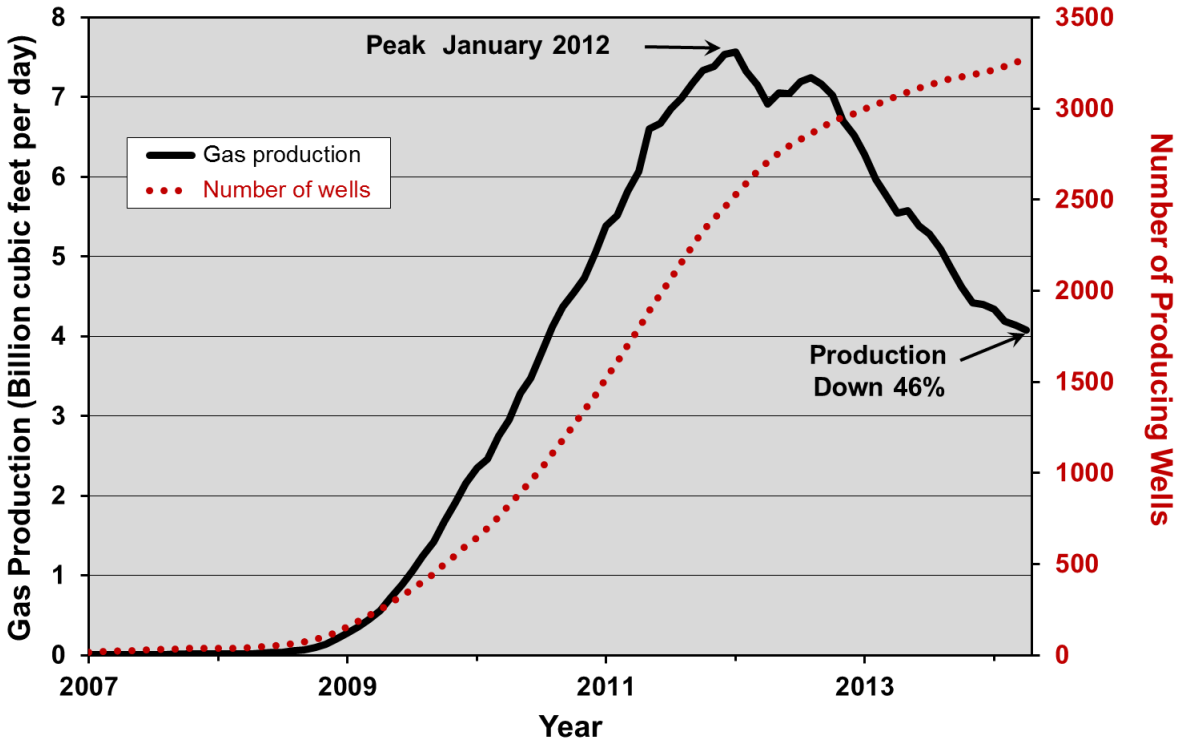

Figure 3-28. Haynesville play shale gas production and number of producing wells, 2007 to 2014.[45]

Gas production data are provided on a "raw gas" basis.

[45] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

Although vertical and directional wells played a role in the early development of the Haynesville play and still produce some oil and gas, new wells are predominantly horizontal. There are still 417 producing vertical and directional wells at the time of writing, or 14% of the 3,274 producing wells in the play, yet they produce less than 5% of gas output. Production by well type is illustrated in Figure 3-29. Very few vertical/directional wells are being drilled today—the future of the play lies in horizontal fracked wells.

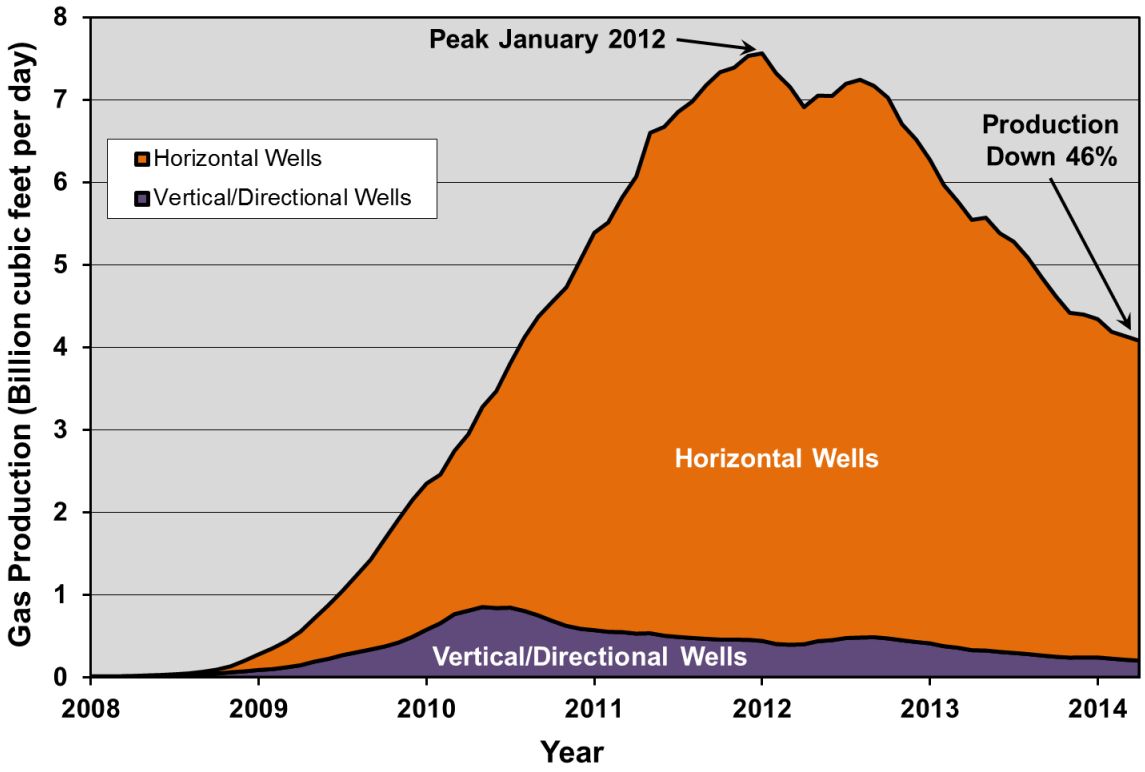

Figure 3-29. Gas production from the Haynesville play by well type, 2008 to 2014.[46]

[46] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

3.3.2.1 Well Decline

The first key fundamental in determining the life cycle of Haynesville production is the *well decline rate*. Haynesville wells exhibit high decline rates in common with all shale plays. Figure 3-30 illustrates the average decline rate of the most recent Haynesville horizontal and vertical/directional wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life is 88%, one of the highest of the plays analyzed. As can be seen, vertical/directional wells have lower productivity than horizontal wells and hence are being phased out.

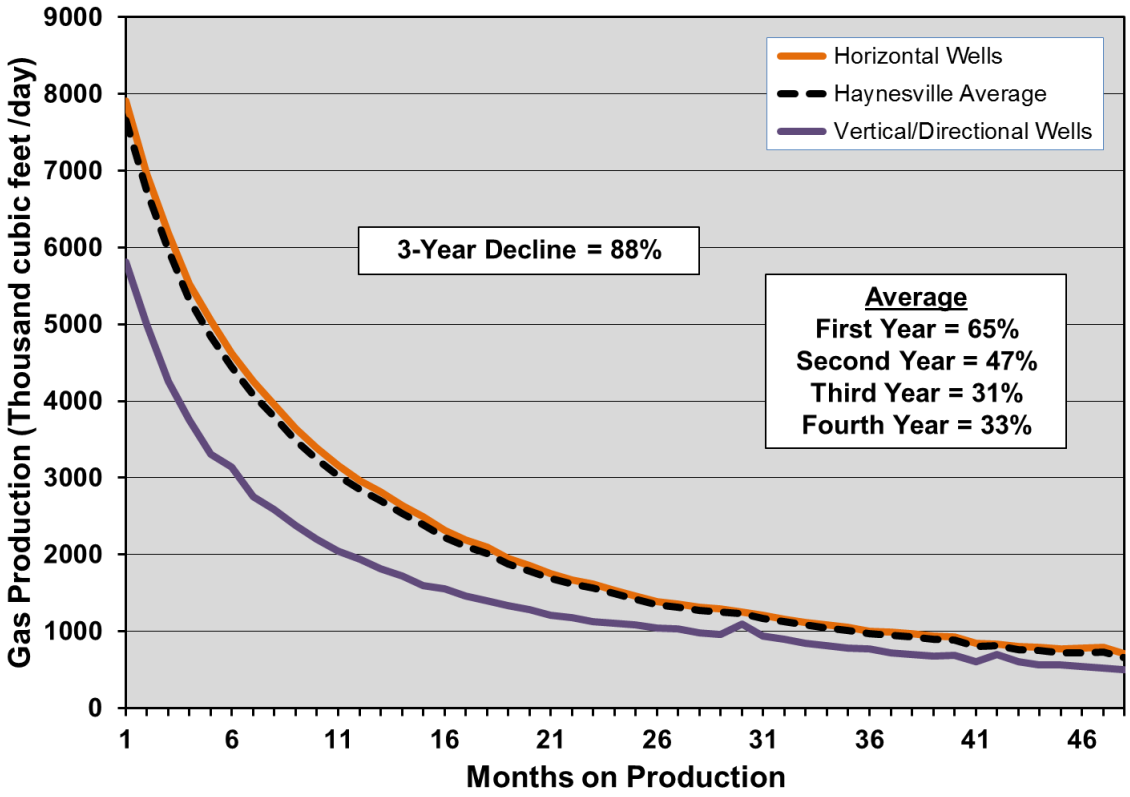

Figure 3-30. Average decline profile for gas wells in the Haynesville play.[47]

Decline profile is based on all shale gas wells drilled since 2009.

[47] Data from Drillinginfo retrieved August 2014.

3.3.2.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in a year in the Haynesville without more drilling. Figure 3-31 illustrates production from the 2,600 horizontal wells drilled prior to 2013. The first-year decline is 49%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. It is also one of the highest field decline rates observed in any shale field. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, approximately 400 new wells each year would be required to offset field decline at current production levels. At an average cost of $9 million per well[48], this would represent a capital input of about $3.6 billion per year, exclusive of leasing and other ancillary costs, just to keep production flat at 2014 levels.

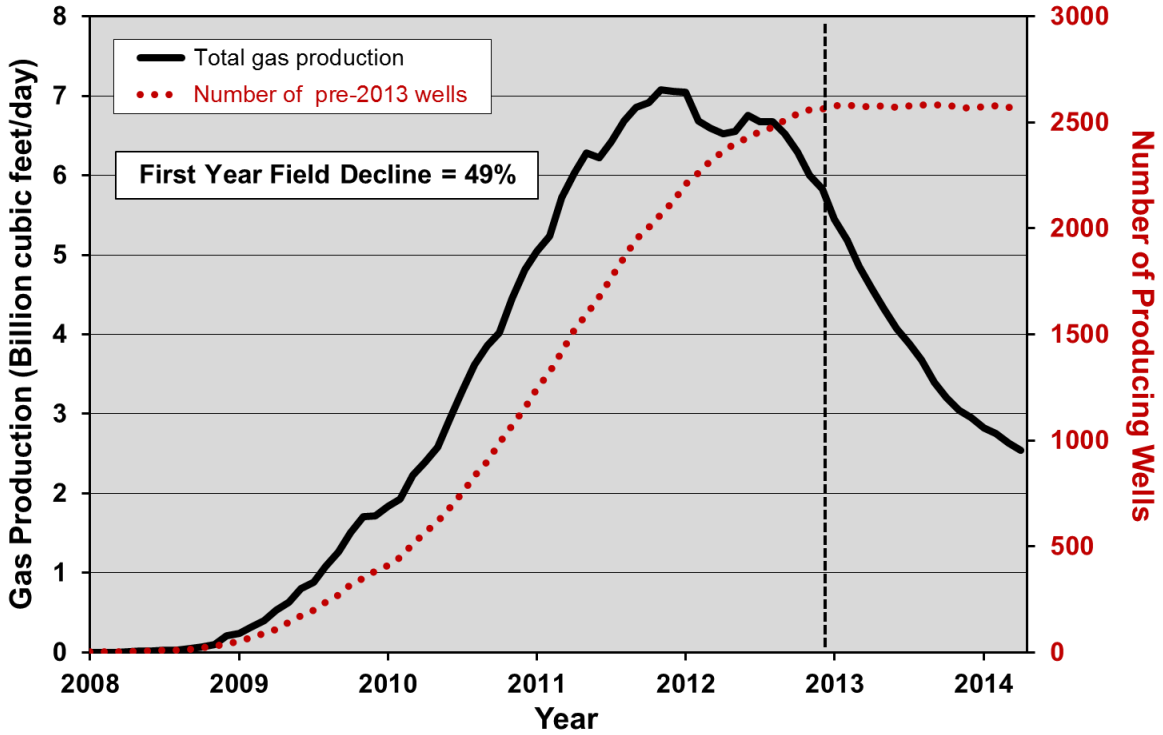

Figure 3-31. Production rate and number of horizontal shale gas wells drilled in the Haynesville play prior to 2013, 2008 to 2014.[49]

This defines the field decline for the Haynesville play, which is 49% per year (only production from horizontal wells is analyzed as few vertical/directional wells are likely to be drilled in the future).

[48] Mark J. Kaiser, June 2014, *Oil and Gas Journal*, "HAYNESVILLE UPDATE—2: North Louisiana drilling costs vary slightly 2007-12," http://www.ogj.com/articles/print/volume-112/issue-1/exploration-development/north-louisiana-drilling-costs-vary-slightly-2007-12.html.
[49] Data from Drillinginfo retrieved August 2014.

3.3.2.3 Well Quality

The third key fundamental is the *average well quality* by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, and improvements in average well quality appear to have ended in the Haynesville. The average first-year production rate of Haynesville wells has been flat over the past year after rising significantly in the early years of the play, as illustrated in Figure 3-32. This is clear evidence that geology is winning out over technology, as drilling moves into lower-quality locations (as investigated further below), given that operators tend to apply more sophisticated technology over time.

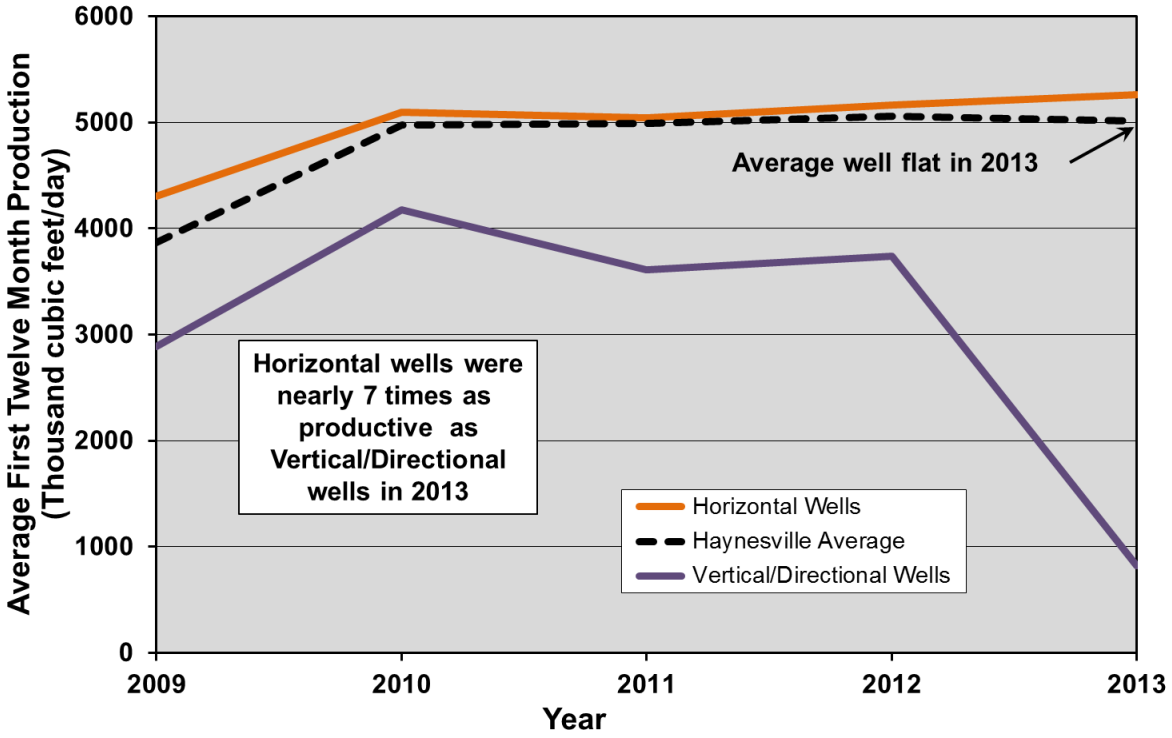

Figure 3-32. Average first-year production rates for Haynesville horizontal and vertical/directional gas wells, 2009 to 2013.[50]

Average well quality is flat in the most recent year after rising significantly in the early years of the play.

[50] Data from Drillinginfo retrieved August 2014.

Another measure of well quality is cumulative production and well life. Nearly 5% of the wells that have been drilled in the Haynesville are no longer productive. Figure 3-33 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 21 months and a mean cumulative production of 1.1 billion cubic feet, many of these wells would be economic losers, although wells that produced more than three billion cubic feet were likely economic despite their short lifespan.

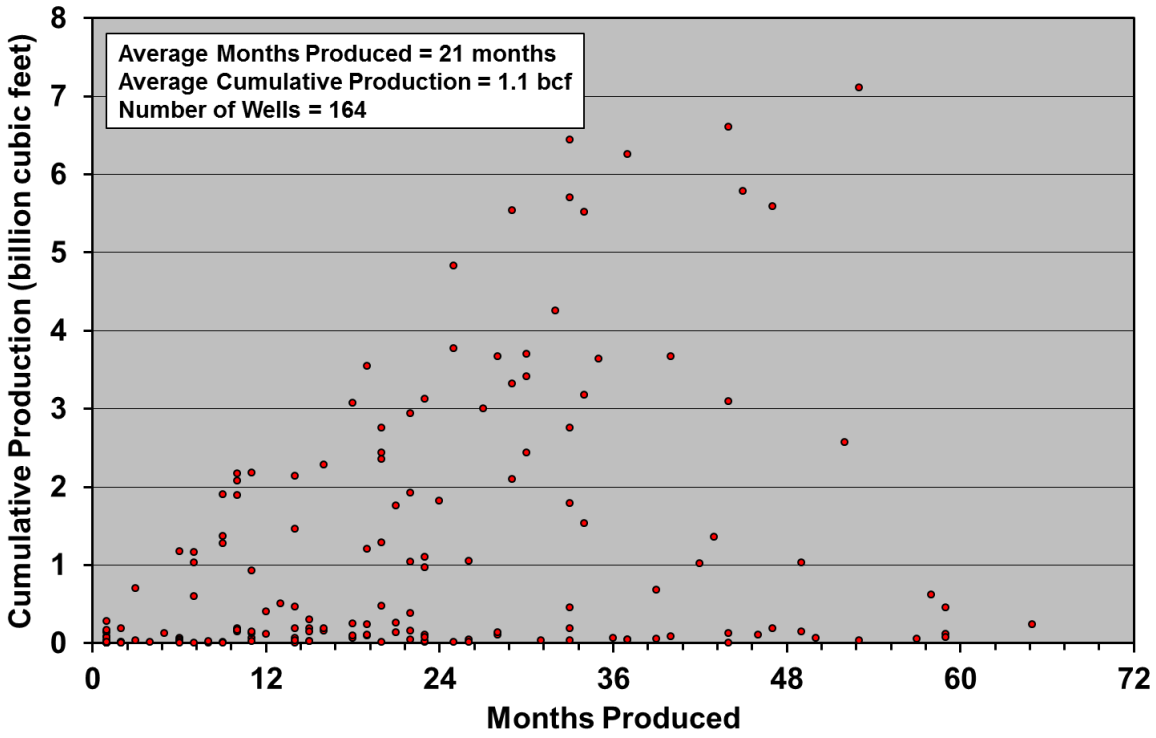

Figure 3-33. Cumulative gas production and length of time produced for Haynesville wells that were not producing as of February 2014.[51]

These well constitute nearly 5% of all horizontal wells drilled; many would be economic failures, given the mean life of 21 months and average cumulative production of 1.1 billion cubic feet when production ended.

[51] Data from Drillinginfo retrieved August 2014.

Figure 3-34 illustrates the cumulative production of all wells that were producing in the Haynesville in March 2014. Roughly 18% of the wells have produced more than 4 billion cubic feet over a relatively short lifespan and are clearly economic; however, 33% have yet to produce 2 billion cubic feet. The average well has produced 2.8 billion cubic feet over a lifespan averaging 38 months. Just 8% of these wells are more than 5 years old.

The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer; this is conjectural at this point given the lack of long-term production data.

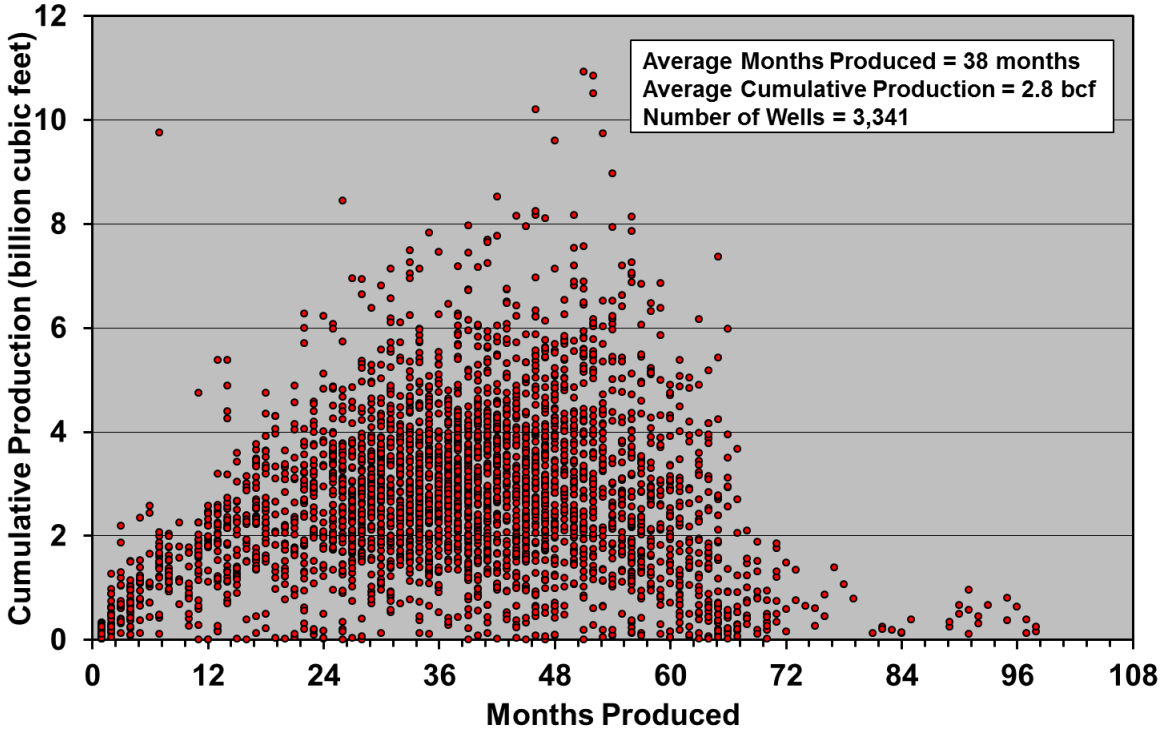

Figure 3-34. Cumulative gas production and length of time produced for Haynesville wells that were producing as of March 2014.[52]

These well constitute 95% of all wells drilled. Very few wells are greater than five years old, with a mean age of 38 months and a mean cumulative recovery of 2.8 billion cubic feet.

[52] Data from Drillinginfo retrieved August 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells is not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality, independent of age, is initial productivity (IP), which is often focused on by operators. Figure 3-35 illustrates the average daily output over the first six months of production for all wells in the Haynesville play (six month IP). Again, as with cumulative production, there are a few exceptional wells——3% produced more than 12 million cubic feet per day (MMcf/d)——but the average for all wells drilled since 2009 is 5.72 MMcf/d. Figure 3-27 illustrates the distribution of IPs in map form.

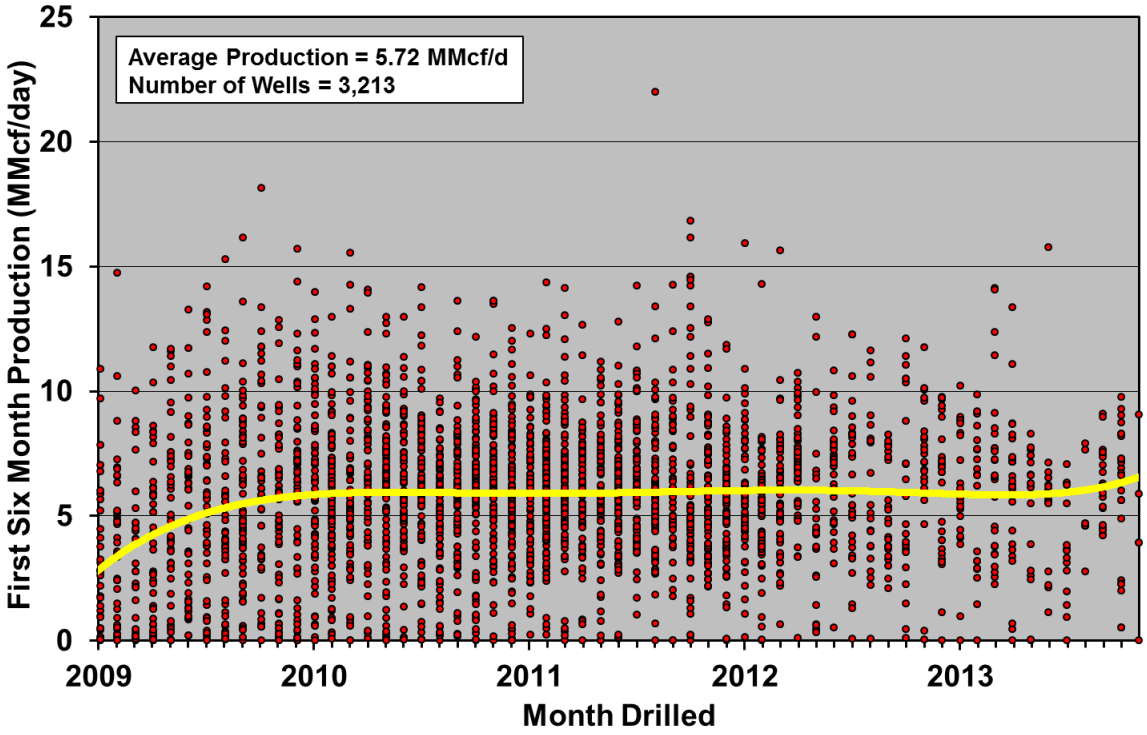

Figure 3-35. Average gas production over the first six months for all wells drilled in the Haynesville play, 2009 to 2014.[53]

Although there are a few exceptional wells, the average well produced 5.48 million cubic feet per day over this period. The trend line indicates mean productivity over time

[53] Data from Drillinginfo retrieved August 2014.

Different counties in the Haynesville display different well quality characteristics which are critical in determining the most likely production profile in the future. Figure 3-36, which illustrates production over time by county, shows that, as of April 2014, the top two counties produced 56% of the total, the top four produced 74%, and the remaining 12 counties produced just 26%.

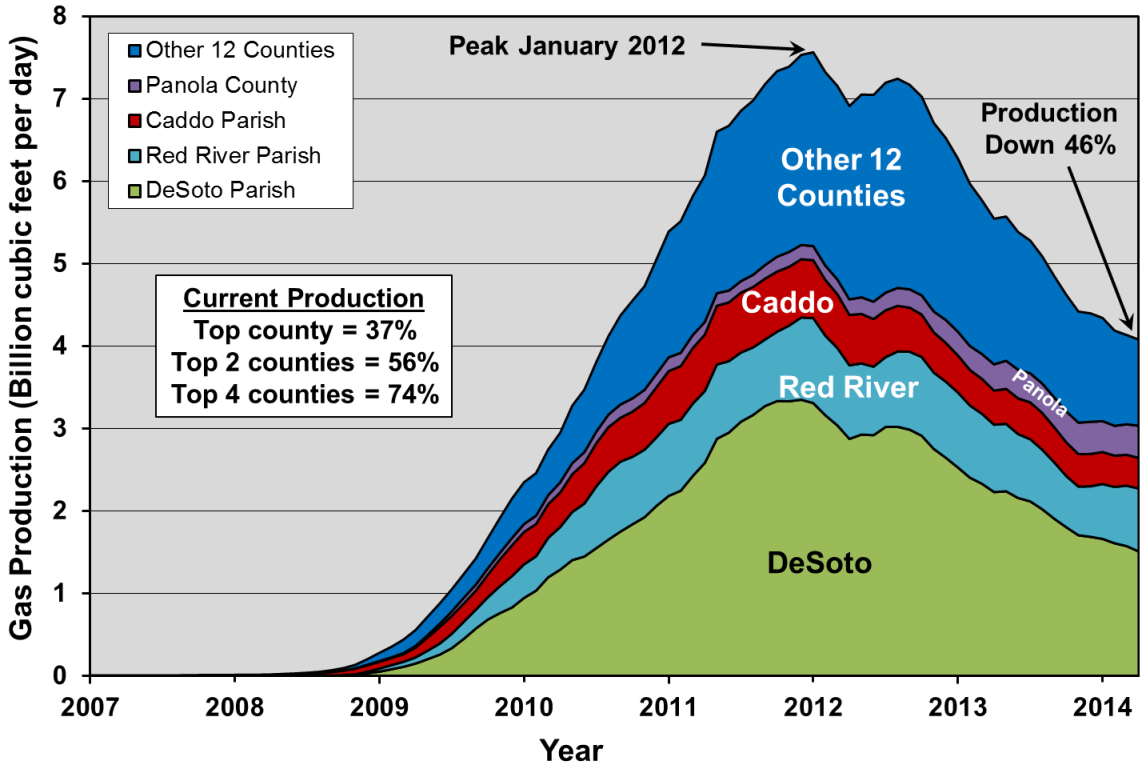

Figure 3-36. Gas production by county in the Haynesville play, 2007 through 2014.[54]
The top four counties produced 74% of production in April 2014.

[54] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-37, the top two counties have produced 56% of the gas and the top four have produced 70%. All of the counties except Panola in Texas have peaked although with increased drilling rates some could conceivably resume production growth. Production in the top county—DeSoto—is down 55% from peak and production in the other counties is down from 26% to 59%.

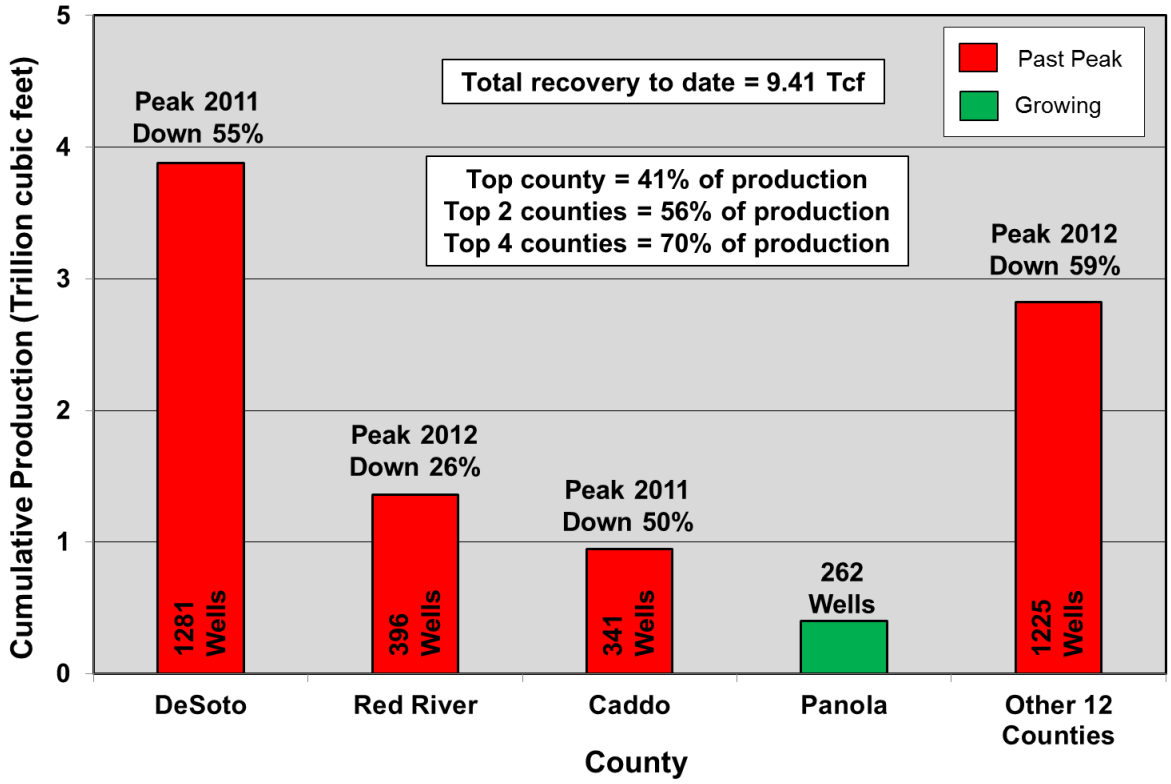

Figure 3-37. Cumulative gas production by county in the Haynesville play through 2014.
The top four counties have produced 70% of the 9.4 trillion cubic feet of gas produced to date.[55]

[55] Data from Drillinginfo retrieved August 2014.

The Haynesville also produces very limited amounts of natural gas liquids and oil. Most liquids production is not within the top four counties as illustrated in Figure 3-38. Some 1.5 million barrels of liquids have been produced since 2006, and although it has somewhat improved economics in marginal counties for gas production, in the big picture liquids production from the Haynesville is insignificant.

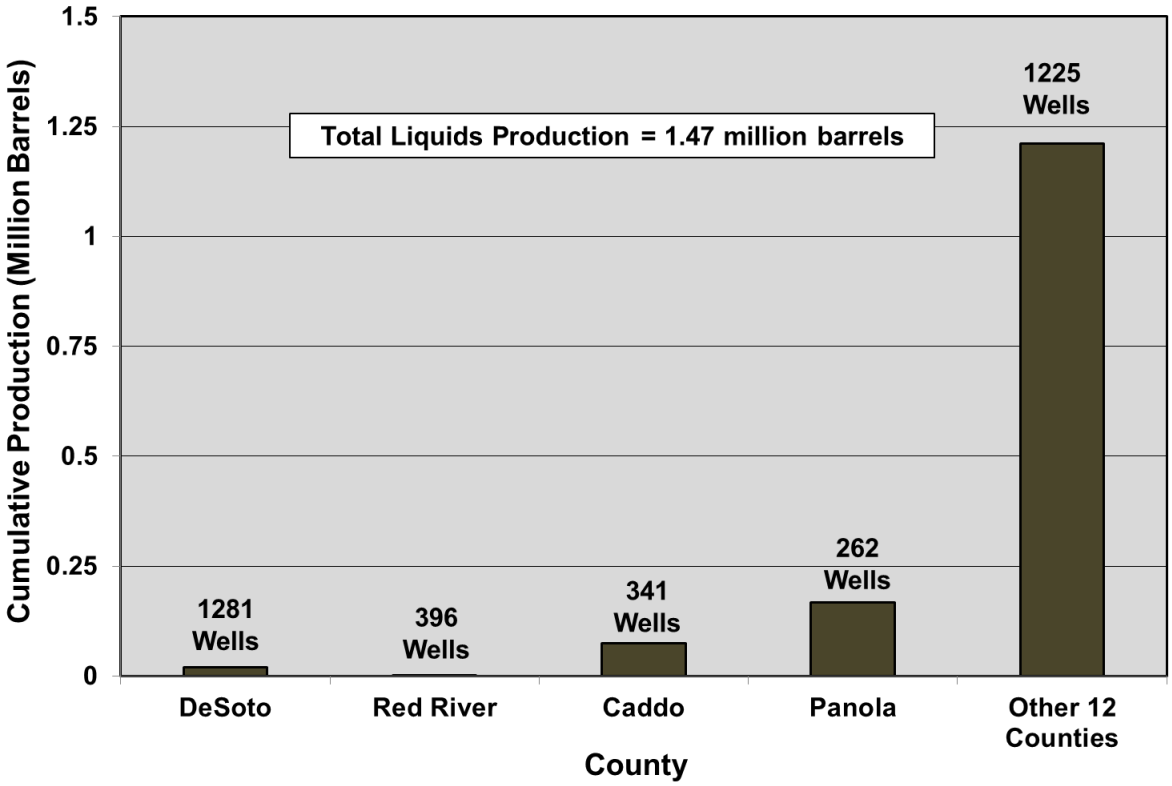

Figure 3-38. Cumulative liquids production by county in the Haynesville play through 2014.

The "other 12" counties account for 82% of the 1.5 million barrels produced to date.[56]

[56] Data from Drillinginfo retrieved August 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of $9 million or more each[57], not including leasing costs and other expenses. The areas of highest quality—the "core" or "sweet spots"—have now been well defined. Figure 3-39 illustrates average well decline curves by county, which are a measure of well quality. Initial well productivities (IPs) are more closely grouped than in the Barnett, however the top producing counties—DeSoto and Red River in Louisiana, —which are in steep decline—are significantly better than Panola County in Texas, which is the only county growing in production. There are still a significant number of locations in which to drill wells in the top producing counties, although the overall play area of the Haynesville is smaller than plays like the Barnett and is dwarfed by the Marcellus.[58]

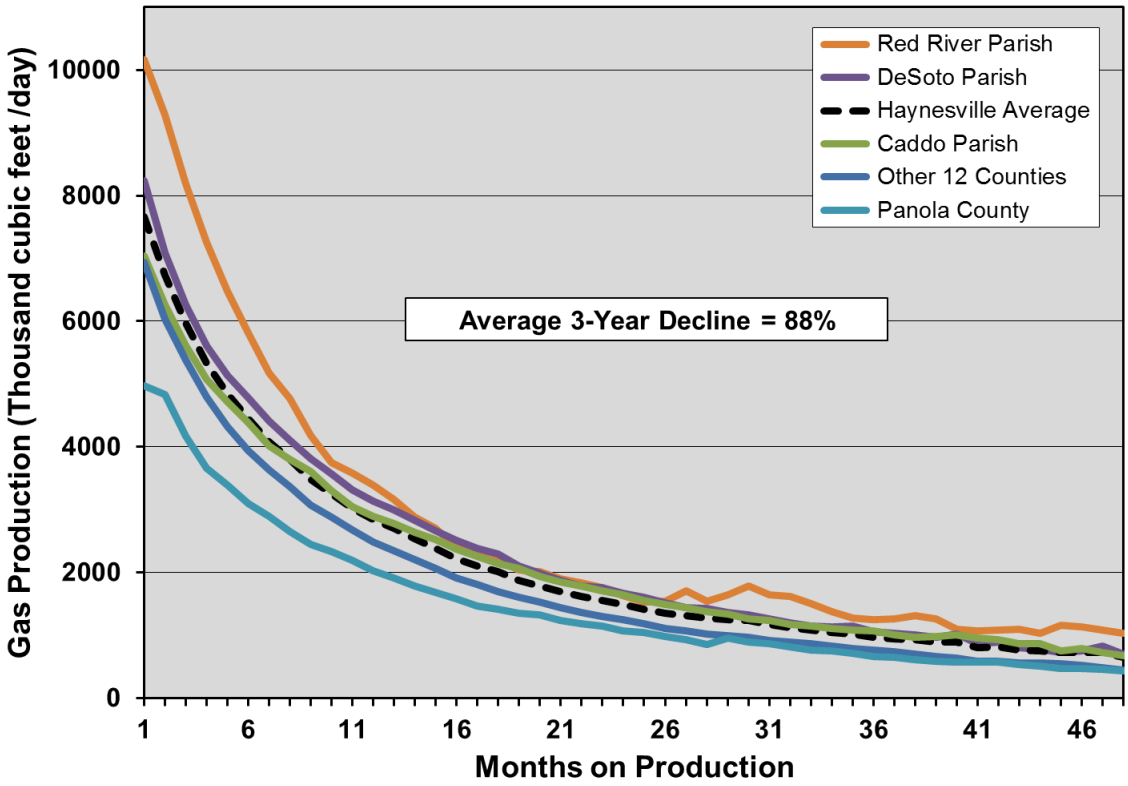

Figure 3-39. Average horizontal gas well decline profiles by county for the Haynesville play.

The top two counties, which have produced much of the gas in the Haynesville, are clearly superior.[59]

Another measure of well quality is "estimated ultimate recovery" or EUR—the amount of gas a well will recover over its lifetime. To be clear, no one knows what the lifespan of an average Haynesville well is, given that few of them are more than five years old (see Figure 3-33 and Figure 3-34), and some 5% of wells drilled have ceased production at an average age of under two years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-39, assuming well life spans of 30-50 years (as is typical for conventional wells), but so far this is speculation given the nature of the extremely low permeability

[57]Mark J. Kaiser, June 2014, *Oil and Gas Journal*, "HAYNESVILLE UPDATE—2: North Louisiana drilling costs vary slightly 2007-12," http://www.ogj.com/articles/print/volume-112/issue-1/exploration-development/north-louisiana-drilling-costs-vary-slightly-2007-12.html.
[58] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[59] Data from Drillinginfo retrieved August 2014.

reservoirs and the completion technologies used in the Haynesville. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-39, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-40 illustrates theoretical EURs by county for the Haynesville for comparative purposes of well quality. These range from 3.0 to 5.9 billion cubic feet per well, which agrees fairly well with the 3.14 to 3.71 billion cubic feet assumed by the EIA.[60] The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 70% and 78% of an average well's lifetime production occurs in the first four years.

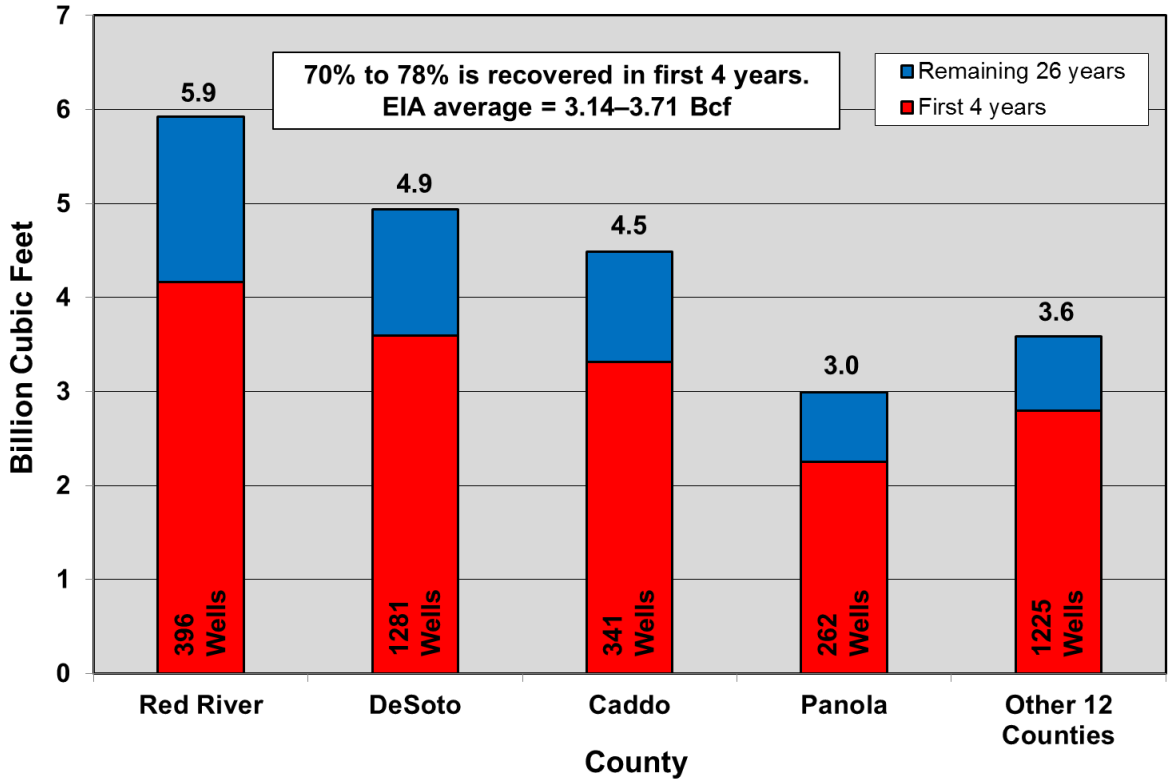

Figure 3-40. Estimated ultimate recovery of gas per well by county for the Haynesville play.[61]

EURs are based on average well decline profiles (Figure 3-39) and a terminal decline rate of 20%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

[60] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[61] Data from Drillinginfo retrieved August 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Figure 3-41 illustrates the average first-year production rate of wells by county. Notwithstanding significant gains in Red River Parish (which has the smallest prospective area of the top four counties), the average well quality is flat on average and is declining in Caddo Parish.

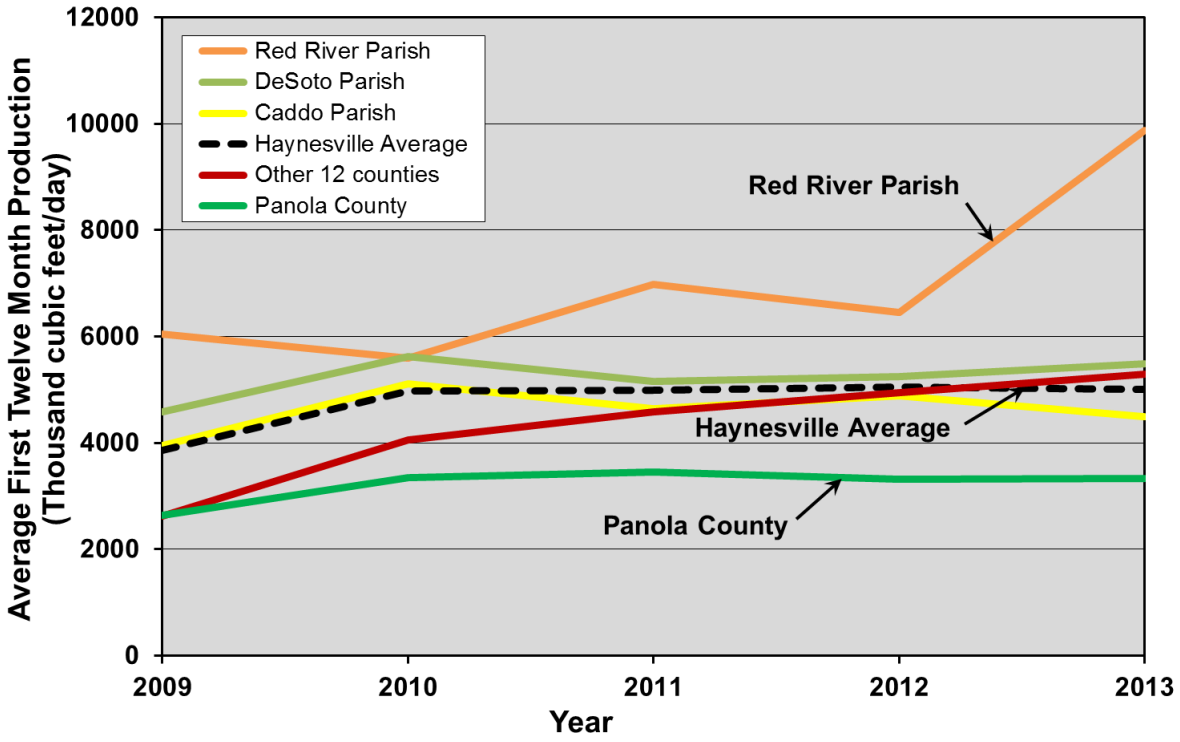

Figure 3-41. Average first year gas production rates of wells by county for the Haynesville play, 2009 to 2013.[62]

Well quality is rising significantly in Red River Parish but is flat on average for the play as a whole. Panola County, which is the only county in which production is rising, had first-year average well production of less than half that of Red River Parish in 2013.

[62] Data from Drillinginfo retrieved August 2014.

3.3.2.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Haynesville play. The EIA has estimated the total play area in Louisiana and Texas at 3,419 square miles and suggests this can be drilled at a well density of six per square mile, for a total of 20,511 wells. As 3,505 wells have already been drilled this leaves 17,006 yet-to-drill wells.

Table 3-2 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Haynesville play.

Parameter	County					Total
	Caddo	DeSoto	Panola	Red River	Other 12	
Production April 2014 (Bcf/d)	0.37	1.51	0.39	0.76	1.04	4.08
% of Field Production	9.1	37.1	9.6	18.7	25.6	100.0
Cumulative Gas (Tcf)	0.95	3.88	0.40	1.36	2.82	9.41
Cumulative Liquids (MMBBL)	0.07	0.02	0.17	0.00	1.21	1.47
Number of Wells	341	1281	262	396	1225	3505
Number of Producing Wells	326	1216	243	369	1120	3274
Average EUR per well (Bcf)	4.5	4.9	3	5.9	3.6	4.9
Field Decline (%)	34	50	52	49	50	49
3-Year Well Decline (%)	86	87	87	88	89	88
Peak Month	Sep-11	Dec-11	Rising	Jan-12	Jul-12	Jan-12
% Below Peak	50	55	Rising	29	59	46
Average First Year Production in 2013 (Mcf/d)	4492	5493	3330	9881	5286	5011
New Wells Needed to Offset Field Decline	28	138	61	38	99	399
Area in square miles	937	895	801	402	8000	11035
% Prospective	35	90	90	80	15	31
Net square miles	328	806	721	322	1243	3419
Well Density per square mile	1.04	1.59	0.36	1.23	0.99	1.03
Additional locations to 6/sq. Mile	1627	3552	4063	1534	6230	17006
Population	254969	26656	22756	9091	N/A	N/A
Total Wells 6/sq. Mile	1968	4833	4325	1930	7455	20511
Total Producing Wells 6/sq. Mile	1952	4768	4306	1902	7351	20280

Table 3-2. Parameters for projecting Haynesville production, by county.

Area in square miles under "Other" is estimated.

3.3.2.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-42 illustrates the historical drilling rates in the Haynesville. Horizontal drilling rates peaked in 2011 at 1,051 wells per year and have fallen to current levels of about 200 wells per year. Current drilling rates are only half the 400 wells per year required to maintain production at current levels, hence each new well drilled now serves only to slow the overall production decline of the play. It appears that the drilling rate is stabilizing at 200 wells per year so production will keep falling until this number of wells is sufficient to offset field decline.

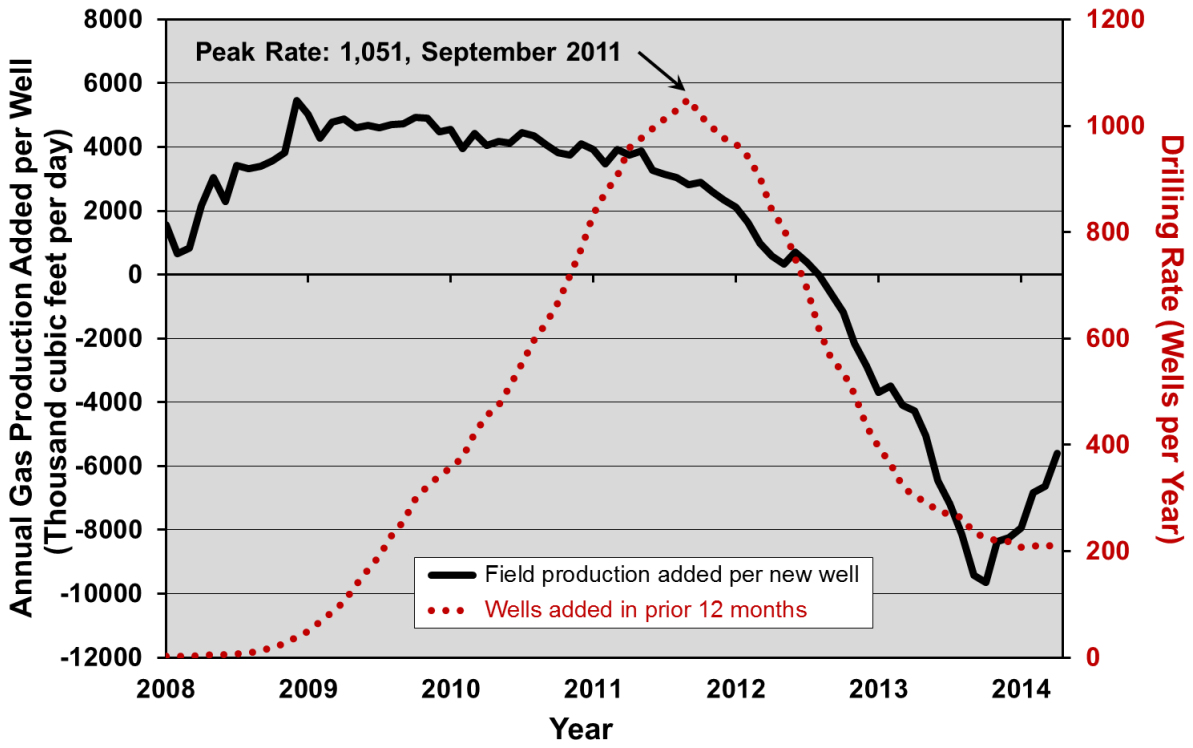

Figure 3-42. Annual gas production added per new horizontal well and annual drilling rate and in the Haynesville play, 2008 through 2014.[63]

Drilling rate peaked in 2011 and is now far below the level needed to keep production flat, hence each new well now only serves to slow the overall production decline of the play.

[63] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

3.3.2.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Haynesville play were developed to illustrate the effects of changing the rate of drilling. Figure 3-43 illustrates the production profiles of three drilling rate scenarios if 100% of the prospective play area is drillable at six wells per square mile (the EIA estimate of well density as well as drillable area[64]). These scenarios are:

1. MOST LIKELY RATE scenario: Drilling increases by 50% from the current rate to 300 wells per year.
2. LOW RATE scenario: Drilling remains at the current rate of 200 wells per year and holds constant.
3. HIGH RATE scenario: Drilling more than doubles to 500 wells per year, then gradually declines to 300 wells per year.

In all of these scenarios there are sufficient drilling locations to maintain drilling beyond 2040.

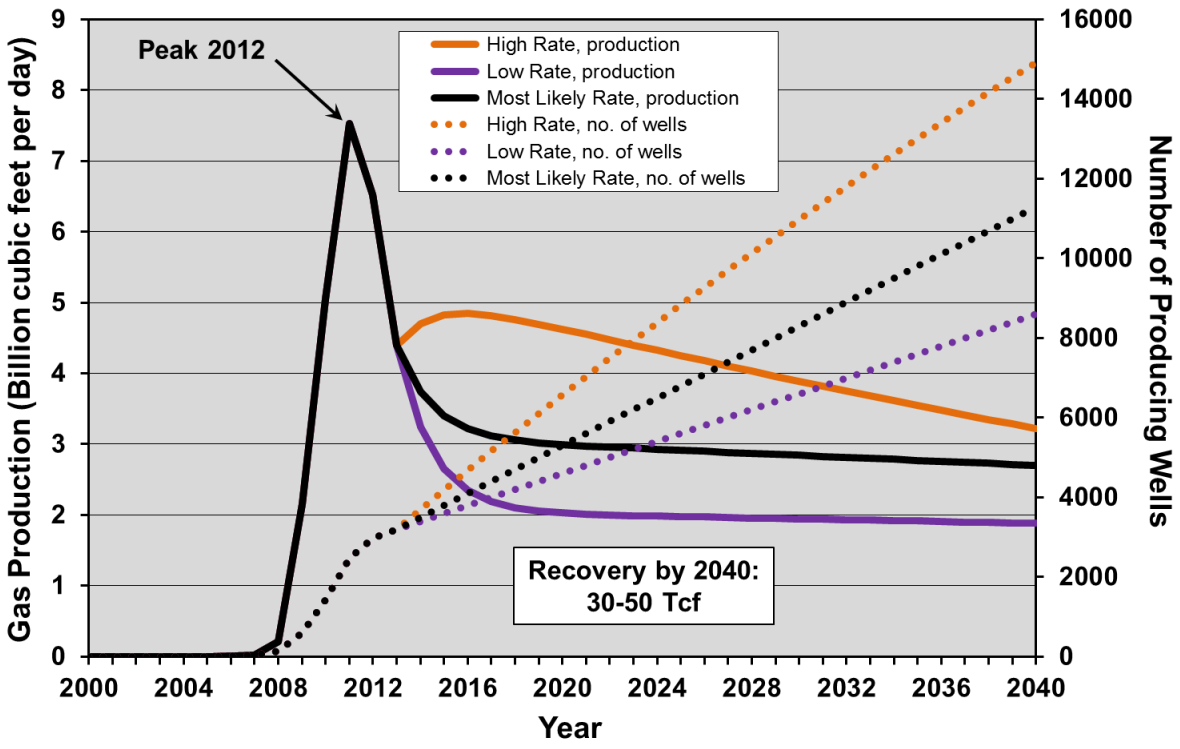

Figure 3-43. Three drilling rate scenarios of Haynesville gas production (assuming 100% of the area is drillable at six wells per square mile).[65]

"Most Likely Rate" scenario: drilling increases to 300 wells/year, holding constant.
"Low Rate" scenario: drilling holds constant at 200 wells/year.
"High Rate" scenario: drilling increases to 500 wells/year, declining to 300 wells/year.

[64] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[65] Data from Drillinginfo retrieved August 2014.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: Production will continue to fall until it stabilizes at about 3 billion cubic feet per day—less than half of the Haynesville's peak rate. Total gas recovery by 2040 would be 38.4 trillion cubic feet and drilling would continue beyond 2040.

2. LOW RATE scenario: Production will continue to fall until stabilizing at about 2 billion cubic feet per day—less than a third of peak production rates. Total gas recovery by 2040 would be 29.7 trillion cubic feet and drilling would continue beyond 2040.

3. HIGH RATE scenario: Production decline in the Haynesville could be temporarily reversed and grow somewhat in the short term. Total gas recovery by 2040 would be 49.8 trillion cubic feet and drilling would continue beyond 2040.

Total recovery of 38.4 trillion cubic feet by 2040 in the "Most Likely Rate" scenario is four times what has been recovered so far in the Haynesville, and in the "High Rate" scenario as much as 49.8 trillion cubic feet could be recovered; however, production rates would be far below those projected by the EIA for the Haynesville play.

3.3.2.7 Comparison to EIA Forecast

Figure 3-44 illustrates the EIA's projection for Haynesville production through 2040 compared to the "Most Likely Rate" scenario. The EIA projects a recovery by 2040 of 102 Tcf to meet its reference case forecast, and projects a new peak of the play in 2027 at a level far higher than the early-2012 peak. This represents the recovery of 110% of both proved reserves[66] and unproved resources.[67] Furthermore, the EIA projects that production in 2040 will be higher than the 2012 peak, suggesting that vastly more gas will be recovered beyond 2040. This strains credibility to the limit. How can all the proved and unproved resources and reserves be extracted and still have production above all-time highs in 2040?

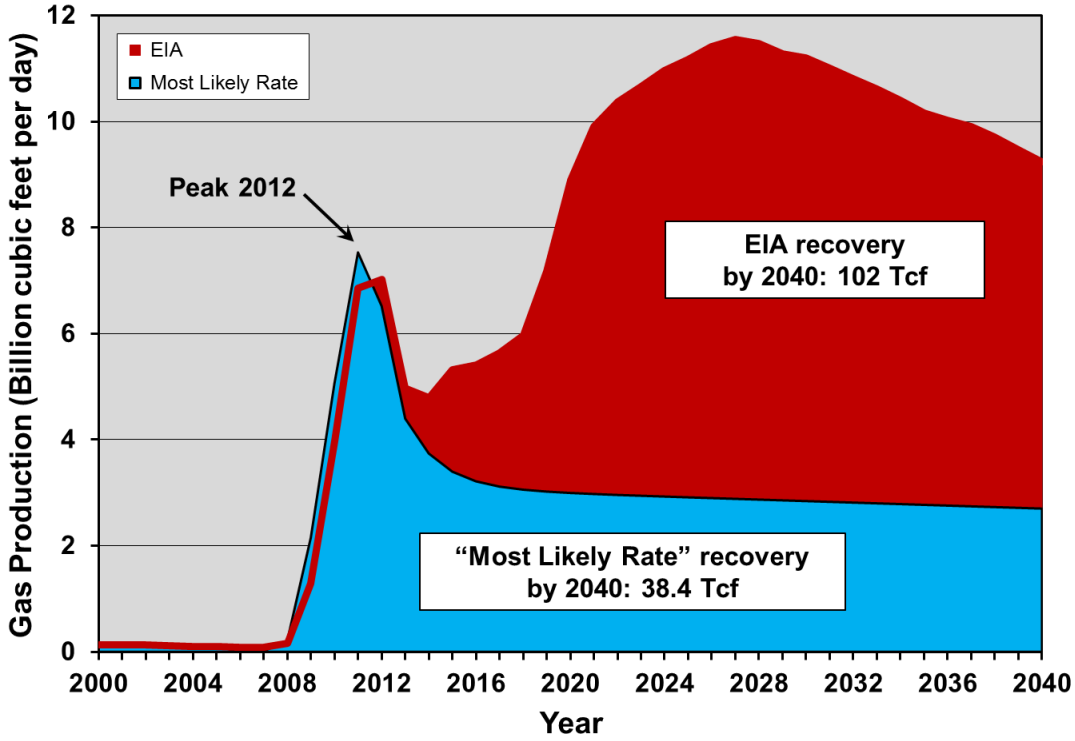

Figure 3-44. "Most Likely Rate" scenario of Haynesville gas production compared to the EIA reference case, 2000 to 2040.[68]

The EIA assumes the Haynesville will reach a new all-time high by 2027, produce 110% of proved reserves and unproved resources by 2040, and presumably produce a great deal more gas in the post-2040 period. . The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

[66] EIA, 2014, "Principal shale gas plays: natural gas production and proved reserves, 2011-12," http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls.
[67] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[68] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

3.3.2.8 Haynesville Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen markedly in the Haynesville due to gas prices, although there are still locations to drill in the sweet spots.

2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. The Haynesville field decline rate of 49% is the highest observed in any shale gas play. Current drilling rates of 200 wells per year are just half of the level required to maintain production. Maintaining production at current levels would require the investment of $3.6 billion per year for drilling (assuming $9 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Maintaining or growing production in the Haynesville would require considerably higher gas prices to justify higher drilling rates.

3. More than doubling current drilling rates could reverse the current production decline temporarily and raise production somewhat, but nowhere near its early 2012 peak. Cumulative recovery by 2040 in this high drilling rate scenario would be increased by 30% over the "Most Likely Rate" scenario but would still be less than half that projected by the EIA in its reference case.

4. The projected recovery of 38.4 Tcf by 2040 in the "Most Likely Rate" scenario represents four times as much gas as has been recovered so far from the Haynesville, yet is only 38% of the 102 Tcf projected by the EIA in its reference case forecast.

5. This report's projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require higher gas prices to be economic. Failure to increase current drilling rates will result in a steeper drop off in production.

6. Nearly four times the current number of wells will need to be drilled to meet the production projection of the "Most Likely Rate" scenario by 2040.

7. The EIA projection for future Haynesville gas production included in its reference case forecast for AEO 2014,[69] which forecasts recovery of 110% of proved reserves plus unproved resources by 2040, strains credibility to the limit. It is highly unlikely to be realized, especially at the gas prices the EIA forecasts.[70]

[69] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[70] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/.

3.3.3 Fayetteville Play

The EIA forecasts recovery of 41.5 Tcf of gas from the Fayetteville play by 2040. The analysis of actual production data presented below suggests that this forecast is highly unlikely to be realized.

The Fayetteville play was discovered in Arkansas in 2005 and production grew rapidly until its peak in late 2012. Since that time it has been on an undulating production plateau with production down just over 2% since peak. Figure 3-45 illustrates the distribution of wells as of early 2014. Nearly 5,300 wells have been drilled to date of which 4,914 were producing at the time of writing. The play covers parts of 10 counties although most of the drilling is concentrated in Cleburne, Conway, Faulkner, Van Buren and White counties.

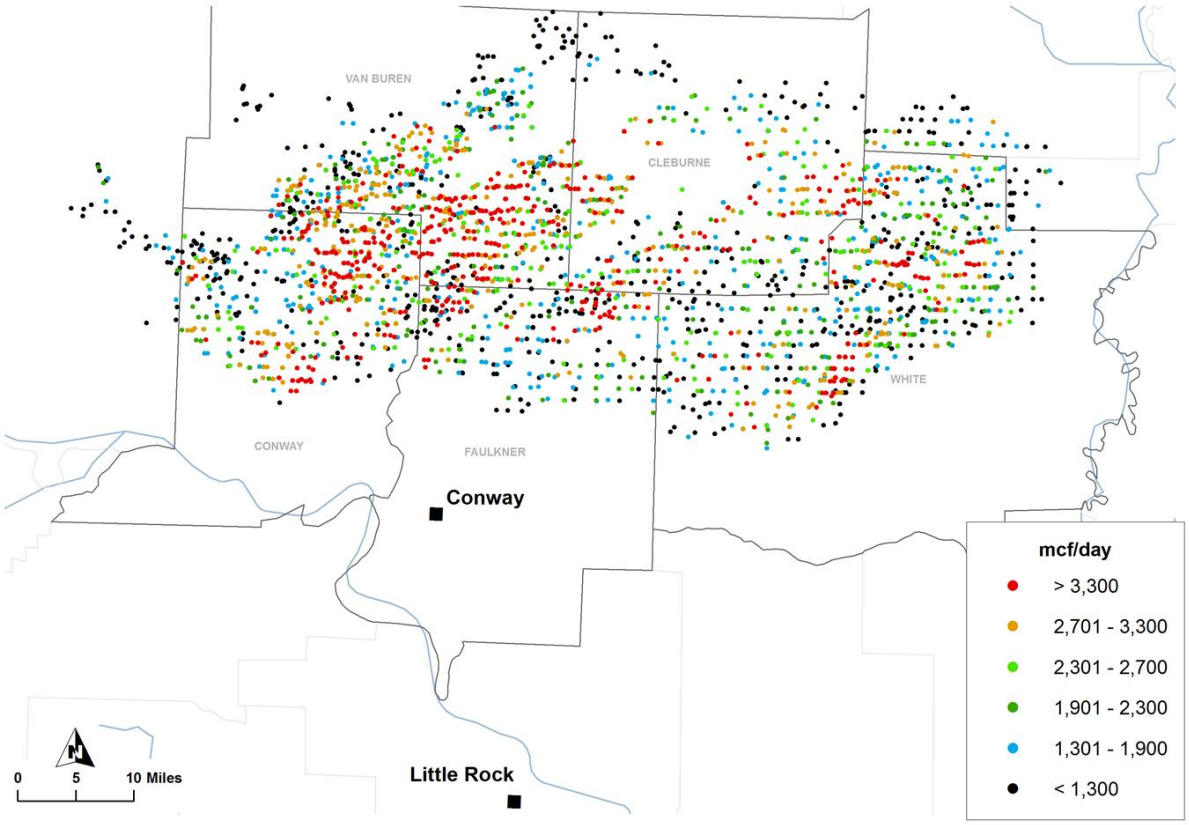

Figure 3-45. Distribution of wells in the Fayetteville play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).[71]

Well IPs are categorized approximately by percentile; see Appendix.

[71] Data from Drillinginfo retrieved April 2014.

Production in the Fayetteville peaked at nearly 3 billion cubic feet per day in December 2012 as illustrated in Figure 3-46. Ninety-nine percent of current production is from horizontal fracked wells. Horizontal drilling grew from virtually nothing in 2006 to a peak rate of nearly 900 wells per year in late-2010. It has since fallen to 500 wells per year, which is insufficient to offset field decline. Drilling rates required to keep production flat at current production levels are about 600 wells per year.

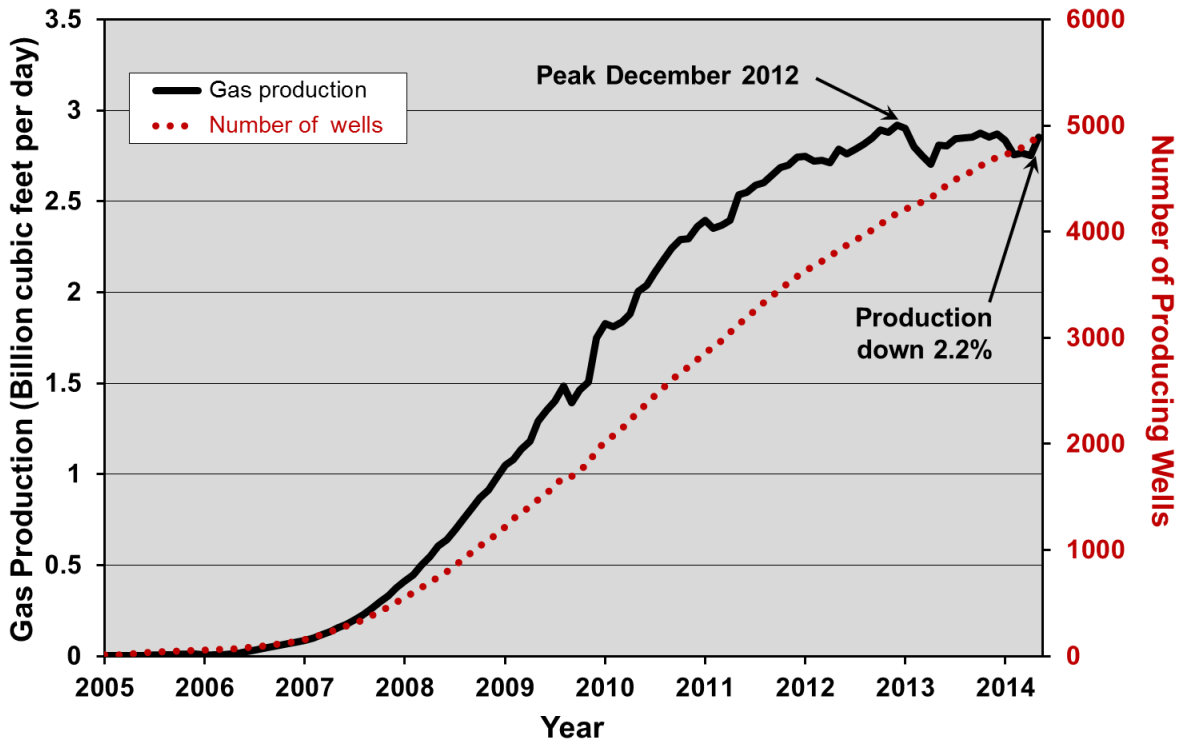

Figure 3-46. Fayetteville play shale gas production and number of producing wells, 2005 to 2014.[72]

Gas production data are provided on a "raw gas" basis.

[72] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

3.3.3.1 Well Decline

The first key fundamental in determining the life cycle of Fayetteville production is the *well decline rate*. Fayetteville wells exhibit high decline rates in common with all shale plays. Figure 3-47 illustrates the average decline rate of Fayetteville wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The average decline rate over the first three years of well life is 79%, which is well within the typical range of shale plays. Wells are generally more productive than Barnett wells and less so than Haynesville wells. Production is almost exclusively dry gas with no liquids.

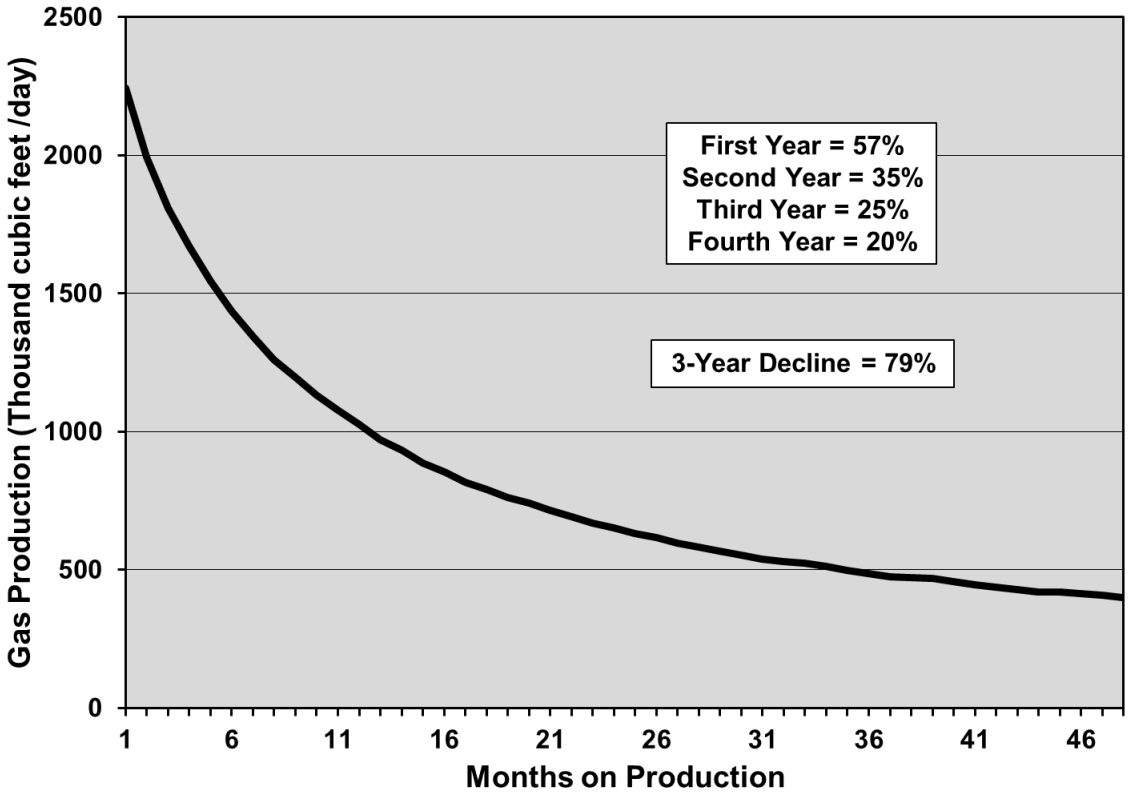

Figure 3-47. Average decline profile for horizontal gas wells in the Fayetteville play.[73]
Decline profile is based on all shale gas wells drilled since 2009.

[73] Data from Drillinginfo retrieved August 2014.

3.3.3.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production in the Fayetteville that would be lost in a year without more drilling. Figure 3-48 illustrates production from the 4,200 wells drilled prior to 2013. The first-year decline rate is 34%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, approximately 600 new wells each year would be required to offset field decline at current production levels. At an average cost of $2.4 million per well[74], this would represent a capital input of about $1.4 billion per year, exclusive of leasing and other ancillary costs, to keep production flat at 2013 levels. Fayetteville wells are among the cheapest of any shale play and this is likely what has allowed relatively high rates of drilling to be maintained.

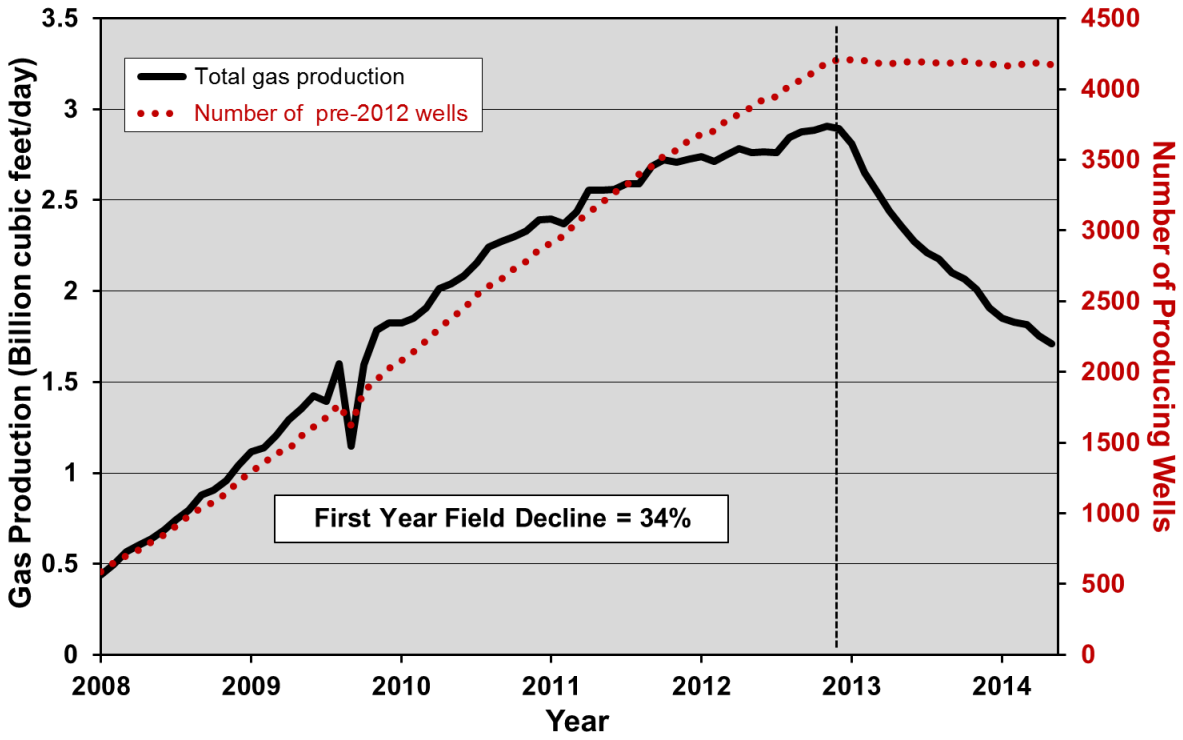

Figure 3-48. Production rate and number of horizontal shale gas wells drilled in the Fayetteville play prior to 2013, 2008 to 2014.[75]

This defines the field decline for the Fayetteville play, which is 34% per year.

[74] Fayetteville Shale, Southwest Energy, 2014, http://www.swn.com/operations/pages/fayettevilleshale.aspx.
[75] Data from Drillinginfo retrieved August 2014.

3.3.3.3 Well Quality

The third key fundamental is the *average well quality* in the Fayetteville by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, with average well productivity in the Fayetteville up just 2% in 2013, after rising significantly in the early years of the play, as illustrated in Figure 3-49. Given the propensity of operators to drill their best locations first, the slight increase in average quality may have as much to do with concentrating drilling on the highest quality locations as with improvements in technology.

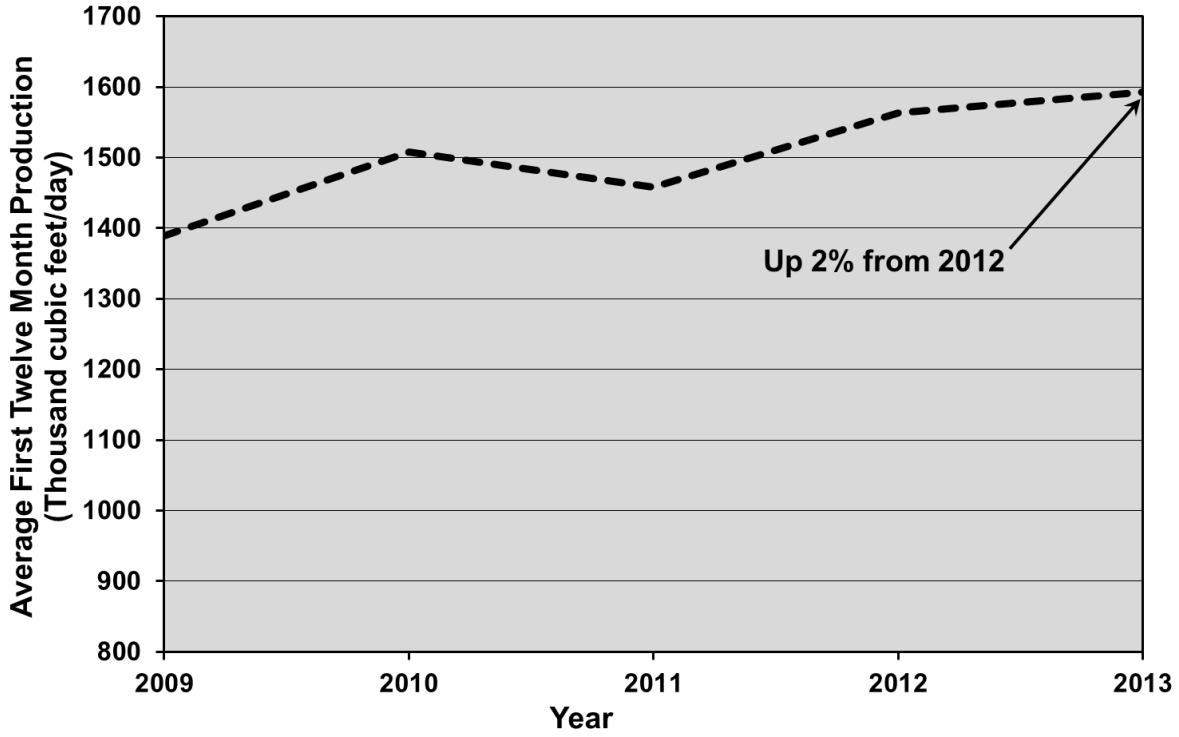

Figure 3-49. Average first-year production rates for Fayetteville gas wells, 2009 to 2013.[76]

Average well quality rose slightly in the most recent year.

[76] Data from Drillinginfo retrieved August 2014.

Another measure of well quality is cumulative production and well life. Nearly 8% of the wells that have been drilled in the Fayetteville are no longer productive. Figure 3-50 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 31 months and a mean cumulative production of 0.34 billion cubic feet, most of these wells would be economic losers.

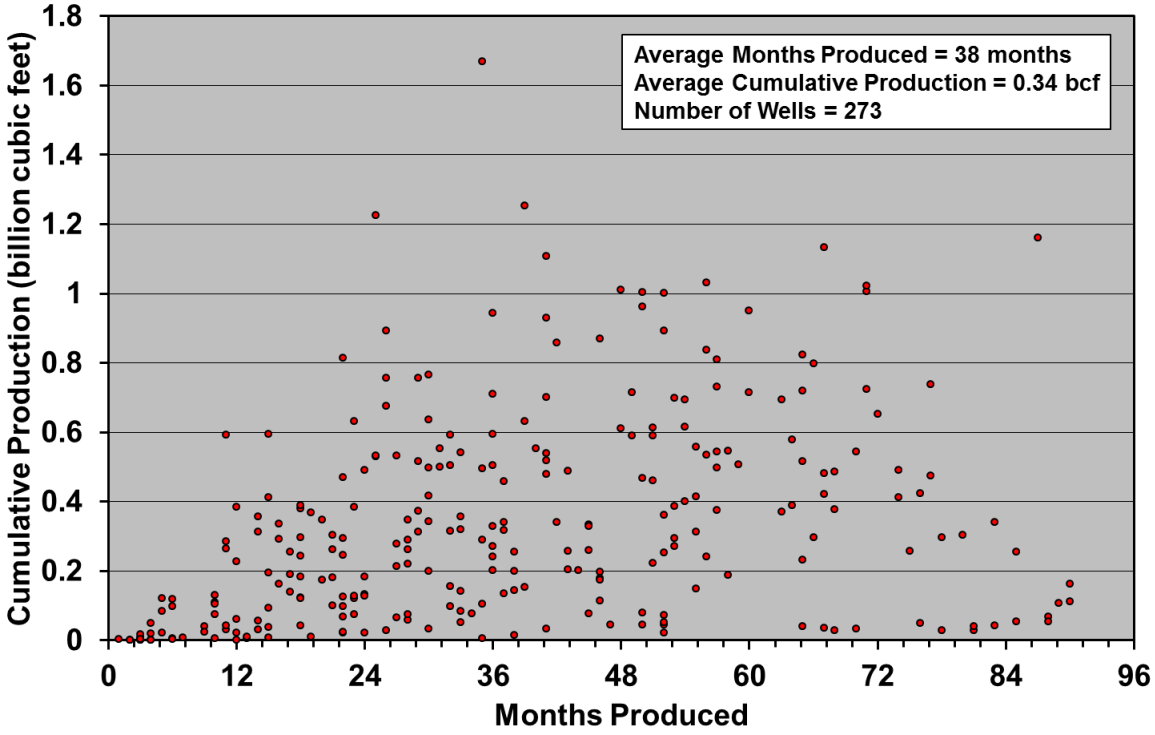

Figure 3-50. Cumulative gas production and length of time produced for Fayetteville wells that were not producing as of February 2014.[77]

These well constitute nearly 8% of all wells drilled; most would be economic failures, given the mean life of 38 months and average cumulative production of 0.34 billion cubic feet when production ended.

[77] Data from Drillinginfo retrieved August 2014.

Figure 3-51 illustrates the cumulative production of all wells that were producing in the Fayetteville in March 2014. Roughly 6% of the wells have produced more than 2 billion cubic feet over a relatively short lifespan and are clearly economic, however 57% have yet to produce 1 billion cubic feet. The average well has produced 0.99 billion cubic feet over a lifespan of 44 months. Just 5% of these wells are more than 7 years old.

The lifespan of wells is another key parameter as many operators assume a minimum well life of 30 years and longer, though this is conjectural given the lack of long term production data.

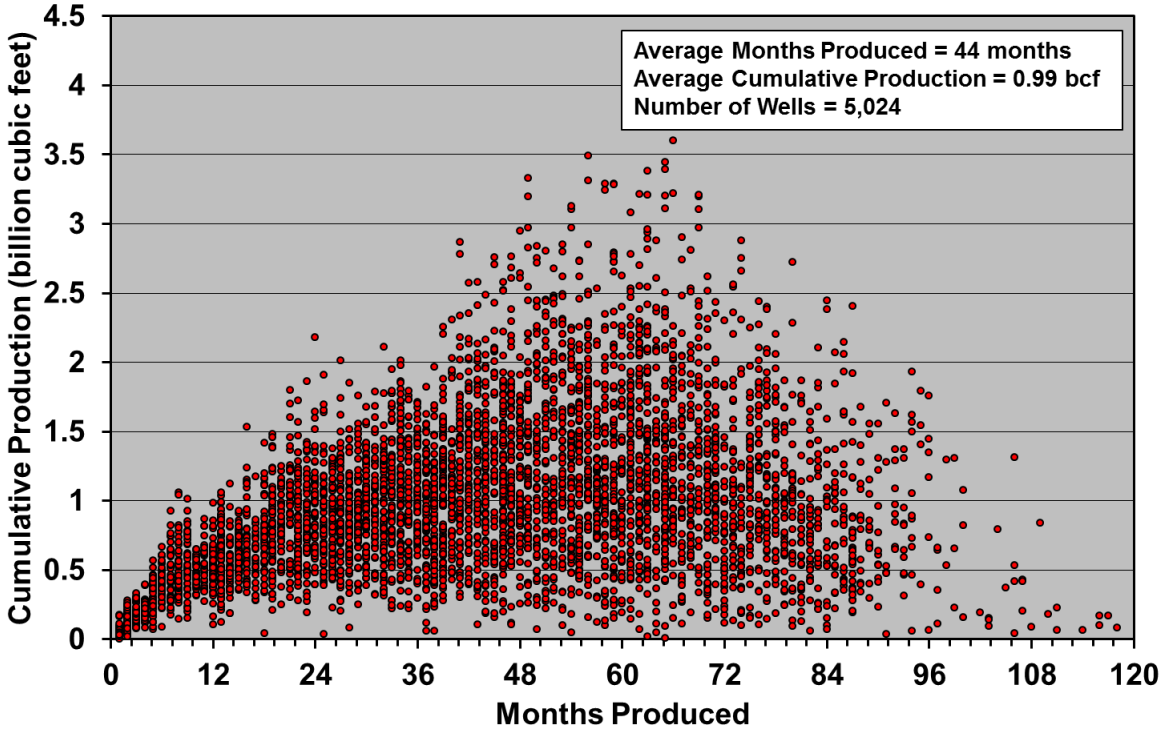

Figure 3-51. Cumulative gas production and length of time produced for Fayetteville wells that were producing as of March 2014.[78]

These constitute 92% of all wells drilled. Very few wells are greater than seven years old, with a mean age of 44 months and a mean cumulative recovery of 0.99 billion cubic feet.

[78] Data from Drillinginfo retrieved August 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality, independent of age, is initial productivity (IP). Figure 3-52 illustrates the average daily output over the first six months of production for all wells in the Fayetteville play (six-month IP). Again, as with cumulative production, there are a few exceptional wells—5% produced more than 3 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 2009 is 1.73 MMcf/d. Figure 3-45 illustrates the distribution of IPs in map form.

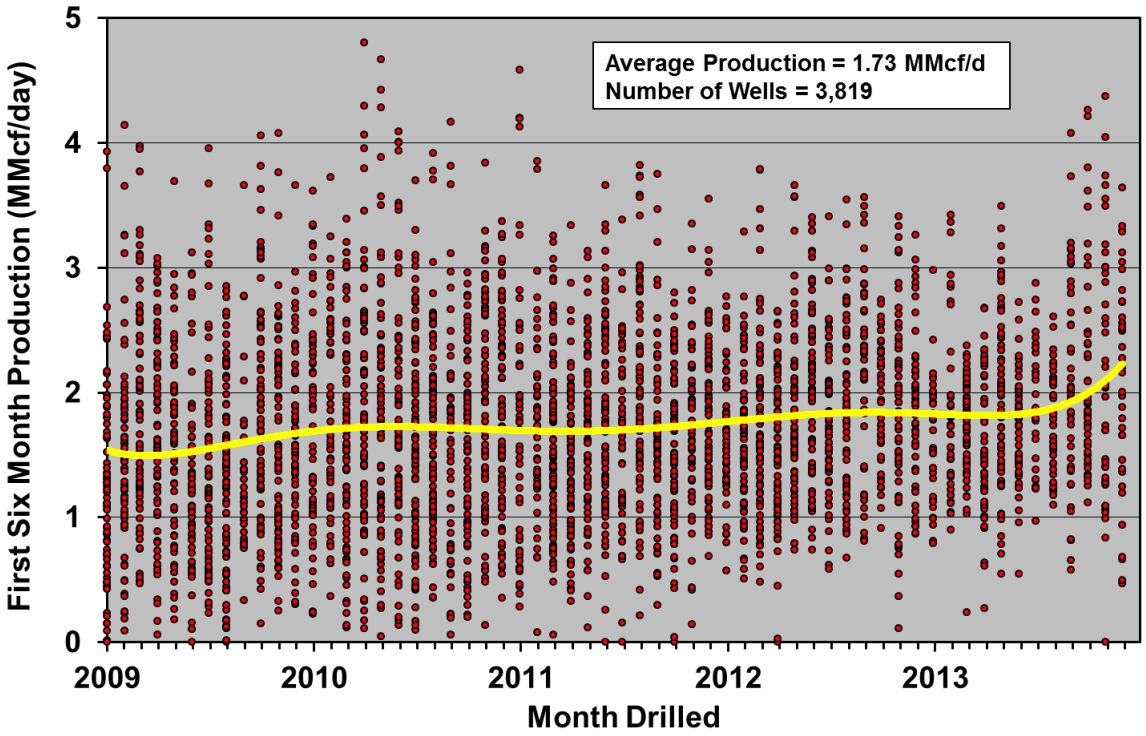

Figure 3-52. Average gas production over the first six months for all wells drilled in the Fayetteville play, 2009 to 2014.[79]

Although there are a few exceptional wells, the average well produced 1.73 million cubic feet per day over this period. The trend line indicates mean productivity over the time period.

[79] Data from Drillinginfo retrieved August 2014.

Different counties in the Fayetteville display different well quality characteristics, which are critical in determining the most likely production profile in the future. Figure 3-53, which illustrates production over time by county, shows that, as of May 2014, the top two counties produced 53% of the total, the top four produced 93%, and the remaining 6 counties produced just 7%. All counties are below peak production except Cleburne.

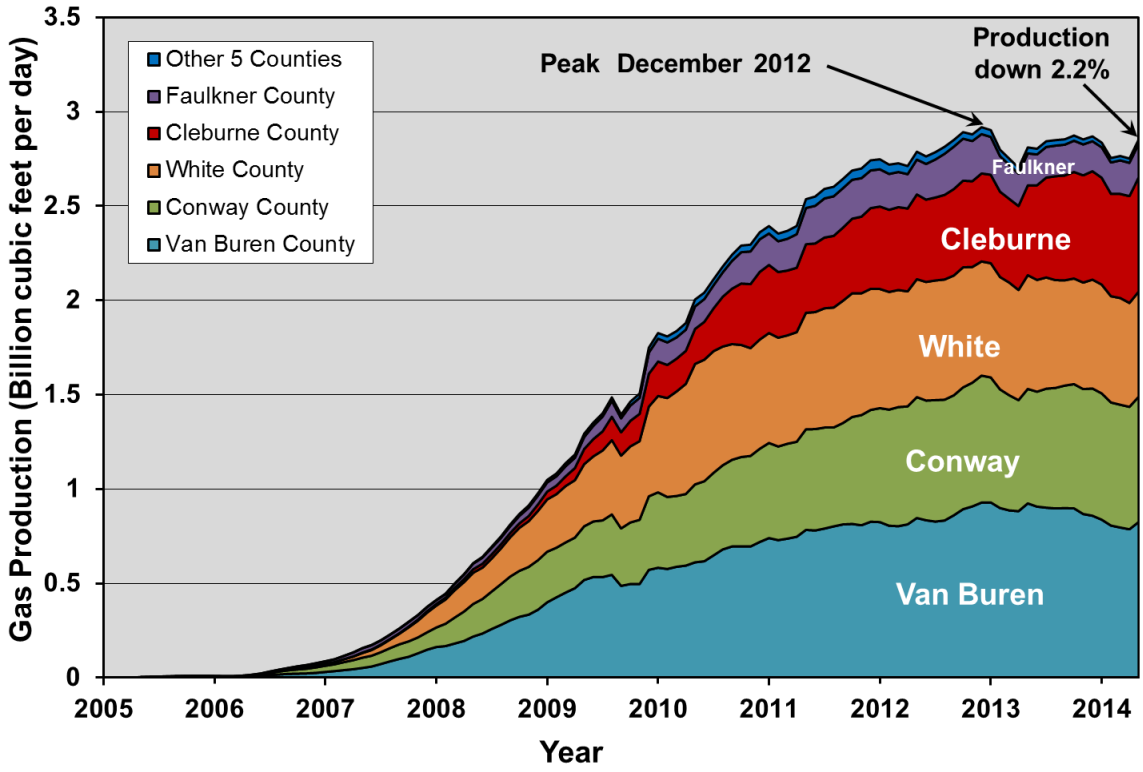

Figure 3-53. Gas production by county in the Fayetteville play, 2005 through 2014.[80]
The top four counties produced 93% of production in May 2014.

[80] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-54, the top two counties have produced 54% of the gas and the top four have produced 92%. All of the counties except Cleburne have peaked, although with increased drilling rates some could conceivably resume production growth. Production in the top county—Van Buren—is down 11% from peak and production in other counties outside of the top four is down from 21 to 56%.

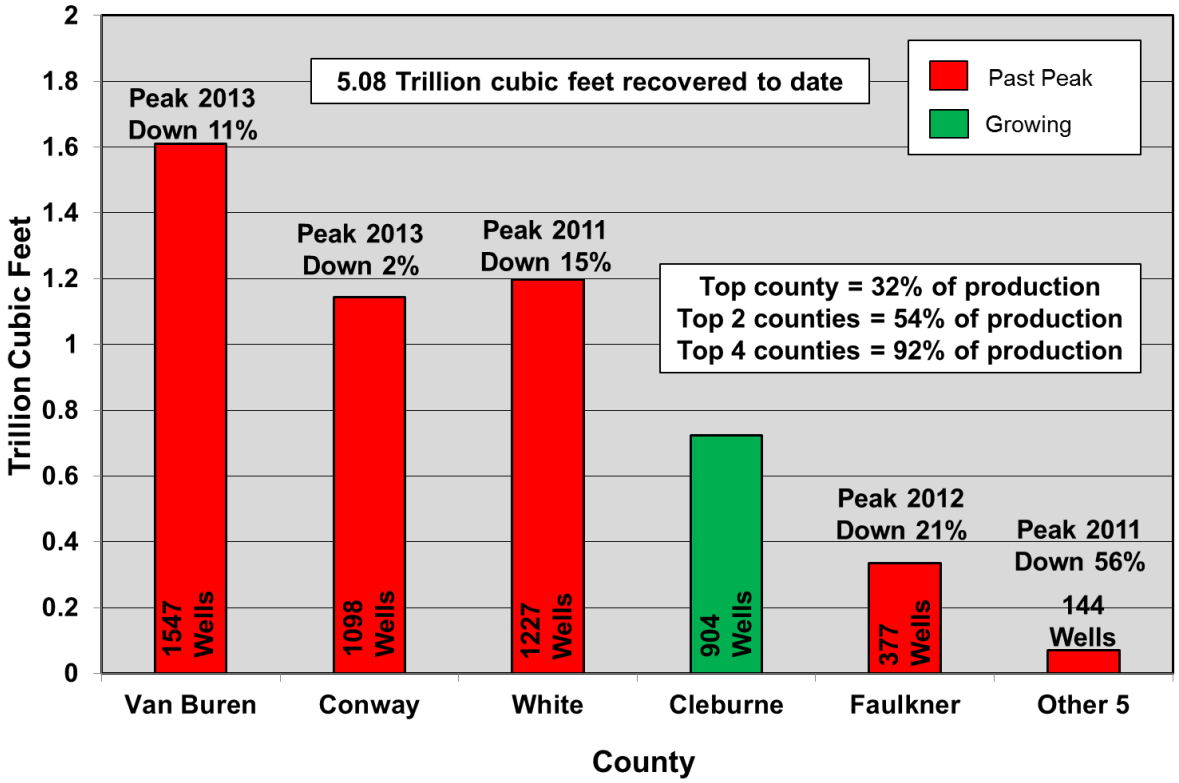

Figure 3-54. Cumulative gas production by county in the Fayetteville play through 2014.[81]

The top four counties have produced 92% of the 5.08 trillion cubic feet of gas produced to date.

[81] Data from Drillinginfo retrieved August 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of $2.4 million each[82], not including leasing costs and other expenses. The areas of highest quality—the "core" or "sweet spots"—have now been well defined. Figure 3-55 illustrates average well decline curves by county which are a measure of well quality. Initial well productivities (IPs) are more closely grouped than in the Barnett; however, the top producing counties—Van Buren and Conway, which are both in decline—are somewhat better than the overall Fayetteville average and are significantly better than counties outside the top five. There are still a significant number of locations to drill wells in the top producing counties, although the overall play area of the Fayetteville is much smaller than plays like the Barnett and is dwarfed by the Marcellus.[83]

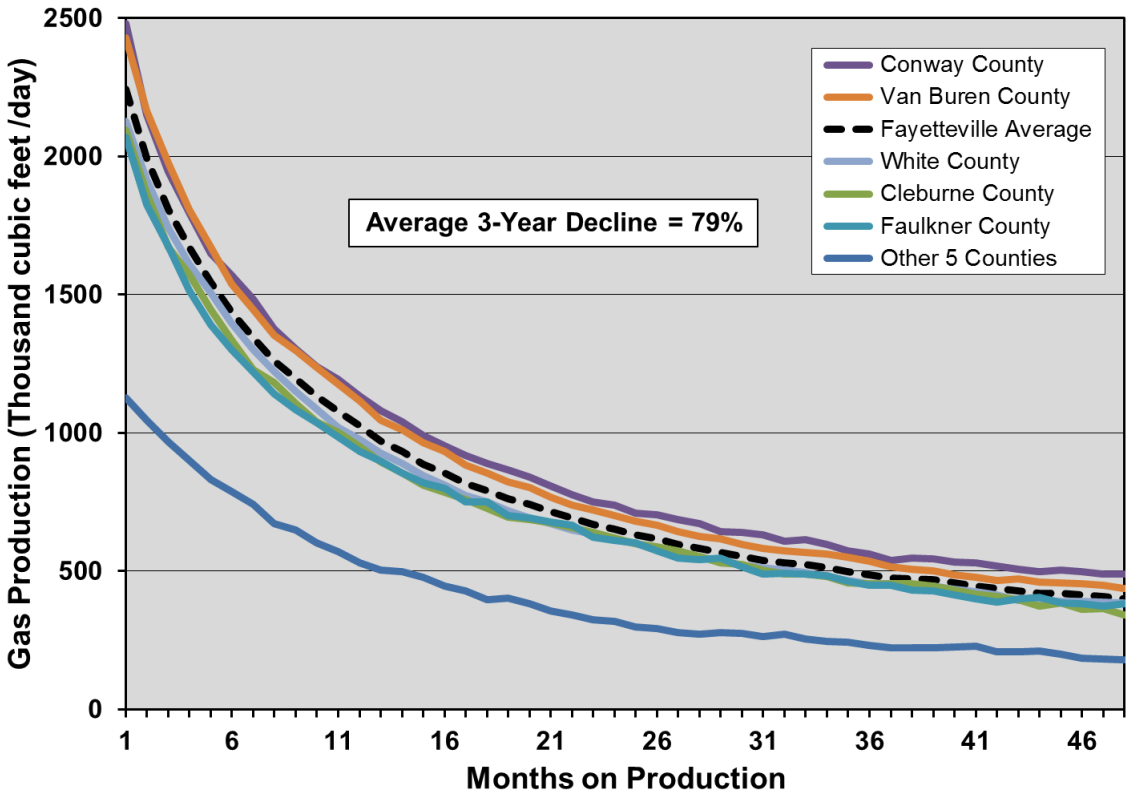

Figure 3-55. Average horizontal gas well decline profiles by county for the Fayetteville play.[84]

The low productivity outside of the top five counties seriously limits expansion of the play.

Another measure of well quality is "estimated ultimate recovery" or EUR—the amount of gas a well will recover over its lifetime. To be clear no one knows what the average lifespan of a Fayetteville well is, given that few of them are more than seven years old (see Figure 3-50 and Figure 3-51), and some 8% of wells drilled have ceased production at an average age of about three years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-55, assuming well life spans of 30-50 years (as is typical for conventional wells) by comparison to conventional wells, but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Fayetteville.

[82] Southwest Energy, 2014, "Fayetteville Shale," http://www.swn.com/operations/pages/fayettevilleshale.aspx.
[83] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[84] Data from Drillinginfo retrieved August 2014.

Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-55, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-56 illustrates theoretical EURs by county for the Fayetteville, for comparative purposes of well quality. These range from 1.02 to 2.43 billion cubic feet per well, which is somewhat higher than the 0.84 to 1.44 billion cubic feet assumed by the EIA.[85] The range of EURs in the top five counties is fairly small, but all are roughly double the outlying counties which will serve to limit expansion of the play in future. The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 55% and 62% of an average well's lifetime production occurs in the first four years.

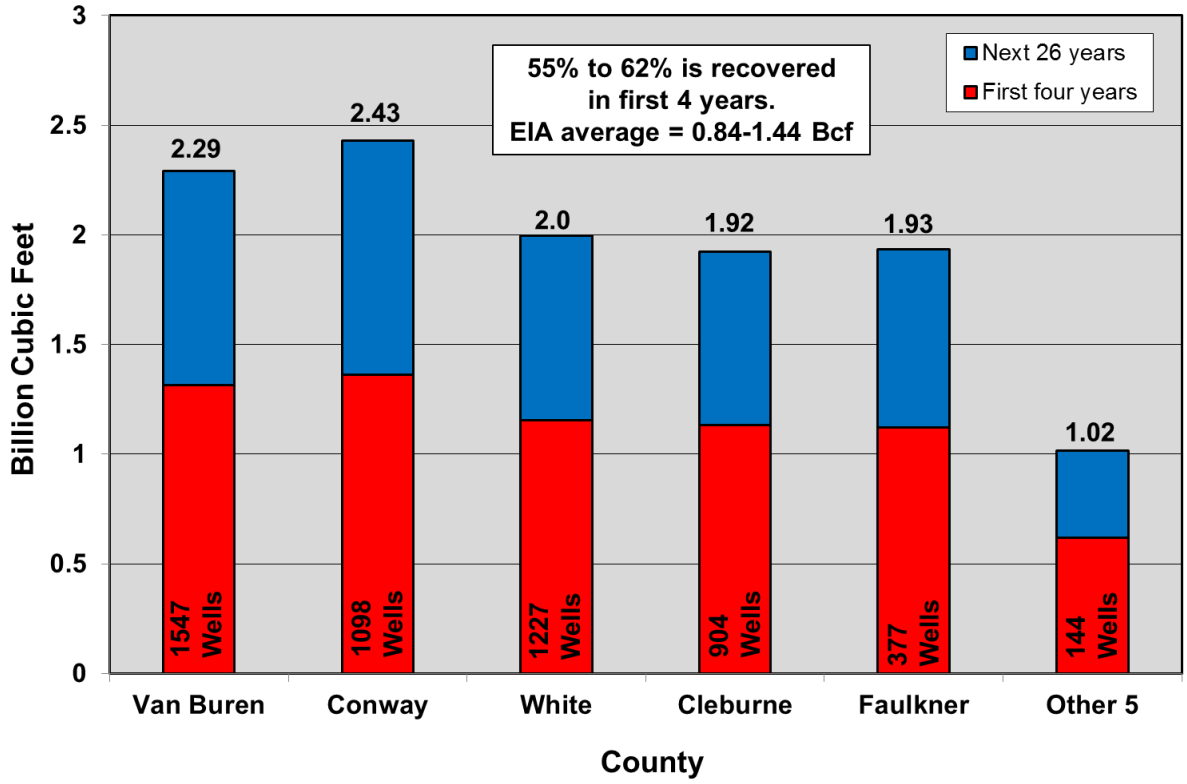

Figure 3-56. Estimated ultimate recovery of gas per well by county for the Fayetteville play.[86]

EURs are based on average well decline profiles (Figure 3-55) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

[85] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[86] Data from Drillinginfo retrieved August 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Figure 3-57 illustrates the average first year production rate of wells by county over time. As noted earlier, average well quality for the play is up 2% in 2013 and four of the top five counties are flat to slightly rising. Van Buren County—the top producer—is declining, and no wells were drilled in 2013 outside of the top five counties, hence an estimate for that year was not possible.

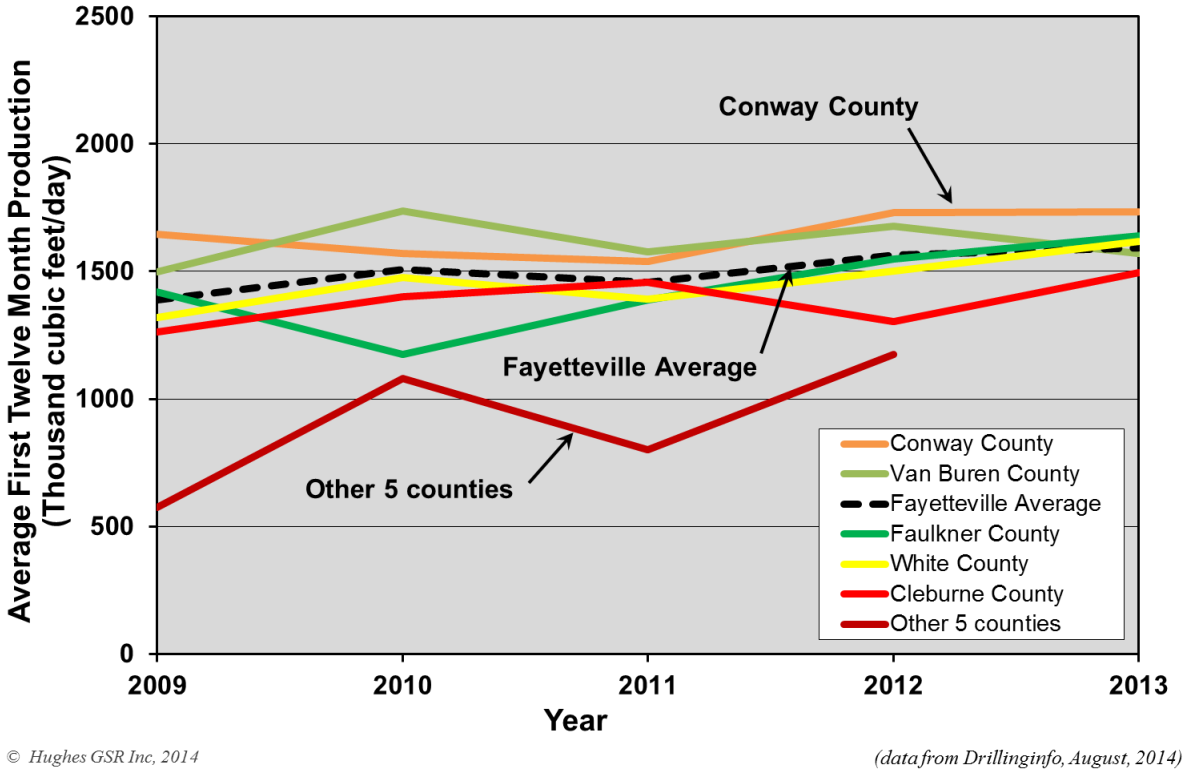

Figure 3-57. Average first-year gas production rates of wells by county in the Fayetteville play, 2009 to 2013.[87]

Well quality is flat to slightly rising in four counties and declining in Van Buren County which is the top producer. There were no wells drilled in 2013 outside of the top five counties so no estimate was possible for that year.

[87] Data from Drillinginfo retrieved August 2014.

3.3.3.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Fayetteville play. The EIA has estimated the total play area as 2,904 square miles, including 2,132 in the "central" and 772 in the "west" area, and suggests this can be drilled at a well density of eight per square mile, for a total of 23,232 wells. In fact, the "west" area of the EIA has limited prospectivity—most wells there have ceased production—and drilling in areas outside the top five counties has ceased as of 2014. A close look at the drilling data limits the overall play area to 2,150 square miles, even allowing for 525 square miles of prospective area outside of the top five counties, for a total well count of 17,230 when the play is completely developed. As 5,297 wells have already been drilled this leaves 11,933 yet-to-drill wells.

Table 3-3 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Fayetteville play.

Parameter	County						Total
	Cleburne	Conway	Faulkner	Van Buren	White	Other 5	
Production May 2014 (Bcf/d)	0.60	0.66	0.18	0.83	0.56	0.02	2.85
% of Field Production	21.20	23.27	6.25	28.93	19.53	0.83	100.00
Cumulative Gas (Tcf)	0.72	1.14	0.33	1.61	1.20	0.07	5.08
Cumulative Liquids (MMBBL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Number of Wells	904	1098	377	1547	1227	144	5297
Number of Producing Wells	848	1015	322	1441	1168	120	4914
Average EUR per well (Bcf)	1.92	2.43	1.93	2.29	2.00	1.02	2.10
Field Decline (%)	34.64	37.02	37.02	27.22	26.12	31.32	34.02
3-Year Well Decline (%)	78	78	78	79	79	80	79
Peak Year	Rising	2013	2012	2013	2011	2011	2012
% Below Peak	N/A	2	21	11	15	56	2.2
Average First Year Production in 2013 (Mcf/d)	1496	1734	1641	1571	1616	1174	1592
New Wells Needed to Offset Field Decline	140	142	40	143	90	6	610
Area in square miles	553	556	647	712	1034	3500	7002
% Prospective	70	50	30	50	40	15	31
Net square miles	387	278	194	356	414	525	2153
Well Density per square mile	2.34	3.95	1.94	4.35	2.97	0.27	2.46
Additional locations to 8/sq. Mile	2193	1126	1176	1301	2082	4056	11933
Population	25970	21273	113237	17295	77076	N/A	N/A
Total Wells 8/sq. Mile	3097	2224	1553	2848	3309	4200	17230
Total Producing Wells 8/sq. Mile	3041	2141	1498	2742	3250	4176	16847

Table 3-3. Parameters for projecting Fayetteville production, by county.

Area in square miles under "Other" is estimated.

A recent in-depth study of the Fayetteville by the Bureau of Economic Geology at the University of Texas (UT) at Austin takes a more conservative view.[88] Although they assign a study area of 2,737 square miles, they exclude 20% of "partly drained" portions and 60% of undrilled portions from consideration, given uncertainties about surface access and prospectivity. At the time of the 2011 data cutoff used in that study, 1,252 square miles had been tested by drilling, leaving 1,485 square miles undrilled—which leaves a net developable area of 1,596 square miles. The UT study assumes in its base case that a total of 10,117 wells will be drilled by 2030, which leaves just 4,820 yet-to-drill wells by 2030 given the 5,297 wells drilled as of May 2014.

[88] Browning et al., 2014, *Oil and Gas Journal*, "Study develops Fayetteville Shale reserves, production forecast," http://www.beg.utexas.edu/info/docs/Fayetteville%20Shale%20OGJ%20article.pdf.

3.3.3.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-58 illustrates the historical drilling rates in the Fayetteville. Drilling rates peaked in 2011 at just over 800 wells per year and have fallen to current levels of about 500 wells per year. Current drilling rates are close to the 600 wells per year required to maintain production at current levels, hence production is maintaining a slowly downward trending plateau.

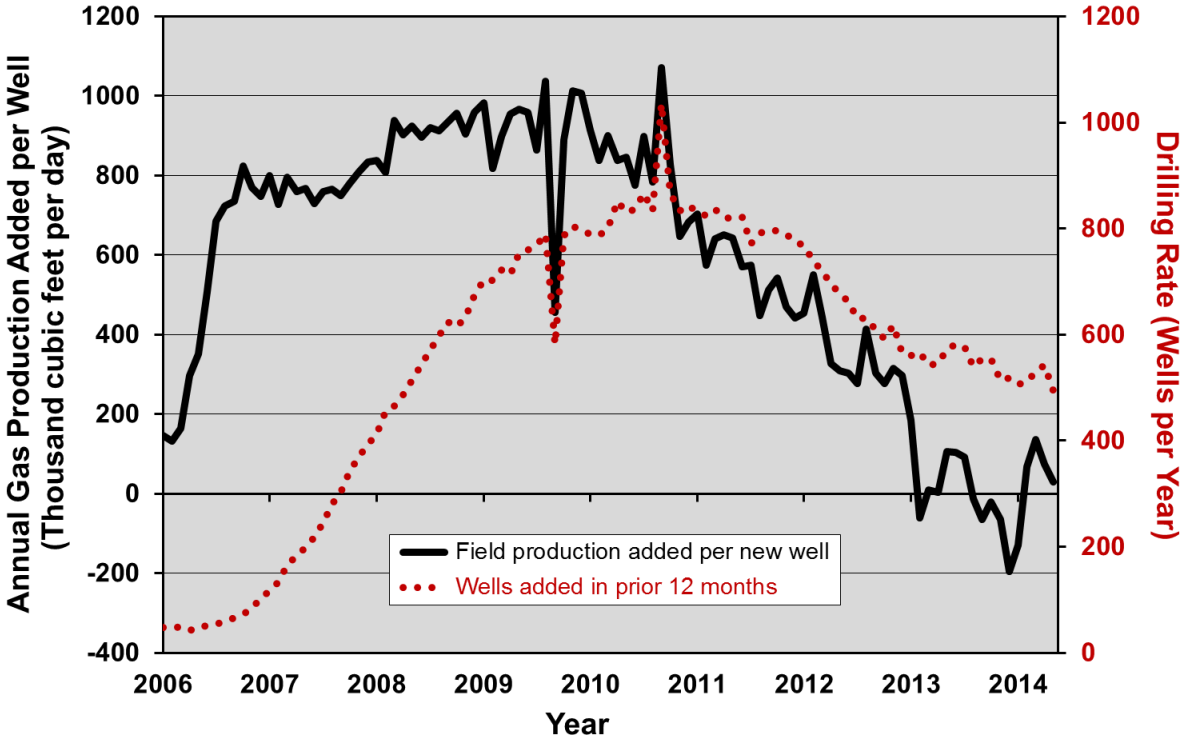

Figure 3-58. Annual gas production added per new horizontal well and annual drilling rate in the Fayetteville play, 2006 through 2014.[89]

Drilling rate peaked in 2010 and is now slightly below the level needed to keep production flat.

[89] Data from Drillinginfo retrieved August 2014. Three-month trailing moving average.

3.3.3.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Fayetteville play were developed to illustrate the effects of changing the rate of drilling. Figure 3-59 illustrates the production profiles of three drilling rate scenarios if 100% of the prospective play area is drillable at eight wells per square mile. These scenarios are:

1. MOST LIKELY RATE scenario: Drilling remains at the current rate of 500 wells per year, then gradually declines to 300 wells per year.

2. EXISTING RATE scenario: Drilling remains constant at the current rate of 500 wells per year.

3. HIGH RATE scenario: Drilling increases to 750 wells per year, then gradually declines to 500 wells per year.

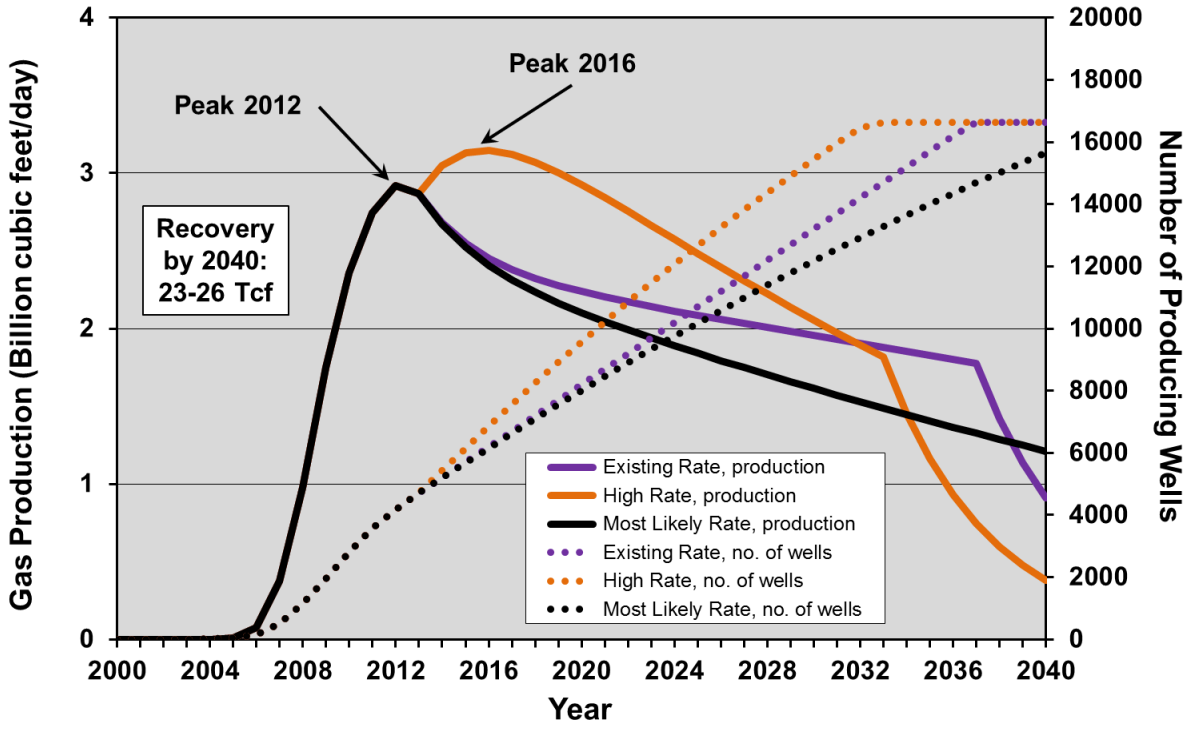

Figure 3-59. Three drilling rate scenarios of Fayetteville gas production (assuming 100% of the area is drillable eight wells per square mile).[90]

"Most Likely Rate" scenario: drilling holds at 500 wells/year, declining to 300 wells per year.
"Existing Rate" scenario: drilling holds constant at 500 wells/year.
"High Rate" scenario: drilling increases to 750 wells/year, declining to 500 wells/year.

[90] Data from Drillinginfo retrieved August 2014.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: The rate of drilling declines as the inventory of drilling locations is used up and drilling moves into outlying areas. Total gas recovery by 2040 would be 22.8 trillion cubic feet and drilling would continue beyond 2040.

2. HIGH RATE scenario: The rate of drilling increases by 50% immediately and production would increase to a new peak in 2016.. This scenario is considered unlikely unless there is a marked increase in gas price in the very near future. Total gas recovery by 2040 would be 26 trillion cubic feet and drilling would end in 2033.

3. EXISTING RATE scenario: Drilling continues at 500 wells per year until locations run out; this scenario is also considered unlikely given the decline in well quality in later years as drilling moves into lower productivity counties. Total gas recovery by 2040 would be 24.9 trillion cubic feet and drilling would end in 2037.

Total recovery of 22.8 trillion cubic feet by 2040 in the ”Most Likely Rate” scenario is more than four times what has been recovered so far in the Fayetteville. In the “High Rate” scenario as much as 26 trillion cubic feet could be recovered; however, production rates would be far below those projected by the EIA for the Fayetteville play.

3.3.3.7 Comparison to EIA Forecast

Figure 3-60 illustrates the EIA's projection for Fayetteville production through 2040 compared to the "Most Likely Rate" scenario. The EIA projects a recovery by 2040 of 41.5 Tcf to meet its reference case forecast, and projects a new peak of the play in 2036 at a level far higher than the late-2012 peak. This represents the recovery of 98% of proved reserves[91] and unproved resources.[92] Furthermore, the EIA projects that production in 2040 will be much higher than the 2012 peak, suggesting that vastly more gas will be recovered beyond 2040. This strains credibility to the limit. How can all the proved and unproved resources and reserves be extracted and still have production near all-time highs in 2040?

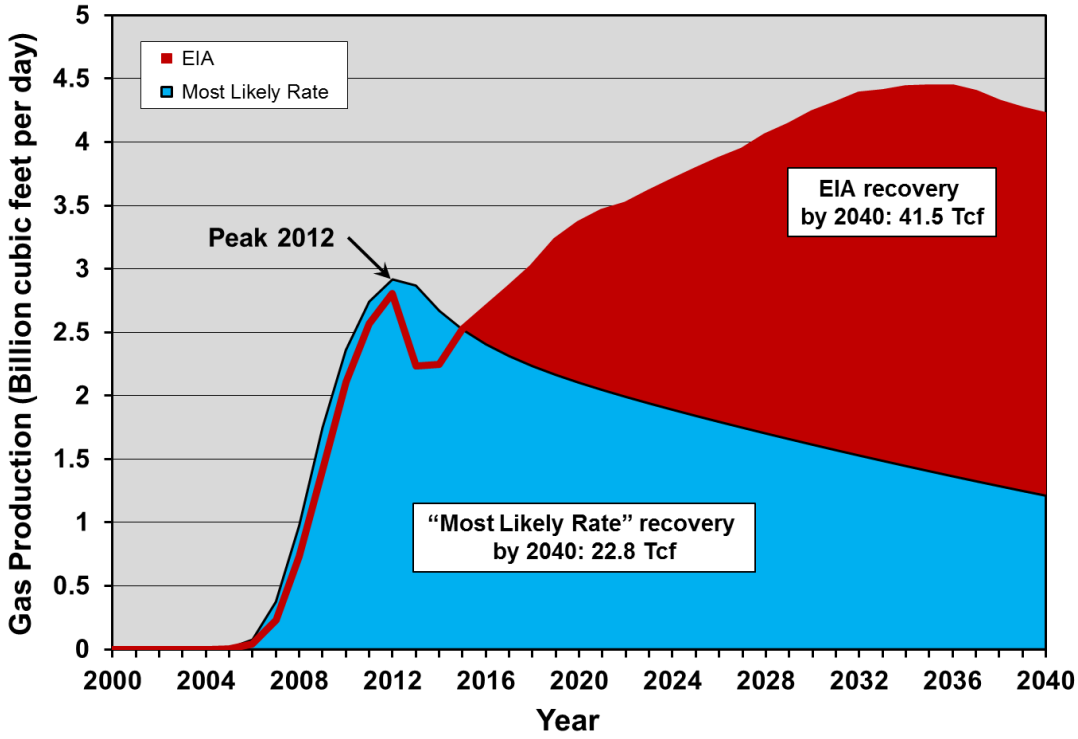

Figure 3-60. "Most Likely Rate" scenario of Fayetteville gas production compared to the EIA reference case, 2000 to 2040.[93]

The EIA assumes the Fayetteville will reach a new all-time high by 2036, produce 98% of proved reserves and unproved resources by 2040, and presumably produce a great deal more gas in the post-2040 period. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

[91] EIA, 2014, "Principal shale gas plays: natural gas production and proved reserves, 2011-12," http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls.
[92] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[93] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.

3.3.3.8 Fayetteville Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen somewhat in the Fayetteville due to gas prices, but are still remarkably high likely due to the relatively low cost of wells compared to other plays.

2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. The Fayetteville field decline rate of 34% is in the lower range for shale gas plays. Current drilling rates of 500 wells per year are slightly below the level required to maintain current production levels. Maintaining production at current levels would require the investment of $1.4 billion per year for drilling (assuming $2.4 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Growing production in the Fayetteville would require considerably higher gas prices to justify higher drilling rates.

3. Increasing current drilling rates by 50% could reverse the current production decline and raise production to a new peak, at 3.15 Bcf/d, in 2016, which is 10% higher than current levels. Cumulative recovery by 2040 in this high drilling rate scenario would be increased by 14% but would still be only 63% of that projected by the EIA in its reference case.

4. The projected recovery of 22.8 Tcf by 2040 in the "Most Likely Rate" scenario represents four times as much gas as has been recovered so far from the Fayetteville, and is more optimistic than the "base case" estimated ultimate recovery of 18.2 Tcf projected by the Bureau of Economic Geology at the University of Texas.[94] Both are significantly less than the 41.5 Tcf projected by the EIA in its reference case forecast.

5. This report's projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require higher gas prices to be economic. Failure to increase current drilling rates will result in a steeper drop off in production.

6. Nearly three times the current number of wells will need to be drilled to meet the production projection of the "Most Likely Rate" scenario by 2040.

7. The EIA projection for future Fayetteville gas production included in its reference case forecast for AEO 2014,[95] which forecasts recovery of 98% of proved reserves plus unproved resources by 2040, strains credibility to the limit. It is highly unlikely to be realized, especially at the gas prices the EIA forecasts.[96]

[94] Browning et al., 2014, *Oil and Gas Journal*, "Study develops Fayetteville Shale reserves, production forecast," http://www.beg.utexas.edu/info/docs/Fayetteville%20Shale%20OGJ%20article.pdf.
[95] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[96] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

3.3.4 Woodford Play

The EIA forecasts recovery of 23.8 Tcf of gas from the Woodford play by 2040. The analysis of actual production data presented below suggests that this forecast is somewhat—but not significantly—higher than the data suggest, although the forecast production profile is improbable.

The Woodford play in Oklahoma is primarily a shale gas play, for although parts of it are liquids rich, 92% of the energy produced from it in mid-2014 was natural gas. It is a complex play, comprising parts of the Anadarko Basin on the west, the Arkoma Basin on the east, the Chautauqua Platform in the central and northern portions, and the Oklahoma- and Ouachita-folded belts in the south and southeast. Figure 3-61 illustrates the distribution of wells as of early 2014. Since 2005 over 3,600 wells have been drilled, of which 3,062 were producing at the time of writing. The play covers parts of 31 counties although 70% of production is concentrated in five counties.

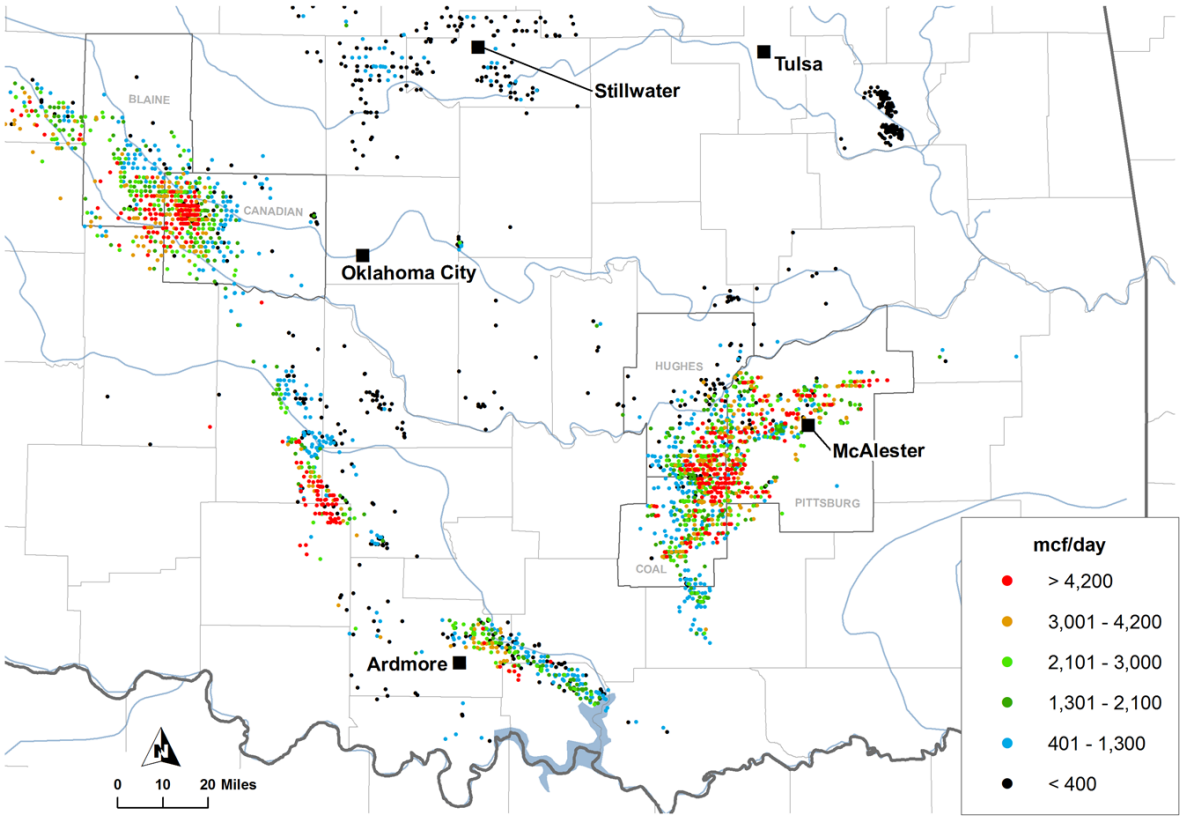

Figure 3-61. Distribution of wells in the Woodford play as of early 2014, illustrating highest one-month gas production (initial productivity, IP).[97]

Well IPs are categorized approximately by percentile; see Appendix.

[97] Data from Drillinginfo retrieved August 2014.

Production in the Woodford peaked at nearly 1.9 billion cubic feet per day in June 2013 as illustrated in Figure 3-62.

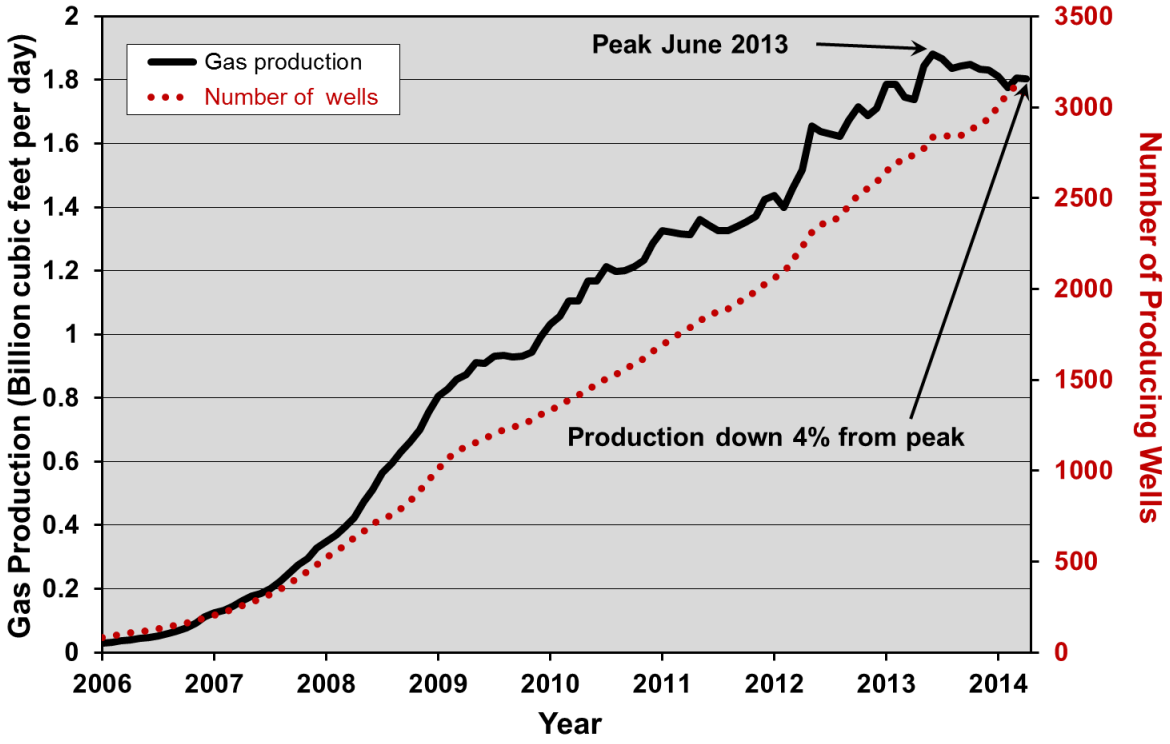

Figure 3-62. Woodford play shale gas production and number of producing wells, 2006 to 2014.[98]

Gas production data are provided on a "raw gas" basis.

[98] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

Although some 14% of producing wells in the Woodford are vertical/directional, 98% of current production is from horizontal fracked wells as illustrated in Figure 3-63. The rate of drilling peaked at more than 600 wells per year in 2010 but has since fallen to less than the roughly 405 wells per year required to keep production flat at current production levels. Very few vertical/directional wells are being drilled today—the future of the play lies in drilling horizontal fracked wells.

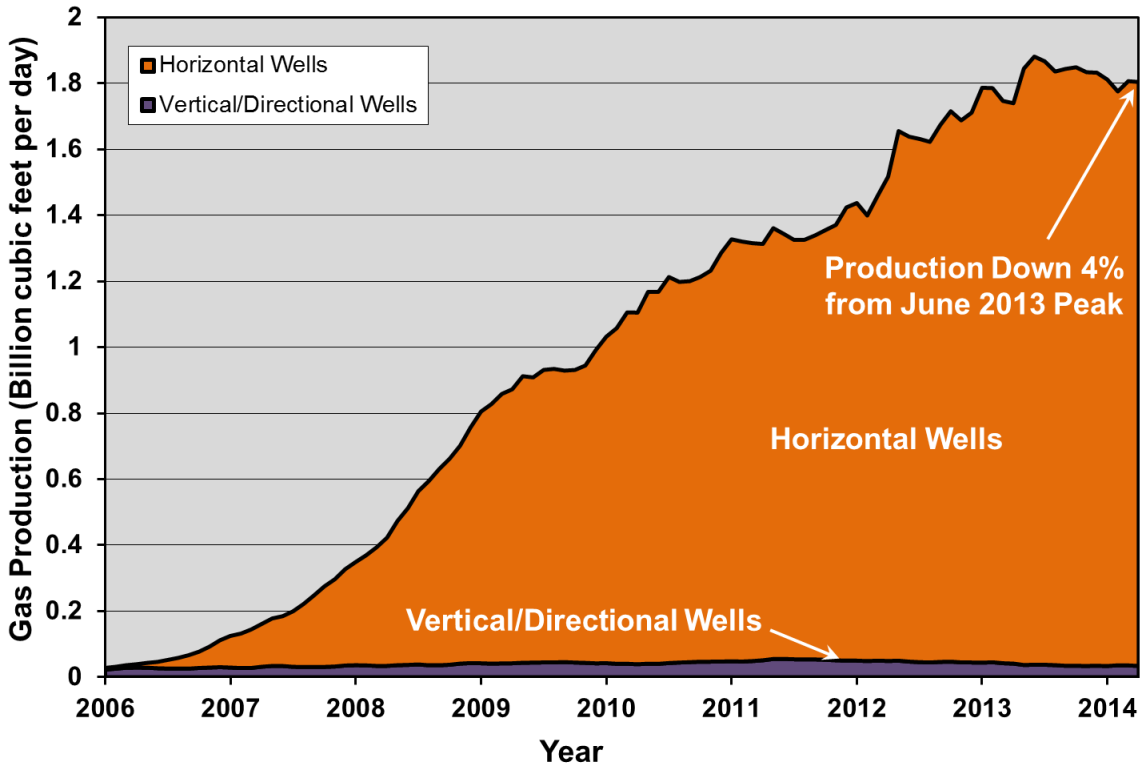

Figure 3-63. Gas production from the Woodford play by well type, 2006 to 2014.[99]

[99] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

3.3.4.1 Well Decline

The first key fundamental in determining the life cycle of Woodford production is the *well decline rate*. Woodford wells exhibit high decline rates in common with all shale plays. Figure 3-64 illustrates the average decline rate of Woodford horizontal and vertical/directional wells. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The decline rate over the first three years of average well life is 74%, which is at the low end of typical shale plays. As can be seen, vertical/directional wells have much lower productivity than horizontal wells and hence are being phased out.

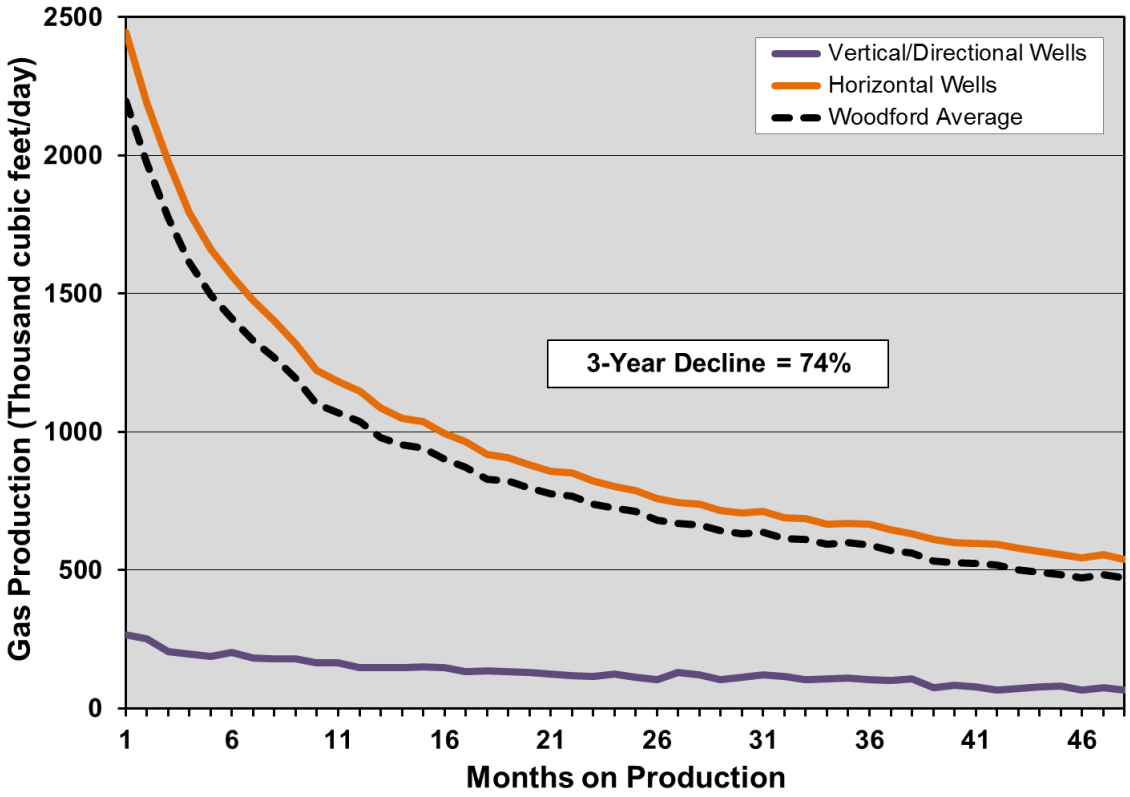

Figure 3-64. Average decline profile for gas wells in the Woodford play.[100]

Decline profile is based on all shale gas wells drilled since 2009.

[100] Data from Drillinginfo retrieved September 2014.

3.3.4.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in the Woodford in a year without more drilling. Figure 3-65 illustrates production from the 2,600 horizontal wells drilled prior to 2013 (horizontal wells only are considered as very few vertical/directional wells are being drilled). The first-year decline rate is 34%. This is lower than the well decline rate as the field decline is made up of both new wells declining at high rates and older wells declining at lesser rates. It's also at the low end of field decline rates observed in shale plays. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, 405 new wells each year would be required to offset field decline at current production levels. At an average cost of $9 million per well,[101] this would represent a capital input of about $3.6 billion per year, exclusive of leasing and other infrastructure costs, just to keep production flat at 2013 levels.

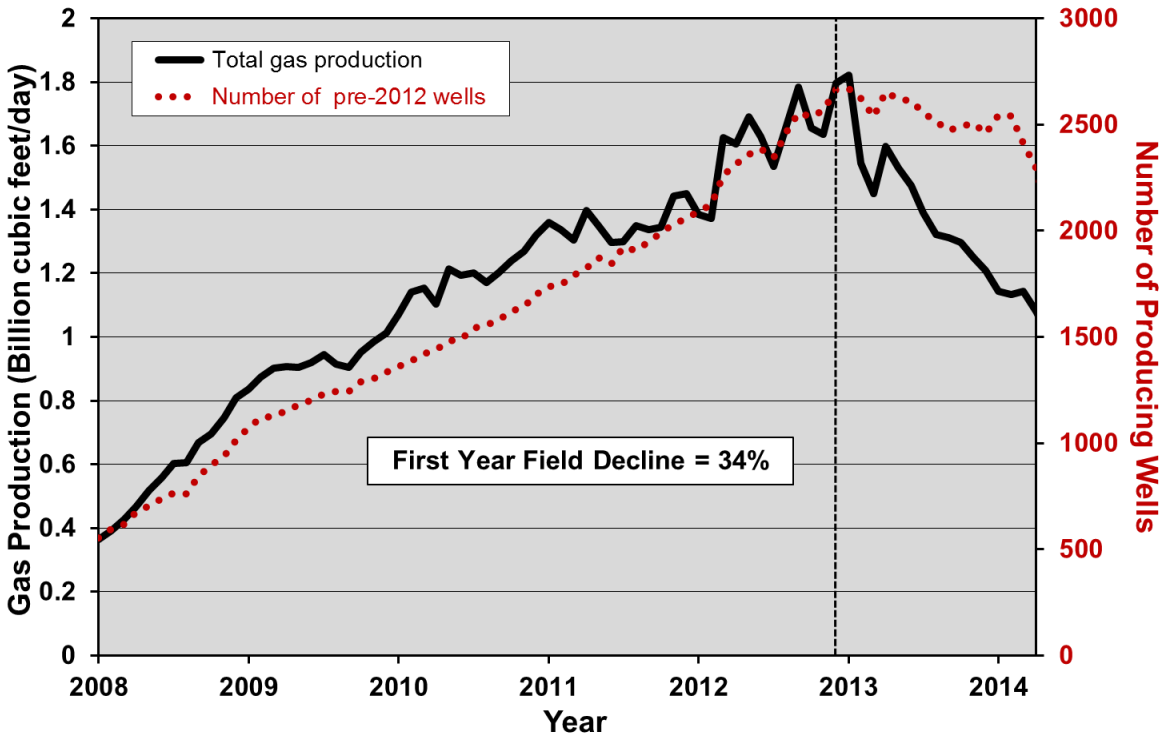

Figure 3-65. Production rate and number of horizontal shale gas wells drilled in the Woodford play prior to 2013, 2008 to 2014.[102]

This defines the field decline for the Woodford play which is 34% per year (only production from horizontal wells is analyzed as few vertical/directional wells are likely to be drilled in the future).

[101] Mason, Richard, June 27, 2013, "Targeting Oklahoma's Ubiquitous Woodford Shale," http://www.ugcenter.com/Woodford/Targeting-Oklahomas-Ubiquitous-Woodford-Shale_118127.
[102] Data from Drillinginfo retrieved September 2014.

3.3.4.3 Well Quality

The third key fundamental is the *average well quality* in the Woodford by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. It is, however, approaching the limits of diminishing returns, and improvements in average well quality are non-existent in the Woodford. The average first year production rate of Woodford wells is down 24% from what it was in 2010, as illustrated in Figure 3-66. This is clear evidence that geology is winning out over technology, as drilling moves into lower-quality locations, as investigated further below, although some of the decline may be related to moves into more liquids-rich parts of the play.

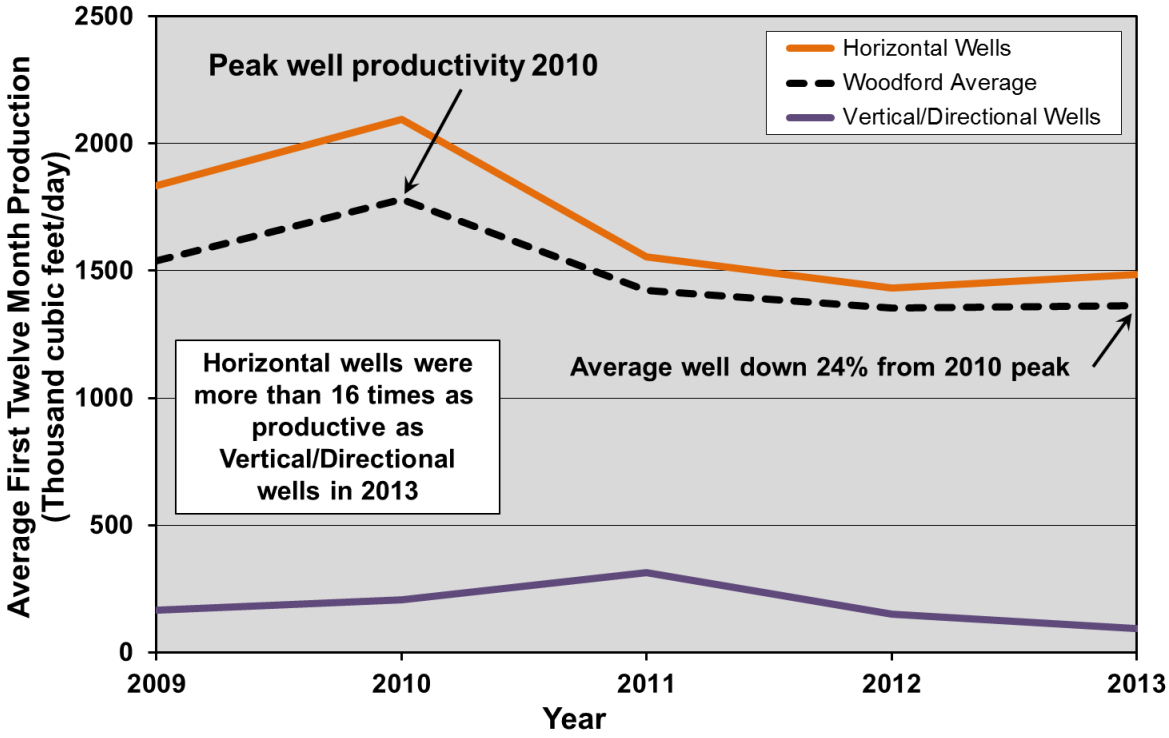

Figure 3-66. Average first-year production rates for Woodford horizontal and vertical/directional gas wells from 2009 to 2013.[103]

Average well quality has fallen by 24% from 2010, a clear indication that geology is trumping technology in this shale play.

[103] Data from Drillinginfo retrieved September 2014.

Another measure of well quality is cumulative production and well life. Ten percent of the wells that have been drilled in the Woodford are no longer productive. Figure 3-67 illustrates the cumulative production of these shut-down wells over their lifetime. At a mean lifetime of 32 months and a mean cumulative production of 0.26 billion cubic feet, these wells would in large part be economic losers.

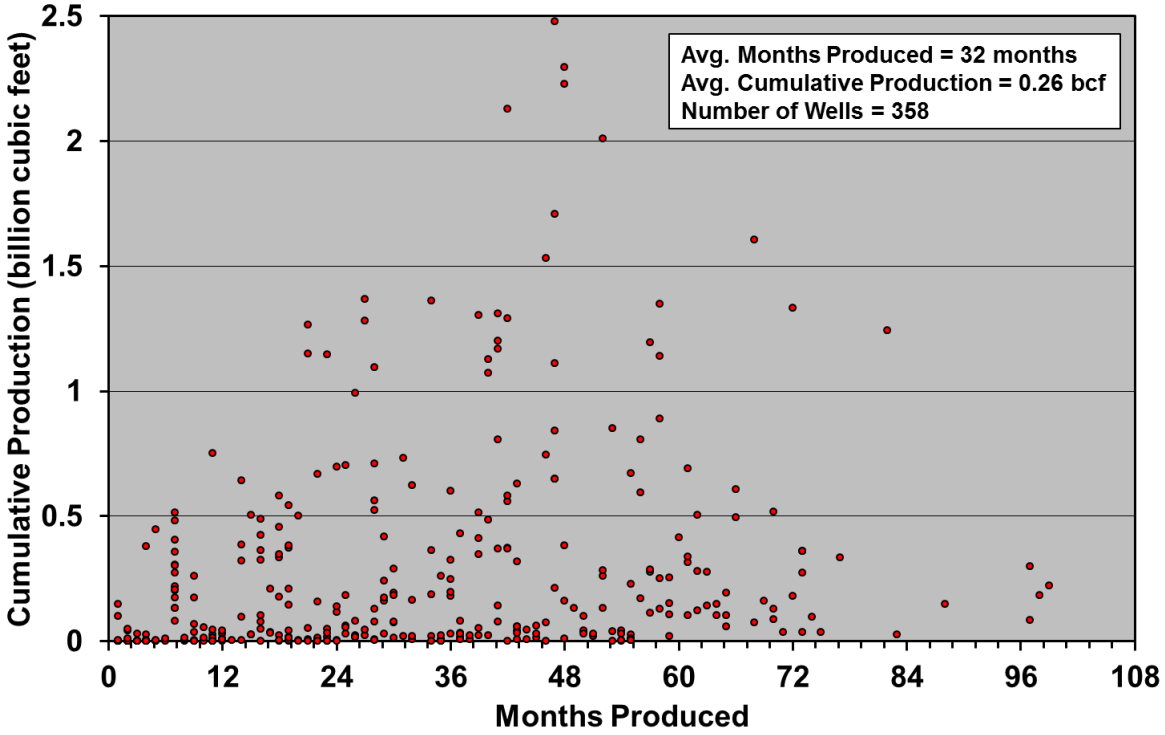

Figure 3-67.Cumulative gas production and length of time produced for Woodford wells that were not producing as of February 2014.

These well constitute 10% of all wells drilled; most would be economic failures, given the mean life of 32 months and average cumulative production of 0.26 billion cubic feet when production ended.[104]

[104] Data from Drillinginfo retrieved September 2014.

Figure 3-68 illustrates the cumulative production of all horizontal wells that were producing in the Woodford as of March 2014. Although it can be seen that there are a few very good wells that recovered large amounts of gas in the first few years, and undoubtedly were great economic successes, the average well had produced just 0.92 billion cubic feet over a lifespan averaging 42 months. Just 3% of these wells are more than 8 years old.

The lifespan of wells is another key parameter, as many operators assume a minimum well life of 30 years and longer, though this is conjectural given the lack of data and the significant number of wells that have been shut down after less than 8 years.

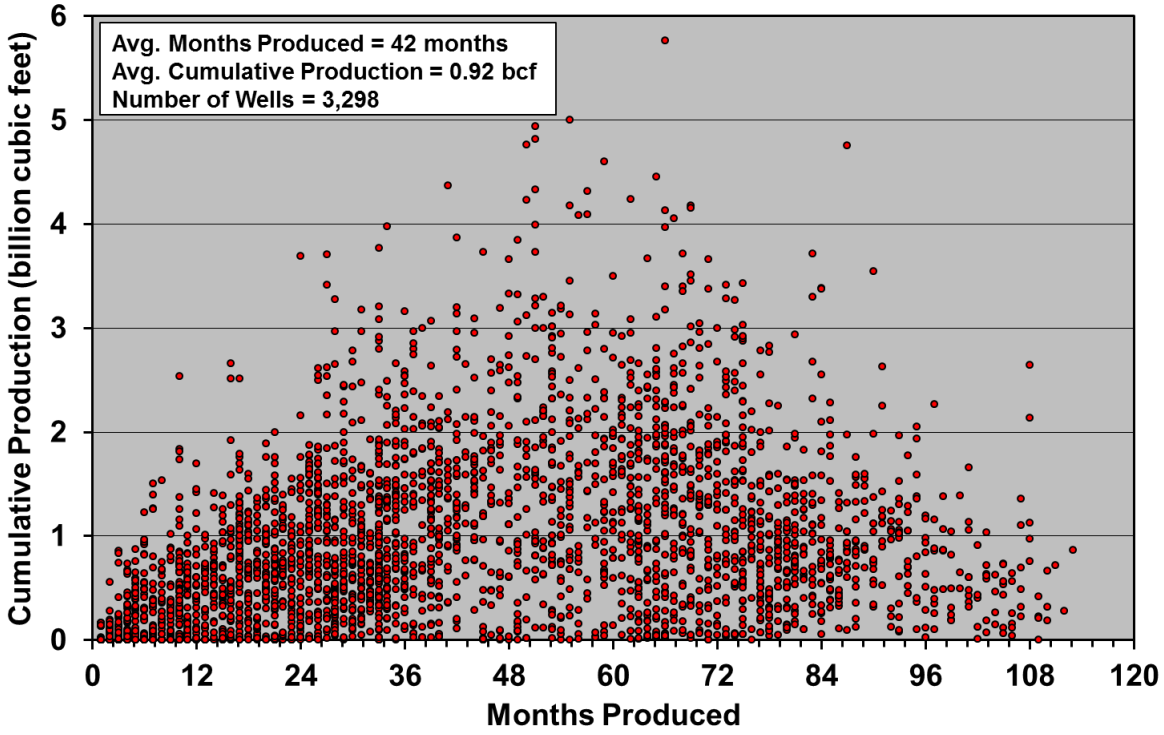

Figure 3-68. Cumulative gas production and length of time produced for Woodford wells that were producing as of March 2014.[105]

These well constitute 90% of all wells drilled. Very few wells are greater than eight years old, with a mean age of 42 months and a mean cumulative recovery of 0.92 billion cubic feet.

[105] Data from Drillinginfo retrieved September 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells in not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP). Figure 3-69 illustrates the average daily output over the first six months of production for all wells in the Woodford play (six-month IP). Again, as with cumulative production, there are a few exceptional wells—5% produced more than 4 million cubic feet per day (MMcf/d)—but the average for all wells drilled since 2005 is just 1.41 MMcf/d. Figure 3-61 illustrates the distribution of IPs in map form.

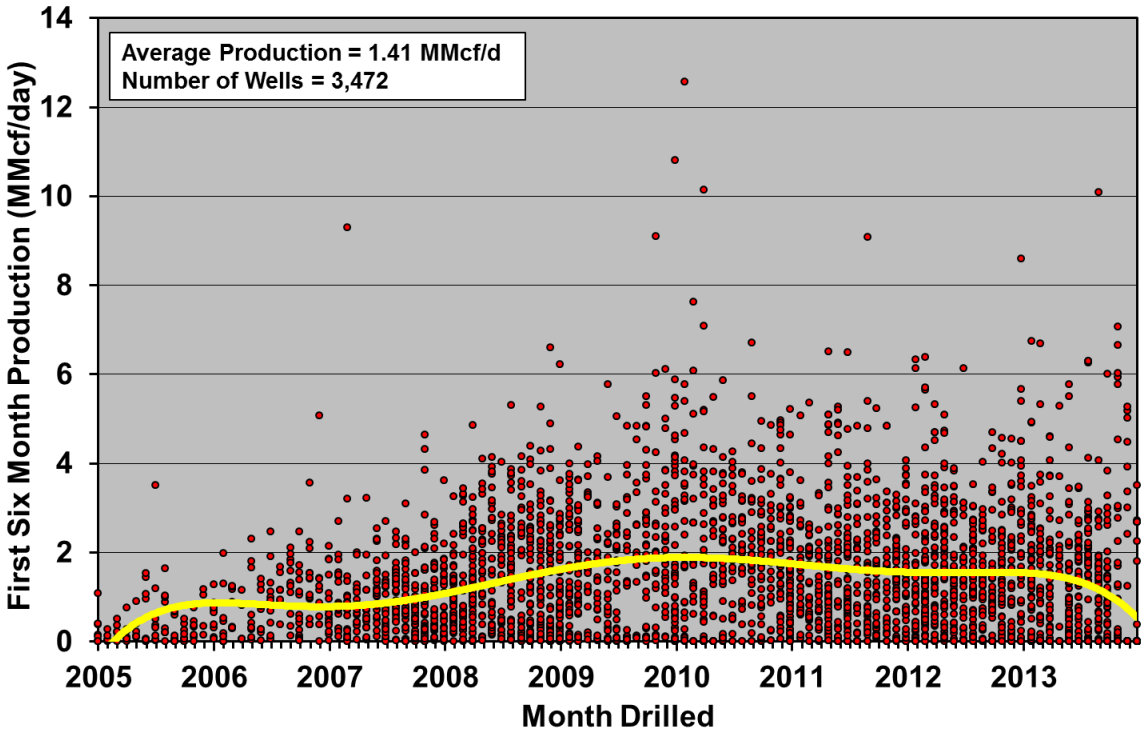

Figure 3-69. Average gas production over the first six months for all wells drilled in the Woodford play, 2005 to 2014.[106]

Although there are a few exceptional wells, the average well produced 1.41 million cubic feet per day over this period. The trend line indicates mean productivity over time.

[106] Data from Drillinginfo retrieved September 2014.

Different counties in the Woodford display markedly different well quality characteristics, which are critical in determining the most likely production profile in the future. Figure 3-70, which illustrates production over time by county, shows that as of April 2014, the top two counties produced 45% of the total, the top five produced 69%, and the remaining 26 counties produced 31%.

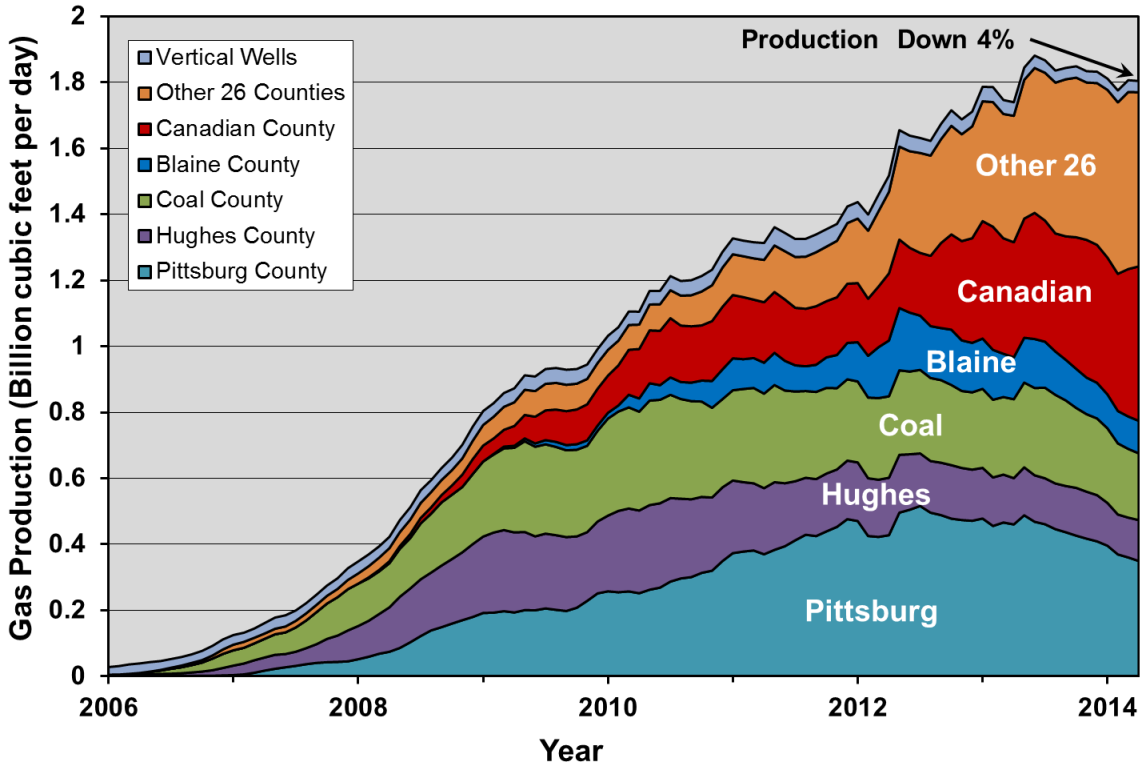

Figure 3-70. Gas production by county in the Woodford play, 2006 through 2014.[107]
The top five counties produced 69% of production in April 2014.

[107] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The same trend holds in terms of cumulative production since the field commenced. As illustrated in Figure 3-71, the top two counties have produced 49% of the gas and the top five have produced 85%. Production in four of the top five counties peaked in 2010 to 2012 and is down sharply. Production is growing in Canadian County and is flat in the 26 counties outside the top five, which tend to be richer in liquids and are the focus of drilling in a period of low priced gas. An increase in the rate of drilling given higher gas prices could temporarily halt and perhaps reverse declines in those counties that have peaked.

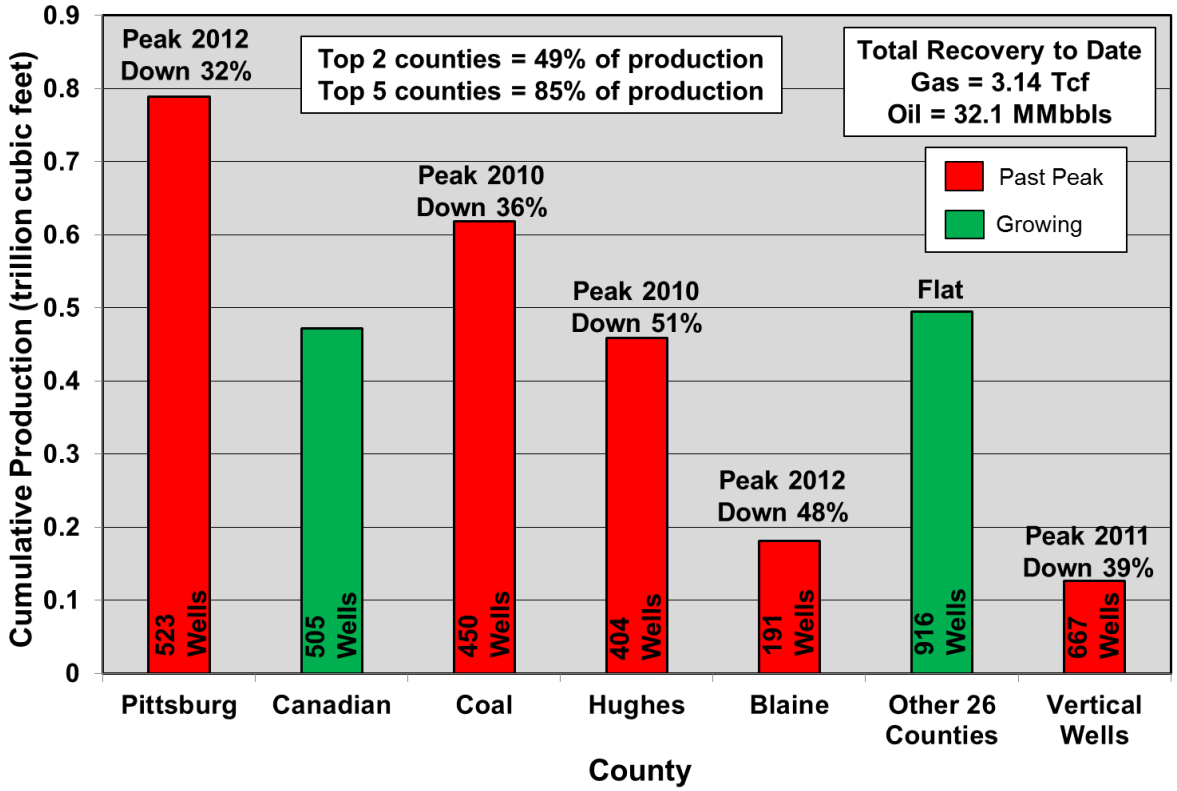

Figure 3-71. Cumulative gas production by county in the Woodford play through 2014.[108]

The top five counties have produced 85% of the 3.14 trillion cubic feet of gas produced to date.

[108] Data from Drillinginfo retrieved September 2014.

The Woodford also produces limited amounts of natural gas liquids and oil. With the exception of Canadian County, most liquids production is not within the top five counties but is located in the central and northern portions, as illustrated in Figure 3-72. Some 32 million barrels of liquids have been produced since 2005, and, given low gas prices, has improved economics and driven drilling to counties where liquids can be produced.

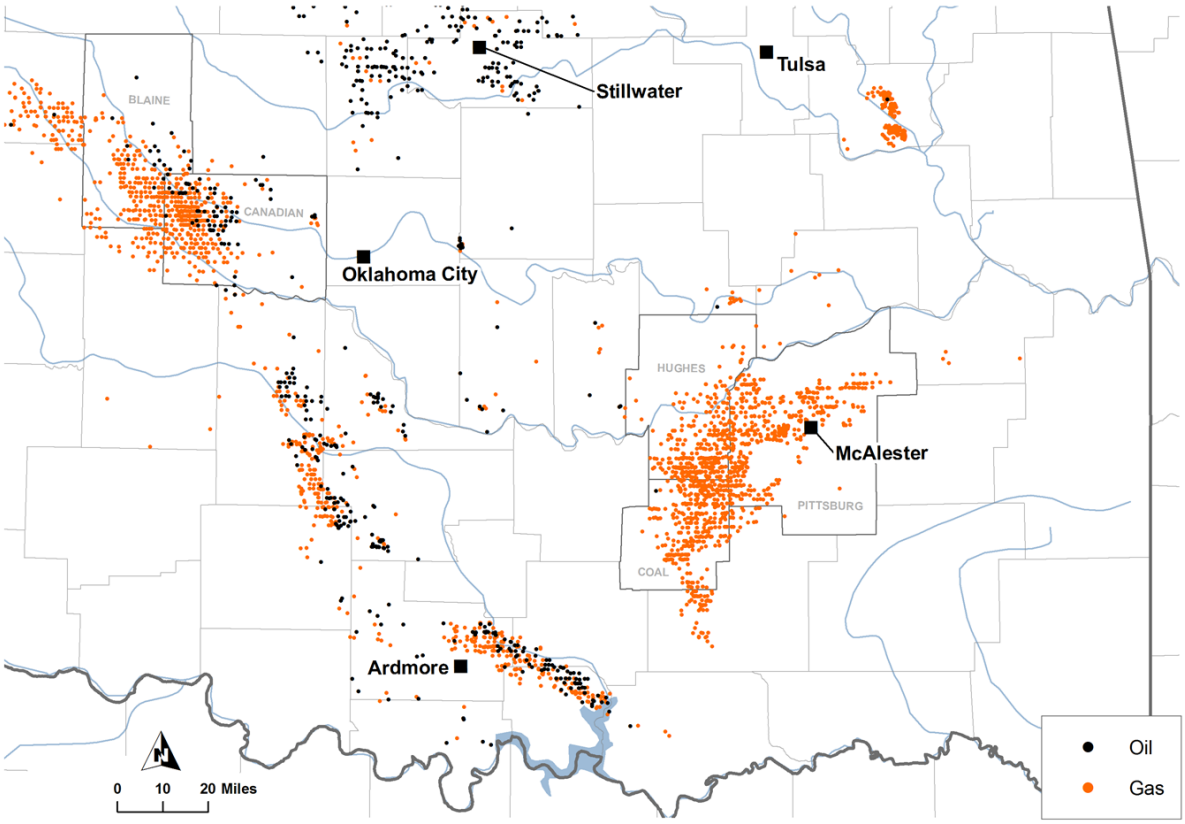

Figure 3-72. Distribution of gas and oil wells in Woodford play as of early 2014.[109]

Liquids production from wells classified as "oil" occurs mainly in the central and northern portions of the play.

[109] Data from Drillinginfo retrieved August 2014.

Figure 3-73 illustrates liquids production in the Woodford by county. In the big picture liquids production from the Woodford is relatively insignificant, for although it has grown significantly since 2005 it still amounted to less than 8% of the energy produced from the Woodford play in early 2014. In fact, liquids production has fallen more than 30% from a peak of 38,000 barrels per day reached in June 2013.

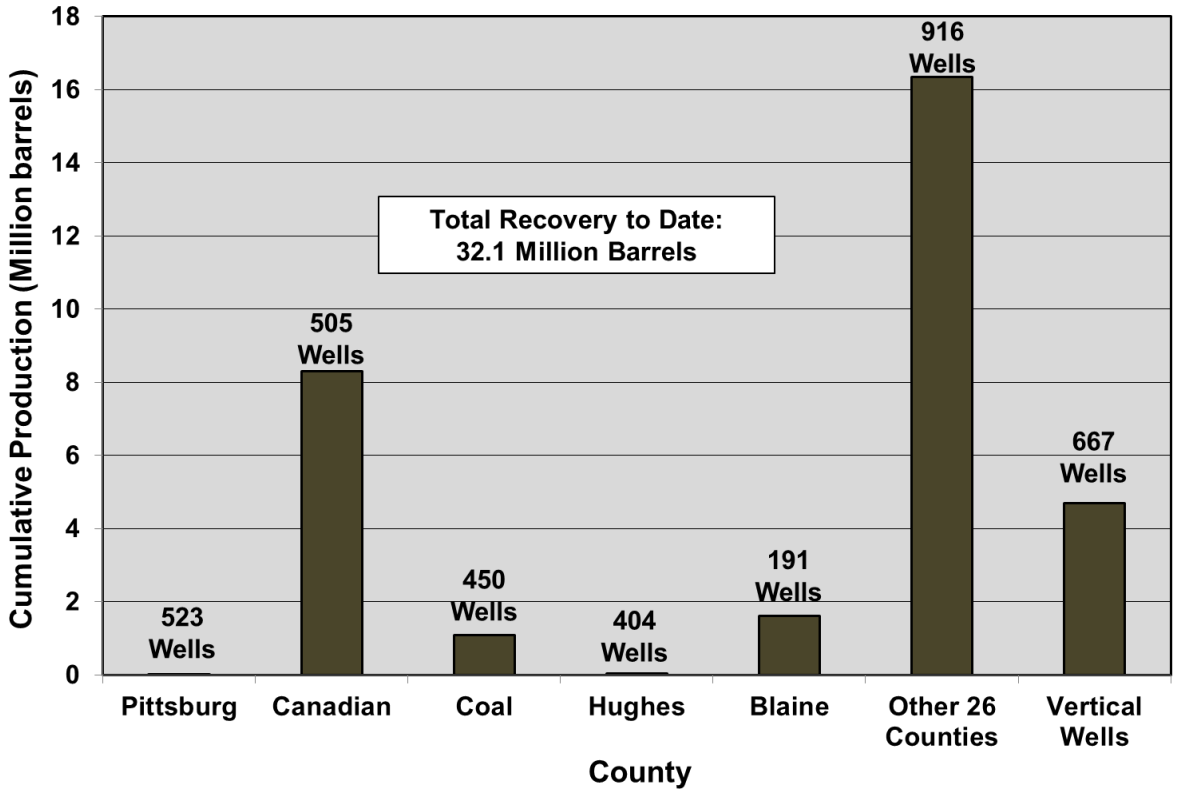

Figure 3-73. Cumulative liquids production by county in the Woodford play through 2014.[110]

Canadian and the "other 26" counties account for 77% of the 32 million barrels produced to date.

[110] Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost on the order of $9 million or more each, not including leasing costs and other expenses.[111] The areas of highest quality—the "core" or "sweet spots"—have now been well defined. Figure 3-74 illustrates average horizontal well decline curves by county which are a measure of well quality (recognizing that future gas production from the Woodford will be dominantly from horizontal, not vertical, wells). Initial well productivities (IPs) from Pittsburg, Coal and Hughes counties are significantly higher than Canadian, Blaine and the "other 26" counties, although the latter benefit from significant liquids production which improves economics. Notwithstanding the higher productivity of wells in the top counties, production has fallen between 32% and 52% from peak in four of the top five counties—a function of low gas prices, expensive wells, and available drilling locations. Halting production declines even temporarily in these counties will require significantly higher gas prices.

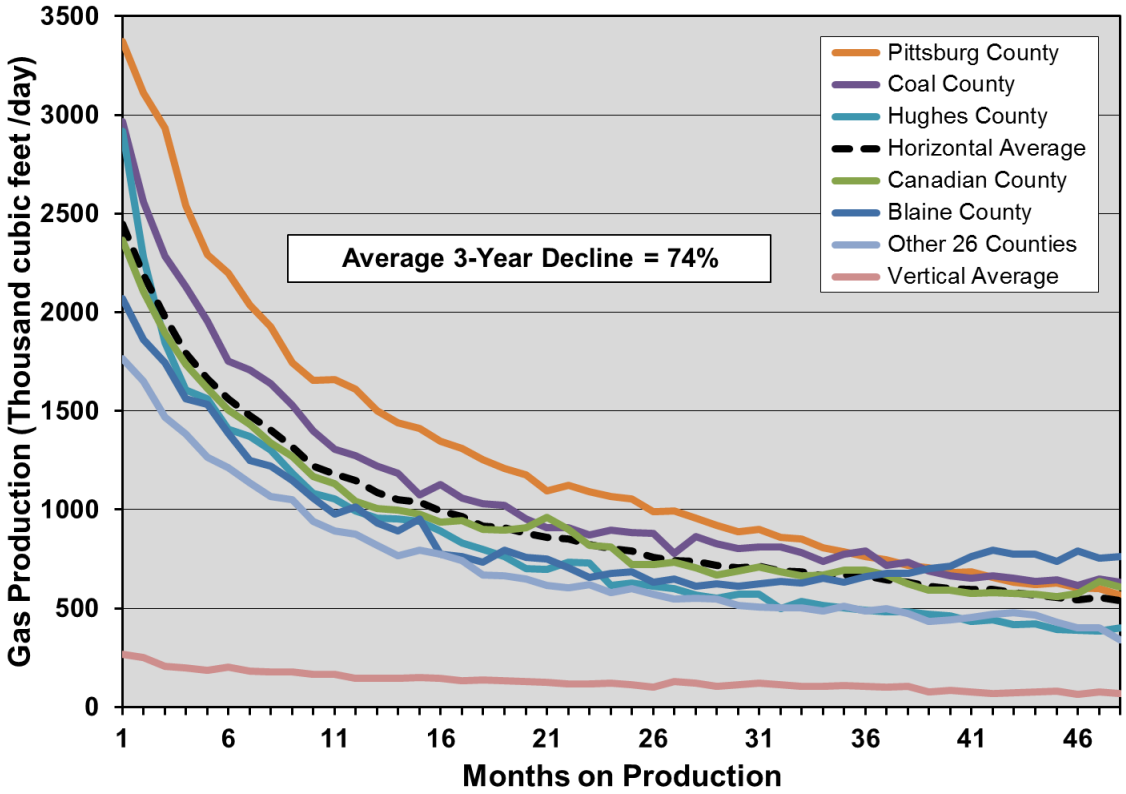

Figure 3-74. Average horizontal gas well decline profiles by county for the Woodford play.[112]

The top two counties, which have produced much of the gas in the Woodford, are clearly superior.

Another measure of well quality is "estimated ultimate recovery" or EUR—the amount of gas a well will recover over its lifetime. To be clear, no one knows what the lifespan of an average Woodford well is, given that few of them are more than eight years old (see Figure 3-67 and Figure 3-68), and some 10% of horizontal wells drilled have ceased production at an average age of less than three years. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-74, assuming well life spans of

[111] Mason, Richard, June 27, 2013, "Targeting Oklahoma's Ubiquitous Woodford Shale," http://www.ugcenter.com/Woodford/Targeting-Oklahomas-Ubiquitous-Woodford-Shale_118127.
[112] Data from Drillinginfo retrieved September 2014.

30-50 years (as is typical for conventional wells), but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Woodford. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-74, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-75 illustrates theoretical EURs by county for the Woodford for comparative purposes of well quality. These range from 1.95 to 3.19 billion cubic feet per well, which are somewhat higher than the 1.18 to 1.51 billion cubic feet assumed by the EIA.[113] The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 45% and 60% of an average well's lifetime production occurs in the first four years.

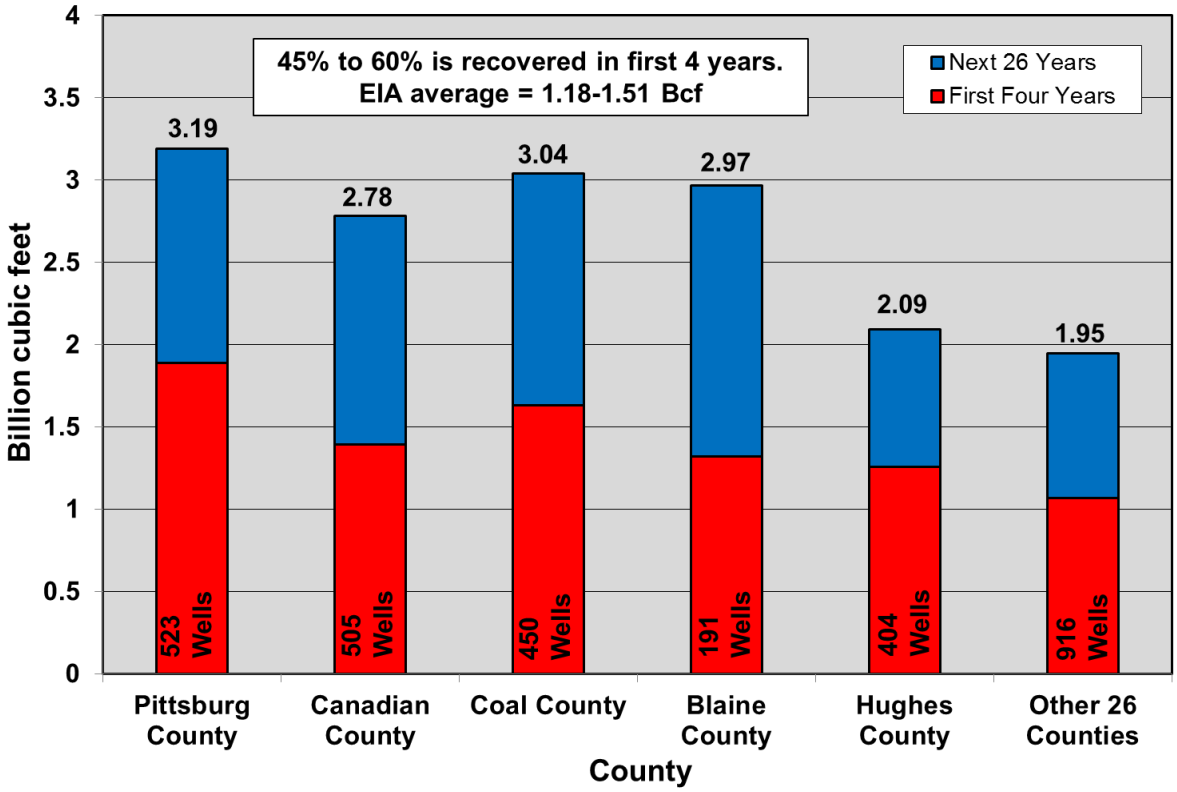

Figure 3-75. Estimated ultimate recovery of gas per well by county for the Woodford play.[114]

EURs are based on average well decline profiles (Figure 3-74) and a terminal decline rate of 15%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know both the rate of production in the first year of the average well and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Figure 3-76 illustrates the average first-year production rate of wells in the Woodford by county. With the

[113] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[114] Data from Drillinginfo retrieved September 2014.

exception of Pittsburg County, which had its peak rate in 2011, all counties experienced peak rates in 2010 and on average the play is down 24% since then. In the past two years average productivity has been flat, including significant improvement in Coal County and continued decline in Blaine and Pittsburg counties. This reflects both a lack of improvement from better technology as well as a move into liquids rich-parts of the play which in general have somewhat lower gas productivities.

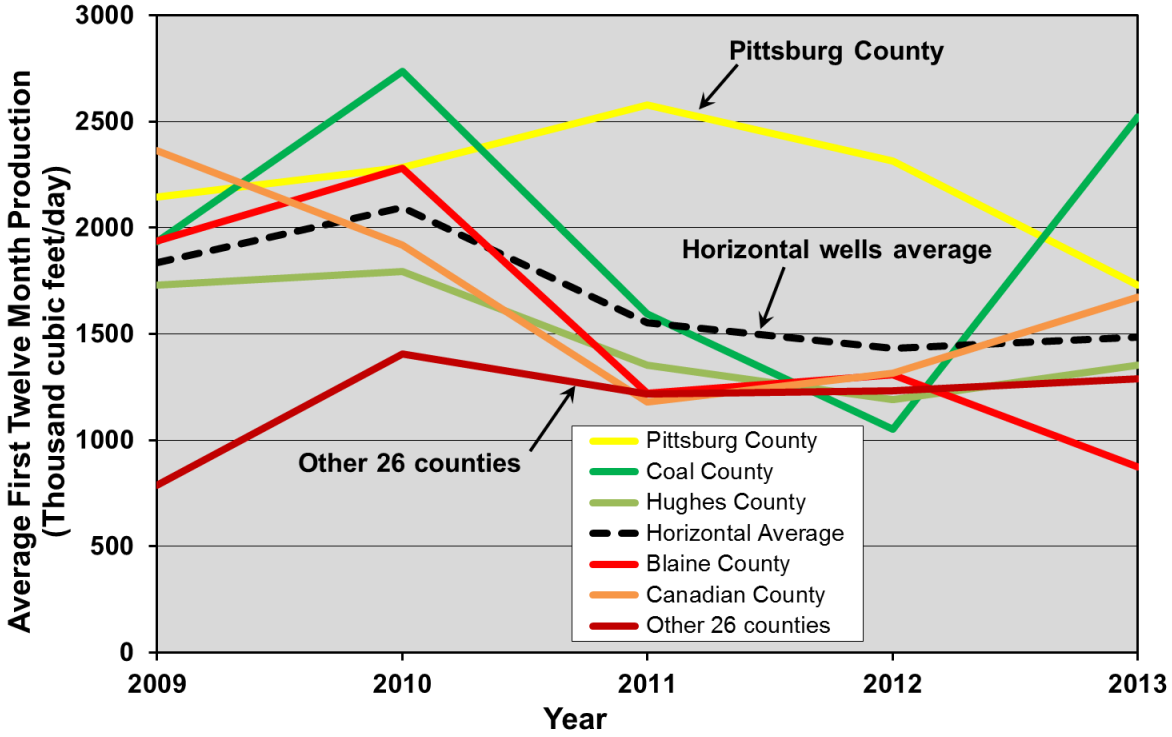

Figure 3-76. Average first-year gas production rates of wells by county for the Woodford play, 2009 to 2013.[115]

Well quality is down 24% on average from 2010, notwithstanding a recent increase in Coal County.

[115] Data from Drillinginfo retrieved September 2014.

3.3.4.4 Number of Wells

The fourth key fundamental is the number of wells that can ultimately be drilled in the Woodford play. A careful review of the top five counties suggests a prospective area of 2,358 square miles within them. The EIA has estimated the total play area at 4,246 square miles,[116] which leaves 1,888 prospective square miles outside the top five counties. This appears to be overly optimistic, given the distribution of production outlined in Figure 3-61, but for the sake of argument is assumed to be correct. The EIA further assumes that between 4 and 8 wells can be drilled per square mile, for an average well density of 4.6 wells per square mile.[117] The existing well density over this area is 0.84 wells per square mile (including vertical wells), and 0.7 including only horizontal wells. Assuming that only horizontal wells will be drilled in future, and given that vertical wells are already at a density of 0.14 per square mile, a final density of 4.5 horizontal wells per square mile is assumed. Given that 3,656 wells have already been drilled, that leaves 16,118 horizontal yet-to-drill wells, for a final well count of 19,107.

Table 3-4 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Woodford play.

[116] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[117] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.

Parameter	County						Total
	Blaine County	Canadian County	Coal County	Hughes County	Pittsburg County	Other 26 Counties	
Production April 2014 (Bcf/d)	0.10	0.47	0.20	0.12	0.35	0.53	1.77
% of Field Production	6	26	11	7	20	30	100
Cumulative Gas (Tcf)	0.18	0.47	0.62	0.46	0.79	0.50	3.01
Cumulative Liquids (MMbbl)	1.61	8.31	1.09	0.04	0.00	16.35	27.41
Number of Wells	191	505	450	404	523	916	2989
Number of Producing Wells	171	451	423	361	481	745	2632
Average EUR per well (Bcf)	2.09	2.78	3.04	2.97	3.19	1.95	2.64
Field Decline (%)	38.1	46.5	14.1	17.9	28.4	40.3	32.7
3-Year Well Decline (%)	63	74	79	86	83	81	78
Peak Year	2012	Rising	2010	2010	2012	Flat	2012
% Below Peak	48	N/A	36	51	32	N/A	4
Average First Year Production in 2013 (Mcf/d)	875	1673	2522	1354	1728	1290	1486
New Wells Needed to Offset Field Decline	29	170	27	19	43	170	405
Area in square miles	929	900	518	807	1306	10000	14460
% Prospective	50	60	70	50	45	19	29
Net square miles	465	540	363	404	588	1888	4246
Well Density per square mile	0.41	0.94	1.24	1.00	0.89	0.49	0.70
Additional locations to 4.5/sq. Mile	1899	1925	1182	1412	2122	7579	16118
Population	11943	115541	5925	14003	45837	N/A	N/A
Total Wells 4.5/sq. Mile	2090	2430	1632	1816	2645	8495	19107
Total Producing Wells 4.5/sq. Mile	2070	2376	1605	1773	2603	8324	18750

Table 3-4. Parameters for projecting Woodford production, by county.

Area in square miles under "Other" is estimated.

3.3.4.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling—the fifth key fundamental. Figure 3-77 illustrates the historical drilling rates in the Woodford. Horizontal drilling rates peaked in January 2013 at 601 wells per year and have fallen to current levels of less than 300 wells per year. Current drilling rates are somewhat less than the roughly 400 wells per year required to maintain current production, hence production is gradually declining.

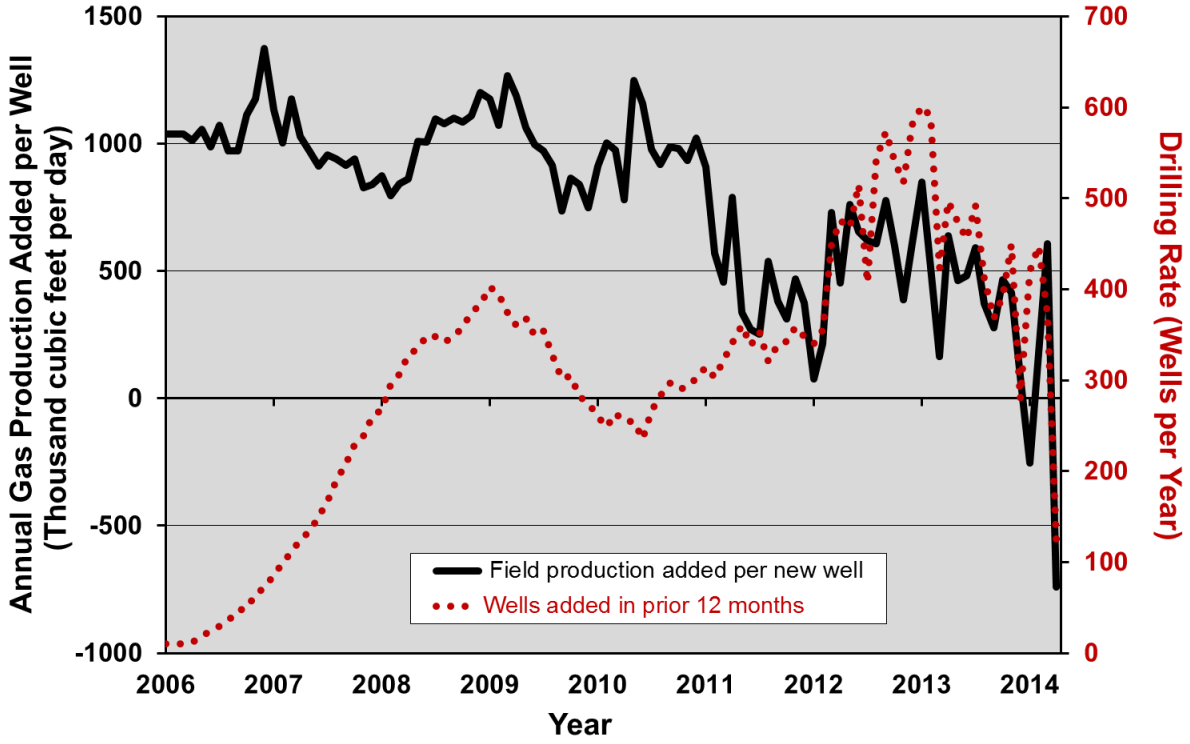

Figure 3-77. Annual production added per new horizontal well and annual drilling rate in the Woodford play, 2006 through 2014.[118]

Drilling rate peaked in January 2013 and is now somewhat below the level needed to keep production flat, hence each new well now only serves to slow the overall production decline of the play.

[118] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

3.3.4.6 Future Production Scenarios

Based on the five key fundamentals outlined above, several production projections for the Woodford play were developed to illustrate the effects of changing the rate of drilling. Figure 3-78 illustrates the production profiles of three drilling rate scenarios if 100% of the prospective play area is drillable at 4.5 horizontal wells per square mile. These scenarios are:

1. MOST LIKELY RATE scenario: Drilling increases somewhat to 400 wells per year, then gradually declines to 300 wells per year.

2. LOW RATE scenario: Drilling remains at 300 wells per year, then gradually declines to 250 wells per year.

3. HIGH RATE scenario: Drilling roughly doubles to 550 wells per year, then gradually declines to 300 wells per year.

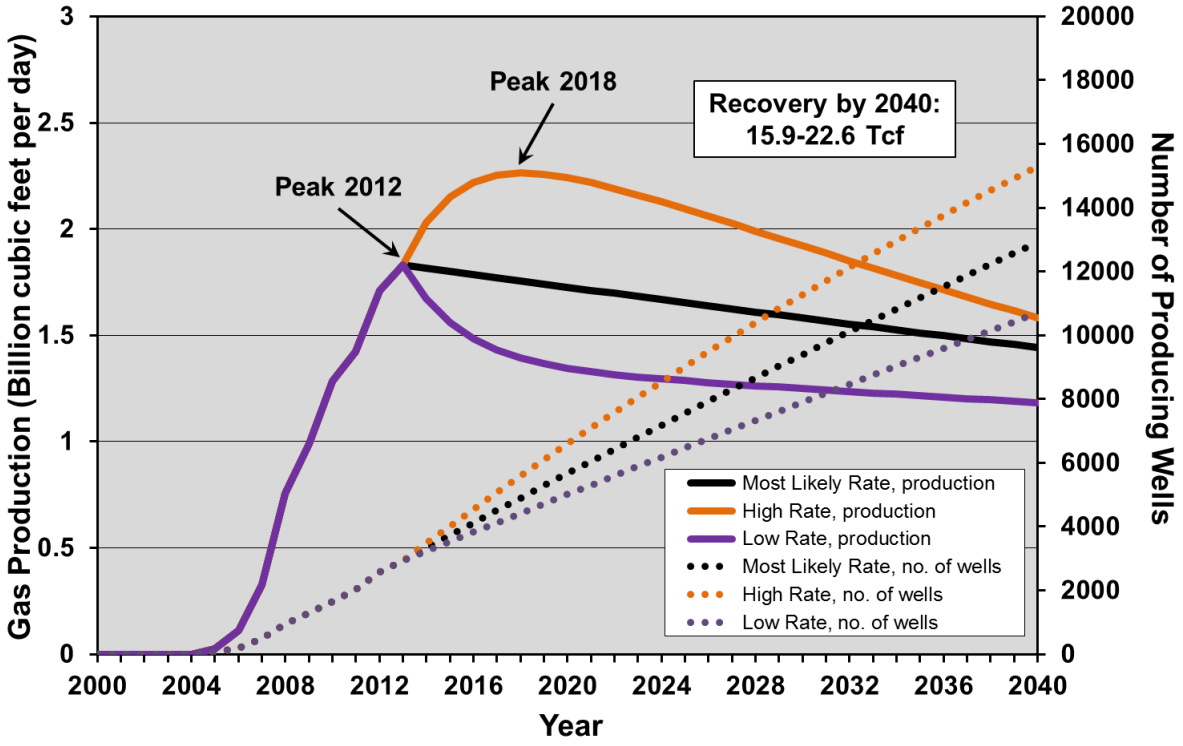

Figure 3-78. Three drilling rate scenarios of Woodford gas production (assuming 100% of the area is drillable at 4.5 horizontal wells per square mile).[119]

"Most Likely Rate" scenario: drilling increases to 400 wells/year, declining to 300 wells per year.
"Low Rate" scenario: drilling continues at 300 wells/year, declining to 250 wells/year.
"High Rate" scenario: drilling increases to 550 wells/year, declining to 300 wells/year.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: The drilling rate increases somewhat from current levels on strengthening gas prices, and then gradually declines as lower quality parts of the play are drilled.

[119] Data from Drillinginfo retrieved September 2014.

Total gas recovery by 2040 would be 19.1 trillion cubic feet and drilling would continue beyond 2040.

2. LOW RATE scenario: Drilling would continue at current rates. Total gas recovery by 2040 would be 15.9 trillion cubic feet and drilling would continue beyond 2040.

3. HIGH RATE scenario: Nearly doubling drilling rates would reverse decline and production would grow to a new peak in 2018. Total gas recovery by 2040 would be 22.6 trillion cubic feet and drilling would continue beyond 2040.

The recovery of 19.1 trillion cubic feet by 2040 in the "Most Likely" drilling rate scenario, and the recovery of 22.6 trillion cubic feet in the "High" drilling rate scenario, are somewhat less but reasonably close to the recovery of 23.8 trillion cubic feet assumed by the EIA. The "Most Likely" drilling rate scenario would see the recovery of more than six times as much gas as has been recovered to date (3.01 Tcf).

3.3.4.7 Comparison to EIA Forecast

Figure 3-79 illustrates the EIA's projection for Woodford production through 2040 compared to the "Most Likely Rate" scenario. Although the total recovery is not that different, the EIA has underestimated actual recovery through 2014 and assumes that production rate will ramp to a new peak in 2026 some 36% higher than the peak in 2012, and maintain production at levels considerably higher than today through 2040.[120] This implies the recovery of 82% of the proved reserves[121] and unproved resources[122] that the EIA assigns to the Woodford play. Although this seems highly optimistic, the EIA forecast for the Woodford is more restrained than its estimates for most other major shale plays.

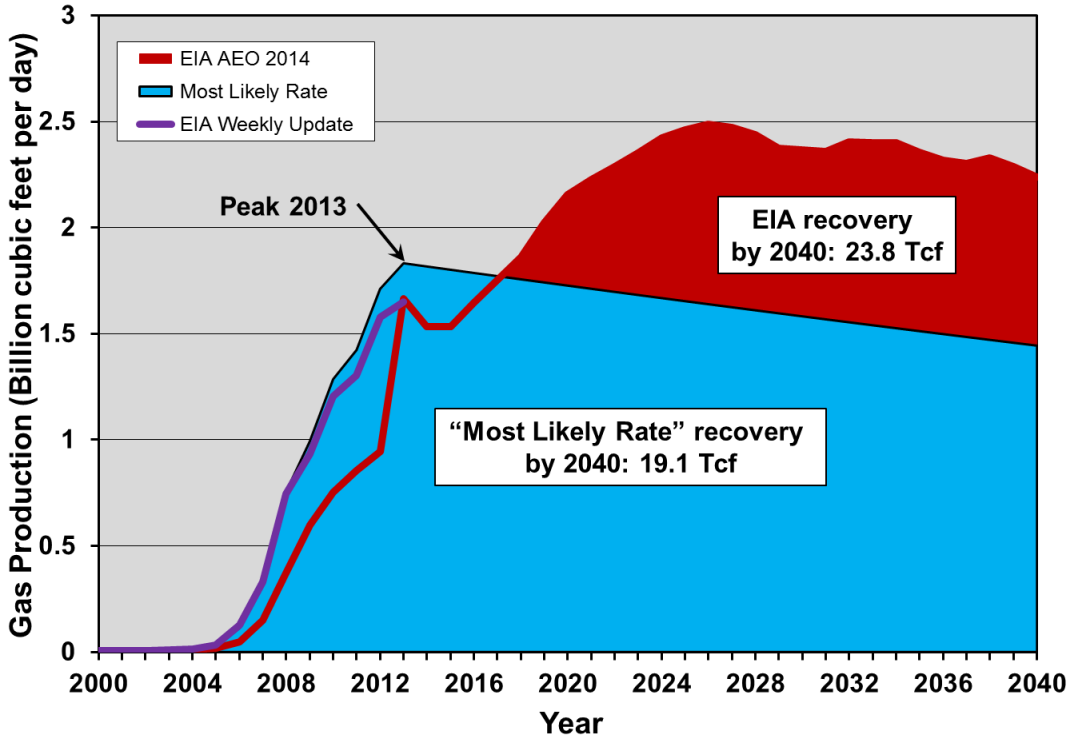

Figure 3-79. "Most Likely Rate" scenario of Woodford gas production compared to the EIA reference case, 2000 to 2040.[123]

The EIA assumes the Woodford will reach a new all-time high by 2026, and maintain production at considerably higher than present levels through 2040. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis. Also shown are the EIA's Woodford gas production statistics from its *Natural Gas Weekly Update*,[124] which contradict the early years of its AEO 2014 forecast.

[120] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[121] EIA, 2014, "Principal shale gas plays: natural gas production and proved reserves, 2011-12," http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls.
[122] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[123] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[124] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly.

3.3.4.8 Woodford Play Analysis Summary

Several things are clear from this analysis:

1. Drilling rates have fallen in the Woodford due to gas prices, and drilling has moved to liquids-rich parts of the play.

2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of about 300 wells per year are somewhat below the level of about 400 wells per year required to maintain production, which would require the investment of $3.6 billion per year for drilling (assuming $9 million per well). Future production profiles are most dependent on drilling rate and, to a lesser extent, on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Maintaining or growing gas production in the Woodford would require considerably higher gas prices to justify higher drilling rates.

3. Doubling current drilling rates could reverse the current production decline and raise production to a new peak in the 2018 timeframe, but would increase cumulative recovery only by 19% by 2040 and wouldn't change the ultimate recovery of the play. Increasing drilling rates effectively recovers the gas sooner making the supply situation worse later.

4. The projected recovery of 19.1 Tcf by 2040 in the "Most Likely Rate" scenario, is somewhat less than the 23.8 Tcf projected by the EIA in its reference case forecast. The EIA forecast of the Woodford rising to a new production peak in 2026 at significantly higher rates than today is improbable.

5. This report's projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained. They also assume that 100% of the prospective area is drillable. This is not a sure thing as drilling in the poorer quality parts of the play will require considerably higher gas prices to be economic. Failure to maintain drilling rates will result in a steeper drop off in production.

6. More than triple the current number of wells will need to be drilled to meet the production projection of the "Most Likely Rate" scenario by 2040.

7. The EIA projection for future Woodford gas production included in its reference case forecast for AEO 2014[125] is highly optimistic in that it forecasts the current production decline will be reversed and rise to a new peak in 2026 at a level 36% higher than the 2012 peak of the play, and then maintain production through 2040 at levels far higher than today. This is highly unlikely to be realized, especially at the gas prices the EIA forecasts.[126]

[125] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[126] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.

3.3.5 Marcellus Play

The Marcellus play is now the largest and fastest growing shale gas play in the U.S. Production growth in the Marcellus has more than compensated for declines in other plays. It is also the largest play in terms of areal extent, stretching from New York State to southern West Virginia and west to Ohio, although most production comes from Pennsylvania. Figure 3-80 illustrates the distribution of wells as of mid-2014. Over 10,700 wells have been drilled to date of which 7,006 were producing at the time of writing. Of these, more than 7,900 are in Pennsylvania, 5,302 of which were producing in mid-2014. There is a large backlog of drilled but not connected wells (also indicated in Figure 3-80), believed to be over two thousand in number. This is a function of the rate of drilling and the relative youth of the play; most of these wells will be connected over time as pipeline infrastructure catches up.

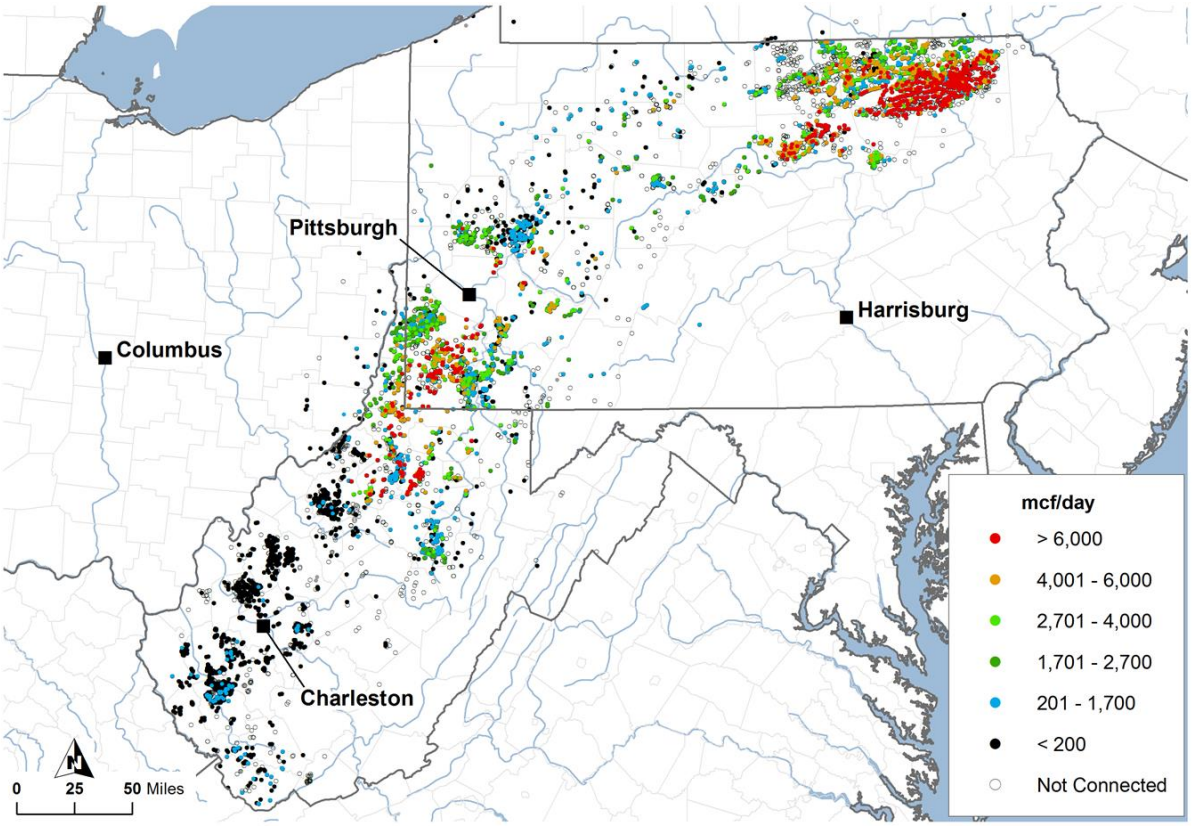

Figure 3-80. Distribution of wells in Marcellus play as of mid-2014, illustrating highest one-month gas production (initial productivity, IP).[127]

Well IPs are categorized approximately by percentile; see Appendix.

[127] Data from Drillinginfo retrieved September 2014.

Production from the Marcellus exceeded 12 billion cubic feet per day in June 2014 as illustrated in Figure 3-81. More than 91% of production came from Pennsylvania with most of the remainder from West Virginia. Ohio and New York State production is negligible. Over 98% of Pennsylvania production is from horizontal fracked wells, whereas 22% of production in West Virginia came from vertical/directional wells. The rate of drilling grew to a maximum of more than 1,500 wells per year in mid-2012 through 2013 and has now fallen to about 1,300 per year. Drilling rates are still well above the approximately 1,000 wells per year required to keep production flat at current production levels, so production will keep rising.

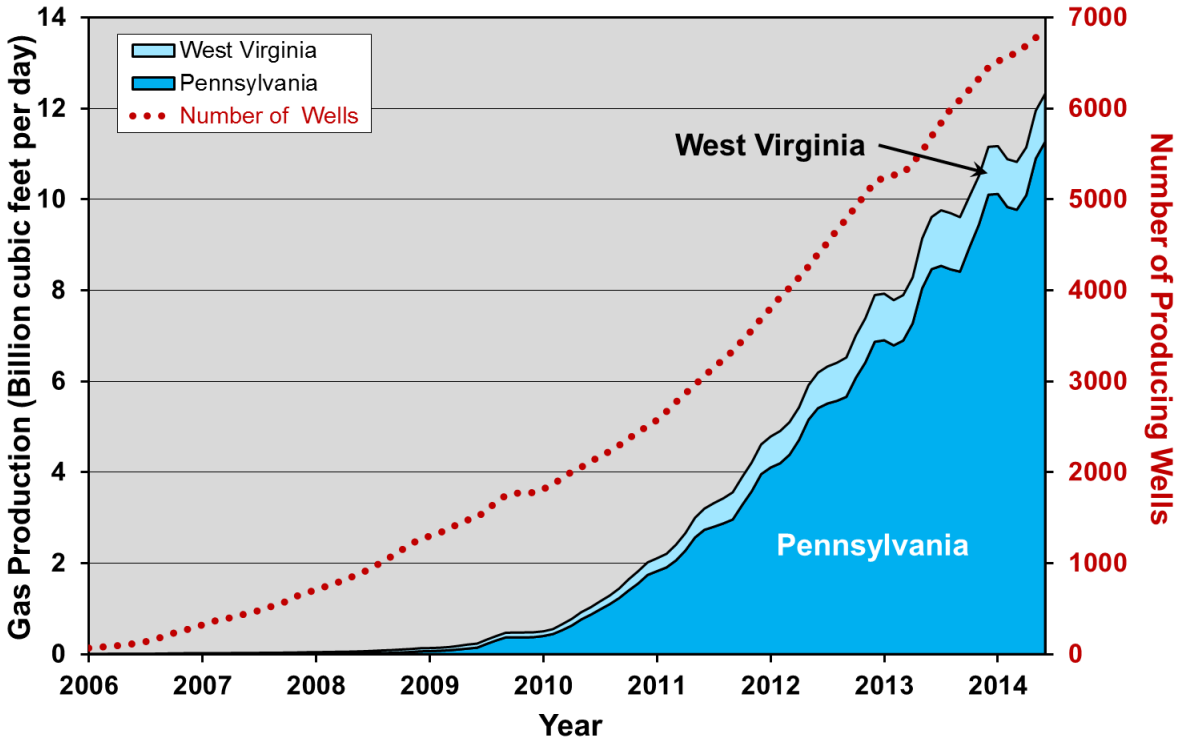

Figure 3-81. Marcellus play shale gas production, differentiating between Pennsylvania and West Virginia, and number of producing wells, 2006 to 2014.[128]

Gas production data are provided on a "raw gas" basis.

[128] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

Vertical wells played a significant role in the early development of the Marcellus play in West Virginia and still produce some oil and gas, although new wells are predominantly horizontal. Although there are some legacy vertical wells in Pennsylvania, virtually all new drilling is horizontal. The distribution of horizontal and vertical/directional wells in the play is illustrated in Figure 3-82.

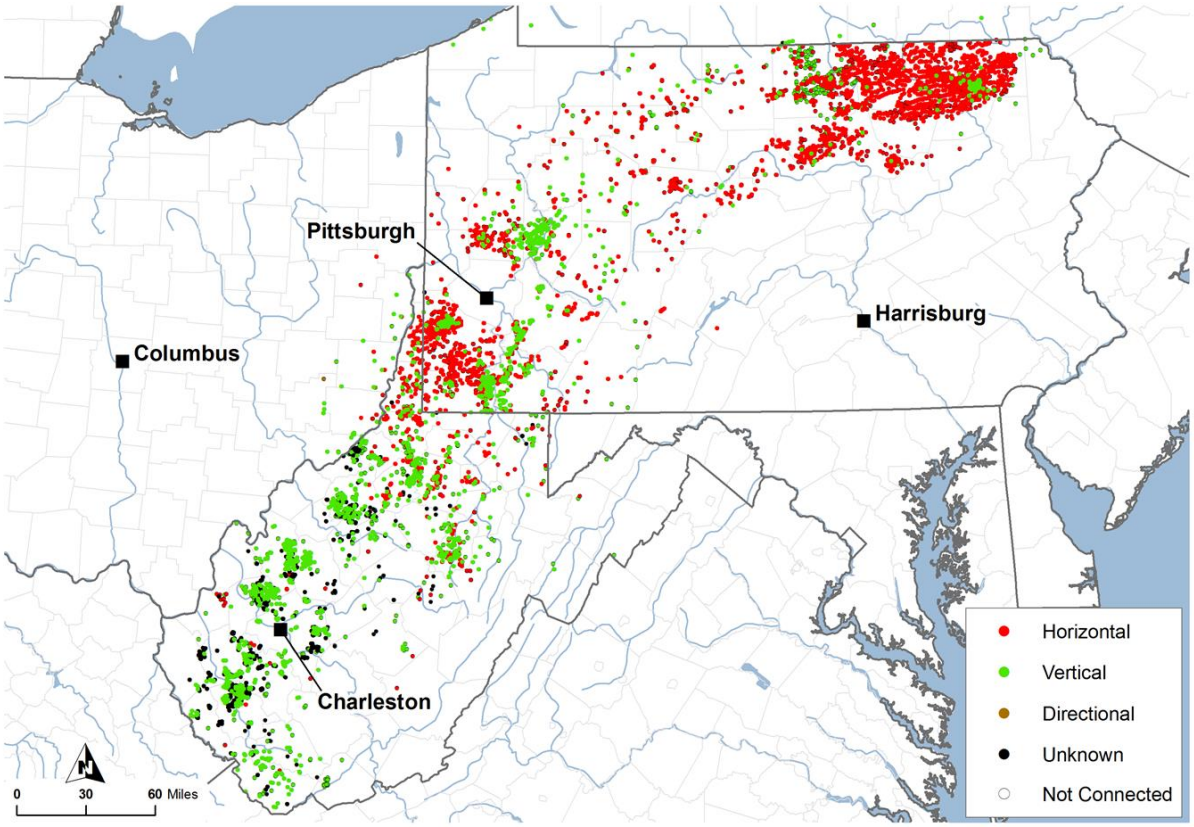

Figure 3-82. Distribution of wells in Marcellus play categorized by drilling type as of mid-2014.[129]

Development began with vertical and directional wells before expanding to largely horizontal drilling at present.

[129] Data from Drillinginfo retrieved September 2014.

Cumulative gas recovery by well type in Pennsylvania and West Virginia is illustrated in Figure 3-83. Although vertical/directional wells make up 23% of currently producing wells, they have produced less than 4% of the gas. There will be few if any additional vertical/directional wells drilled in the Marcellus play—future production growth will rely on horizontal fracked wells.

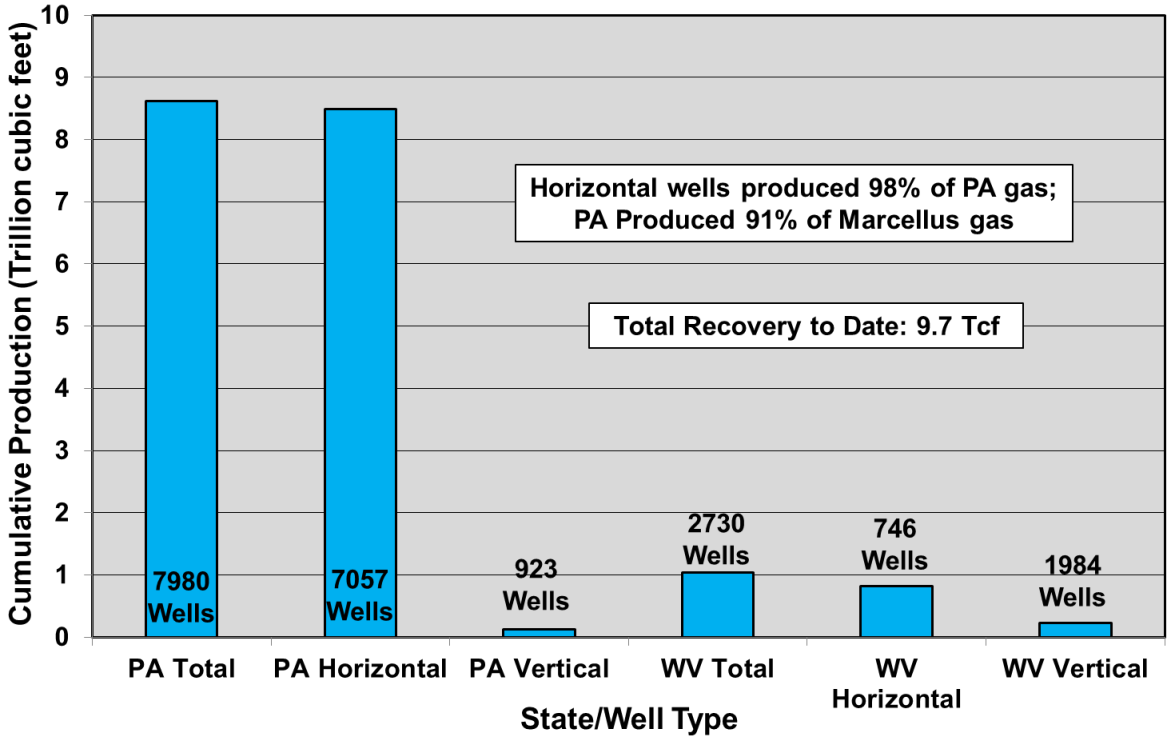

Figure 3-83. Cumulative gas production in the Marcellus play by well type and state, 2000 to 2014.[130]

The well count includes all producing wells as well as those drilled but not producing, either because they are not connected to pipelines or have ceased production.

[130] Data from Drillinginfo retrieved September 2014.

3.3.5.1 Well Decline

The first key fundamental in determining the life cycle of Marcellus production is the *well decline rate*. Marcellus wells exhibit high decline rates in common with all shale plays. Figure 3-84 illustrates the average decline rate of the most recent Marcellus horizontal and vertical/directional wells by state. Decline rates are steepest in the first year and are progressively less in the second and subsequent years. The decline rates over the first three years of average well life range between 74% and 82%, which is on the lower end of the range for most shale plays. As can be seen, vertical/directional wells have much lower productivity than horizontal wells and hence are being phased out.

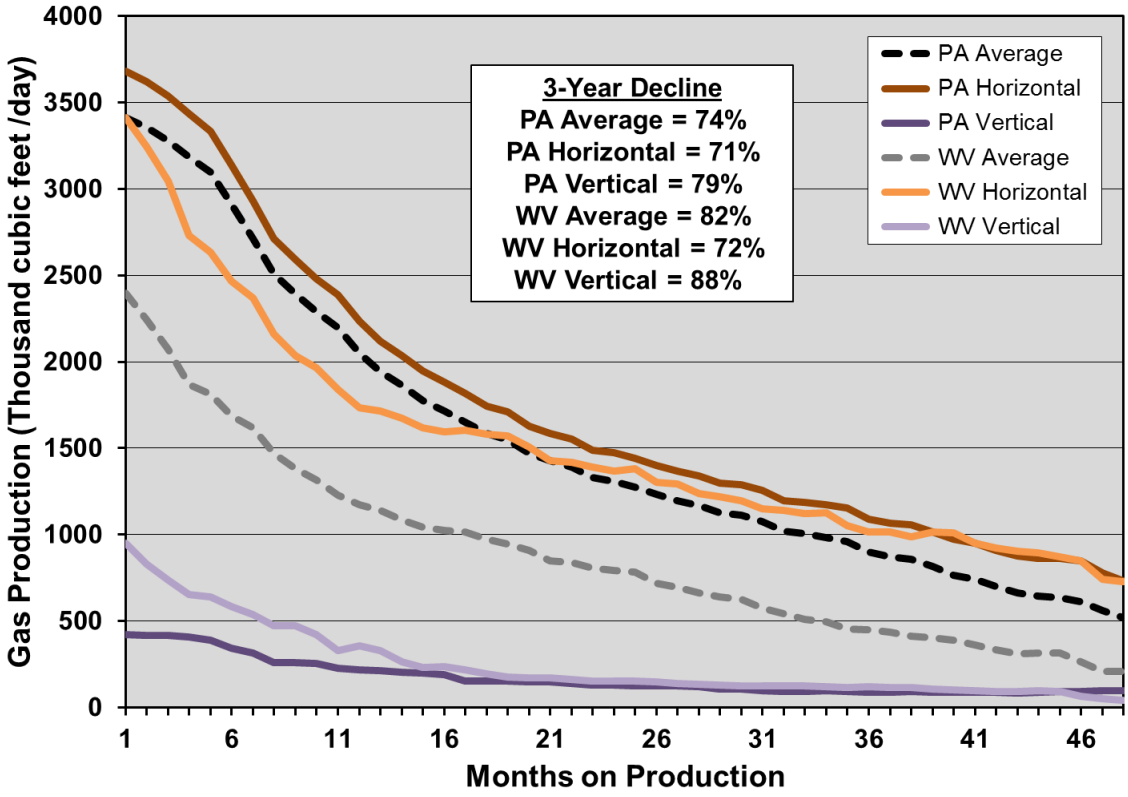

Figure 3-84. Average decline profile for horizontal and vertical/directional gas wells in the Marcellus play, by state.[131]

Decline profile is based on all shale gas wells drilled since 2009.

[131] Data from Drillinginfo retrieved September 2014.

3.3.5.2 Field Decline

A second key fundamental is the overall *field decline rate*, which is the amount of production that would be lost in a year without more drilling. Figure 3-85 illustrates production from the 3,500 horizontal wells drilled prior to 2013 in Pennsylvania. The first-year decline rate is 32%, which is on the low end of field decline rates observed for shale plays. Assuming new wells will produce in their first year at the average first-year rates observed for wells drilled in 2013, approximately 1,000 new wells each year would be required to offset field decline at current production levels. At an average cost of $5 million per well, this would represent a capital input of about $5 billion per year, exclusive of leasing and other infrastructure costs, to keep production flat at mid-2014 levels.

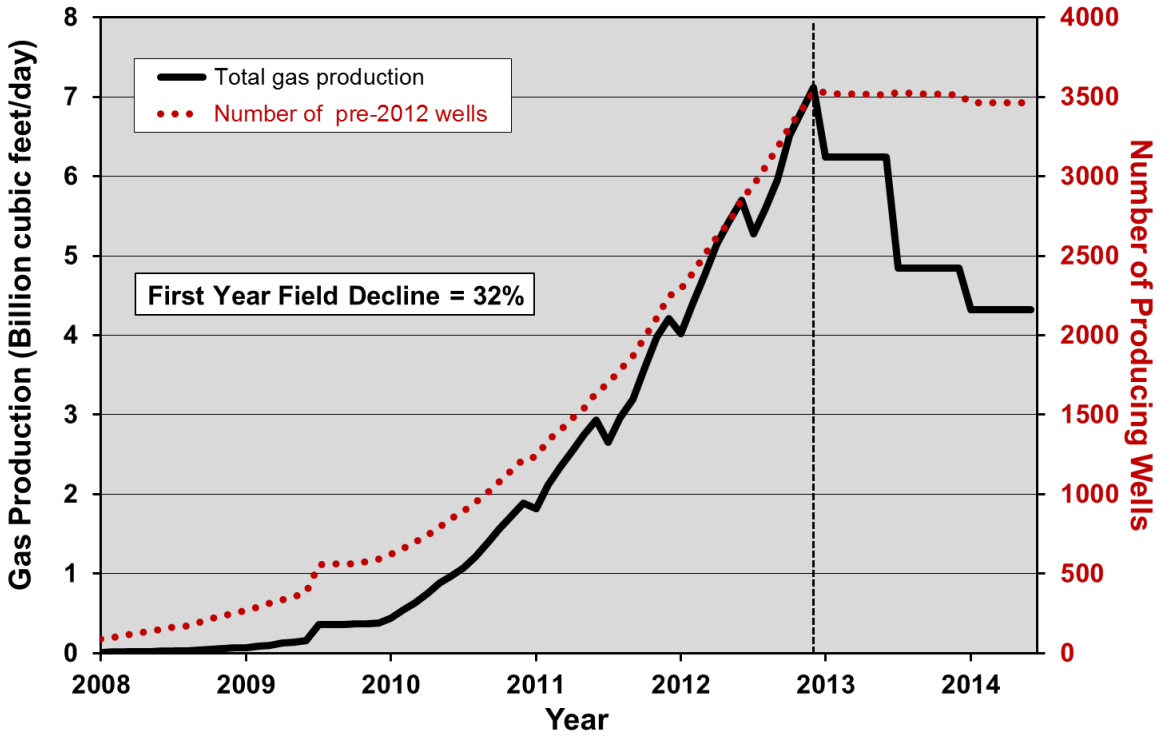

Figure 3-85. Production rate and number of horizontal shale gas wells drilled in the Marcellus play in Pennsylvania prior to 2013, 2008 to 2014.[132]

This defines the field decline for the Marcellus play which is 32% per year (horizontal wells will be responsible for virtually all future production). The stepped nature of the production curve is due to the fact that Pennsylvania releases data in six month chunks, not on a monthly basis.

[132] Data from Drillinginfo retrieved September 2014.

3.3.5.3 Well Quality

The third key fundamental is the *average well quality* by area and its trend over time. Petroleum engineers tell us that technology is constantly improving, with longer horizontal laterals, more frack stages per well, more sophisticated mixtures of proppants and other additives in the frack fluid injected into the wells, and higher-volume frack treatments. This has certainly been true over the past few years, along with multi-well pad drilling which has reduced well costs. In the Marcellus, well quality is continuing to grow strongly, suggesting that better technology is having an effect, along with a better understanding of the reservoir and the location of sweet spots. The average first-year production rate of Marcellus wells over time is illustrated in Figure 3-86.

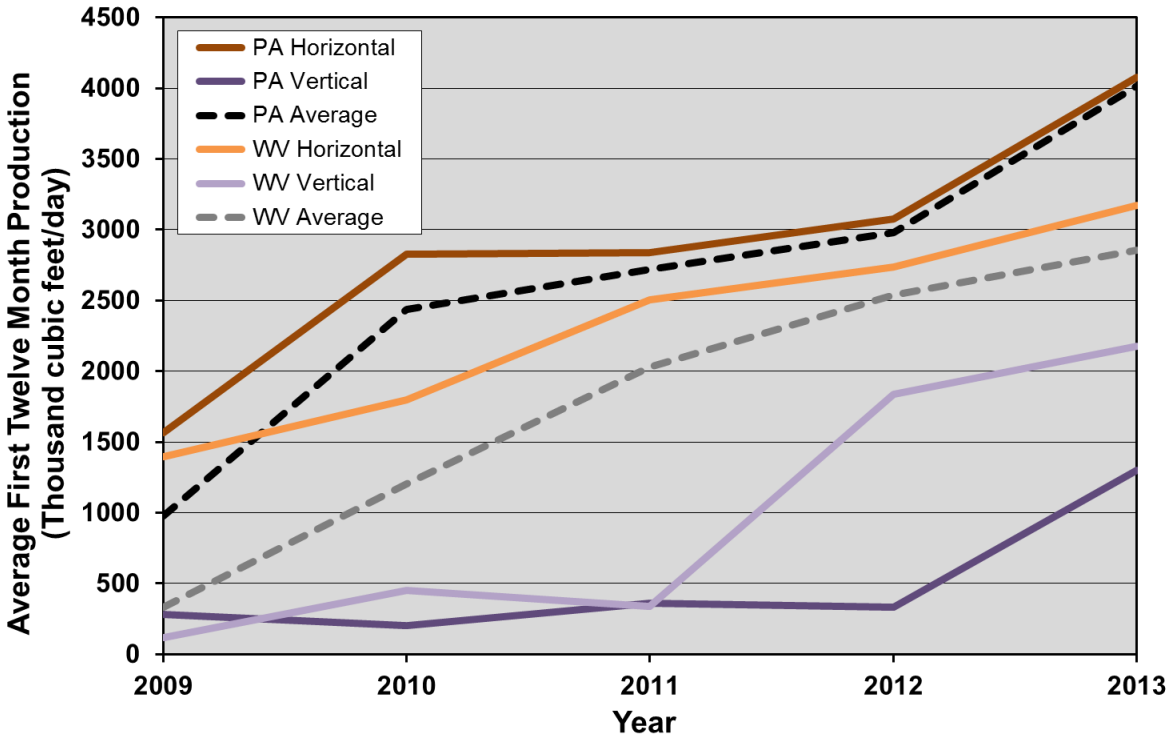

Figure 3-86. Average first-year production rates for Marcellus horizontal and vertical/directional gas wells by state, 2009 to 2013.[133]

Average well quality has increased substantially as better technology is applied and drilling is focused on the sweet spots.

[133] Data from Drillinginfo retrieved September 2014.

Another measure of well quality is cumulative production and well life. Figure 3-87 illustrates the cumulative production of all horizontal wells that were producing in the Pennsylvania Marcellus as of June 2014 (Pennsylvania is focused on as it has generally higher quality wells and more than 90% of Marcellus production). Although it can be seen that there are a few very good wells that recovered large amounts of gas in the first few years, and undoubtedly were great economic successes—7% of wells had recovered more than 4 billion cubic feet after less than 5 years—the average well had produced just 1.56 billion cubic feet over a lifespan averaging 28 months. Less than 6% of these wells are more than 5 years old.

The lifespan of wells is another key parameter as many operators assume a minimum life of 30 years and longer—this is conjectural at this point given the lack of long term well performance data.

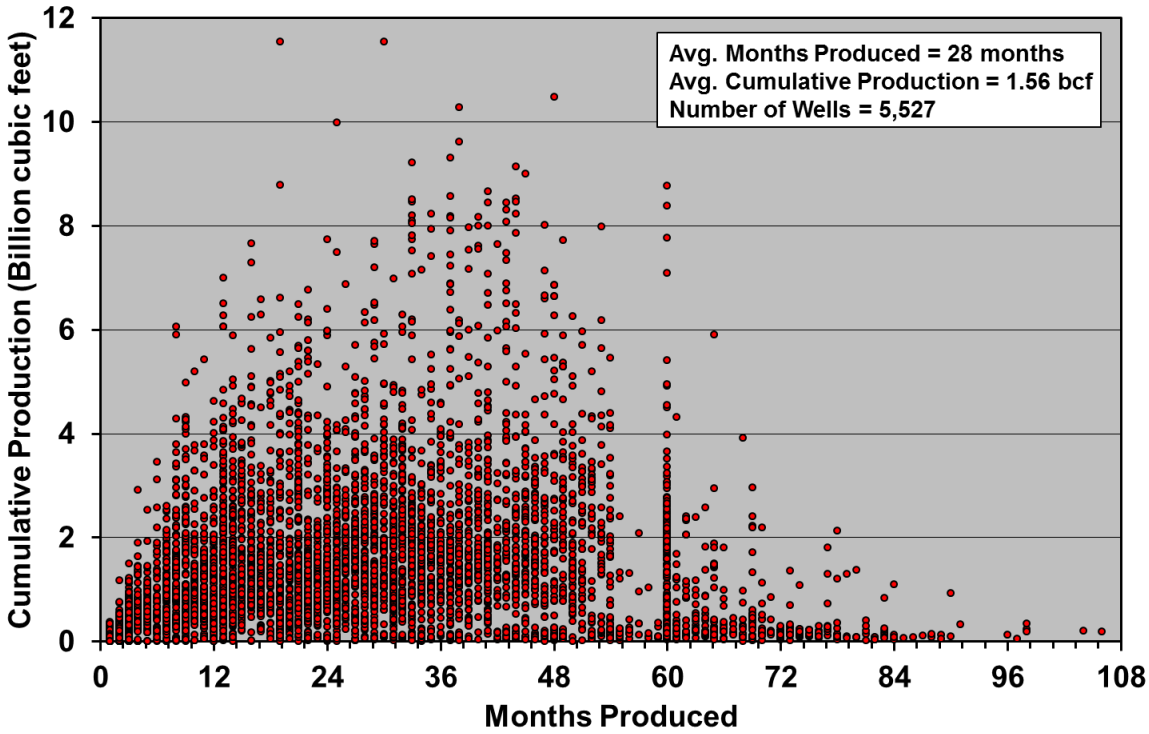

Figure 3-87. Cumulative gas production and length of time produced for wells in the Marcellus play in Pennsylvania.

Few wells are greater than five years old, with a mean age of 28 months and a mean cumulative recovery of 1.56 billion cubic feet.[134]

[134] Data from Drillinginfo retrieved September 2014.

Cumulative production of course depends on how long a well has been producing, so looking at young wells is not necessarily a good indication of how much gas these wells will produce over their lifespan (although production is heavily weighted to the early years of well life). A measure of well quality independent of age is initial productivity (IP) which is often focused on by operators. Figure 3-88 illustrates the average daily output over the first six months of production for all wells in the Pennsylvania portion of the Marcellus play (six month IP). The IPs are higher than most other shale plays—averaging 3.45 million cubic feet per day (MMcf/d) for all wells over the 2010 to 2014 period—and are trending upward, through both better technology and concentration of drilling in sweet spots. Again, as with cumulative production, there are a few exceptional wells—4% produced more than 10 MMcf/d—although the average of the most recent wells was about 5 MMcf/d overall. Figure 3-82 illustrates the distribution of IPs in map form illustrating the concentration of drilling in sweet spots.

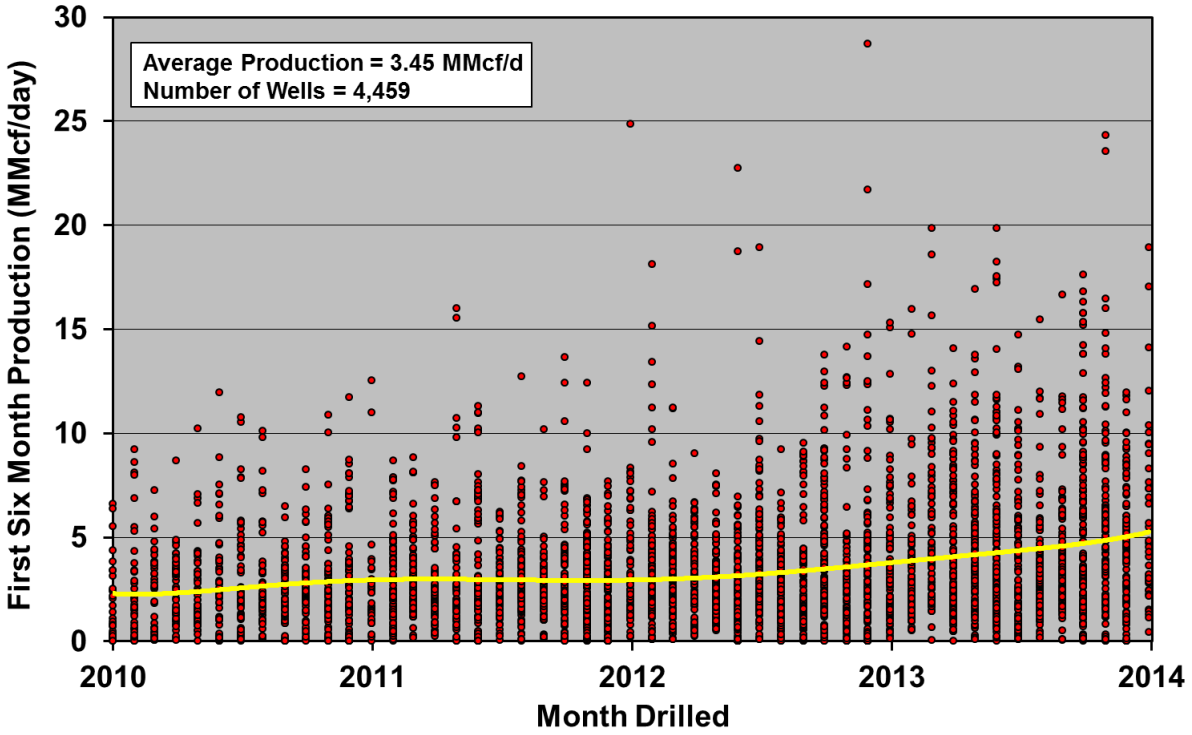

Figure 3-88. Average gas production over the first six months for all wells drilled in the Marcellus play of Pennsylvania, 2010 to 2014.[135]

Although there are a few exceptional wells, the average well produced 3.45 MMcf/d over the 2010 to 2014 period, with the most recent wells producing 5 MMcf/d. The trend line indicates mean productivity over time.

[135] Data from Drillinginfo retrieved September 2014.

Different counties in the Marcellus display markedly different well quality characteristics which are critical in determining the most likely production profile in the future. Figure 3-89, which illustrates production over time by county and state, shows that in June 2014, two counties in Pennsylvania produced 41% of all Marcellus gas and the top six Pennsylvania counties produced 76%.

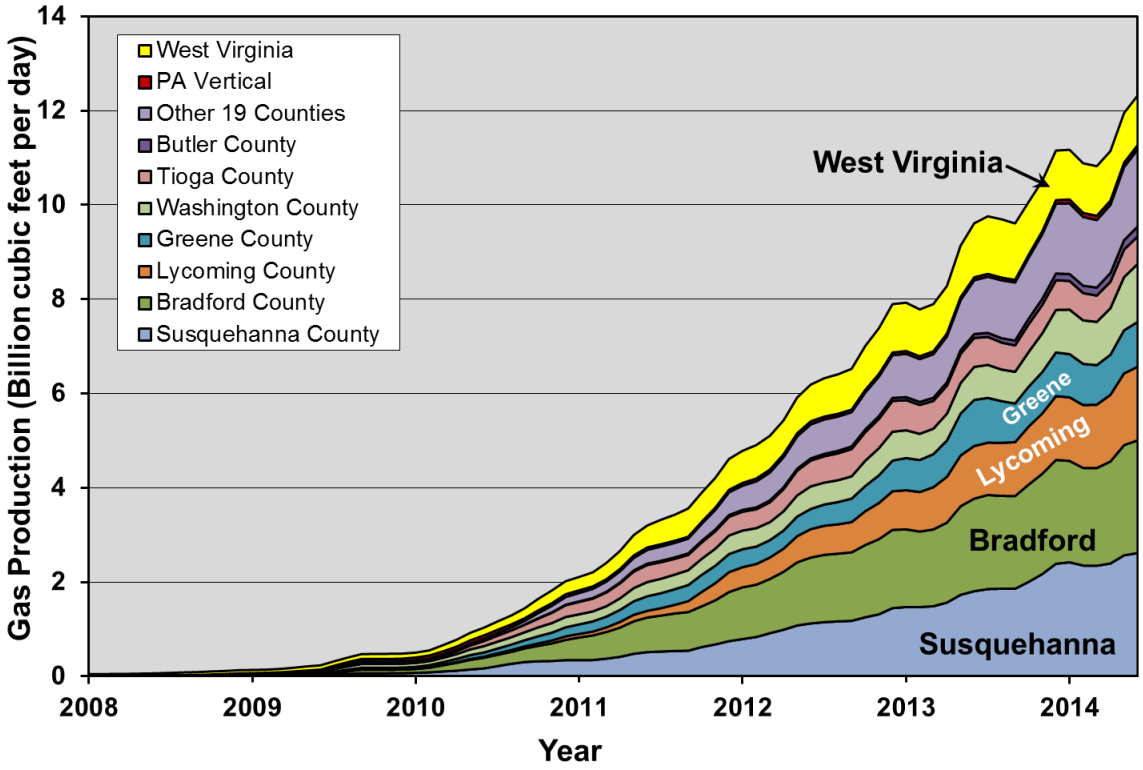

Figure 3-89. Gas production by county in the Marcellus play, 2008 through 2014.[136]
The top six Pennsylvania counties produced 76% of production in June 2014.

[136] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

The location of sweet spots is a function of the combination of many geological characteristics, including depth, thickness, organic matter content, thermal maturity, lithological characteristics allowing fractures to propagate, and the presence of natural fracture systems. Despite the widespread nature of the Marcellus, two sweet spots have been defined that produce the bulk of the gas. The northeast Pennsylvania sweet spot, centered in Susquehanna and Bradford counties, is illustrated with IPs in Figure 3-90, and the southwest Pennsylvania/West Virginia sweet spot, centered on Washington and Greene counties, is illustrated in Figure 3-91. Berman and Pettinger provide an in-depth discussion of the variation in quality of the Marcellus and the price of gas required to be profitable in various areas; they conclude that relatively little commercial gas exists in southern New York State.[137]

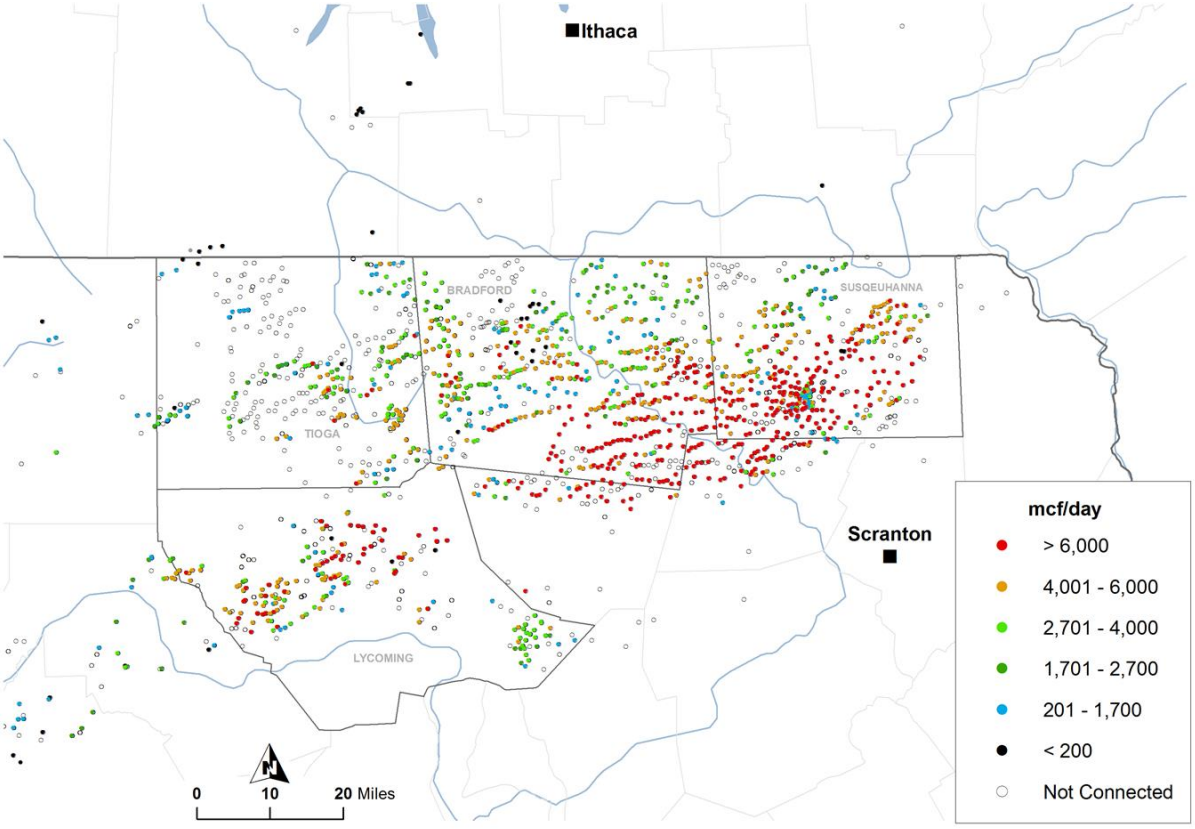

Figure 3-90. Distribution of wells in the northeast Pennsylvania sweet spot of the Marcellus play, illustrating highest one-month gas production (initial productivity, IP).[138]

Bradford and Susquehanna counties produced 41% of all Marcellus gas in June 2014.

[137] Berman, A.E. and Pettinger, L, 2014, *Resource Assessment of Potentially Producible Natural Gas Volumes from the Marcellus Shale, State of New York*, http://www.lwvny.org/advocacy/natural-resources/hydrofracking/2014/Marcellus-Resource-Assessment-NY_0414pdf.pdf.
[138] Data from Drillinginfo retrieved September 2014.

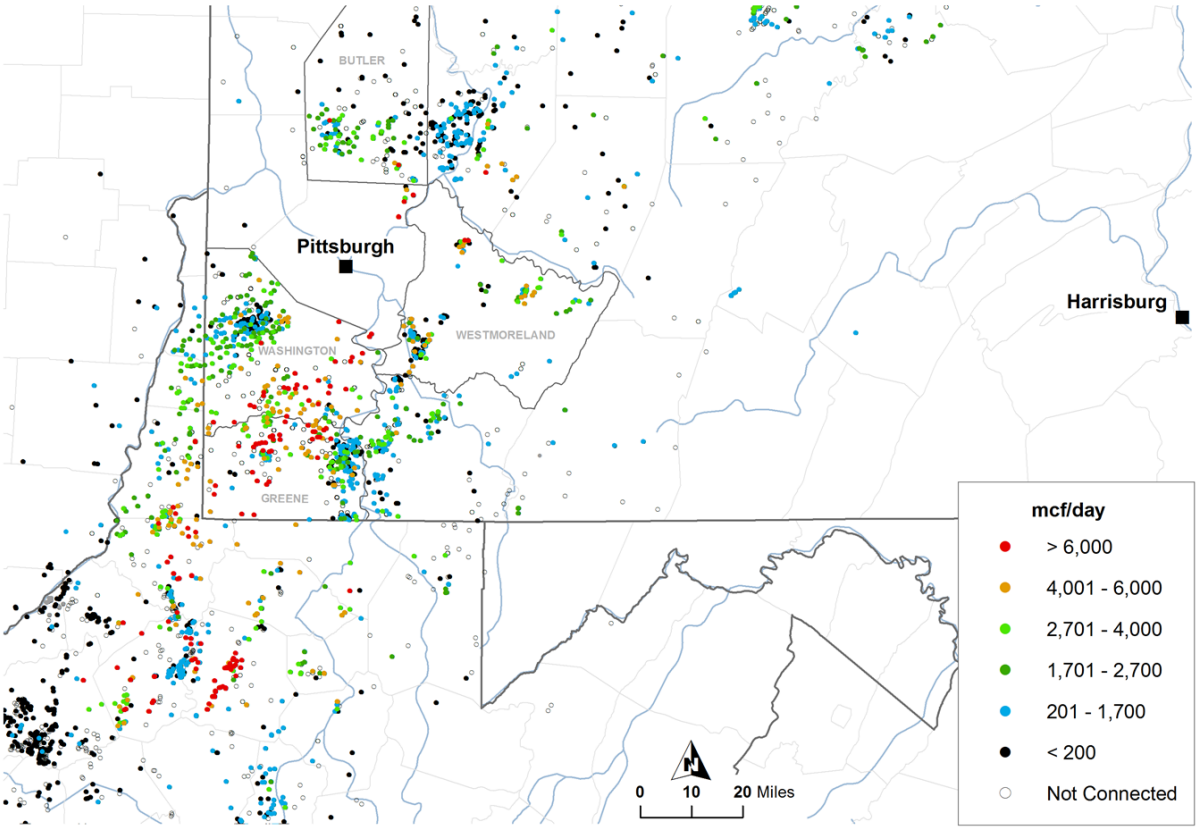

Figure 3-91. Distribution of wells in the southwest Pennsylvania / northern West Virginia sweet spot of the Marcellus play, illustrating highest one-month gas production (initial productivity, IP). [139]

Washington and Greene counties along with northern West Virginia produce most of the liquids associated with Marcellus gas.

[139] Data from Drillinginfo retrieved September 2014.

Cumulative production since the field commenced is also concentrated in the sweet spots. As illustrated in Figure 3-92, the top two counties have produced 40% of the gas and the top six have produced 75%. Production in most counties is growing although Greene and Tioga counties in Pennsylvania, and the state of West Virginia in general, are down somewhat from peak production.

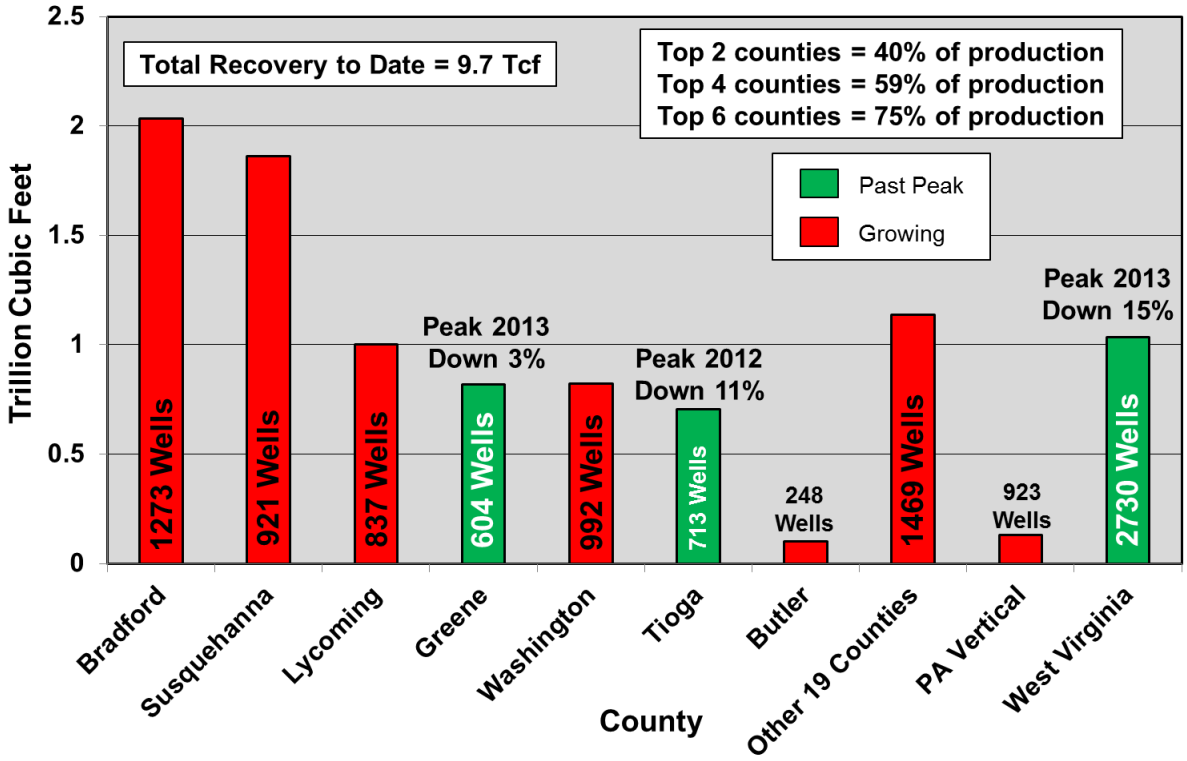

Figure 3-92. Cumulative gas production by county in the Marcellus play through June 2014.[140]

The top six counties have produced 75% of the 9.7 trillion cubic feet of gas produced to date. Greene and Tioga counties in Pennsylvania as well as West Virginia are below peak production, but all other areas are rising.

[140] Data from Drillinginfo retrieved September 2014.

The Marcellus also produces limited amounts of natural gas liquids and oil. Most liquids production is in Washington County in southwestern Pennsylvania and in northern West Virginia, as illustrated in Figure 3-93. Although more than 13 million barrels of liquids have been produced since 2005, in the big picture liquids production from the Marcellus is relatively insignificant.

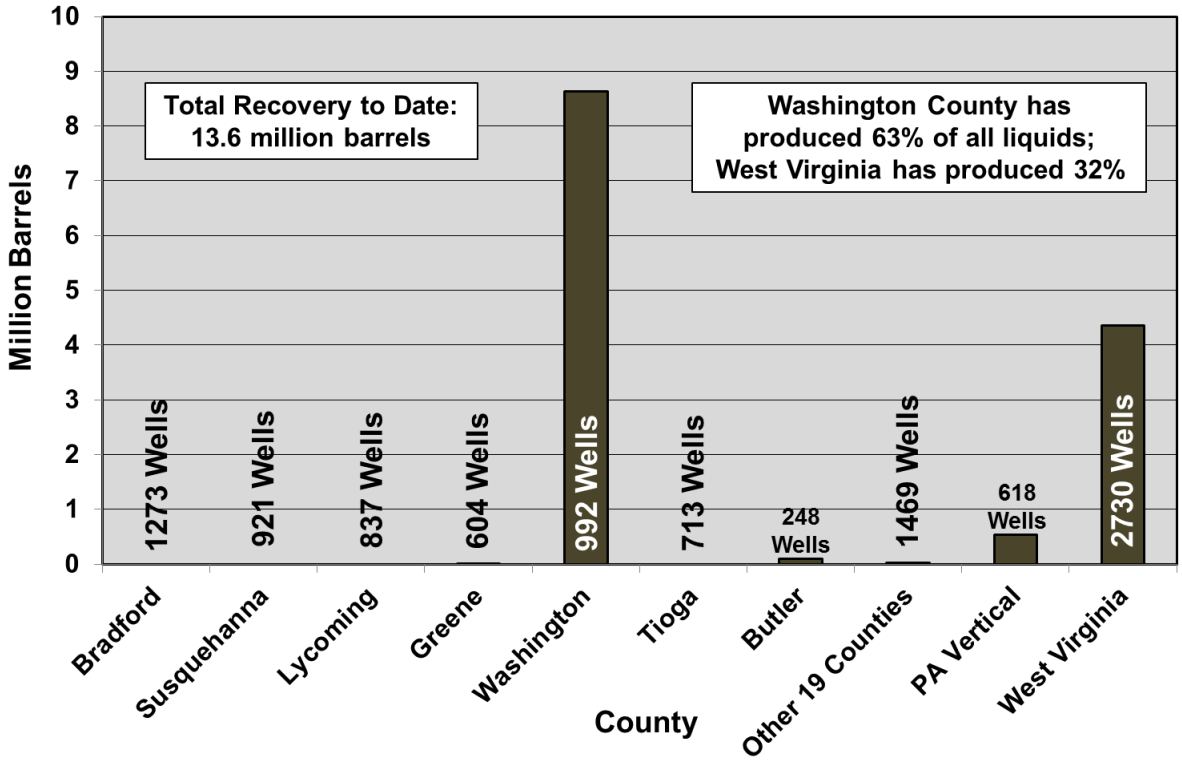

Figure 3-93. Cumulative liquids production by county in the Marcellus play through 2014.[141]

Production is concentrated in southwest Pennsylvania and northern West Virginia.

[141] Data from Drillinginfo retrieved September 2014.

Operators are highly sensitive to the economic performance of the wells they drill, which typically cost in the order of $6 million or more each, not including leasing costs and other expenses.[142] The areas of highest quality—the "core" or "sweet spots"—have now been well defined. Figure 3-94 illustrates average horizontal well decline curves by county, which are a measure of well quality (recognizing that future gas production from the Marcellus will be from horizontal, not vertical, wells). Initial well productivities (IPs) from Susquehanna County are more than double those of most other counties (excepting Bradford, Lycoming and Greene). The decline curves from the top four counties are all above the Marcellus average, hence these counties are attracting the bulk of the drilling and investment. Future drilling will have to focus more and more on lesser quality counties.

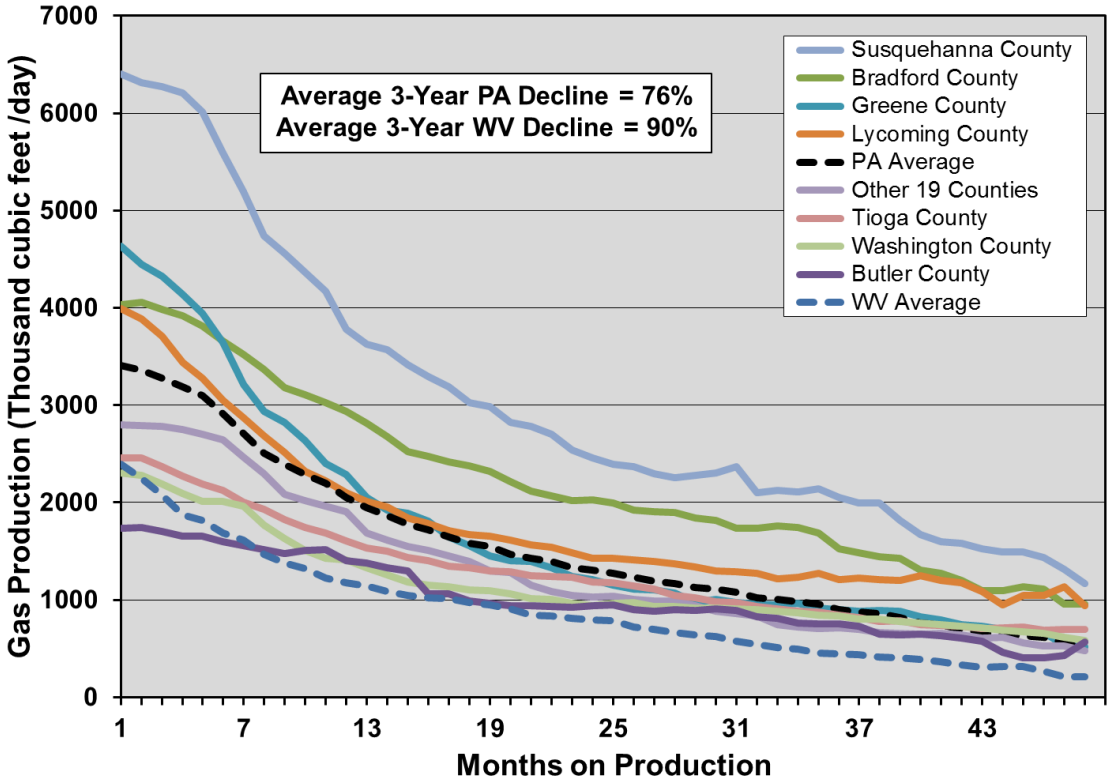

Figure 3-94. Average horizontal gas well decline profiles by county and state for the Marcellus play.[143]

The top four Pennsylvania counties, which have produced much of the gas in the Marcellus, are clearly superior.

[142] Cabot Investor Presentation, December 2013, http://www.cabotog.com/wp-content/uploads/2013/12/December-2013-Company-Update.pdf.
[143] Data from Drillinginfo retrieved September 2014.

Another measure of well quality is "estimated ultimate recovery" or EUR—the amount of gas a well will recover over its lifetime. Although to be clear no one knows what the lifespan of a Marcellus well is, given that few of them are more than five years old (see Figure 3-87 and Figure 3-88), EURs provide a useful metric to compare well quality between areas. Operators fit hyperbolic and/or exponential curves to data such as presented in Figure 3-94, assuming well life spans of 30-50 years (as is typical for conventional wells), but so far this is speculation given the nature of the extremely low permeability reservoirs and the completion technologies used in the Marcellus. Nonetheless, for comparative well quality purposes only, one can use the data in Figure 3-94, which exhibits steep initial decline with progressively more gradual decline rates, and assume a constant terminal decline rate thereafter to develop a theoretical EUR.

Figure 3-95 illustrates theoretical EURs by county in Pennsylvania for the Marcellus for comparative purposes of well quality. These range from 2.21 to 7.05 billion cubic feet per well, which are comparable to the 0.55 to 7.14 billion cubic feet assumed by the EIA.[144] The steep initial well production declines mean that well payout, if it is achieved, comes in the first few years of production, as between 63% and 72% of an average well's lifetime production occurs in the first four years.

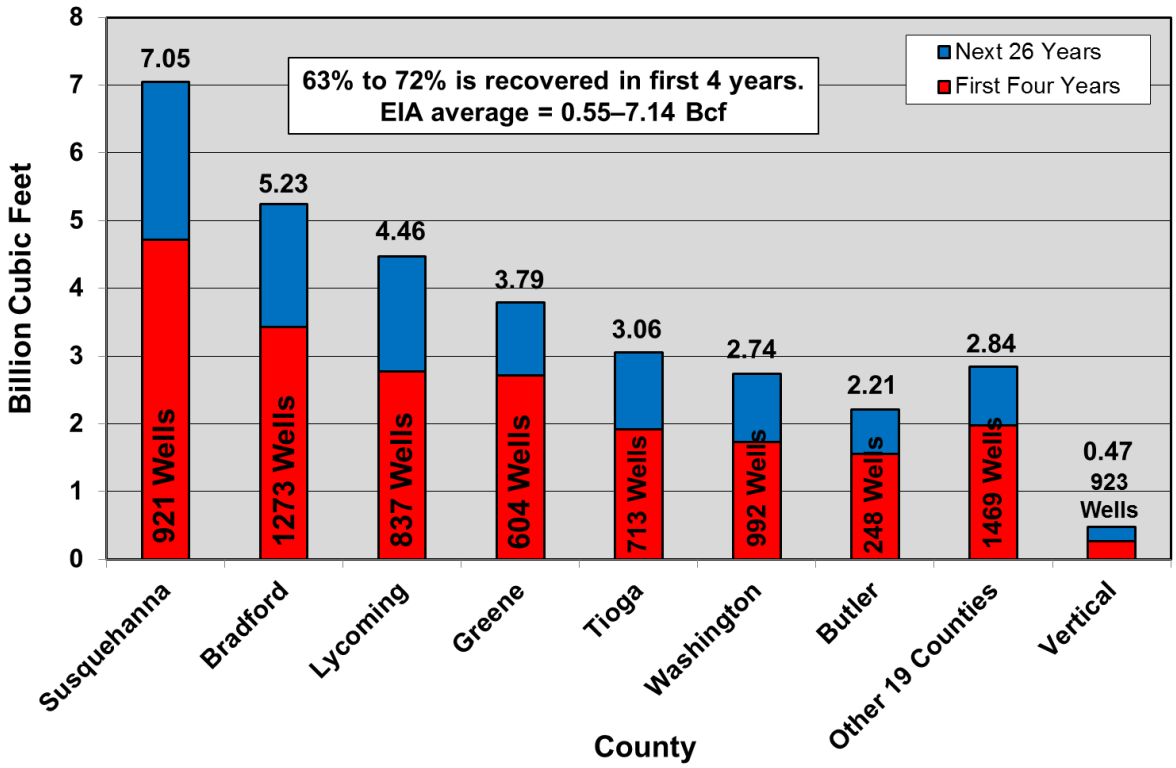

Figure 3-95. Estimated ultimate recovery of gas by county for the Marcellus play in Pennsylvania.[145]

EURs are based on average well decline profiles (Figure 3-94) and a terminal decline rate of 20%. These are for comparative purposes only as it is highly uncertain if wells will last for 30 years. The steep decline rates mean that most production occurs early in well life. The lowest 22 counties average less than half of the EUR of the top county, Susquehanna.

[144] EIA, July 2014, *Oil and Gas Supply Module*, http://www.eia.gov/forecasts/aeo/nems/documentation/ogsm/pdf/m063(2014).pdf.
[145] Data from Drillinginfo retrieved September 2014.

Well quality can also be expressed as the average rate of production over the first year of well life. If we know the rate of production in the first year of the average well, and the field decline rate, we can calculate the number of wells that need to be drilled each year to offset field decline in order to maintain production. Given that drilling is currently focused on the highest quality counties, the average first year production rate per well will fall as drilling moves into lower quality counties over time as the best locations are drilled off. As average well quality falls, the number of wells that must be drilled to offset field decline must rise, until the drilling rate can no longer offset decline and the field peaks.

Figure 3-96 illustrates the average first year production rate of wells by county. Average well quality has been rising in all areas through application of better technology—longer horizontal laterals, more frack stages, higher volumes of more sophisticated additives, and higher-volume frack treatments. The top three counties—Susquehanna, Greene and Bradford—are significantly higher than the average well productivity of the rest. Considering the large areal extent of the Marcellus play, relatively few wells have been drilled and thus there is still considerable room for more wells in the best areas. The current drilling rate of about 1,300 wells per year is above the 1,000 wells needed to offset field decline at current production levels, so Marcellus production will keep rising in the short to medium term as long as these drilling rates are maintained.

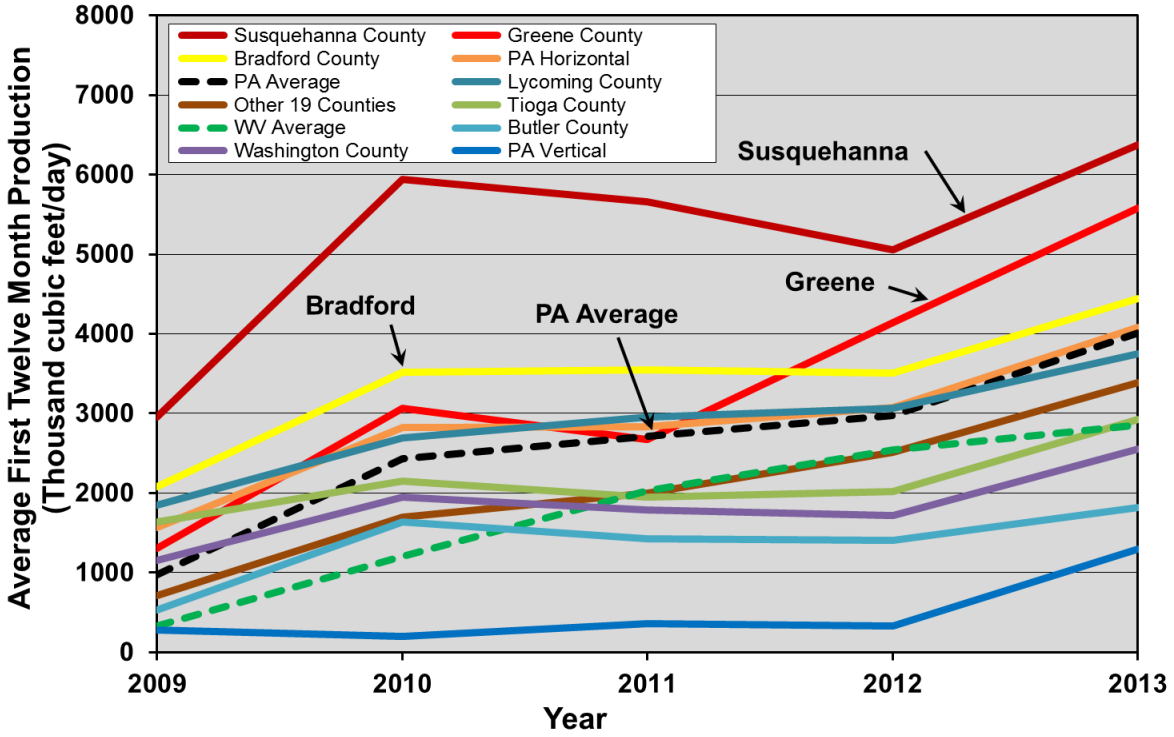

Figure 3-96. Average first-year gas production rates of wells by county in the Marcellus play, 2009 to 2013.[146]

Well quality is rising in most areas indicating that better technology—longer horizontal laterals and higher volume frack treatments—are improving productivity. First year production rate in the "other 19" counties, where more than half of the remaining drilling locations are found, is roughly half that of the top two counties.

[146] Data from Drillinginfo retrieved September 2014.

3.3.5.4 Number of Wells

A fourth critical parameter is the number of wells that can ultimately be drilled in the Marcellus play. The EIA estimates an area of 16,688 square miles for the "Marcellus Interior" and an additional 869 square miles for the "Marcellus Foldbelt" for a total of 17,566 square miles. They assign an average EUR of 1.59 Bcf to the former and 0.32 to the latter. They also include a "Marcellus Western" area of 2,684 square miles with an average EUR of 0.26 Bcf (which has less than 4% of total unproved resources). Assuming the EIA's estimates for the Marcellus interior and foldbelt regions are correct—and eliminating the low productivity western area due to its likely lack of economic viability—leaves a play area of 17,566 square miles. Using the EIA's estimate of 4.3 wells per square mile over this region, a total of 76,415 wells would be developed when the region is completely drilled off, or some ten times the current number of producing wells.

Given that Pennsylvania and West Virginia are relatively densely populated states, with some difficult topography, a more conservative estimate may be that only 80% of the remaining drilling locations are actually accessible to development—allowing for towns, cities, parks and other surface restrictions to development. In this case 63,274 wells would be drilled in total, or an additional 52,564 wells over what are currently in place.

Table 3-5 breaks down the number of yet-to-drill wells by county along with other critical parameters used for determining the future production rates of the Marcellus play.

Parameter	County											Total
	Bradford	Butler	Greene	Lycoming	Susquehanna	Tioga	Washing-ton	Other 19	PA Vertical	PA Total	WV Total	
Production June 2014 (Bcf/d)	2.39	0.21	0.95	1.56	2.62	0.58	1.23	1.63	0.09	11.27	1.05	12.32
% of Field Production	19.40	1.73	7.71	12.67	21.23	4.72	9.98	13.26	0.75	91.46	8.54	100.00
Cumulative Gas (Tcf)	2.03	0.10	0.82	1.00	1.86	0.71	0.82	1.14	0.13	8.62	1.04	9.65
Cumulative Liquids (MMBBL)	0.00	0.09	0.00	0.00	0.00	0.00	8.63	0.03	0.53	9.29	4.35	13.64
Number of Wells	1273	248	604	837	921	713	992	1469	923	7980	2730	10710
Number of Producing Wells	896	142	416	615	662	485	734	862	490	5302	1704	7006
Average EUR per well (Bcf)	5.24	2.21	3.79	4.48	7.05	3.06	2.74	2.84	0.42	3.41	1.67	3.06
Field Decline (%)	25	31	48	37	33	33	32	26	30	32	29	32
3-Year Well Decline (%)	62	57	81	70	68	66	64	75	79	74	81	76
Average First Year Production in 2013 (Mcf/d)	4440	1823	5578	3750	6368	2924	2554	3390	1297	4012	2858	3932
New Wells Needed to Offset Field Decline	135	36	82	154	134	65	155	127	21	899	107	1003
Area in square miles	1161	795	578	1244	832	1137	861	19000	25608	25608	13656	39264
% Prospective	90	90	80	50	75	60	90	34	45	45	45	45
Net square miles	1045	716	462	622	624	682	775	6486	11412	11412	6145	17556
Well Density per square mile	1.22	0.35	1.31	1.35	1.48	1.05	1.28	0.23	0.08	0.70	0.44	0.61
Additional locations to 4.3/sq. Mile	3220	2829	1384	1838	1762	2220	2340	26420	0	42013	23692	65705
Population	62622	183862	38686	116111	43356	41981	207820	N/A	N/A	N/A	N/A	N/A
Total Wells 4.3/sq. Mile	4493	3077	1988	2675	2683	2933	3332	27889	923	49993	26422	76415
Producing Wells 4.3/sq. Mile	4116	2971	1800	2453	2424	2705	3074	27282	490	47315	25396	72711
Risked 80% Total Wells 4.3/sq. Mile	3849	2511	1711	2307	2331	2489	2864	22605	0	40667	21684	63274
Risked 80% Producing Wells 4.3/sq. Mile	3472	2405	1523	2085	2072	2261	2606	21998	0	38422	20658	59570

Table 3-5. Parameters for projecting Marcellus production, by county.

Area in square miles under "Other" is estimated. Wells by county are horizontal only; "Total" columns include both horizontal and vertical wells.

3.3.5.5 Rate of Drilling

Given known well- and field-decline rates, well quality by area, and the number of available drilling locations, the most important parameter in determining future production levels is the rate of drilling. Figure 3-97 illustrates the historical drilling rates in the Marcellus of Pennsylvania. Horizontal drilling rates in Pennsylvania peaked in 2013 at about 1,350 wells per year and have since fallen to current levels of about 1,200 wells per year. Coupled with drilling rates of 120 wells per year in West Virginia, current rates are about 1,320 wells per year. This is considerably higher that the approximately 1,000 wells per year needed to offset field decline at current production rates, hence Marcellus production will keep rising in the short to medium term as long as these drilling rates are maintained.

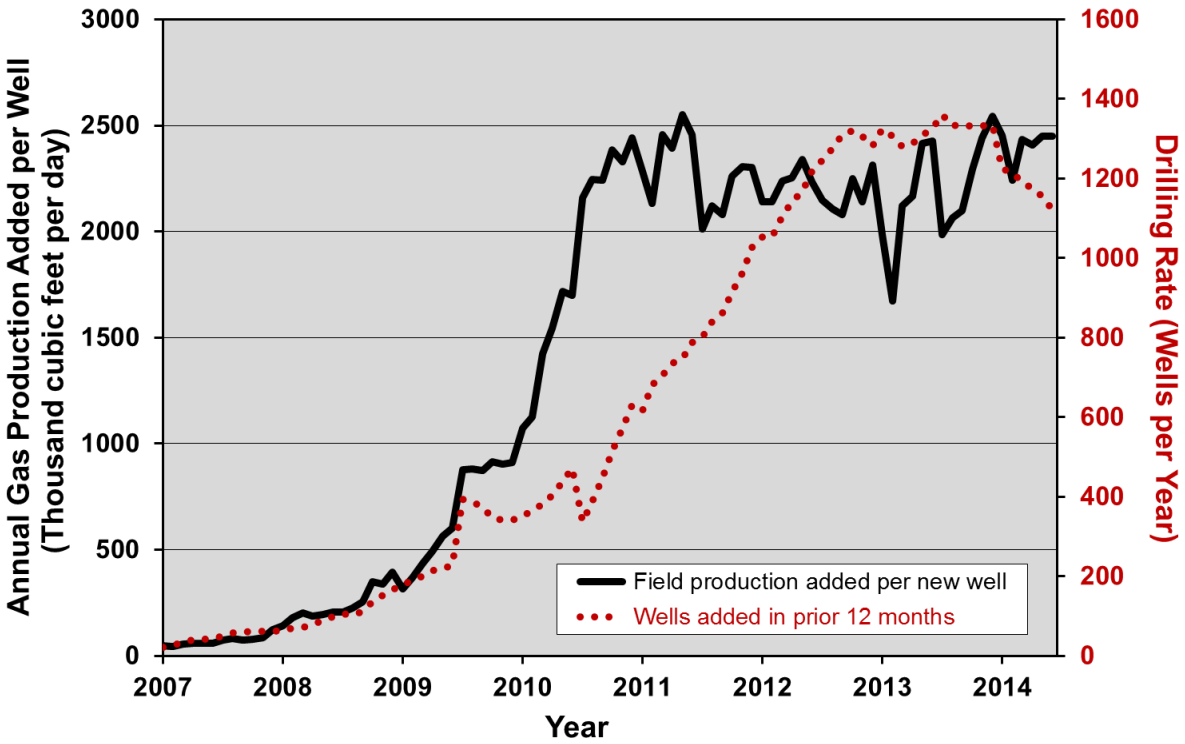

Figure 3-97. Annual gas production added per new horizontal well and annual drilling rate and in the Marcellus play, 2007 through 2014.[147]

Drilling rate peaked in 2013 but remains well above the level needed to offset field decline, hence production will continue to grow in the short to medium term.

[147] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

3.3.5.6 Future Production Scenarios

Several drilling rate scenarios were used to develop production projections for the Marcellus play given the number of available drilling locations. Figure 3-98 illustrates the production profiles in Pennsylvania for three drilling rate scenarios if 80% of the prospective play area is drillable at 4.3 wells per square mile (for a total of 63,274 wells in the play with 40,677 of them in Pennsylvania). These scenarios are:

- MOST LIKELY RATE scenario: Assumes that drilling rate continues at current levels and then gradually declines to 800 wells per year as drilling moves into lower quality parts of the play.
- HIGH RATE scenario: Assumes that drilling will continue at current rates until all locations are drilled off.
- REDUCED RATE scenario: Assumes that wells will continue at current rates but decline more steeply to 200 wells per year as the last wells are drilled.

In all scenarios drilling continues through 2040 and beyond.

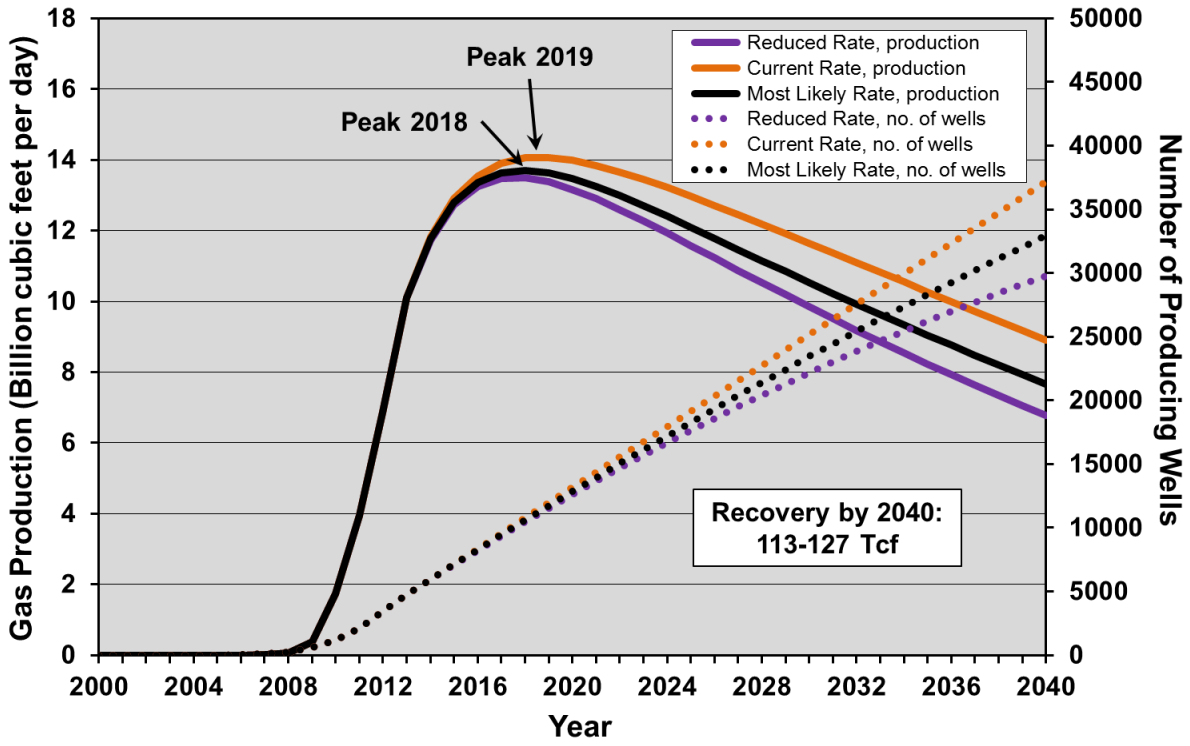

Figure 3-98. Three drilling rate scenarios of Marcellus gas production in Pennsylvania (assuming 80% of the area is drillable at 4.3 wells per square mile).[148]

"Most Likely Rate" scenario: drilling continues at 1,200 wells/year, declining to 800/year.
"High Rate" scenario: drilling continues at 1,200 wells/year.
"Reduced Rate" scenario: drilling continues at 1,200 wells/year, declining to 200/year.

[148] Data from Drillinginfo retrieved September 2014.

The drilling rate scenarios have the following results:

1. MOST LIKELY RATE scenario: Total gas recovery by 2040 would be 118.2 trillion cubic feet and drilling would continue beyond 2040. Peak production would occur in 2018.

2. HIGH RATE scenario: Total gas recovery by 2040 would be 127 trillion cubic feet and drilling would continue beyond 2040. Peak production would occur in 2019.

3. REDUCED RATE scenario: Total gas recovery by 2040 would be 113 trillion cubic feet and drilling would continue beyond 2040. Peak production would occur in 2017.

The recovery of between 113 and 127 trillion cubic feet, with118.2 trillion cubic feet in the "Most Likely Rate" scenario by 2040, makes the Marcellus the most important shale gas play in the U.S. by a wide margin. Nonetheless, it peaks in the 2017-2019 timeframe followed by a long period of decline. If projected production from the Marcellus in West Virginia is included, production in the "Most Likely Rate" scenario will reach nearly 15 Bcf/d, with recovery of 129 trillion cubic feet by 2040 (assuming drilling is continued at the current rate in West Virginia of 120 wells per year) as illustrated in Figure 3-99 .

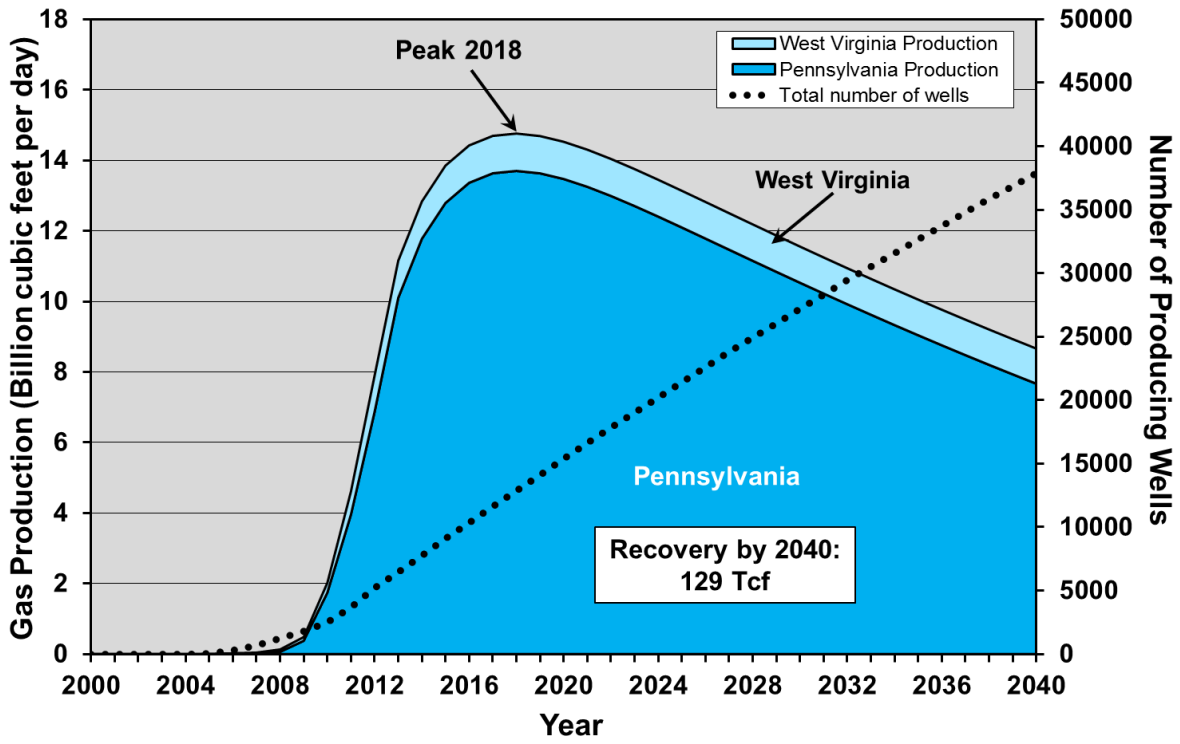

Figure 3-99. "Most Likely Rate" scenario of Marcellus gas production including both Pennsylvania and West Virginia.

Total recovery by 2040 of 129 Tcf is 13 times the amount of gas recovered to date. In this "Most Likely Rate" scenario, with the addition of West Virginia, drilling continues at 1,320 wells/year, declining to 920/year.

3.3.5.7 Comparison to EIA Forecast

Figure 3-100 illustrates the EIA's projection for Marcellus production through 2040 compared to the "Most Likely Rate" scenario. The EIA projects recovery by 2040 of 129 Tcf to meet its reference case forecast, which coincidentally is exactly the same quantity as projected in the "Most Likely Rate" scenario. The shape of the EIA production profile in its reference case, however, appears to underestimate past and current production—even compared to its own independent estimates (*Natural Gas Weekly Update* and *Drilling Productivity Report*[149])—and overestimate production in later years, beyond 2024. The EIA projects a peak in 2024 at 13.8 Bcf/d—lower than the 14.8 Bcf/d peak in 2018 in this report—and generally higher production in the post-2022 timeframe.

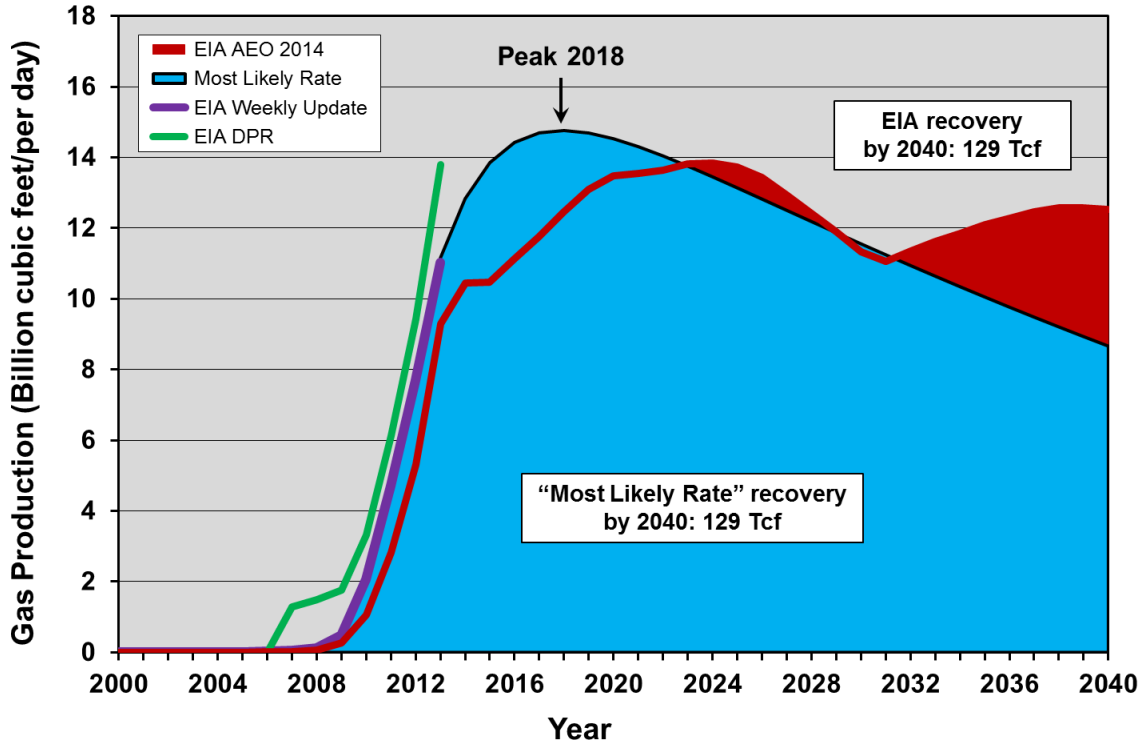

Figure 3-100. EIA reference case for Marcellus shale gas[150] vs. this report's "Most Likely Rate" scenario, 2000 to 2040.

The EIA underestimates past and current production compared to the "Most Likely Rate" scenario and its own independent estimates,[151] but overestimates production in later years. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

[149] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly. EIA, *Drilling Productivity Report*, retrieved October 2014, http://www.eia.gov/petroleum/drilling.
[150] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[151] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly. EIA, *Drilling Productivity Report*, retrieved October 2014, http://www.eia.gov/petroleum/drilling.

3.3.5.8 Marcellus Play Analysis Summary

Several things are clear from this analysis:

1. Marcellus production is growing strongly and drilling rates are sufficient to see continued growth through 2018. There is a significant backlog of wells drilled but not connected—estimated at over 2,000 wells—which will serve to maintain productive well additions in the near term even if rig count and new well drilling declines.

2. High well- and field-decline rates mean a continued high rate of drilling is required to maintain, let alone increase, production. Current drilling rates of 1,320 wells per year are considerably above the roughly 1,000 wells per year required to offset field decline at current production rates. Offsetting field decline requires an investment of $6 billion per year for drilling (assuming $6 million per well), not including leasing, infrastructure and operating costs. Future production profiles are most dependent on drilling rate and to a lesser extent on the number of drilling locations (i.e., greatly increasing the number of drilling locations would not change the production profile nearly as much as changing the drilling rate). Although drilling in the sweet spots is certainly economic at current prices, prices will have to increase to justify drilling in lower quality parts of the play when sweet spots are exhausted.

3. Production in the "Most Likely Rate" scenario will rise to 15 Bcf/d at peak in the 2018 timeframe followed by a gradual decline. The "High" drilling rate scenario would move this peak forward to 2019 at more than 15 Bcf/d. Drilling will continue in all scenarios until well beyond 2040.

4. The projected recovery of 129 Tcf by 2040 in the "Most Likely Rate" scenario, is the same as the EIA reference case. However, the EIA has underestimated near term production rates and overestimated production rates in the longer term.

5. These projections are optimistic in that they assume the capital will be available for the drilling treadmill that must be maintained to keep production up. This is not a sure thing as drilling in the poorer quality parts of the play will require higher gas prices to make it economic. Failure to maintain drilling rates will result in a lower production profile.

6. More than four times the current number of wells will need to be drilled by 2040 to meet production projections.

7. The projections in this report assume that of the total number of wells that could be drilled if 100% of the surface area was accessible for drilling at 4.3 wells per square mile, only 80% of the undrilled locations will be available, owing to surface land use. Any additional restrictions on land use would further limit the number of wells that could be drilled and result in lower production.

3.4 Major U.S. Tight Oil Plays with Significant Associated Shale Gas Production

Two tight oil plays which were analyzed in depth in Part 2 (Tight Oil) of this report also produce significant quantities of natural gas. As of June 2014, the Eagle Ford play ranked third and the Bakken play ranked seventh in terms of gas output from U.S. shale plays, as illustrated in Figure 3-101.[152] These plays are analyzed for future gas production below. Given that they are primarily oil plays, drilling rates and progression of drilling from sweet spots to lower quality areas will be governed by oil production—hence the analysis of these plays relies on the analysis in Part 2 of this report in order to determine likely future production.

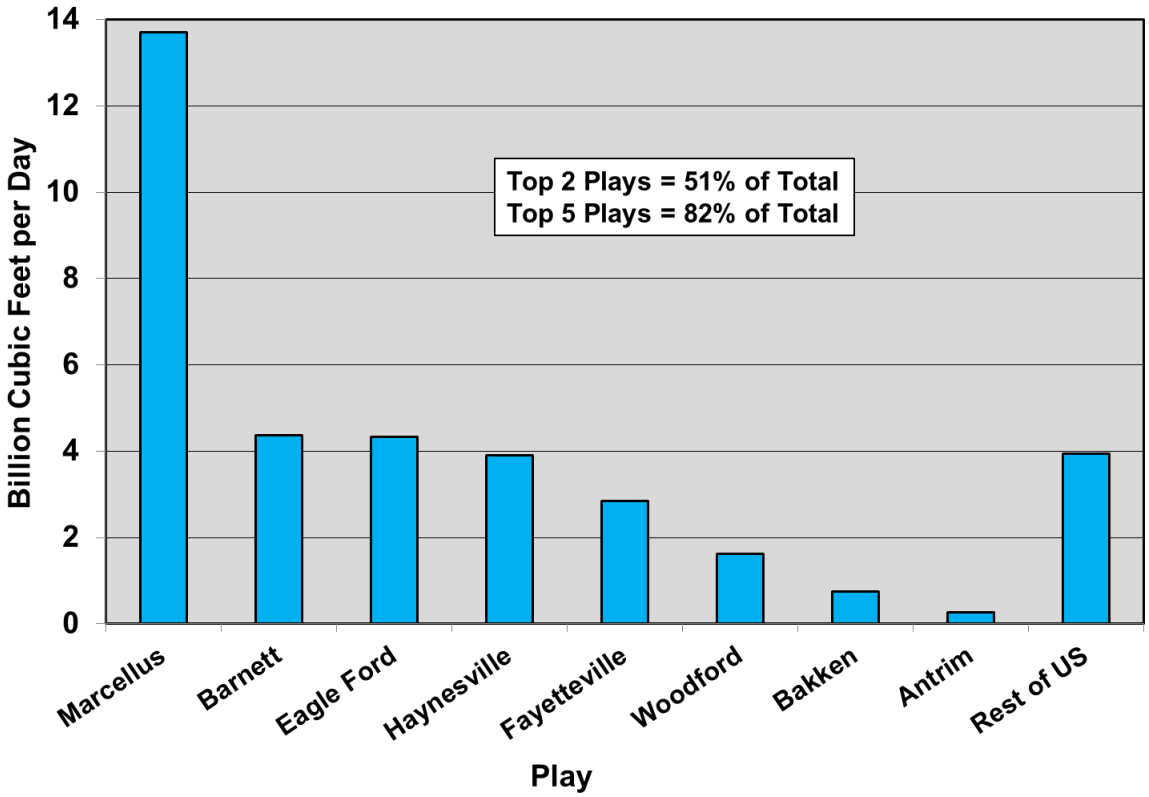

Figure 3-101. U.S. shale gas daily production by play as of June 2014.[153]

The Bakken tight oil play and especially the Eagle Ford tight oil play are also significant producers of shale gas.

[152] EIA, *Natural Gas Weekly Update*, retrieved July 2014, http://www.eia.gov/naturalgas/weekly/archive/2014/07_24/index.cfm. Note that the EIA in October 2014 published an estimate from the Utica of 1.174 Bcf/d, but this appears to be total gas production from Ohio, not specifically shale gas from the Utica Play; http://www.eia.gov/naturalgas/weekly retrieved October 9, 2014.

[153] EIA, *Natural Gas Weekly Update*, retrieved July 2014, http://www.eia.gov/naturalgas/weekly/archive/2014/07_24/index.cfm

3.4.1 Eagle Ford Play

The Eagle Ford play is divided into oil-, condensate- and gas-windows with increasing depth as discussed in Part 2 of this report. Therefore the best locations for oil production are not necessarily the same as the best locations for gas production. Figure 3-102 illustrates the distribution of well quality for gas production in the Eagle Ford as defined by highest one-month production (IP).

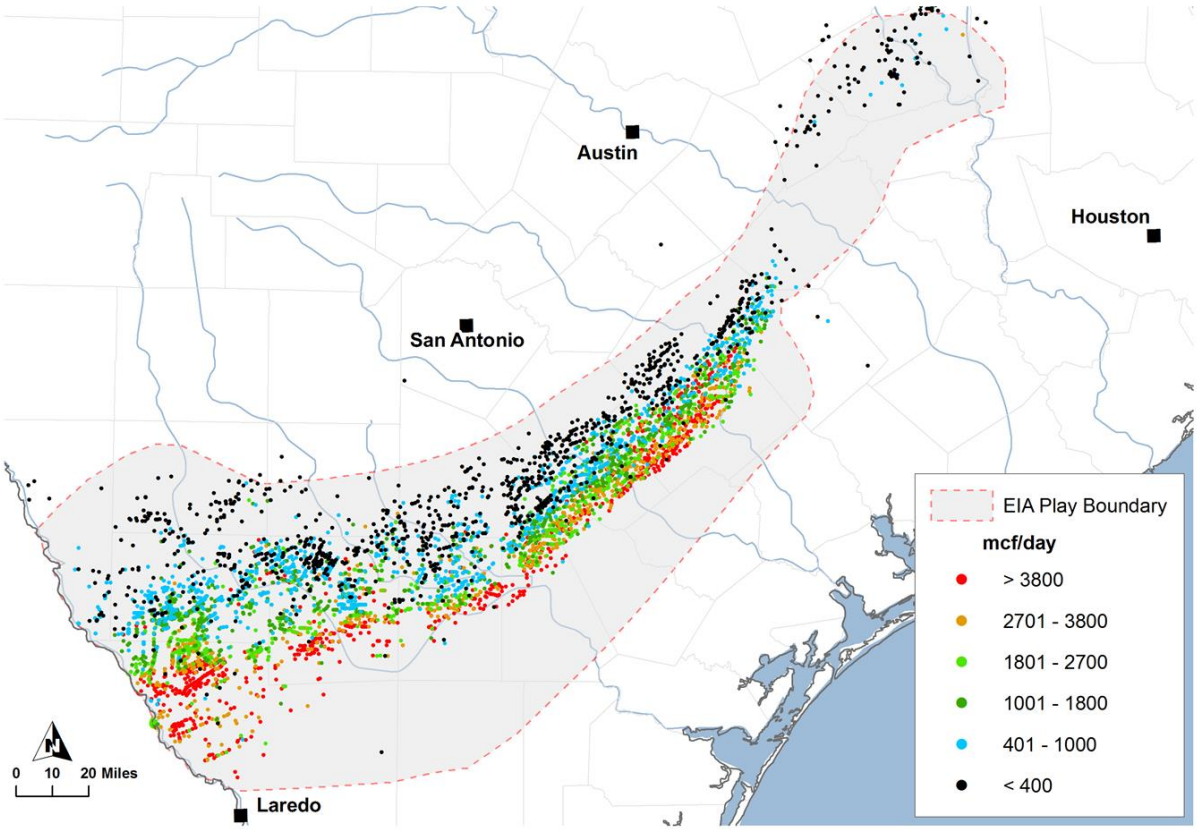

Figure 3-102. Distribution of wells in the Eagle Ford play as of mid- 2014, illustrating highest one-month gas production (initial productivity, IP).[154]

Well IPs are categorized approximately by percentile; see Appendix.

[154] Data from Drillinginfo retrieved August 2014.

Figure 3-103 provides a closer view of the main gas production area along with the counties utilized in the analysis.

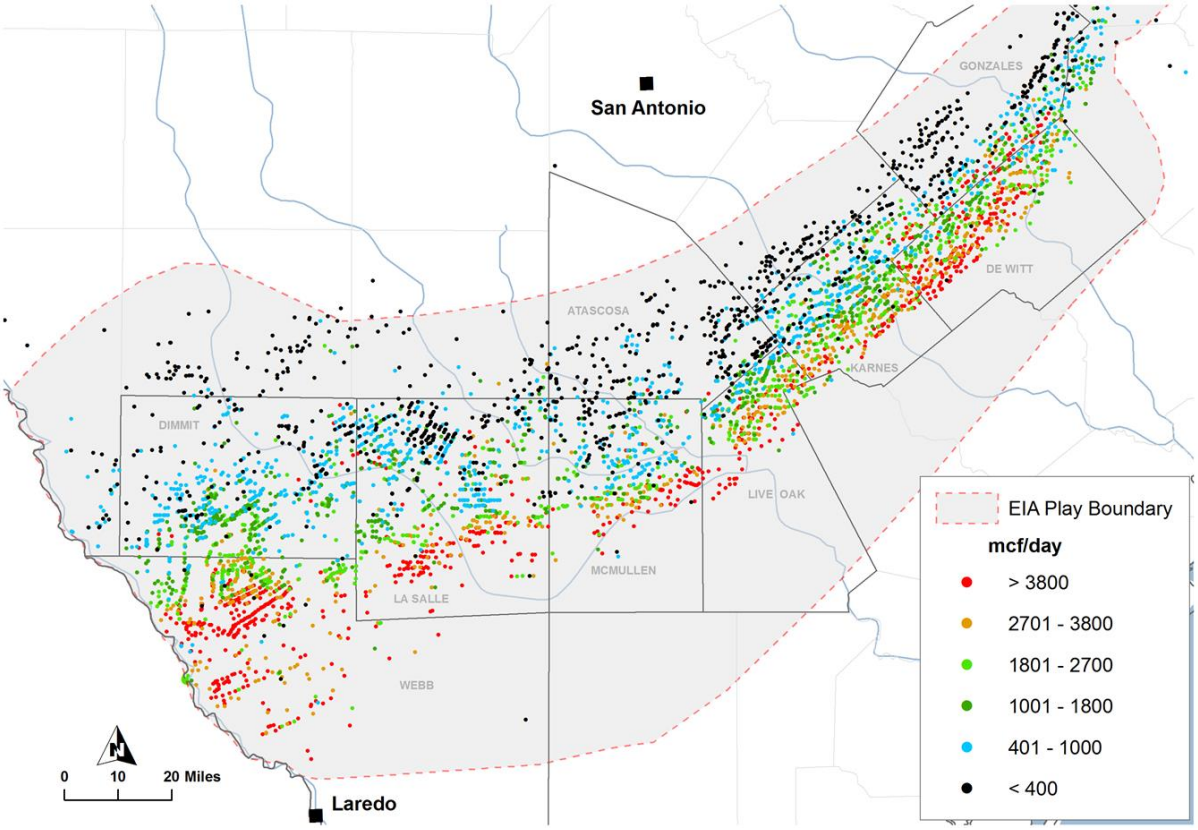

Figure 3-103. Detail of the Eagle Ford play showing distribution of wells as of mid-2014, illustrating highest one-month gas production (initial productivity, IP).[155]

Well IPs are categorized approximately by percentile; see Appendix.

[155] Data from Drillinginfo retrieved August 2014.

Figure 3-104 illustrates gas production in the Eagle Ford from 2007 through mid-2014. Production is nearing 5 Bcf/d from just over 10,000 producing wells.

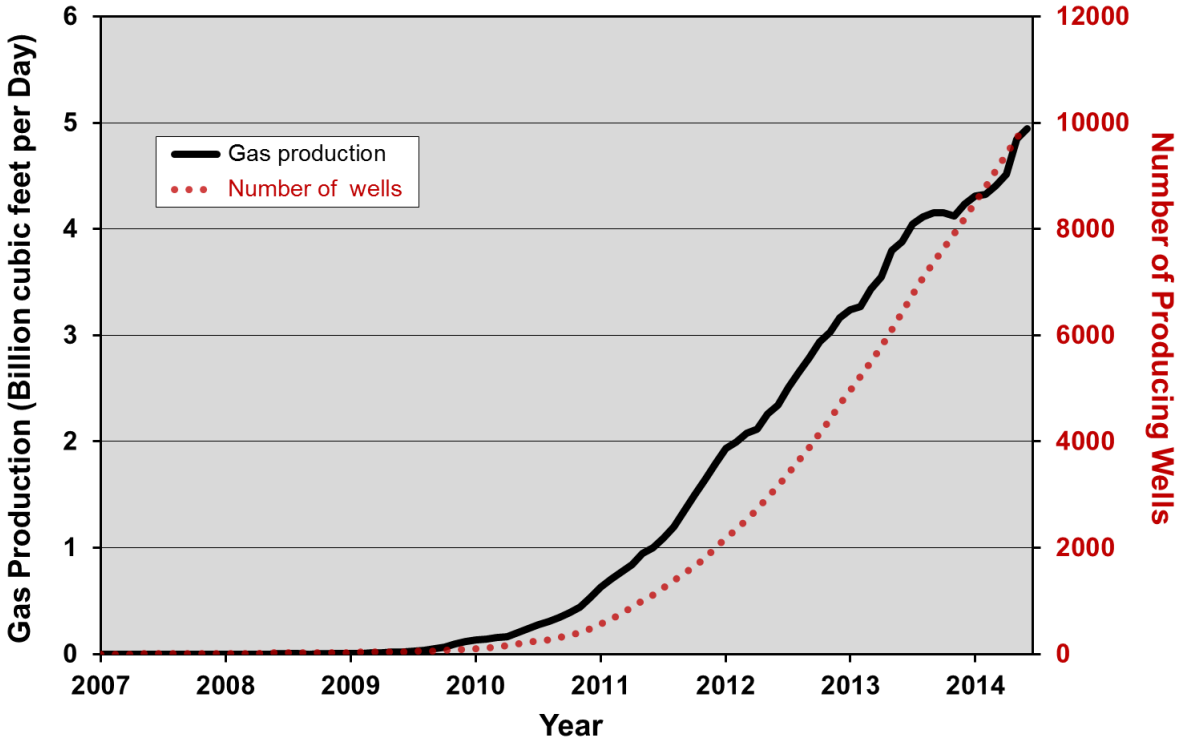

Figure 3-104. Eagle Ford play shale gas production and number of producing wells, 2007 through 2014.[156]

Gas production data are provided on a "raw gas" basis.

[156] Data from Drillinginfo retrieved September 2014. Three-month trailing moving average.

3.4.1.1 Critical Parameters

Other critical parameters include the average well decline, which is 80% over 3 years, and the average field decline, which is 47% for gas wells. The distribution of gas production by county is illustrated in Part 2 of this report, and the evolution of well quality over time is illustrated in Figure 3-105.

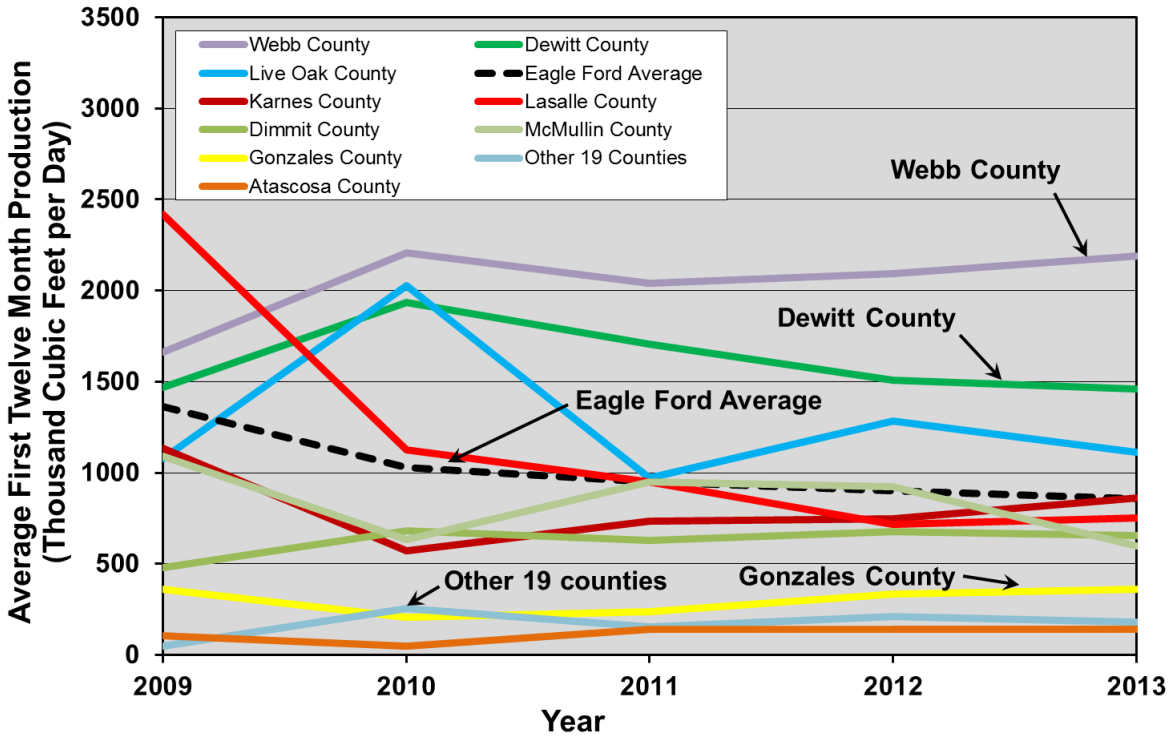

Figure 3-105. Average first-year gas production rates of wells by county in the Eagle Ford play, 2009 to 2013.[157]

Gas production is an important economic component of Eagle Ford wells as it comprises nearly 40% of the energy produced on average from the play (the distribution of energy production from the Eagle Ford on a "barrels of oil equivalent" basis is illustrated in Part 2 of this report). As can be seen in Figure 3-105, the average well quality from a gas production point of view has been declining. This is likely a result of drilling moving into areas more favorable for oil production and less favorable for gas production, and is not an indicator of what well quality for gas production will look like later on as sweet spots for oil production become saturated with wells. Webb County, for example, which is the best county for gas production but one of the worst for oil production, will see a lot more drilling in later stages of the play's development. Hence the average well quality, from a gas production point of view, is likely to increase in later stages of play development.

[157] Data from Drillinginfo retrieved September 2014.

3.4.1.2 Future Production Scenarios

Given that oil production is the driving force in the Eagle Ford at the current time, the "Most Likely Rate" scenario of the "Realistic Case" for oil production as outlined in Part 2 of this report is used for projection of future Eagle Ford gas production. This scenario assumes that more than 37,000 wells will be drilled in total (compared to just over 10,000 wells at present), and that drilling will continue at current rates of 3,550 wells per year and gradually fall to 2,000 wells per year as the play is drilled off. It also assumes that well quality for gas production will rise 50% from current levels as drilling moves from oil-prone areas back into gas-prone areas later in the play's development.

Figure 3-106 illustrates the "Most Likely Rate" projection for Eagle Ford production (see Part 2 of this report for other key parameters used for this projection). Production is forecast to rise considerably from current levels to nearly 6.5 Bcf/d by 2017 before declining. Total gas recovery through 2040 will be about 35.5 Tcf, or nearly 10 times the amount produced from the play so far.

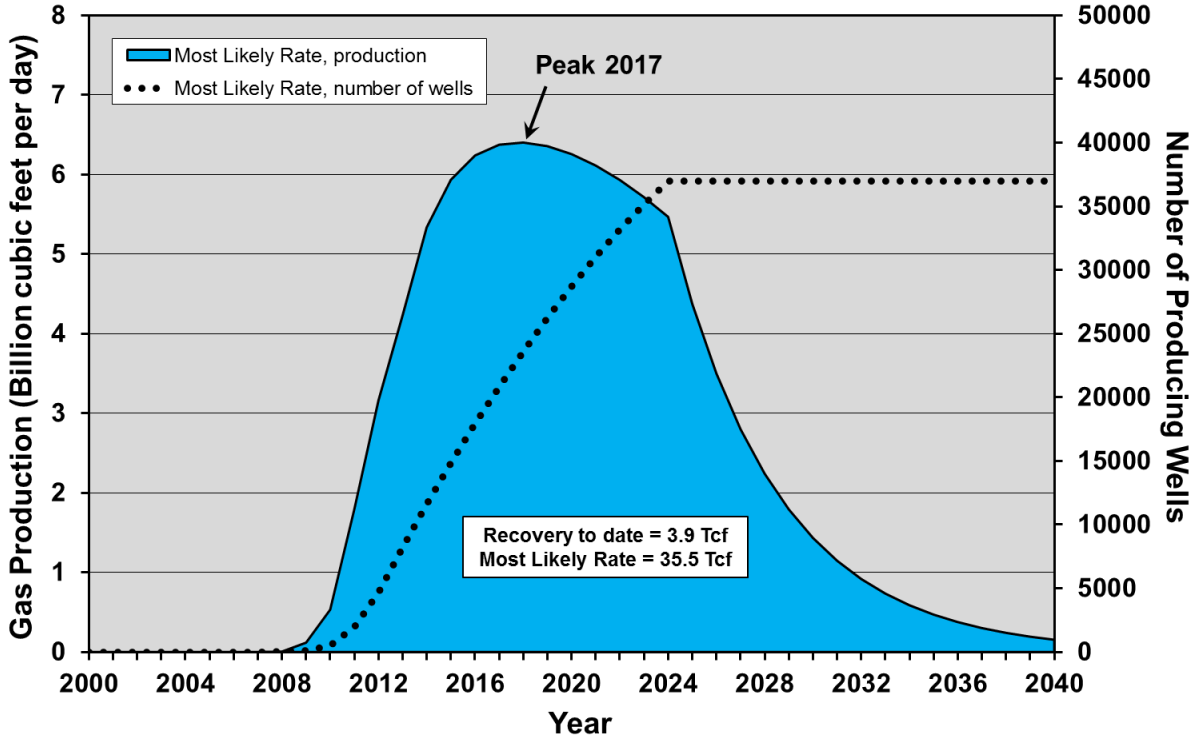

Figure 3-106. "Most Likely Rate" scenario of Eagle Ford production for gas in the "Realistic Case" (80% of the remaining area is drillable at six wells per square mile).

This projection assumes that well quality for gas production will rise in later stages of play development as drilling moves back into gas prone parts of the play.

3.4.1.3 Comparison to EIA Forecast

Figure 3-107 illustrates the comparison of the "Most Likely" drilling rate scenario to the EIA's reference case forecast. Several points are evident:

- The EIA is underestimating current production in the Eagle Ford in its forecast and highly overestimating production later on, after 2024. The EIA's near term forecast is invalidated by its own data as shown in Figure 3-107, which shows much higher current production.
- The EIA forecasts a recovery of 57.2 Tcf over the 2000-2040 period, or 21.7 Tcf more than the "Most Likely Rate" scenario over the same period.
- The EIA forecasts continuing growth in Eagle Ford gas production to an all-time high well over 7 Bcf/d in 2040. This is unrealistic given the data.

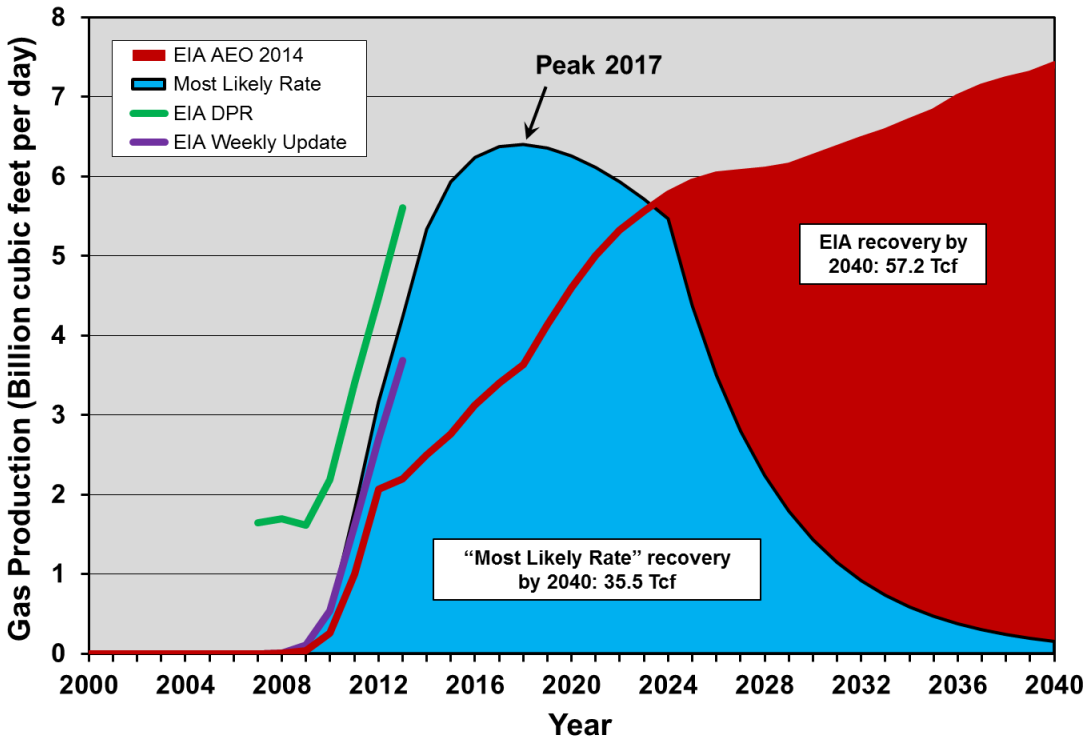

Figure 3-107. EIA reference case for Eagle Ford shale gas[158] vs. this report's "Most Likely Rate" scenario of the "Realistic Case," 2000 to 2040

Also shown are the EIA's Eagle Ford gas production statistics from its *Drilling Productivity Report* and its *Natural Gas Weekly Update*,[159] which contradict the early years of its AEO 2014 forecast. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

[158] EIA, *Annual Energy Outlook 2014*.
[159] EIA, *Drilling Productivity Report*, retrieved October 2014, http://www.eia.gov/petroleum/drilling. EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly.

3.4.2 Bakken Play

The Bakken play's areas of highest gas production per well are shifted a few miles west of the areas of highest oil production per well, but are generally in fairly close proximity. Figure 3-108 illustrates the distribution of well quality for gas production in the Bakken as defined by highest one-month production (IP)—see Part 2 of this report for a comparison to well quality for oil production.

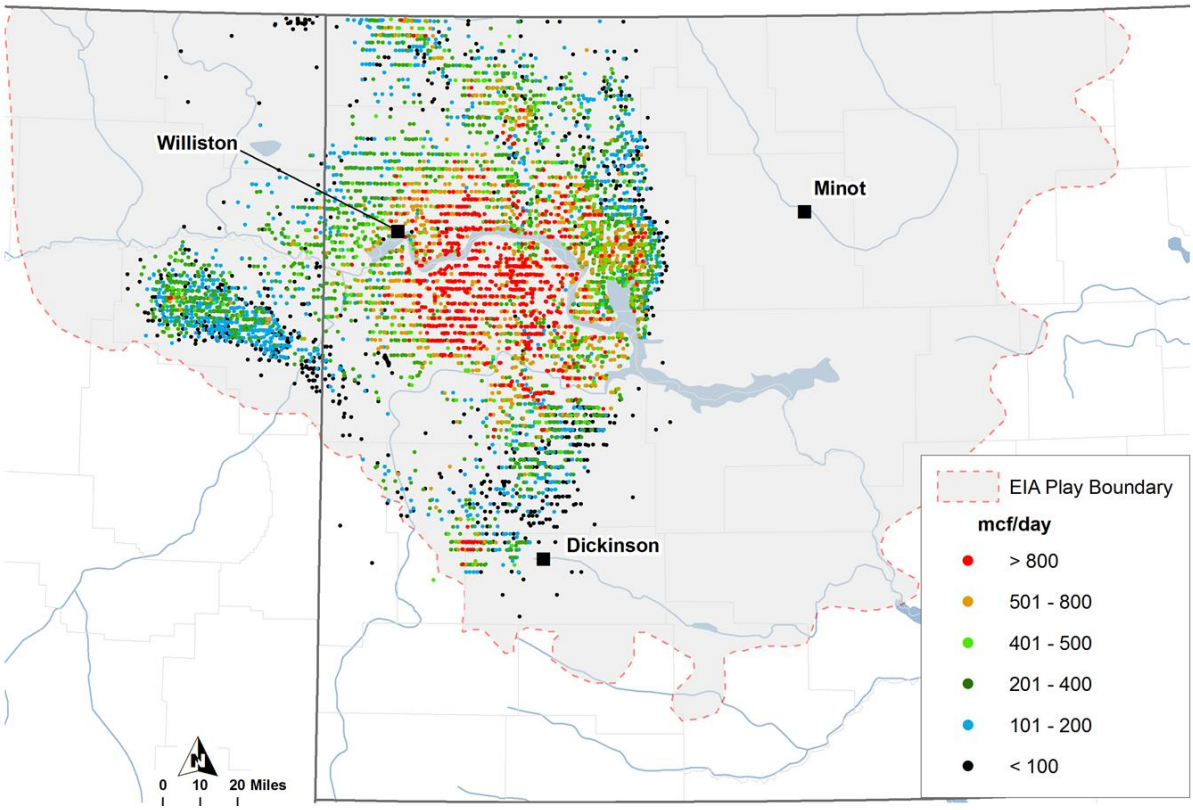

Figure 3-108. Distribution of wells in the Bakken play as of mid-2014 illustrating highest one-month gas production (initial productivity, IP).[160]

Well IPs are categorized approximately by percentile; see Appendix.

[160] Data from Drillinginfo retrieved August 2014.

Figure 3-109 provides a closer view of the main gas production area along with the counties utilized in the analysis.

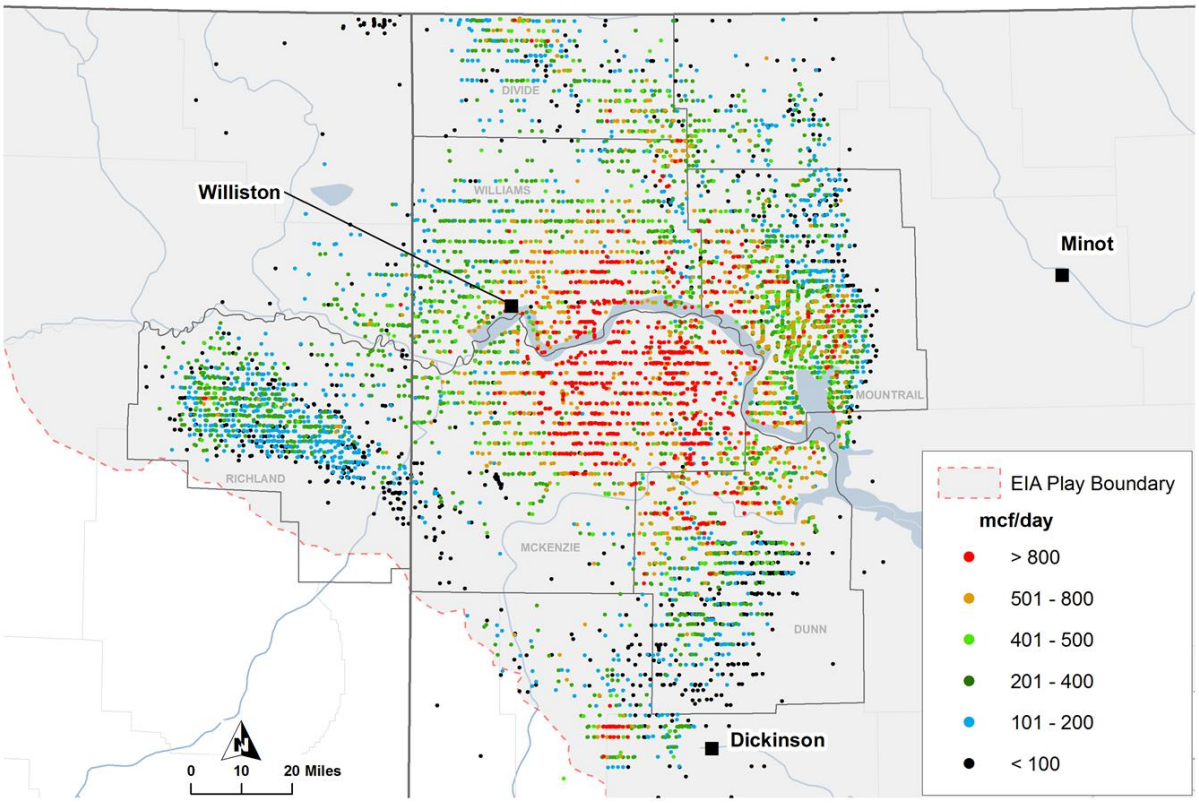

Figure 3-109. Detail of the Bakken play showing distribution of wells as of mid-2014, illustrating highest one-month gas production (initial productivity, IP).[161]

Well IPs are categorized approximately by percentile; see Appendix.

[161] Data from Drillinginfo retrieved August 2014.

Figure 3-110 illustrates gas production in the Bakken from 2003 through mid-2014. Production is about 1.1 Bcf/d from over 8,500 producing wells.

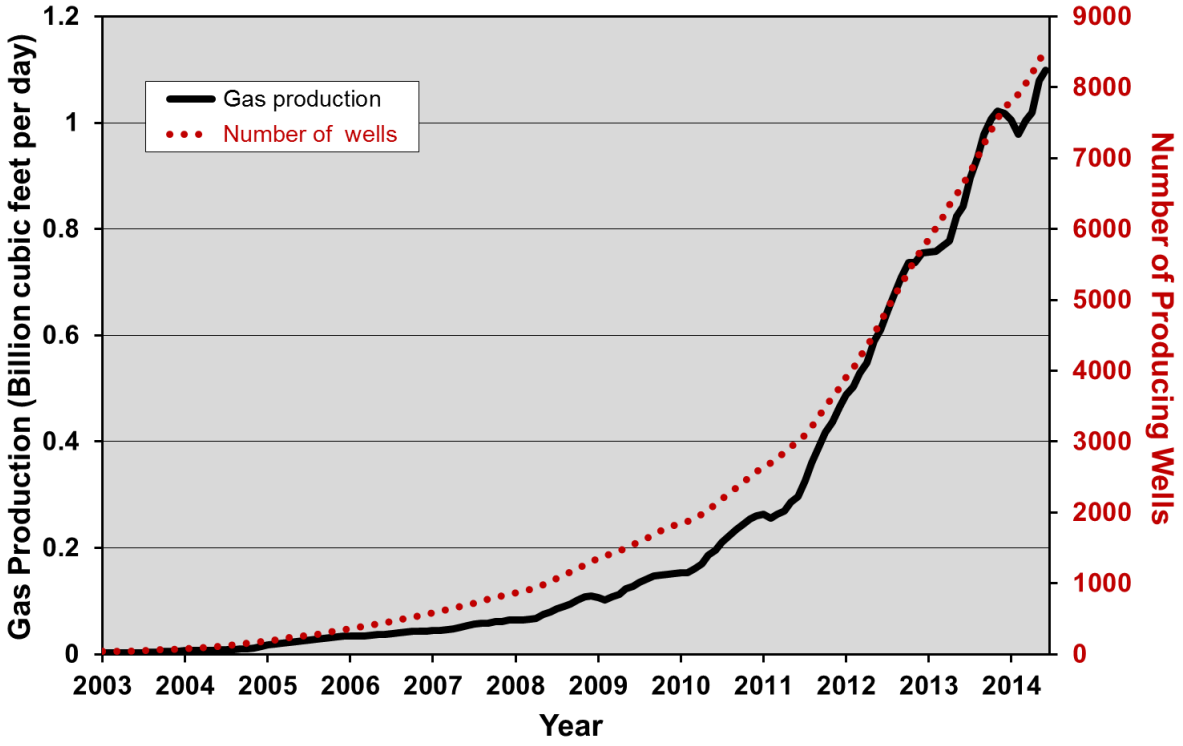

Figure 3-110. Bakken play shale gas production and number of producing wells, 2003 through 2014.[162]

Gas production data are provided on a "raw gas" basis.

[162] Data from Drillinginfo retrieved September 2014.

3.4.2.1 Critical Parameters

Other critical parameters include the average well decline, which is 81% over 3 years, and the average field decline, which is 41% for gas wells. The evolution of well quality over time for gas production is illustrated in Figure 3-111.

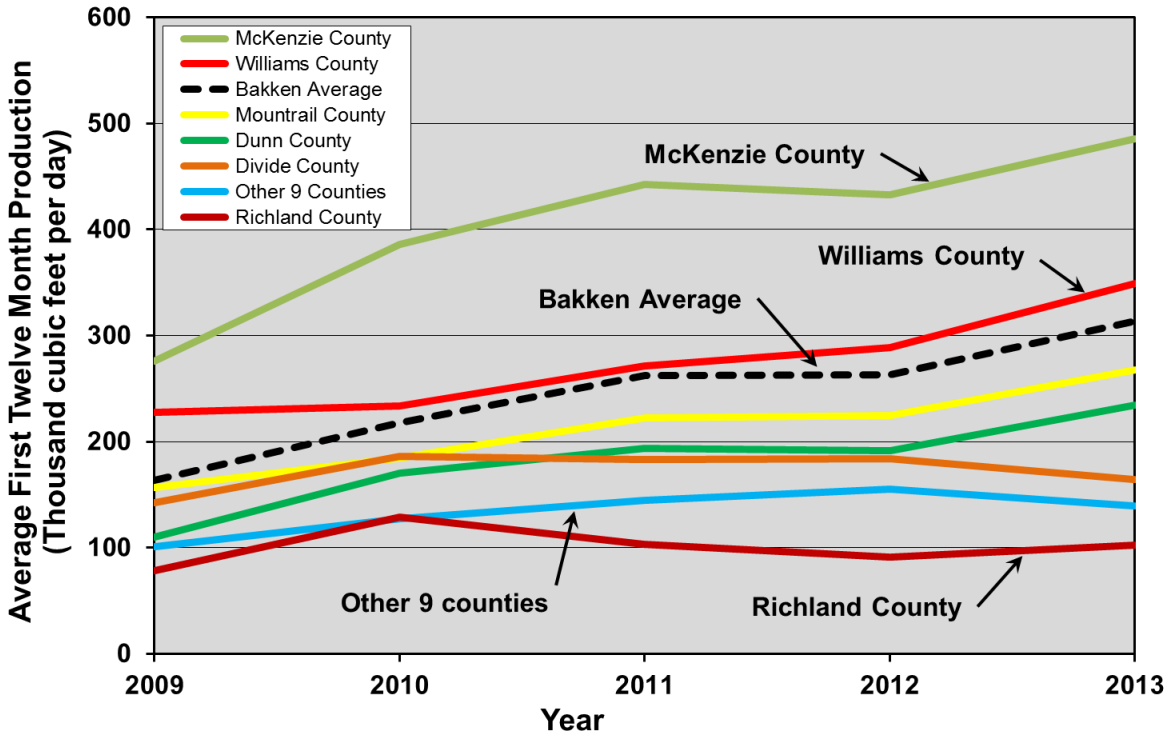

Figure 3-111. Average first-year gas production rates of wells by county in the Bakken play, 2009 to 2013.[163]

Gas production is a less important economic component of Bakken wells than for the Eagle Ford as only about 16% of the energy produced from the play is gas, and much of the gas is flared in areas remote from infrastructure (roughly 30% of gas production is flared).[164] New regulations on flaring will likely reduce the amount in future and divert more of this production to sales.[165] As can be seen in Figure 3-111, the average well quality from a gas production point of view has been increasing in the top four counties and declining or flat in the other 11 counties. Given the close proximity of high quality oil wells to high quality gas wells, the decline in well quality for gas as drilling moves to lower quality parts of the play is expected to parallel the decline in well quality for oil.

[163] Data from Drillinginfo retrieved September 2014.
[164] Styles, Geoffrey, August 2014, *The Energy Collective*, "Bakken shale gas flaring highlights global problem," http://theenergycollective.com/geoffrey-styles/449241/bakken-shale-gas-flaring-highlights-global-problem.
[165] Carroll, Joe, July 2014, *Bloomberg*, "Bakken Oil Explorers Told to Cut Flaring or Face Crude Caps," http://www.bloomberg.com/news/2014-07-01/bakken-oil-explorers-told-to-cut-flaring-or-face-crude-caps-1-.html.

3.4.2.2 Future Production Scenarios

Given that oil production is the driving force in the Bakken, and gas is a relatively small component of production, the "Most Likely" drilling rate scenario of the "Realistic Case" for oil production as outlined in Part 2 of this report is used for projection of future Bakken gas production. This scenario assumes that more than 32,000 wells will be drilled in total (compared to just over 8,500 wells at present), and that drilling will continue at current rates of 2,000 wells per year and gradually fall to 1,000 wells per year as the play is drilled off. It also assumes that well quality for gas production will decline from current levels as drilling moves from sweet spots for oil and gas into lower quality counties later in the play's development.

Figure 3-112 illustrates the "Most Likely Rate" scenario for Bakken production (see Part 2 of this report for other key parameters used for this projection). Production is forecast to rise considerably from current levels to roughly 1.3 Bcf/d by 2016 before declining. Total gas recovery through 2040 will be about 7.1 Tcf, or nearly 7 times the amount produced from the play so far.

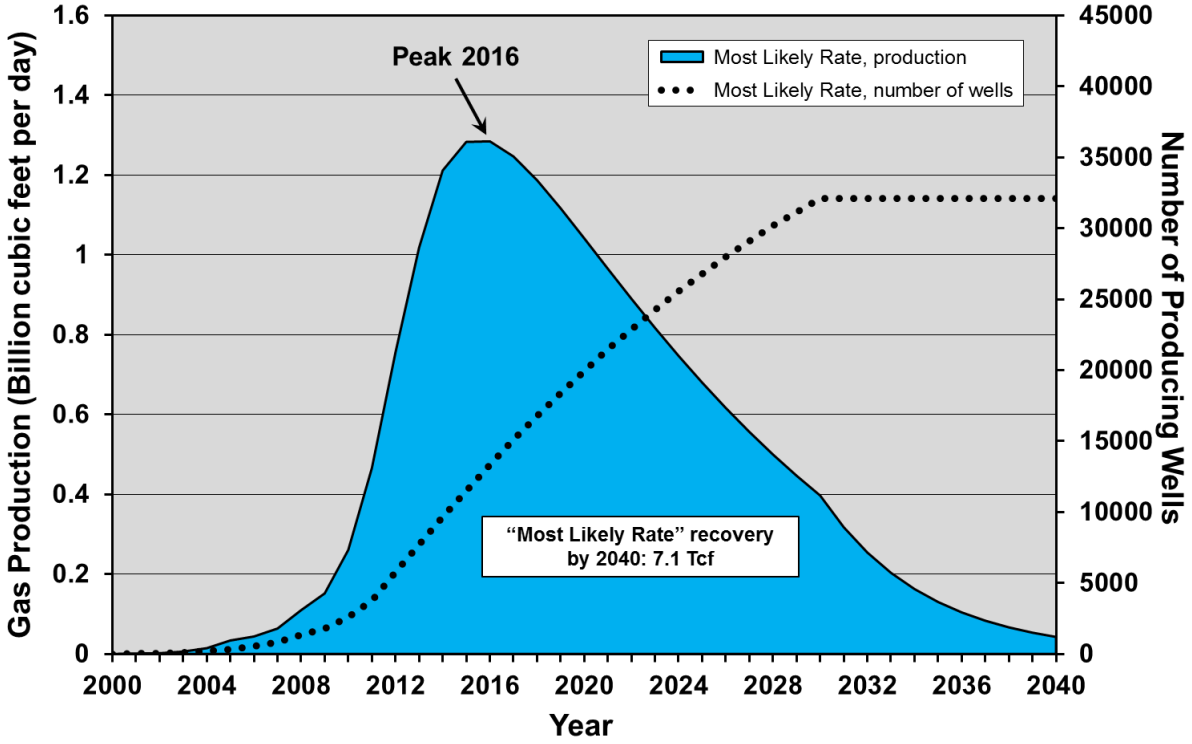

Figure 3-112. "Most Likely Rate" scenario of Bakken gas production in the "Realistic Case" (80% of the remaining area is drillable at three wells per square mile).

This projection assumes that well quality for gas production will parallel well quality trends for oil production as drilling moves into lower quality parts of the play.

3.4.2.3 Comparison to EIA Forecast

Figure 3-113 illustrates the comparison of the "Most Likely" drilling rate projection to the EIA's reference case forecast. Several points are evident:

- The EIA is highly underestimating current production in the Bakken in its forecast and overestimating production later on, after 2030. The EIA's near term forecast is invalidated by its own data as shown in Figure 3-113, which shows much higher current gas production.
- The EIA forecasts a recovery of just 5.1 Tcf over the 2000-2040 period, or 2.0 Tcf less than the "Most Likely Rate" scenario over the same period. However, it assumes production of 0.7 Tcf more gas after 2030. This is a result of the underestimates of current and short- to medium-term Bakken production.
- The EIA forecasts peak Bakken gas production at roughly the same time as this report (2016), albeit at production levels of less than half that of this report.

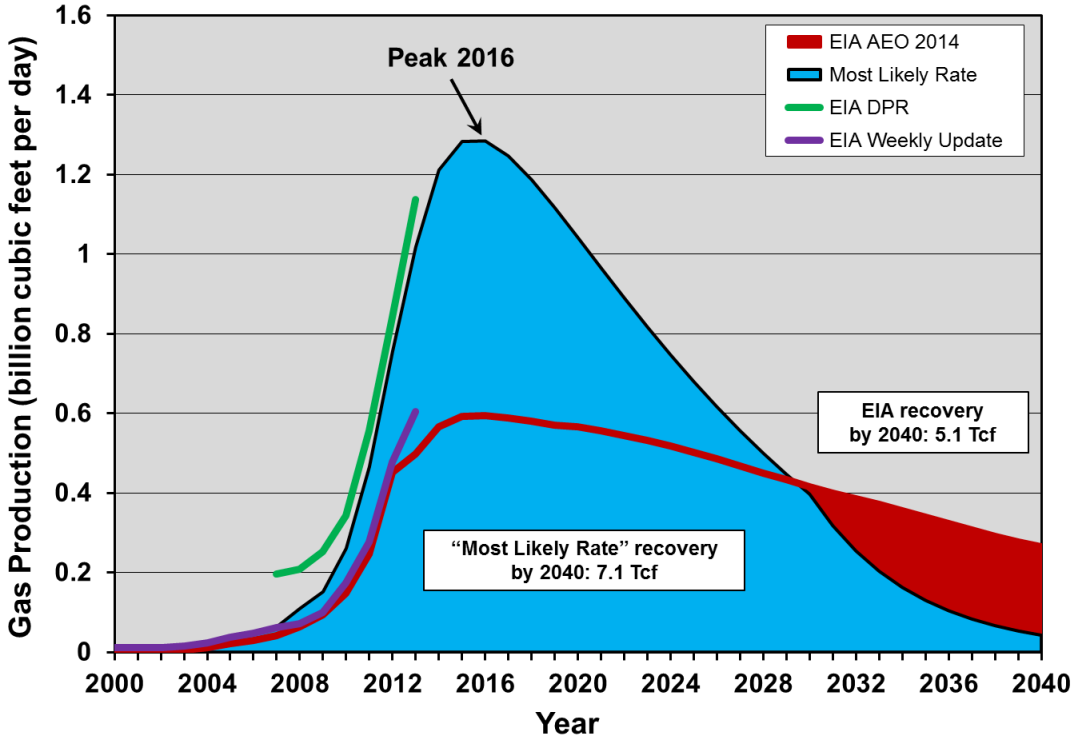

Figure 3-113. EIA reference case for Bakken shale gas[166] vs. this report's "Most Likely Rate" scenario of the "Realistic Case," 2000 to 2040

Also shown are the EIA's Bakken gas production statistics from its *Drilling Productivity Report* and its *Natural Gas Weekly Update*,[167] which contradict the early years of its AEO 2014 forecast. The EIA forecast is made on a "dry gas" basis, whereas the "Most Likely Rate" scenario forecast is made on a "raw gas" basis.

[166] EIA, *Annual Energy Outlook 2014*.
[167] EIA, *Drilling Productivity Report*, retrieved October 2014, http://www.eia.gov/petroleum/drilling. EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly.

3.5 ALL-PLAYS ANALYSIS

The foregoing analysis of shale gas plays has reviewed 88% of estimated June 2014, shale gas production[168] and 88% of the cumulative shale gas production that is forecast in the EIA's 2012-2040 reference case.[169] Although the EIA forecast for the Marcellus play is rated as "reasonable" and its forecast for the Bakken play is rated "conservative," the deficit left by being "very highly optimistic" on some of the other plays makes finding and developing the gas required to meet the overall forecast highly to very highly optimistic.

This section will further explore the outlook for overall U.S. shale gas production with a summary analysis of the plays' EIA forecasts, well quality, and production prospects to 2040.

3.5.1 Summary of EIA Forecasts

Table 3-6 summarizes the salient details of the EIA projections versus historical production and the EIA's estimates of "unproved technically recoverable resources" and "proved reserves."

Play	EIA Recovery 2012-2040 (Tcf)	Production to Date (Tcf)	EIA Unproved Resources as of January 1, 2012 (Tcf)	EIA Proved Reserves as of 2012 (Tcf)	Total Proved and Unproved Technically Recoverable (Tcf)	Percent of Unproved Resources and Proved Reserves Recovered by 2040 in EIA Forecast	Percent of Total Recovery in EIA Reference Case	EIA Production in 2040 (Tcf/year)	Optimism Bias
Barnett	44.4	15.60	20.3	23.7	44.0	101.0	10.1	2.15	Very High
Haynesville	97.2	9.41	70.9	17.7	88.6	109.8	22.0	3.37	Very High
Fayetteville	38.9	5.08	29.8	9.7	39.5	98.4	8.8	1.53	Very High
Woodford	22.8	3.14	16.8	11.1	27.9	81.6	5.2	0.82	High
Marcellus	127.2	9.70	118.9	42.8	161.7	78.7	28.8	4.57	Reasonable
Bakken	4.8	1.10	6.4	N/A	6.3	75.9	1.1	0.10	Conservative
Eagle Ford	56.7	3.90	60.3	16.2	76.5	74.2	12.8	2.70	Very High
Other	49.6	11.66	165.8	8.2	174.0	28.5	11.2	4.58	Unknown
Total	441.6	59.59	489.0	129.4	618.4	71.4	100.0	19.82	High to Very High

Table 3-6. Comparison of EIA reference case shale gas forecast assumptions[170] with unproved technically recoverable resources[171] and proved reserves[172] to cumulative production from shale gas plays.[173]

A determination of each play's "optimism bias" is included. Numbers may not add due to rounding.

[168] EIA, *Natural Gas Weekly Update*, retrieved July 2014, http://www.eia.gov/naturalgas/weekly/archive/2014/07_24/index.cfm.
[169] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA. EIA, *Annual Energy Outlook 2014*, reference case forecast, Table 14, oil and gas supply, http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx.
[170] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[171] EIA, *Assumptions to the Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf.
[172] EIA, http://www.eia.gov/naturalgas/crudeoilreserves/index.cfm.
[173] Data from Drillinginfo retrieved August to September 2014.

3.5.2 Well Quality

A comparison of plays analyzed in this report reveals that they are highly variable in terms of well quality and that the Marcellus and Haynesville stand out as clearly superior. The estimated ultimate recovery (EUR) of wells has been reviewed in the discussion of each play in this report, with the caveat that these are merely estimates and subject to change as more data emerge on longer-term well productivity.

Another measure for comparison of plays is the average first-year production from wells. This metric builds in the current geology and the cumulative impact of all technological innovations in drilling and completions to date if the most recent year is used. Figure 3-114 illustrates the average first-year production of horizontal wells in the seven plays analyzed in this study for 2013 for both the average of all wells in the play and the average for wells in the best county. Although the best play from this comparison is clearly the Haynesville, the Haynesville has a much higher field decline rate than the Marcellus which will tend to equalize the two over time. It is clear, however, that high quality shale gas plays are not ubiquitous, and even within the top producers there is considerable variation in average well quality.

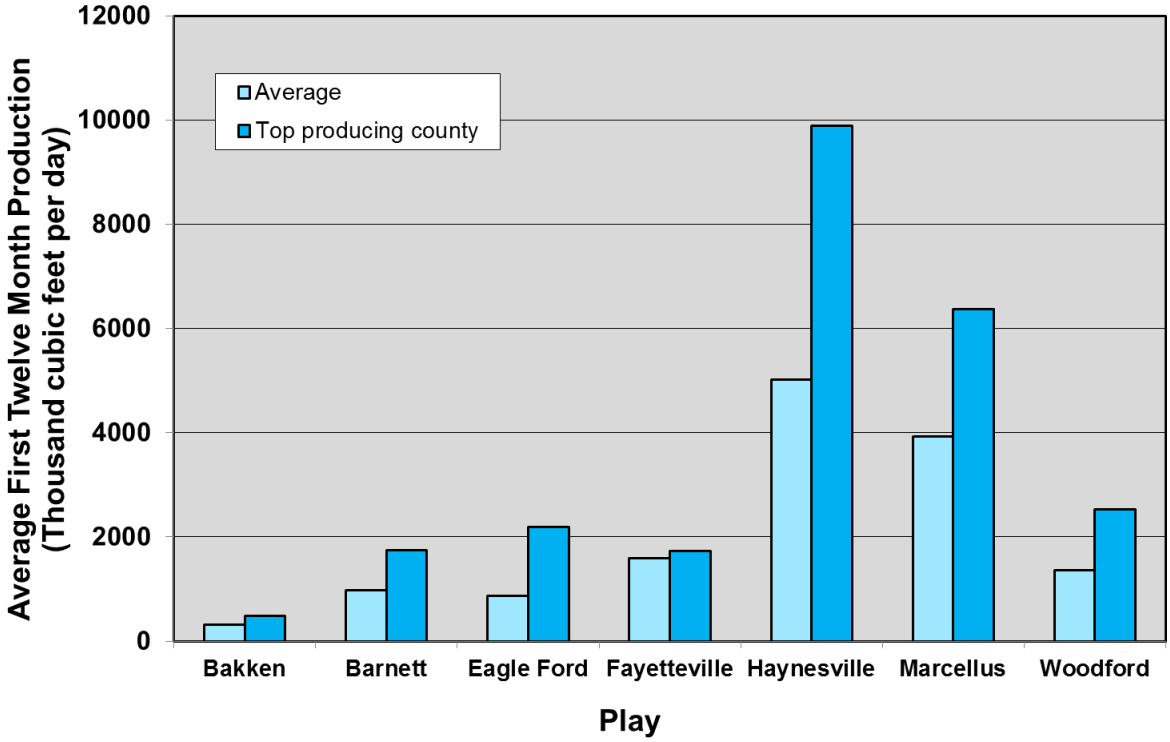

Figure 3-114. Average first-year gas production per well in 2013 from horizontal wells both play-wide and in the top-producing county for the plays analyzed in this report.[174]

[174] Data from Drillinginfo retrieved August to September 2014.

3.5.3 Production Through 2040

Figure 3-115 illustrates the sum of shale gas production from the plays analyzed in this report through 2040 in the "Most Likely" drilling rate scenario, along with the number of wells required to achieve it. Production from these plays peaks in 2016 at nearly 34 Bcf/d and declines to below 16 Bcf/d by 2040, or more than 50%. Total production over the 2000 to 2040 period is projected to be 291.7 trillion cubic feet. The Marcellus will make up 55% of production from these plays in 2040. Approximately 130,000 additional wells will need to be drilled by 2040 to meet the projections in Figure 3-115, on top of the 50,000 wells drilled in these plays through 2013. Assuming an average well cost of $7 million, this would require $910 billion of additional capital input by 2040, not including leasing, operating, and other ancillary costs.

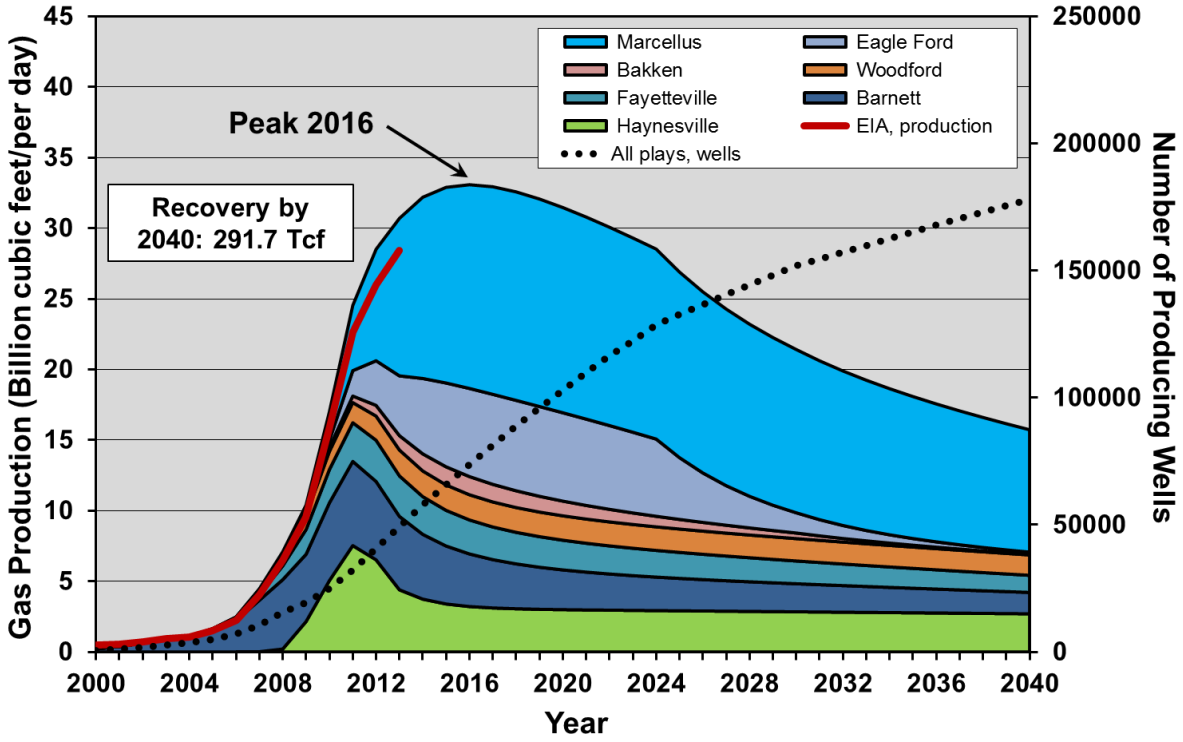

Figure 3-115. "Most Likely Rate" scenarios for the seven shale gas plays analyzed in this report and number of producing wells, through 2040.

The "Most Likely Rate" scenario projections here are made on a "raw gas" basis. 180,000 wells will be producing by 2040 in this scenario. Also shown is the EIA's production data for dry gas through August 2014 for these plays.[175]

[175] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly.

Figure 3-116 illustrates the EIA's reference case forecast for shale gas compared to the projections in this report for the seven plays analyzed. This comparison is made on a "dry" basis, given that the EIA forecast is for dry gas.[176] As can be seen, actual production of shale gas from these plays is higher in the near term than the EIA forecast and higher yet for the EIA's own independent estimate (from its *Natural Gas Weekly Update*) of actual shale gas production through August 2014. In the longer term, however, the EIA forecast overestimates production from the plays in this report's "Most Likely Rate" scenario through 2040 by 147.4 Tcf, or 64%. The EIA further estimates that in 2040, production from the plays analyzed in this report with be 182% higher (nearly 3 times) than estimated herein, and that by 2040, another 49.6 Tcf will have been recovered from other plays not analyzed in this report. Indeed, if the analysis in this report is correct, in order to meet the EIA reference case forecast other plays will have to recover an additional 198.2 Tcf—nearly 4 times the EIA's own estimate for other plays.

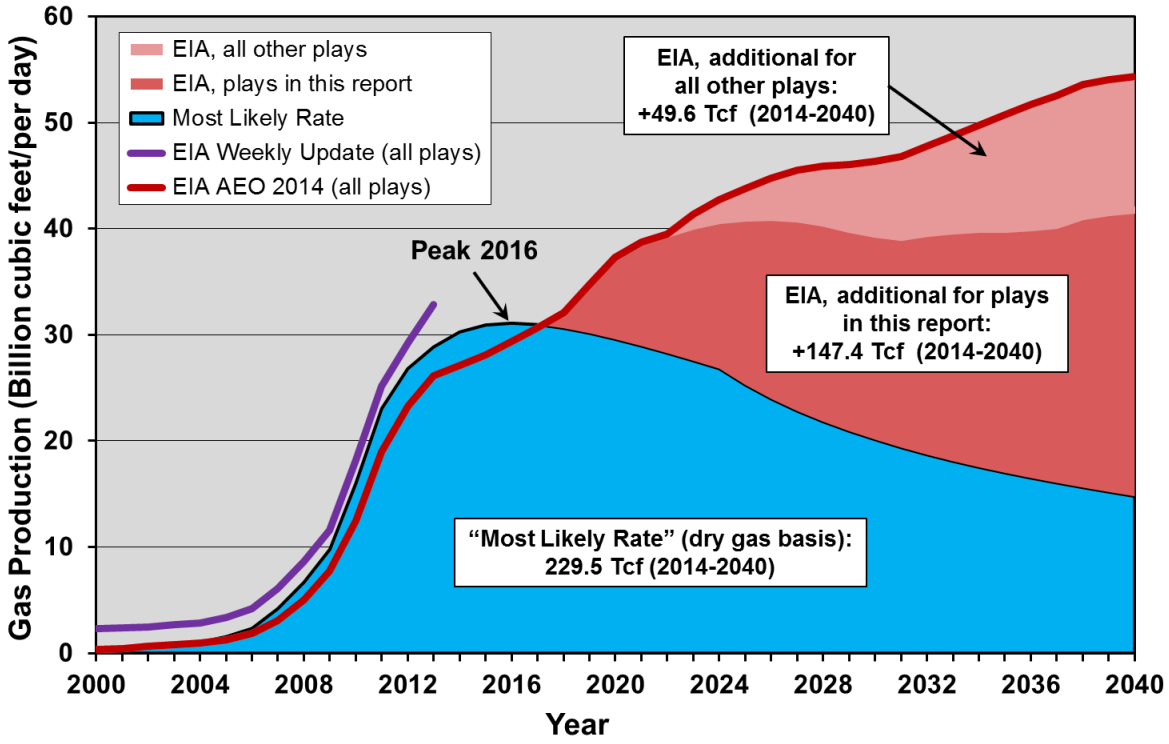

Figure 3-116. Totaled "Most Likely Rate" scenarios for the seven shale gas plays analyzed in this report, compared to the EIA's reference case forecast for these plays and for all plays.[177,178]

The "Most Likely Rate" scenario projections here are made on a "dry gas" basis. Also shown are the EIA's gas production statistics from its *Natural Gas Weekly Update*,[179] which contradict the early years of its AEO 2014 forecast.

[176] Dry gas has had liquids and other impurities removed and results in a shrinkage factor—in this case a shrinkage factor to dry basis is estimated at 6%, although the actual shrinkage factor varies by play and can be considerably higher for some plays—and lower for others.
[177] EIA, *Annual Energy Outlook 2014*, unpublished tables from AEO 2014 provided by the EIA.
[178] EIA, *Annual Energy Outlook 2014*, reference case forecast, Table 14, oil and gas supply, http://www.eia.gov/forecasts/aeo/excel/aeotab_14.xlsx.
[179] EIA, *Natural Gas Weekly Update*, retrieved October 2014, http://www.eia.gov/naturalgas/weekly.

3.6 Summary and Implications

The growth of U.S. shale gas production has been a game-changer in a natural gas supply picture that as recently as 2005 was thought to be in terminal decline. The assumption that natural gas will be cheap and abundant for the foreseeable future has prompted fuel switching from coal to gas, along with investment in new generation and gas distribution infrastructure, investment in new North American manufacturing infrastructure, and calls for exporting the shale gas bounty to higher-priced markets in Europe and Asia.

Given these assumptions—and the investments being made and planned because of them—it is important to understand the long-term supply limitations of U.S. shale gas. The analysis presented herein, which is based on one of the best commercial databases of well production information available.[180] finds that the continued growth in supply over the long term at low prices is highly questionable. Certainly production will rise in the short term, but with the likely collective peaking of the seven major plays analyzed in this report (which provide 88% of current and estimated long-term U.S. shale gas output) in the 2016-2017 timeframe, maintaining production or even stemming the decline will require maintenance of high drilling rates, along with the capital input to sustain them.

This report finds that major shale plays are variable in well quality, with some plays—like the Marcellus and Haynesville—being much more productive on average than the rest. Furthermore, the assessment of individual counties within plays reveals that well quality varies considerably, and that the best counties are attracting most of the drilling and investment—meaning that the poorer-quality counties, which account for most of the remaining drilling locations, will be drilled last. Given that field declines are steep, requiring 25-50% of production to be replaced each year, the levels of drilling and capital investment needed to maintain production will escalate going forward. Without the considerably higher prices needed to justify drilling in poorer quality rock, production will fall. The concept that high-quality shale gas plays are widespread is false, along with the concept that they are "manufacturing operations", where tens of thousands of wells can be drilled with the same productivity.

The EIA, which is viewed as perhaps the most authoritative source of U.S. energy production forecasts, has often overestimated future oil and gas production.[181] The analysis presented herein suggests that this is the case with respect to shale gas. A play-by-play analysis of the data with respect to the EIA forecasts reveals a high to very high "optimism bias" for most plays. The EIA assumes that 74% to 110% of its "unproved technically recoverable resources as of January 1, 2012" plus "proved reserves" will be recovered by 2040 for most plays. Unproved resources have no price constraints applied and are loosely constrained, compared to "reserves" which are proven to be recoverable with existing technology and economic conditions. Not only do the EIA's projections demonstrate a high or very high optimism bias, they also assume that the U.S. will exit 2040 with shale gas production significantly higher than today, at 54.3 Bcf/d. This is highly unlikely given a thorough analysis of the data.

The major shale plays analyzed in this report have produced just under 45 trillion cubic feet through 2013, and will certainly continue to produce more gas. This report projects that they will produce an additional 230 trillion cubic feet over the 2014-2040 period, with production of 14.8 Bcf/d in 2040, given unconstrained capital input and no restrictions in access to drilling locations. In contrast, the EIA forecasts 377 trillion cubic feet of gas will be recovered from the plays analyzed in this report over this period, and that production will be nearly three times as high in 2040 at 41.8 Bcf/d. Figure 3-117 illustrates the stark difference between the EIA's projections and this report's projections for the seven major shale gas plays analyzed.

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[180] DI Desktop (formerly HDPI), produced by Drillinginfo.
[181] Hughes, J.D., 2013, *Drill Baby Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?*, Post Carbon Institute, http://www.postcarbon.org/publications/drill-baby-drill.

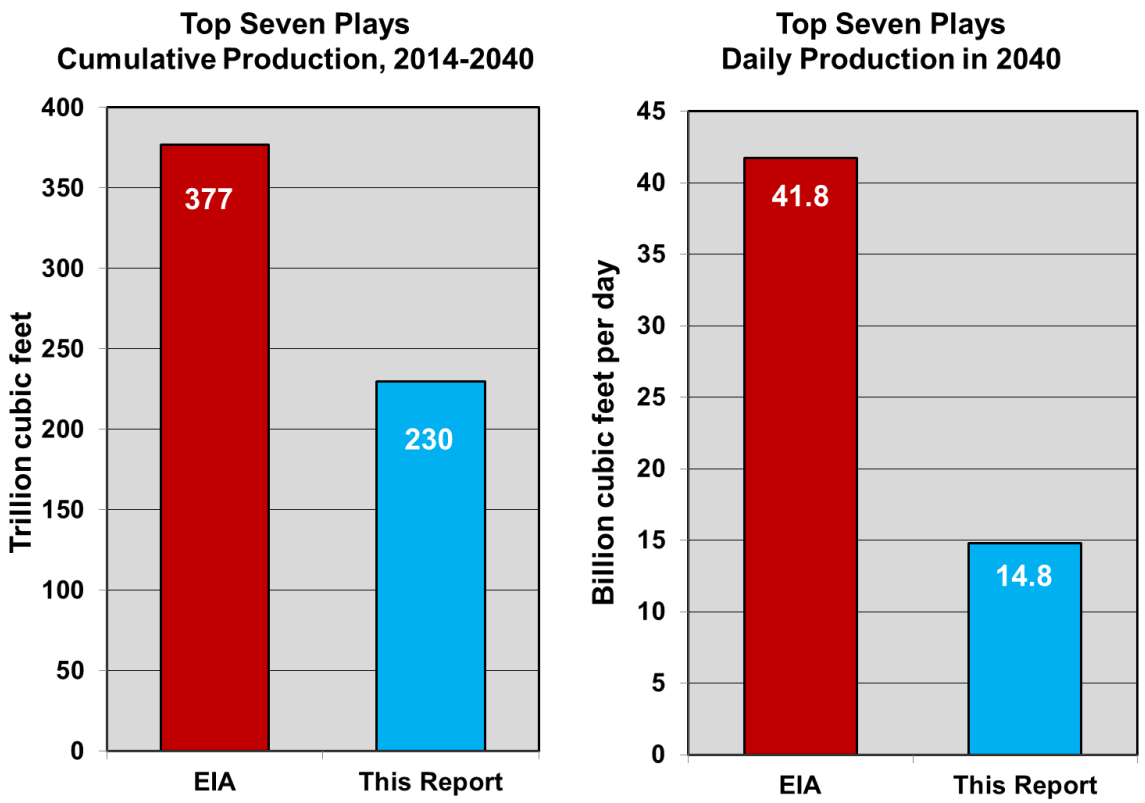

Figure 3-117. Projected cumulative gas production to 2040 and daily gas production in 2040, EIA projection[182] versus this report's projection.

The values given here are for the seven plays analyzed in this report. These plays constitute 88% of cumulative U.S. shale gas production from 2014 to 2040 in the EIA's reference case forecast.

The EIA's forecast strains credibility, given the known decline rates, well quality by area, available drilling locations, and the number of wells that would need to be drilled to make the forecast a reality. Given this report's "Most Likely" scenario estimate for the seven major plays analyzed, the remaining significant U.S. shale gas plays would need to produce 198.2 trillion cubic feet, or nearly 4 times the EIA's own estimate for "other" plays, by 2040. Failing to do this would jeopardize many current and future investments made on the assumption of a cheap, abundant, and long-term domestic gas supply. Most troubling from an energy security point of view is that much of the shale gas production will occur in the early years of this period, when decisions about long-term investment in exports and domestic infrastructure are being made—making any supply constraints later even more problematic.

The consequences of getting it wrong on future shale gas production are immense. The EIA projects that the U.S. will be a significant LNG exporter in 2040 (15% of total production—see Figure 3-2). Although the flush of shale gas production is likely to peak by 2020 and decline thereafter, there are 4 approved, 13 proposed, and 13 potential[183] LNG export facilities under consideration. The wisdom of liquidating as quickly as possible what will likely turn out to be a short-term bonanza should be questioned. A sensible energy policy would be based on this prospect.

[182] EIA, *Annual Energy Outlook 2014*, http://www.eia.gov/forecasts/aeo.
[183] FERC, September 30, 2014, "Approved LNG terminals," http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf; "Proposed LNG terminals," http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-proposed.pdf; "Potential LNG terminals," http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-potential.pdf.

APPENDIX

WELL IP COLOR CODING

In certain Figures in this report, wells are displayed by initial productivity (IP) and color-coded by their approximate percentage rank for the wells for that play. These ranks are:

- Red, top 15% of wells (i.e., above the 85th percentile)
- Orange, next 15% of wells (i.e., between the 70th and 85th percentile)
- Light green, next 15% of wells (i.e., between the 55th and 70th percentile)
- Dark green, next 15% of wells (i.e., between the 40th and 55th percentile)
- Blue, next 20% of wells (i.e., between the 20th and 40th percentile)
- Black, bottom 20% of wells (i.e., below the 20th percentile)

The IP values of the respective categories have been rounded for simplicity. For example, if the lowest IP in top 15% of wells in the Barnett is 3,024 Mcf per day, the lower boundary of this category on the Barnett map will be rounded to 3,000. IP on these maps is defined as the highest one-month production.

ABBREVIATIONS

/d	per day
bbl	barrel
bbls	barrels
Bbbls	billion barrels
Bcf	billion cubic feet
Btu	British thermal unit (1,055 Joules)
CAPP	Canadian Association of Petroleum Producers
EIA	Energy Information Administration of the U.S. Department of Energy
ERCB	Alberta Energy Resources Conservation Board
EUR	estimated ultimate recovery
GDP	Gross Domestic Product
IEA	International Energy Agency, the energy watchdog of the Organization for Economic Cooperation and Development (OECD)
IP	initial productivity (i.e., of a well),typically the highest rate of production over well lifetime achieved in the first month of production
Kbbl	thousand barrels
LNG	liquefied natural gas
Mcf	thousand cubic feet
MMcf	million cubic feet
MMbbl	million barrels
MMBtu	million British thermal units
NEB	Canadian National Energy Board
SAGD	Steam-Assisted Gravity Drainage
Tcf	trillion cubic feet
TRR	technically recoverable resources
URR	ultimate recoverable resources
USGS	United States Geological Survey

GLOSSARY

Basin — A large depressed structural geological entity which is the loci of sedimentation over tens to hundreds of millions of years.

Bench — An informal term applied to discreet rock layers, assumed to be productive, of formations such as the Three Forks in the Bakken Field.

Crude oil — As used herein, conventional crude oil not including natural gas liquids, biofuels or refinery gains. Lease condensate is included in the EIA definition and has been differentiated in this report for plays like the Eagle Ford where it is a significant component.

Dry Gas — Natural gas that has had all impurities removed to end use specifications and is essentially nearly pure methane.

Formation — A formal name in stratigraphic nomenclature for a rock unit with recognizable attributes distributed over a wide area.

Horizontal well — A well typically started vertically which is curved to horizontal at depth to follow a particular rock stratum or reservoir.

Hydraulic fracturing ("fracking") — The process of inducing fractures in reservoir rocks through the injection of water and other fluids, chemicals and solids under very high pressure.

Multi-stage hydraulic-fracturing — Each individual hydraulic fracturing treatment is a "stage" localized to a portion of the well. There may be as many as 30 individual hydraulic fracturing stages in some wells.

Oil shale — Organic-rich rock that contains kerogen, a precursor of oil. Depending on organic content it can sometimes be burned directly with a calorific value equivalent to a very low grade coal. Can be "cooked" in situ at high temperatures for several years to produce oil or can be retorted in surface operations to produce petroleum liquids.

Petroleum liquids (also, "liquids") — All petroleum-like liquids used as liquid fuels including crude oil, lease condensates, natural gas liquids, refinery gains and biofuels.

Play — A prospective area for the production of oil, gas or both. Usually a relatively small contiguous geographic area focused on an individual reservoir.

Raw Gas — Gas as produced at the well head which often contains significant amounts of impurities such as carbon dioxide, hydrogen sulfide, nitrogen, and water vapor, as well as other contaminants and hydrocarbon liquids. Gas cleanup to a "dry basis" will result in shrinkage, which is variable depending on the reservoir, and may range from less than 3% to more than 12% by volume.

Reserve — A deposit of oil, gas or coal that can be recovered profitably within existing economic conditions using existing technologies. Has legal implications in terms of company valuations for the Securities and Exchange Commission. A detailed classification scheme is available from the SPE.[1]

[1] Society of Petroleum Engineers, *Guidelines for Application of the Petroleum Resources Management System*, November 2011, http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf.

Resource — Energy resources inferred to exist using probabilistic methods extrapolated from available exploration data and discovery histories. Usually designated with confidence levels. For example, P90 indicates a 90% chance of having a least the stated resource volume whereas a P10 estimate has only a 10% chance. Resources may be “in situ”, which are all resources thought to exist in place, or “technically recoverable” but without any implied price needed for economic recovery. Shale gas and oil resources are referred to by the EIA as “unproved technically recoverable.”

Risked scenario — The reduction of play area to account for the “risk” that all parts of a play will not be accessible for drilling (allowing for towns, parks etc.). This reduces the number of available drilling locations and therefore the ultimate production from a play.

Shale gas — Gas contained in shale with very low permeabilities in the micro- to nano-darcy range. Typically produced using horizontal wells with multi-stage hydraulic fracture treatments.

Shale oil—See “tight oil.”

Stripper well—An oil or gas well that is nearing the end of its economically useful life. In the U.S., a "stripper" gas well is defined by the Interstate Oil and Gas Compact Commission as one that produces 60,000 cubic feet (1,700 m^3) or less of gas per day at its maximum flow rate. Oil wells are generally classified as stripper wells when they produce ten barrels per day or less for any 12-month period.

Tank-to-wheels emissions—Emissions generated from burning gasoline or diesel fuel not considering the emissions in the extraction and refining process.

Tight oil—Also referred to as shale oil. Oil contained in shale and associated clastic and carbonate rocks with very low permeabilities in the micro- to nano-darcy range. Typically produced using horizontal wells with multi-stage hydraulic fracture treatments.

Well decline profile—The average production declines for all wells in a given area or play from the first month on production. For most shale plays there are only four or five years of data given their relative youth, although operators routinely fit hyperbolic and/or exponential functions to this data and extrapolate well lives of 25 or more years. Also known as a well decline curve.

Well-to-wheels emissions—Full cycle emissions including those associated with extraction, refining and burning at point of use.

JULY 2016

A BRIDGE TOO FAR:

HOW APPALACHIAN BASIN GAS PIPELINE EXPANSION WILL UNDERMINE U.S. CLIMATE GOALS

OILCHANGE INTERNATIONAL · BOLD ALLIANCE · CCAN CHESAPEAKE CLIMATE ACTION NETWORK · EARTHWORKS · ENVIRONMENTAL ACTION SINCE 1970 · BREDL

SIERRA CLUB · 350.org · PROTECT OUR WATER, HERITAGE, RIGHTS (VIRGINIA & WEST VIRGINIA) · SIERRA CLUB WEST VIRGINIA · Friends of Water · Appalachian Voices

July 2016

Design: paul@hellopaul.com
Cover image: Despite Maryland's moratorium on hydraulic fracturing, the pipeline buildout in the state is moving right along. This photo shows the right-of-way of Columbia's 26″ Line MB extension, 21 miles of natural gas transmission line, currently being built through Harford and Baltimore Counties. (FERC Docket CP13-8). ©Sierra Shamer, FracTracker Alliance.

Oil Change International is a research, communications, and advocacy organization focused on exposing the true costs of fossil fuels and facilitating the coming transition towards clean energy.

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www.priceofoil.org

List of Figures:

EXECUTIVE SUMMARY

"There is such a thing as being too late when it comes to climate change. The science tells us we have to do more."
President Barack Obama, August 2015

This report details the increasing threat to the climate from American natural gas production. We document the emergence of the Appalachian Basin as the key source of projected natural gas production growth in the coming decades. We also identify the proposed pipelines that would enable that growth, and how this gas production would undermine national and global climate goals.

In the early 1990's, many promoted natural gas as a "bridge" to a clean energy future. Despite 25 years of changing economics, technology, and climate science, some in government and industry still believe in this bridge over a gap that no longer exists. This report rebuts the remaining "natural gas as bridge fuel" arguments and recommends constraining gas production by applying a climate test to the permitting of all gas pipeline proposals. Energy policy must align with climate science.

KEY POINTS

- Current projections for U.S. natural gas production – fueled by the ongoing gas boom in the Appalachian Basin – are not aligned with safe climate goals, or the current U.S. long-term climate target.

- Any analysis of the need for gas supply must be premised on national and international climate goals, not business-as-usual.

- Currently there are 19 pending natural gas pipeline projects that will increase the takeaway capacity from the Appalachian Basin and enable a doubling in gas production from the region in the coming decade. Dozens of downstream projects are also planned.

- With the 40-year plus lifespan of gas pipelines and power plants, new pipelines would lock in unsustainable levels of gas production, as investors and operators will have financial incentive to maximize production once initial investment is complete.

- Reducing methane leakage is important, but it does not provide a license to grow production.

- The Obama Administration must work to align FERC and all government agency decisions with safe climate goals. A Climate Test is essential for all decisions regarding fossil fuels: www.climatetest.org

- It doesn't have to be this way. Clean energy technology is here now, affordable, and ready to meet our needs

THE APPALACHIAN BASIN IS THE KEY SOURCE OF POTENTIAL U.S. GAS PRODUCTION GROWTH

In the past decade, natural gas production in the Appalachian Basin has experienced unprecedented growth – particularly in the Marcellus and Utica shale formations in Pennsylvania, West Virginia, and Ohio. As a result of the use of hydraulic fracturing (fracking) and horizontal drilling to access previously inaccessible gas formations, gas production from the Appalachian Basin has growth 13-fold since 2009, reaching over 18 billion cubic feet per day (Bcf/d) in 2015.

It is widely expected that production in the Appalachian Basin region will double over current levels by the early 2030s. In 2010, the Appalachian Basin produced just four percent of U.S. gas production, but by 2030 it could provide around 50 percent.

THE PIPELINE RUSH WOULD UNLOCK NEW GAS

To support this planned huge expansion of production, the industry wants to build infrastructure, and in particular, pipelines. Dozens of proposed pipeline projects in the region are currently being considered for permitting by FERC. Of these, there are 19 key pending pipeline projects that would unlock at least 15.2 Bcf/d of production. Building these pipelines would enable the Appalachian Basin to expand production well beyond current levels. All together, these 19 pending pipeline projects would enable 116 trillion cubic feet of additional gas production by 2050.

U.S. GAS PRODUCTION GROWTH IS OUT OF SYNC WITH CLIMATE GOALS

The potential for further growth in gas production represents a major challenge for U.S. climate policy. The Paris Agreement on climate change, signed by 178 nations as of June 2016, establishes the goal of "holding the increase in global average temperature to well below 2°C above preindustrial levels and pursuing efforts to limit the temperature increase to 1.5°C above preindustrial levels."[1] The current U.S. long-term climate target – which may not be enough to achieve the 'well below 2 degrees' goal set in Paris – is an emissions cut of 83 percent from 2005 levels by 2050.[2]

The U.S. Energy Information Administration's (EIA) latest projection for U.S. gas supply and demand (Annual Energy Outlook 2016) shows a 55 percent increase in production and a 24 percent increase in consumption by 2040. The difference between the greater rise in production than consumption would go to export, making the U.S. a major exporter of natural gas in the coming decades. This projection also sees U.S. energy-related CO_2 emissions declining only around 4 percent from 2015 levels, in stark contrast to the climate leadership this Administration has strived for.

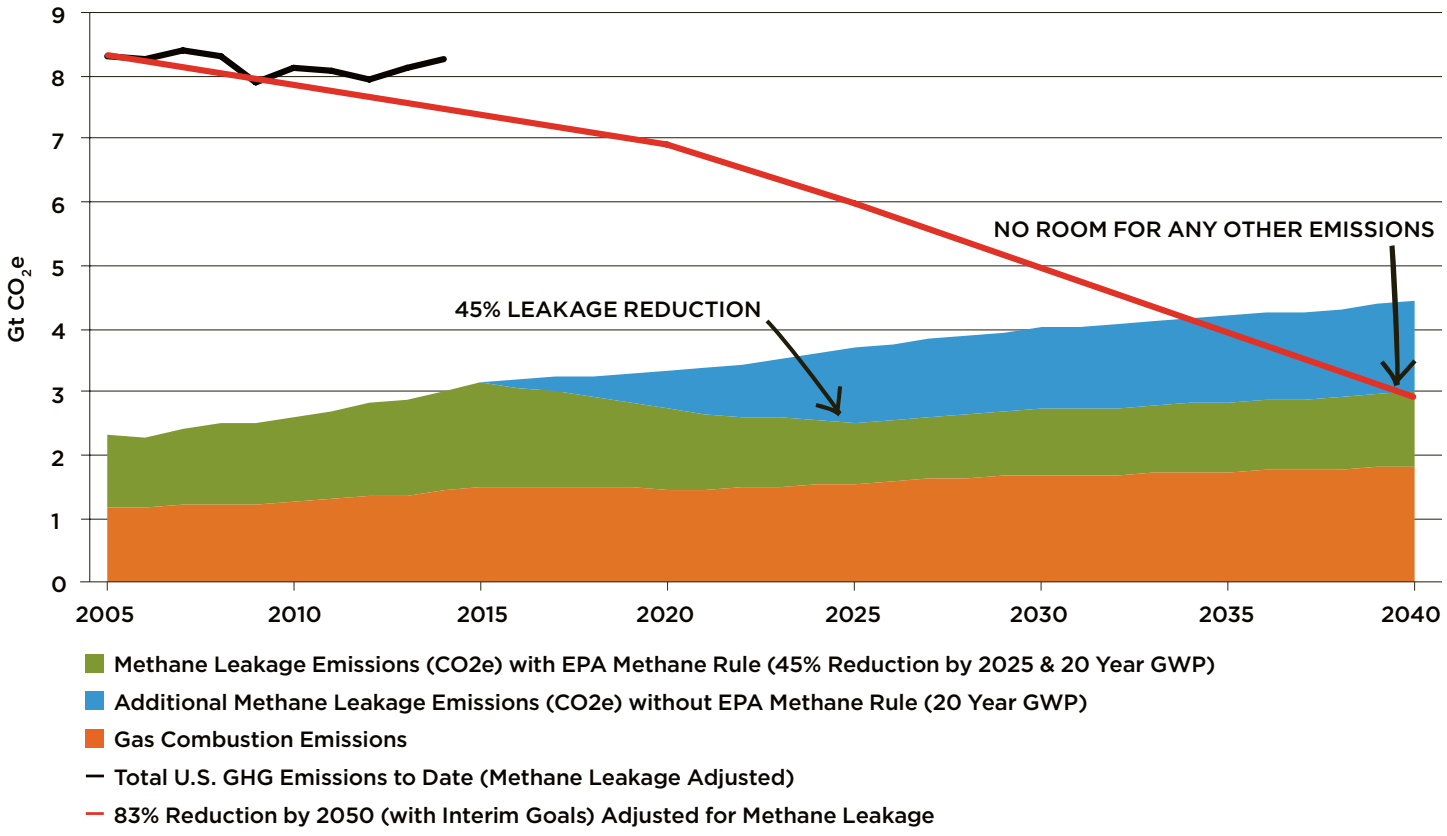
Cross-country pipe being installed.
©Ed Wade, Wetzl County Action Group, FracTracker Alliance

The currently planned gas production expansion in Appalachia would make meeting U.S. climate goals impossible, even if the Administration's newly proposed methane rules are successful in reducing methane leakage by 45 percent. Our calculations show that the rise in gas consumption projected by the EIA would alone lead to emissions that would surpass the current long-term U.S. climate target by 2040, even after accounting for methane leakage cuts. This ignores the emissions from the production (and consumption) of exported gas. In other words, even if gas were the only source of greenhouse gases in 2040, it would still blow the U.S. carbon budget. This makes it clear that the growing use of gas is out of sync with U.S. climate goals (see Figure ES-1).

New gas power plants and pipelines are designed to last at least 40 years. Once the initial capital has been spent on them, they will likely operate even at a loss to the detriment of cleaner sources. It makes more sense to avoid these investments now and instead allow clean energy technologies to fulfill their maximum potential.

When President Obama made the historic decision to deny the Presidential Permit for the Keystone XL pipeline, he did so because, in his words: "America is now a global leader when it comes to taking serious action to fight climate change. And frankly, approving this project would have undercut that global leadership. And that's the biggest risk we face – not acting."[4]

Figure ES-1: Projected U.S. GHG Emissions from Gas Usage & Leakage vs. U.S. 2050 Climate Target
Sources: U.S. Energy Information Administration, Environmental Protection Agency, and the Intergovernmental Panel on Climate Change[3]



RECOMMENDATIONS

Not acting to constrain gas production and consumption to within science-based climate limits is a major risk. The planned gas pipelines in the Appalachian Basin simply cannot be built if the U.S. is to achieve climate goals. Gas pipelines and other fossil fuel projects must be considered in light of climate targets. Specifically:

- All federal government agencies and departments, including FERC, should apply a climate test in the permitting processes of all fossil fuel infrastructure, including in Programmatic Environmental Impact Statements.

- No new natural gas pipeline projects should be considered unless they can pass a climate test. The climate test should be applied to all currently pending and future pipeline applications.

- The EIA should provide detailed guidance in its Outlook reports for U.S. fossil fuel supply and demand under various climate goals, including the nation's long-term climate goal, a 2°C path, and a 1.5°C path.

RENEWABLE ENERGY IS READY

Renewable energy is already set to become the dominant source of new generation, replacing coal and gas with zero-carbon power. In many parts of the U.S., renewable energy is today the lowest-cost and lowest-impact means to add generation capacity to our electricity system. Battery storage and grid management technology are ready to even out the intermittency of wind and solar. Widely held assumptions about the need for fossil fuel baseload power and limits to renewable energy penetration are unravelling fast. It is increasingly clear that the clean energy sector is poised to transform our energy system.

There is nothing standing in the way of building the renewable energy capacity we need to sustain our electricity needs – except maybe the entrenched interests of the natural gas industry. Renewables are the clear choice for future energy production, and natural gas is simply a bridge too far.

U.S. Climate Goals

The U.S. has made a series of international and domestic climate commitments:

- **Paris Agreement (2015): "Holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels";**

- **Intended Nationally Determined Contribution pledge (2015): 26-28% reduction in emissions from 2005 levels by 2025;**

- **Copenhagen long-term goal (2010): "By 2050, the Obama administration's goal is to reduce U.S. greenhouse gas emissions approximately by 83 percent from 2005 levels".**

For the purposes of this report, we have measured against the existing Copenhagen target, which has the virtue of being both long term and specific. Oil Change International believes that the science demands full decarbonization of energy systems as soon as possible, on a trajectory that meets or exceeds internationally agreed upon goals.

INTRODUCTION

On April 22, 2016, over 170 nations signed the Paris Agreement on climate change at the U.N. in New York. Today the number of signatories stands at 178. The U.S. received credit for working with China and other large emitters to seal the deal.

The targets in the agreement aim to keep global temperatures "well below" 2°C and "pursu[e] efforts to limit the temperature increase to 1.5°C above preindustrial levels". Given the level that emissions have reached in recent years; these targets will require a dramatic effort.

The role of the U.S. in achieving these goals is paramount. As the world's second largest emitter of greenhouse gases (GHGs) and as one of the most prolific sources of fossil fuels in the world, the U.S. will need to coordinate every level of government to play its role in achieving the world's climate goals. With a currently stated national goal to cut emissions by 83 percent from 2005 levels by 2050, the U.S. has no time to waste.

To date, such coordination is sorely lacking. Departments and agencies of the federal government that are responsible for permitting fossil fuel infrastructure are pursuing a business-as-usual approach that neglects climate change as a factor in their decision-making. FERC is one such agency.

FERC is responsible for issuing permits for the construction and operation of interstate natural gas pipelines, among other things. As the proliferation of fracking and horizontal drilling has triggered an unprecedented growth in natural gas production, FERC has issued dozens of permits in recent years to expand and redirect existing pipelines, and plow new pipelines across the country to facilitate further expansion.

In the next few years, the Appalachian Basin could become the epicenter of this pipeline buildout, and FERC stands as the gatekeeper to dozens of major projects yet to be permitted. These projects could unleash a massive surge in natural gas production from this region, allowing U.S. natural gas production to aggressively grow at precisely the time that the world needs to constrain fossil fuels of every kind.

At stake is the attainment of U.S. climate goals. Locking in new natural gas infrastructure, with an economic lifespan of at least 40 years, could appropriate all of the U.S. emissions budget for natural gas alone. In other words, far from providing a bridge to clean energy, natural gas could undermine the transition that is required for a safe climate future.

At the core of this issue are two myths that have so far been diligently plied by the natural gas industry: 1) that gas is substantially cleaner than coal, and 2) that relentless gas production growth is integral to the clean energy transition and therefore in the public interest.

Both of these myths are countered in this report.

This report details the following:

- The Appalachian Basin could become the primary source of U.S. gas in the future.
- Proposed pipelines in the Appalachian Basin would unlock substantial growth in U.S. natural gas production.
- The surge in natural gas supply associated with these pipelines is entirely out of sync with U.S. climate goals.
- Renewable energy is ready now to supply U.S. energy needs at competitive cost.

Finally, the report recommends that in order for the U.S. to achieve the climate goals it has set, government agencies must apply a climate test to future infrastructure and policy decisions. The test should be based on prevailing climate science and an understanding of the role of fossil fuel supply on energy markets. In particular, FERC must apply a climate test to gas pipelines and other gas infrastructure that seeks a permit.

Cross-country pipe being installed.
©Samantha Malone, FracTracker Alliance

THE APPALACHIAN BASIN IS THE KEY SOURCE OF POTENTIAL U.S. GAS PRODUCTION GROWTH

The Appalachian Basin is defined by the U.S. Geological Survey as stretching from Alabama to Maine, encompassing the majority of the U.S. eastern seaboard.[5] For the purposes of this briefing, we focus on the centers of natural gas production in the states of Pennsylvania (PA), West Virginia (WV), and Ohio (OH). We use the term Appalachian Basin to encompass the gas production in these three states.

In 2009, dry gas[i] production from these three states was barely 1.7 Bcf/d. This is only slightly more than the capacity of just one of the larger proposed major pipelines, such as the 1.5 Bcf/d Atlantic Coast Pipeline proposed in Virginia by Dominion Resources and Duke Energy. The nearly 13-fold growth in gas production in the Appalachian Basin since 2009 has primarily come from the emergence of fracking and horizontal drilling in two key geological formations: the Marcellus and Utica.

The Marcellus formation has proved to be America's – and one of the world's – most prolific natural gas formations. Production is primarily located in northwest West Virginia and southwestern and northeastern Pennsylvania.[ii] Dry gas production from the Marcellus grew from zero in 2006 to nearly 15 Bcf/d in 2015.[iii] In that time, nearly 18 trillion cf of dry natural gas has been extracted, along with nearly 200 million barrels of natural gas liquids (NGLs). Production could more than double to around 33 Bcf/d by the early 2030s.

The Utica formation lies beneath the Marcellus in certain parts of West Virginia and Pennsylvania but is predominantly located in eastern Ohio. Its exploitation only started to gather pace in 2013. Dry gas production has grown from zero in 2010 to nearly 2.6 Bcf/d in 2015. By the end of that year, over 1.5 trillion cf of dry natural gas and over 120 million barrels of NGLs and oil have been extracted from this formation. Gas production in the Utica could reach over 4.5 Bcf/d by the early 2020s.

In total, over 18 Bcf/d of dry gas is produced from the Marcellus and Utica formations today. Rystad Energy projects that production will double by the early 2030s to over 36 Bcf/d, led by expansion in the Marcellus. Other formations in the region could bring the total dry gas production for the Appalachian Basin to over 37 Bcf/d.

The role of the Appalachian Basin in the potential growth in U.S. gas production cannot be overstated. Figure 2 shows that the region is projected to play an increasingly dominant role in U.S. gas production in the decades ahead. In 2010, the Appalachian Basin produced just four percent of U.S. gas production. At its projected peak in the 2030s, the Appalachian Basin could be supplying around 50 percent.

This production growth cannot be realized without building the pipeline capacity to carry it to market. We calculate that around 15.2 Bcf/d of the anticipated 18.5 Bcf/d production growth cannot go ahead without the pipelines that are currently proposed and under review.

i. This report discusses the impact of dry gas production and dry gas pipelines. While some natural gas liquids (NGLs) are produced in this region, they are beyond the scope of this report. Unless otherwise stated, the figures used refer to dry gas production only. Other sources, such as the EIA Drilling Productivity Report, include data for mixed wet and dry gas production, as production at the well is a combination of these hydrocarbons. Dry gas is separated from liquids in processing plants and transported to market in dedicated pipelines. The expansion of this dry gas pipeline network from the Appalachian Basin is the subject of this report.
ii. The Marcellus formation reaches into New York and Virginia but although pipeline routes travel through these states, there is currently no plan for production in these states.
iii. All gas production data are from Rystad Energy AS.

Figure 1: Dry Gas Production in the Appalachian Basin (Past and Forecast) *Source: Rystad Energy AS*

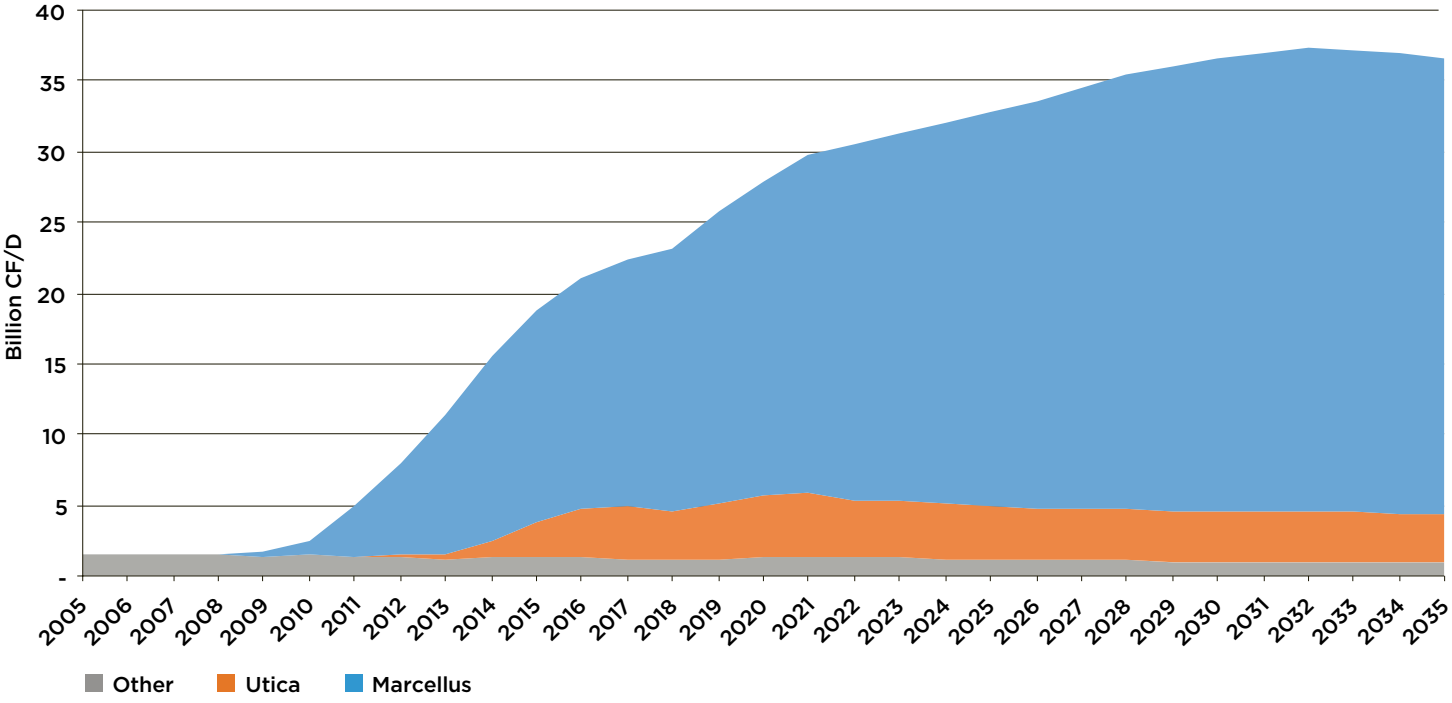
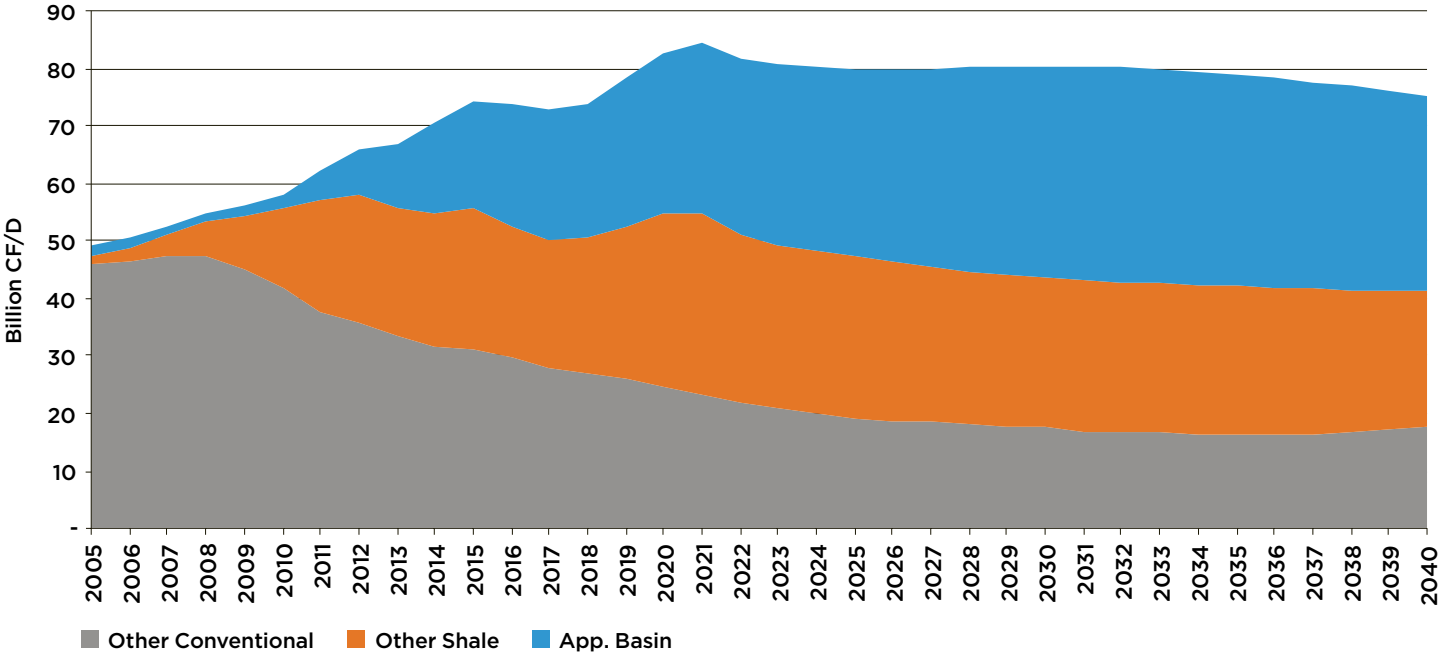


Figure 2: The Increasing Role of the Appalachian Basin in U.S. Dry Gas Production *Source: Rystad Energy AS*



Differing Projections, Similar Conclusions

In this report, we use data from Rystad Energy's UCube database to provide a breakdown of both historical and projected production by geological formation in order to understand the role of the Appalachian Basin in the potential future of U.S. gas production. We also use EIA outlooks for national-level projections.

There are other sources that offer different projections. The future of any hydrocarbon production depends on many factors, including the size of the hydrocarbon resource in the ground, the development of extraction technology, and market prices and policies that may affect prices or costs of development. All projections are based on different assumptions of these factors and must be viewed as projections rather than predictions. Therefore, we do not endorse any particular outlook as being the most accurate, but view all of them as a guide to what could happen.

To date, production of oil and gas from U.S. shale formations, in particular gas production from the Marcellus, has repeatedly outperformed projections. Figure 3 is from BP's Annual Energy Outlook 2016 and shows the company's repeatedly revised projections for U.S. tight oil and shale gas production.

The latest projection in the chart (2016) suggests continued very steep growth with U.S. shale gas production reaching around 80 Bcf/d in 2035. This is much greater than the 63 Bcf/d that the Rystad data we have used shows as a peak in U.S. shale gas production in the 2030s. BP does not provide a breakdown of formations, but it seems likely that stronger growth from the Marcellus and Utica accounts for a significant part of its bullish forecast.

It should also be noted that EIA projections show a steady increase in U.S. gas production through 2040, the last year of the EIA's outlook range. EIA revised up its gas production projection in its latest annual flagship report, the Annual Energy Outlook (AEO). The AEO 2016 has only been published as a limited early release at this time and does not show a regional breakdown of projected gas production. However, it is remarkable that projected U.S. gas production in 2040 has been revised up nearly 20 percent from the AEO 2015 (see Figure 4). The projection now sees gas production rising 55 percent from 2015 to 2040. Production in 2040 would be some 55 percent higher than in Rystad's projection.

No one really knows what the future will bring, but it is clear that without climate policies, U.S. natural gas production is very likely to grow substantially in the coming decades, and the Appalachian Basin is very likely to be at the heart of that growth.

Figure 3: BP Outlook 2016, Shale Play Forecasts. *Source: BP p.l.c. 2016*[6]

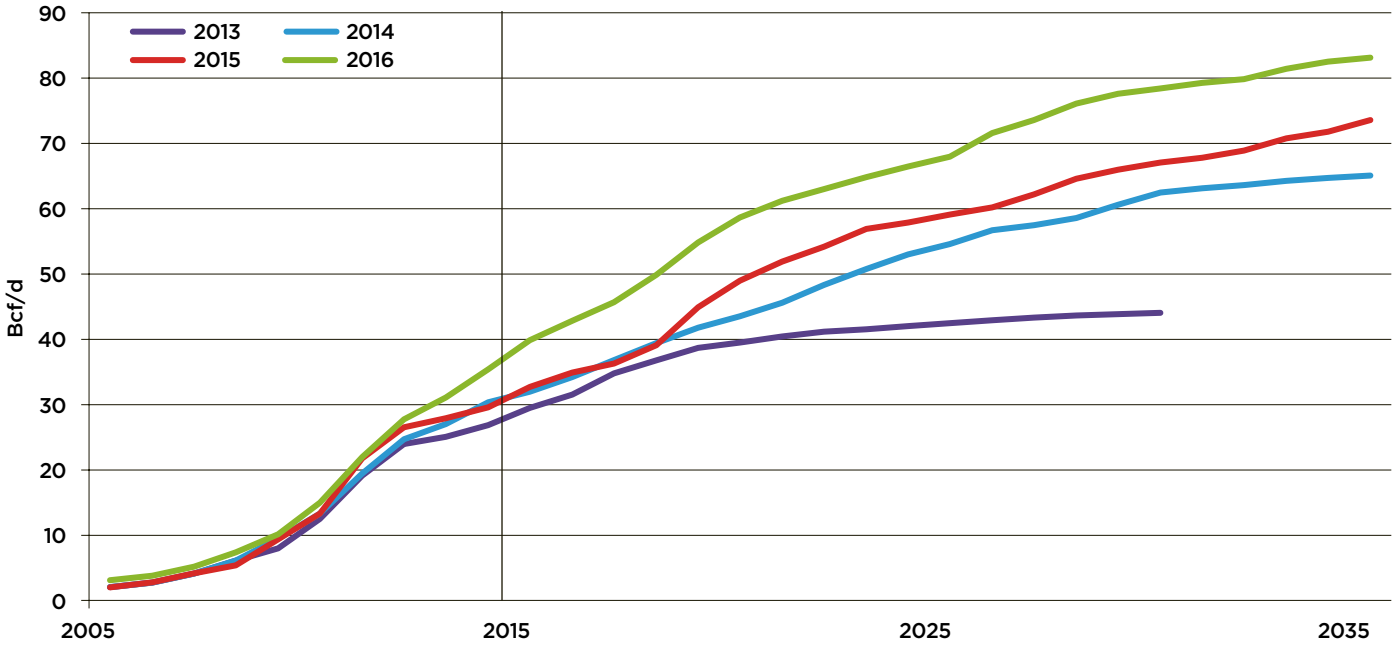
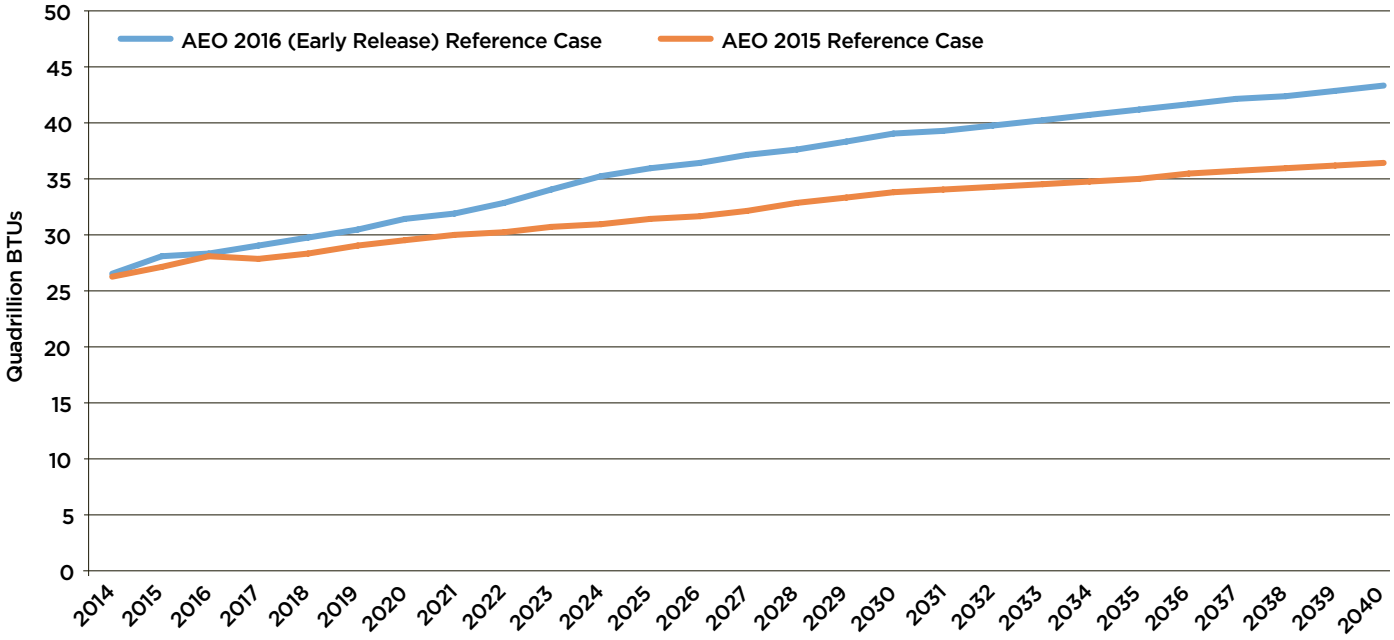


Figure 4: EIA Projected U.S. Gas Production Revised Up in 2016 *Source: U.S. Energy Information Administration*



THE PIPELINE RUSH WOULD UNLOCK NEW GAS

How much new capacity is proposed?

There has already been tremendous growth in gas production from the Appalachian Basin. The region was barely producing enough gas to fill one major pipeline in the first decade of the 21st century, and much of this gas was consumed locally. But since 2009, production has grown over 1,000 percent, spawning a wholesale re-plumbing of the pipeline network in the region. In the past, pipelines brought gas into the region, primarily from the Gulf Coast states of Louisiana and Texas. The main interstate pipelines came through the region on their way north, feeding distribution lines on their way.

Our analysis of the pipeline buildout is focused on the climate impact, and therefore we assess only those pipeline projects that add takeaway capacity from the Appalachian Basin. These are sometimes referred to as first mile projects. There are dozens of projects that expand the distribution capacity of the gas pipeline network, but while these broaden the reach of Appalachian Basin gas, these do not in of themselves increase the takeaway capacity from the basin. They therefore may not by themselves enable production growth, which leads to increased climate impact.

There are also proposed pipeline projects for Natural Gas Liquids (NGLs) in this region but we do not deal with these here. Dry gas constitutes the vast majority of the hydrocarbons that are projected to come from the Appalachian Basin.

In 2014 and 2015, eleven major projects, some with multiple phases, were completed, adding around 5.25 Bcf/d of takeaway capacity from the region. All of these involved reversals and/or expansion of existing pipeline systems. Some new pipe was laid, and new compression stations added, but none of these involved creating major new pipeline corridors.

In addition, two projects are currently under construction, and construction on another had started but has since been halted. The larger of the two that are still going forward is the latest expansion of the Rockies Express (REX) pipeline, called the Zone 3 Capacity Enhancement Project. This will add 800 million cf/d by early 2017. The other is a 130 million cf/d supply line that Dominion Transmission Inc. is building to feed southwest Pennsylvania supply into the Lebanon hub in Ohio. This hub supplies gas to various pipelines heading south to the Gulf Coast and west into the Rockies.

The Constitution Pipeline is a new-build project that began construction this spring but stalled when the New York State Department of Environmental Conservation (NYSDEC) denied the project's Section 401 Water Quality Certification.[7] The companies involved, led by pipeline giant Williams, have vowed to continue with the project.[8] If it goes ahead, Constitution will add 650 million cf/d of new takeaway capacity from northeast Pennsylvania.

Waiting on the sidelines are 18 additional major projects that could add nearly 18 Bcf/d to the takeaway capacity from the region. Ten of these projects are expansions and/or reversals of existing pipelines (see Map 1). However, to achieve those expansions some new pipeline will be laid and several new compression stations will be built to increase pressure to enable the flow of additional gas. These ten expansion projects would add over 5.5 Bcf/d of additional takeaway capacity.

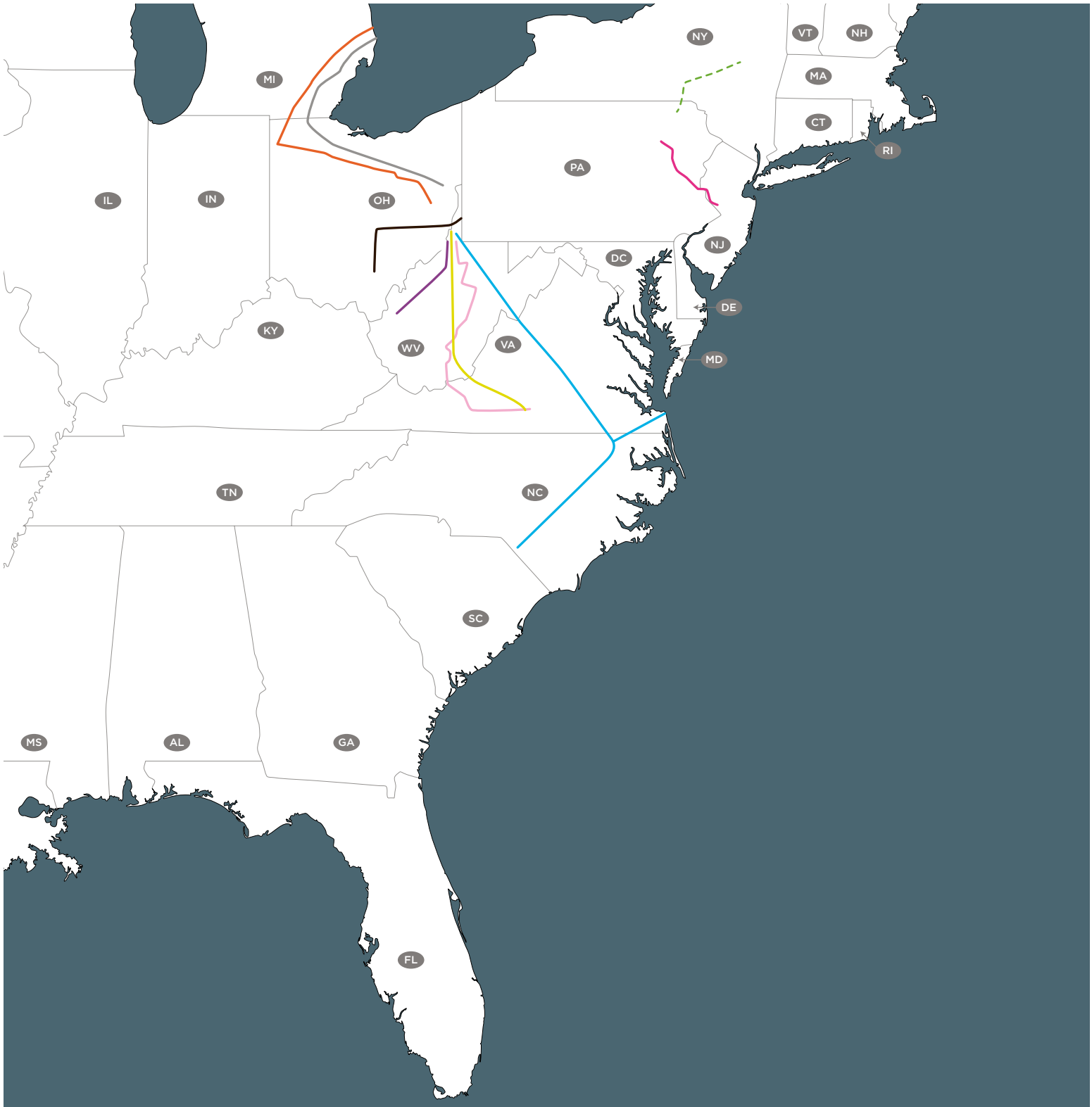
Eight of the proposed pipelines are new-build projects forging new pipeline corridors over hundreds of miles (see Map 2). These would add another 12.4 Bcf/d of takeaway capacity. Together with the Constitution Pipeline, there is over 18.6 Bcf/d of takeaway capacity hanging in the balance. Building these pipelines would enable the Appalachian Basin to expand production to its likely maximum potential (see Figure 5).

Table 1: Proposed Pipeline Expansions

Pipeline	Capacity (Million CF/D)	Destination	Status (FERC Docket No.)
Boardwalk Northern Supply Access	384	Texas	FERC Docket CP15-513
Spectra TEAM Gulf Markets 1	250	Texas	FERC Docket CP15-90
Spectra TEAM Gulf Markets 2	400	Texas	FERC Docket CP15-90
NFGS Northern Access 2016	497	New York & Canada	FERC Docket CP15-115
Williams Transco Atlantic Sunrise	1,700	Serves Entire Mid-Atlantic onto Florida	FERC Docket CP15-138
Spectra TEAM Adair Southwest	200	Kentucky	FERC Docket CP15-3
Spectra TEAM Access South	320	Alabama & Mississippi	FERC Docket CP15-3
NFGS Empire North	300	New York & Canada	FERC Docket CP15-115
KM Broad Run Expansion	200	Tennessee, connects to Georgia & South East	FERC Docket CP15-77
CGT WB Xpress	1,300	Connects to U.S. Gulf Coast Systems and Mid Atlantic Markets	FERC Docket CP16-38
Total Capacity	5,551		

Table 2: Proposed New-Build Pipelines

Pipeline	Capacity (Million CF/D)	Destinations	Status (FERC Docket No.)
Spectra Constitution	650	New York	Construction Stalled
CGT Leach Xpress	1,000	Gulf Coast Markets	FERC Docket CP15-514
ETP Rover	2,750	Michigan & Canada	FERC Docket CP15-93
Spectra PennEast	990	Pennsylvania	FERC Docket CP15-558
Spectra NEXUS	1,500	Michigan & Canada	FERC Docket CP16-22
Dominion Atlantic Coast	1,500	Virginia & North Carolina	FERC Docket CP15-554
EQT Mountain Valley	2,000	Virginia	FERC Docket CP16-10
CGT Mountaineer Express	750	Connects to US Gulf Coast	FERC Pre-filing
Williams Transco Appalachian Connector	1,900	Connects to Atlantic Sunrise - Mid-Atlantic and SE as far as Florida	Preliminary Evaluation
Total Capacity	13,040		



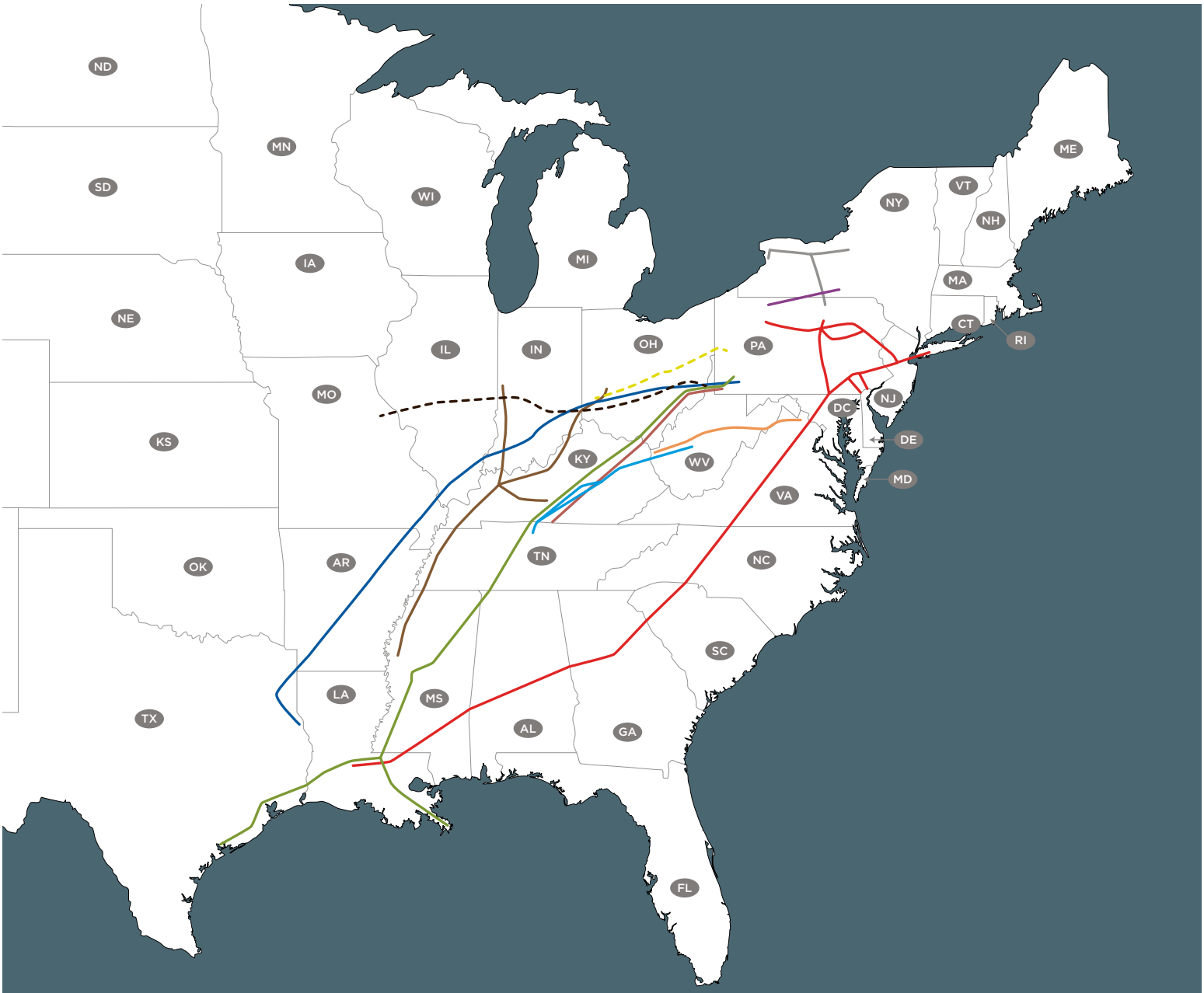
Proposed New Build Pipelines

- Appalachian Connector
- Atlantic Coast
- Leach Xpress
- Mountain Valley
- Mountaineer Xpress
- Nexus
- PennEast
- Rover

New Build Proposed Pipelines - Construction Stalled

- Constitution

All pipeline routes are approximate



Proposed Expansion Pipelines

- Access South
- Adair Southwest
- Atlantic Sunrise
- Broad Run Expansion
- Empire North
- Gulf Markets 1 & 2
- Northern Access 2016
- Northern Supply Access
- WB Xpress

Proposed Expansion Pipelines Under Construction

- Rockies Express Pipeline Zone Three Capacity Enhancement
- Lebanon West II

All pipeline routes are approximate

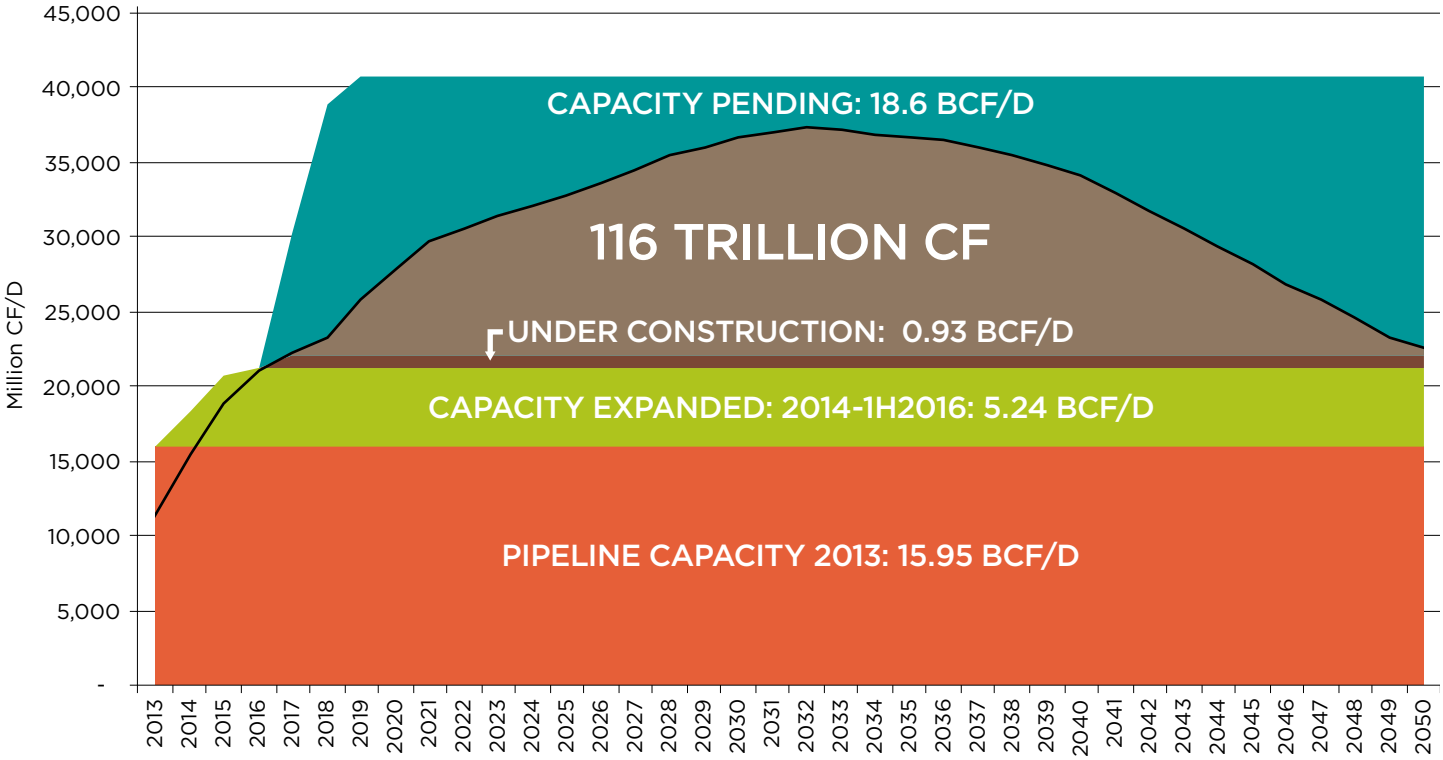
ASSESSING THE CLIMATE IMPACT

A starting point for looking at the climate impact of this pipeline buildout is to estimate how much gas production is enabled by the full realization of all the proposed pipelines.

Figure 5 shows the capacity implications of the region's pipeline buildout, including pipelines that are already built, those that are currently under construction, and those yet to break ground. It also shows the Rystad Energy forecast for Appalachian Basin gas production – in particular, the gray shaded area within the "capacity pending" area shows the total production that would be enabled by the increase in pipeline capacity from currently planned pipelines.

As the chart shows, current pipeline capacity could become full in 2017, constraining projected Appalachian Basin gas production growth to 2050 and beyond. If no new takeaway capacity is built, production of around 116 trillion cubic feet of potential gas production from now through 2050 would be avoided. New gas drilling in the region would only occur as production from existing wells declines to free up pipeline capacity. Avoiding production of the additional gas would dent U.S. gas production growth and, as we will demonstrate in subsequent sections of this report, could help prevent the U.S. from overshooting its climate goals.

Figure 5: The Appalachian Gas Pipeline Buildout and Projected Production *Sources: Bloomberg New Energy Finance, Rystad AS, RBN Energy*



Resistance to Pipelines

Whether these proposed pipelines are new-build projects or expansions of existing infrastructure, many are facing resistance to the appropriation of land for pipeline corridors and/or additional compression stations and other associated equipment. As Map 2 shows, proposed new-build projects are heavily concentrated in West Virginia and Virginia, and resistance is particularly strong in the Allegheny Mountains, where the projects threaten fragile mountain ecosystems, national forests, and the headwaters of the region's rivers.

The threat of eminent domain to force through these pipelines has angered many residents along these proposed routes, and growing resistance to this abuse of a law designed to appropriate land for the public good – not private profit – is increasingly threatening the realization of these plans.

Citizens resisting the proposed Atlantic Coast Interstate Gas Pipeline through West Virginia and Virginia plant Seeds of Resistance in Nelson County Virginia. June 2016. ©Peter Aaslastad, Oil Change International and Bold Alliance.

U.S. GAS PRODUCTION GROWTH IS OUT OF SYNC WITH CLIMATE GOALS

Primarily through the development of fracking and horizontal drilling, the U.S. has become one of the largest global producers of oil and gas, rivaling Saudi Arabia and Russia. The recent oil price crash has slowed growth somewhat, but the expectation of an eventual turn in the price cycle would herald a return to the frantic drilling rates seen in recent years.

This potential for further fossil fuel production growth represents a major challenge for U.S. climate policy. The U.S. cannot continue to supply increasing quantities of oil and gas to both domestic and global markets and strive to achieve the goals set by its climate change commitments.

This section examines U.S. climate goals, and the implications of the increase in U.S. natural gas production spurred by growth in the Appalachian Basin.

U.S. CLIMATE TARGETS

In 2010, the U.S. Department of State set goals for U.S. emissions reductions in its "Fifth National Communication of the United States of America Under the United Nations Framework Convention on Climate Change."[9] The long-term target is for an emissions cut of 83 percent from 2005 levels by 2050.

This goal may not be consistent with keeping warming below 2°C, even if every country cut emissions at equal rates. Equivalent emissions reduction rates raise equity issues given that the U.S. is responsible for the largest share of historical emissions to date. In other words, to balance the responsibility for emissions more equitably, the U.S. would likely need to cut emissions more dramatically than its current goal to play its role in achieving the Paris Agreement goal of keeping warming well below 2°C.

However, as the 83 percent emissions reduction goal is the current commitment of the U.S. government, we use it here to assess whether rising natural gas production and consumption is in sync with U.S. policy.

The emissions reduction goal set out above has guided the Obama Administration's actions on climate change ever since it was put in place. While current policies are not nearly enough to fulfill the 2050 goal of an 83 percent reduction, the 2025 goal of a 28 percent reduction, which was submitted as the U.S. Intended Nationally Determined Contribution (INDC) to the Paris Agreement process,[10] may be within grasp if policies such as the Clean Power Plan (CPP) and vehicle efficiency standards (CAFE) reach their full potential.

However, cheap, abundant natural gas may lead to a lock-in of infrastructure that would undermine attainment of the more dramatic cuts required after 2025.

NATURAL GAS CONSUMPTION AND THE U.S. CLIMATE GOAL

The most commonly used energy forecast in the U.S. is the Reference Case produced by the EIA in its Annual Energy Outlook (AEO). The EIA's Reference Case is based on a model that freezes energy policy at the time the report is produced and has a very cautious approach to technological and behavioral change. In other words, it is not meant as a forecast for how energy flows will necessarily pan out (although it is often treated as such), but rather a projection of how energy flows might look if all current policies and expectations of technology change remain static.[11] As the projections span 25 years, it is extremely unlikely that major changes would not take place.

However, the Reference Case serves a purpose of indicating what the future will look like should we stop innovating both technology and policy. When it comes to addressing climate change, the EIA Reference Case shows how much more we need to do to prevent catastrophe.

For the purposes of assessing whether we can expand natural gas production and consumption and still meet our climate goals, the EIA Reference Case is useful because it approximately matches growth goals of the gas industry.

Figure 6 shows the AEO 2016 (Early Release)[12] Reference Case projections for natural gas production and consumption in the U.S. Production is expected to increase 55 percent between 2015 and 2040, while consumption is seen increasing 24 percent in the same period. The difference between production and consumption is accounted for by exports. The U.S. was a net zero

Figure 6: Projected U.S. Gas Production and Consumption in the AEO 2016 Reference Case *Source: U.S. Energy Information Administration*

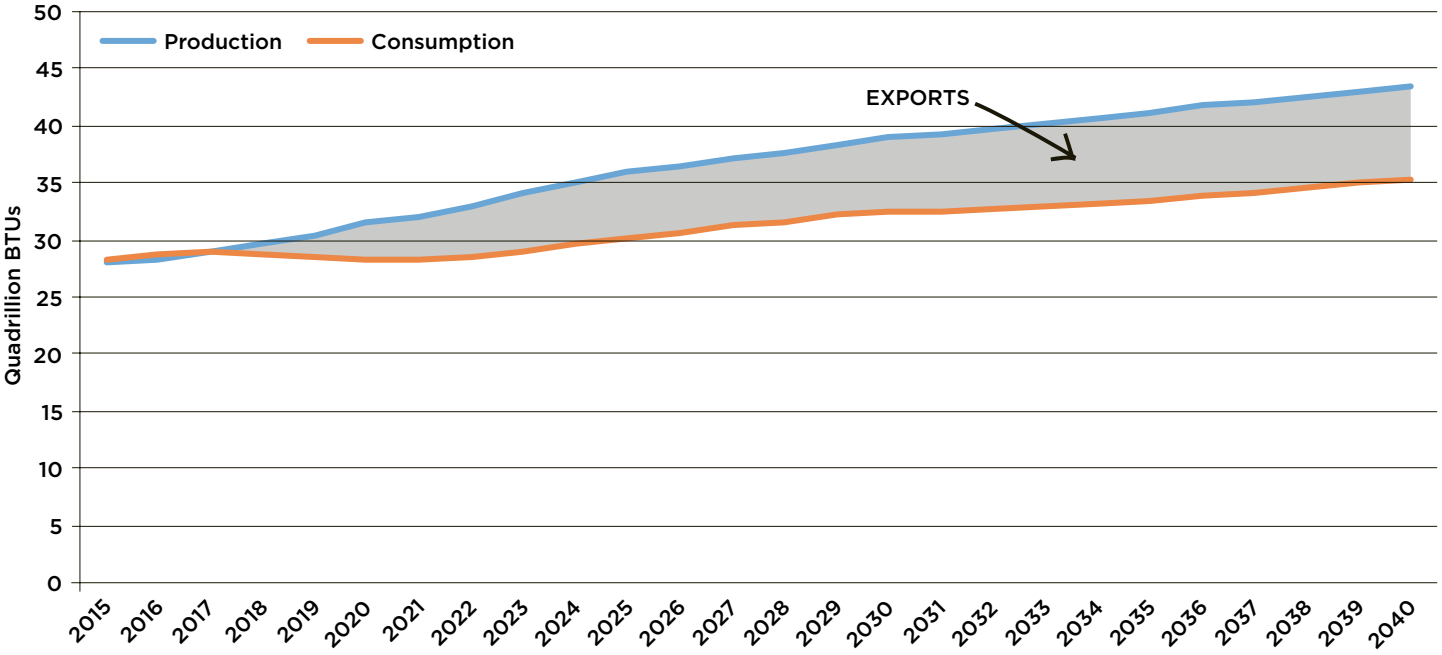
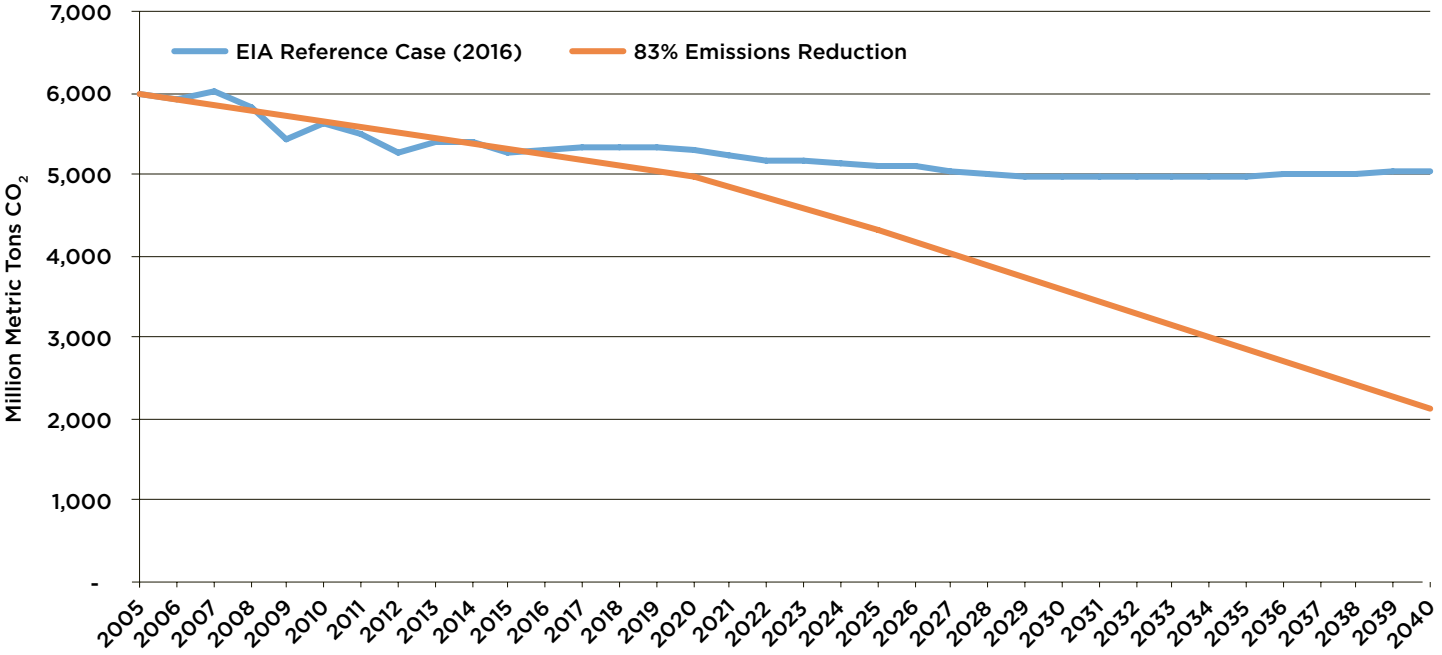


Figure 7: U.S. Energy-Related Greenhouse Gas Emissions in AEO 2016 versus U.S. Climate Goal[iv]
Source: U.S. Energy Information Administration & U.S. Department of State



exporter in 2015, but could be exporting as much as nine trillion cubic feet in 2040, according to these projections.

The Reference Case also shows that if U.S. consumption of fossil fuels does follow the trajectory that the projections suggest, U.S. emissions reductions goals will be missed by an order of magnitude. Using energy-related emissions only, the Reference Case suggests that emissions could be only around 16 percent below 2005 levels in 2040, or around four percent less than in 2015. It is worth noting that the AEO 2016 Reference Case does include the impact of implementing the Clean Power Plan (CPP), the key power sector climate policy being pursued by the current administration. The CPP is projected to reduce emissions in 2040 by around eight percent compared to business as usual. However, as Figure 7 clearly shows, the U.S. would still be dramatically off course in reaching its climate goals. The difference is stark. Emissions in 2040 are nearly 140 percent higher in the Reference Case than they would need to be to stay on course with the 2050 U.S. climate goal.

The increase in natural gas production and consumption is not the only reason emissions in the Reference Case are so far from the U.S. climate goal. But it is one part of a wider failure to reign in fossil fuels that the Reference Case clearly illustrates.

iv. U.S. climate goal percentage reduction is equally applied to energy as to other GHG sources, i.e. 83% from 2005 to 2050.

NATURAL GAS DOES NOT PROVIDE NEEDED CLIMATE BENEFITS

For rising natural gas production and consumption to fit into a scenario of rapidly declining GHG emissions, natural gas would need to be a significant enabler of substantial emissions reductions.

The natural gas industry claims that natural gas replaces coal, leading to reduced emissions. But there is increasing evidence that not only has the past role of natural gas in emissions reduction been exaggerated, but that future natural gas consumption growth could account for more emissions than the U.S. climate goal allows for, even if emissions from all other sources are mitigated.

To assess the climate impacts of new natural gas infrastructure, several facts should be considered:

- When methane leakage is considered, natural gas can be equally or more polluting than coal.
- Reducing methane leakage is very important, but it does not provide a license for production growth.
- Even with zero methane leakage, replacing an old coal plant with a new natural gas plant may reduce emissions in the immediate term, but will lead to a net increase in aggregate CO_2 emissions if the gas plant is still emitting CO_2 decades after the coal plant would have been retired.

THE EFFECTS OF METHANE LEAKAGE ARE SIGNIFICANT

Dry gas is almost pure methane (CH_4). When combusted, the greenhouse gas emitted is carbon dioxide (CO_2), the same as with coal and oil. In general, the CO_2 emissions associated with gas combustion are lower per unit of energy produced than with coal and oil.

But if methane is vented directly to the atmosphere without combustion, the global warming potential of that gas in the atmosphere is pound-for-pound much greater than CO_2. For this reason, methane leaks occurring during the production, processing, transportation, and storage of gas can substantially increase its climate impact.

The fifth report (AR5) of the Intergovernmental Panel on Climate Change (IPCC) updated the global warming potential of methane compared to CO_2. Two figures are most often quoted for the potential – a 100-year figure and 20-year figure – which refer to the potential of the gas to force temperature change over the given time span. Methane has a shorter life span in the atmosphere than CO_2 but a much higher impact. The AR5 put the 20-year impact of methane at 86 times that of CO_2 and the 100-year impact at 36 times.

The methane leakage rate during the production, processing, transportation, and storage of gas is central to assessing the climate impact of gas use. Independent analysis suggests that average US conventional gas leakage are between 3.8% and 5.4 % of total production, while shale gas leaks at roughly 12%. Both rates would put the climate impact of gas on par with, or much greater than, coal.[13]

In recognition that methane leaking from the oil and gas sector is a crucial issue to be addressed, in March 2016 President Obama announced an initiative with Canada to cut methane leakage from the two countries' oil and gas sectors by 45 percent.[14] If it can be implemented – the American Petroleum Institute threatened to sue[15] – this initiative would be a good start to reducing the impact of existing natural gas supply.

However, although crucially important, we will see in the next section that reducing methane leakage does not provide room in the carbon budget to increase natural gas production.

CLIMATE IMPACTS OF RISING GAS PRODUCTION OUTWEIGH METHANE MITIGATION

The idea of natural gas as a 'bridge' to a low carbon future is a much-used talking point for the industry and its supporters, but study after study has examined the issue to find that increasing gas-fired power

generation can only at best shave a couple of percentage points from overall emissions rates, and may undermine the transition to clean energy entirely. One of the problems is that rising gas use does not only displace coal; it also displaces zero-carbon energy.

For example, a Stanford University study published in 2013 used a variety of modeling tools to estimate the "emissions and market implications of new natural gas supplies."[16] The study found that none of the six modeling systems they sampled showed a significant reduction in U.S. emissions as a result of rising gas use up to 2050. The authors concluded that "[s]hale development has relatively modest impacts on (emissions), particularly after 2020. Over future years, this trend towards reducing emissions becomes less pronounced as natural gas begins to displace nuclear and renewable energy." In general, the models used found that higher gas supplies lowered prices for gas and increased primary energy demand, leading to higher emissions in the 2050 projections than in the lower gas supply scenario.

Contamination caused by an oil and gas well failure. ©FracTracker Alliance

Another study from different researchers at Stanford together with U.C. Irvine found that cumulative U.S. GHG emissions from 2013 to 2055 were a mere 2% lower in a high gas supply scenario compared to a low one.[17] They found that without strict climate policies, increased natural gas supply would not only reduce coal-fired generation but renewable energy generation as well. Similar to the EIA Reference Case, this leads to U.S. power sector emissions in 2050 that are barely less than they are today. They also found that methane leakage rates from zero to three percent made little difference to the overall result. Once again, in this study the effect of higher gas supplies is to reduce renewable energy market share and maintain unsustainable levels of CO_2 emissions.

Statoil Kuhn Well Pad, West Virginia. ©FracTracker Alliance

Most recently, a study out of Oxford University examined the '2°C Capital Stock' to see how close the world is to building the electricity generation infrastructure that, if utilized to the end of its economic life, would take the world past the 2°C goal.[18] The disturbing conclusion they came to is that we will be there in 2017. Those researchers used a 50-50 chance of staying below 2°C, in the climate model simulations, which we consider highly risky given the consequences of crossing the 2°C threshold.[19] The authors conclude that "[p]olicymakers and investors should question the economics of new long-lived energy infrastructure involving positive net emissions."

The paper raised an important point about replacing coal plants with gas, particularly when the coal plant is due to retire within a decade or so. In the case of a coal plant with ten years of economic life left, shutting the coal plant early and replacing it with a gas-fired generator may cut emissions in half (assuming no methane leakage) for those first ten years. But when the gas plant's economic life is 40 years, the cumulative emissions from the gas plant are in fact double those from ten years of operating the coal plant. This is because the gas plant would emit half as much CO_2 per year, but for forty years rather than ten.

The nature of the climate problem is that it is the total cumulative emissions that matter. Once we have filled the atmospheric space with CO_2, there is no turning back. As we enter a period in which we have just a few decades at best to decarbonize, it is time to seriously question any investment in infrastructure that does not clearly and dramatically reduce emissions.

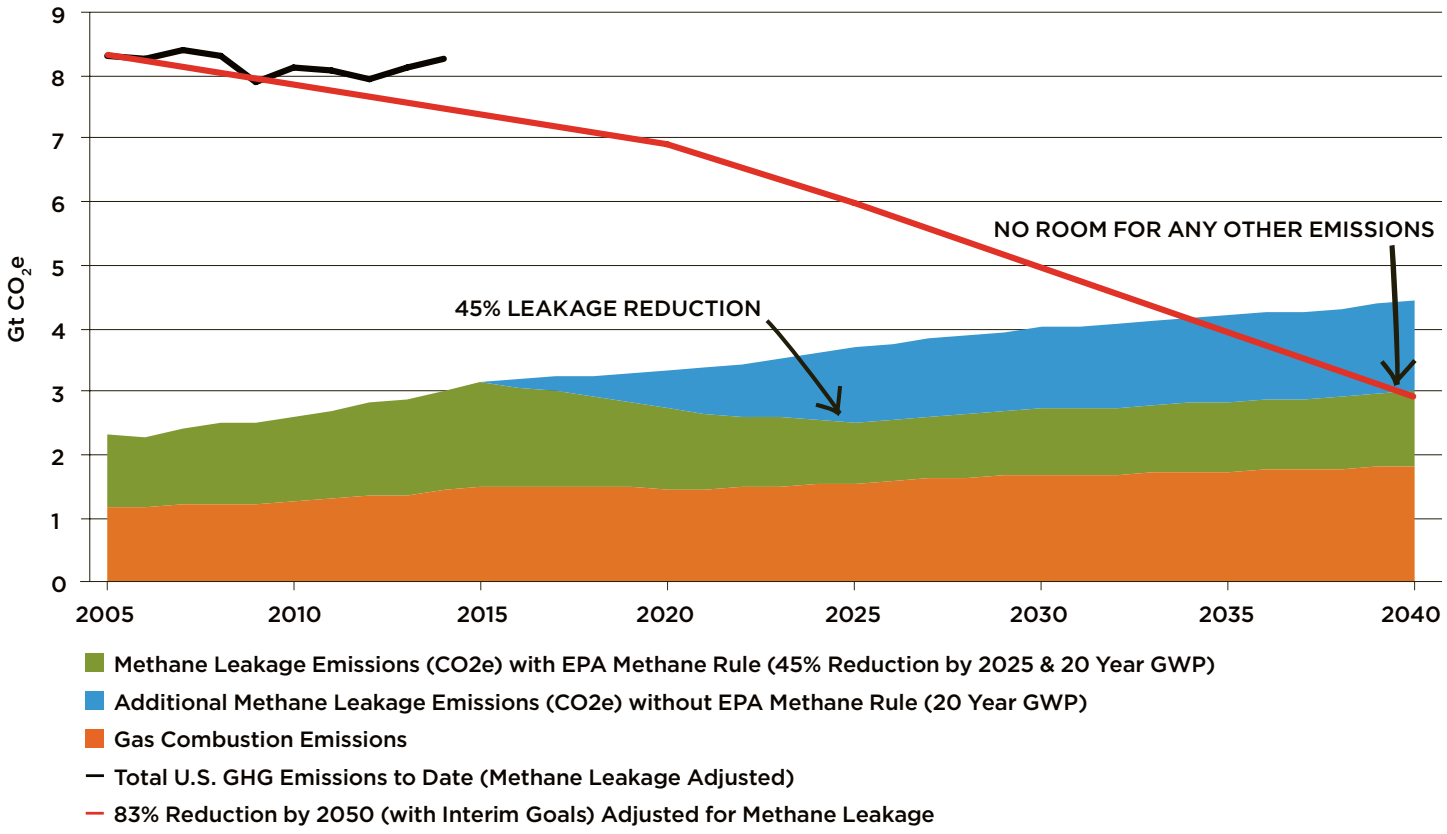
RISING U.S. GAS CONSUMPTION MAKES MEETING U.S. CLIMATE GOALS IMPOSSIBLE

Using the EIA's current Reference Case as a starting point, we calculate that emissions from projected U.S. natural gas consumption growth would more than overshoot U.S. climate goals. In other words, even if the U.S. reduced all coal and petroleum use to zero by 2040, the U.S. would still exceed its climate goals based on natural gas emissions alone.

This is even more concerning in light of the fact that the projections factor in the methane leakage reduction goals recently proposed by the EPA. This means that even under reduced methane leakage rates, U.S. gas demand must decline over the next 25 years in order to meet climate goals. This is in stark contrast to both EIA projections and the ambition of the gas industry, which is focused on massive production growth primarily centered on the Appalachian Basin.

Figure 8 shows our estimate of emissions from gas consumption and methane leakage, together with the trajectory of the U.S. climate goal to cut emissions 83 percent from 2005 levels.[v] It is clear that methane leakage plays a very large role in the emissions associated with gas consumption and that reducing leakage

Figure 8: Projected U.S. GHG Emissions from Gas Usage & Leakage vs. U.S. 2050 Climate Target *Sources: U.S. Energy Information Administration, Environmental Protection Agency, and the Intergovernmental Panel on Climate Change*[20]



can cut emissions dramatically. However, our calculations show that the rise in gas consumption alone projected by the EIA would lead to emissions from gas that would surpass the current long-term U.S. climate target by 2040, even after accounting for methane leakage cuts. This ignores the emissions from the production (and consumption) of exported gas.

Even if natural gas were the only source of greenhouse gas emissions in 2040 (and there were zero emissions from coal, oil, cement, and all other sources), the U.S. would still blow its carbon budget. This makes it clear that the growing use of gas is out of sync with U.S. climate goals.

About Figure 8:

We used leakage rates of 3.8%, which is the low end of estimates of gas leakage in production from Howarth 2015. Those rates are then reduced 45% under the EPA rule, which we treat as phased in on a straight line from 2015 to 2025.

We have adjusted the EPA's GHG totals to be comparable with the natural gas emissions, by replacing its (low) estimates of methane leakage from natural gas production. As well as understating the volumes (compared to other recent assessments), the EPA used the 100-year global warming potential (GWP) of methane, which is much lower than the 20-year GWP because though potent, methane is short-lived.

We have used the 20-year GWP because whereas CO2 accumulates in the atmosphere over the long-term, the impact of methane is felt in the short term: according to the latest climate science, the impact of short-lived GHGs is related more closely to their annual emissions than their cumulative emissions - and is most significantly felt at the time of peak CO2 concentrations. In this respect the shorter-range GWP is the relevant measure.

(For further discussion see IPCC 5AR WG1 sec.12.5.4, p.1108, http://ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter12_FINAL.pdf and sec.8.7.1.12, pp.711-712, http://ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter08_FINAL.pdf)

RENEWABLE ENERGY IS READY

As renewable energy evolves, natural gas-fired power generation increasingly competes not only with coal, but with renewable energy as well. If the abundance of natural gas locks in natural gas power capacity that renewable energy could have filled, the net increase in GHG emissions is vast. As the world looks for ways to reverse emissions growth and move as rapidly as possible towards zero carbon, building new gas capacity where zero-carbon technology is possible is a clear disaster for our climate.

The idea that we need to increase gas-fired generation now because renewable energy is not yet ready is rapidly losing what little validity it ever had. In many parts of the Unites States and the world, renewable energy is today the lowest cost and lowest impact means to add generation capacity to our electricity system.[21] There is nothing standing in the way of building the renewable energy capacity we need to sustain our electricity needs except the entrenched interests of the natural gas industry.

The past decade has seen an accelerating transformation of the renewable energy sector, and innovation and evolution in the sector is far from over. In the coming decade, we can only expect greater economies of scale and more transformational technology.

The rapid growth in first wind, then solar, and now efficiency and battery storage, suggests an imminent transformation of our energy landscape. There is now little doubt that the future will be powered by clean energy. We now need to accelerate the transformation in line with our climate goals.

Solar: The U.S. solar energy sector grossed over $22.6 billion in 2015, a 21 percent increase over 2014, and 174 percent greater than in 2011.[22] This revenue growth is all the more remarkable given that costs have declined 80 percent since 2008.[23] Installed solar capacity totaled 27 GW in 2015, and is expected to grow at least fourfold by 2022.[24] Small-scale solar could attract around $10 billion of investment per year over the next 25 years in the U.S. alone.[25]

Globally, the amount of electricity produced by solar power has doubled seven times since 2000.[26] As Tom Randall at Bloomberg Business puts it, "(t)he reason solar-power generation will increasingly dominate: It's a technology, not a fuel. As such, efficiency increases and prices fall as time goes on."[27]

Wind: U.S. wind enjoyed revenue growth of 75 percent in 2015 despite tax structure uncertainty that was finally resolved at the end of the year. Costs have fallen 50 percent since 2009.[28] Onshore wind is at cost parity with new-build gas in many parts of the country and is set to reach cost parity in all parts of the country by 2025.[29]

The CEO of wind generator giant Vestas recently told investors in London that the next wave of growth for the sector will be in 'repowering' retiring equipment with new more powerful and efficient turbines.[30] This signals a maturing industry set to increase market share through technology improvements.

Efficiency and Flattening Demand: Increasing energy efficiency is reducing the demand for electricity in America. Bloomberg New Energy Finance (BNEF) recently reported that, "The past five years in the US have seen a fundamental decoupling between electricity demand, on the one hand, and population and GDP, on the other. Looking across the next 25 years, we anticipate this trend to continue." The BNEF New Energy Outlook 2016 projects that U.S. electricity demand will likely peak in 2022, even with robust electric vehicle growth providing one of the few remaining drivers of power demand growth. This means that new generation capacity will in most cases replace retiring capacity, providing an opportunity to dramatically reduce emissions through switching from coal and gas to renewable energy.

Storage and Batteries: The U.S. energy storage sector grew tenfold in 2015, generating over $730 million in revenues.[31] All indications are that energy storage is poised to change the energy sector forever. Primarily driven by demand for electric

vehicles, lithium-ion battery costs fell 65 percent from 2010 to 2015.[32] Further cost declines and performance improvements are widely expected, with some estimating a further 60 percent cost decline by 2020.[33]

The next areas of market penetration are likely to be utility-scale storage as well as residential- and commercial-scale applications for both supporting solar generation and balancing demand from the grid. Tesla's PowerWall battery is likely to be just one of many products on the market designed for storing energy for use in buildings by the early 2020s. The company's 'Gigafactory' is soon to be followed by several others already under construction in the U.S. and China. According to Navigant Research, global new installed energy storage systems for renewable energy integration power capacity is expected to grow from 196.2 MW in 2015 to 12.7 GW in 2025, a 65-fold increase in ten years.[34]

BNEF projects exponential growth in what it calls 'behind-the-meter' storage – batteries supporting solar energy systems and demand balancing in homes and commercial buildings. Globally, this use of batteries could grow from 400 megawatt-hours today to 760 gigawatt-hours by 2040.[35]

Clean Energy Jobs: The clean energy sector is also breaking barriers when it comes to

Solar voltaic panels. ©Associated Press

job creation. The International Renewable Energy Agency reported that 2015 saw clean energy jobs surpass oil and gas for the first time. The global clean energy workforce grew 5 percent in 2015 to reach 8.1 million workers, and is expected to triple to 24 million by 2030.[36]

AVOIDING LOCK-IN

Looking ahead, it is increasingly clear that renewable energy will be the least-cost option for new generation capacity, with costs continuing to decline while the cost of gas-fired power increases. In other words, expanding gas-fired power today threatens to lock in an increasingly expensive source of power when cheaper, cleaner renewable energy will be available to meet our energy needs. The latest data and projections from BNEF illustrate this point.

According to BNEF's New Energy Outlook 2016, wind and solar power are already competitive with low-priced gas in certain markets in the U.S., where both renewable resources are abundant and state polices are favorable.[37]

However, as we move into the next decade, the unsubsidized cost of clean power across the country will become cheaper than new-build gas power, which requires new capital, but it will not yet be cheaper than the cost of existing gas-fired power plants where capital has already been sunk.[38] This demonstrates the danger of locking in more gas-fired power than is optimum in the coming decade.

Existing power plants are in a position to reduce their selling price to compete, even if it means making a long-term loss on capital. This is because once capital is sunk, it is better to keep operating as long as revenue covers operating costs. Any additional revenue generated above operating cost reduces the loss on capital. Therefore, new utility-scale renewable energy projects will face stiff competition from existing gas-fired power plants until installation capital costs become low enough that they can undercut existing gas plants and still provide a return on capital.

As natural gas prices are likely to rise over time (gas being a finite resource), renewable energy plants will eventually reach a point when they will price out even existing plants. However, when it comes to meeting climate goals, it is imperative to keep in mind the urgency of the problem and the danger of locking in polluting infrastructure now.

As gas-fired power plants and pipelines built today generally have a design life of around forty years, gas infrastructure built over the next decade could be operating in the 2050s and beyond. It is imperative that we avoid locking in emissions today that we cannot afford to emit in the later part of the infrastructure's economic lifespan.

INTERMITTENCY, BASELOAD, AND STORAGE ARE NOT BARRIERS TO RENEWABLE ENERGY GROWTH

Much is made by fossil fuel proponents of the intermittency of wind and solar and the need for some breakthrough in energy storage before we can give up on fossil fuels and substantially increase levels of renewable energy generation. These solutions are sometimes said to be decades away. These arguments do not reflect either the reality of renewable energy today or where it is heading.

Wind and solar energy provided 6.2 percent of total power generated in the U.S. in the past year.[39] All renewable generation, including wind, solar, geothermal, biomass, and hydro, hit close to 15 percent of generation.[40] A 2012 report by the National Renewable Energy Laboratory that extensively examined high-penetration renewable energy scenarios for the U.S. found that by better managing existing dispatchable power and storage capacity, the U.S. grid can handle as much as 50 percent wind and solar penetration and still keep the grid balanced.[41]

Advances in grid management are reducing intermittency issues associated with increasing wind and solar penetration. Wind and solar tend to have complimentary cycles of power availability. Solar power obviously tracks the sun in peaking around the middle of the day. Offshore wind tends to log higher generation during the day as well, whereas onshore wind tends to ramp up around dusk and peaks during the night. Greater penetration of diverse renewable energy technologies is a solution to intermittency rather than a source of it.

One analyst explains this using the Law of Large Numbers, in which a larger number of variables –in this case weather and diurnal dynamics at widely dispersed locations – tend to result in less volatility across the whole.[42] Sophisticated algorithms, similar to those used to manage online advertising, are increasingly being used to predict wind and solar dynamics and facilitate grid management in areas of high renewable energy penetration.[43]

The increasing ability to manage grid dynamics with high renewable energy penetration has also undermined another standard talking point of fossil fuel proponents: that renewable energy cannot provide reliable baseload power, which can only be supplied by fossil fuel and nuclear

Solar voltaic panels. ©Associated Press

plants. Earlier this spring, top executives at the world's largest grid operator, China State Grid Corp., told a stunned audience of fossil fuel executives at an industry conference in Houston that, "coalfired generators could only serve as "reserve power" to supplement renewables", and that "[t]he only hurdle to overcome is 'mindset'. There's no technical challenge at all."[44]

Evidence from China and Australia shows that coal is indeed increasingly serving as reserve power. Some coal plants in those countries are running at barely 50 percent utilization, and in some cases even less.[45] Grid operators are increasingly using thermal power plants, where operating costs are relatively high due to fuel costs, to supplement other sources rather than as baseload. Sven Teske, an analyst with the Institute for Sustainable Futures in Sydney states that "[b]ase load is not a technical concept, it is an economic concept and a business concept of the coal industry that is no longer feasible."[46] According to Teske, the focus of grid operators will move toward renewable energy, flexible generation, demand management, and energy efficiency.

These factors point to the ability of the U.S. electricity system to absorb increasing levels of renewable energy penetration before a substantial increase in storage will be needed. Nevertheless, the development of affordable storage solutions is happening at a rapid pace. As detailed above, both utility-scale and 'behind-the-meter' storage solutions are set to exponentially increase their market penetration over the next decade. The age of affordable power storage is upon us.[47]

Essentially, the issue of how much renewable energy can be absorbed into the grid has been solved. It is now up to the industry to invest in genuine clean energy and for government to forge policies that support the speediest transition possible.

CONCLUSION AND RECOMMENDATIONS

The development of new and expanded gas pipelines out of the Appalachian Basin could unlock significant new flows of natural gas. These pipelines would drive an increase in U.S. gas production that would be incompatible with achieving stated climate goals.

Enabling U.S. gas demand to follow the current projection in the EIA Reference Case (2016) would lead to emissions from gas alone that would surpass the U.S. emissions goal by 2040. In other words, the current trajectory of gas production and demand is out of sync with the nation's climate goals and must be constrained.

Data presented in this report shows that the vast majority of projected gas production growth would likely come from the Appalachian Basin, but this can only happen if the pipeline projects listed in this report go ahead. That should not be allowed to happen.

The surge in gas-fired power generation that would accompany this production growth is not an inevitable or needed feature of our nation's future power market. Clean energy technologies are surging ahead at this time and are projected to become a leading source of energy in the coming decade. Our electricity grid is set to be transformed into a system based on diverse and flexible generation sources, storage solutions, and advanced grid management. Total power demand is set to decrease even as electric vehicles grow to become a major new source of demand. Now is the time to question the need and impact of new fossil fuel infrastructure and plan an energy future that is in sync with climate science.

When President Obama made the historic decision to deny the Presidential Permit for the Keystone XL pipeline, he did so because, in his words: "America is now a global leader when it comes to taking serious action to fight climate change. And frankly, approving this project would have undercut that global leadership. And that's the biggest risk we face – not acting."[48]

Not acting to constrain gas production and consumption to within science based climate limits is a major risk we face. This and future administrations have the ability to apply the same standard to gas infrastructure what was applied to the Keystone XL pipeline. That means applying a climate test to these proposed gas pipelines and all proposed fossil fuel infrastructure. A climate test would assess the need for new fossil fuel infrastructure against science-based climate goals.

The challenge to meet the Paris Agreement's goals of keeping average global warming well below 2°C and pursuing a 1.5°C target cannot be met if a business-as-usual policy continues to permit an expansion of fossil fuel supply. For this reason, every government agency should apply a climate test if it is faced with any decision that could increase fossil fuel supply. FERC, which authorizes the construction and expansion of interstate natural gas pipelines, cannot be exempt from this requirement.

Recommendations:

- All federal government agencies and departments, including FERC, should apply a climate test in the permitting processes of all fossil fuel infrastructure, including Programmatic Environmental Impact Statements.
- No new natural gas pipeline projects should be considered unless they can pass a climate test. The climate test should be applied to all currently pending and future pipeline applications.
- The EIA should provide detailed guidance in the form of alternative cases in its Outlook reports for U.S. fossil fuel supply and demand under various climate goals, including the nation's long-term climate goal, a 2°C path, and a 1.5°C path.

Rig PA. ©Schmerling, FracTracker Alliance

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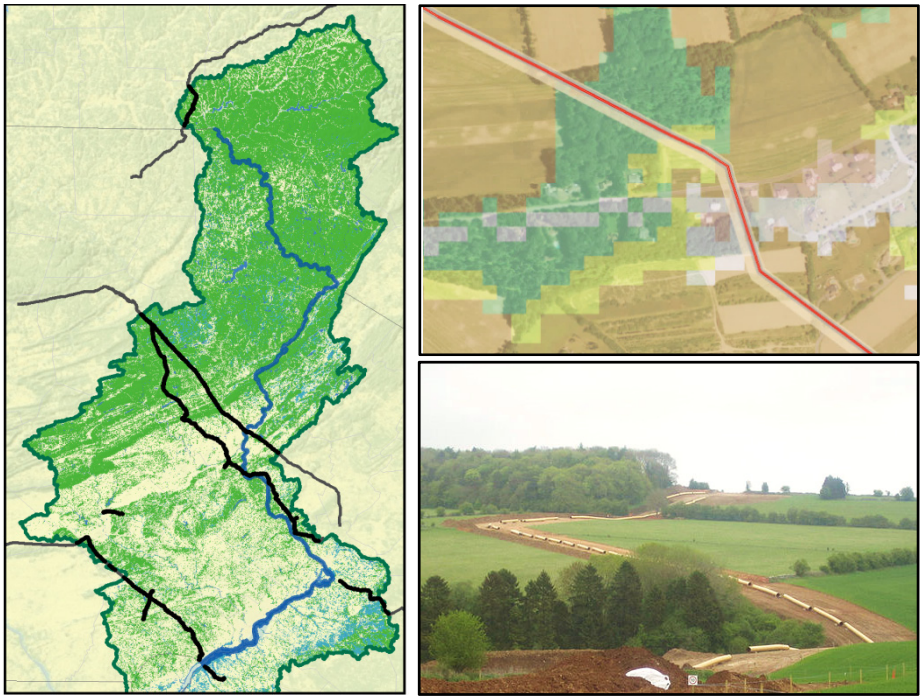
July 2016

Cumulative Land Cover Impacts of Proposed Transmission Pipelines in the Delaware River Basin

Lars Hanson and Steven Habicht

May 2016



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Approved by: **May 2016**

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Abstract

Transmission pipelines function to transport petroleum products over long distances to connect locations where these products are produced or refined to demand centers. The development of Marcellus shale gas with hydraulic fracturing in Pennsylvania has been accompanied by several proposals for new transmission pipelines. At least eight of these proposed transmission pipeline projects will cross the Delaware River Basin (DRB) to bring natural gas produced from the Marcellus shale play to demand centers on the East Coast, or otherwise connect to the larger petroleum products pipeline network. Each proposed interstate pipeline must undergo a review by the Federal Energy Regulatory Commission (FERC), which includes an environmental impact analysis. The potential environmental impacts of pipeline construction include land cover change, deforestation, sedimentation and erosion, water quality degradation, stream degradation, wetland loss, and air emissions, among others. In this report, we investigate the cumulative land cover change impacts for eight proposed transmission pipelines within the DRB, which total 322 miles in length. Specifically, using geographic information systems (GIS) methods, we investigated total land cover change, loss of forest and wetland area, and stream crossings for the eight proposed projects. We found that during construction, the pipelines' rights-of-way will impact 2,977 acres, including roughly 1,060 acres of forest, and 41 acres of wetlands. The pipelines' permanent rights-of-way will impact 1,328 acres, including roughly 450 acres of forest, and 22 acres of wetlands. In addition, we identified 175 likely stream crossings where a proposed pipeline route will cross a perennial stream.

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Executive Summary

The primary function of transmission pipelines for petroleum is to provide long distance transport of liquid fuels to where there is demand for them. The planning and construction of pipelines can be a long and complicated process because pipelines and the land needed for their rights-of-way impact property owners, land resources, water resources, air quality, and wildlife along the proposed routes. These impacts may be magnified if multiple pipelines are built concurrently.

The rapid expansion of natural gas production due to the development of the Marcellus shale with hydraulic fracturing has been accompanied by proposals for new transmission pipelines. Although there is a moratorium on natural gas development in the Delaware River Basin (DRB), at least eight proposed transmission pipeline projects will cross the DRB in order to bring natural gas produced in the Marcellus to demand centers on the East Coast, or otherwise connect to the larger petroleum products pipeline network. Each proposed interstate natural gas pipeline must undergo a review by the Federal Energy Regulatory Commission (FERC), which includes an environmental impact analysis. The potential environmental impacts of pipeline construction include land cover change, deforestation, sedimentation and erosion, water quality degradation, stream degradation, wetland loss, and air emissions, among others. The environmental analyses in the FERC approval process document many of these potential impacts, and the proposed measures to mitigate these impacts during construction and operation for each pipeline project. However, the environmental analyses for the individual pipeline projects do not consider the cumulative impact of multiple independent pipeline projects proposed concurrently in the same geographic area – in this case, the DRB.

In this report, we investigated the cumulative land cover change impacts for proposed transmission pipelines within the DRB. Specifically, using geographic information systems (GIS) methods, we investigated total land disturbance, loss of forest and wetland area, and stream crossings for eight proposed projects. This work was funded by the Clean Air Council, which requested that CNA provide an estimate of the land area affected by the eight proposed pipeline projects' rights-of-way (ROW) in the DRB and, especially, an estimate of the total forest area that could be lost as a result of pipeline construction.

Figure ES-1 on the following page shows a map of the proposed pipeline routes overlaid on forest and wetland area within the DRB.

Our results present information that is typical in pipeline environmental analysis, but in new and useful ways. Notably, we present the land disturbance and forest loss broken down by watershed, with totals for the entire DRB. In addition, we compute the new cumulative disturbance area for eight proposed projects (with no double-counting of area where pipelines are adjacent). These cumulative results, presented by watershed, offer a more complete picture of the impact of the pipeline projects in the DRB than the individual, pipeline-specific environmental analyses can offer on their own.

We found that the land disturbance results are very sensitive to the stage of the development process and proximity to other pipelines. For instance, the land disturbance is highest during construction, when a wider ROW is needed for moving equipment. After construction, a smaller permanent ROW is affected, and in some cases, a portion of the permanent ROW may be allowed to return to prior land uses, leaving a smaller permanently cleared area. In addition, pipelines that run adjacent to existing pipelines, and can share a portion of the existing ROW may cause less land disturbance per mile than new, or "greenfield" pipeline projects.

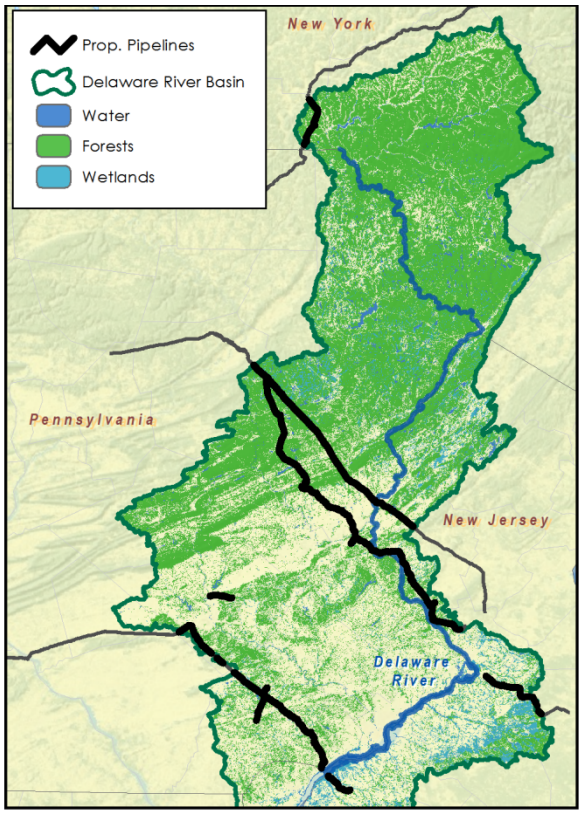

Figure ES-1. Proposed pipelines and forest and wetland areas in the Delaware River Basin

Overall, for the Delaware River Basin, we calculated the following impacts for the eight proposed projects:

- Total land disturbance during construction is 2,977 acres, of which roughly 1,050 are forest, and 41 are wetlands.
- Total land disturbance for the permanent right-of-way is 1,328 acres, of which roughly 440 are forest, and 22 are wetlands.
- The proposed pipeline routes will require at least 175 stream crossings, of which 92 potentially could be shared with existing pipelines.

The most significant impacts with respect to area of forest and wetland disturbance, as well as stream crossings, will happen in the central part of the DRB, in the Lehigh and Middle Delaware subbasins. This concentration of impacts is caused by the Diamond East, Leidy SE, and especially the PennEast pipeline project (which accounts for 40–50 percent of the total land disturbance area in the DRB) passing through a similar corridor, which is heavily forested. Analyzing multiple pipeline projects simultaneously allows easier detection of these types of concentrated impacts. The body of the report contains many more tables, figures, and maps that break down results by pipeline, county, and subwatershed in much more detail.

These results offer a clear picture of the potential scale of pipeline development impacts on land cover across the Delaware River Basin, offering stakeholders a significantly different view than they might receive when reviewing individual projects. In the future, similar methodology may be used to investigate impacts in other geographic areas of interest. Or, these results could be used to conduct follow-on analyses of secondary impacts of pipeline infrastructure development in the DRB such as forest fragmentation, or water quality pollutant loadings.

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Glossary

DRB	Delaware River Basin
EIS	Environmental Impact Statement
GIS	geographic information systems
FERC	Federal Energy Regulatory Commission
HDD	horizontal directional drilling
NHD	National Hydrography Dataset
NLCD	National Land Cover Dataset
ROW	Right-of-way
USGS	United States Geological Survey
ac	acres
ft	feet
mi	miles
easement	Legal term to describe the holding of land area to ensure access to pipelines (see "right-of-way").
gathering pipeline	Small diameter pipelines used to transport from wells to the larger gas pipeline network.
greenfield	Term to describe construction in a new right-of-way
looping	Type of pipeline project in which a new pipeline is added parallel to an existing pipeline, and connected at both ends to form a 'loop' allowing for greater capacity and control of flow.
play	A geologic formation containing petroleum (natural gas) resources with potential for development.
right-of-way	The land area around a pipeline needed for access to construct the pipeline and protect, and maintain it over time. Typically wider during construction.
spoil side	Term to describe the side of the pipeline ROW where the excavated soil ("spoils") will be stored during construction.
well pad	The location from which gas wells are drilled from the surface into the shale. Typically, flat, covered with gravel, and two–five acres in size to accommodate equipment needed for well drilling.
working side	Term to describe the side of the pipeline ROW where construction equipment travels, and pipeline segments are laid out and assembled.

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Introduction

Over the past decade, the rapid expansion of unconventional natural gas development with hydraulic fracturing in the Marcellus Shale has been accompanied by an increase in pipeline construction proposals in Pennsylvania, New Jersey and New York. The process of shale gas development requires many miles of small gathering pipelines to connect well pads where gas is extracted to transmission pipelines that allow the gas to reach customers. In recent years, the operators of these transmission pipelines have proposed both upgrades and extensions to existing pipeline networks and entirely new pipelines. Many of these proposed pipelines cross the Delaware River Basin by virtue of its location between the Marcellus Shale and densely populated areas with demand for natural gas on the East Coast. It is these proposed transmission pipelines that are the focus of this analysis.

Interstate natural gas transmission pipelines (those that involve building infrastructure in more than one state) must be authorized by the Federal Energy Regulatory Commission (FERC).[1] The typical process is for the pipeline proponent to notify FERC of intention to build an interstate transmission pipeline, followed by the pipeline proponent marketing the pipeline to determine if enough contracts can be sold to build it, followed by a much more detailed route and design process. Then the pipeline proponent works in tandem with FERC staff to perform necessary environmental reviews before finalizing the pipeline route, acquiring necessary permits from relevant federal and state agencies, negotiating with land owners, developing construction plans, and building the pipeline [1]. The scope of the FERC environmental review process is broad, covering land use change impacts, water use, stream crossings and wetland impacts, potential impacts to species (fish, wildlife, and vegetation), soils, and air emissions, among others (including socioeconomic and cultural resource impacts) [2].

Pipelines, as linear features, bring a different set of challenges than most land development activities. While the pipeline itself requires a trench no more than a few

[1] This study also investigates a few transmission pipelines transporting other liquid fuels, and intrastate gas pipelines (those that do not cross state lines), which do not require FERC approval, but have very similar construction methods and impacts on land and water resources.

feet wide, the construction process requires a much wider right-of-way (ROW) area. In addition, the linearity of pipeline projects means that they cross numerous property boundaries, municipalities, and watersheds. The impact on any one of these geographic entities is typically limited, but over the entire length of the pipeline, the total land disturbance area can be significant. Furthermore, several pipelines built in the same area can cause larger cumulative impacts than the individual projects.

Pipeline construction can result in a wide range of environmental impacts, some of them interacting and layered. Experts studying the risks of shale gas development term the chain of potential impacts a "Risk Pathway," which describes how an *activity* (pipeline construction) leads to *burdens* (land cover change) that create *intermediate impacts* (e.g., forest fragmentation), leading to *final impacts* or *outcomes* (e.g., ecosystem change) [3-4]. In the case of pipeline construction, among the most well-known burdens and intermediate impacts are stream and wetland crossing impacts, land cover change, forest fragmentation, and habitat loss [5-9]. These impacts can lead to other impacts and outcomes, including ecosystem changes (relative changes in species abundance, impacts on specialist or threatened and endangered species), and hydrologic and water quality impacts resulting from the land disturbance (erosion and sedimentation, flow changes, and stream buffer impacts) [5, 10-12]. The hydrologic and water quality changes may in turn impact aquatic ecosystems in streams and wetlands [3, 5].

The FERC environmental review process does investigate many of these impacts in a series of resource reports and environmental assessments, often in detail, but there are some shortcomings for the projects examined in this report. Notably, the land cover change estimates are often broken down by political boundaries, but not always relevant natural boundaries, especially watersheds. Most importantly, the resource reports rarely investigate the cumulative land cover change impacts of multiple concurrent pipeline proposals on watersheds or sensitive land resources. We note that the environmental analyses prepared for many of these analyses were published prior to updated FERC guidance [2] that clarifies instructions for assessing cumulative impacts.[2] In this analysis, we investigate the combined land cover change of eight proposed pipelines within the boundaries of the Delaware River Basin (DRB).

The Delaware River drains an area of 13,000 square miles, and its watershed (i.e., the DRB) spans portions of Pennsylvania, New Jersey, and Delaware. The river itself, 330

[2] Guidance for the FERC environmental review process was updated in December 2015, after the majority of the analysis for this report was completed. The guidance clarifies cumulative impact as the "the impact on the environment which results from the incremental impact of the action [being studied] when added to other past, present, and reasonably foreseeable future actions…", and further notes that the geographic area to be examined should be specific and relevant to each resource category examined (e.g. land and water, air, cultural resources, etc.).

miles long, forms the border between Pennsylvania and New Jersey, and empties into the Delaware Bay, which separates Delaware and New Jersey. The DRB is the source of drinking water for roughly eight million people living within the basin, and roughly an equal number outside who receive water transferred from the basin [13]. Much of the basin has exceptional water quality in part due to the over five million acres (7,800 square miles) of forest and wetlands. The forests have been estimated to provide roughly $2,000 per acre per year (in 2010 dollars) in ecosystem service benefits such as water treatment, air pollution removal, and carbon sequestration, and the wetlands as much as $13,000 per acre. Another 4,500 square miles is used for agriculture, which is responsible for roughly $3.5 billion per year in revenue from farm products [14]. Land cover changes have the potential to degrade some of these benefits either directly (conversion to other land uses) or indirectly (e.g., pollutant runoff or fragmentation).

This study does not examine loss of these benefits in detail or the ultimate environmental outcomes from pipeline development, but these consequences establish the rationale for investigating the land cover changes. This study aims to provide credible estimates of the area of land cover changes associated with the eight transmission pipeline proposals.

Methodology

In this study, we use Geographic Information Systems (GIS) methods to generate estimates of land cover change using spatially referenced pipeline route information (existing and proposed) and baseline land cover data. The goal of this methodology is to develop cumulative projections of land cover disturbance impacts for eight proposed pipeline projects that are currently anticipated to cross through the DRB. The primary metric of interest is the affected land area that is newly "disturbed" (i.e. converted from an existing non-pipeline related land use) within the pipeline projects' construction or permanent ROW, exclusive of area already within existing pipelines' ROW.

Pipelines and Data Sources

Table 1 lists the eight pipeline projects included in this study. The most important data source for this analysis is pipeline route information. The primary source of pipeline route information was commercially available U.S. oil and gas pipeline facilities data purchased from IHS [15], which includes GIS data for both active and proposed pipelines. The IHS data includes route information for all of the pipeline projects except the Southern Reliability Link, and Penn East Pipeline project. The quality of the IHS data for the majority of pipeline routes is rated as "Excellent" (accurate within 50 feet), with the remainder rated as "Very Good" (50–300 feet), or "Good" (301–500 feet). The pipeline route information as purchased was current through the end of 2014.

We verified route information for all pipelines using other data sources. These sources include a GIS geodatabase provided by the Clean Air Council [16], which included preliminary route information for the Southern Reliability Link and Penn East Pipeline project (quality estimated as "Very Good"). In addition, we used maps available in FERC documents and from project proponent reports and websites. We projected digital versions of these maps into ArcGIS 10.2 in order to compare them with the geo-referenced pipeline route features. We also used these maps to update the route information when the route had changed during the course of the project planning. Table 1 includes references to the documents and maps from which we acquired all pipeline information used in this study.

Table 1. Proposed pipeline projects included in this study

	Pipeline Project	Proponent	Details /Segments	Length in DRB [mi]	Sources*
1	Constitution Pipeline	Williams		13.5	[17-19]
2	Diamond East Project	Williams		56.8	[15]
3	Leidy SE Project	Williams	Franklin Loop	11.2	[20-21]
4	Mariner East[a]	Sunoco Logistics	Mariner East 1, Mariner East 2	49.9 49.8	[22-23]
5	Southern Reliability Link[b]	NJ Natural Gas		18.2	[24-25]
6	PennEast Pipeline	PennEast Pipeline Co.		100.9	[26-29]
7	TEAM 2014 Expansion Project	Spectra Energy	Bernville Loop	5.6	[30]
8	East Side Expansion Project	Columbia Pipeline Group	NJ Loop 10345, PA Loop 1278	7.4 8.8	[31-37]
	Total			**322.2**	

* Sources common to several pipelines: [15-16]; [a] – transports other petroleum products; [b] – Not an interstate pipeline.

For the PennEast project, we used detailed project maps [29] (last updated July 22, 2015) as the primary data source and digitized the pipeline features over the entire project length.

We note that pipeline routes can and do change during project planning, and even construction. We have attempted to include the most recent preferred project routing available from the listed data sources as of September 30, 2015.

In addition to the pipeline route information, we also acquired land cover data. For this study, we used the National Land Cover Dataset (NLCD), 2011 version [38], for the states of New York, New Jersey, and the Commonwealth of Pennsylvania. This data is available as a raster data type, with a spatial resolution of 30 meters. Land cover types are distinguished by numeric codes. For this analysis, we combined some of the land cover types into larger groupings for simplicity. Table 2 shows these groupings. For example, three different forest types are combined into the "Forest" grouping.

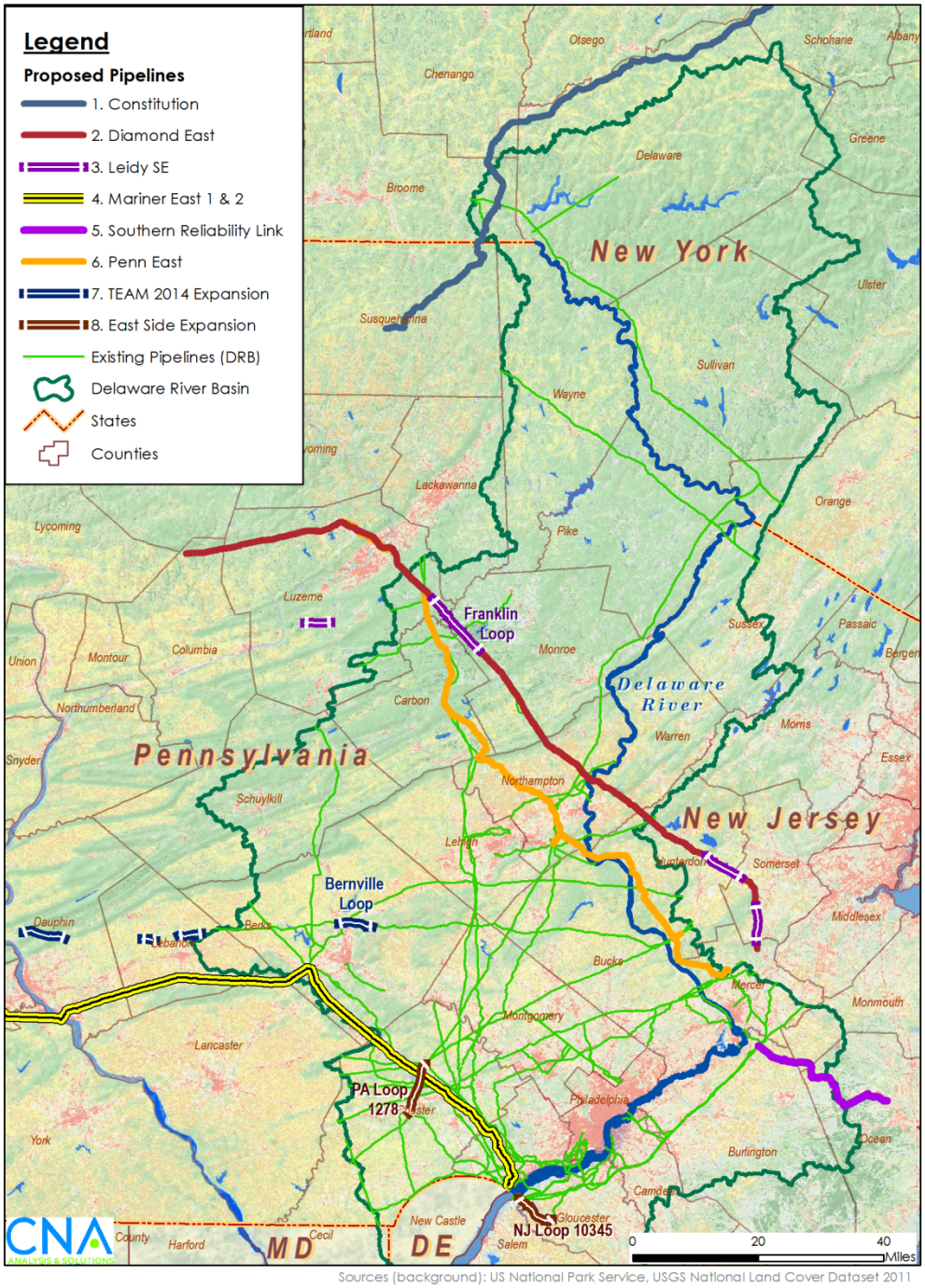
Table 2. Land cover groupings by 2011 National Land Cover Dataset classifications

Grouping	NLCD Classifications Included
Forest	41 – Deciduous Forest; 42 – Evergreen Forest; 43 – Mixed Forest
Wetland	90 – Woody Wetlands; 95 – Emergent Herbaceous Wetlands
Agriculture (Ag) – Pasture	81 – Pasture/Hay
Ag - Cultivated	82 – Cultivated Crops
Grassland/Shrub	71 – Grassland Herbaceous; 52- Shrub/Scrub
Open Space	21 – Developed Open Space; 31 – Barren Land
Developed	22 – Developed Low Intensity; 23- Developed Medium Intensity; 24 – Developed High Intensity
Water	11 – Open Water

Source: [39]

Figure 1 shows an overview map of the study area with the route information for the proposed pipelines overlaid on the NLCD 2011 land cover raster. In addition, the DRB boundary, county boundaries, and existing pipeline routes are shown for reference.

Figure 1. Map of proposed pipelines within the Delaware River Basin



Source: CNA; [15-17, 19, 24-26, 29, 31-32]

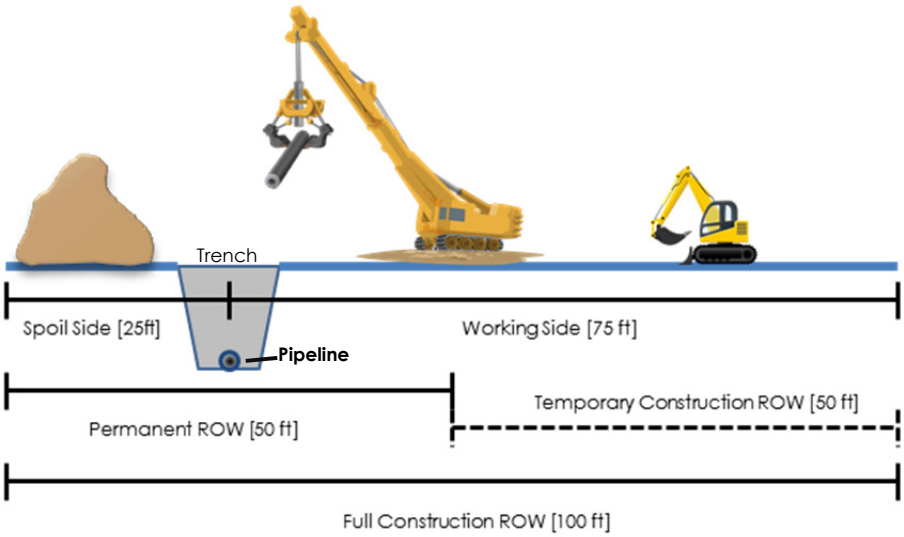
Right-of-Way Assumptions

Construction and Permanent Rights-of-Way

This analysis focuses primarily on the land disturbance required for pipeline development, which includes both permanent land use change impacts and additional disturbance during construction. For the purpose of this analysis, we define the permanent land cover change area as the new permanent right-of-way of the pipeline exclusive of existing permanent right-of-way shared by adjacent pipelines. The land cover change area during construction includes the new permanent right-of-way and additional temporary work space associated with construction, but excludes existing permanent right-of-way shared by adjacent pipelines. The FERC filings and other documents released by the project proponents differ in their presentation and description of these areas. In this study, "New Permanent ROW" is new area cleared for the permanent right-of-way, and "Construction ROW" is total area cleared during construction, inclusive of the New Permanent ROW. The temporary workspace may be inferred by subtraction. See Figure 2 for an illustration of typical ROWs for pipeline construction.

This analysis is limited to the direct pipeline ROWs and construction areas, and does not include additional land area needed for pipeline facilities (e.g. launchers, pump stations, etc.), access roads, or temporary equipment storage areas.

Figure 2. Typical pipeline rights-of-way illustration



Source: CNA; Clip art: clker.com, openclipart.org, office.com

Greenfield Construction

Greenfield construction refers to pipeline construction through areas where no existing pipelines or rights-of-way are present. The entire operation requires new clearing for construction and operation.

When new pipelines are constructed outside of existing ROWs, a new permanent easement is created, and additional land is usually needed for construction. In general, construction ROWs are divided into a spoil side (area for storing soil and materials excavated from, or used for, backfilling the trench) and a larger working side for moving equipment, and aligning and connecting the pipeline itself before lowering into the trench.

The size of the construction area can vary depending on the type of terrain crossed. In wetlands or core forest areas, the construction ROW can be reduced to limit impacts. In urban or suburban areas, construction ROW may need to be reduced to avoid existing buildings, property lines, or utility infrastructure. In agricultural areas, sometimes a larger right-of-way is needed so that agricultural land can be quickly returned to productive use after construction. The additional area is needed to store the agricultural top soil that is removed during construction so that it can be replaced later, when the construction right-of-way returns to agricultural use.

Adjacent to Existing Rights-of-Way

Pipelines are often routed adjacent to existing pipelines to minimize new clearing and costs of purchasing new easements. Looping projects are nearly always adjacent to the existing pipeline, but new pipelines may also run adjacent to existing pipelines, where possible, to reduce land disturbance impacts and costs. While some additional right-of-way is typically needed, the pipeline itself can often be laid within or very close to the existing permanent easement of another pipeline. That is, the spacing between pipelines can be reduced so that each pipeline does not need its own (typically 50-foot) full permanent right-of-way. When the existing and new pipelines have different owners, a new permanent ROW is generally required even when the routes are adjacent.

In general, it appears that the existing ROW of the adjacent existing pipeline is used as the spoil side of the construction right-of-way for the new pipeline. The wider working side of the construction ROW generally requires new clearing, so as to limit potential damage to existing pipelines due to the movement of heavy equipment.

Typical Right-of-Way Widths

Our default assumption for the typical ROW width is 50 feet for the permanent easement and 100 feet for the total construction ROW. In this analysis, we analyze both a simplistic symmetric case with equal width on either side of the pipeline, and a more realistic case where the construction ROW is split asymmetrically across the pipeline. The rest of the section documents the assumption when an asymmetric ROW is used.

In greenfield construction, we assume the typical construction ROW is split into a 25-foot spoil side, and a 75-foot working side, with the outer 50 feet being temporary workspace, and 25 feet on either side of the pipeline as permanent easement (see Figure 2). For looping projects or pipelines adjacent to existing pipelines, we assume up to 25 feet of shared right-of-way on the spoil side. Thus, in the case that shared right-of-way is 25 feet, the new disturbance ROW width (all on the working side) is 25 feet for permanent right-of-way and 75 feet for construction ROW. Based on the location of the adjacent pipelines, we varied the amount of shared ROW between 10 and 25 feet. Accordingly, we reduced the spoil side width for construction between 0 and 15 feet, meaning that the new permanent ROW is between 25 and 40 feet in width (instead of 500 feet for greenfield projects). In situations when the proposed project pipeline route diverged from the path of the existing pipelines, we treated it as greenfield construction. Table 3 displays the default ROW widths we used in this study. Several of the pipelines have specific ROW widths specified by land cover type in their project documentation, including the PennEast and Constitution projects.

Table 3. Assumptions for right-of-way widths

Pipeline/ Construction method	**Permanent ROW [ft]**	**Construction ROW [ft]**				
		Spoil side	Working-General	Working-Ag	Working-Wetland	Working-Forest
Greenfield:						
Default	50	25	75	100	50	
PennEast	50	35	65	90	40	
Constitution	50	30	80	95	45	70
Looping:						
Default	25-40	0 - 15	75	100	50	

We used best professional judgment to determine on which side the spoil side and working side will fall, based on the route and location of other pipelines and infrastructure.

In cases where pipeline documentation specified techniques to reduce pipeline impacts, we attempted to replicate these using mile markers and other notes on construction methods as a guide.[3]

To check the validity of these assumptions, we calculated the implied average width for several pipeline segments using length and disturbance area reported in the FERC or project proponent documentation [17, 27, 33, 37]. Table 4 displays the relevant average ROW width for six pipeline segments, which was computed simply by dividing reported disturbance area for various types of ROW by pipeline length.

Table 4. Average width of pipeline ROWs based on reported disturbance area and pipeline length

			Average ROW Width [ft]			
Pipeline Project	**Segment**	**Length** [mi]	New Perm.	Const. Temp.	Const. Total (new)	W/in Existing
East Side Expansion[a]	Loop 10345 NJ	7.41	26.5	50.2	76.8	~25
East Side Expansion[a]	Loop 1278 PA	8.93	25.5	56.2	81.7	~25
Leidy SE[a]	Franklin Loop	11.47	26.0	30.0	55.9	45.0
TEAM 2014[a]	Bernville Loop	5.60	24.0	75.3	99.3	63.2
Constitution[b]	Broome County	16.85	45.9	57.8	103.7	
PennEast[b]	Entire	110.60	58.6	71.5	130.2	

Sources: [17, 27, 33, 37]

a. Looping project, or adjacent to existing pipeline ROW.

b. New "greenfield" construction project.

Based on Table 4, our assumptions for right-of-way width seem reasonable. The average new permanent ROW ("New Perm.") width for the four looping projects is 25.5 feet, and the temporary construction ROW ("Const. Temp.") width is 52.9 feet, for a construction total ROW of 78.4 feet of new clearing. So in general it is valid to assume that looping projects save roughly 25 feet of clearing width by using existing ROW on the spoil side during construction and sharing permanent ROW.

The new construction projects average 52.3 feet for new permanent ROW width, and an additional 64.6 feet for temporary construction ROW. Although the PennEast

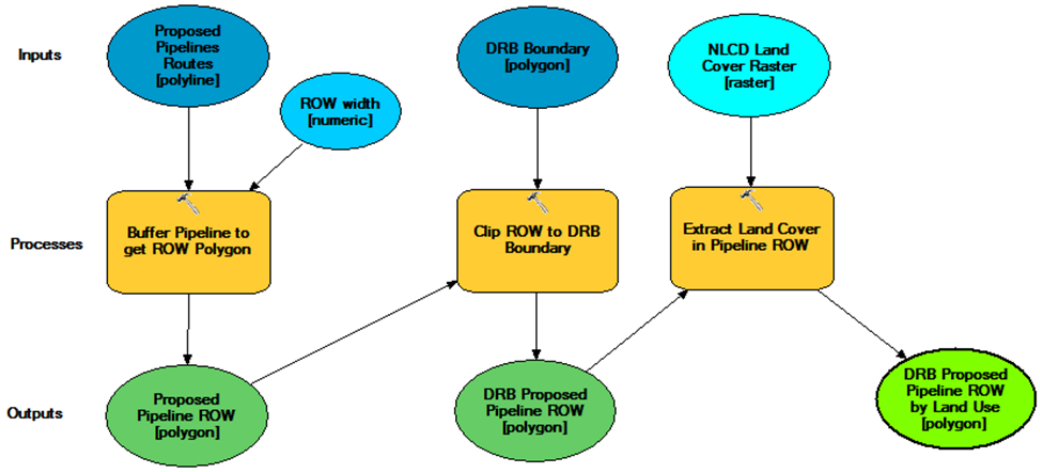
[3] For example, for horizontal directional drilling (HDD), we assumed a permanent ROW of 10 feet (to protect the pipeline) but no construction ROW over the drilled segment. We assumed a 250-by-200-foot drilling pad at the start and end of the HDD sections during construction.

appears to run adjacent to several existing pipelines for portions of its length, the reported areas in the PennEast project documentation [27] (and the calculated average widths) seem to suggest that a full-width permanent easement will be needed along its entire length. This may reflect the fact that PennEast will have a different proponent than the adjacent pipelines, and therefore will need its own easement.

GIS Methods

The land cover analysis for pipelines involves two major steps: (1) converting pipeline route information (in line format) to right-of-way area (in polygon format), and (2) extracting land use types that fall within the right-of-way polygon. In Figure 3, we illustrate the general GIS methodology used for this analysis, including the inputs, processes, and outputs. The major inputs are the pipeline routes, DRB boundary, the NLCD 2011 raster, and the desired ROW width. GIS data types are shown in brackets. We performed additional post-processing as necessary to analyze the results at the county and watershed level.

Figure 3. Generalized GIS process for identifying land use breakdown within proposed pipeline right-of-way



Source: CNA, created with ESRI ArcGIS 10.2 ModelBuilder.

The actual process is slightly more complicated, and requires more steps to extract values from the NLCD raster over the correct domain and convert to a polygon data type. The process as shown can be used only for a symmetrical buffer about the pipeline, which is suitable for analyzing the permanent right-of-way, but not ideal for analyzing the construction ROW, which is typically asymmetric.

As a result, we used two separate methodologies - asymmetric buffering and symmetric buffering - to estimate the new disturbance caused by pipelines. The asymmetric method cuts the pipelines into segments, and uses two fields of the attribute table to create independent buffers on the left side, and then the right side of the feature. This permits setting the left and right side buffers to different values, allowing for an asymmetric simulated ROW. We adjusted the relevant right or left buffer width for each segment to account for shared rights-of-way with existing pipelines. For example, for an existing pipeline located 25 feet to the topographic left of the proposed pipeline, we would set the left buffer distance to zero instead of the typical 25 feet because there would no 'new' clearing needed.

The symmetric method uses a single entered value (e.g., 25 feet) to buffer a constant distance from the pipeline, which results in a symmetric ROW with a width of twice the entered value. We excluded the rights-of-way for existing pipelines by creating buffers (assuming a 50-foot permanent ROW) around the existing pipelines, and "erased" that area from the proposed pipeline ROW.

We also performed a third analysis based on the symmetric methodology to determine the total land disturbance for full-width ROWs with no exclusions for existing pipelines. We did not erase the existing pipeline ROWs in this case.

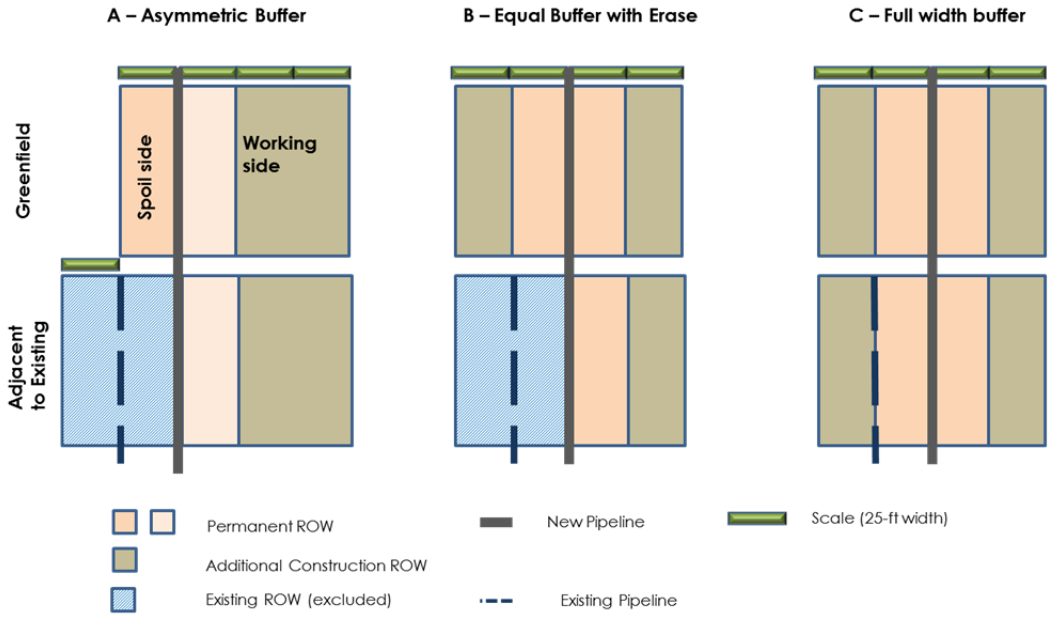
Table 5 describes these three methodologies in more detail. Figure 4 shows an illustration of the differences between the methodologies, including differences in handling cases involving shared ROWs with existing pipeline projects. The figure illustrates how the ROW is computed for both greenfield construction (top), and construction adjacent to existing ROWs (bottom).

In all three cases, we performed the analysis twice; first, we used smaller buffers for the permanent ROW, and then larger buffers for the construction ROW. Table 3 displays the assumed widths for these ROW cases.

Table 5. Methods for estimating land use area impacts of proposed pipelines

Method	Name	Description
A	Asymmetric Buffer	Divide all pipelines into segments, and enter a buffer distance for the topographic left and right side of the feature. Adjust buffer width to account for different land use types and existing ROWs. In addition, account for special cases such as HDD and encroachments.
B	Equal Buffer with Erase	Buffer the proposed pipeline by a constant width (equating to either permanent or construction ROW), symmetric about the pipeline. In GIS, also buffer all existing pipeline features to account for a 50-ft permanent right-of-way. Use the Erase tool in GIS to remove the existing ROW area from the proposed ROW area.
C	Full-width buffer	Buffer the proposed pipeline by a constant width (equating to either permanent or construction ROW), symmetric about the pipeline.

Figure 4. GIS methodology illustration for the three area impact calculation methods for both greenfield construction (top), and construction adjacent to existing ROWs (bottom).



Estimation of Total Forest Area Impact

While this study investigates land cover disturbance for the entire range of land cover types in the NLCD, a particular metric of interest is the total direct forest area impact for the entire Delaware River Basin. (This study does not examine indirect effects such as loss of core forest area due to new forest edges.) We first calculate the forest area impact based on the GIS methodology described, but we recognize some limitations posed by using the NLCD raster. Namely, the coarseness of the NLCD and issues with assignment of land cover types could lead to errors for an individual land use type such as forests. Specifically, we have observed that existing pipeline rights-of-way are often classified as forest (instead of grassland or developed/open space), which may slightly over-estimate forest area. To a lesser extent, low-density residential (or agricultural) land with some tree canopy may also be classified as forest. The 30-meter resolution (cell size) of the NLCD may also come into play, as each cell is slightly wider than the typical construction ROW, and the land cover type may not be completely homogenous within the cell.

In order to correct potential errors in forest area, we validate our GIS results against forest area impacts reported in the FERC or pipeline proponent documentation, which should be more accurate due to greater precision of right-of-way limits and possibly more precise land cover data. Through comparison of these two forest area estimates, we generate adjustment factors that can be used to compute a refined estimate of forest area impacts for the whole basin based on the GIS results. The next section, particularly Table 6, explains the validation process for the forest areas, and presents the adjustment factors we use to compute the best estimate of total forest area impact.

Results

This section presents results of the land cover disturbance analysis. We first present a validation of the methodology. Then we present the total land disturbance area within the DRB for both permanent ROWs and construction ROWs, followed by more granular results by pipeline, by county, and by watershed. Finally, we present our own calculations of the total number of stream and waterbody crossings.

Validation

We validated our GIS methodology by comparing estimates of new pipeline impact by land use to similar estimates in the FERC documentation. All of the GIS estimates used for validation were generated using the "A – Asymmetric Buffer" methodology (see Table 5). We focused on pipelines with disturbance area broken out by land cover type in the documentation, and with pipeline segments within the DRB. Three pipeline projects had segments entirely within the DRB with detailed land cover impact estimates: the Leidy SE Franklin Loop, the TEAM 2014 Bernville Loop, and the two loops in the East Side expansion project. While these projects all fit these criteria, they are also primarily looping projects. Thus we also included the Broome County section of the Constitution pipeline, which is mostly within the DRB, in order to check the methodology on a primarily greenfield construction project.

For validation, we elected to compare the new area impacted for forest, and for all land cover types. Table 6 displays the validation results for forest area impact, and Table 7 for total area impact (all land cover types). The definitions of land cover class groupings for computation of area impact varied by pipeline project. In some cases, the existing right-of-way area was not separated from the total impact area. Generally, the "Open Space" land cover type included the existing pipeline ROW areas. In these cases, we left out the "Open Space" land cover type (where existing ROW area was included in the documentation) from the total. We have denoted the projects to which this assumption was applied with an asterisk. We analyzed the impacts using all the remaining land cover types.

Generally, our GIS estimates of forest disturbance are about 25 percent high for permanent ROW, and 13 percent high for construction ROW as compared to the pipeline documentation. By contrast, GIS estimates of total disturbance are about 5

percent high for permanent ROW and 3 percent low for construction ROW, which amounts to an overall average error of 1.5 percent high.

Table 6. Validation of new forest disturbance [ac] from pipeline documentation ("Document") versus GIS estimates for the permanent and construction ROWs

	New Permanent ROW			Construction ROW		
Pipeline Project	Document [ac]	GIS [ac]	Error [%]	Document [ac]	GIS [ac]	Error [%}
Leidy SE - Franklin	14.9	21.9	47.5%	42.6	51.8	21.5%
TEAM 2014- Bernville	5.9	6.7	13.6%	22.6	26.3	16.6%
East Side - NJ				10.3	3.0	-70.8%
East Side - PA				21.4	25.0	16.9%
Constitution (Broome County)	47.5	56.6	19.1%	98.5	114.3	16.0%
Median			19.1%			16.6%
Weighted Average	**68.3**	**85.2**	**24.8%**	**195.5**	**220.5**	**12.8%**

Table 7. Validation of total new disturbance area [ac] from pipeline documentation ("Document") versus GIS estimates for the permanent and construction ROWs

	New Permanent ROW			Construction ROW		
Pipeline Project	Document [ac]	GIS [ac]	Error [%]	Document [ac]	GIS [ac]	Error [%]
Leidy SE - Franklin	36.1	33.9	-6.0%	77.7	75.6	-2.7%
TEAM 2014 - Bernville *	16.4	18.4	12.0%	69.7	61.5	-11.7%
East Side - NJ *				65.5	65.2	-0.3%
East Side - PA *				89.7	82.7	-19.4%
Constitution (Broome County)	93.4	100.9	8.0%	211.1	211.7	0.3%
Median			8.0%			-2.7%
Weighted Average	**145.9**	**153.2**	**5.0%**	**513.6**	**496.8**	**-3.3%**

* Open Space excluded from calculations because pipeline documentation does not distinguish open space in existing ROWs from new open space impacts.

Land Cover Distribution near Pipelines

Land cover disturbance area estimates could theoretically be sensitive to small errors or potential changes in pipeline route information. It is common that pipelines may have small shifts in routing all the way through construction. For instance, the PennEast pipeline has a 400-foot right-of-way "study area" to account for some of these potential shifts in the final route [26]. In addition, the GIS pipeline route data on which we based this analysis was of varying spatial accuracy (generally within 50 feet, but occasionally only within 300–500 feet).

Before investigating the new disturbance areas within the pipeline ROWs only, we investigated the sensitivity of the land cover impact area to uncertainty in pipeline route. To do so, we computed the land cover characteristics of the larger areas in successively wider 'corridors' around proposed pipeline routes. Here we assume a symmetric buffer and we don't exclude existing ROW, so the calculation method is method C (see Table 5).

We examined the land cover distribution as a function of distance from the proposed route by progressively increasing the buffer width from the pipeline. If the distribution does not change as the buffer distance increases, we can be reasonably confident that the errors associated with route uncertainty are relatively small. If the relative proportions of a given land use change as the buffer distance (i.e. ROW width) increases, then pipeline siting may be effectively avoiding (or targeting) certain types of land uses. Plotting the areas of disturbance versus pipeline ROW width also gives an idea of the general makeup of the land cover in the neighborhood of pipelines.

We first investigated the area very close to the pipeline at several ROW widths, including 10 feet (minimum in areas such as wetlands), 30 feet (typical cleared ROW width in the permanent easement), 50 feet (typical permanent easement), and 100 feet (typical construction easement).

Figure 5 displays these results, which do not exclude existing ROW, and so is not solely new disturbance area. Figure 6 displays the results for larger buffer distances (up to a width of 400 feet) on a continuous stacked area plot. For each land cover type, the increase is nearly linear.

Figure 5. Land cover disturbance area for typical ROW widths for the 8 proposed pipeline projects

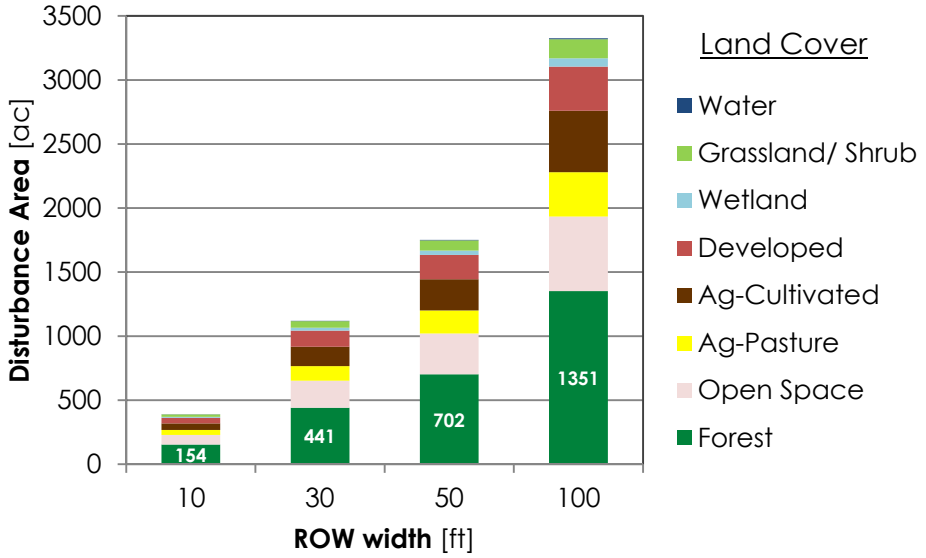
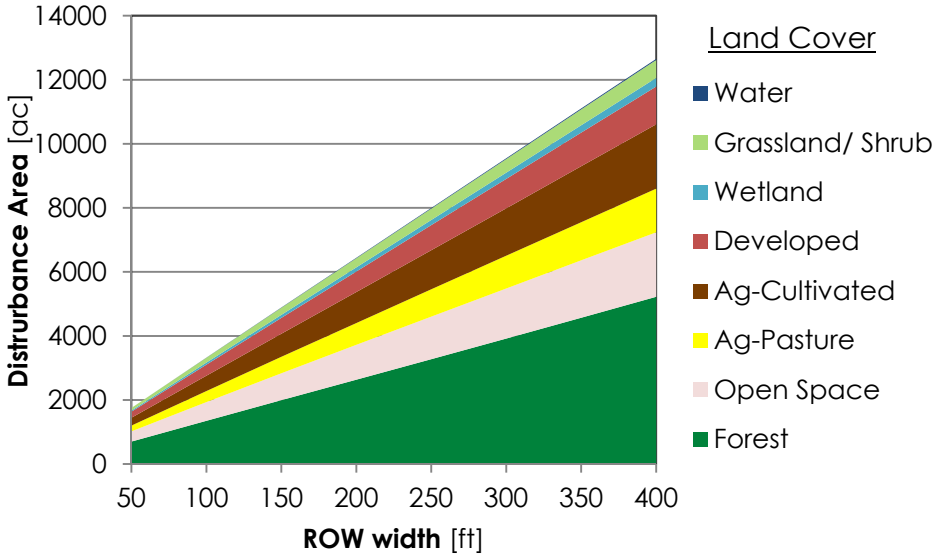
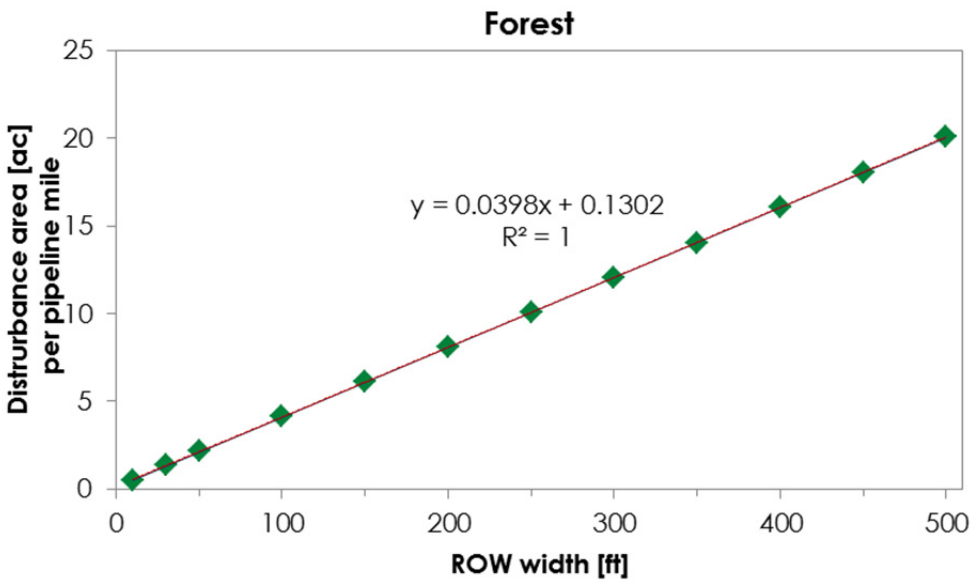


Figure 6. Disturbance area by land cover type versus theoretical ROW buffer width for the 8 pipelines examined in the DRB



We can check these results to see whether the increase in area versus increase in ROW width for particular land use types is truly linear. First we analyze forest impacts. Figure 7 shows the amount of forest area affected versus pipeline ROW width. In this case, the forest area is normalized to the pipeline length, so the vertical axis shows impacted acreage per mile of pipeline. The figure demonstrates that the trend is very much linear. By fitting a trendline to the data, we generate a useful equation that gives the expected forest area impacted per mile for each additional foot of pipeline ROW width. In this case, the slope of the trendline indicates that, on average, each mile of new pipeline in the DRB will affect 0.04 acres of forest for each foot of ROW width. So a 50-foot ROW will affect roughly two acres of forest per mile.

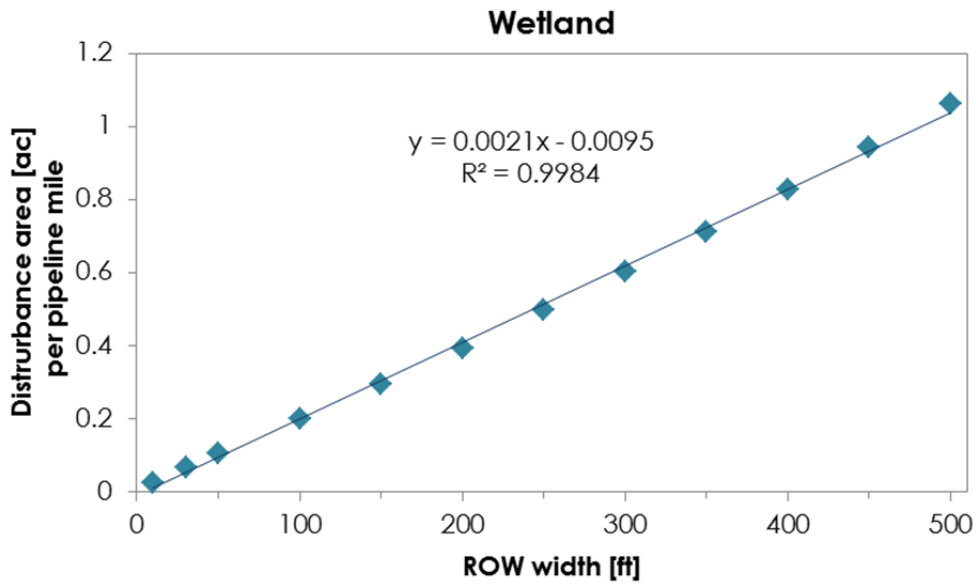
Figure 7. As ROW width increases, forest area impacts increase in a linear fashion.



Many of the other land cover types show a similar pattern. For wetlands, the trend is nearly linear (see Figure 8). Based on this analysis, the slope of the trendline indicates that, on average, each mile of new pipeline in the DRB will affect 0.002 acres of wetland for each foot of ROW width. So, a 50-foot ROW will affect roughly 0.1 acres of wetland per mile on average.

The equations presented here can provide a useful means for generating an initial estimate of the potential impact from pipeline development in the DRB if no information is known about the specific route. Though we add the caveat that the relationships are based on the eight pipeline projects we examined. A more localized analysis would then be needed to generate more refined estimates of the impacts for a specific pipeline project once the route is known.

Figure 8. As ROW width increases, the increase in wetland impact area is nearly linear

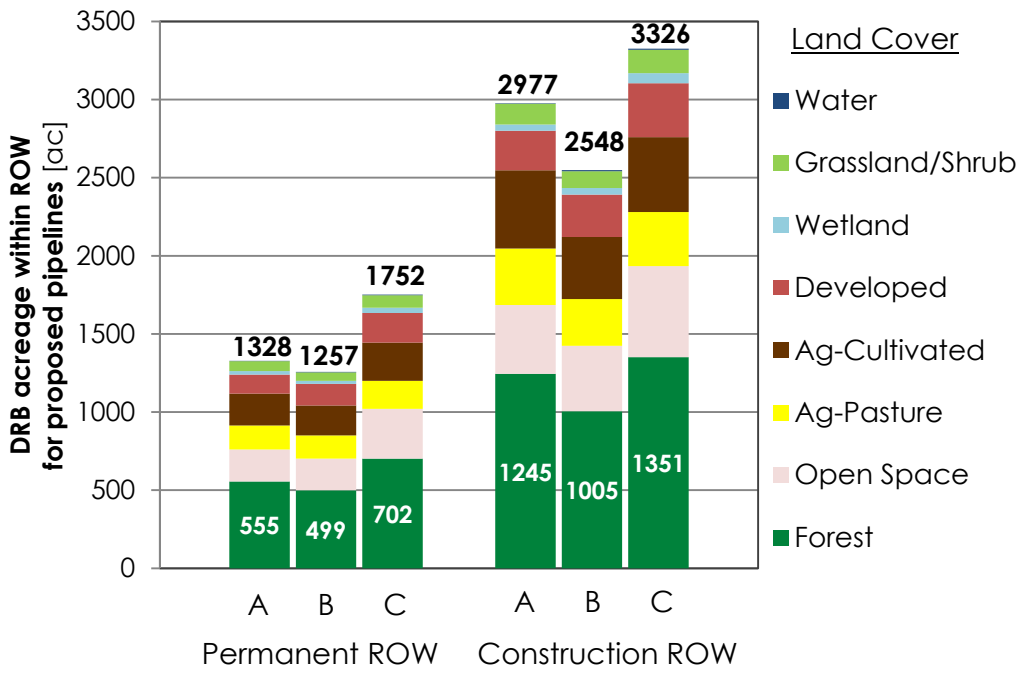


Land Cover Impact in the DRB

Figure 9 displays the total new disturbance area in the DRB associated with ROW construction for the eight proposed pipelines projects. The results for the new permanent ROW are shown on the left, and the construction ROW on the right, each computed via three separate methodologies (refer to Table 5). Labels on the graph display the forest area impacted and total area impacted for each methodology.

Method A is the best estimate using asymmetric buffers, and excluding existing ROW. Method B is the symmetric buffer method excluding existing ROW. Method C is the symmetric buffer method with no exclusions. The forest impact area and total area in acres are labeled on the chart. We note that the computations for Methods A and B are very similar for the permanent ROW, but are different for the construction ROW. This is likely due to the fact that the asymmetric buffer used for Method A would create less overlap with existing ROW than the symmetric buffer method used in Method B. Method C does not exclude any existing ROW, and is unsurprisingly the highest estimate.

Figure 9. Total disturbance areas in the DRB for the permanent and construction ROWs for the proposed pipeline as generated by the three GIS methods (A,B, &C) used in this study



Impact by Pipeline

The total new disturbance area can be separated by pipeline only to a limited extent because some of the new pipelines share a ROW for part of their length: For instance, the Diamond East and Leidy SE projects (see Figure 1), which also have the same pipeline proponent. Or the Mariner East and East Side Expansion projects, which intersect each other.

Table 8 displays the estimated disturbance area by pipeline, broken down by land cover type for the new permanent ROW. Table 9 shows the same for the construction ROW. In both cases, the areas shown are the areas only within the DRB. The area calculations reflect the Method A methodology (see Table 5) applied for each pipeline. The total area disturbed by land cover type is shown at the bottom as the sum of the individual pipeline results. This total includes double-counting of some area where the proposed pipeline ROWs cross or are parallel. Hence, we also present the totals for all pipelines computed where all proposed pipeline ROWs are merged

to avoid double-counting. We observe from the Method A total results (computed with the same methods as the sum of individual pipeline results) that the double-counted area is roughly 18 acres (1346 minus 1328). Results for Methods B and C (see Table 5) are shown for comparison.

Table 8. Estimated disturbance area [ac] within the DRB by pipeline and land cover type for the new permanent ROW

Pipeline	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Constitution Pipeline	40.7	0.9	1.3	29.0	4.9	3.8	0.1	0.0	**80.8**
Diamond East Project	96.7	6.3	3.7	9.2	23.7	26.6	3.9	0.6	**170.7**
Leidy SE Project	21.9	3.7	3.3	0.3	0.1	4.0	0.1	0.4	**33.9**
Mariner East 1&2	75.5	1.4	16.6	28.2	25.3	76.1	51.7	0.0	**274.9**
NJ Natural Gas Project	7.1	1.4	1.8	4.3	11.3	48.1	36.0	0.0	**110.0**
PennEast Pipeline	311.2	6.6	36.7	72.8	132.3	33.8	14.1	0.4	**607.9**
TEAM 2014 Expansion Proj.	6.7	0.1	0.4	2.5	2.5	2.7	3.3	0.1	**18.4**
East Side Expansion Project	8.6	2.5	2.0	6.8	4.2	12.0	12.9	0.0	**49.0**
NJ Loop 10345	*0.9*	*1.9*	*0.4*	*2.1*	*1.2*	*4.9*	*9.0*	*0.0*	**20.6**
PA Loop 1278	*7.7*	*0.6*	*1.6*	*4.7*	*3.0*	*7.1*	*3.8*	*0.0*	**28.5**
TOTALS - by method									
Sum of Pipeline Results [a]	568	23	66	153	204	207	122	1.5	**1346**
A - Asymmetric buffer	555	22	64	153	204	205	122	1.4	**1328**
B - Symmetric buffer	499	20.2	56.4	149	192	200	137	3.2	**1257**
C - Full symmetric buffer	702	34.3	79.8	180	244	319	189	4.1	**1752**

[a.] "Sum of Pipeline Results" includes some double counting of areas, notably for Mariner East 1 and 2, and Leidy SE, Diamond East, and PennEast.

NOTE: Pipeline results generated using Method A. Totals shown for other methodologies by comparison. Totals may not sum exactly due to rounding.

Table 9. Estimated disturbance area [ac] within the DRB by pipeline and land cover type for the new construction ROW.

Pipeline	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Constitution Pipeline	80.8	1.5	2.4	65.0	11.1	8.1	0.4	0.0	**169.3**
Diamond East Project	295.7	15.1	8.0	28.8	71.5	74.4	11.7	2.2	**507.4**
Leidy SE Project	51.8	6.1	5.4	0.9	0.3	10.0	0.3	0.8	**75.6**
Mariner East 1&2	172.0	3.9	39.6	64.7	64.2	160.2	100.9	0.1	**605.7**
Southern Reliability Link	16.2	2.7	3.5	11.4	29.8	83.2	68.0	0.0	**214.7**
PennEast Pipeline	633.3	11.1	71.3	164.3	305.8	70.7	27.9	0.7	**1285.1**
TEAM 2014 Expansion Project	19.7	0.3	0.8	6.4	7.3	6.9	7.4	0.1	**48.9**
East Side Expansion Project	24.8	4.3	5.2	20.1	11.5	34.2	36.5	0.0	**136.6**
NJ Loop 10345	*2.5*	*3.1*	*1.3*	*6.8*	*3.8*	*13.8*	*24.8*	*0.0*	**56.2**
PA Loop 1278	*22.3*	*1.2*	*3.8*	*13.3*	*7.7*	*20.4*	*11.8*	*0.0*	**80.5**
TOTALS - by method									
Sum of Pipeline Results[a]	1294	45	136	362	501	448	253	3.9	**3043**
A - Asymmetric buffer	1245	41	133	361	501	440	253	3.3	**2977**
B - Symmetric buffer	1005	42	112	299	398	414	272	6.6	**2548**
C - Full width symmetric buffer	1351	65	149	344	479	582	344	8.1	**3324**

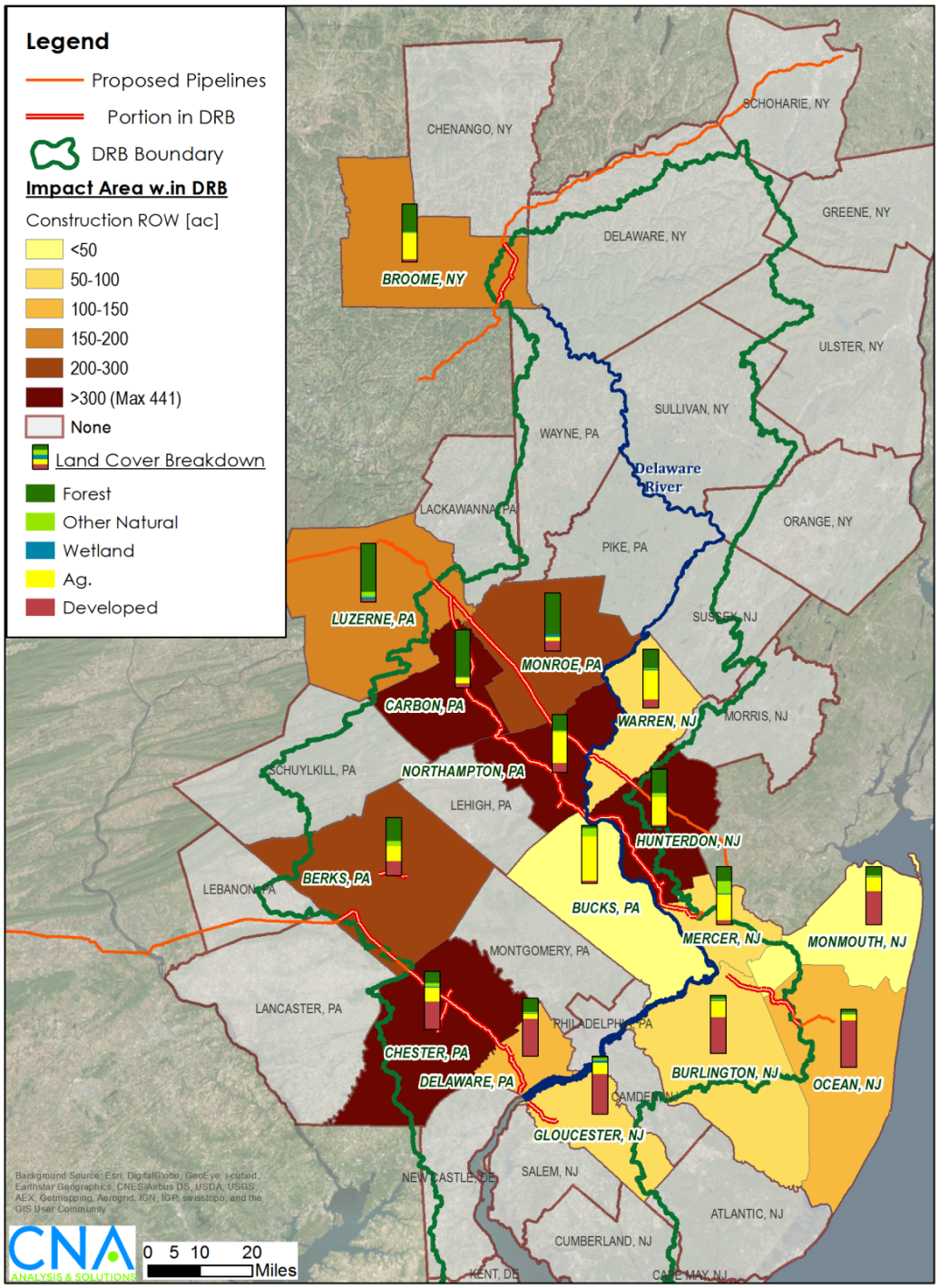
[a.] "Sum of Pipeline Results" includes some double counting of areas, notably for Mariner East 1 and 2, and Leidy SE, Diamond East, and Penn East.

NOTE: Pipeline results generated using Method A. Totals shown for other methodologies by comparison. Totals may not sum exactly due to rounding.

Impact by County

We computed the total area impact by county by intersecting the Method A total impact area in the DRB with county boundaries. Figure 10 maps the construction ROW impact by county. Shading shows the total area impacted by construction ROW within the DRB portion of each county. Stacked bars on the map show the breakdown of the impacted area by land cover type. See Appendix A for the results by county in tabular format. (Table 11 displays the county-level area impact for the new permanent ROW, and Table 12 does so for the construction ROW.)

Figure 10. Land area impacts of proposed pipeline construction within the Delaware River Basin (DRB), by county



In Figure 9, it appears the impacts will be most concentrated in the central portion of the DRB. Carbon, Monroe, and Hunterdon counties all have in excess of 200 acres of land disturbance, while Northampton has the highest of any county, with 441. These counties also have the largest percentage of the impact affecting forests. For instance, over 75 percent of the total impact area in Luzerne and Carbon counties will be in forests.

The lower portion of the watershed also has a concentration of impacts. Chester and Berks Counties each have over 200 acres affected during construction. The land cover types impacted are distributed more across agriculture, developed land, and forests than in the middle portion of the basin.

Broome is the only county with impacts in the upper basin. The area of impact is roughly evenly divided between forest and agriculture.

Overall, the breakdown of land cover types affected by pipeline development follow the general land cover patterns of the DRB as a whole: predominantly forest in the Upper and Western portions of the basin, more agriculture in the middle and Eastern portions, and finally, much more developed land in the lower portion of the basin.

Impact by Watershed

In addition to analyzing the results by county, we also investigated the results by using hydrographic boundaries. We totaled the results by Hydrologic Unit Code–10 digit (HUC10) watershed using data from the USGS Watershed Boundary Dataset [40]. In Figure 11, we display the results for new permanent ROW area by HUC10 watershed as a stacked bar chart. Figure 12 shows similar results for the new construction ROW. On the left, the HUC10s are grouped by the larger HUC8 watershed subdivision, with the HUC8 names labeled. (Figure 13 shows the spatial location of both the HUC10 and HUC8 boundaries.) The bold number labels on the graph indicate total area impacted in acres. The breakdown of the area by land cover type is shown in a table format in Appendix A (see Table 13 and Table 14).

Figure 13 shows the total new construction ROW area impact on a map instead. (Shading denotes total new construction ROW area [ac] by HUC10 for the proposed pipeline projects.) It is clear from the map that the most area will be affected through the middle portion of the DRB, especially in the Lehigh and Middle Delaware HUC8 watersheds, and to a lesser extent the Schuylkill, Brandywine-Christina, and Lower Delaware watersheds. These areas, especially the Lehigh subbasin, also have the majority of the forest disturbance.

Figure 11. New permanent ROW land cover breakdown by watershed (HUC10), with grouping by HUC8 watershed name (labels show total impact area)

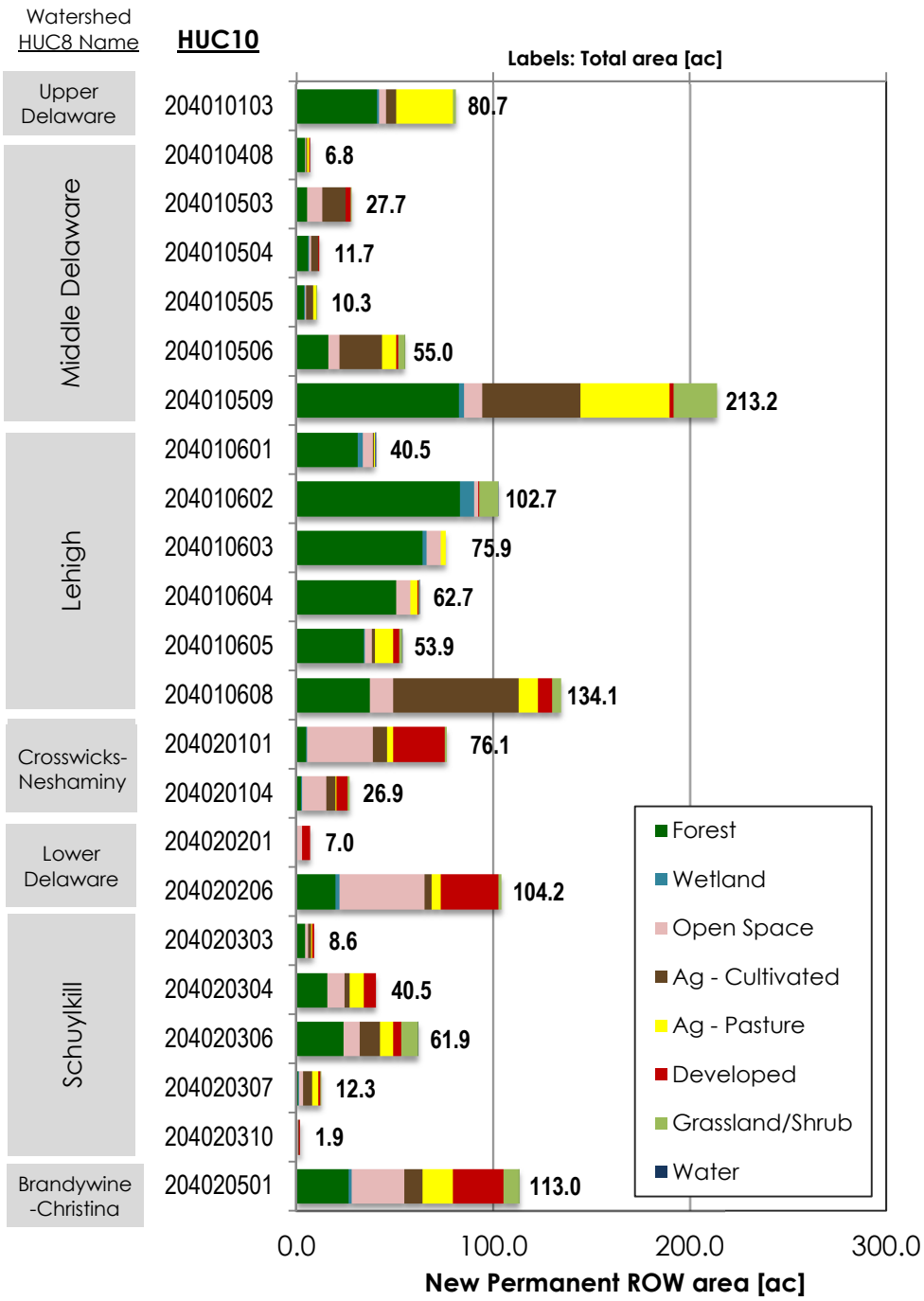


Figure 12. New construction ROW land cover breakdown by watershed (HUC10), with grouping by HUC8 watershed name (labels show total impact area)

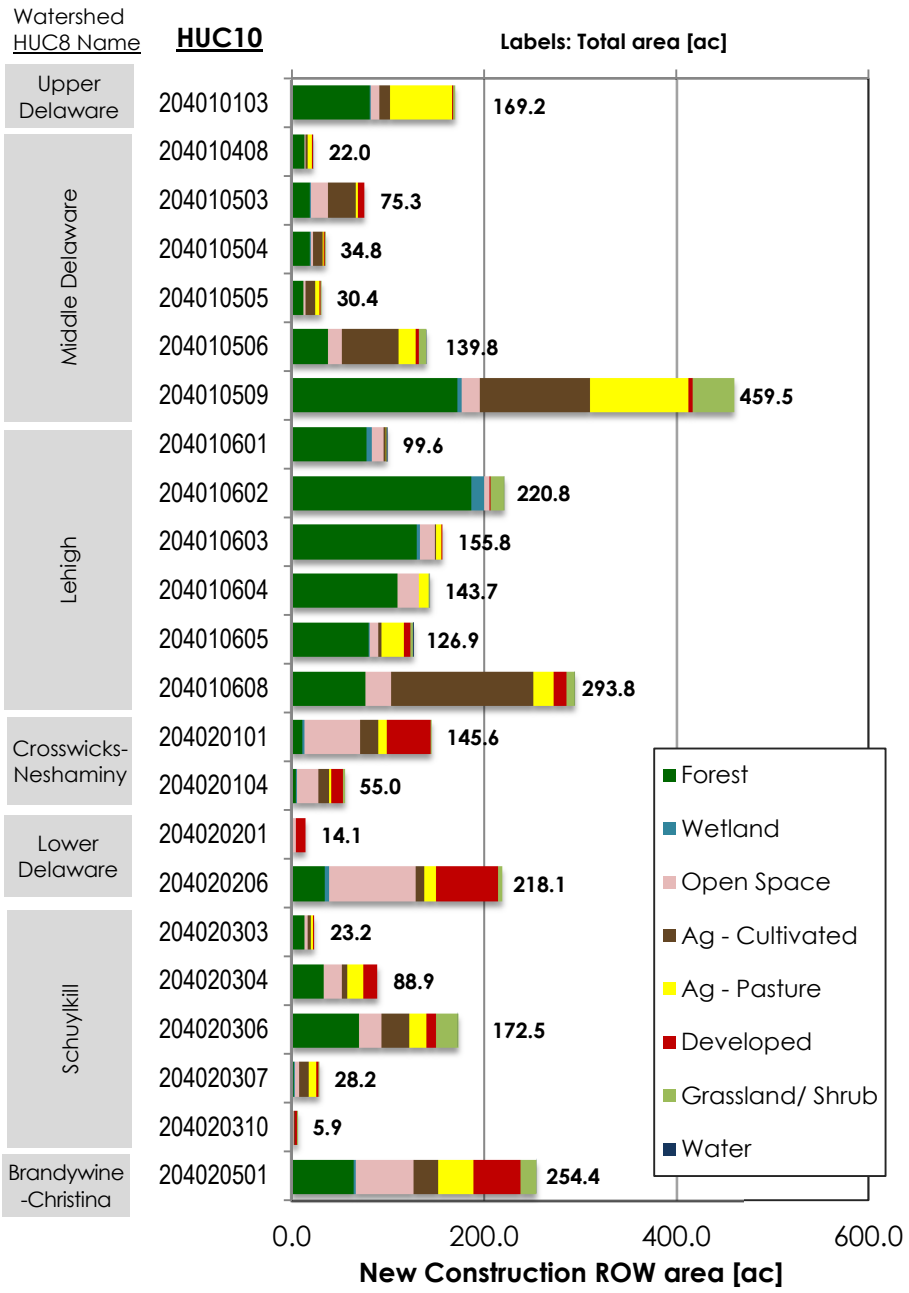
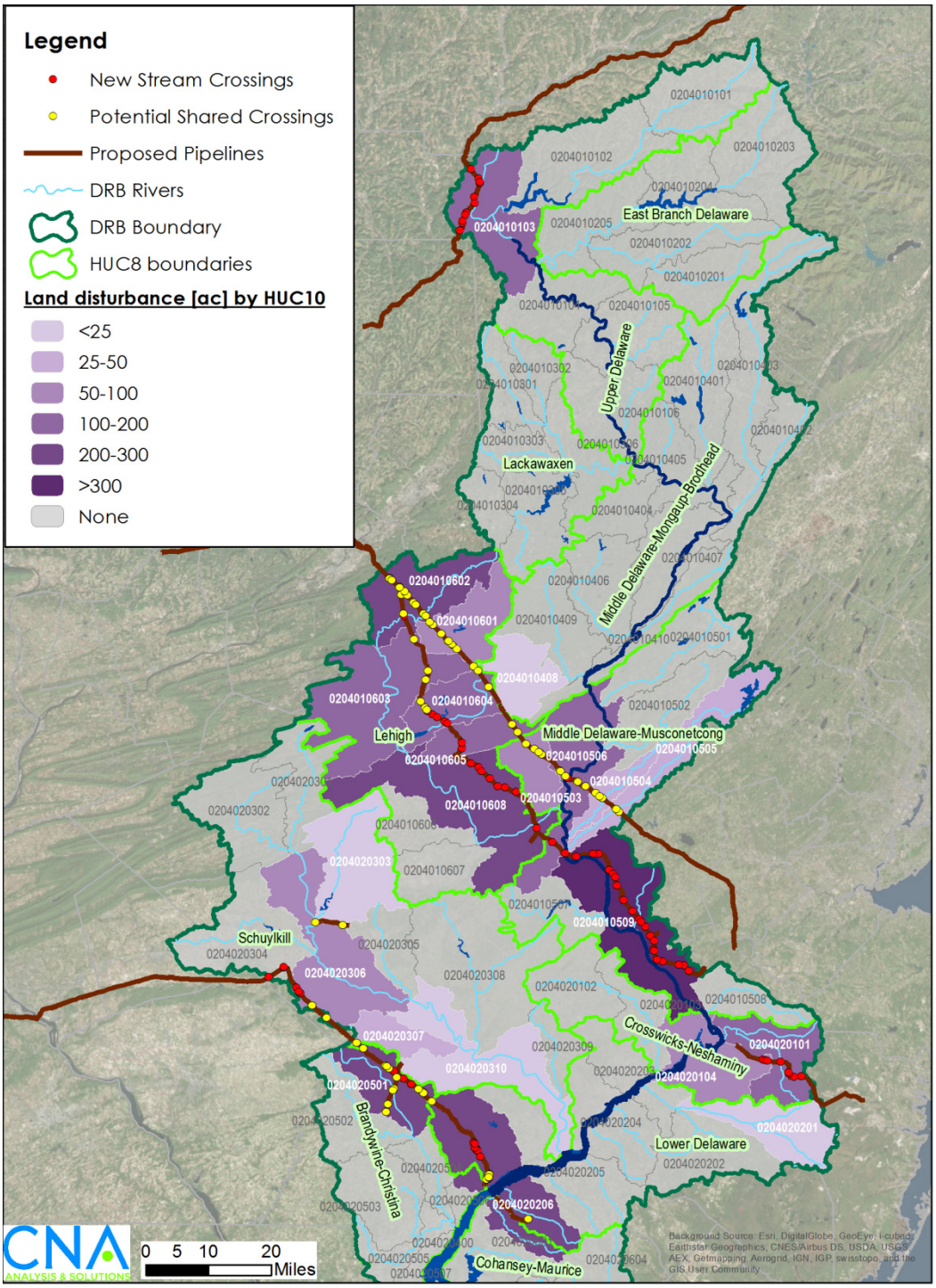


Figure 13. Watershed impacts of pipeline construction – land disturbance and stream crossings (labels show HUC10 numbers)



Potential Stream Crossings

Stream crossings are a particular area of concern for pipeline development, as land in close proximity to waterways is at high risk for erosion, nutrient export, and potential pollutant export. In addition, any sediment or pollutants that enter the stream will be carried downstream in the waterway.

While the final EIS documents approved by FERC for pipeline projects contain listings of the proposed stream crossings, it is difficult to determine the total number of stream crossings for all eight projects for several reasons. Not all of the pipelines have final EIS documents, and the location of stream crossings is not in a consistent format across the different documents. In some cases, it is difficult to assess whether certain streams are within the Delaware River Basin. For these reasons, we assessed stream crossings using a consistent methodology for all of the proposed pipelines.

We computed the number of stream intersections[4] in GIS using the pipeline route information and the National Hydrography Dataset Plus Version 2 (NHDPlus v2) stream flowlines. The NHDPlus v2 dataset is fairly high resolution (stream segments drain less than one square mile on average in the Delaware River basin), but does not include most intermittent streams or ephemeral streams in the Eastern US.

We also accounted for the possibility that existing stream crossings could be used where proposed pipelines are parallel to existing pipelines. We assumed that when an existing pipeline intersected the stream within 250 feet[5] of the proposed pipeline's crossing, a shared crossing would be used.

Figure 13 shows these intersection points that indicate stream crossings. The yellow points indicate crossings that have some potential to share an existing crossing. The red points indicate "new" crossings that are not adjacent to existing pipeline crossings of streams. Table 15 (in Appendix A) tabulates the intersections by HUC10.

In total, we found 175 potential new crossings, of which 92 have the potential to be "shared" crossings with existing pipelines.

[4] We used the ArcGIS Intersect tool with the pipeline routes and NHDPlus flowlines as inputs (both are polyline datatype), which results in a point file with a point marking each location a stream and a proposed pipeline intersect.

[5] We generated a second set of intersection points using existing pipeline routes and NHDPlus flowlines. Then we computed the number of proposed intersection points falling within 250 feet of these intersections. We chose 250 feet as a generous buffer that can identify potential shared crossings even when the stream line is nearly parallel to the pipeline ROWs.

This total counts only intersections with streams in the NHDPlus database, and likely dramatically undercounts the total number of stream crossings due to many intermittent and ephemeral streams not included in the database. We note that the environmental assessment documents issued by FERC and the pipeline proponents usually provide a more complete accounting of potential stream crossings, most likely gathered from local field and site analysis. As an example, a permit application to Delaware River Basin Commission for the Mariner East project found over 180 potential stream crossings, the great majority of which are intermittent or ephemeral [23]. Without the ability to do field investigation, or access to much more complete stream data for the entire basin, we were limited to identifying crossings of the predominantly perennial streams in the NHDPlus database.

Best Estimate of Impacts

Forest Area Impacts

The metrics presented in this report present an estimate of the land cover impacts of pipeline construction. The estimates for individual land cover type impacts depend heavily on the accuracy of the pipeline routes, and the accuracy of the NLCD data used. As mentioned previously, we observed that existing pipeline rights-of-way were often classified as forest in the NLCD, which may slightly overestimate forest impact area. To a lesser extent, pipeline routes running through or adjacent to low-density residential (or agricultural) land with some tree canopy may also be classified as forest.

In order to partially account for these potential discrepancies, we used our validation data (refer to Table 6) to develop adjustment factors for forest area impact. We report three key metrics in Table 10, computed in three ways: First, the GIS results for both the construction and permanent ROW areas, computed via the asymmetric method (A). The third metric is the permanently cleared forest area that would be within the permanent ROW, commonly estimated to be 30 feet wide (see, for example, [19]). This metric identifies the forest impact over the longer term, assuming some of the permanent ROW (outside 30 feet) is allowed to regrow, while still leaving the center of the ROW cleared.[6] Since our results show forest area impact scales linearly with ROW width (see Figure 6 and Figure 7), we calculate this

[6] This metric is almost certainly a low estimate of potential impact since many pipeline operators may elect to keep the entire permanent ROW clear. This also does not take into account looping projects where one side of the permanent ROW may be shared with an existing pipeline, and therefore would not be suitable for allowing forest regrowth.

permanently cleared area by multiplying permanent ROW impact area by the ratio of widths (30/50), or 0.6.

The second and third data columns in Table 10 are computed using two adjustment factors computed from the validation data. The specific adjustment factor uses values specific to the construction and permanent ROWs. The permanent ROW specific adjustment factor used is 0.752, and the construction ROW specific factor is 0.872. The general adjustment factor uses an average, constant adjustment applied to both ROW types.[7] The resulting general adjustment factor used is 0.832, or a 16.8 percent reduction in forest area from GIS results. In all cases, the permanently cleared area estimate is computed by multiplying the permanent ROW estimate by 0.6.

Table 10. Estimated total forest area impact for pipeline ROWs in the DRB by ROW type for the eight proposed pipelines in this study

	DRB Forest Area Impact [ac]				
ROW Type (width)	GIS Results	Adjusted (Specific)	Adjusted (General)	**Adj. Factor** (Specific)	**Adj. Factor** (General)
Construction (~100 ft)	1,245	1,036	1,086	0.872	0.832
Permanent (~50 ft)	555	462	418	0.752	0.832
Permanently cleared (~30ft)	333	277	251	0.6[a]	0.6[a]

[a.] Adjusted by multiplying by Permanent ROW Forest Impact Area

So, in total, we estimate that within the DRB, the eight pipeline projects in this study will impact:

- Approximately 1,040–1,090 acres of forest within construction ROW during construction
- Approximately 420–460 acres of forest that will fall within the proposed pipelines' new permanent ROWs
- Approximately 250–280 acres of forest that will be permanently lost in the cleared area of the pipeline ROWs, if all pipeline projects keep only 30 feet of width in the permanent ROW cleared.

[7] Since we had an unequal number of pipeline validations for the construction and permanent ROW, we computed the general adjustment factor by weighted average of the construction and permanent factors, with the nominal ROW width as the weight. That is, the construction ROW factor had twice the weight as the permanent factor.

We note that these estimates do not include all potential forest impacts for the pipelines' construction. Typically, pipeline construction requires additional area for pipeline facilities (compressors, pumps, valves, terminals), temporary workspace for equipment storage and staging, as well as access roads to bring equipment and materials to the working ROW. A spatial analysis of the location of these facilities and their associated impacts was beyond the scope of this study. However, based on pipeline documentation, the potential additional area associated with these facilities ranges from about 17 percent of total area impact for greenfield projects (e.g., Constitution [19]) to over 30 percent for looping projects (Leidy SE Franklin Loop [20], East Side Expansion [37]). Relative to the pipeline ROW area only (not the total impact area), these percentages are 20 percent for greenfield projects, and 45 percent for looping projects.

Wetland Area Impacts

For wetland impacts, developing reasonable adjustment factors is impractical because of the small areas involved for any individual pipeline. We report the results for our GIS analysis (Method A), which did take into account narrower ROWs when passing through wetland areas. In total, we estimate that within the DRB, the eight pipeline projects in this study will impact:

- 41 acres of wetlands within the construction ROW
- 22 acres of wetlands within the new permanent ROW.

Discussion

This analysis computed the cumulative impacts of eight proposed natural gas transmission pipelines on existing land cover in the Delaware River Basin (DRB). The length of the new pipelines will total 322 miles within the DRB, a length roughly equivalent to the Delaware River itself. We found that the total area of new land disturbance is 2,977 acres (4.7 square miles) during construction and 1,328 acres (2.1 square miles) in the permanent right-of-way (ROW). These impacts only account for the ROWs directly, and not total impacts for associated activities such as road buildings, or equipment storage. Forests account for over one-third of the land area impacted (roughly 40 percent before adjustment). The basin-wide totals don't present the whole story, however. Our analysis showed that results vary significantly by pipeline, construction method, and watershed location.

We found that the cumulative area of impact was far greater than for any individual pipeline project, but several of the projects do have disproportionate impacts compared to the others. In part, this depends on the pipeline route and construction methods. Unsurprisingly, our results indicate that greenfield pipeline projects result in more land disturbance and forest loss per mile than looping projects or those that parallel an existing ROW. Combined, the PennEast, Constitution, and NJ Natural Gas Southern Reliability Link projects, which are all predominantly greenfield projects, account for well over half of the total potential disturbance area. The PennEast pipeline project has the largest potential impact within the DRB. The Mariner East 1 and 2, and Diamond East projects would affect a large amount of acreage due to their length, but less than they otherwise would, as the majority of their length is adjacent to existing pipeline ROWs. This reduction in affected acreage is more evident in the permanent ROW results than the construction ROW results, possibly because the wider working side of the pipeline usually can't be shared with existing ROWs, and requires new clearing.

The pipeline results also indicate a few key portions of the watershed with disproportionate impacts. The PennEast, Diamond East, and Leidy SE projects cross through the middle portion of the basin, especially the Lehigh, and Middle Delaware subbasins in Carbon, Northampton, Hunterdon, Luzerne, Monroe, Mercer, and Warren counties. These projects in particular pass through heavily forested areas, and account for the largest impacts on forests in the basin. The Mariner East, East Side Expansion, and Southern Reliability Link projects substantially affect the Brandywine-Christina, Lower Delaware, and Crosswicks-Neshaminy subbasins in the

lower portion of the watershed, where the land cover tends to be more agricultural or developed. Finally, the Constitution Pipeline is the only pipeline of the eight affecting the Upper portion of the watershed as it passes through Broome County, NY. The land cover along its route is split between agriculture and forest. Of course, additional pipeline proposals could change the distribution of impacts in the future.

This analysis also demonstrated how geospatial analysis can be used to determine a rough estimate of land disturbance area based only on pipeline route information. There is often a considerable delay between the initial route proposal for a pipeline and the environmental analysis or environmental impact statement that includes a full accounting of the land cover impacts using detailed ROW information. The pipeline proponent and FERC will have access to the most authoritative information on the project, and are in the best position to assess potential impacts with a high degree of certainty. The higher-resolution data for both the pipeline ROW and potentially, existing land cover (plus, likely field surveying) allow a higher degree of certainty than we could achieve in this analysis. Nonetheless, our methodology in this report demonstrates that a fairly accurate initial estimate of impacts can be generated using only proposed and existing pipeline route information and the National Land Cover Dataset (NLCD). We validated our results, and found that the error in total disturbance area was less than 5 percent compared to the FERC environmental analysis documents. The specification of forest area impacted requires an adjustment factor to account for uncertainty and coarse resolution in the NLCD.

We also determined that small errors in the pipeline route are not likely to be extremely consequential with respect to land cover breakdown. Changes in overall length due to altered routes will of course affect acreage of impact, but small perturbations or uncertainty in the proposed route may not greatly affect results. The overall breakdown of land cover disturbance is nearly constant as theoretical ROW width expands, even far beyond the construction ROW. This leads to some potentially useful rules of thumb for pipeline construction. For instance, a 50-foot ROW will affect, on average, four acres of forest per mile in the DRB (based on the routes of these eight pipelines).

There are several ways this analysis could be expanded in the future. First, the analysis method could be applied to other geographic areas such as the Susquehanna River Basin or the entire State of Pennsylvania. At present, this analysis considers only land cover changes due to development of the pipeline ROWs, and potential stream crossings, but no secondary impacts on land or water resources. The results from this study could feed into secondary impact analyses. For instance, the permanent pipeline ROWs could be used with existing land cover data to estimate secondary forest impacts such as fragmentation and loss of core forest as a result of the new forest edges along the ROWs. Or the total disturbance area and existing land

cover distribution could be used as inputs in a water quality model to estimate potential changes in sediment loading to streams.

It is worth noting that in Pennsylvania, pipelines are a special topic of concern because of the rapid increase in shale gas development since 2007. Some estimate that 30,000 miles of additional pipelines may be constructed in Pennsylvania in the next 30 years [41]. The majority of those will likely be the smaller gathering lines to move gas from production wells to the existing distribution network, but new transmission lines will also be needed to handle the increased production. In 2015, Pennsylvania Governor Tom Wolf appointed a pipeline task force, managed by the PA Department of Environment Protection, to study pipeline impacts in Pennsylvania and come up with a list of recommendations [42]. Similar to the motivations of this study, the task force found that the pipeline approval and permitting review process may not always account for long term, cumulative impacts: "Chosen routes do not necessarily avoid sensitive lands, habitats, and natural features. . . . Impacts to natural and cultural resources, landowners, and communities along them not always avoided, minimized or mitigated. . . . Individual decisions can accumulate into a much broader and longer impact on the citizens and the lands of a community, county or watershed" [42].

The Pipeline Task Force's report included 12 top recommendations, and 184 overall recommendations for improving the pipeline infrastructure development process in Pennsylvania [43]. These recommendations may affect the permit and approval process in the future, and thus, pipeline routing and construction methods. (Note that no policy changes have been adopted, and these state level recommendations likely will not directly affect the FERC process.) Accordingly, the methodology used in this study would have to be adapted to account for potential changes where possible. Some of the most relevant recommendations relate to better information sharing about pipeline routes, planning routes to avoid or mitigate environmental impacts, and construction methods and offsets to reduce net environmental impacts. The recommendation for earlier information sharing about proposed pipeline routes (including GIS data) would make assessing impacts with a methodology like the one used in this study easier. Other recommendations might affect ROW routes or widths. For instance, the recommendation to "Reduce Forest Fragmentation in Pipeline Development" could discourage routes from going through core forest areas. The recommendation to "Minimize Impacts to Riparian Areas at Stream Crossings" could result in changing assumptions about ROW width near stream crossings. Finally, several recommendations include policies for either mitigation banking or net loss limits for certain land cover types such as wetlands, forests in headwater watersheds, riparian buffers [43]. These types of policies would require more clarification in order to be modeled, and the methodology would have to account for the policies' impact through adjustment factors or additional assumptions (e.g., assume forest area loss is replaced within the same watershed).

In summary, the next several years and decades will witness much more pipeline development in Pennsylvania and the Delaware River Basin. The pipeline projects will result in some impacts to land resources, water resources, cultural resources, ecosystems, and air quality, among others, even after accounting for project-specific mitigation measures. Analyzing several projects at once can give a clearer picture of potential cumulative impacts, but it requires timely and accurate geospatial information on proposed pipeline routes. It appears likely that Pennsylvania will consider recommendations to change the pipeline infrastructure development process to further mitigate or avoid impacts, especially for particularly sensitive resources. These changes may complicate future analyses such as this one, but may ultimately result in lessened impacts over the landscape of development.

Analyzing the cumulative impacts of concurrent pipeline projects is likely to be an ongoing need in Pennsylvania, for FERC interstate transmission pipeline proposals, and wherever pipeline infrastructure is being expanded. Pipelines are necessary to move liquid fuels across the country; they are an efficient means of transport, but their development does have short-term and long-term impacts on the landscape over which they are built. Policymakers at various levels may find analyses such as that presented in this study useful for comprehending how new pipeline proposals add to the cumulative impacts in geographic areas of interest. They may then determine whether mitigation measures may be appropriate, based on cumulative landscape impacts rather than solely on project-specific impacts.

Appendix A: County and Watershed Results Tables

Table 11 displays the county-level area impact for the new permanent ROW, and Table 12 does so for the construction ROW.

Table 13 shows the impact area for the permanent ROW, broken down by land cover type and HUC10 watershed. Table 14 shows the impact area for the construction ROW, broken down by land cover type and HUC10 watershed.

Table 15 shows the number of stream crossings in each HUC10 watershed. These crossings reflect points of intersection between proposed pipeline routes and NHDPlus v2 stream flowlines within the DRB. We used existing pipeline routes to identify where existing crossings are located. In situations where a proposed pipeline's crossing is within 250 feet of an existing crossing, there may be the potential for a shared crossing, which could reduce the impact of the stream crossing. It is certainly possible these potential shared crossings may require a new crossing. Nonetheless, we have identified the total number of crossings, potential "shared" crossings, and the remaining crossings—which, by default, will be "new" crossings. Many of the new crossings that occur are associated with greenfield construction, and the potential shared crossing locations are typical for looping projects.

Table 11. Total land disturbance by county for new permanent ROWs[a]

County	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Burlington, NJ	2.8	0.6	0.8	2.4	6.3	18.6	10.4	0.0	**41.9**
Gloucester, NJ	0.9	1.9	0.4	2.1	1.2	4.9	9.0	0.0	**20.6**
Hunterdon, NJ	76.0	1.2	10.8	39.2	40.5	7.5	0.7	0.0	**175.9**
Mercer, NJ	10.5	1.4	11.6	8.4	9.9	2.5	1.2	0.0	**45.5**
Monmouth, NJ	2.0	0.1	0.4	1.6	2.4	7.6	1.9	0.0	**15.9**
Ocean, NJ	2.4	0.8	0.5	0.4	2.6	21.9	23.6	0.0	**52.2**
Warren, NJ	9.3	0.4	0.5	1.1	14.0	3.8	0.5	0.1	**29.6**
Broome, NY	40.7	0.9	1.3	29.0	4.9	3.8	0.1	0.0	**80.8**
Berks, PA	43.9	0.3	8.4	14.6	14.3	18.1	11.3	0.1	**111.0**
Bucks, PA	0.6	0.0	1.5	0.9	6.5	0.4	0.3	0.0	**10.3**
Carbon, PA	137.7	1.7	2.0	13.0	1.2	9.8	3.6	0.4	**169.5**
Chester, PA	27.7	1.4	8.7	18.6	14.0	41.5	35.5	0.0	**147.5**
Delaware, PA	18.4	0.4	1.4	2.2	2.5	26.5	12.0	0.0	**63.4**
Luzerne, PA	65.8	4.9	9.7	0.0	0.0	2.2	0.5	0.0	**83.1**
Monroe, PA	63.5	5.3	0.2	4.2	1.4	14.1	0.6	0.8	**90.1**
Northampton, PA	53.4	0.5	5.8	15.3	82.6	22.1	10.5	0.0	**190.3**
TOTALS - by State									
Subtotal - NJ	*104*	*6*	*25*	*55*	*77*	*67*	*47*	*0*	***382***
Subtotal - NY	*41*	*0.9*	*1.3*	*29*	*5*	*4*	*0*	*0.0*	***81***
Subtotal - PA	*411*	*15*	*38*	*69*	*123*	*135*	*74*	*1*	***865***
TOTAL - DRB	**555**	**22**	**64**	**153**	**204**	**205**	**122**	**1**	**1328**

[a.] Land disturbance estimate computed by Method A (see table 5). Totals may not sum exactly due to rounding.

Table 12. Total land disturbance by county for construction ROWs[a]

County	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Total
Burlington, NJ	5.4	1.2	1.6	6.9	16.3	31.2	19.4	0.0	**81.9**
Gloucester, NJ	2.5	2.9	1.3	6.8	3.8	13.8	24.8	0.0	**55.9**
Hunterdon, NJ	157.9	2.2	24.1	88.9	92.0	15.3	1.6	0.0	**382.1**
Mercer, NJ	24.2	2.4	20.5	19.2	24.0	4.8	2.9	0.0	**97.9**
Monmouth, NJ	4.7	0.3	0.7	3.3	4.1	14.2	3.7	0.0	**30.9**
Ocean, NJ	6.1	1.2	1.2	1.2	9.4	37.8	44.9	0.0	**101.9**
Warren, NJ	29.1	1.0	1.7	2.9	41.6	10.8	1.8	0.3	**89.2**
Broome, NY	80.8	1.0	2.4	65.0	11.1	8.1	0.4	0.0	**168.8**
Berks, PA	115.6	0.9	22.6	35.3	38.1	45.2	26.8	0.1	**284.6**
Bucks, PA	1.2	0.0	3.2	2.2	15.4	0.7	0.4	0.0	**23.0**
Carbon, PA	276.5	2.5	4.0	31.6	2.9	20.3	7.5	0.5	**345.7**
Chester, PA	67.2	3.4	19.0	44.2	35.3	86.1	67.4	0.1	**322.6**
Delaware, PA	31.3	1.1	2.7	4.9	5.8	56.0	25.8	0.0	**127.7**
Luzerne, PA	150.4	9.8	14.3	0.0	0.0	5.1	1.1	0.0	**180.7**
Monroe, PA	170.9	9.1	0.5	13.3	4.0	40.6	1.9	2.1	**242.5**
Northampton, PA	121.5	1.9	12.7	35.3	197.4	49.9	22.1	0.2	**441.0**
TOTALS - by State									
Subtotal - NJ	*230*	*11*	*51*	*129*	*191*	*128*	*99*	*0*	***840***
Subtotal - NY	*81*	*1.0*	*2.4*	*65*	*11*	*8*	*0.4*	*0.0*	***169***
Subtotal - PA	*935*	*29*	*79*	*167*	*299*	*304*	*153*	*3.0*	***1968***
TOTAL - DRB	**1245**	**41**	**133**	**361**	**501**	**440**	**253**	**3**	**2977**

[a.] Land disturbance estimate computed by Method A (see table 5). Totals may not sum exactly due to rounding.

Table 13. Pipeline land area impact [acres] by watershed, Permanent ROW

Watershed (HUC)	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Grand Total
Upper Delaware	40.7	0.9	3.8	4.9	29.0	0.1	1.3	0.0	**80.7**
204010103	*40.7*	*0.9*	*3.8*	*4.9*	*29.0*	*0.1*	*1.3*		***80.7***
Middle Delaware	117.4	3.5	24.9	90.0	56.3	6.4	26.0	0.1	**324.6**
204010408	*4.2*		*0.4*	*0.5*	*1.3*	*0.4*		*0.0*	***6.8***
204010503	*5.1*	*0.4*	*7.6*	*11.5*	*0.4*	*2.6*	*0.1*		***27.7***
204010504	*6.0*	*0.3*	*1.2*	*3.2*	*0.5*	*0.2*	*0.3*		***11.7***
204010505	*3.8*	*0.3*	*0.8*	*3.4*	*1.5*	*0.3*	*0.2*		***10.3***
204010506	*15.9*	*0.2*	*5.6*	*21.6*	*7.2*	*1.2*	*3.3*	*0.1*	***55.0***
204010509	*82.4*	*2.4*	*9.3*	*49.9*	*45.4*	*1.9*	*22.0*		***213.2***
Lehigh	299.4	12.1	37.6	66.0	25.8	11.5	16.2	1.1	**469.7**
204010601	*30.9*	*2.8*	*5.0*	*0.7*	*0.5*			*0.5*	***40.5***
204010602	*82.9*	*7.0*	*2.4*			*0.5*	*9.7*	*0.1*	***102.7***
204010603	*63.9*	*1.8*	*7.3*	*0.2*	*2.4*	*0.3*			***75.9***
204010604	*50.6*		*7.1*	*0.0*	*3.8*	*0.3*	*0.6*	*0.3*	***62.7***
204010605	*34.0*	*0.4*	*3.9*	*1.1*	*9.2*	*3.3*	*1.6*	*0.2*	***53.9***
204010608	*36.9*	*0.1*	*11.9*	*63.9*	*9.8*	*7.1*	*4.2*		***134.1***
Crosswicks-Neshaminy	7.1	1.4	45.5	11.3	4.3	31.7	1.7	0.0	**103.0**
204020101	*4.6*	*0.9*	*33.3*	*6.9*	*3.6*	*26.0*	*0.9*		***76.1***
204020104	*2.4*	*0.5*	*12.2*	*4.4*	*0.8*	*5.7*	*0.8*		***26.9***
Lower Delaware	19.5	2.3	45.8	3.7	4.5	33.4	2.0	0.0	**111.2**
204020201	*0.1*		*2.6*			*4.3*	*0.0*		***7.0***
204020206	*19.4*	*2.3*	*43.2*	*3.7*	*4.5*	*29.1*	*1.9*		***104.2***
Schuylkill	44.9	0.5	13.7	19.4	17.2	20.4	9.1	0.1	**125.2**
204020303	*4.5*		*1.5*	*1.2*	*0.6*	*0.8*	*0.0*		***8.6***
204020304	*15.7*			*7.1*	*2.5*	*8.7*	*6.5*		***40.5***
204020306	*69.2*	*0.9*	*25.6*	*16.7*	*30.1*	*24.7*	*5.2*	*0.1*	***172.5***
204020307	*0.9*	*0.2*	*2.2*	*4.5*	*2.9*	*1.3*	*0.3*		***12.3***
204020310	*0.1*		*0.6*	*0.3*		*0.6*	*0.4*		***1.9***
Brandywine-Christina	26.5	1.2	26.9	9.3	15.6	25.6	7.9	0.0	**113.0**
204020501	*26.5*	*1.2*	*26.9*	*9.3*	*15.6*	*25.6*	*7.9*	*0.0*	***113.0***
TOTAL - DRB	**555**	**22**	**198**	**205**	**153**	**129**	**64**	**1**	**1327**

Table 14. Pipeline land area impact [acres] by watershed, Construction ROW.

Watershed (HUC)	Forest	Wetland	Grassland/Shrub	Ag - Pasture	Ag- Cultivated	Open Land	Developed	Water	Grand Total
Upper Delaware	80.7	1.5	8.1	11.1	65.0	0.4	2.4	0.0	**169.2**
204010103	*80.7*	*1.5*	*8.1*	*11.1*	*65.0*	*0.4*	*2.4*		***169.2***
Middle Delaware	271.6	7.0	56.4	223.9	133.0	16.1	53.6	0.3	**761.8**
204010408	*13.3*		*1.1*	*1.5*	*5.3*	*0.9*	*0.0*	*0.0*	***22.0***
204010503	*18.8*	*1.3*	*17.2*	*29.5*	*1.5*	*6.5*	*0.4*		***75.3***
204010504	*18.7*	*0.6*	*2.9*	*9.7*	*1.3*	*0.7*	*1.0*	*0.0*	***34.8***
204010505	*11.5*	*0.8*	*2.3*	*9.7*	*4.6*	*0.9*	*0.7*		***30.4***
204010506	*37.3*	*0.2*	*14.1*	*58.8*	*18.4*	*2.6*	*8.2*	*0.3*	***139.8***
204010509	*172.0*	*4.1*	*18.8*	*114.7*	*101.9*	*4.5*	*43.4*		***459.5***
Lehigh	660.0	22.3	91.3	153.4	60.1	23.3	27.4	2.8	**1040.6**
204010601	*77.8*	*5.0*	*12.4*	*1.8*	*1.3*		*0.0*	*1.3*	***99.6***
204010602	*186.6*	*13.2*	*5.5*			*1.1*	*14.3*	*0.1*	***220.8***
204010603	*130.1*	*2.8*	*16.0*	*0.4*	*5.6*	*1.0*	*0.0*		***155.8***
204010604	*109.9*		*21.4*	*0.2*	*10.0*	*0.6*	*1.3*	*0.3*	***143.7***
204010605	*79.7*	*0.7*	*9.7*	*2.9*	*22.7*	*7.0*	*3.2*	*0.9*	***126.9***
204010608	*76.0*	*0.6*	*26.3*	*148.1*	*20.5*	*13.6*	*8.6*	*0.2*	***293.8***
Crosswicks-Neshaminy	15.7	2.7	79.6	29.8	11.4	58.4	3.1	0.0	**200.6**
204020101	*11.1*	*1.5*	*57.9*	*18.7*	*8.9*	*45.8*	*1.6*		***145.6***
204020104	*4.5*	*1.2*	*21.6*	*11.1*	*2.5*	*12.6*	*1.6*		***55.0***
Lower Delaware	34.9	4.2	93.1	9.7	11.8	73.7	4.8	0.0	**232.2**
204020201	*0.5*		*3.6*			*9.6*	*0.4*		***14.1***
204020206	*34.3*	*4.2*	*89.4*	*9.7*	*11.8*	*64.1*	*4.5*		***218.1***
Schuylkill	118.4	1.6	35.5	46.4	44.6	50.4	21.6	0.1	**318.6**
204020303	*13.3*		*3.2*	*3.6*	*1.4*	*1.6*	*0.0*		***23.2***
204020304	*33.1*		*0.0*	*15.9*	*5.6*	*19.2*	*15.1*		***88.9***
204020306	*69.2*	*0.9*	*25.6*	*16.7*	*30.1*	*24.7*	*5.2*	*0.1*	***172.5***
204020307	*2.4*	*0.7*	*4.6*	*9.7*	*7.4*	*3.0*	*0.4*		***28.2***
204020310	*0.4*		*2.1*	*0.6*		*1.9*	*1.0*		***5.9***
Brandywine-Christina	63.9	2.7	59.8	25.0	36.7	49.0	17.2	0.1	**254.4**
204020501	*63.9*	*2.7*	*59.8*	*25.0*	*36.7*	*49.0*	*17.2*	*0.1*	***254.4***
TOTAL - DRB	**1245**	**41**	**424**	**499**	**363**	**271**	**130**	**3**	**2977**

Table 15. Stream crossings by HUC-10 watershed: total, shared (potentially, with existing crossings), and new (=total – shared)

Watershed (HUC10 #)	Total	Shared	New
Upper Delaware	11	0	11
204010103	*11*		*11*
Middle Delaware	39	15	24
204010408[a]			*0*
204010503	*6*	*6*	*0*
204010504	*3*	*3*	*0*
204010505	*3*	*3*	*0*
204010506	*6*	*3*	*3*
204010509	*21*	*0*	*21*
Lehigh	58	42	16
204010601	*13*	*13*	*0*
204010602	*20*	*19*	*1*
204010603	*4*	*4*	*0*
204010604	*9*	*4*	*5*
204010605	*4*	*2*	*2*
204010608	*8*		*8*
Crosswicks-Neshaminy	8	0	8
204020101	*5*		*5*
204020104	*3*		*3*
Lower Delaware	15	7	8
204020201	*0*		*0*
204020206	*15*	*7*	*8*
Schuylkill	18	8	10
204020303	*2*		*2*
204020304	*2*		*2*
204020306	*12*	*6*	*6*
204020307	*2*	*2*	*0*
204020310			*0*
Brandywine-Christina	26	20	6
204020501	*26*	*20*	*6*
TOTAL - DRB	**175**	**92**	**83**

[a.] HUC10 numerical codes shown grouped by HUC8 name. This HUC10 is in the Middle Delaware-Mongaup-Brodhead HUC8. The remaining HUC10s in this grouping are in the Middle Delaware-Musconetcong HUC8.

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« Natural Gas Price Increase Inevitable in 2016

Posted in The Petroleum Truth Report on February 21, 2016

Every week, the EIA proclaims a new record for natural gas production. But their own forecasts show that the U.S. will be short on supply by October of this year. A price increase is inevitable beginning later in 2016.

Popular Myth vs Reality

The popular myth is that gas production will continue to increase and that prices will remain low for years. In the myth, price has no effect on production. The reality is that price matters and production is down 1.2 bcfd1 since September 2015 (Figure 1).

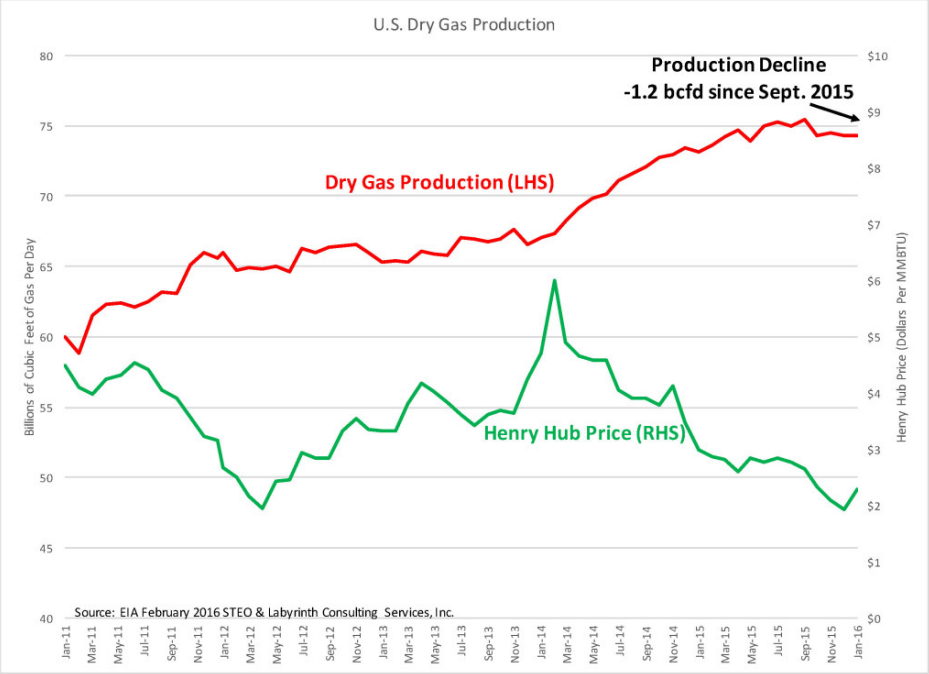

Figure 1. U.S. dry gas production. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

The production increases reported by EIA are year-over-year comparisons that don't reflect declines during the last 4 months.

Prices have fallen to less than half what they were in early 2014. The average price for the first quarter of 2016 is only $2.25 per MBTU2 (Figure 2).

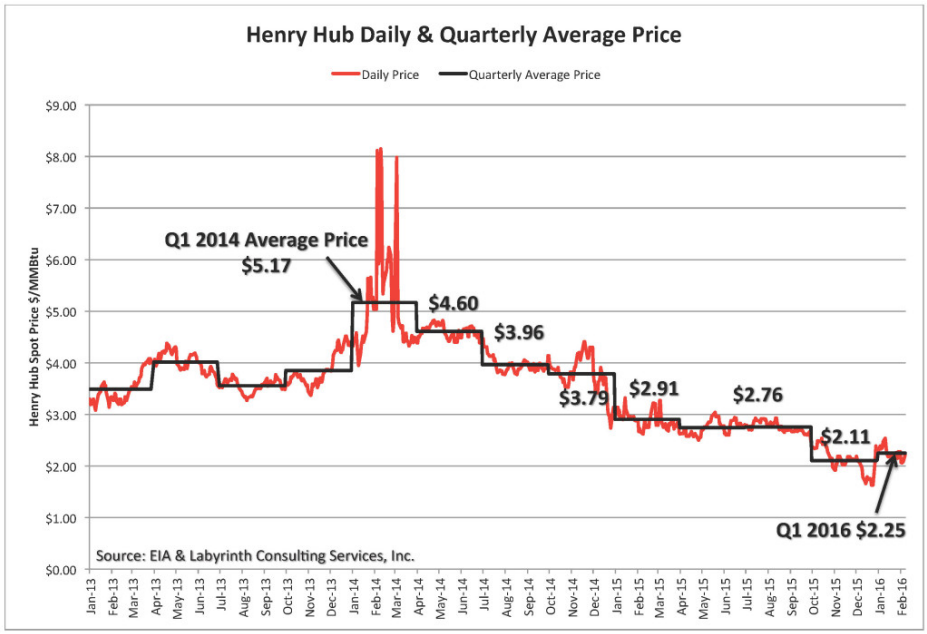

Figure 2. Henry Hub daily and quarterly average natural gas prices. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

Hedges made when prices were in the $5-range carried many companies through falling prices as they continued to produce like there was no tomorrow. Tomorrow has arrived and the hedges are gone.

Over-production in the Marcellus Shale means that producers have to compete for limited pipeline capacity by deeply discounting their sales price. The best core area locations are commercial at $4 per mcf3 but wellhead prices averaged only $1.75 per mcf in 2015.

No Simple Solution to Falling Supply

There is no simple solution to falling supply. That's because almost half

of U.S. supply is conventional gas and it is in terminal decline. Now, shale gas is also in decline (Figure 3).

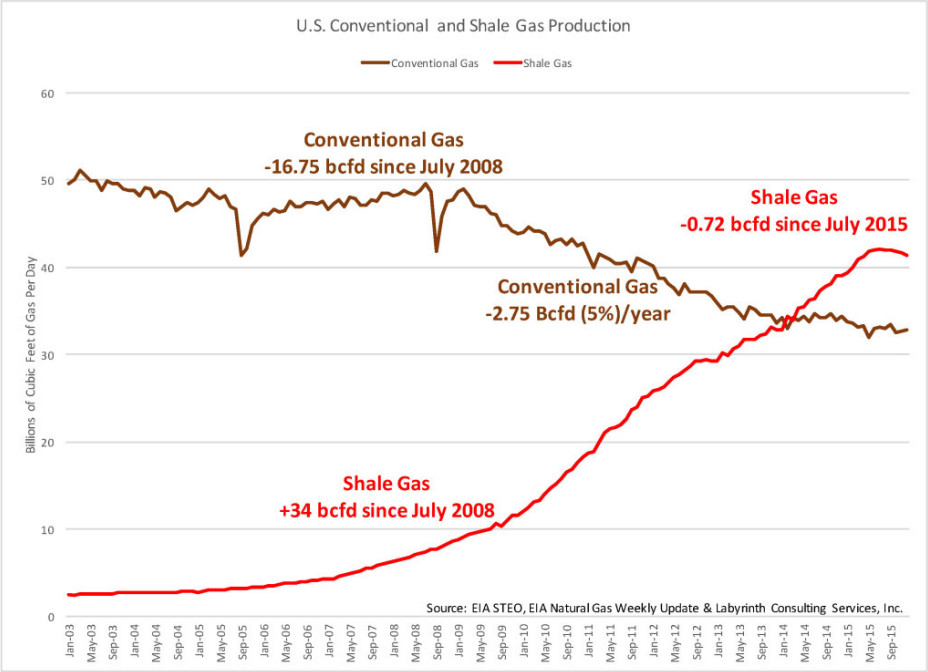

Figure 3. U.S. conventional and shale gas production. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

Conventional gas supply has fallen 16.75 bcfd since July 2008. Until July 2015, increases in shale gas production more than offset those losses.

Conventional gas will continue to decline at about 5% per year because few companies are drilling those plays. Shale gas must, therefore, continue to grow by at least 15 bcfd per year just to offset annual conventional gas decline (~2.5 bcfd per year) and legacy shale gas production decline (~12.5 bcfd per year).

It will take 15 bcfd of new shale gas production in 2016 to keep U.S. production *flat*.

Shale gas production replacement and growth for 2015 were 14.5 bcfd, down from almost 18 bcfd in 2014. It will be difficult to match 14.5 bcfd in 2016 because shale gas production has been falling 0.72 bcfd (~2.2 bcfd annualized) for the last 4 months of data (Figure 4).

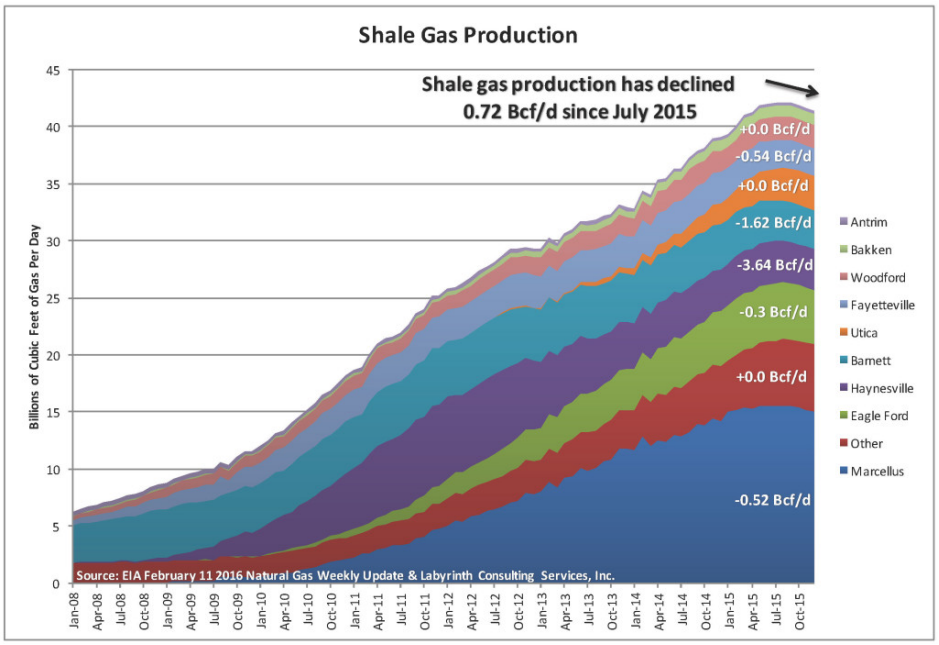

Figure 4. Shale gas production. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

The biggest declines since peak production are from the older "legacy" shale gas plays namely, the Barnett, Fayetteville and Haynesville (Table 1).

Billions of Cubic Ft/Day	Haynesville	Barnett	Fayetteville	Marcellus	Eagle Ford	Antrim	Bakken	Other	Utica	Woodford	Total
Maximum Production	7.21	5.01	2.90	15.57	5.02	0.34	0.99	5.94	3.07	2.09	48.13
Dec. 2015 Production	3.57	3.39	2.36	15.05	4.73	0.24	0.94	5.94	3.07	2.09	41.37
Change	-3.64	-1.62	-0.54	-0.52	-0.30	-0.10	-0.04	0.00	0.00	0.00	-6.76

Table 1. Summary table of shale gas volume changes since peak production. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

Although additional reserves exist in the Barnett and Fayetteville plays, the core areas have been largely developed and marginal areas require substantially higher gas prices to be commercial. There is only one horizontal rig operating in the Barnett and there are none in the Fayetteville.

Production in the Haynesville Shale has decreased by 3.64 bcfd since its peak. High costs and relatively low EURs make the play uneconomic below about $6.50 gas prices. Parts of the core areas remain under-developed at today's prices.

Marcellus production declined 0.52 mcfd since July 2015. Most of this

probably represented intentional shut-ins because of low wellhead prices. Marcellus production can grow but new pipelines are needed to turn reserves into supply. Even with additional infrastructure, production will peak in the next few years just like in the older plays.

Production in the Utica and Woodford plays is increasing but it is largely offset by declining associated gas from the Eagle Ford, Bakken and other tight oil plays.

A Supply Deficit Even In The Optimistic EIA Case

The EIA forecasts that net dry gas production will increase 1.4 bcfd in 2016 and 1.6 bcfd 2017. Even with that optimistic forecast, their data still shows that the U.S. will have a supply deficit beginning in the last quarter of 2016 (Figure 5). A more realistic forecast implies a much greater deficit that begins sooner.

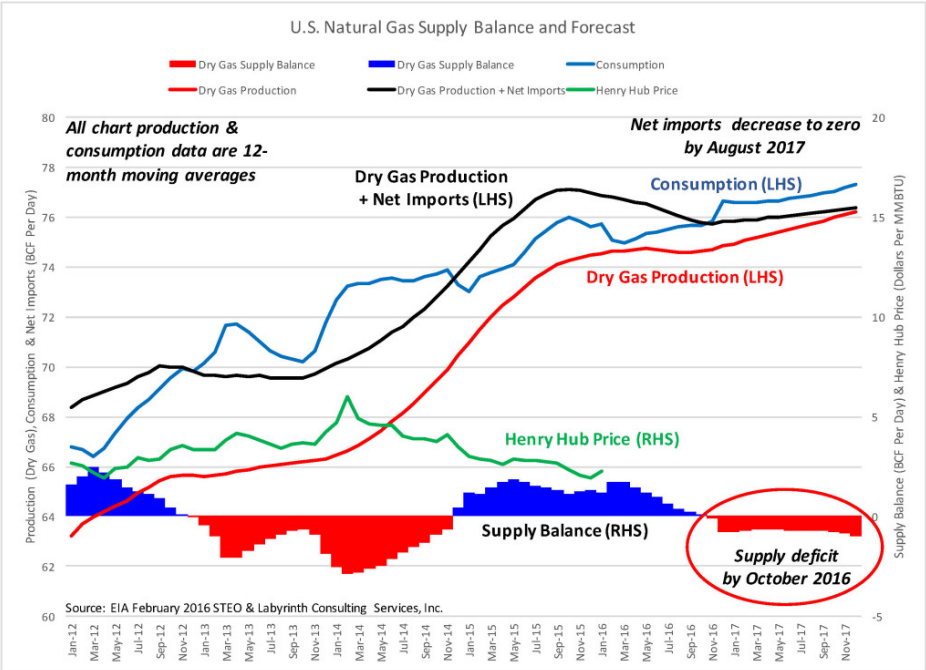

Figure 5. U.S. natural gas supply balance and forecast. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

A supply deficit does not mean that there won't be enough gas. There is ample gas presently in storage to cover a supply shortfall for awhile. That is what happened during the supply deficit in 2013-2014 (Figure 5). That deficit was created by flat production similar to what EIA predicts for the first 3 quarters of 2016.

What is different this time, however, is that *net* imports will reach zero in early 2017 because of decreasing imports from Canada and increasing exports. Add to that the challenge of replacing conventional gas depletion, and there is a much more serious supply problem than EIA's already questionable forecast suggests.

Another big difference is that in 2013-2014, capital was freely available with average oil prices above $90 per barrel and average gas prices more than $4 per MBTU. Today, the oil and gas industry is in financial shambles with both oil and gas prices at very low levels, and it is unlikely that companies can raise the capital necessary to ramp up gas drilling quickly if at all.

Export plans of at least 7 bcfd by 2020 are not helpful considering the challenges of meeting domestic supply in coming years (Figure 6).

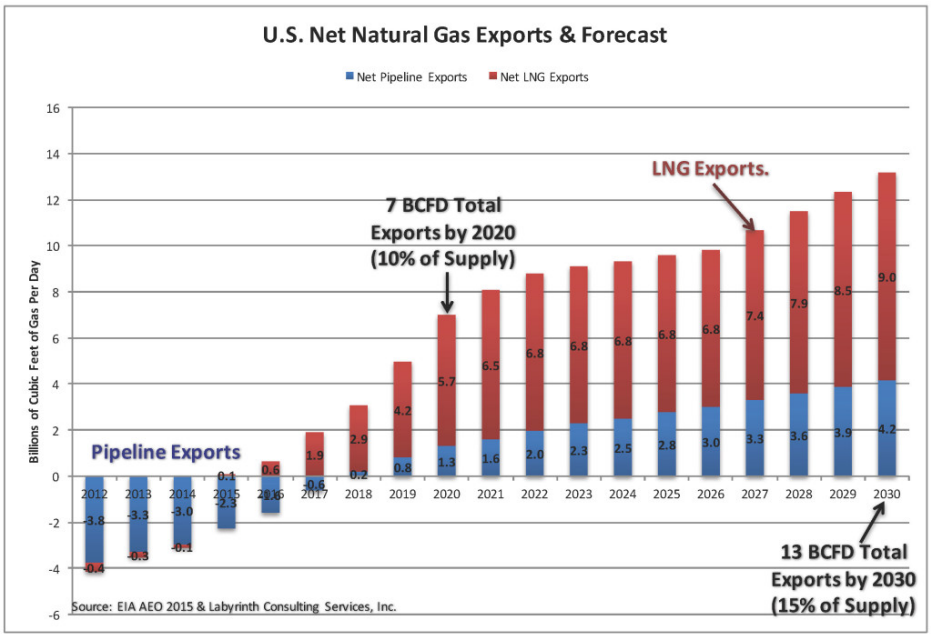

Figure 6. U.S. net natural gas exports. Source: EIA and Labyrinth Consulting Services, Inc.
(Click image to enlarge)

The prospect of exports increasing to 13 bcfd by 2030 is even more troubling absent some new shale gas play that we don't know about yet.

Higher Gas Prices Are Inevitable

A few years ago, the oil and gas industry convinced the world that the U.S. had 100 years of natural gas. Some of us cautioned that it is worth reading the fine print, that there is a difference between a

resource and a reserve. The harsh light of reality eventually reveals that what seems too good to be true usually is.

The obvious solution to declining gas supply is higher prices.

The EIA's STEO forecast calls for $3.17 per MBTU gas prices by December 2016 and for $3.62 by December 2017. Those prices will not support necessary drilling in legacy shale gas plays. EIA's AEO 2015 reference case does not call for gas prices to reach $5 per mcf until 2025. We can't afford to wait 9 years.

It is, therefore, inevitable that natural gas prices must increase sooner, preferably in the next 12 to 24 months. If oil prices remain low, a shale-gas revival may save the domestic E&P business. During the last supply deficit in 2014, gas prices averaged $4.36 per mcf compared to only $2.63 in 2015.

But it will take time for producers to reverse the decline in drilling and production. It may be difficult to raise capital for renewed drilling given the current distress in the oil and gas industry.

Something will have to give sooner than later. That will be natural gas export.

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1 billion cubic feet of gas per day
2million British thermal units, approximately 1000 cubic feet of gas
3thousand cubic feet of gas

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42 comments on this entry

1. On February 22nd, 2016 at 3:56 am from Dean

   Thanks for the interesting post. Is it possible to know what is the percentage of associate gas from oil wells over total dry gas production ? Thanks,Dean

2. On February 22nd, 2016 at 8:54 am from Arthur Berman

   Dean,

   The EIA publishes production data for gas production from oil wells and, specifically, the gas production from the main tight oil plays. Also, there is a weekly update on shale gas production that includes gas from tight oil plays.

   All the best,

   Art

3. On February 22nd, 2016 at 6:49 am from Cloud9

   If prices don't go up, we are cooked. The real question is has the EROEI reached the tipping point?

4. On February 22nd, 2016 at 9:00 am from Arthur Berman

   Cloud9,

   EROI or net energy is difficult to know. Getting reliable and consistent data on this has been frustrating to the researchers also.

   Net energy is a critical factor and is unfortunately best understood with basic economics. Most shale gas production is non-commercial at current gas prices. That is a proxy for an imbalance in net energy. Quantifying how the loss in net present value relates to net energy is another thing.

   Thanks for your question,

   Art

5. On February 22nd, 2016 at 10:17 am from Mike

   Art,

   I'm curious as to what effect the Permian associated gas has on this metric?

   Mike

6. On February 22nd, 2016 at 12:10 pm from Arthur Berman

   Mike,

   What metric are you referring to? Net energy (EROI) or the contribution to total gas production from gas associated with tight oil production?

   The Permian basin is complicated because almost no production is from shale. Most of the production using horizontal drilling and hydraulic fracturing is from 3 conventional oil plays: Wolfcamp, Spraberry and Bone Spring. Oil and gas production in the Permian basin peaked in 1974 at 2.3 mmbpd and 10.4 bcfd, respectively. Today, oil production has recovered to 2 mmbpd and gas, to 7 bcfd.

   Wolfcamp-Spraberry-Bone Spring gas production is 3.1 bcfd and oil production is 0.9 mmbpd. This is the production that people

should focus on. 3 bcfd is comparable to the Barnett, Utica and Haynesville but less than the Eagle Ford or Marcellus (see table 1 in my current post). It is 4% of total dry gas production.

Let me know if this is the answer you are looking for if there is some other metric you are asking about.

Art

7. On February 22nd, 2016 at 12:19 pm from Terrel Shields

   Do you think the gas heavy players (SWN, CHK, etc.) can "ramp up" gas production if prices improve? It seems to me that financing may play a role. We are now down to zero rigs in the Fayetteville (in fact, in the whole state of Arkansas) and many of these rigs are in mothballs. I don't see where SWN is going to scrape up the cash to really bring back a lot of rigs in say the Fayetteville.

8. On February 22nd, 2016 at 12:22 pm from Arthur Berman

   Terrel,

   I agree with you. I don't think that it will be easy to raise capital to ramp up shale gas drilling–certainly not with the E&P business in its current mess. In a few years with higher gas prices, yes.

   All the best,

   Art

9. On February 23rd, 2016 at 4:56 am from TaylorScott

   Art, thank you so much for sharing your data driven and factual knowledge of all manner oil and gas industry. It is invaluable and I am grateful that you are gracious to share it with the public. As a 30 year veteran of the oil and gas industry I have never read more accurate, forthright and valuable articles. Please continue to write so we may all learn the truth about the complex oil and gas industry. Scott.

10. On February 23rd, 2016 at 9:22 pm from Arthur Berman

    Scott,

Thanks for those supportive comments!

All the best,

Art

11. On February 23rd, 2016 at 1:47 pm from Dave

    Art,

    Thoughtful commentary – thank you. With all the money from Private Equity and to a large extent, plentiful supply still coming from the public market, would there likely be a quick response to higher prices w/ increased drilling bringing new production on-line quickly, plus efficiency gains (lower drilling and completion costs), plus DUC's leading a muted price response and/or the proclivity for producers to hedge future too quickly after sustained low prices?

12. On February 23rd, 2016 at 9:28 pm from Arthur Berman

    Dave,

    I believe that the capital for shale gas and tight oil is largely gone although we see some last gasps like the Devon and Pioneer equity offerings. I don't think it will come back quickly either. The debacle in the banking business with energy debt is just beginning, and it will be ugly and may spill over into other markets. The bankruptcies will be sobering as well.

    Most of the talk about efficiency gains and DUCs is noise to distract from the truth that the companies are losing their asses. Everyone has been wrong about when the bubble will finally deflate so I don't want to be too adamant but I believe the U.S. E&P business is injured more than many realize. That's not good news.

    All the best,

    Art

13. On February 23rd, 2016 at 6:49 pm from David Ryan

    Art, can you give me a ballpark estimate of what you think gas prices might rise to before we see a supply response?

Thank you sir

14. On February 23rd, 2016 at 9:30 pm from Arthur Berman

    David,

    I don't do price forecasts. I stated in the post that prices averaged more than $4/mcf during the last supply deficit during 2012-2013. That's not a bad guideline but really, a lot depends on weather and the economy.

    All the best,

    Art

15. On February 23rd, 2016 at 10:24 pm from PaOil

    Hi Art,

    As always, thank you for your solid work. In the Marcellus/Utica there remain a number of completed but shut-in wells. A number frequently discussed in the industry is 1200 to 2000 such wells. (These are in addition to DUC's.)

    If that number is in the ballpark, and if they are shut in due to either pipeline constraint or pricing, they are presumably able to come on line when heightened demand frees up pipeline capacity or lifts pricing.

    How have shut in wells factored into your thinking and is 1000+ consistent with information you are hearing about the Marcellus/Utica? Are completed but shut in wells a factor in any other play?

    Thanks. Always look forward to your research and perspective.

16. On February 24th, 2016 at 5:45 am from Arthur Berman

    PaOil,

    During the fall in rig count after the Financial Collapse a few years ago, there were all kinds of articles speculating that there were thousands of shut-in and waiting-on-completion wells that would overwhelm supply. At one point, I saw an estimate of 12,000 of these wells. Although there were unquestionably many

valid cases of spare capacity wells, the outcome was like Y2K–much ado about little.

Shut-in and WOC wells represent poor planning and management of capital. They also appear to be a normal part of the development cycle for shale companies as drilling exceeds the availability of completion crews and take-away infrastructure. It is no surprise that chronically cash-flow negative companies are poorly managed.

I have no idea how many spare capacity wells there are in the Marcellus. The real question is, What is the normal, ambient backlog of these wells and how do current guesses about their numbers compare to those levels?

There are a host of issues that the industry and pandering analysts throw out to the public to distract from the reality that the shale gas plays are not commercial. DUCs are a sure bet to get people's attention. Drilling efficiency is another. We must be diligent to separate the signal from the noise.

If there is spare capacity production in the Marcellus, it will need pipeline capacity to reach sales. I don't see a lot of new capacity getting added with the E&P industry in shambles and the overall economy weak but I could be wrong. I suspect that most renewed pipeline approval and construction will have to wait on higher gas prices and suppliers in a stronger financial position to deliver on send-or-pay commitments.

I don't envision gas prices rising to the $6-8 level. Coal vs gas pricing creates a ceiling. Prices above $4 would not surprise me in the coming few quarters.

All the best,

Art

17. On February 23rd, 2016 at 10:25 pm from Dave

Thanks Art,

There could be a view that all the dry powder from Energy Private Funds raised will prolong the glut beyond what seems reasonable or rational. Today, a SPAC backed by Riverstone (Silver Run) raised $450MM to buy distressed companies in the

E&P space and there is north of $125bn of dry powder for PE firms to invest (Preqin) in energy and over 200 funds raising fresh capital at the moment, the demand remains high. It will be interesting to see how well this new money gets put to work.

18. On February 24th, 2016 at 5:22 am from Bradley

    Dean,

    I was looking for the same info today and according to this it is 8% and in 2014 represented 33% of the nat gas growth. http://www.reuters.com/article/us-energy-natgas-shale-idUSKBN0IP03D20141105

19. On February 24th, 2016 at 5:46 am from Bradley

    Thank you Art,

    Your predictions have really been on point for the last year (the period I have been following your articles) and your insight has been a great help. BTW I think the figures from the article I posted above are incorrect when bumped up against EIA's data. No surprise.

    Question: What effects do you believe the increasing bankruptcies (40 or so last year) will have on Natural Gas production? I have read some terminate drilling but some do not.

    Bradley

20. On February 24th, 2016 at 5:55 am from Arthur Berman

    Bradley,

    I was on a panel at UT Austin last week for UT Energy Week and the other panelists were energy economists, hedge fund managers and E&P financial people. They agreed that more than 30% of U.S. oil and gas companies will go bankrupt in 2016. That will have a huge effect on drilling, production and pipeline construction. Bankruptcy allows all contracts to be ignored, I believe—drilling, send-or-pay, etc.

    Please see this recent article "As U.S. shale sinks, pipeline fight sends woes downstream" on energy bankruptcies.

All the best,

Art

21. On February 24th, 2016 at 12:05 pm from Clueless

    Your comment on fig 3: "Conventional gas supply has fallen 16.75 bcfd since July 2008. Until July 2016, increases in shale gas production more than offset those losses."

    Should that be until July 2015?

22. On February 24th, 2016 at 12:20 pm from Arthur Berman

    Clueless,

    Thanks for noticing that error. It is fixed now.

    All the best,

    Art

23. On February 24th, 2016 at 12:48 pm from Martin

    Wow, you guys are amazing! Thank you Art for all the insight and substantive details you share with us. I have learnt so much with you in the last few years.

    All the comments here are also spot on. I had some questions but you beat me to the smart ones.

    Thank you,

    Martin

24. On February 24th, 2016 at 1:49 pm from Sergey

    Hello Art,

    I've been reading your articles for a while. Thank you for providing such usefull and consistent information. One question arises though: according to the last few EIA's natural gas weekly updates, production of dry gas has risen almost 6% for the last 1.5-2 month. However, there is no such information in Drilling Productivity Report. In the report for week ending February 10

they say that "New Northeast pipelines help boost gas production 18%", but it only explains 4% growth max.

I would be really greatful if you could privide some comments on that.

All the best,

Sergey

25. On February 24th, 2016 at 5:25 pm from Arthur Berman

Sergey,

EIA's most recent Short-Term Energy Report shows both dry gas and marketed gas for January 2016 lower by more than 1 bcfd from peak levels in September 2015.

In the Monthly Energy Review, EIA cites Bentek as the source of higher gas production. Bentek measures pipeline flows and is a long-time sycophant of the natural gas-shale gas business. Obviously, EIA thinks enough of their work to mention them in the MER but not enough to include their data in the STEO.

The main new northeast pipeline capacity is from the Rockies Express that has been reversed to take 0.55 bcfd of gas west from Pennsylvania and Ohio. Columbia, Tennessee and Tetco also completed pipeline expansions that will carry another 1.3 bcfd. I assume that this new capacity is included in the January STEO data so I cannot really address your questions except to say that when I see the increase in the February STEO, I will report it. I do not have a partisan position about Marcellus gas and am just summarizing the patterns that I see in the EIA data.

All the best,

Art

26. On February 25th, 2016 at 10:13 am from Terrel Shields

You mentioned the damage done to the industry will be severe. One of the old timers (in other words, my age group) I visit with regularly will be spudding a well soon and he mentioned that the companies hired are cheap now but he expects costs to rise because the more rigs that lay down, the more companies go

under, then there won't be that many rigs to choose from. In fact, those high dollar rigs are mostly doomed in his mind. They may never drill another well and are headed for the scrap pile. So I am pretty confident that this shake out will seriously impact the service sector at least as much as the explorers. If the glut shrinks fast, and power plants ramp up gas consumption for electric production at the expense of coal (which suffers from Presidential headwinds) then it suggests natural gas could pop upwards and new drilling isn't going to fuel a glut for some time. The recovery may be very slow, even beside the fact the banks are being toasted dark brown and won't be so eager to lend.

– "We can't just drill our way to lower gas prices," Later in his speech, he added: "anybody who tells you that we can drill our way out of this problem doesn't know what they're talking about, or just isn't telling you the truth." "You can bet that since it is an election year, they're already dusting off their three-point plans for $2 gas. I'll save you the suspense: Step one is drill, step two is drill, step three is drill." – Obama 4 years ago (thanks for the quote to Marita Noon, energy columnist)

27. On February 25th, 2016 at 4:15 pm from Shale Gov Bailout 4 exports? O&G growth needs ave $65/bbl & $6.5/Mcf | Arlington TX Barnett Shale Blogger

    […] Berman said on 2/21/16 that the price of natural going up is inevitable. […]

28. On February 27th, 2016 at 3:52 pm from Joseph Wells

    Art, great article. You nailed it. The sooner than later price increase will be between now and July 2016. I made a similar prediction in the following article. My forecast was made by computer model where production of all wells was determined theoretically based on past drilling activity. The process also depends on production curves and published EIA drilling rig productivity and results in production that is amazingly close to EIA records. By playing with the model I was also able to deduce that the overall effect DUCs is very small. BTW I'm just an engineer who recently took an interest in natural gas because of the wild swing happening right now.

    http://seekingalpha.com/article/3911266-2016-oil-natural-gas-production-storage-forecasts

29. On March 6th, 2016 at 2:15 pm from Dan Steffens

    Horizontal oil wells in four major oil producing regions (Bakken, Eagle Ford, Niobrara and Permian Basin) produced about 8 Bcf per day in 2015. Gas from all four is now on steep decline.

30. On March 7th, 2016 at 4:38 pm from Arthur Berman

    Dan,

    Niobrara and Eagle Ford have certainly declined a lot. Shale gas is down 0.7 bcf/d excluding Barnett, Fayetteville and Haynesville–with them, its 6.7 bcfd.

    Thanks for your comments,

    Art

31. On March 10th, 2016 at 2:56 pm from Flint Ogle

    Great analysis, Mr. Berman. Regarding your figure 5, are you somehow normalizing the data (I assume drawn partially from table 5a in the EIA STEO)? I created a similar chart from the data in the March STEO just out, and it is far choppier… Thanks for any input. Flint

32. On March 10th, 2016 at 7:12 pm from Flint Ogle

    Regarding my prior question, please disregard. Just noticed the note on figure 5 regarding moving averages…

33. On April 7th, 2016 at 5:25 pm from Why Natural Gas Prices Could Double From Here | Energy News Corporation

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. As a result, the […]

34. On April 8th, 2016 at 4:48 am from Natural Gas Prices Should Double | Energy News

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the

past 15 years. As a result, the […]

35. On April 8th, 2016 at 12:04 pm from Why Natural Gas Prices Could Double From Here | CAPITOL ZERO

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. As a result, the […]

36. On April 8th, 2016 at 2:39 pm from Why Natural Gas Prices Could Double From Here | Political American

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. As a result, the […]

37. On April 12th, 2016 at 11:33 am from Why Natural Gas Prices Will Surge Over The Next Year | Oil News

    […] 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. […]

38. On April 18th, 2016 at 1:20 pm from Why Natural Gas Prices Could Double From Here – ValuBit

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. As a result, the […]

39. On June 14th, 2016 at 11:32 am from Solar Thermal – a Strategic Vision – Solar UV Solutions

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. As a result, the […]

40. On July 28th, 2016 at 5:51 am from Kinder Morgan: Don't Be Disappointed | Energy Traders

[…] decline in natural gas production is due to lower shale gas production and conventional gas that has either stopped growing or have been declining in the past few years. […]

41. On August 5th, 2016 at 7:38 am from Art P

    Hi Art,

    Any concerns with the strong import volumes from Canada we've been seeing? "What is different this time, however, is that net imports will reach zero in early 2017 because of decreasing imports from Canada and increasing exports."

    Cheers,
    A fellow Art

42. On August 15th, 2016 at 2:58 pm from Chesapeake Energy Corporation, United States Natural Gas Fund, LP, Cheniere Energy, Inc.: Why Natural Gas Prices Will Surge Over The Next Year | ETF DAILY NEWS

    […] October 2015* because gas production is flat, imports are decreasing and exports are increasing. Shale gas production has stopped growing and conventional gas has been declining for the past 15 years. As a result, […]

EXECUTIVE OFFICE OF THE PRESIDENT
COUNCIL ON ENVIRONMENTAL QUALITY
WASHINGTON, D.C. 20503

August 1, 2016

MEMORANDUM FOR HEADS OF FEDERAL DEPARTMENTS AND AGENCIES

FROM: CHRISTINA GOLDFUSS
COUNCIL ON ENVIRONMENTAL QUALITY

SUBJECT: Final Guidance for Federal Departments and Agencies on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews

I. INTRODUCTION

The Council on Environmental Quality (CEQ) issues this guidance to assist Federal agencies in their consideration of the effects of greenhouse gas (GHG) emissions[1] and climate change when evaluating proposed Federal actions in accordance with the National Environmental Policy Act (NEPA) and the CEQ Regulations Implementing the Procedural Provisions of NEPA (CEQ Regulations).[2] This guidance will facilitate compliance with existing NEPA requirements, thereby improving the efficiency and consistency of reviews of proposed Federal actions for agencies, decision makers, project proponents, and the public.[3] The guidance provides Federal agencies a common

[1] For purposes of this guidance, CEQ defines GHGs in accordance with Section 19(m) of Exec. Order No. 13693, Planning for Federal Sustainability in the Next Decade, 80 Fed. Reg. 15869, 15882 (Mar. 25, 2015) (carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, nitrogen trifluoride, and sulfur hexafluoride). Also for purposes of this guidance, "emissions" includes release of stored GHGs as a result of land management activities affecting terrestrial GHG pools such as, but not limited to, carbon stocks in forests and soils, as well as actions that affect the future changes in carbon stocks. The common unit of measurement for GHGs is metric tons of CO_2 equivalent (mt CO_2-e).
[2] *See* 42 U.S.C. 4321 et seq.; 40 CFR Parts 1500–1508.
[3] This guidance is not a rule or regulation, and the recommendations it contains may not apply to a particular situation based upon the individual facts and circumstances. This guidance does not change or substitute for any law, regulation, or other legally binding

approach for assessing their proposed actions, while recognizing each agency's unique circumstances and authorities.[4]

Climate change is a fundamental environmental issue, and its effects fall squarely within NEPA's purview.[5] Climate change is a particularly complex challenge given its global nature and the inherent interrelationships among its sources, causation, mechanisms of action, and impacts. Analyzing a proposed action's GHG emissions and the effects of climate change relevant to a proposed action—particularly how climate change may change an action's environmental effects—can provide useful information to decision makers and the public.

CEQ is issuing the guidance to provide for greater clarity and more consistency in how agencies address climate change in the environmental impact assessment process. This guidance uses longstanding NEPA principles because such an analysis should be similar to the analysis of other environmental impacts under NEPA. The guidance is intended to assist agencies in disclosing and considering the reasonably foreseeable effects of proposed actions that are relevant to their decision-making processes. It confirms that agencies should provide the public and decision makers with explanations of the basis for agency determinations.

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requirement, and is not legally enforceable. The use of non-mandatory language such as "guidance," "recommend," "may," "should," and "can," is intended to describe CEQ policies and recommendations. The use of mandatory terminology such as "must" and "required" is intended to describe controlling requirements under the terms of NEPA and the CEQ regulations, but this document does not affect legally binding requirements.

[4] This guidance also addresses recommendations offered by a number of stakeholders. *See* President's State, Local, and Tribal Leaders Task Force on Climate Preparedness and Resilience, *Recommendations to the President* (November 2014), p. 20 (recommendation 2.7), *available at* www.whitehouse.gov/sites/default/files/docs/task_force_report_0.pdf; U.S. Government Accountability Office, *Future Federal Adaptation Efforts Could Better Support Local Infrastructure Decision Makers*, (Apr. 2013), *available at* http://www.gao.gov/assets/660/653741.pdf. Public comments on drafts of this guidance document are available at http://www.whitehouse.gov/administration/eop/ceq/initiatives/nepa/comments.

[5] NEPA recognizes "the profound impact of man's activity on the interrelations of all components of the natural environment." (42 U.S.C. 4331(a)). It was enacted to, *inter alia,* "promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man." (42 U.S.C. 4321).

Focused and effective consideration of climate change in NEPA reviews[6] will allow agencies to improve the quality of their decisions. Identifying important interactions between a changing climate and the environmental impacts from a proposed action can help Federal agencies and other decision makers identify practicable opportunities to reduce GHG emissions, improve environmental outcomes, and contribute to safeguarding communities and their infrastructure against the effects of extreme weather events and other climate-related impacts.

Agencies implement NEPA through one of three levels of NEPA analysis: a Categorical Exclusion (CE); an Environmental Assessment (EA); or an Environmental Impact Statement (EIS). This guidance is intended to help Federal agencies ensure their analysis of potential GHG emissions and effects of climate change in an EA or EIS is commensurate with the extent of the effects of the proposed action.[7] Agencies have discretion in how they tailor their individual NEPA reviews to accommodate the approach outlined in this guidance, consistent with the CEQ Regulations and their respective implementing procedures and policies.[8] CEQ does not expect that implementation of this guidance will require agencies to develop new NEPA implementing procedures. However, CEQ recommends that agencies review their NEPA procedures and propose any updates they deem necessary or appropriate to facilitate their consideration of GHG emissions and climate change.[9] CEQ will review agency

[6] The term "NEPA review" is used to include the analysis, process, and documentation required under NEPA. While this document focuses on NEPA reviews, agencies are encouraged to analyze GHG emissions and climate-resilient design issues early in the planning and development of proposed actions and projects under their substantive authorities.
[7] *See* 40 CFR 1502.2(b) (Impacts shall be discussed in proportion to their significance); 40 CFR 1502.15 (Data and analyses in a statement shall be commensurate with the importance of the impact…).
[8] *See* 40 CFR 1502.24 (Methodology and scientific accuracy).
[9] *See* 40 CFR 1507.3. Agency NEPA implementing procedures can be, but are not required to be, in the form of regulation. Section 1507.3 encourages agencies to publish explanatory guidance, and agencies also should consider whether any updates to explanatory guidance are necessary. Agencies should review their policies and implementing procedures and revise them as necessary to ensure full compliance with NEPA.

proposals for revising their NEPA procedures, including any revision of CEs, in light of this guidance.

As discussed in this guidance, when addressing climate change agencies should consider: (1) The potential effects of a proposed action on climate change as indicated by assessing GHG emissions (e.g., to include, where applicable, carbon sequestration);[10] and, (2) The effects of climate change on a proposed action and its environmental impacts.

This guidance explains the application of NEPA principles and practices to the analysis of GHG emissions and climate change, and

- Recommends that agencies quantify a proposed agency action's projected direct and indirect GHG emissions, taking into account available data and GHG quantification tools that are suitable for the proposed agency action;
- Recommends that agencies use projected GHG emissions (to include, where applicable, carbon sequestration implications associated with the proposed agency action) as a proxy for assessing potential climate change effects when preparing a NEPA analysis for a proposed agency action;
- Recommends that where agencies do not quantify a proposed agency action's projected GHG emissions because tools, methodologies, or data inputs are not reasonably available to support calculations for a quantitative analysis, agencies include a qualitative analysis in the NEPA document and explain the basis for determining that quantification is not reasonably available;

[10] Carbon sequestration is the long-term carbon storage in plants, soils, geologic formations, and oceans.

- Discusses methods to appropriately analyze reasonably foreseeable direct, indirect, and cumulative GHG emissions and climate effects;
- Guides the consideration of reasonable alternatives and recommends agencies consider the short- and long-term effects and benefits in the alternatives and mitigation analysis;
- Advises agencies to use available information when assessing the potential future state of the affected environment in a NEPA analysis, instead of undertaking new research that is , and provides examples of existing sources of scientific information;
- Counsels agencies to use the information developed during the NEPA review to consider alternatives that would make the actions and affected communities more resilient to the effects of a changing climate;
- Outlines special considerations for agencies analyzing biogenic carbon dioxide sources and carbon stocks associated with land and resource management actions under NEPA;
- Recommends that agencies select the appropriate level of NEPA review to assess the broad-scale effects of GHG emissions and climate change, either to inform programmatic (e.g., landscape-scale) decisions, or at both the programmatic and tiered project- or site-specific level, and to set forth a reasoned explanation for the agency's approach; and
- Counsels agencies that the "rule of reason" inherent in NEPA and the CEQ Regulations allows agencies to determine, based on their expertise and

experience, how to consider an environmental effect and prepare an analysis based on the available information.

II. BACKGROUND

A. NEPA

NEPA is designed to promote consideration of potential effects on the human environment[11] that would result from proposed Federal agency actions, and to provide the public and decision makers with useful information regarding reasonable alternatives[12] and mitigation measures to improve the environmental outcomes of Federal agency actions. NEPA ensures that the environmental effects of proposed actions are taken into account before decisions are made and informs the public of significant environmental effects of proposed Federal agency actions, promoting transparency and accountability concerning Federal actions that may significantly affect the quality of the human environment. NEPA reviews should identify measures to avoid, minimize, or mitigate adverse effects of Federal agency actions. Better analysis and decisions are the ultimate goal of the NEPA process.[13]

Inherent in NEPA and the CEQ Regulations is a "rule of reason" that allows agencies to determine, based on their expertise and experience, how to consider an environmental effect and prepare an analysis based on the available information. The usefulness of that information to the decision-making process and the public, and the

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[11] 40 CFR 1508.14 ("'Human environment' shall be interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment.").

[12] 40 CFR 1508.25(b) ("Alternatives, which include: (1) No action alternative. (2) Other reasonable courses of actions. (3) Mitigation measures (not in the proposed action).").

[13] 40 CFR 1500.1(c) ("Ultimately, of course, it is not better documents but better decisions that count. NEPA's purpose is not to generate paperwork—even excellent paperwork—but to foster excellent action. The NEPA process is intended to help public officials make decisions that are based on understanding of environmental consequences, and take actions that protect, restore, and enhance the environment.").

extent of the anticipated environmental consequences are important factors to consider when applying that "rule of reason."

B. Climate Change

Climate change science continues to expand and refine our understanding of the impacts of anthropogenic GHG emissions. CEQ's first Annual Report in 1970 referenced climate change, indicating that "[m]an may be changing his weather."[14] At that time, the mean level of atmospheric carbon dioxide (CO_2) had been measured as increasing to 325 parts per million (ppm) from an average of 280 ppm pre-Industrial levels.[15] Since 1970, the concentration of atmospheric carbon dioxide has increased to approximately 400 ppm (2015 globally averaged value).[16] Since the publication of CEQ's first Annual Report, it has been determined that human activities have caused the carbon dioxide content of the atmosphere of our planet to increase to its highest level in at least 800,000 years.[17]

It is now well established that rising global atmospheric GHG emission concentrations are significantly affecting the Earth's climate. These conclusions are built upon a scientific record that has been created with substantial contributions from the

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[14] *See* CEQ, *Environmental Quality The First Annual Report*, p. 93 (August 1970); *available at* https://ceq.doe.gov/ceq_reports/annual_environmental_quality_reports.html.

[15] *See* USGCRP, *Climate Change Impacts in the United States The Third National Climate Assessment* (Jerry M. Melillo, Terese (T.C.) Richmond, & Gary W. Yohe eds., 2014) [hereinafter "Third National Climate Assessment"], *Appendix 3 Climate Science Supplement*, p. 739; EPA, April 2015: *Inventory of U.S. Greenhouse Emissions and Sinks 1990-2013, available at* https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Main-Text.pdf. *See also* Hartmann, D.L., A.M.G. Klein Tank, M. Rusticucci, et al., *2013 Observations Atmosphere and Surface. In Climate Change 2013 The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K., et al. (eds)]. Cambridge University Press: Cambridge, United Kingdom and New York, NY, USA. *Available at* http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter02_Final.pdf.

[16] *See* Ed Dlugokencky & Pieter Tans, National Oceanic and Atmospheric Administration/Earth System Research Laboratory, http://www.esrl.noaa.gov/gmd/ccgg/trends/global.html.

[17] *See* http://earthobservatory.nasa.gov/Features/CarbonCycle; University of California Riverside, National Aeronautics and Space Administration (NASA), and Riverside Unified School District, *Down to Earth Climate Change*, http://globalclimate.ucr.edu/resources.html; USGCRP, *Third National Climate Assessment, Appendix 3 Climate Science Supplement*, p. 736 ("Although climate changes in the past have been caused by natural factors, human activities are now the dominant agents of change. Human activities are affecting climate through increasing atmospheric levels of heat-trapping gases and other substances, including particles.").

United States Global Change Research Program (USGCRP), which informs the United States' response to global climate change through coordinated Federal programs of research, education, communication, and decision support.[18] Studies have projected the effects of increasing GHGs on many resources normally discussed in the NEPA process, including water availability, ocean acidity, sea-level rise, ecosystem functions, energy production, agriculture and food security, air quality and human health.[19]

Based primarily on the scientific assessments of the USGCRP, the National Research Council, and the Intergovernmental Panel on Climate Change, in 2009 the Environmental Protection Agency (EPA) issued a finding that the changes in our climate caused by elevated concentrations of greenhouse gases in the atmosphere are reasonably anticipated to endanger the public health and public welfare of current and future generations.[20] In 2015, EPA acknowledged more recent scientific assessments that "highlight the urgency of addressing the rising concentration of CO_2 in the atmosphere," finding that certain groups are especially vulnerable to climate-related effects.[21] Broadly

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[18] *See* Global Change Research Act of 1990, Pub. L. 101–606, Sec. 103 (November 16, 1990). For additional information on the United States Global Change Research Program [hereinafter "USGCRP"], visit http://www.globalchange.gov. The USGCRP, formerly the Climate Change Science Program, coordinates and integrates the activities of 13 Federal agencies that conduct research on changes in the global environment and their implications for society. The USGCRP began as a Presidential initiative in 1989 and was codified in the Global Change Research Act of 1990 (Public Law 101–606). USGCRP-participating agencies are the Departments of Agriculture, Commerce, Defense, Energy, Interior, Health and Human Services, State, and Transportation; the U.S. Agency for International Development, the Environmental Protection Agency, NASA, the National Science Foundation, and the Smithsonian Institution.

[19] *See* USGCRP, *Third National Climate Assessment*, *available at* http://nca2014.globalchange.gov/system/files_force/downloads/low/NCA3_Climate_Change_Impacts_in_the_United%20States_LowRes.pdf?download=1; IPCC, *Climate Change 2014 Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (R.K. Pachauri, & L.A. Meyer eds., 2014), *available at* https://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_FINAL_full.pdf; *see also* http://www.globalchange.gov; 40 CFR 1508.8 (effects include ecological, aesthetic, historic, cultural, economic, social, and health effects); USGCRP, *The Impacts of Climate Change on Human Health in the United States A Scientific Assessment, available at* https://health2016.globalchange.gov/.

[20] *See generally Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496 (Dec. 15, 2009). (For example, at 66497-98: "[t]he evidence concerning how human-induced climate change may alter extreme weather events also clearly supports a finding of endangerment, given the serious adverse impacts that can result from such events and the increase in risk, even if small, of the occurrence and intensity of events such as hurricanes and floods. Additionally, public health is expected to be adversely affected by an increase in the severity of coastal storm events due to rising sea levels").

[21] *See* EPA, *Final Rule for Carbon Pollution Emission Guidelines for Existing Stationary Sources Electric Utility Generating Units*, 80 Fed. Reg. 64661, 64677 (Oct. 23, 2015) ("Certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related effects. Recent studies also find that certain communities, including low-income communities and some communities of color … are disproportionately affected by certain climate change related impacts—including heat waves, degraded air quality, and

stated, the effects of climate change observed to date and projected to occur in the future include more frequent and intense heat waves, longer fire seasons and more severe wildfires, degraded air quality, more heavy downpours and flooding, increased drought, greater sea-level rise, more intense storms, harm to water resources, harm to agriculture, ocean acidification, and harm to wildlife and ecosystems.[22]

III. CONSIDERING THE EFFECTS OF GHG EMISSIONS AND CLIMATE CHANGE

This guidance is applicable to all Federal actions subject to NEPA, including site-specific actions, certain funding of site-specific projects, rulemaking actions, permitting decisions, and land and resource management decisions.[23] This guidance does not – and cannot – expand the range of Federal agency actions that are subject to NEPA. Consistent with NEPA, Federal agencies should consider the extent to which a proposed action and its reasonable alternatives would contribute to climate change, through GHG emissions, and take into account the ways in which a changing climate may impact the proposed action and any alternative actions, change the action's environmental effects over the lifetime of those effects, and alter the overall environmental implications of such actions.

This guidance is intended to assist agencies in disclosing and considering the effects of GHG emissions and climate change along with the other reasonably foreseeable environmental effects of their proposed actions. This guidance does not establish any

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extreme weather events—which are associated with increased deaths, illnesses, and economic challenges. Studies also find that climate change poses particular threats to the health, well-being, and ways of life of indigenous peoples in the U.S.").

[22] *See* http://www.globalchange.gov/climate-change/impacts-society and Third National Climate Assessment, Chapters 3-15 (Sectors) and Chapters 16-25 (Regions), *available at* http://nca2014.globalchange.gov/downloads.

[23] *See* 40 CFR 1508.18.

particular quantity of GHG emissions as "significantly" affecting the quality of the human environment or give greater consideration to the effects of GHG emissions and climate change over other effects on the human environment.

A. GHG Emissions as a Proxy for the Climate Change Impacts of a Proposed Action

In light of the global scope of the impacts of GHG emissions, and the incremental contribution of each single action to global concentrations, CEQ recommends agencies use the projected GHG emissions associated with proposed actions as a proxy for assessing proposed actions' potential effects on climate change in NEPA analysis.[24] This approach, together with providing a qualitative summary discussion of the impacts of GHG emissions based on authoritative reports such as the USGCRP's National Climate Assessments and the Impacts of Climate Change on Human Health in the United States, a Scientific Assessment of the USGCRP, allows an agency to present the environmental and public health impacts of a proposed action in clear terms and with sufficient information to make a reasoned choice between no action and other alternatives and appropriate mitigation measures, and to ensure the professional and scientific integrity of the NEPA review.[25]

Climate change results from the incremental addition of GHG emissions from millions of individual sources,[26] which collectively have a large impact on a global scale.

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[24] *See* 40 CFR 1502.16, 1508.9.

[25] *See* 40 CFR 1500.1, 1502.24 (requiring agencies to use high quality information and ensure the professional and scientific integrity of the discussions and analyses in environmental impact statements).

[26] Some sources emit GHGs in quantities that are orders of magnitude greater than others. *See* EPA, *Greenhouse Gas Reporting Program 2014 Reported Data*, Figure 2: Direct GHG Emissions Reported by Sector (2014), *available at* https://www.epa.gov/ghgreporting/ghgrp-2014-reported-data (amounts of GHG emissions by sector); *Final Rule for Carbon Pollution Emission Guidelines for Existing Stationary Sources Electric Utility Generating Units*, 80 Fed. Reg. 64661, 64663, 64689 (Oct. 23, 2015) (regulation of GHG emissions from fossil fuel-fired electricity generating power plants); *Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources*, 81 Fed. Reg. 34824, 35830 (June 3, 2016 (regulation of GHG emissions from oil and gas sector).

CEQ recognizes that the totality of climate change impacts is not attributable to any single action, but are exacerbated by a series of actions including actions taken pursuant to decisions of the Federal Government. Therefore, a statement that emissions from a proposed Federal action represent only a small fraction of global emissions is essentially a statement about the nature of the climate change challenge, and is not an appropriate basis for deciding whether or to what extent to consider climate change impacts under NEPA. Moreover, these comparisons are also not an appropriate method for characterizing the potential impacts associated with a proposed action and its alternatives and mitigations because this approach does not reveal anything beyond the nature of the climate change challenge itself: the fact that diverse individual sources of emissions each make a relatively small addition to global atmospheric GHG concentrations that collectively have a large impact. When considering GHG emissions and their significance, agencies should use appropriate tools and methodologies for quantifying GHG emissions and comparing GHG quantities across alternative scenarios. Agencies should not limit themselves to calculating a proposed action's emissions as a percentage of sector, nationwide, or global emissions in deciding whether or to what extent to consider climate change impacts under NEPA.

1. GHG Emissions Quantification and Relevant Tools

This guidance recommends that agencies quantify a proposed agency action's projected direct and indirect GHG emissions. Agencies should be guided by the principle that the extent of the analysis should be commensurate with the quantity of projected GHG emissions and take into account available data and GHG quantification tools that

are suitable for and commensurate with the proposed agency action.[27] The rule of reason and the concept of proportionality caution against providing an in-depth analysis of emissions regardless of the insignificance of the quantity of GHG emissions that would be caused by the proposed agency action.

Quantification tools are widely available, and are already in broad use in the Federal and private sectors, by state and local governments, and globally.[28] Such quantification tools and methodologies have been developed to assist institutions, organizations, agencies, and companies with different levels of technical sophistication, data availability, and GHG source profiles. When data inputs are reasonably available to support calculations, agencies should conduct GHG analysis and disclose quantitative estimates of GHG emissions in their NEPA reviews. These tools can provide estimates of GHG emissions, including emissions from fossil fuel combustion and estimates of GHG emissions and carbon sequestration for many of the sources and sinks potentially affected by proposed resource management actions.[29] When considering which tool(s) to employ, it is important to consider the proposed action's temporal scale, and the availability of input data.[30] Examples of the kinds of methodologies agencies might consider using are presented in CEQ's 2012 Guidance for Accounting and Reporting GHG Emissions for a wide variety of activities associated with Federal agency operations.[31] When an agency determines that quantifying GHG emissions would not be

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[27] *See* 40 CFR 1500.1(b) ("Most important, NEPA documents must concentrate on the issues that are truly significant to the action in question, rather than amassing needless detail."); 40 CFR 1502.2(b) (Impacts shall be discussed in proportion to their significance); 40 CFR 1502.15 (Data and analyses in a statement shall be commensurate with the importance of the impact…).
[28] *See* https://ceq.doe.gov/current_developments/GHG-accounting-tools.html.
[29] For example, USDA's COMET-Farm tool can be used to assess the carbon sequestration of existing agricultural activities along with the reduction in carbon sequestration (emissions) of project-level activities, http://cometfarm.nrel.colostate.edu/. Examples of other tools are available at https://ceq.doe.gov/current_developments/GHG-accounting-tools.html.
[30] *See* 40 CFR 1502.22.
[31] *See* https://www.whitehouse.gov/sites/default/files/microsites/ceq/revised_federal_greenhouse_gas_accounting_and_reporting_guidance_

warranted because tools, methodologies, or data inputs are not reasonably available, the agency should provide a qualitative analysis and its rationale for determining that the quantitative analysis is not warranted. A qualitative analysis can rely on sector-specific descriptions of the GHG emissions of the category of Federal agency action that is the subject of the NEPA analysis.

When updating their NEPA procedures[32] and guidance, agencies should coordinate with CEQ to identify 1) the actions that normally warrant quantification of their GHG emissions, and consideration of the relative GHG emissions associated with alternative actions and 2) agency actions that normally do not warrant such quantification because tools, methodologies, or data inputs are not reasonably available. The determination of the potential significance of a proposed action remains subject to agency practice for the consideration of context and intensity, as set forth in the CEQ Regulations.[33]

2. The Scope of the Proposed Action

In order to assess effects, agencies should take account of the proposed action – including "connected" actions[34] – subject to reasonable limits based on feasibility and practicality. Activities that have a reasonably close causal relationship to the Federal action, such as those that may occur as a predicate for a proposed agency action or as a consequence of a proposed agency action, should be accounted for in the NEPA analysis.

060412.pdf. Federal agencies' Strategic Sustainability Performance Plans reflecting their annual GHG inventories and reports under Executive Order 13514 are available at https://www.performance.gov/node/3406/view?view=public#supporting-info.

[32] *See* 40 CFR 1507.3.

[33] 40 CFR 1508.27 ("'Significantly' as used in NEPA requires considerations of both context and intensity: (a) Context. This means that the significance of an action must be analyzed in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality. . . . (b) Intensity. This refers to the severity of impact.").

[34] 40 CFR 1508.25(a) (Actions are connected if they: (i) Automatically trigger other actions which may require environmental impact statements; (ii) Cannot or will not proceed unless other actions are taken previously or simultaneously, or; (iii) Are interdependent parts of a larger action and depend on the larger action for their justification.).

For example, NEPA reviews for proposed resource extraction and development projects typically include the reasonably foreseeable effects of various phases in the process, such as clearing land for the project, building access roads, extraction, transport, refining, processing, using the resource, disassembly, disposal, and reclamation. Depending on the relationship between any of the phases, as well as the authority under which they may be carried out, agencies should use the analytical scope that best informs their decision making.

The agency should focus on significant potential effects and conduct an analysis that is proportionate to the environmental consequences of the proposed action.[35] Agencies can rely on basic NEPA principles to determine and explain the reasonable parameters of their analyses in order to disclose the reasonably foreseeable effects that may result from their proposed actions.[36]

3. Alternatives

Considering alternatives, including alternatives that mitigate GHG emissions, is fundamental to the NEPA process and accords with NEPA Sections 102(2)(C) and 102(2)(E).[37] The CEQ regulations emphasize that the alternatives analysis is the heart of the EIS under NEPA Section 102(2)(C).[38] NEPA Section 102(2)(E) provides an independent requirement for the consideration of alternatives in environmental documents.[39] NEPA calls upon agencies to use the NEPA process to "identify and assess the reasonable alternatives to proposed actions that will avoid or minimize adverse effects of these actions upon the quality of the human environment."[40] The requirement to

[35] *See* 40 CFR 1501.7(a)(3), 1502.2(b), and 1502.15.
[36] *See* 40 CFR 1502.16.
[37] 42 U.S.C. 4332(2)(C), 4332(2)(E); 40 CFR 1502.14, 1508.9(b).
[38] 40 CFR 1502.14.
[39] *See* 40 CFR 1500.2, 1508.9(b).
[40] 40 CFR 1500.2(c).

consider alternatives ensures that agencies account for approaches with no, or less, adverse environmental effects for a particular resource.

Consideration of alternatives also provides each agency decision maker the information needed to examine other possible approaches to a particular proposed action (including the no action alternative) that could alter the environmental impact or the balance of factors considered in making the decision. Agency decisions are aided when there are reasonable alternatives that allow for comparing GHG emissions and carbon sequestration potential, trade-offs with other environmental values, and the risk from – and resilience to – climate change inherent in a proposed action and its design.

Agencies must consider a range of reasonable alternatives consistent with the level of NEPA review (e.g., EA or EIS) and the purpose and need for the proposed action, as well as reasonable mitigation measures if not already included in the proposed action or alternatives.[41] Accordingly, a comparison of these alternatives based on GHG emissions and any potential mitigation measures can be useful to advance a reasoned choice among alternatives and mitigation actions. When conducting the analysis, an agency should compare the anticipated levels of GHG emissions from each alternative – including the no-action alternative – and mitigation actions to provide information to the public and enable the decision maker to make an informed choice.

Agencies should consider reasonable alternatives and mitigation measures to reduce action-related GHG emissions or increase carbon sequestration in the same fashion as they consider alternatives and mitigation measures for any other environmental effects. NEPA, the CEQ Regulations, and this guidance do not require the decision

[41] *See* 42 U.S.C. 4332(2)(C), 4332(2)(E), and 40 CFR 1502.14(f), 1508.9(b). The purpose and need for action usually reflects both the extent of the agency's statutory authority and its policies.

maker to select the alternative with the lowest net level of emissions. Rather, they allow for the careful consideration of emissions and mitigation measures along with all the other factors considered in making a final decision.

4. Direct and Indirect Effects

If the direct and indirect GHG emissions can be quantified based on available information, including reasonable projections and assumptions, agencies should consider and disclose the reasonably foreseeable direct and indirect emissions when analyzing the direct and indirect effects of the proposed action.[42] Agencies should disclose the information and any assumptions used in the analysis and explain any uncertainties.

To compare a project's estimated direct and indirect emissions with GHG emissions from the no-action alternative, agencies should draw on existing, timely, objective, and authoritative analyses, such as those by the Energy Information Administration, the Federal Energy Management Program, or Office of Fossil Energy of the Department of Energy.[43] In the absence of such analyses, agencies should use other available information. When such analyses or information for quantification is unavailable, or the complexity of comparing emissions from various sources would make quantification overly speculative, then the agency should quantify emissions to the extent that this information is available and explain the extent to which quantified emissions information is unavailable while providing a qualitative analysis of those emissions. As

[42] For example, where the proposed action involves fossil fuel extraction, direct emissions typically include GHGs emitted during the process of exploring for or extracting the fossil fuel. The indirect effects of such an action that are reasonably foreseeable at the time would vary with the circumstances of the proposed action. For actions such as a Federal lease sale of coal for energy production, the impacts associated with the end-use of the fossil fuel being extracted would be the reasonably foreseeable combustion of that coal.
[43] For a current example, see Office of Fossil Energy, Nat'l Energy Tech. Lab., U.S. Dep't of Energy, *Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States*, Pub. No. DOE/NETL-2014/1649 (2014), *available at* http://energy.gov/sites/prod/files/2014/05/f16/Life%20Cycle%20GHG%20Perspective%20Report.pdf.

with any NEPA analysis, the level of effort should be proportionate to the scale of the emissions relevant to the NEPA review.

5. Cumulative Effects

"Cumulative impact" is defined in the CEQ Regulations as the "impact on the environment that results 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 other actions."[44] All GHG emissions contribute to cumulative climate change impacts. However, for most Federal agency actions CEQ does not expect that an EIS would be required based *solely* on the global significance of cumulative impacts of GHG emissions, as it would not be consistent with the rule of reason to require the preparation of an EIS for every Federal action that may cause GHG emissions regardless of the magnitude of those emissions.

Based on the agency identification and analysis of the direct and indirect effects of its proposed action, NEPA requires an agency to consider the cumulative impacts of its proposed action and reasonable alternatives.[45] As noted above, for the purposes of NEPA, the analysis of the effects of GHG emissions is essentially a cumulative effects analysis that is subsumed within the general analysis and discussion of climate change impacts. Therefore, direct and indirect effects analysis for GHG emissions will adequately address the cumulative impacts for climate change from the proposed action and its alternatives and a separate cumulative effects analysis for GHG emissions is not needed.

6. Short- and Long-Term Effects

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[44] 40 CFR 1508.7.

[45] *See* 40 CFR 1502.16, 1508.7, 1508.8. *See also* CEQ Memorandum to Heads of Federal Agencies, *Guidance on the Consideration of Past Actions in Cumulative Effects Analysis*, June 24, 2005, *available at* https//ceq.doe.gov/nepa/regs/Guidance_on_CE.pdf.

When considering effects, agencies should take into account both the short- and long-term adverse and beneficial effects using a temporal scope that is grounded in the concept of reasonable foreseeability. Some proposed actions will have to consider effects at different stages to ensure the direct effects and reasonably foreseeable indirect effects are appropriately assessed; for example, the effects of construction are different from the effects of the operations and maintenance of a facility.

Biogenic GHG emissions and carbon stocks from some land or resource management activities, such as a prescribed burn of a forest or grassland conducted to limit loss of ecosystem function through wildfires or insect infestations, may result in short-term GHG emissions and loss of stored carbon, while in the longer term a restored, healthy ecosystem may provide long-term carbon sequestration. Therefore, the short- and long-term effects should be described in comparison to the no action alternative in the NEPA review.

7. Mitigation

Mitigation is an important component of the NEPA process that Federal agencies can use to avoid, minimize, and compensate for the adverse environmental effects associated with their actions. Mitigation, by definition, includes avoiding impacts, minimizing impacts by limiting them, rectifying the impact, reducing or eliminating the impacts over time, or compensating for them.[46] Consequently, agencies should consider reasonable mitigation measures and alternatives as provided for under existing CEQ Regulations and take into account relevant agency statutory authorities and policies. The NEPA process is also intended to provide useful advice and information to State, local

[46] *See* 40 CFR 1508.20, 1508.25 (Alternatives include mitigation measures not included in the proposed action).

and tribal governments and private parties so that the agencies can better coordinate with other agencies and organizations regarding the means to mitigate effects of their actions.[47] The NEPA process considers the effects of mitigation commitments made by project proponents or others and mitigation required under other relevant permitting and environmental review regimes.[48]

As Federal agencies evaluate potential mitigation of GHG emissions and the interaction of a proposed action with climate change, the agencies should also carefully evaluate the quality of that mitigation to ensure it is additional, verifiable, durable, enforceable, and will be implemented.[49] Agencies should consider the potential for mitigation measures to reduce or mitigate GHG emissions and climate change effects when those measures are reasonable and consistent with achieving the purpose and need for the proposed action. Such mitigation measures could include enhanced energy efficiency, lower GHG-emitting technology, carbon capture, carbon sequestration (e.g., forest, agricultural soils, and coastal habitat restoration), sustainable land management practices, and capturing or beneficially using GHG emissions such as methane.

Finally, the CEQ Regulations and guidance recognize the value of monitoring to ensure that mitigation is carried out as provided in a record of decision or finding of no significant impact.[50] The agency's final decision on the proposed action should identify those mitigation measures that the agency commits to take, recommends, or requires

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[47] NEPA directs Federal agencies to make "advice and information useful in restoring, maintaining, and enhancing the quality of the environment" available to States, Tribes, counties, cities, institutions and individuals. NEPA Sec. 102(2)(G).

[48] *See* CEQ Memorandum to Heads of Federal Agencies, *Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact*, 76 FR 3843 (Jan. 21, 2011) *available at* https://ceq.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf.

[49] *See* Presidential Memorandum: *Mitigating Impacts on Natural Resources from Development and Encouraging Related Private Investment* (https://www.whitehouse.gov/the-press-office/2015/11/03/mitigating-impacts-natural-resources-development-and-encouraging-related) defining "durability" and addressing additionality.

[50] *See* 40 CFR 1505.2(c), 1505.3. *See also* CEQ Memorandum to Heads of Federal Agencies, *Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact*, 76 FR 3843 (Jan. 21, 2011) *available at* https://ceq.doe.gov/current_developments/docs/Mitigation_and_Monitoring_Guidance_14Jan2011.pdf.

others to take. Monitoring is particularly appropriate to confirm the effectiveness of mitigation when that mitigation is adopted to reduce the impacts of a proposed action on affected resources already increasingly vulnerable due to climate change.

B. CONSIDERING THE EFFECTS OF CLIMATE CHANGE ON A PROPOSED ACTION AND ITS ENVIRONMENTAL IMPACTS

According to the USGCRP and others, GHGs already in the atmosphere will continue altering the climate system into the future, even with current or future emissions control efforts.[51] Therefore, a NEPA review should consider an action in the context of the future state of the environment. In addition, climate change adaptation and resilience — defined as adjustments to natural or human systems in response to actual or expected climate changes — are important considerations for agencies contemplating and planning actions with effects that will occur both at the time of implementation and into the future.[52]

1. Affected Environment

An agency should identify the affected environment to provide a basis for comparing the current and the future state of the environment as affected by the proposed action or its reasonable alternatives.[53] The current and projected future state of the environment without the proposed action (i.e., the no action alternative) represents the reasonably foreseeable affected environment, and this should be described based on

[51] *See* Third National Climate Assessment, *Appendix 3 Climate Science Supplement* 753-754, *available at* http://s3.amazonaws.com/nca2014/low/NCA3_Full_Report_Appendix_3_Climate_Science_Supplement_LowRes.pdf?download=1.
[52] *See* Third National Climate Assessment, Chapter 28, "Adaptation" and Chapter 26, "Decision Support: Connecting Science, Risk Perception, and Decisions," *available at* http://www.globalchange.gov/nca3-downloads-materials; see also, Exec. Order No. 13653, 78 Fed. Reg. 66817 (Nov. 6, 2013) and Exec. Order No.13693, *Planning for Federal Sustainability in the Next Decade*, 80 Fed. Reg. 15869 (Mach 25, 2015) (defining "climate-resilient design").
[53] *See* 40 CFR 1502.15 (providing that environmental impact statements shall succinctly describe the environmental impacts on the area(s) to be affected or created by the alternatives under consideration).

authoritative climate change reports,[54] which often project at least two possible future scenarios.[55] The temporal bounds for the state of the environment are determined by the projected initiation of implementation and the expected life of the proposed action and its effects.[56] Agencies should remain aware of the evolving body of scientific information as more refined estimates of the impacts of climate change, both globally and at a localized level, become available.[57]

2. Impacts

The analysis of climate change impacts should focus on those aspects of the human environment that are impacted by both the proposed action and climate change. Climate change can make a resource, ecosystem, human community, or structure more susceptible to many types of impacts and lessen its resilience to other environmental impacts apart from climate change. This increase in vulnerability can exacerbate the effects of the proposed action. For example, a proposed action may require water from a stream that has diminishing quantities of available water because of decreased snow pack in the mountains, or add heat to a water body that is already warming due to increasing atmospheric temperatures. Such considerations are squarely within the scope of NEPA and can inform decisions on whether to proceed with, and how to design, the proposed action to eliminate or mitigate impacts exacerbated by climate change. They can also

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[54] *See, e.g.,* Third National Climate Assessment (Regional impacts chapters) *available at* http://www.globalchange.gov/nca3-downloads-materials.

[55] *See, e.g.,* Third National Climate Assessment (Regional impacts chapters, considering a low future global emissions scenario, and a high emissions scenario) *available at* http://www.globalchange.gov/nca3-downloads-materials.

[56] CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act* (1997), https://ceq.doe.gov/publications/cumulative_effects html. Agencies should also consider their work under Exec. Order No. 13653, *Preparing the United States for the Impacts of Climate Change*, 78 Fed. Reg. 66817 (Nov. 6, 2013), that considers how capital investments will be affected by a changing climate over time.

[57] *See, e.g.,* http://nca2014.globalchange.gov/report/regions/coasts.

inform possible adaptation measures to address the impacts of climate change, ultimately enabling the selection of smarter, more resilient actions.

3. Available Assessments and Scenarios

In accordance with NEPA's rule of reason and standards for obtaining information regarding reasonably foreseeable effects on the human environment, agencies need not undertake new research or analysis of potential climate change impacts in the proposed action area, but may instead summarize and incorporate by reference the relevant scientific literature.[58] For example, agencies may summarize and incorporate by reference the relevant chapters of the most recent national climate assessments or reports from the USGCRP.[59] Particularly relevant to some proposed actions are the most current reports on climate change impacts on water resources, ecosystems, agriculture and forestry, health, coastlines, and ocean and arctic regions in the United States.[60] Agencies may recognize that scenarios or climate modeling information (including seasonal, inter-annual, long-term, and regional-scale projections) are widely used, but when relying on a single study or projection, agencies should consider their limitations and discuss them.[61]

4. Opportunities for Resilience and Adaptation

As called for under NEPA, the CEQ Regulations, and CEQ guidance, the NEPA review process should be integrated with agency planning at the earliest possible time that would allow for a meaningful analysis.[62] Information developed during early

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[58] *See* 40 CFR 1502.21 (material may be incorporated by reference if it is reasonably available for inspection by potentially interested persons during public review and comment).
[59] *See* http://www.globalchange.gov/browse/reports.
[60] *See* Third National Climate Assessment, *Our Changing Climate*, *available at* http://nca2014.globalchange.gov/report. Agencies should consider the latest final assessments and reports when they are updated.
[61] *See* 40 CFR 1502.22. Agencies can consult www.data.gov/climate/portals for model data archives, visualization tools, and downscaling results.
[62] *See* 42 U.S.C. 4332 ("agencies of the Federal Government shall … utilize a systematic, interdisciplinary approach which will insure the integrated use of the natural and social sciences and the environmental design arts in planning and in decision-making"); 40 CFR 1501.2 ("Agencies shall integrate the NEPA process with other planning at the earliest possible time…"); *See also* CEQ Memorandum

planning processes that precede a NEPA review may be incorporated into the NEPA review. Decades of NEPA practice have shown that integrating environmental considerations with the planning process provides useful information that program and project planners can consider in the design of the proposed action, alternatives, and potential mitigation measures. For instance, agencies should take into account increased risks associated with development in floodplains, avoiding such development wherever there is a practicable alternative, as required by Executive Order 11988 and Executive Order 13690.[63] In addition, agencies should take into account their ongoing efforts to incorporate environmental justice principles into their programs, policies, and activities, including the environmental justice strategies required by Executive Order 12898, as amended, and consider whether the effects of climate change in association with the effects of the proposed action may result in a disproportionate effect on minority and low income communities.[64] Agencies also may consider co-benefits of the proposed action, alternatives, and potential mitigation measures for human health, economic and social stability, ecosystem services, or other benefit that increases climate change preparedness or resilience. Individual agency adaptation plans and interagency adaptation strategies, such as agency Climate Adaptation Plans, the National Fish, Wildlife and Plants Climate Adaptation Strategy, and the National Action Plan: Priorities for Managing Freshwater

for Heads of Federal Departments and Agencies, *Improving the Process for Preparing Efficient and Timely Environmental Reviews under the National Environmental Policy Act*, 77 Fed. Reg. 14473 (Mar. 12, 2012), *available at* https://ceq.doe.gov/current_developments/docs/Improving_NEPA_Efficiencies_06Mar2012.pdf.

[63] *See* Exec. Order No. 11988, "Floodplain Management," 42 Fed. Reg. 26951 (May 24, 1977), *available at* http://www.archives.gov/federal-register/codification/executive-order/11988.html; Exec. Order No. 13690, *Establishing a Federal Flood Risk Management Standard and a Process for Further Soliciting and Considering Stakeholder Input*, 80 Fed. Reg. 6425 (Jan. 30, 2015), *available at* https://www.gpo.gov/fdsys/pkg/FR-2015-02-04/pdf/2015-02379.pdf.

[64] *See* Exec. Order No. 12898, *Federal Actions to Address Environmental Justice in Minority and Low-Income Populations*, 59 Fed. Reg. 7629 (Feb. 16, 1994), *available at* https://ceq.doe.gov/nepa/regs/eos/ii-5.pdf; CEQ, *Environmental Justice Guidance Under the National Environmental Policy Act* (Dec. 1997), *available at* http://ceq.doe.gov/nepa/regs/ej/justice.pdf.

Resources in a Changing Climate, provide other good examples of the type of relevant and useful information that can be considered.[65]

Climate change effects on the environment and on the proposed project should be considered in the analysis of a project considered vulnerable to the effects of climate change such as increasing sea level, drought, high intensity precipitation events, increased fire risk, or ecological change. In such cases, a NEPA review will provide relevant information that agencies can use to consider in the initial project design, as well as alternatives with preferable overall environmental outcomes and improved resilience to climate impacts. For example, an agency considering a proposed long-term development of transportation infrastructure on a coastal barrier island should take into account climate change effects on the environment and, as applicable, consequences of rebuilding where sea level rise and more intense storms will shorten the projected life of the project and change its effects on the environment.[66] Given the length of time involved in present sea level projections, such considerations typically will not be relevant to short-term actions with short-term effects.

In addition, the particular impacts of climate change on vulnerable communities may be considered in the design of the action or the selection among alternatives to

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[65] *See* http://sustainability.performance.gov for agency sustainability plans, which contain agency adaptation plans. *See also* http://www.wildlifeadaptationstrategy.gov; http://www.whitehouse.gov/sites/default/files/microsites/ceq/2011_national_action_plan.pdf; and https://www.epa.gov/greeningepa/climate-change-adaptation-plans

[66] *See* U.S. Department of Transportation, Gulf Coast Study, Phase 2, *Assessing Transportation Vulnerability to Climate Change Synthesis of Lessons Learned and Methods Applied*, FHWA-HEP-15-007 (Oct. 2014) (focusing on the Mobile, Alabama region), *available at* http://www.fhwa.dot.gov/environment/climate_change/adaptation/ongoing_and_current_research/gulf_coast_study/phase2_task6/fhwahep15007.pdf; U.S. Climate Change Science Program, Synthesis and Assessment Product 4.7, Impacts of Climate Change and Variability on Transportation Systems and Infrastructure: Gulf Coast Study, Phase I (Mar. 2008) (focusing on a regional scale in the central Gulf Coast), *available at* https://downloads.globalchange.gov/sap/sap4-7/sap4-7-final-all.pdf. Information about the Gulf Coast Study is *available at* *http //www.fhwa.dot.gov/environment/climate_change/adaptation/ongoing_and_current_research/gulf_coast_study*. *See also* Third National Climate Assessment, Chapter 28, "Adaptation," at 675 (noting that Federal agencies in particular can facilitate climate adaptation by "ensuring the establishment of federal policies that allow for "flexible" adaptation efforts and take steps to avoid unintended consequences"), *available at* http://nca2014.globalchange.gov/report/response-strategies/adaptation#intro-section-2.

assess the impact, and potential for disproportionate impacts, on those communities.[67] For example, chemical facilities located near the coastline could have increased risk of spills or leakages due to sea level rise or increased storm surges, putting local communities and environmental resources at greater risk. Increased resilience could minimize such potential future effects. Finally, considering climate change preparedness and resilience can help ensure that agencies evaluate the potential for generating additional GHGs if a project has to be replaced, repaired, or modified, and minimize the risk of expending additional time and funds in the future.

C. Special Considerations for Biogenic Sources of Carbon

With regard to biogenic GHG emissions from land management actions – such as prescribed burning, timber stand improvements, fuel load reductions, scheduled harvesting, and livestock grazing – it is important to recognize that these land management actions involve GHG emissions and carbon sequestration that operate within the global carbon and nitrogen cycle, which may be affected by those actions. Similarly, some water management practices have GHG emission consequences (e.g., reservoir management practices can reduce methane releases, wetlands management practices can enhance carbon sequestration, and water conservation can improve energy efficiency).

Notably, it is possible that the net effect of ecosystem restoration actions resulting in short-term biogenic emissions may lead to long-term reductions of atmospheric GHG concentrations through increases in carbon stocks or reduced risks of future emissions. In the land and resource management context, how a proposed action affects a net carbon sink or source will depend on multiple factors such as the climatic region, the distribution

[67] For an example, *see* https://www.blm.gov/epl-front-office/projects/nepa/5251/42462/45213/NPR-A_FINAL_ROD_2-21-13.pdf.

of carbon across carbon pools in the project area, and the ongoing activities and trends. In addressing biogenic GHG emissions, resource management agencies should include a comparison of estimated net GHG emissions and carbon stock changes that are projected to occur with and without implementation of proposed land or resource management actions.[68] This analysis should take into account the GHG emissions, carbon sequestration potential, and the changes in carbon stocks that are relevant to decision making in light of the proposed actions and timeframes under consideration.

One example of agencies dealing with biogenic emissions and carbon sequestration arises when agencies consider proposed vegetation management practices that affect the risk of wildfire, insect and disease outbreak, or other disturbance. The public and the decision maker may benefit from consideration of the influence of a vegetation management action that affects the risk of wildfire on net GHG emissions and carbon stock changes. NEPA reviews should consider whether to include a comparison of net GHG emissions and carbon stock changes that are anticipated to occur, with and without implementation of the proposed vegetation management practice, to provide information that is useful to the decision maker and the public to distinguish between alternatives. The analysis would take into account the estimated GHG emissions (biogenic and fossil), carbon sequestration potential, and the net change in carbon stocks relevant in light of the proposed actions and timeframes under consideration. In such cases the agency should describe the basis for estimates used to project the probability or likelihood of occurrence or changes in the effects or severity of wildfire. Where such

[68] One example of a tool for such calculations is the Carbon On Line Estimator (COLE), which uses data based on USDA Forest Service Forest Inventory & Analysis and Resource Planning Assessment data and other ecological data. COLE began as a collaboration between the National Council for Air and Stream Improvement, Inc. (NCASI) and USDA Forest Service, Northern Research Station. It currently is maintained by NCASI. It is available at http://www.fs.usda.gov/ccrc/tools/cole.

tools, methodologies, or data are not yet available, the agency should provide a qualitative analysis and its rationale for determining that the quantitative analysis is not warranted. As with any other analysis, the rule of reason and proportionality should be applied to determine the extent of the analysis.

CEQ acknowledges that Federal land and resource management agencies are developing agency-specific principles and guidance for considering biological carbon in management and planning decisions.[69] Such guidance is expected to address the importance of considering biogenic carbon fluxes and storage within the context of other management objectives and ecosystem service goals, and integrating carbon considerations as part of a balanced and comprehensive program of sustainable management, climate change mitigation, and climate change adaptation.

IV. TRADITIONAL NEPA TOOLS AND PRACTICES

A. Scoping and Framing the NEPA Review

To effectuate integrated decision making, avoid duplication, and focus the NEPA review, the CEQ Regulations provide for scoping.[70] In scoping, the agency determines the issues that the NEPA review will address and identifies the impacts related to the proposed action that the analyses will consider.[71] An agency can use the scoping process to help it determine whether analysis is relevant and, if so, the extent of analysis

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[69] *See* Council on Climate Change Preparedness and Resilience, *Priority Agenda Enhancing the Climate Resilience of America's Natural Resources*, at 52 (Oct. 2014), *available at* http://www.whitehouse.gov/sites/default/files/docs/enhancing_climate_resilience_of_americas_natural_resources.pdf.

[70] *See* 40 CFR 1501.7 ("There shall be an early and open process for determining the scope of issues to be addressed and for identifying the significant issues related to a proposed action. This process shall be termed scoping."); *see also* CEQ Memorandum for Heads of Federal Departments and Agencies, *Improving the Process for Preparing Efficient and Timely Environmental Reviews under the National Environmental Policy Act*, March 6, 2012, *available at* https://ceq.doe.gov/current_developments/docs/Improving_NEPA_Efficiencies_06Mar2012.pdf (the CEQ Regulations explicitly require scoping for preparing an EIS, however, agencies can also take advantage of scoping whenever preparing an EA).

[71] *See* 40 CFR 1500.4(b), 1500.4(g), 1501.7.

appropriate for a proposed action.[72] When scoping for the climate change issues associated with the proposed agency action, the nature, location, timeframe, and type of the proposed action and the extent of its effects will help determine the degree to which to consider climate projections, including whether climate change considerations warrant emphasis, detailed analysis, and disclosure.

Consistent with this guidance, agencies may develop their own agency-specific practices and guidance for framing the NEPA review. Grounded on the principles of proportionality and the rule of reason, such aids can help an agency determine the extent to which an analysis of GHG emissions and climate change impacts should be explored in the decision-making process and will assist in the analysis of the no action and proposed alternatives and mitigation.[73] The agency should explain such a framing process and its application to the proposed action to the decision makers and the public during the NEPA review and in the EA or EIS document.

B. Frame of Reference

When discussing GHG emissions, as for all environmental impacts, it can be helpful to provide the decision maker and the public with a recognizable frame of reference for comparing alternatives and mitigation measures. Agencies should discuss relevant approved federal, regional, state, tribal, or local plans, policies, or laws for GHG emission reductions or climate adaptation to make clear whether a proposed project's

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[72] *See* 40 CFR 1501.7 (The agency preparing the NEPA analysis must use the scoping process to, among other things, determine the scope and identify the significant issues to be analyzed in depth) and CEQ, *Memorandum for General Counsels, NEPA Liaisons, and Participants in Scoping*, April 30, 1981, *available at* https://ceq.doe.gov/nepa/regs/scope/scoping.htm.

[73] *See, e.g.,* Matthew P. Thompson, Bruce G. Marcot, Frank R. Thompson, III, Steven McNulty, Larry A. Fisher, Michael C. Runge, David Cleaves, and Monica Tomosy, *The Science of Decisionmaking Applications for Sustainable Forest and Grassland Management in the National Forest System* (2013), *available at* http://www.fs.fed.us/rm/pubs_other/rmrs_2013_thompson_m004.pdf; U.S. Forest Service Comparative Risk Assessment Framework And Tools, *available at* www.fs.fed.us/psw/topics/fire_science/craft/craft; and Julien Martin, Michael C. Runge, James D. Nichols, Bruce C. Lubow, and William L. Kendall, *Structured decision making as a conceptual framework to identify thresholds for conservation and management* (2009), Ecological Applications 19:1079–1090, *available at* http://www.esajournals.org/doi/abs/10.1890/08-0255.1.

GHG emissions are consistent with such plans or laws.[74] For example, the Bureau of Land Management has discussed how agency actions in California, especially joint projects with the State, may or may not facilitate California reaching its emission reduction goals under the State's Assembly Bill 32 (Global Warming Solutions Act).[75] This approach helps frame the policy context for the agency decision based on its NEPA review.

C. Incorporation by Reference

Incorporation by reference is of great value in considering GHG emissions or where an agency is considering the implications of climate change for the proposed action and its environmental effects. Agencies should identify situations where prior studies or NEPA analyses are likely to cover emissions or adaptation issues, in whole or in part. When larger scale analyses have considered climate change impacts and GHG emissions, calculating GHG emissions and carbon stocks for a specific action may provide only limited information beyond the information already collected and considered in the larger scale analyses. The NEPA reviews for a specific action can incorporate by reference earlier programmatic studies or information such as management plans, inventories, assessments, and research that consider potential changes in carbon stocks, as well as any relevant programmatic NEPA reviews.[76]

Accordingly, agencies should use the scoping process to consider whether they should incorporate by reference GHG analyses from other programmatic studies, action

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[74] *See* 40 CFR 1502.16(c), 1506.2(d) (where an inconsistency exists, agencies should describe the extent to which the agency will reconcile its proposed action with the plan or law). *See also* Exec. Order No. 13693, 80 Fed. Reg. 15869 (Mar. 25, 2015) (establishing GHG emission and related goals for agency facilities and operations. Scope 1, 2, and 3 emissions are typically separate and distinct from analyses and information used in an EA or EIS.).

[75] *See*, *e.g.*, U.S. Bureau of Land Management, Desert Renewable Energy Conservation Plan Proposed Land Use Plan Amendment and Final Environmental Impact Statement, Vol. I, § I.3.3.2, at 12, *available at* http://drecp.org/finaldrecp/.

[76] *See* 40 CFR 1502.5, 1502.21.

specific NEPA reviews, or programmatic NEPA reviews to avoid duplication of effort. Furthermore, agencies should engage other agencies and stakeholders with expertise or an interest in related actions to participate in the scoping process to identify relevant GHG and adaptation analyses from other actions or programmatic NEPA documents.

D. Using Available Information

Agencies should make decisions using current scientific information and methodologies. CEQ does not expect agencies to fund and conduct original climate change research to support their NEPA analyses or for agencies to require project proponents to do so. Agencies should exercise their discretion to select and use the tools, methodologies, and scientific and research information that are of high quality and available to assess the impacts.[77]

Agencies should be aware of the ongoing efforts to address the impacts of climate change on human health and vulnerable communities.[78] Certain groups, including children, the elderly, and the poor, are more vulnerable to climate-related health effects, and may face barriers to engaging on issues that disproportionately affect them. CEQ recommends that agencies periodically engage their environmental justice experts, and the Federal Interagency Working Group on Environmental Justice,[79] to identify approaches to avoid or minimize impacts that may have disproportionately high and

[77] *See* 40 CFR 1502.24 (requiring agencies to ensure the professional and scientific integrity of the discussions and analyses in environmental impact statements).
[78] USGCRP, *The Impacts of Climate Change on Human Health in the United States A Scientific Assessment* (Apr. 2016), *available at* https://health2016.globalchange.gov/downloads.
[79] For more information on the Federal Interagency Working Group on Environmental Justice co-chaired by EPA and CEQ, *see* http://www.epa.gov/environmentaljustice/interagency/index.html.

adverse human health or environmental effects on minority and low-income populations.[80]

E. Programmatic or Broad-Based Studies and NEPA Reviews

Agency decisions can address different geographic scales that can range from the programmatic or landscape level to the site- or project-specific level. Agencies sometimes conduct analyses or studies that are not NEPA reviews at the national level or other broad scale level (e.g., landscape, regional, or watershed) to assess the status of one or more resources or to determine trends in changing environmental conditions.[81] In the context of long-range energy, transportation, and resource management strategies an agency may decide that it would be useful and efficient to provide an aggregate analysis of GHG emissions or climate change effects in a programmatic analysis and then incorporate by reference that analysis into future NEPA reviews.

A tiered, analytical decision-making approach using a programmatic NEPA review is used for many types of Federal actions[82] and can be particularly relevant to addressing proposed land, aquatic, and other resource management plans. Under such an approach, an agency conducts a broad-scale programmatic NEPA analysis for decisions such as establishing or revising USDA Forest Service land management plans, Bureau of Land Management resource management plans, or Natural Resources Conservation Service conservation programs. Subsequent NEPA analyses for proposed site-specific

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[80] *President's Memorandum for the Heads of All Departments and Agencies, Executive Order on Federal Actions to Address Environmental Justice in Minority and Low-Income Populations* (Feb. 11, 1994), *available at* https://ceq.doe.gov/nepa/regs/eos/ii-5.pdf; CEQ, *Environmental Justice Guidance Under the National Environmental Policy Act*, *available at* https://ceq.doe.gov/nepa/regs/ej/justice.pdf.

[81] Such a programmatic study is distinct from a programmatic NEPA review which is appropriate when the action under consideration is itself subject to NEPA requirements. *See* CEQ, *Memorandum for Heads of Federal Departments and Agencies, Effective Use of Programmatic NEPA Reviews*, Dec. 18, 2014, § I(A), p. 9, *available at* https://www.whitehouse.gov/sites/default/files/docs/effective_use_of_programmatic_nepa_reviews_final_dec2014_searchable.pdf (discussing non-NEPA types of programmatic analyses such as data collection, assessments, and research, which previous NEPA guidance described as joint inventories or planning studies).

[82] *See* 40 CFR 1502.20, 1508.28. A programmatic NEPA review may be appropriate when a decision is being made that is subject to NEPA, such as establishing formal plans, programs, and policies, and when considering a suite of similar projects.

decisions – such as proposed actions that implement land, aquatic, and other resource management plans – may be tiered from the broader programmatic analysis, drawing upon its basic framework analysis to avoid repeating analytical efforts for each tiered decision. Examples of project- or site-specific actions that may benefit from being able to tier to a programmatic NEPA review include: constructing transmission lines; conducting prescribed burns; approving grazing leases; granting rights-of-way; issuing leases for oil and gas drilling; authorizing construction of wind, solar or geothermal projects; and approving hard rock mineral extraction.

A programmatic NEPA review may also serve as an efficient mechanism in which to assess Federal agency efforts to adopt broad-scale sustainable practices for energy efficiency, GHG emissions avoidance and emissions reduction measures, petroleum product use reduction, and renewable energy use, as well as other sustainability practices.[83] While broad department- or agency-wide goals may be of a far larger scale than a particular program, policy, or proposed action, an analysis that informs how a particular action affects that broader goal can be of value.

F. Monetizing Costs and Benefits

NEPA does not require monetizing costs and benefits. Furthermore, the weighing of the merits and drawbacks of the various alternatives need not be displayed using a monetary cost-benefit analysis and should not be when there are important qualitative considerations.[84] When an agency determines that a monetized assessment of the impacts of greenhouse gas emissions or a monetary cost-benefit analysis is appropriate and

[83] *See* Exec. Order No. 13693, 80 Fed. Reg. 15869 (Mar. 25, 2015).
[84] *See* 40 CFR 1502.23.

relevant to the choice among different alternatives being considered, such analysis may be incorporated by reference[85] or appended to the NEPA document as an aid in evaluating the environmental consequences.[86] For example, a rulemaking could have useful information for the NEPA review in an associated regulatory impact analysis which could be incorporated by reference.[87] When using a monetary cost-benefit analysis, just as with tools to quantify emissions, the agency should disclose the assumptions, alternative inputs, and levels of uncertainty associated with such analysis. Finally, if an agency chooses to monetize some but not all impacts of an action, the agency providing this additional information should explain its rationale for doing so.[88]

V. CONCLUSION AND EFFECTIVE DATE

Agencies should apply this guidance to all new proposed agency actions when a NEPA review is initiated. Agencies should exercise judgment when considering whether to apply this guidance to the extent practicable to an on-going NEPA process. CEQ does not expect agencies to apply this guidance to concluded NEPA reviews and actions for

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[85] *See* 40 CFR 1502.21 (material may be cited if it is reasonably available for inspection by potentially interested persons within the time allowed for public review and comment).

[86] When conducting a cost-benefit analysis, determining an appropriate method for preparing a cost-benefit analysis is a decision left to the agency's discretion, taking into account established practices for cost-benefit analysis with strong theoretical underpinnings (for example, see OMB Circular A-4 and references therein). For example, the Federal social cost of carbon (SCC) estimates the marginal damages associated with an increase in carbon dioxide emissions in a given year. Developed through an interagency process committed to ensuring that the SCC estimates reflect the best available science and methodologies and used to assess the social benefits of reducing carbon dioxide emissions across alternatives in rulemakings, it provides a harmonized, interagency metric that can give decision makers and the public useful information for their NEPA review. For current Federal estimates, *see* Interagency Working Group on Social Cost of Carbon, United States Government, *Technical Support Document Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (revised July 2015), *available at* https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.

[87] For example, the regulatory impact analysis was used as a source of information and aligned with the NEPA review for Corporate Average Fuel Economy (CAFÉ) standards, *see* National Highway Traffic Safety Administration, Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2017-2025, Final Environmental Impact Statement, Docket No. NHTSA-2011-0056 (July 2012), § 5.3.2, *available at* http://www.nhtsa.gov/Laws+&+Regulations/CAFE+-+Fuel+Economy/Environmental+Impact+Statement+for+CAFE+Standards,+2017-2025.

[88] For example, the information may be responsive to public comments or useful to the decision maker in further distinguishing between alternatives and mitigation measures. In all cases, the agency should ensure that its consideration of the information and other factors relevant to its decision is consistent with applicable statutory or other authorities, including requirements for the use of cost-benefit analysis.

which a final EIS or EA has been issued. Agencies should consider applying this guidance to projects in the EIS or EA preparation stage if this would inform the consideration of differences between alternatives or address comments raised through the public comment process with sufficient scientific basis that suggest the environmental analysis would be incomplete without application of the guidance, and the additional time and resources needed would be proportionate to the value of the information included.

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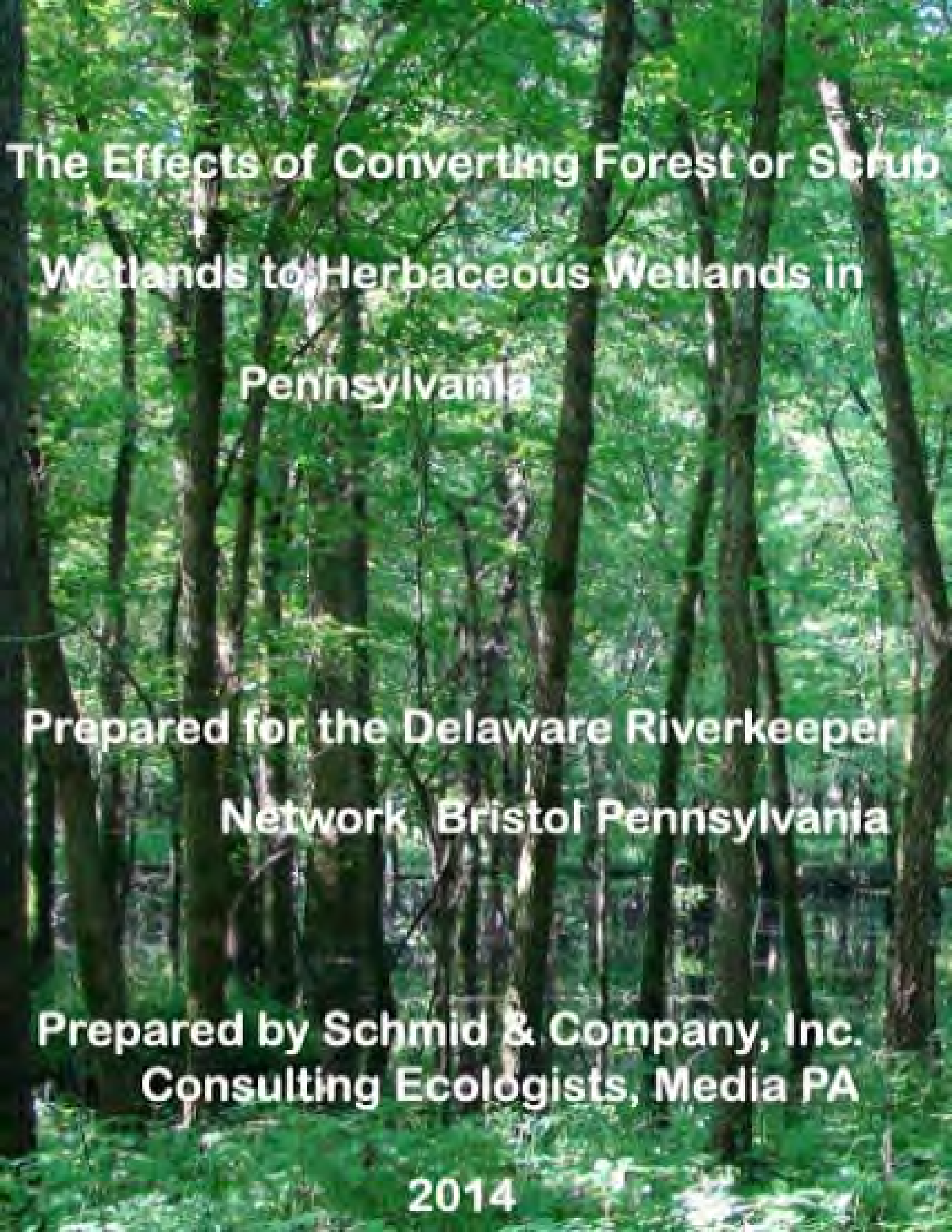

The Effects of Converting Forest or Scrub Wetlands to Herbaceous Wetlands in Pennsylvania

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The Effects of Converting Forest or Scrub Wetlands to Herbaceous Wetlands in Pennsylvania

Wetlands are tracts of land characterized by the recurrent and prolonged presence of surface water and/or near-surface groundwater. Their vegetation, wildlife, and soil properties are greatly influenced by wetness, that is, by their hydrology. Wetness has a profound effect on the biogeochemical reactions that occur in the top foot of wetland soil, allowing bacteria to render such soils anaerobic (oxygen-free) and thereby affecting the chemistry of the soil particles as observed in soil color and organic matter, determining the kinds of microorganisms present, selecting the kinds of rooted plants able to survive and compete, and in turn affecting the quality of habitat for animals including humans. Like streams, ponds, lakes, rivers, and oceans, wetlands today are deemed to be bodies of surface water, peculiar places transitional between (1) permanent open waters and (2) dry lands wet only during precipitation events. Some wetlands are associated with areas where surface waters and groundwater interconnect.

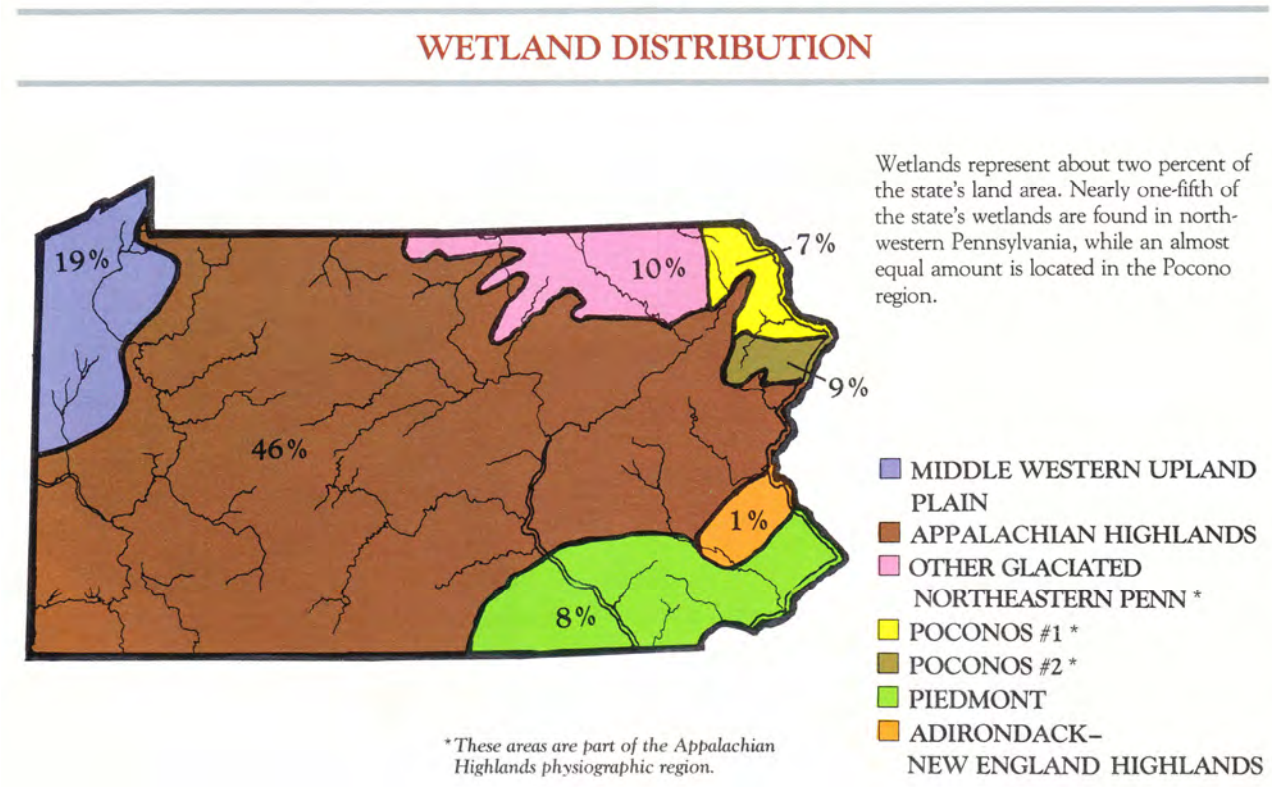
For many years wetlands were regarded as wastelands, and public policy encouraged their physical conversion to accommodate more highly valued land uses of many kinds (farms, cities, roads, residential and commercial development). In response, millions of acres of wetlands were destroyed across the United States, including more than half of Pennsylvania's wetlands (more than 600,000 acres). Not until the latter half of the twentieth century were the environmental and societal values of suddenly scarce wetlands broadly appreciated and subjected to legal protection against unnecessary alteration in the United States (Schmid 2000). Today most construction activities in wetlands are regulated by public agencies concerned with environmental protection. Regulators at the federal, State, and/or municipal level may be involved in permit review and approval. Most construction activities that would affect wetlands are unlawful, unless previously authorized by permit, but the applicable laws vary greatly from place to place in their scope and stringency.

Wetness (above-ground inundation or in-ground saturation within the uppermost foot of topsoil) for periods of two weeks or more, at least seasonally recurrent, is the primary characteristic that locally distinguishes individual wetlands from non-wetland areas that may display similar climate, exposure (aspect), slope, geology (rock type), soils, and biota (plants, animals, bacteria, fungi). The prolonged presence of surface water at relatively shallow depth (< 6 feet) and the presence of emergent vegetation distinguish wetlands from the deep, open waters of lakes and the flowing channels (some with submerged or floating plants) of streams---other bodies of surface water with which wetlands often are closely associated. Wetlands often occupy a landscape zone transitional between open waters and the seldom-wet uplands found at higher elevations. Along with groundwater, surface streams, rivers, lakes, ponds, and wetlands are regulated Waters of the Commonwealth of Pennsylvania. Many, but not all, of the wetlands and other

surface water bodies in Pennsylvania are also Waters of the United States (USEPA and USACE 2014).

In the large and diverse Commonwealth of Pennsylvania there are many kinds of wetlands. Pennsylvania wetlands in the aggregate occupy a small proportion of the land surface, and are most extensive in formerly glaciated areas such as the plateaus of the northeastern and northwestern counties, as shown below in a National Wetland Inventory drawing (from Tiner 1987). Individual wetlands can range in size from a few square feet to many acres. Wetlands today are recognized as contributing to water quality, wildlife habitat, endangered species protection, and the human landscape far out of proportion to their percentage share of the Pennsylvania land surface, and thus warrant stringent protection from human modifications to the extent practicable. These values increase as human population and population density increase. At the same time, the economic value of property where the destruction of wetlands has been authorized can greatly exceed the cash value of that property in its natural condition. Hence the extent to which public agencies can protect wetland resources often conflicts with the desire of private landowners to alter the property which they own.

Pennsylvania Wetlands Are Geographically Concentrated.



Agencies tasked with implementing the federal Clean Water Act (P.L. 92-500, 86 Stat. 816) and the Pennsylvania Dam Safety and Encroachments Act (32 P.S. 693) and Clean Streams Law (35 P.S. 691), long have defined wetlands as

> Areas that are inundated or saturated by surface water or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions, including swamps, marshes, bogs and similar areas (25 *Pa. Code* 105.1.)

Accurate wetland identification and delineation depend upon a careful analysis of plants, soils, and hydrology using the best available scientific guidance to apply the official definition in each real situation on the surface of the earth. In the central sections of most wetlands the general public can readily ascertain the distinctive conditions that characterize tree-filled swamps and herb-dominated marshes. Precisely locating the boundaries of a wetland, however, in gently sloping transitional areas where the requisite field indicators gradually drop out, typically requires specialized training in the visual appearance of vegetation, soils, and hydrology as they occur outdoors in all seasons, along with thorough knowledge of relevant agency rules for consistent decisionmaking. The details of scientific knowledge of wetland functions and regulatory adjustments in setting regulatory boundaries and analyzing impacts have changed over recent decades as our understanding of wetlands has increased.

To apply the regulatory definition of wetlands in the field, federal and Pennsylvania regulators (25 *Pa. Code* 105.451) employ the Army Corps of Engineers *Wetland Identification and Delineation Manual* (ERL 1987) in conjunction with its recent regional supplements (for example, USACE 2012) and other technical support documents (including Lichvar *et al*. 2014, Vasilas *et al*. 2010, USACE 2014). These official documents provide the guidance necessary for recognizing the current extent of regulated wetlands under various conditions of season, wetness, and human disturbance, using field indicators of vegetation, soil, and hydrology.

In Pennsylvania the Army Corps of Engineers provides, in response to landowner requests, formal written Jurisdictional Determinations (JDs) that confirm the accurately mapped extent of wetlands and bodies of surface water eligible for regulation at the federal, State, and municipal level on specific tracts of land. Absent the issuance of a valid JD, there is no way for a landowner or the public to ascertain accurately the limits of a regulated wetland. Topographic maps, National Wetland Inventory maps, floodplain maps, soil survey maps, and planning maps of many kinds can provide useful technical information, but do not identify in detail the limits of regulated wetlands (or streams) that need to be considered by the sponsors of construction projects. Consultants typically document sites on behalf of landowners and prepare paperwork for agency review. Careful documentation of wetlands whose proffered boundaries are superimposed onto a land ownership survey is required as part of a request for a

JD, and Corps staff typically inspect each property in the field prior to approving a JD. JDs remain valid for five years, in recognition of the fact that wetland boundaries can change over time as a result of natural changes as well as unregulated human activities nearby. Only the Natural Resources Conservation Service (NRCS), an arm of the US Department of Agriculture, issues permanent wetland identifications for purposes of eligibility for federal programs that support crop production. Such NRCS determinations apply only to farming, not to general construction activities.

Delineated wetlands are best avoided when new construction projects are proposed, and permit applicants are expected to minimize unavoidable impacts insofar as practicable. The JD forms the informational basis for permit calculations and for designing compensatory mitigation to offset agency-approved impacts to the extent practicable.

Recent experience confirms that applicant-proffered wetland boundaries continue to warrant detailed scrutiny by the Army Corps of Engineers and other regulators. In one 2010 mining application in Greene County, National Wetland Inventory maps disclosed 4 wetlands on a 642-acre site. The applicant's consultant submitted a proposed delineation to PADEP showing 10 wetlands. After field inspection by the Corps, the JD drawing of the same tract of land showed 27 wetlands (Schmid & Co., Inc. 2013). In Sullivan County a gas company consultant delineated streams and wetlands in a 50-foot wide right-of-way along some 4,000 feet of unpaved township road. After the adjoining landowners secured Corps JDs, the square footage of regulated streams and wetlands increased to 700% of that flagged for the gas company within the same 4-acre strip of land (Schmid & Co., Inc. 2011b). The Corps field representative commented that significant under-identification of wetlands had occurred at several recent gas well installations where he had been involved with enforcement actions. None of those permittees had secured a Corps JD, and PADEP as usual had approved their permits without questioning the accuracy of information in the applications. It is not possible to overemphasize the necessity for JD applications followed by field-checking by Corps staff of proffered delineations as critical to the identification of wetlands in Pennsylvania prior to permit approval. Unidentified wetlands are not protected at all.

Wetland Permits

Regulated activities in Pennsylvania wetlands and other bodies of water cannot legally be initiated prior to permit approval by the Department of Environmental Protection (PADEP), except for waivered activities (25 *Pa. Code* 105.12) and registered activities that conform to the requirements of pre-approved general permits (25 *Pa. Code* 105.441 *et seq.*). Above established minimum thresholds of impact, regulated activities in federally regulated wetlands and waters also require approval from the Army Corps of Engineers. Except for those areas and

activities excluded from regulation by waiver or authorized via general permits, wetland functions by regulation must be identified by an applicant when permit approval is sought for activities that will encroach upon wetlands and other bodies of water in Pennsylvania (25 *Pa. Code* 105.13). Permit applications for relatively small encroachments may be reviewed only by State agencies; larger or more damaging activities must be considered independently also by federal agencies. Few of the more than 2,500 Pennsylvania municipalities have adopted any ordinances protective of wetlands, but some have included wetlands as among resources to be reviewed at the local level, and their wetlands may be protected over and above what State and federal agencies require. Like PADEP, local agencies generally lack the staff resources to identify jurisdictional boundaries for wetlands.

After wetlands have been identified, permit applicants are expected to avoid impacts, and where unavoidable, to make every practicable effort to minimize impacts when planning their construction projects; PADEP is to review such efforts to avoid and minimize impacts [25 *Pa. Code* 105.14(b)(7)]. Where encroachments are proposed into wetlands, it is the responsibility of the permit applicant to identify onsite conditions in every affected wetland as a basis for ascertaining the probable alteration of functions when analyzing unavoidable adverse impacts and providing appropriate compensatory mitigation (25 *Pa. Code* 105.14, .15, and .18a). Impacts are to be analyzed in an Environmental Assessment (§105.15). The extent and nature of unavoidable impacts become the basis for developing the applicant's proposal for site restoration and compensatory mitigation. The quality of wetland assessment depends on the thoroughness and accuracy of underlying wetland inventory as well as the professional competence of the delineator and agency reviewer. Wetland functions form a principal aspect of the environmental assessment.

PADEP and district offices of the Army Corps of Engineers have adopted a joint permit application (Form 3150-PM-BWEW0036A, March 2013) and related forms that solicit the minimum information needed for agency decisionmaking regarding affected wetlands and other bodies of water on properties where construction is planned that may damage these resources. Public notice is required for individual joint permit applications, but not for waivered activities or for registrations of applicant intent to rely upon general permits. PADEP staffers are charged with reviewing each application to insure its completeness, its accuracy, and the applicant's proposed compliance with applicable regulations. Permit files, application data, and related correspondence are public records and can be examined by persons concerned about wetland protection through the procedures of Pennsylvania's Right to Know Law (Act 3 of 2008) and the federal Freedom of Information Act (5 USC 552 *et seq*.). Upon approval of a PADEP permit, the window for filing appeals to the Pennsylvania Environmental Hearing Board by any aggrieved party remains open for thirty days. Applicants are required to conform to the conditions and limitations set forth in general and individual permits. All recipients of individual permits by regulation are required

to file a statement of compliance with permit requirements within 30 days of work completion and to file final as-built plans within 90 days showing any changes from original plans and specifications (25 *Pa. Code* 105.107).

In Pennsylvania some wetlands are deemed more valuable than others. Exceptional Value wetlands deserve *specia*l protection. Such wetlands exhibit one or more of the following characteristics (25 *Pa. Code* 105.17):

1. Serve as habitat for fauna or flora listed as threatened or endangered under federal or Pennsylvania law.
2. Are hydrologically connected to or located within 0.5 mile of the above and maintain the habitat of the endangered species.
3. Are located in or along the floodplain of the reach of a wild trout stream or waters listed as having Exceptional Value and the floodplain of their tributary streams, or within the corridor of a federal or Pennsylvaia designated Wild or Scenic River.
4. Are located along an existing public or private drinking water supply and maintain the quantity or quality of that surface water or groundwater supply.
5. Are located in State-designated natural or wild areas within State parks or forests, in federally designated Wilderness Areas or National Natural Landmarks.

Wetlands that qualify as having Exceptional Value are defined as surface waters of Exceptional Ecological Significance (25 *Pa. Code* 93.1), and thus (like Pennsylvania streams that have been designated or have attained Exceptional Value uses) are to be treated as Tier 3 Outstanding National Resource Waters in the language of the Clean Water Act of 1972 (as amended, 33 *USC* §1251 *et seq*.; *US Environmental Protection Agency Water Quality Handbook* - Chapter 4: Antidegradation [40 *CFR* 131.12]). These highest-quality resources are to be protected from degradation. Wetlands that do not exhibit any of the above-listed characteristics are deemed “Other” wetlands.

Permits for structures and activities in Exceptional Value wetlands are not to be approved unless PADEP finds that: the dam, water obstruction, or encroachment will not have an adverse impact on the wetland, as determined in accordance with §§ 105.14(b) and 105.15; the project is water dependent, requiring access to, proximity to, or siting within the wetland to fulfill its basic purpose; there is no practicable alternative that would not involve a wetland or that would have less adverse effect on the wetland and not have other significant adverse effects on the environment; the project will not cause or contribute to a violation of an applicable State water quality standard; the project will not cause or contribute to pollution of groundwater or surface water resources or diminution of resources sufficient to interfere with their uses; and the applicant replaces the affected wetland in accordance with criteria at § 105.20a [25 *Pa. Code* 105.18a(a)]. Yet Corps Jurisdictional Determinations are not required for Exceptional Value wetlands in Pennsylvania, so these wetlands are equally likely to be overlooked as those lacking exceptional value.

“Other” wetlands also are deemed “a valuable public natural resource” (25 *Pa. Code* 105.17) that is to be protected from significant impacts in similar fashion to

Exceptional Value wetlands. Permits are to be granted to dams, water obstructions, or encroachments affecting Other wetlands only when PADEP finds that: the project will not have a significant adverse impact considering the areal extent of the impacts, values, and functions of the wetlands, the uniqueness of the wetland functions and values in the area or region; comments from environmental agencies have been addressed; adverse impacts on the wetland are to be avoided or reduced to the maximum extent possible; there is no practicable non-wetland impacting alternative; the applicant has convincingly demonstrated that non water-dependent projects have no practicable alternative, overcoming the rebuttable presumption that such alternatives exist; the project will not cause or contribute to violation of an applicable State water quality standard; the project will not cause or contribute to pollution of groundwater or surface water resources or diminution of resources sufficient to interfere with their uses; the cumulative effect of this project and other projects will not result in a major impairment of the Commonwealth's wetland resources; and the applicant replaces the affected wetland in accordance with criteria at § 105.20a [25 *Pa. Code* 18a(b)]. On paper, Pennsylvania offers stringent protection to its wetlands.

Wetland Functions

Nine wetland functions are specifically identified in the definitions section of Pennsylvania's Dam Safety and Encroachments regulations (25 *Pa. Code* 25.1). By regulation, these functions are the minimum that require consideration as PADEP evaluates every encroachment permit affecting 1 acre or less of wetlands. Larger wetlands, as well as Exceptional Value wetlands smaller than 1 acre may require more complex assessment of additional functions and values in addition to these [25 *Pa. Code* 105.13(d)(3)]:

Wetland Functions Requiring Analysis in PADEP Permits

1. Serving natural biological functions, including food chain production; general habitat; and nesting, spawning, rearing and resting sites for aquatic or land species.
2. Providing areas for study of the environment or as sanctuaries or refuges.
3. Maintaining natural drainage characteristics, sedimentation patterns, salinity distribution, flushing characteristics, natural water filtration processes, current patterns or other environmental characteristics.
4. Shielding other areas from wave action, erosion, or storm damage.
5. Serving as a storage area for storm and flood waters.
6. Providing a groundwater discharge area that maintains minimum baseflows.
7. Serving as a prime natural recharge area where surface water and groundwater are directly interconnected.
8. Preventing pollution.
9. Providing recreation.

Different wetlands exhibit different combinations of functions. Some mutually exclusive functions (for example, groundwater recharge and groundwater

discharge) can alternate over time within a single wetland. The functions performed by a wetland may vary over seasons and from year to year. The functions that any given wetland is capable of performing result from both the internal characteristics of the wetland itself and the surrounding context in which that wetland exists, including its connection with other natural areas and with watercourses. Corridors for wildlife movement, for example, are important to allow populations of animals to move between areas of wetland habitat, and many streams function as wildlife corridors. Similarly, only a wetland located on the shore of an open water body can shield other areas from wave action. The success of a wetland in performing functions can be affected greatly by past or ongoing human activity. Most wetland functions are disrupted permanently or temporarily by construction activities that impinge upon the wetland vegetation, soils, or hydrology directly. Human activities that increase performance of one function can accompany decreasing performance of other functions by that wetland.

Wetland functions also can be affected by construction outside the wetland itself out to a distance of 1,500 feet or more (Houlahan *et al*. 2006). For example, wildlife that breed in wetlands, such as reptiles and amphibians including frogs and salamanders, normally range into the adjoining uplands for distances of many hundreds of feet in eastern North America during the course of an annual cycle. If the adjacent lands are deforested or paved, or the wetland isolated by an intervening road or fence, the wetland habitat can be rendered useless to such creatures. By way of further example, altering the light and wind by removing the surrounding forest can cause a major change in the plants and animals that can survive in a wetland. Surface disturbances outside a wetland also can have major impact on the hydrology of the wetland, profoundly altering its ecosystem by draining or flooding it.

There is no State-regulated wetland buffer in Pennsylvania, such as exists in New Jersey or New York. Those States have expressed concern for the variable boundaries of wetlands that result from differing weather conditions year to year. They wisely recognize that the associated transitional areas adjacent to wetlands comprise essential parts of the functioning ecosystem of each wetland. Hence they long have considered the preservation of ecosystems adjacent to a wetland to be an essential part of protecting that wetland's functions and values. The absence of regulated buffers around wetlands in Pennsylvania renders its wetlands at risk of unavoidable degradation, especially in areas of concentrated human populations. A few Pennsylvania municipalities have recognized or sought to remedy this environmental risk through local ordinances that provide for maintenance of some amount of undeveloped protective buffer outside the wetland.

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Wetland Classification

The functions and values of a wetland differ according to the placement of the wetland in the landscape and the manner in which it gains its wetness.

Functional analysis logically addresses different classes of wetlands differently when addressing their potential for damage or rehabilitation. Wetlands and shallow water bodies are usefully categorized at the most basic level by general hydrogeomorphic system. Across most of the Pennsylvania landscape, wetlands and small ponds are assigned to the Palustrine (P) system, which is distinguished from tidal estuarine and marine classes, lakes, and large rivers. Wetlands along the boundaries of water bodies are assigned to the Riverine (R) or Lacustrine (L) systems, although many floodplain wetlands are labeled as Palustrine. Marine (M) and Estuarine (E) classes are of limited extent in Pennsylvania.

The following table identifies the most recent hydrogeomorphic classifications under development by the PADEP (draft Technical Guidance Document 310-2137-002, 7 March 2014, p. 27). The classification is significant as it affects the functional analysis of all water bodies including wetlands.

Mid-Atlantic HGM Wetland Classification:

- Classes
  - Subclasses
    - Modifiers
- Marine
  - subtidal
  - intertidal
- Estuarine
  - subtidal
  - lunar intertidal
  - wind intertidal
  - impounded
- Riverine
  - lower perennial
  - floodplain complex
  - upper perennial
  - headwater complex
  - intermittent
    - beaver impounded
    - human impounded
- Lacustrine (fringe)
  - permanently flooded
  - semipermanently flooded
  - intermittently flooded
  - artificially flooded
- Palustrine
  - Flat
    - Flat mineral soil
    - Flat organic soil
  - Slope
    - Stratigraphic
    - Topographic
      - mineral soil
      - organic soil
  - Depression
    - perennial
    - seasonal
    - temporary
      - human impounded
      - human excavated
      - beaver impounded

PADEP goes on to offer additional detail on the principal kinds of wetlands in Pennsylvania classed by location associated with hydrology that require consideration during functional assessments. The modifiers give an idea of the variability of the basic types (draft Technical Guidance Document 310-2137-002, 7 March 2014, p. 24-25). Once these distinctions have been formally adopted by PADEP for consideration in each permit application, the precision and quality of data provided by applicants' consultants should improve, along with the quality of impact analysis.

Pennsylvania Hydrogeomorphic Wetland Classification Key.

1.	Wetland found along tidal fringe of a marine ecosystem (ocean, beach, rocky shore)	2
1.	Wetland not associated with marine ecosystem	3
2.	Continuously submerged littoral zone	**Marine subtidal** (MF1)
2.	Alternately flooded and exposed to air	**Marine intertidal** (MF2)
3.	Wetland associated with shallow estuarine ecosystem (Mixture of saline and freshwater)	4
3.	Wetland not associated with shallow estuarine ecosystem	7
4.	Wetland not impounded	5
4.	Wetland impounded	**Estuarine impounded** (EFh)
5.	Wetland continuously submerged	**Estuarine subtidal** (EF1)
5.	Wetland alternately flooded and exposed to air	6
6.	Wetland regularly or irregularly flooded by semidiurnal, storm, or spring tides	**Estuarine lunar intertidal** (EF2l)
6.	Wetland flooding induced by wind	**Estuarine wind intertidal** (EF2w)
7.	Wetland associated with freshwater stream or river	8
7.	Wetland not associated with freshwater stream or river	11
8.	Wetland associated with permanent flowing water from surface sources	9
8.	Wetland dominated by ground water or intermittent flows	10
9.	Wetland associated with low gradient tidal creek (see Estuarine types 3)	
9.	Wetland associated with low gradient and low velocities, within a well-developed floodplain (typically >3rd order)	**Riverine lower perennial** (R2)
9.	Wetland part of a mosaic dominated by floodplain features (former channels, depressions) that may include slope wetlands supported by ground water (see Slope 17)	**Riverine floodplain complex** (R2c)
9.	Wetland associated with high gradient and high velocities with relatively straight channel, with or without a floodplain (typically 1st - 3rd order)	**Riverine upper perennial** (R3)
10.	Wetland part of a mosaic of small streams, depressions, and slope wetlands generally supported by ground water	**Riverine headwater complex** (R3c)
10.	Wetland associated with intermittent hydroperiod	**Riverine intermittent** (R4)

Note:	For any riverine type that is impounded, distinguish between:	
	Wetland impounded by beaver activity	**Riverine...beaver impounded** (R...b)
	Wetland impounded by human activity	**Riverine...human impounded** (R...h)
11.	Wetland fringing on a lake or reservoir	**12**
11.	Wetland not fringing on lake or reservoir	**14**
12.	Wetland inundation controlled by relatively natural hydroperiod	**13**
13.	Wetland inundation is permanent with minor fluctuations (year round)	**Lacustrine permanently flooded** (LFH)
13.	Wetland inundation is semipermanent (growing season)	**Lacustrine semipermanently flooded** (LFF)
13.	Wetland inundation is intermittent (substrate exposed often)	**Lacustrine intermittently flooded** (LFJ)
12.	Wetland inundation controlled by dam releases	**Lacustrine artificially flooded** (LFK)
14.	Wetland water source dominated by precipitation and vertical fluctuations of the water table due to low topographic relief	**15**
14.	Wetland differs from above	**16**
15.	Wetland substrate is primarily of mineral origin	**Flat mineral soil** (FLn)
15.	Wetland substrate is primarily of organic origin	**Flat organic soil** (FLg)
16.	Wetland water source is primarily ground water and has unidirectional and horizontal flows	**17**
16.	Wetland forms a depression	**18**
17.	Water source for wetland derived from structural geologic discontinuities resulting in discharge of groundwater from distinct point(s) on slope	**Stratigraphic slope** (SLs)
17.	Water source for wetland accumulates at toe-of-slope before discharging	**Topographic slope** (SLt)
Note:	For any slope type, distinguish between: Wetland substrate is primarily of mineral origin	**...slope mineral soil** (SL...n)
	Wetland substrate is primarily of organic origin	**...slope organic soil** (SL...g)
18.	Wetland with frequent surface connections conveying channelized flow	**Depression perennial** (DFH)
18.	Wetland with infrequent surface water connections conveying channelized flow	**Depression seasonal** (DFC)
18.	Wetland with no surface outlet, often perched above water table	**Depression temporary** (DFA)
Note:	For any depression type that is impounded or excavated distinguish between:	
	Wetland is impounded by human activities	**Depression...human impounded** (DPh)
	Wetland is excavated by human activities	**Depression...human excavated** (DPx)
	Wetland is impounded by beaver activities	**Depression...beaver impounded** (DPb)

Another of the basic classifications of wetlands derived from their appearance and germane to assessing their functions is their vegetation type. The descriptive framework for vegetation structure was devised by the US Fish and Wildlife Service (Cowardin *et al*. 1979) and is used for small-scale mapping by the National Wetlands Inventory. Vegetation and hydrogeomorphic location are combined to identify the principal habitat types identified by PADEP in Pennsylvania (Draft Technical Guidance Document 310-2137-001, March 2014,

p. 7). Notably, PADEP to date has not identified any nontidal Riverine wetland habitat types:

Some Pennsylvania Wetland Habitat Types.

LAB	Lacustrine Aquatic Bed
LEM	Lacustrine Emergent
LFL	Lacustrine Flat
PAB	Palustrine Aquatic Bed
PEM	Palustrine Emergent
PFL	Palustrine Flat
PFO	Palustrine Forested
PSS	Palustrine Scrub/Shrub

Lacustrine Emergent Wetland and Lacustrine Aquatic Bed.

Palustrine wetlands are the most numerous and widespread kinds in Pennsylvania, accounting for 97% of the wetlands mapped in the Commonwealth by the National Wetland Inventory from high-elevation aerial photos taken during the late1970s and early 1980s (Tiner 1990). National Wetland Inventory mapping is a useful tool whose results are valuable for regional wildlife resource management, but it significantly omits many forested wetlands in Pennsylvania and is not a reliable guide to regulated wetland locations or boundaries.

Nevertheless, its incomplete and approximate data are readily available online and often are displayed on maps generated by geographical information systems. Hydric soil map units in county soil maps and wetland patterns on US Geological Survey topographic quadrangles also offer clues to wetland locations. But the actual extent of wetlands and streams can be determined only by field delineation of specific properties when construction activities are proposed.

The principal kinds of vegetation found in Palustrine wetlands are classed as forest (PFO), scrub (PSS), and herbland (PEM) based on visual observation and/or aerial photographs. Available statistics probably underestimate the proportion of forested wetlands in Pennsylvania, inasmuch as they are based on aerial photographs rather than field investigation and omit forested wetlands not distinguishable remotely. Palustrine flats (FL) devoid of vegetation are not common. The focus of vegetation classification is on the size and structure of the general mass of vegetation present in the landscape. An individual plant, depending on species, can pass through the structural stages of herb, shrub, and tree as it grows in wetlands or uplands. The US Fish and Wildlife Service has reported their estimate of cover types of National Wetland Inventory wetlands in Pennsylvania based on 1975-1985 aerial photographs (Tiner 1990):

Palustrine Forests.

Delhaas Woods, Bucks County. Photograph by Roger Earl Latham.

Columbus Bog, State Game Lands 197, Warren County. Photograph by Paul Wiegman.

Acres of National Wetland Inventory Wetlands in Pennsylvania, 1975-1985.

Palustrine Wetlands	
Emergent	*52,338 a*
Deciduous Forested	*146,715 a*
Evergreen Forested	*31,204 a*
Deciduous Scrub-Shrub	*47,539 a*
Evergreen Scrub-Shrub	*1,849 a*
Mixed Deciduous Shrub-Emergent	*25,000 a*
Open Water	*61,841 a*
Other Mixed Types	*26,242 a*
Total Palustrine Wetlands	*392,728 a*
Lacustrine Wetlands	*8,521 a*
Riverine Wetlands	*2,675 a*
PENNSYLVANIA WETLANDS	***403,924 a***

Forest vegetation (FO) is dominated by trees at least 3 inches in minimum trunk diameter measured 4.5 feet above the ground and at least 20 feet tall. Shrubs and herbs can grow beneath the canopy trees, or the forest floor can be essentially bare. Scrub (SS) is dominated by shrubs with multiple stems less than 3 inches in diameter and rarely taller than 20 feet. Herbs can be abundant beneath the shrubs but trees are few; light tends to reach the land surface to a much greater degree than in forests. Herblands (EM) are generally devoid of woody plants but instead support various kinds of non-woody, herbaceous higher plants that emerge from the soil surface. Their plant cover can be sparse or dense. Tracts of land that qualify as forest, scrub, or herbland may intergrade and are mapped as mixed types (for example, FO/SS). The forest, scrub, and herbland categories each can be subdivided into numerous subtypes, depending on the purpose of such classification and appropriate level of detail. For example, Palustrine forest and scrub polygons on maps can be broadleaf deciduous (assigned the modifier “1” by the National Wetland Inventory, as in “PFO1”) or needleaf evergreen (“PFO4”); emergent herbs can be persistent year-round (“1” as in “PEM1”) or nonpersistent (“PEM2”), and any of these modifiers

can be further supplemented by codes for dominant plant genus or species or for other ecosystem attributes where more precise distinctions are needed.

In Pennsylvania Palustrine ecosystems, forested wetlands are more extensive than scrub and herbaceous wetlands. Natural plant succession generally trends toward forest conditions in eastern North America (Braun 1950, Küchler 1964), and thus herbaceous and scrub wetlands tend to reflect earlier stages of natural post-disturbance succession than forested wetlands. The first-approximation airphoto mapping of Pennsylvania wetlands by the US Fish and Wildlife Service reported deciduous forests making up 37% of Palustrine wetlands; evergreen forest, 8%; deciduous scrub, 12%; evergreen scrub, <0.1%; mixed deciduous scrub-herbland, 6%; herbland, 13%; open water (including farm ponds), 16%; and other mixed types, 7% based on 1975-1985 aerial photographs (Tiner 1990). Under natural conditions the forest community is disrupted occasionally by storms, fire, and beaver activity. Human activities today are a much more common source of forest removal. Not all herblands, however, are rapidly changing categories of plant succession on their way to becoming forests; some can persist naturally for long periods of time as viewed by humans. The plants found in particular wetland communities can range from diverse species to almost monotypic where invasives have become established.

State and federal agencies that keep records of wetlands and wetland modifications use these vegetation types for data collection and analysis. Each distinctive vegetation type also is associated with characteristic functions. Herbaceous wetland vegetation is capable of being reestablished relatively quickly following temporary disturbance, within only a few growing seasons, if soil and hydrologic conditions are favorable. Shrubs require additional years to reach full size, and forest trees require decades for canopy closure, even where soil disturbance has not been severe. Diverse populations of desirable native species can require long periods of time to become established in disturbed or newly created wetlands.

Functions of Pennsylvania Wetlands

This section discusses the functions listed above (as set forth in 25 *Pa. Code* 105.1) that are typically associated with Palustrine forested (PFO) wetlands and compares them with similar functions in scrub (PSS) and herbaceous (PEM) wetlands. These functions are subject to disruption by human activities as well as by catastrophic occurrences of weather (hurricanes, tornadoes), ice storms, landslides, floods, and fires. Reductions in some functions may accompany increases in others.

The PADEP list of nine wetland functions in Chapter 105 regulations is reasonably comprehensive and suited to project-scale analysis based on the specific acreage of wetlands affected by an individual permittee. Current regulations do not focus on quantitative annual productivity of timber or wildlife, removal of air pollutants, carbon sequestration, or less tangible functions such as

aesthetic or historic/cultural appreciation. Nor do they require measurement of the values of any identified functions to individuals or groups. They do not specify how to compare the relative values of different functions, how to index current, past, or future functions of specific wetlands to generally accepted "reference" natural wetlands, call attention to the context of land surrounding a wetland, address the scarcity of a vegetation type, or provide for actual consideration of cumulative wetland impacts beyond an individual permit. PADEP long has found it virtually impossible to consider cumulative impacts, even for a single large project, because of its longstanding willingness to consider permits for fragments of a project on a piecemeal basis independently. PADEP does not expect an applicant to address its entire single project in a joint permit submission, much less analyze its proposed impacts cumulatively with those of other permittees over large areas. PADEP also does not focus on the uniqueness or heritage value of specific wetlands (aside from their potential for classing a wetland as having Exceptional Value) or a wetland's actual replaceability or irreplaceability, should damage be authorized.

1. Natural Biological Functions and General Habitat

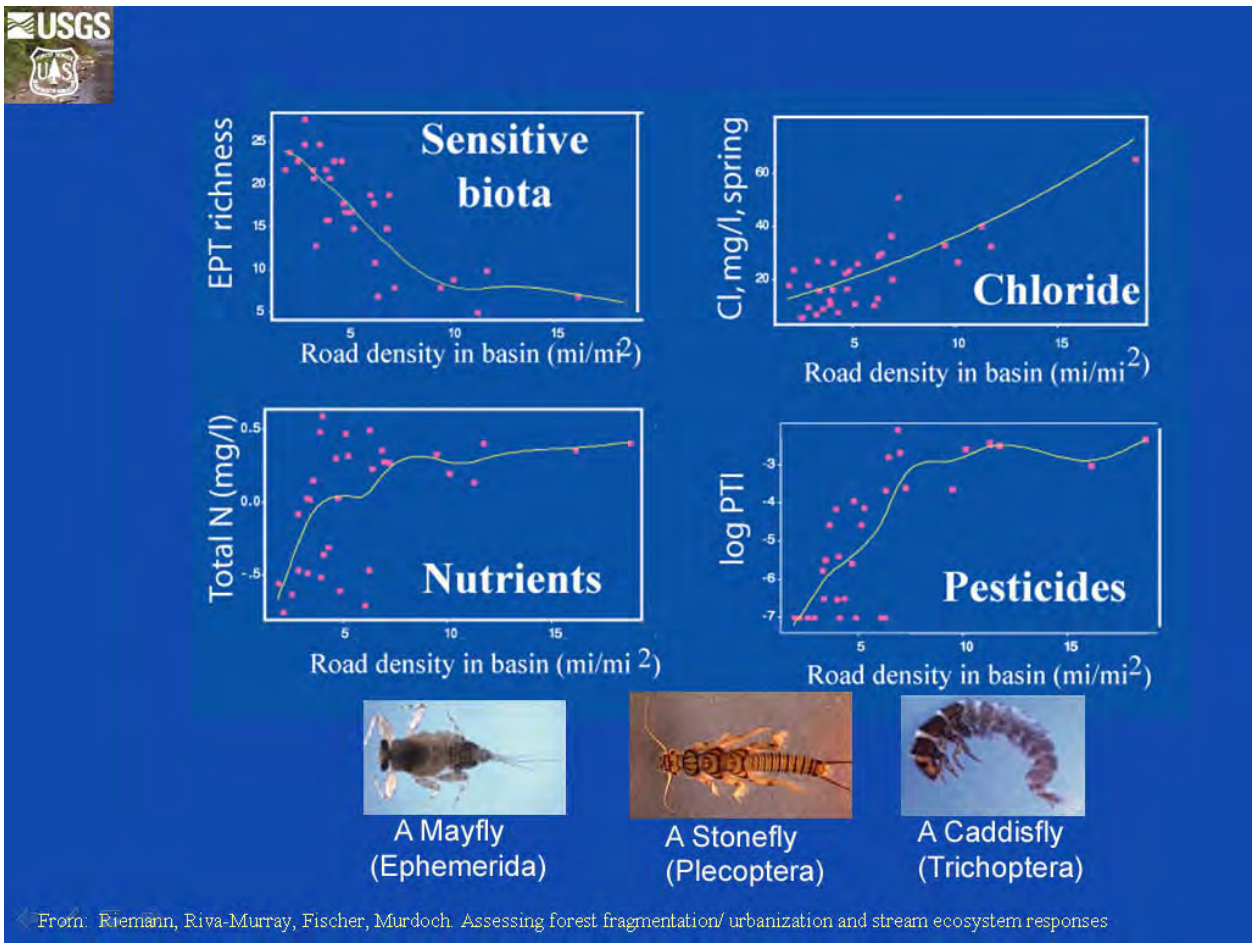
Natural biological functions of all wetlands include food chain production, general habitat, and resting-nesting-spawning-rearing sites for animals and fish. Many rare species of plants and animals are directly dependent on wetland habitats. Trees are the largest kinds of plants and have the greatest ability to modify the environmental effects of solar radiation, precipitation, temperature, humidity, and air quality as a result of their above-ground biomass. These natural, localized environmental modifications are of vital importance to the other plants and to the animals that live within and beneath forest cover. Tree leaves produce more tons of biomass per acre than shrubs for consumption by grazers and accumulate larger standing crops of organic material above ground. Tree trunks and limbs provide food for some animals and homes for many, with more complex structure than scrubs or herblands.

Pennsylvania forests consist of a wide variety of broadleaf deciduous trees, each species of which provides a somewhat different diet to the consumers that depend on it (Zimmerman *et al*. 2012; McShea & Healy 2002). Oaks, maples, ashes, elms, cherries, birches, and beech reflect the ancient geological history of Appalachia, and they returned to glaciated regions when the Pleistocene ice sheets melted. Pennsylvania forests also support many needleaf evergreen trees such as pines, hemlocks, and spruces. Very few stands of unharvested primeval forest remain in Pennsylvania; most of its forests have regrown following two or more episodes of intensive logging, burning, and other human disturbance during the past four centuries---episodes that have greatly affected the streams of the Commonwealth. Closed canopy forest consisting of mature trees requires about a century to recover to a recognizable mature forest structure after fire or clearcutting. About one third of Pennsylvania's forest stands are 80 years old or more; only 7%, 100 years old or more (McCaskill *et al*.

2013). Regenerated forest stands may or may not resemble their predecessors in their species composition when examined in detail, and the largest regrown individual trees are significantly smaller than historic records document as inherited by European colonists. Selective harvesting can remove key forest constituents, thereby reducing habitat value, and the forest canopy is further disrupted by logging roads, well pads, pipeline rights-of-way, borrow areas, and spills of fuel, brine, and other pollutants. Various kinds of shrubs and herbs grow only beneath a mature forest canopy. Wood ducks (*Aix sponsa*), a particularly handsome native species of waterfowl, require tree cavities for nesting as well as nearby water.

Trees growing in adjacent wetlands and streambanks are the major source of food for aquatic organisms in small, headwater streams. The intensity of ongoing human disturbance on the streams of forested areas can be estimated by the linear extent of roads per unit area. As summarized graphically by the United States Forest Service and US Geological Survey, human activity as approximated by road density has a dramatic effect on the quality of streams for sensitive aquatic insects that form the base of the aquatic food chain:

Road Density and Aquatic Parameters.



Both broadleaf and evergreen trees can dominate Pennsylvania wetlands, although broadleaf trees remain much more abundant (McCaskill *et al*. 2013). The value of forested wetlands to wildlife and to landowners is affected by the number of kinds of trees and other plants present (species diversity), their density and biomass (timber volume), the amount of dead timber standing and on the ground, the amount of grazing by domestic livestock and browsing by white-tailed deer, and the proportion of non-natives present. Diverse, high-quality vegetation is at greatest risk of human degradation and is the most difficult to restore (Olson and Doherty 2011). Wetland forests provide nesting, rearing, resting, and feeding sites for birds and mammals. One third of the bird species in the United States depend on wetlands (230 of 636; Welsch *et al*. 1995). Bears spend 60% of their time in forested wetlands during spring and summer (Newton 1988).

Unfragmented wetland forests are of great importance to many declining species of migratory songbirds. Wet forest floors are attractive wintering areas in which endangered bog turtles hibernate, and thick stands of evergreens shelter wintering deer and other animals. As already noted, the nutrients derived from tree leaves and twigs are vital to the macroinvertebrates and fish of Pennsylvania streams. Forest ecosystems are limited in their growth capability and affected in species composition by the availability of nutrients provided by the weathering of rock and transported in by air masses. The carbon from tree litter in turn can make up 99% of the total dissolved organic carbon at the base of the aquatic food web in forested streams (Stoler and Relyea 2011). Isolated vernal pools free of predatory fish are critically important to many uncommon reptiles and amphibians whose populations are dwindling. Discharges of stormwater, waste chemicals, and rubbish can degrade general habitat functions in forest and other wetlands.

Permanent forest disruption across Pennsylvania wetlands and uplands.

Scrub wetlands accumulate less standing biomass than mature forests. Hence any of the functions that derive from quantity of biomass are reduced in scrub as compared with forest wetlands, such as influence on microclimate, the amount of organic matter available for consumers of plant biomass, or the protection offered to soil from erosion. Some herbaceous wetlands can produce biomass in quantities rivaling forests above and below ground, but they lack the structural diversification of above-ground biomass of the woody wetlands. For animals adapted to herbaceous wetlands, such ecosystems provide important general habitat, nesting, resting, and rearing sites. The microtopography of hummocks provides habitat diversity critical to many species. Temporarily or permanently inundated herbaceous wetlands linked to streams and lakes have key importance as spawning and nursery grounds for fish, and inundated scrub wetlands are more common than inundated forests in Pennsylvania. The scrubs and sedge meadows with deep organic deposits associated with very wet herbaceous wetlands are prime spring and summer areas for various reptiles including the endangered bog turtle (*Glyptemys muehlenbergii*). Bog turtles prefer to overwinter in mats of tree roots where emerging groundwater warms near-surface temperatures. Herbaceous wetlands are of special importance to migrating waterfowl.

2. Environmental Study Areas and Refuges

Forested wetlands can serve as environmental study areas, particularly when located near schools, in public parks, and on other sites available to the public. Because natural plant succession in Pennsylvania normally trends toward forest vegetation, forests usually characterize refuges and sanctuaries relatively undisturbed by people, and forested wetlands typically provide high quality habitat to wildlife. The significance of forest cover to wetland wildlife increases as the size of wetlands decreases, particularly in landscapes with intensive human activity.

Scrub and herbaceous wetlands also can serve as study areas and biological refuges. They are less screened visually and aurally from adjacent human activities by their relatively lower quantities of biomass. They provide key habitat for wetland plants and animals that require open sun reaching the soil surface. Herbaceous wetlands are prime locations for birders.

3. Water Quality and Quantity Protection and Drainage Patterns

Forest wetland vegetation has maximal effect on processes affecting water movement and interaction with the land. By their mass, trees are able to slow the energy of falling raindrops and thereby limit soil erosion. Similarly, their mass and shade render the affected ground beneath the trees moister and cooler than nearby areas open to the sun. Decaying leaves provide a surface that readily accepts precipitation and allows it to infiltrate soil rather than quickly running off the surface.

The interflow through soils in turn contributes to natural extended flow of streams, minimizing both flooding and stream dryup. Nutrients can be bound up in tree trunks for centuries, and thereby kept out of waterways. The complex chemical reactions in wetland soils allow bacterial denitrification fostered by the carbon from leaves and vital to preventing excess nitrate-nitrogen from reaching streams. Wetland tree roots also can help anchor banks of streams against erosion. Forest loss to other land uses in Pennsylvania occurs at the rate of about 150 acres per day (McCaskill *et al*. 2013). Presumably most of these converted lands are not wetland forests, inasmuch as PADEP acknowledges the loss of less than 100 acres of all wetlands annually via individual permits, including forested wetlands.

Scrub and nonpersistent herbaceous wetlands stockpile less biomass on the land surface year-round than forested wetlands. They may offer less protection to the soil than forested wetlands, and their smaller roots may provide less resistance to physical erosion of streambanks.

Discharges of wastewater can contain pollutants at sufficient concentrations to overwhelm the ability of natural wetland systems to accommodate the pollutants, resulting in severe damage to the wetland ecosystems by manure, sewage, spilled brine, oil, and other chemicals. Rubbish also can degrade general habitat functions in forest and other wetlands.

4. Shoreline Protection and Stormwater Shielding

Aside from those on the banks of lakes and large rivers, forested wetlands in Pennsylvania generally have limited opportunity to shield other areas from wave and storm damage. Tree roots can stabilize streambanks large and small against stormwater erosion. To a lesser degree scrub wetlands can function similarly. Shrub willows often are planted to stabilize shorelines.

Some herbaceous wetlands occupy the shallow fringes of large water bodies, where they serve to reduce wave action and encourage sedimentation (thereby protecting water quality).

5. Flood Storage

Forested wetlands often serve as temporary storage areas for storm and flood waters. The economic value of such storage increases annually as flood damages rise in response to increased runoff from a growing human population, impervious surfaces from ever-expanding land development, and storm events of increasing severity driven by global warming in response to the burning of fossil fuels. Many forest ecosystems are adjusted to and dependent upon seasonal flooding, unlike most human structures that are easily damaged even by short-term inundation during flood peaks. Scrub and herbaceous wetlands, provided that they are suitably located, can function equally as well as forested wetlands for temporary

stormwater storage, although they may not shade the stored water so effectively and therefore not keep its temperature so low as a dense forest cover.

6. Groundwater Discharge

Spring seep areas are characteristic along the base of slopes in Pennsylvania forested wetlands. The forest shade keeps summer temperatures low as groundwater travels over the land surface toward headwater streams. Trout are a major feature of Pennsylvania streams and much sought-after by anglers. Many Pennsylvania streams have water near the limit of summer warmth that trout can tolerate. Forested wetlands along watercourses are essential to maintaining temperatures low enough for trout to survive and reproduce as global warming continues in response primarily to the burning of fossil fuels. Conversely, because of the warmth of groundwater, spring seeps may become snow-free earlier than dry uplands, and thereby attract feeding turkeys and other wildlife.

Shrub and herbaceous wetlands also can be associated with seeps flowing toward small streams. They are less able to keep surface water temperatures low than forests because of their lesser shade, but they may transpire fewer gallons of water during the course of a hot day. As mentioned previously, groundwater seeps closely associated with masses of tree roots are especially attractive areas for overwintering bog turtles.

Forested Wetland with Seeping Groundwater Discharge.

7. Groundwater Recharge

Countless local topographic depressions in forested wetlands store precipitation, slow its movement toward streams during periods of flood, and enable it to recharge local groundwater during wet seasons. Recharged groundwater, in turn, typically finds outlets to local streams. Recharge can be greater in scrub and herbaceous wetland depressions, because their plant cover transpires less water into the atmosphere than large trees.

8. Pollution Prevention and Sediment Control

Forested wetlands prevent pollution of water bodies by reducing the erosive force of rainstorms. Their trees break the fall of droplets hitting leaves and branches; they anchor the soil with roots and cover it with absorptive leaf litter; their roots bind streambank soils against erosion. Forested wetland soils enable sedimentation, denitrification, and other biogeochemical processing as surface waters pass through. Scrub and herbaceous wetlands can function comparably, but provide less physical protection against soil erosion by precipitation. Forested buffers surrounding wetlands can provide the most effective long-term protection of wetlands from sediment influx originating in disturbed lands.

9. Human Recreation

Wetland forests provide recreational opportunities for Pennsylvania citizens and visitors, calling forth significant contributions to the economy of the Commonwealth on a sustainable basis by those who use the outdoors. Great numbers of people find the seasonally changing display of blooms and colored leaves highly attractive and a sharp contrast to landscapes in urban centers. Recreational hunters seek the game animals---deer, bear, squirrels, waterfowl, and other game birds---that depend on wetland as well as upland forests. Anglers depend on riparian forests to keep the Pennsylvania streams cool enough and to supply food for salmonids. Forested wetlands are especially effective in providing humans with natural landscapes contrasting sharply with urban commercial and industrial environments.

Scrub and herbaceous wetlands also provide recreational opportunities for hiking and for game habitat. Herbaceous wetlands often attract spectacular flocks of migratory waterfowl.

Palustrine Deciduous Scrub Opening in Needleaf-Dominated Bog on Peat.

Rosencrans Bog Natural Area, Clinton County. Photograph by Staff of The Western Pennsylvania Conservancy.

Through its recent draft technical guidance documents PADEP appears to be seeking to expand from a strictly acreage-based evaluation of wetland impacts and working instead toward a weighting of functions, indexing to reference ecosystems, and consideration of conditions adjacent to the affected wetland. State methodology also is just beginning to consider cumulative effects on a watershed basis, which is essential for rationally offsetting the negative side effects (externalities) of construction in wetlands. The proposed technical guidance draws conceptually on federally sponsored work on wetland functions that has been underway for twenty years (Smith *et al*., 1995) as well as the more recent work by Robert Brooks and his coworkers at Riparia, the Cooperative Wetlands Research Center at Pennsylvania State University. PADEP's current list of functions is displayed below.

Table 2
Wetland Functions and Their Value

Functions Related to Hydrologic Processes	Benefits, Products, and Services Resulting from the Wetland Function
Short-Term Storage of Surface Water: the temporary storage of surface water for short periods.	Onsite: Replenish soil moisture, import/export materials, conduit for organisms. Offsite: Reduce downstream peak discharge and volume and help maintain and improve water quality.
Long-Term Storage of Surface Water: the temporary storage of surface water for long periods.	Onsite: Provide habitat and maintain physical and biogeochemical processes. Offsite: Reduce dissolved and particulate loading and help maintain and improve surface water quality.
Storage of Subsurface Water: the storage of subsurface water.	Onsite: Maintain biogeochemical processes. Offsite: Recharge surficial aquifers and maintain baseflow and seasonal flow in streams.
Moderation of Groundwater Flow or Discharge: the moderation of groundwater flow or groundwater discharge.	Onsite: Maintain habitat. Offsite: Maintain groundwater storage, baseflow, seasonal flows, and surface water temperatures.
Dissipation of Energy: the reduction of energy in moving water at the land/water interface.	Onsite: Contribute to nutrient capital of ecosystem Offsite: Reduced downstream particulate loading helps to maintain or improve surface water quality
Functions Related to Biogeochemical Processes	**Benefits, Products, and Services Resulting from the Wetland Function**
Cycling of Nutrients: the conversion of elements from one form to another through abiotic and biotic processes.	Onsite: Contributes to nutrient capital of ecosystem. Offsite: Reduced downstream particulate loading helps to maintain or improve surface water quality.
Removal of Elements and Compounds: the removal of nutrients, contaminants, or other elements and compounds on a short-term or long-term basis through burial, incorporation into biomass, or biochemical reactions.	Onsite: Contributes to nutrients capital of ecosystem. Contaminants are removed, or rendered innocuous. Offsite: Reduced downstream loading helps to maintain or improve surface water quality.
Retention of Particulates: the retention of organic and inorganic particulates on a short-term or long-term basis through physical processes.	Onsite: Contributes to nutrient capital of ecosystem. Offsite: Reduced downstream particulate loading helps to maintain or improve surface water quality.
Export of Organic Carbon: the export of dissolved or particulate organic carbon.	Onsite: Enhances decomposition and mobilization of metals. Offsite: Supports aquatic food webs and downstream biogeochemical processes.
Functions Related to Habitat	**Benefits, Goods and Services Resulting from the Wetland Function**
Maintenance of Plant and Animal Communities: the maintenance of plant and animal community that is characteristic with respect to species composition, abundance, and age structure.	Onsite: Maintain habitat for plants and animals (e.g., endangered species and critical habitats), for rest and agriculture products, and aesthetic, recreational, and educational opportunities. Offsite: Maintain corridors between habitat islands and landscape/regional biodiversity.

Stressors

The functional values of wetlands can be reduced by many stressors, most of which are directly or indirectly the result of human activity and also are more intense and persistent than natural disruptive forces. The evolving PADEP list of stressors lists 37 kinds that are readily observable in the field, grouped into five categories (Draft Technical Guidance Document 310-2137-002, March 2014, p. 33). They prudently have left a blank for other, unlisted stressors in each of the five categories, for less commonly encountered conditions.

PADEP-listed Wetland Stressors.

Vegetation Alteration
Mowing
Moderate livestock grazing (within one year)
Crops (annual row crops, within one year)
Selective tree harvesting/cutting (>50% removal, within 5 years)
Right-of-way clearing (mechanical or chemical)
Clear cutting or Brush cutting (mechanized removal of shrubs and saplings)
Removal of woody debris
Aquatic weed control (mechanical or herbicide)
Excessive herbivory (deer, muskrat, nutria, carp, insects, etc.)
Plantation (conversion from typical natural tree species, including orchards)
Other:
Total Number:
Hydrologic Modification
Ditching, tile draining, or other dewatering methods
Dike/weir/dam
Filling/grading
Dredging/excavation
Stormwater inputs (culvert or similar concentrated urban runoff)
Microtopographic alterations (e.g., plowing, forestry bedding, skidder/ATV tracks)
Dead or dying trees (trunks still standing)
Thermal alteration (power plant or industrial discharges with evidence of high temperatures)
Stream alteration (channelization or incision)
Other:
Total Number:
Sedimentation
Sediment deposits/plumes
Eroding banks/slopes
Active construction (earth disturbance for development)
Active plowing (plowing for crop planting in past year)
Intensive livestock grazing (in one year, ground is >50% bare)
Active selective forestry harvesting (within one year)
Active forest harvesting (within two years, includes roads, borrow areas, pads, etc.)
Turbidity (moderate concentration of suspended solids in the water column, obvious sediment discharges)
Other:
Total Number:

Eutrophication
Direct discharges from agricultural feedlots, manure pits, etc.
Direct discharges from septic or sewage treatment plants, fish hatcheries, etc.
Heavy or moderately heavy formation of algal mats
Other:
Total Number:
Contaminant/Toxicity
Severe vegetation stress (source unknown or suspected)
Obvious spills, discharges, plumes, odors, etc.
Acidic drainages (mined sites, quarries, road cuts)
Point discharges from adjacent industrial facilities, landfills, railroad yards, or comparable sites
Chemical defoliation (majority of herbaceous and woody plants affected, within one year)
Fish or wildlife kills or obvious disease or abnormalities observed
Excessive garbage/dumping
Other:
Total Number:

The more numerous the stressors affecting a wetland, the lower its value. When rating the value of wetland conditions, the proposed PADEP scoring also assigns higher value to wetlands surrounded by forests than to those surrounded by scrub, and assigns higher value to those wetlands surrounded by scrub than to those surrounded by herblands or ponds. Managed wetland buffers are scored lower than wild, unmanaged buffers (Draft Technical Guidance Document 310-2137-002, March 2014, p. 33).

In 2006 PADEP sampled 204 wetlands and used their evolving protocols to rank the condition of those wetlands (PADEP 2014c). How representative the sampled wetlands might be of Pennsylvania wetlands as a whole was not stated, but the rankings from their protocol testing were reported as follows:

Condition Category	Number of Wetlands	Total Acreage	Percent of Resource
Highest	13	127.74	6.10%
High	59	556.19	26.70%
Medium	41	468.89	22.50%
Low	91	930.07	44.70%
Totals	**204**	**2082.88**	**100.00%**

Conversion of Woody Wetlands to Herbaceous Wetlands

Forest and scrub wetlands can be converted to herbaceous wetlands in various ways with effects more or less catastrophic, even if wetland conditions are not intentionally obliterated permanently to enable the construction of roads, buildings, or farm fields. Woody stems can be cut at the ground surface and merely the aboveground trees and shrubs removed, if the goal is to reduce disruption of the soil. More invasively, tree stumps and shrub roots can be grubbed. Biologically active soils can be removed entirely. Hydrology can be diverted or impounded. The amounts and kinds of functions lost and gained will be determined by what conditions previously existed in the wetland as well as the nature and extent of disturbance. If any one of the three major wetland characteristics (hydrophytic vegetation, hydric soils, or hydrology) is not or cannot be restored to natural conditions, then the conversion of wetland to non-wetland will be permanent. The conversion of forested wetlands to scrub or herbaceous wetlands is not readily reversible, inasmuch as forest regrowth at best requires many decades, and may be intentionally prevented by repeated cutting or by spraying herbicides.

When wetland vegetation is changed by people from forest or scrub to herbaceous, many of the wetland's functions can be altered. Detailed study is necessary in order to predict accurately the probable changes and compose plans for appropriate mitigation, because the affected functions will vary at each location supporting a natural wetland.

Where naturally variable wetland hydrology has been restored, some generalist wetland plants usually will follow quickly unless toxic substances also have been introduced, and hydric soils eventually will become recognizable after many years of weathering have elapsed. Pennsylvania wetlands evolved after the retreat of glacial ice, and their biota retains the ability to recover following natural disturbances that are less drastic than those of current technology. Unless artificial plantings are made to accelerate the establishment of desirable species, however, invasives that thrive in human-disturbed wetlands are likely to invade and crowd out preferred species of native plants. Construction activities usually provide ample opportunities for invasive plants and animals to arrive at construction sites. Various online sources provide links to information on invasive species, including those of the Governor's Invasive Species Council of Pennsylvania (www.invasivespeciescouncil.com), the Pennsylvania Department of Conservation and Natural Resources (www.dcnr.state.pa.us/conservationscience/), and the US Forest Service (www.fs.fed.us/invasivespecies).

If the objective is to restore pre-disturbance native wetland vegetation, then near-replacement of pre-disturbance hydrology and soils is most likely to yield the desired plant community. Such replacement only succeeds where careful investigation of plants, soils, and hydrology preceded the wetland disturbance, so that mitigation site modification effectively can mimic the structure of the lost

wetland. Light-tolerant herbaceous and scrub wetland plants can be restored more rapidly than forest vegetation, which takes many years for trees to reach mature size and natural diversity even where maximally successful. Protection of new plantings of native woody species from browsing deer and rabbits often is critical for the survival of the plants during the early years after wetland creation or restoration, and supplemental watering may be necessary during unusually dry years while root systems are being formed. Plantings of herbaceous wetlands can be devastated by migrating waterfowl. Moreover, the early-succession trees which will thrive in an open wetland only slowly are replaced by shade-tolerant species of late forest succession. Late-succession native herbs characteristic of mature Pennsylvania forested wetlands would not be expected to grow until the forest canopy has become reestablished and soil formation has proceeded to approximate natural conditions.

Compensatory mitigation in the form of replacement wetland creation or degraded wetland restoration is intended to result in functioning wetlands that do not require ongoing human intervention. Pennsylvania permit conditions long have required five years of monitoring for wetland restoration and creation projects along with written reports to PADEP, but post-construction monitoring has been sporadic at best and approved wetland restoration plans often have been unsuccessful in execution. Ponds are much easier and quicker to build than forested wetlands, but do not provide mitigation for various wetland functions. Similarly, basins engineered to detain stormwater flows from developed areas seldom result in high-value wetlands.

As one illustrative example of the conversion of woody wetlands to herbaceous cover, pipelines can be considered. The excavation of trenches for miles uphill, downhill, and across streams and wetlands is a catastrophic event followed by some measure of soil cover replacement on top of the pipes. But few pipeline operators

Pipeline construction through Pennsylvania wetlands. The corridor will be maintained free of woody vegetation after the pipe is buried.

Herbaceous Wetland 40 Years after Pipeline Installation.

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are prepared to allow reforestation to obscure right-of-way conditions. Thus pipelines are likely to involve vegetation stressors such as right-of-way clearing, clear-cutting of brush, and removal of woody debris both prior to and for the long term subsequent to pipeline installation. Mechanical clearing using equipment occurs, as does spraying with non-selective chemical herbicides to prevent the reestablishment of trees and shrubs so that rights-of-way can be quickly inspected on the ground and from the air.

In summary, the most probable, usually adverse effects of human conversion of forest or scrub to herbaceous wetlands on PADEP-listed wetland functions, the following would be expected and should be considered carefully:

1. **General Habitat and Natural Biological Functions**
   Aboveground biomass: decrease
   Forest interior habitat: loss
   Structural diversity: decrease within converted wetland
   Visual and aural screening from human activity: loss
   Local climate amelioration: decrease
   Evergreen winter cover for wildlife: loss
   Suitability for shade-loving species of plants: loss
   Production of mast (such as acorns) for wildlife: loss

Exposure to harsh wind, ice, sun: increase
Localized effects of global warming on biota: increase

2. **Study Areas and Refuges**
   Structural diversity of ecosystem: decrease within converted wetland
   Species diversity of plants and animals: decrease within converted wetland
   Visual and aural screening from human activity: loss
   Rare, ancient trees: loss

3. **Drainage Patterns, Water Quantity, and Water Quality**
   Streambank anchoring against erosion: decrease
   Soil stabilization: decrease
   Erosion and sedimentation: increase
   Nutrient storage in ecosystem: decrease
   Maintenance of cold water temperature for trout: decrease

4. **Storm Damage Shielding and Shoreline Protection**
   Streambank stabilization: decrease

5. **Flood Storage**
   Storage volume: no significant change

6. **Groundwater Discharge**
   Volume discharged: increase (reduced transpiration)

7. **Groundwater Recharge**
   Volume recharged: increase (if soil not disrupted)

8. **Pollution Prevention and Sediment Control**
   Erosion and sedimentation control: decrease

9. **Human Recreation**
   Landscape aesthetics: disruption
   Species composition, plants and animals: change
   Forest interior species: loss
   Maintenance of cold water temperature for trout: decrease
   View and hiking corridors: increase

How much functional loss will occur as a result of authorized conversion from forest or scrub to herbland at any wetland location will depend on the functions initially present in the forested wetland, the severity of the disruption to the elements of the environment such as its soil and surface elevation, the location of the converted area in the landscape, and its connection with other wetlands, especially along stream corridors. As some functions decrease, others may increase. The degree to which impacts are negative also depends on the context of reference: “edge” species such as whitetailed deer benefit from forest

fragmentation. Given the complexity of the natural world, under some sets of circumstances an anticipated negative change actually could prove beneficial. The functional loss of forested wetland is never quickly reversible, even if active maintenance were to stop, nor is it capable of offsite mitigation except, at best, until after long time delays.

Not currently identified by PADEP in its list of functions, conversion of forest to herbaceous wetland also entails a reduction in the ability of the wetland to affect human climate and to reduce air pollution. Herbaceous wetlands cannot rival forests in providing shade and screening people from wind. Likewise, they cannot promote the deposition of airborne pollutant particles or take up as much gaseous pollution as forest trees.

In principle, some of the functional losses of vegetation conversion eventually can be replaced by successful wetland mitigation onsite or offsite. But the actual substitution of lost functions by compensatory wetlands is not routine.

Wetland Compensatory Restoration and Creation

Because wetland damage and destruction routinely are authorized by permits, agencies by regulation are to require the restoration of temporary damage and the offsetting replacement of permanent loss of natural wetlands. A plan for the mitigation of unavoidable impacts by regulation is required as part of every individual joint permit application for wetland encroachments in Pennsylvania, other than "small" projects deemed by PADEP to have no significant impact on safety or protection of life, health, or the environment [25 *Pa. Code* 105.13(d)(1)(ix)]. Mitigation is defined (at 25 *Pa. Code* 105.1) as

> An action undertaken to accomplish one or more of the following:
>
> Avoid and minimize impacts by limiting the degree or magnitude of the action and its implementation.
>
> Rectify the impact by repairing, rehabilitating or restoring the impacted environment.
>
> Reduce or eliminate the impact over time by preservation and maintenance operations during the life of the action.
>
> If the impact cannot be eliminated by [the foregoing measures], compensate for the impact by replacing the environment impacted by the project or by providing substitute resources or environments.

PADEP records fewer than 100 acres of wetlands authorized for damage annually under individual permits during recent years, along with about 40 miles of streams (PADEP 2014c). These wetland statistics do not include losses through construction authorized by general permits. The statistics also do not include enforcement against unauthorized encroachments into streams and wetlands. (These stream statistics omit altogether about half of the land area of

the Commonwealth that occupies small watersheds where stream, but not wetland, destruction is authorized automatically by waiver.)

Since the 1990s PADEP has sought 1:1 minimum replacement for wetland acreage and functions, with a preference for mitigation adjacent to the loss and on the same property. Mitigation has been designed on an acreage replacement basis, typically with no allowance for less than complete success or the time during which wetland functions are absent. Functional replacement itself has seldom if ever been mandated. For enforcement cases, PADEP policy long has sought to require 2:1 acreage mitigation (PADEP 1992, 1997a). PADEP's stated preference has been for onsite mitigation close to the allowed wetland destruction rather than for remote offsite mitigation. Such mitigation would be undertaken by the permittee, who seldom is expert in wetland mitigation.

Because less intervention is required, the restoration of wetlands previously converted to agricultural uses typically is easier and less uncertain than conversion of uplands to wetlands. Wetland hydrology, for example, sometimes can be restored simply by crushing the drainage tiles installed by farmers in order to dry fields sufficiently for commercial crops. To the extent hydrology is removed temporarily, but then restored, wetland vegetation and some semblance of a wetland ecosystem can be recovered onsite where care is taken to reconstruct natural conditions insofar as practicable. Habitat functions often can be attained more readily in rural mitigation areas than adjacent to urban development sites where the restored or created wetlands are isolated from other areas of comparable habitat. Areas amenable to wetland restoration, however, often are located offsite at considerable distance from impacted areas and affected watersheds. Wetlands in stream valleys and floodplains do not necessarily substitute functionally for wetlands along headwater streams.

Successful wetland creation from dry land, even more than restoration, depends on careful identification of water budgets pre-construction to guide attempted restoration. Abundant field experience has demonstrated that small inaccuracies in analyzing or reconstructing hydrology will result either in dry non-wetlands or in open water ponds rather than vegetated wetlands.

Hydrology normally is removed by blocking the movement of water into a wetland (1) by diking or channelizing and diverting its flow and/or (2) by expediting the removal of water from a wetland by drainage pipes or pumps. Restoration of hydrology may require detailed attention to creating almost flat slopes, and often requires design for seasonal variability in wetness. Most natural wetlands, unlike typical farm ponds and detention basins, have very gently sloping land surfaces rather than abrupt banks. Effective wetness of surface soils within a wetland can be reduced by removal of natural vegetation on and adjacent to the mitigation area, impeding the recovery of wild plants and affecting the survival of replacement plantings. Hydrology derived from channelized stormwater can be toxic to wetland plants, if the stormwater brings in road salts, oil, excessive

nutrients, and other pollutants. Trees typically are less tolerant of salinity change than herbaceous plants (Adamus & Brandt 1990). Where urban runoff is the source of wetland hydrology, functional mitigation may be difficult to achieve.

Timely restoration of near-surface hydric soils that have wetland characteristics depends on the successful removal and segregation of topsoil, and then its replacement above the subsoil. By keeping holding time for stockpiled topsoil to a minimum, some of the natural seed bank can be salvaged to aid in wetland revegetation. Where the structure of the soil layers has been drastically altered, years are required for horizontal layering to become restored by natural weathering. If wetland hydrology was caused by impermeable subsurface layers such as clay lenses, and those are disrupted by excavation, capturing sufficient hydrology for wetland restoration may be impossible. If surface soil density is compacted, additional years are required for natural porosity to return along with the ability for water to penetrate (Stoler and Relyea 2011). The placement of only a few inches of soil on wetland trees and shrubs, as well as herbs, can be fatal to the disturbed plants. Mulch and short-lived cover crops can help stabilize soils without offering severe competition to desirable native wetland plants. A natural balance of groundwater recharge and discharge in constructed or restored wetlands is not easily achieved.

Given these technical considerations and the historical fact that practical humans long focused on draining and converting rather than restoring wetlands and wetland functions, the actual mitigation of wetland impacts has proved generally unsuccessful in Pennsylvania for many decades (*see*, for example, McCoy 1987, 1992; Kline 1991) and has not improved recently (Campbell *et al*. 2002, Cole & Shaffer 2002, Gebo & Brooks 2012, Hoeltje & Cole 2007, Kislinger 2008, PADEP 2014c). Seldom has mitigation created the same kind of wetlands as those damaged. Most attempted mitigation that succeeded in creating wet areas resulted in open water ponds rather than forested or scrub wetlands (Cole and Shaffer 2002). Monitoring and reporting on mitigation success on paper is required of applicants, but often not performed. PADEP staff seldom monitor wetland mitigation sites or require remedial measures of permittees.

PADEP has found that the ability of permittee-constructed mitigation

> to address the needs of a watershed is limited at best. Applicants generally do not have adequate resources to identify watershed needs, plan for and identify high value project sites, and/or secure rights to and produce significant restoration activities. (PADEP 2014c)

69 Permit Wetland Mitigations Scored by PADEP Interns, 1992-1995

Size (acres)	Success	Failure	Not Rated	% Success
0-.10	5	3	1	62.5
.10-.25	8	6	1	57.1
.25-.50	9	7	0	56.3
.50-1.0	11	3	0	78.6
1.0->	13	2	0	86.7
Total	46	21	2	68.7

Most Pennsylvania wetland impacts authorized by individual permit, after avoidance and minimization have been addressed, affect small acreages. Thus PADEP has implemented an acreage-based fee-in-lieu program to enable most permittees affecting small (0.5 acre or less) areas of wetland to substitute a one-time cash payment instead of undertaking their own construction of mitigation wetlands (PADEP 1997b). The half-acre "allowance" for cash contributions was deemed sufficient to allow any landowner enough wetland impact to build a house. Fees were set by PADEP based on its expectation that willing landowners across the Commonwealth would allow conversion of uplands to wetlands or restoration of wetlands with higher quality through voluntary cooperation with PADEP and the National Fish and Wildlife Foundation. This program has greatly assisted permittees, but it has not demonstrably resulted in compensatory wetland mitigation similar in kind or location to wetlands destroyed.

Contributions to the Washington, D.C.-based National Fish and Wildlife Foundation's Pennsylvania Wetland Replacement Project ID 95-096 became routine across the Commonwealth beginning in the 1990s. According to its web page, as of May 2014 this Foundation had sponsored 486 environmental enhancement projects of various kinds in Pennsylvania. Locational and descriptive information for these projects are displayed on an interactive map. But no data apparently exist comparing wetland acreage or functions lost to mitigation accomplished under the Pennsylvania in-lieu-fee program or identifying the geographical proximity of wetland losses versus gains on a watershed basis. Only first-time readers of PADEP regulations might expect any applicant eligible to use the Fund even to consider undertaking onsite mitigation, which is always far more expensive than scheduled contributions to the State's

Fund. The in-lieu fees long have represented a major subsidy to permittees from Pennsylvania residents and their environment (Schmid 1996a, b). Pennsylvania mitigation fees have been the same for Exceptional Value as for Other wetlands, and the acreage-based fees have been presumed to compensate for any and all wetland functions associated with the wetlands lost.

Pennsylvania Wetland Mitigation Replacement Fees (1997-2013).

De minimis impact less than or equal to .05 acre	$ 0.00
Greater than .05 acre to .10 acre	$ 500.00
Greater than .10 acre to .20 acre	$ 1,000.00
Greater than .20 acre to .30 acre	$ 2,500.00
Greater than .30 acre to .40 acre	$ 5,000.00
Greater than .40 acre to .50 acre	$ 7,500.00

Contributions to the Fund relieve permittees of any followup responsibility for mitigation monitoring or success. Between 1997 and 2013 the buying power of cash contributions to the Fund dwindled by about 30% due to inflation, while the market costs of wetland creation can be $100,000 per acre in some locations, according to the Pennsylvania Department of Transportation. Costs are less where free land and prison labor can be obtained (FHWA 2011). Moreover, the success of the wetland mitigation work done under PADEP's Replacement Project apparently has been limited and certainly has been sparsely reported. Pennsylvania's in-lieu-fee program was deemed unacceptable for use to satisfy federal wetland mitigation requirements in 2008, and its "grandfathering" expired in 2013 (33 CFR 332.8). Hence the PADEP currently is seeking federal approval for a new in-lieu-fee program (PADEP 2014c).

The generally laudable goals of the new program include (1) high quality mitigation addressing wetland functions as well as acreage, (2) ecologically based mitigation site selection, (3) efficiencies of scale in constructing, monitoring, and administering a few large mitigation projects instead of many small ones, (4) streamlined federal and State permit approvals, and (5) more effective accounting and compliance reporting (PADEP 2014c). PADEP claims that it has the expertise and staff to run an in-lieu-fee program effectively. As has been repeatedly demonstrated by PADEP staff and by independent academics, mitigation to date by permittees affecting more than the half acre of wetlands to which Fund contributions are limited typically has been of poor quality in Pennsylvania and has failed altogether in replacing the functions of wetlands lost.

The new PADEP technical guidance potentially represents an opportunity to have those who hope to benefit from damaging wetlands more effectively internalize the negative externalities of their conduct, a goal consistent with both Pennsylvania and federal law. It is not self-evident that the functions of multiple small, scattered wetlands high in the landscape can be replaced effectively by

larger wetlands in floodplains, and PADEP may be asked to address this issue, as well as many other technical details, prior to gaining federal approval for its proposed in-lieu-fee program. Unquestionably, more information will need to be generated during preparation and review of each application to damage wetlands, if new PADEP technical guidance is adopted along the lines of its current draft. A significant outcome should be the more effective tailoring of compensatory mitigation to the amount and type of wetland impacts. The full costs of mitigation should include both the risk of mitigation failure and the temporal lag between impacts and restoration of functions---which, for forested wetlands can be immense.

Only if this opportunity is fully exploited will future mitigation begin to compensate for permitted impacts in Pennsylvania. The new guidance also can provide a corrective to the mitigation failures and lack of accountability long prevalent in Pennsylvania, while reducing the previous economic subsidies encouraging private destruction of wetland resources. The new information available also should allow better public understanding of the external costs of development and the benefits of successful mitigation, particularly if public access to permit records is made electronically available.

It is high time that human behaviors with harmful side effects in Pennsylvania be mitigated more effectively to enable continued prosperity for its residents and the planet's survival, as well as compliance with Article 1, Section 27, of the Pennsylvania Constitution:

> The people have a right to clean air, pure water, and to the preservation of the natural, scenic, historic and esthetic values of the environment. Pennsylvania's public natural resources are the common property of all the people, including generations yet to come. As trustee of these resources, the Commonwealth shall conserve and maintain them for the benefit of all the people.

When completed, the new PADEP technical guidance may make possible the actual functional mitigation for conversion of forest and scrub wetlands to herbaceous wetlands. If effective, it also should help reduce so-called "natural" hazards from waters---hazards which are in fact failures of human design, construction, planning, and community development in areas subject to natural processes of stormwater movement. If the opportunity is missed, the alternative includes increased environmental plundering of remaining wetland resources, high costs for disaster survivors, especially the most vulnerable, as well as harm to communities and ever growing costs to taxpayers.

Completion of public review, PADEP revision, and implementation of the new technical guidance for wetland assessment and mitigation may take considerable time. Pennsylvania wetlands only slowly have begun to receive some attention from regulators in the context of damage by longwall (that is, high-extraction underground) bituminous coal mining, which was first allowed by Act 54 of 1994. PADEP long refused to recognize even the possibility of damage to wetlands from

longwall mining, but gradually has been implementing more thorough data collection for mine applications (Schmid & Co., Inc. 2000, 2010a, 2011a, 2012, 2013).

The minimal current PADEP information and review requirements for oil and gas permits provide virtually no assurance that wetlands will be identified and protected from this extractive industry, which currently is experiencing a boom across much of the Commonwealth. Similarly, PADEP has failed to protect too many streams, particularly those streams of highest ecological value (Van Rossum *et al*. 2011; Kunz 2011; Schmid & Co., Inc. 2010b). Oil and gas permit applications generate far less environmental information than coal mining applications. Proposed regulations governing surface oil and gas activities currently are under review (25 *Pa. Code* 78, Subchapter C). PADEP and the Environmental Quality Board are preparing responses to the 24,000 comments received on their proposed oil and gas regulations. New Chapter 78 regulations could specify protection for streams and wetlands far more effectively than the regulations they are replacing.

Whether the proposed wetland analysis and mitigation technical guidance will receive similar public attention remains to be seen. Its comment period is still open and likely to be extended.

Authorship

This report was prepared by James A. Schmid, a biogeographer and plant ecologist. Dr. Schmid received his BA from Columbia College and his MA and PhD from the University of Chicago. After serving as Instructor and Assistant Professor in the Department of Biological Sciences at Columbia University and Barnard College, he joined the environmental consulting firm of Jack McCormick & Associates of Devon, Pennsylvania. Since 1980 he has headed Schmid & Company of Media, Pennsylvania.

Dr. Schmid has analyzed and secured permits for some of the largest wetland mitigation projects in the mid Atlantic States, as well as a myriad of smaller projects. He is certified as a Senior Ecologist by the Ecological Society of America, as a Professional Wetland Scientist by the Society of Wetland Scientists, and as a Wetland Delineator by the Baltimore District, Army Corps of Engineers. He has served on the professional certification committees of the Ecological Society and the Society of Wetland Scientists.

When the US Fish & Wildlife Service Pleasantville Office evaluated actual compliance with approval conditions requiring mitigation by about 100 of the Clean Water Act Section 404 fill permits issued by the Corps of Engineers in the State of New Jersey during the period 1985-1992, every Schmid & Company mitigation project was judged in the field to exhibit full compliance with all permit requirements and mitigation goals. Schmid & Company mitigation projects

represented 21% of all the mitigation projects judged fully successful in New Jersey by USFWS in its written report to USEPA. Dr. Schmid analyzed and secured Wetland Mitigation Council approval for the first major freshwater mitigation bank in New Jersey on behalf of DuPont. That bank was donated to The Nature Conservancy.

Dr. Schmid has often analyzed environmental regulatory programs and commented on proposed regulations. His clients continue to include the construction industry, conservation groups, and government agencies, including the Pennsylvania Department of Environmental Protection.

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Thermal Impacts to Exceptional Value Waterbodies

in Pennsylvania Cut by Gas Pipeline Projects

DELAWARE RIVERKEEPER NETWORK

September 25, 2016

Contents

Introduction

Delaware Riverkeeper Network (DRN) deployed automatic temperature loggers in two freshwater streams and wetland complexes located in Pike County, PA that were crossed by two separate and segmented Tennessee Gas Pipeline (TGP) (Kinder Morgan Energy Partners, L.P.) natural gas transmission Right of Way (ROW) projects: the TGP 300 Line Upgrade and the TGP Northeast Upgrade Project (NEUP). The TGP 300 project was completed in 2011 and the line has been functional since November, 2011. Savantine Creek Wetland complex (W038) was cut across using an open cut during the TGP 300 project. The TGP NEUP was another segmented pipeline project that was completed in 2013 and has been functional since November 1, 2013. Both pipelines were additions to existing pipeline ROWs that were installed by TGP. Pinchot Brook was cut across during the NEUP phase of the pipeline project. The objective of the monitoring was to document potential thermal changes and impacts due to the constructed pipelines and forest clearing that occurred during these construction projects. Temperature monitoring probes were installed upstream and downstream of the pipeline cuts, and within the pipeline ROW for the Savantine Creek wetland complex (W038).

Project Maps and Watershed Characteristics in Study Area

Stream and wetland complexes selected for the temperature study were two tributaries to the Sawkill Creek watershed, Pinchot Brook, and Savantine Creek sub-watersheds. Pinchot Brook and Savantine Creek wetland complex are tributaries and make up two of the seven tributaries of the Sawkill Creek watershed (Gum Brook, Dimmick Meadow Brook, Vantine Brook, Craft Brook, and Sloat Brook are other tributaries of Sawkill Creek some of which were crossed by the TGP pipeline). Both tributaries and their associated wetland complexes flow into Sawkill Creek, an Exceptional Value, Migratory Fishery (EV, MF) waterbody of Pennsylvania. A stream classified as Exceptional Value Water (EV) is afforded special protection under PADEP's regulations (PA Code, Title 25, Chapter 93). This protection includes a requirement for more stringent planning and permitting processes, before a discharge is permitted to these streams. An EV designation indicates that the stream constitutes an outstanding national, state, regional, or local resource. These include: waters of national, state or county parks or forests; waters which are used as a source of unfiltered potable water supply; waters of wildlife refuges or state game lands; waters which have been characterized by the Pennsylvania Fish Commission as "Wilderness Trout Streams"; and other waters of substantial recreational or ecological significance. Anti-degradation requirements mandate that the water quality for EV waters remain unchanged and that the water quality for HQ waters remain unchanged except under special exceptions following socio-economic justification reviews. The Pennsylvania Natural Diversity Inventory (PANDI) classifies the Sawkill Creek as High Gradient Clearwater Creek communities (NC 517).

The TGP pipeline ROW cuts across other headwater tributaries of the Sawkill Creek watershed including Dimmick Meadow and Craft Brook, which means that this EV watershed has sustained multiple cumulative impacts to its headwater tributaries from pipeline crossings. These cascading impacts will likely continue over the life and maintenance of the ROW, and subsequent expansions of the pipeline project over time. Efforts were made by DRN to request that TGP be required to conduct its own waterbody monitoring along special protection anti-degradation waterway crossings to document potential changes and needed restoration. To DRN's knowledge, that was not required nor voluntarily conducted by TGP; agencies instead relied on mitigation measures, implementation of Best Management Practices (BMPs), and limited restoration and photo monitoring plans designed mostly around vegetation cover as an indicator to determine and monitor impacts and changes over time.

The temperature study by DRN was conducted in the late spring and summer of 2014 to document stream temperatures, to assess whether higher water temperatures were detected as a result of pipeline crossings. Within freshwater systems, water temperature is a controlling factor in ecosystem dynamics affecting dissolved oxygen, fish and macroinvertebrate habitat and diversity, aquatic organism physiology and metabolism, mortality, spawning migrations, amphibian life cycles, and egg hatching.[i] In many ways, thermal characteristics are responsible for establishing aquatic organism community composition, particularly in fisheries.[ii] Populations of native brook trout and wild brown trout can be found in Sawkill Creek and its tributaries. These cold water species require low temperatures that carry with it high dissolved oxygen concentrations in order to thrive. In addition, the streams of the Sawkill watershed maintain outstanding diversity of stream macroinvertebrates that are characteristic of cold, clean streams (see Pike County Conservation District stream surveys).

The glacial aquifer that underlies this area between Milford and Matamoras, PA, is one of the most productive in Pike County.[iii] Most businesses and residences along this narrow, 7-mile corridor rely on individual wells for water supply and septic systems for wastewater disposal. In November 1998, the *Pike County Water Supply Plan and Wellhead Protection Study* was completed, and a groundwater pollution vulnerability map was included (Gehringer-Roth Associates). Since groundwater is the main source of potable water in Pike County, each of these formations is considered to be a groundwater reservoir.[iv]

Pinchot Brook originates in Westfall Township from an unnamed pond and flows in a southwesterly direction until it meets with Sawkill Creek. Pinchot Brook encompasses 1.8 sq. miles of the Sawkill Creek sub-watershed and accounts for 7% of the watershed area. It flows for 5.4 miles before it meets the Sawkill Creek. Savantine Creek drains a large area of the northwestern headwaters of Sawkill Creek (4.9 sq. mile or 3,142 acres).

Savantine Creek has its headwaters in Shohola Township just east of the Twin Lakes watershed. It flows in a southeasterly direction until meeting up with Sawkill Creek in Milford Township.[v]

***Figure 1**. Overview Topo map of the TGP ROW pipeline cuts and study areas. Blue pins denote two tributaries and wetlands of the Sawkill Watershed that were a focus of this temperature study.*

Methodology

This study included the installation of five water temperature data loggers to determine if there are potential thermal impact differences to the waterbodies and wetlands being crossed by TGP. Data loggers were installed in the upstream and downstream pipeline ROW cuts along the Tennessee Gas Pipeline in Pike County, PA along two locations located in Delaware State Forest to document water temperatures near the TGP ROW. Calibrated HOBO's were installed and set to record hourly temperature data from May 23, 2014 to August 28, 2014 for four of the stations. Another station, Savantine Brook Wetland Complex ROW (W038), was added on July 1, 2014 and recorded temperature until August 28, 2014, within the pipeline ROW itself. Probes were visited and maintained regularly by DRN staff and additional field readings were taken during the study. There were some instances where the probes were out of the water due to low flows in the summer of 2014. All data are included in the tables and graphs within the body of this report, since hourly temperature readings average out despite occasional low flow conditions, due to the large size of the datasets.

HOBO Temperature Monitoring Locations and Summary Data

Figure 2. *Savantine Creek Wetland Complex – W038 and location of HOBO loggers – blue arrow denotes stream flow direction. 10377357 HOBO was placed within the ROW cut; ROW – 10377358 is downstream of the pipeline ROW cut and 10377360 is upstream of the pipeline ROW cut (blue arrow denotes stream flow) (points were documented from Google Earth, not in the field)*

Figure 3. *Pinchot Brook – location of 2 HOBO loggers upstream (10377359) and downstream (10311249) of pipeline cut.*

Pre and Post Pipeline cuts Photo-Documentation Time Series

Pre and Post Photos of Pinchot Brook along ROW – NEUP Expansion

Looking down to Pinchot Brook. Conditions before TGP NEUP expansion. Existing TGP ROW. Photo taken before leaf out - April 25, 2012, Standing on west side of Pinchot Brook from top of hill facing down to Pinchot Brook and wetland and east.

Pinchot Brook TGP 1950's Pipeline Cut. Note Phragmites and active ATV impacts. Photo April 25, 2012

April 25, 2012 – closer view of Pinchot wetland and stream – note ATV damage on opposite side of wetland and Phragmites. Standing on west side of Pinchot Brook, facing east.

Hobo Temp Station, Downstream of Pinchot Creek TGP NEUP Pipeline Cut in Forested Area. Photo taken 7/14/13

Close up of Hobo Temp Placement – Downstream of Pinchot Pipeline cut. Photo taken 7/14/13

TGP NEUP Active Pipeline Cut across Pinchot Brook, Photo taken 7/14/13. Standing in TWS on the east side of Pinchot Brook crossing.

TGP NEUP Active Pipeline Cut across Pinchot Brook, Standing on the east side of Pinchot brook crossing facing west. Photo taken July 14, 2013.

Savantine Creek Wetland Complex --- Pre and Post 300 Line Upgrade Cut

2008 Google Earth aerial – note the red lines are an estimate of the expansion of the ROW – note mature trees and shrubs present in the wetland.

2012 Google Earth imagery after the pipeline cut. W038 – note open water.

Savantine wetland complex W038 – Photo taken April 29, 2012. Note open water wetland converted from forested wetland. Note *Phragmites australis* in old ROW.

W038 was converted from a forested EV wetland to an open waterbody EV wetland. Photo taken 10/11/12. TGP 300 was completed and transporting natural gas by November 2011.

W038 Savantine Wetland Complex with pipeline crossing. Photo taken 10/11/12. TGP 300 upgrade – note open water conditions that were previously forested wetland habitat. Obligate vernal pool species were documented here on multiple field visits. Note *Phragmites australis* in wetland perimeter.

Note that bubbling of the wetlands (W038) and turbidity was observed on more than 6 field visits by Delaware Riverkeeper Network after new TGP 300 line placement. Bubbling was reported multiple times to agencies and FERC with concern of possible pipeline integrity or leaking issues. Decomposition from churned up soils may also contribute to conditions.

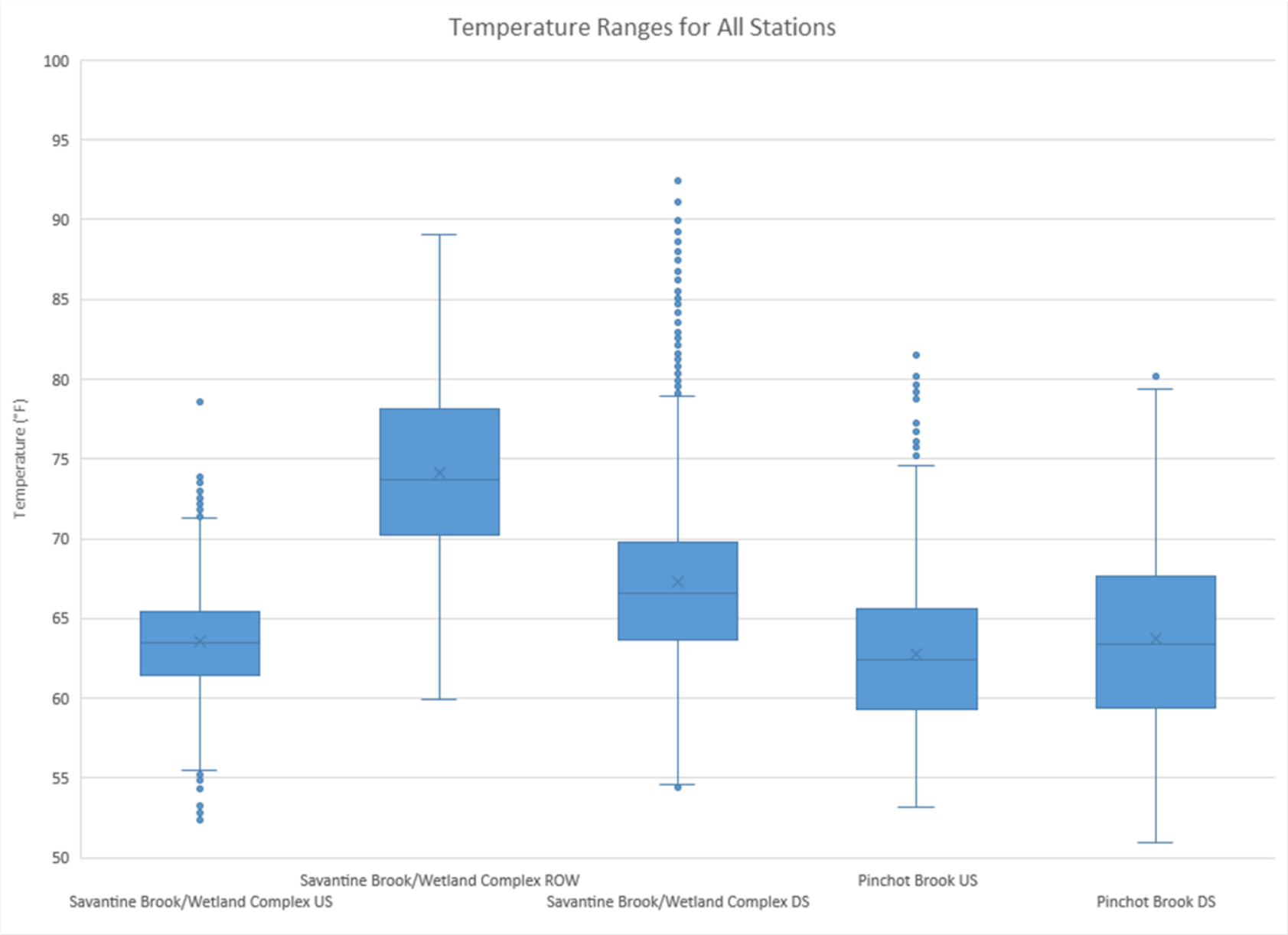
Results

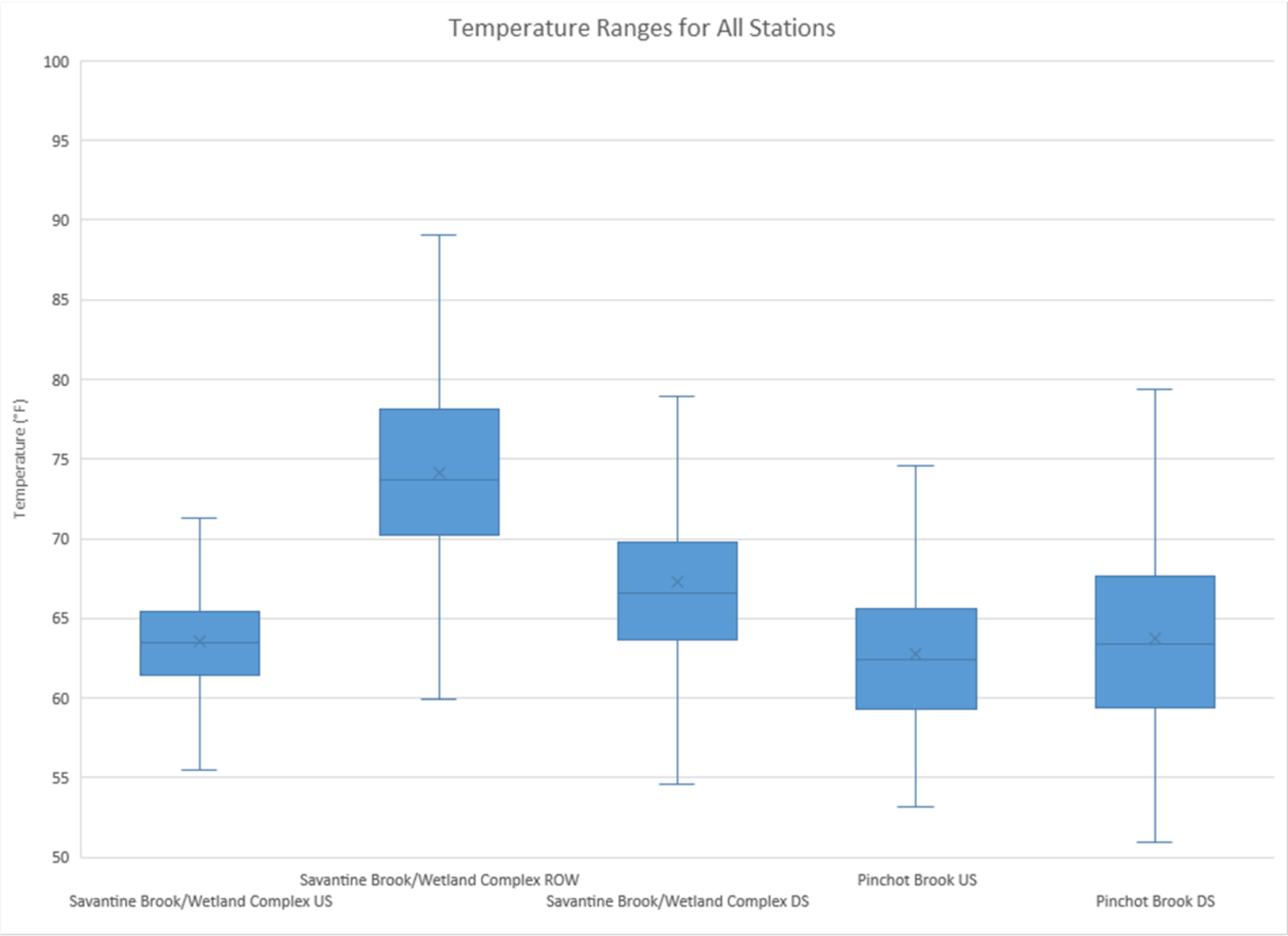
Summary Table for Savantine Creek Wetland Temperatures

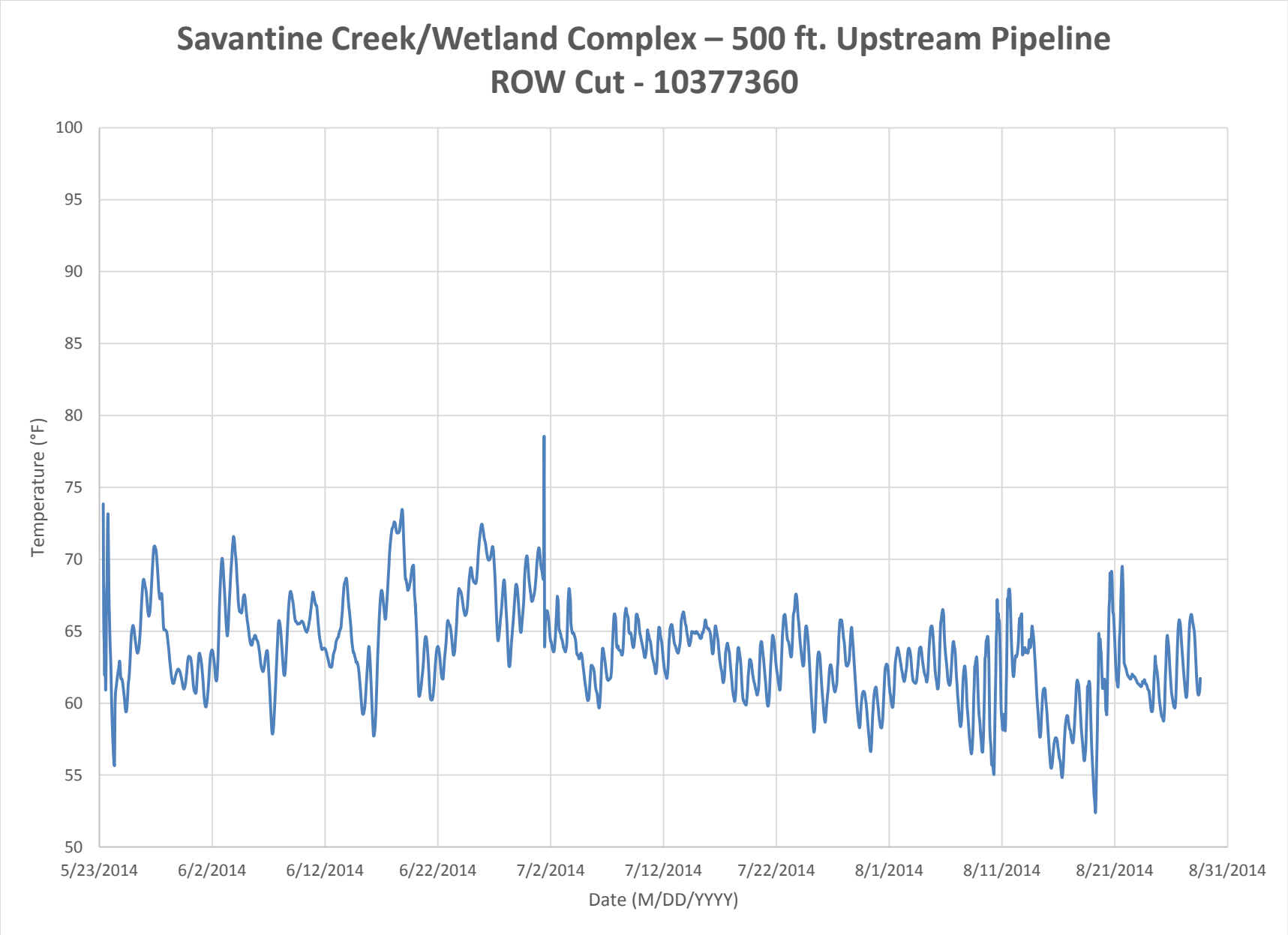
Savantine Creek/Wetland	# of readings	Avg. (°F)	Max (°F)	Min (°F)	Std. Dev.	Span of samples	Serial #
W038 Savantine Creek Wetland Complex (500' US pipeline cut)*	2335.00	63.53	78.56	52.38	3.34	5/23/14 – 8/28/14	10377360
W038 Savantine Creek Wetland Complex (Within Pipeline ROW Cut)*	1397.00	74.14	89.09	59.96	5.38	7/1/14 – 8/28/14	10377357
W038S1 Savantine Creek Wetland Complex (DS pipeline ROW cut)*	2336.00	67.26	92.48	54.39	5.40	5/23 – 8/28/14	10377358

Summary Table for Pinchot Brook Temperatures

Pinchot Brook	# of readings	Avg. (°F)	Max (°F)	Min (°F)	Std. Dev.	Span of samples	Serial #
Upstream Pinchot (US pipeline cut)	2336.00	62.77	81.64	53.12	4.65	5/23/14 – 8/28/14	10377359
Down Pinchot (DS pipeline cut)	2336.00	63.75	80.18	50.97	5.42	5/23/14 – 8/28/14	10311249


Temperature Ranges for All Stations
Temperature (°F)
100
95
90
85
80
75
70
65
60
55
50
Savantine Brook/Wetland Complex US
Savantine Brook/Wetland Complex ROW
Savantine Brook/Wetland Complex DS
Pinchot Brook US
Pinchot Brook DS


Temperature Ranges for All Stations
Temperature (°F)
100
95
90
85
80
75
70
65
60
55
50
Savantine Brook/Wetland Complex US
Savantine Brook/Wetland Complex ROW
Savantine Brook/Wetland Complex DS
Pinchot Brook US
Pinchot Brook DS


Savantine Creek/Wetland Complex – 500 ft. Upstream Pipeline
ROW Cut - 10377360
Temperature (°F)
100
95
90
85
80
75
70
65
60
55
50
5/23/2014
6/2/2014
6/12/2014
6/22/2014
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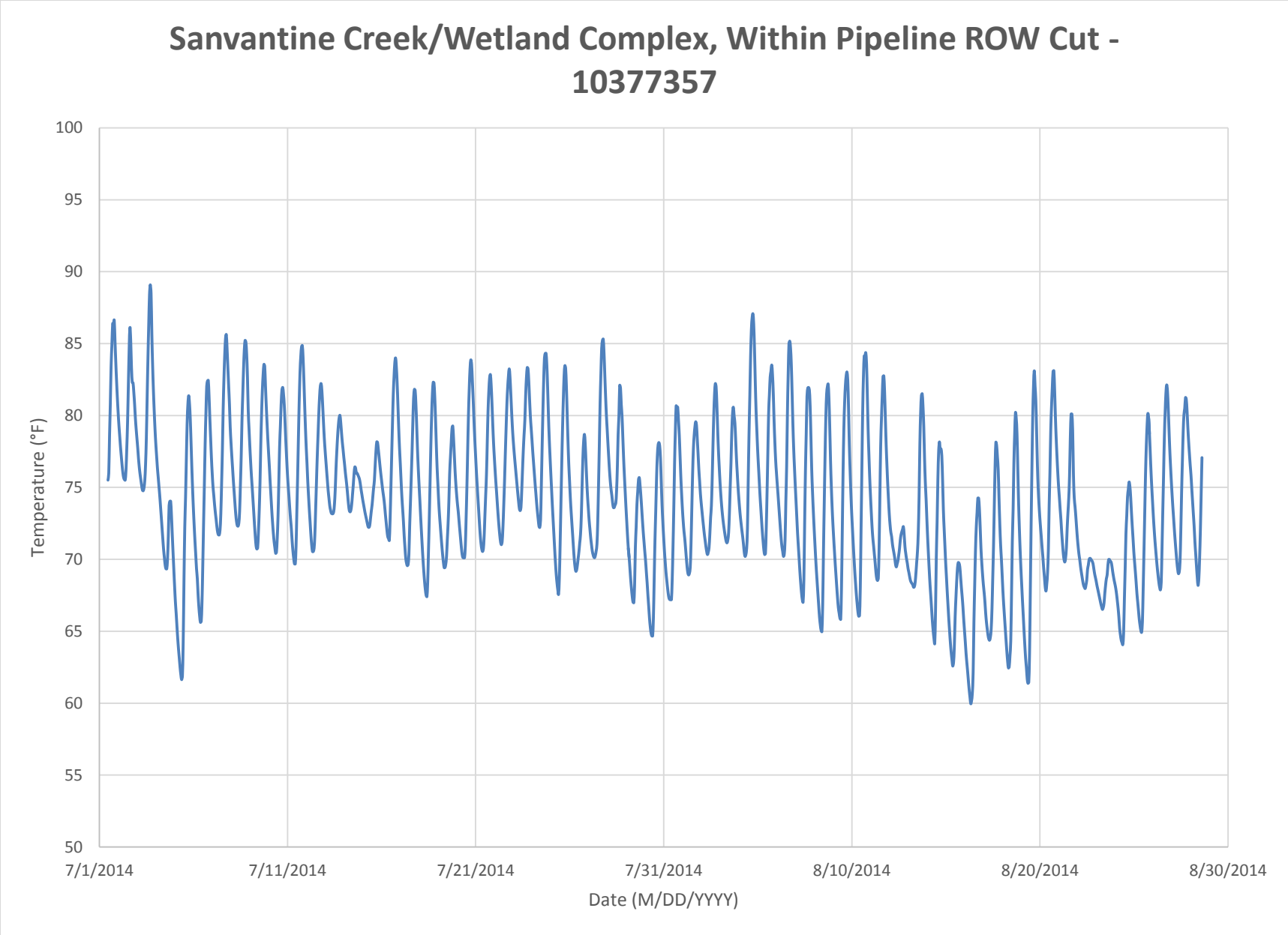
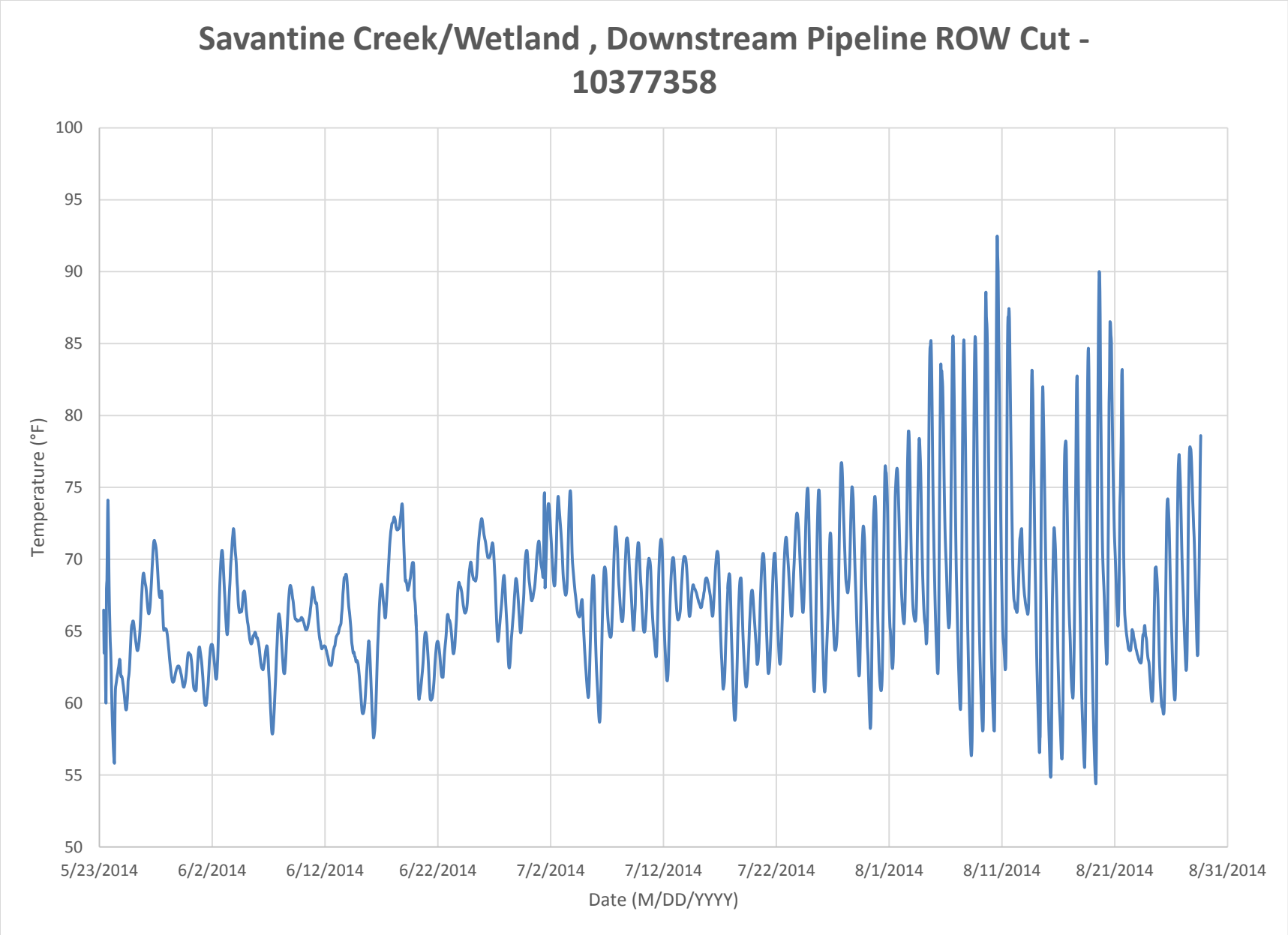
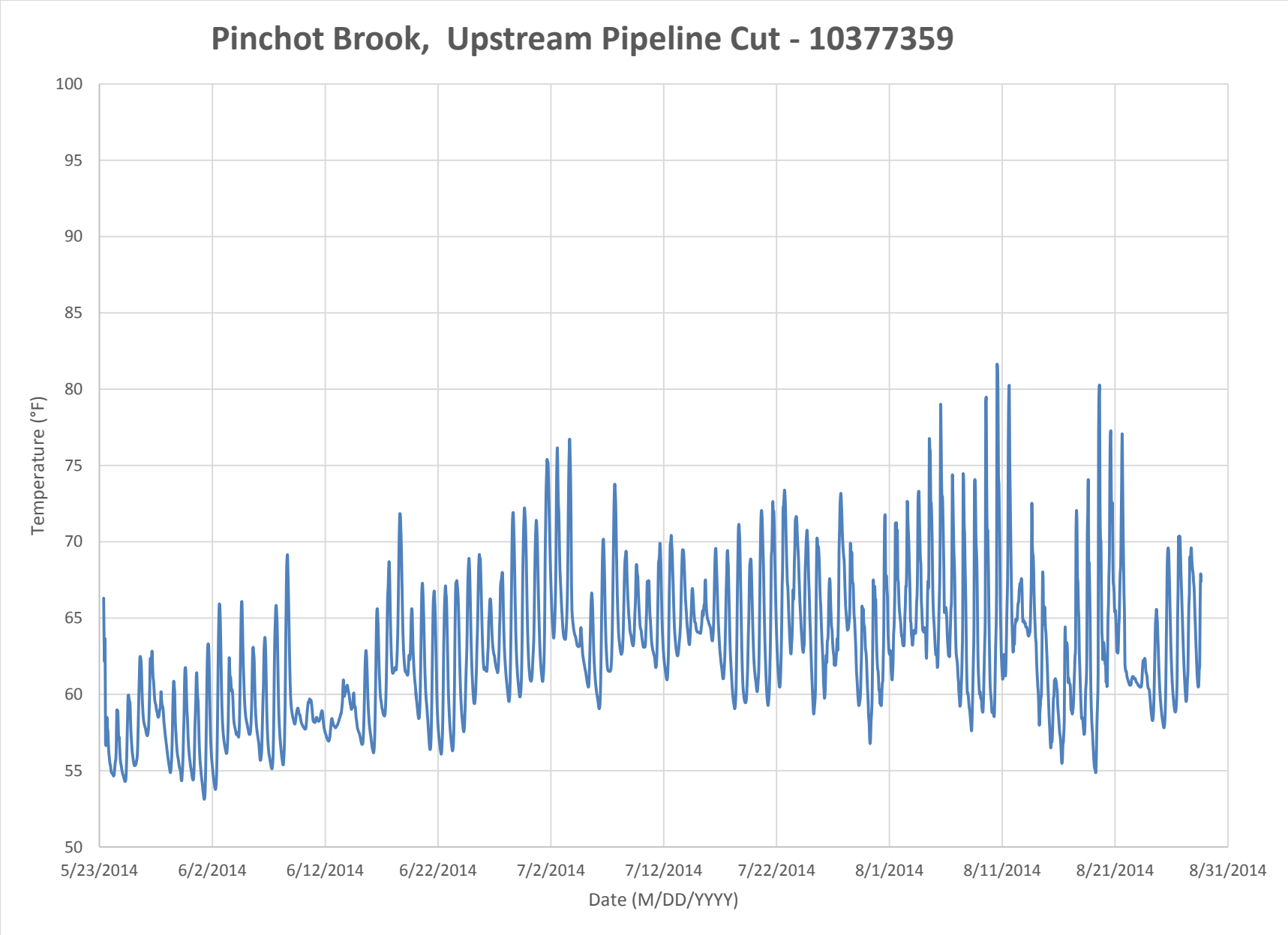
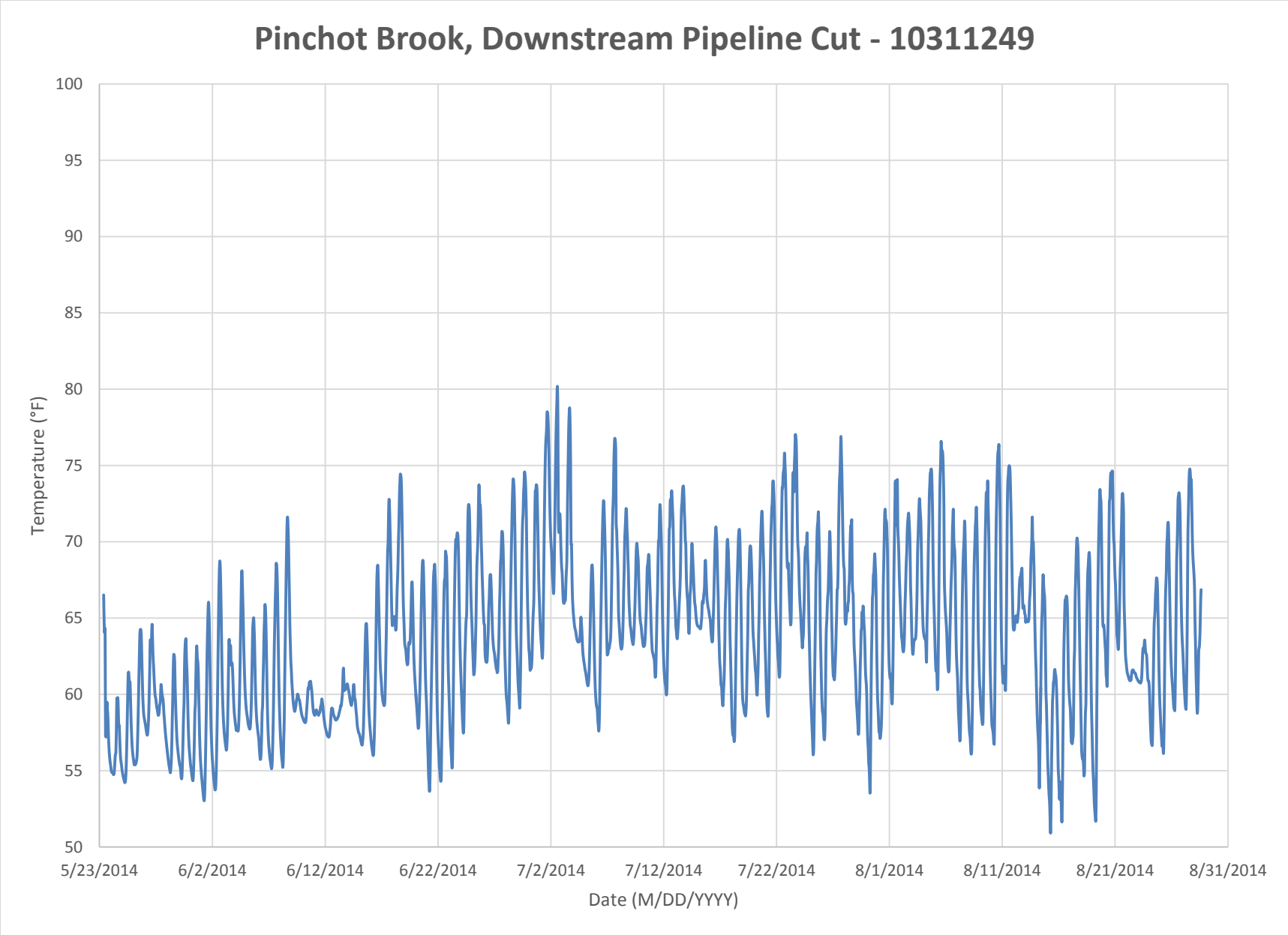
8/21/2014
8/31/2014
Date (M/DD/YYYY)


Sanvantine Creek/Wetland Complex, Within Pipeline ROW Cut - 10377357
100
95
90
85
80
75
70
65
60
55
50
Temperature (°F)
7/1/2014
7/11/2014
7/21/2014
7/31/2014
8/10/2014
8/20/2014
8/30/2014
Date (M/DD/YYYY)


Savantine Creek/Wetland , Downstream Pipeline ROW Cut - 10377358
Temperature (°F)
100
95
90
85
80
75
70
65
60
55
50
5/23/2014
6/2/2014
6/12/2014
6/22/2014
7/2/2014
7/12/2014
7/22/2014
8/1/2014
8/11/2014
8/21/2014
8/31/2014
Date (M/DD/YYYY)


Pinchot Brook, Upstream Pipeline Cut - 10377359
Temperature (°F)
100
95
90
85
80
75
70
65
60
55
50
5/23/2014
6/2/2014
6/12/2014
6/22/2014
7/2/2014
7/12/2014
7/22/2014
8/1/2014
8/11/2014
8/21/2014
8/31/2014
Date (M/DD/YYYY)


Pinchot Brook, Downstream Pipeline Cut - 10311249
Temperature (°F)
100
95
90
85
80
75
70
65
60
55
50
5/23/2014
6/2/2014
6/12/2014
6/22/2014
7/2/2014
7/12/2014
7/22/2014
8/1/2014
8/11/2014
8/21/2014
8/31/2014
Date (M/DD/YYYY)

Discussion

Pinchot Brook and Savantine Creek wetland monitoring data indicate long term thermal impacts, as observed in the summer of 2014, to the stream and wetland complexes from the TGP 300 and NEUP pipeline cuts – two separate but connected pipeline projects of the Tennessee Gas Pipeline. Savantine Creek was cut across in 2011, as part of the TGP 300 upgrade project. Pinchot Brook was cut across again in the next stage of the pipeline project, TGP NEUP, in 2013. Both streams show elevated thermal impacts, as a result of the pipeline cuts. Both streams and wetland complexes are designated Exceptional Value (EV).

Temperatures within the pipeline ROW cut of the 300 pipeline upgrade project for Savantine Creek and wetland complex had the highest average temperatures of all the probes, indicating direct thermal impacts due to the pipeline cut to this Exceptional Value waterway. Savantine Creek within the pipeline cut had an instream average temperature of 74.14° F and a maximum of 89.09°F, with a standard deviation of 5.38 (1,397 temperature readings collected). Downstream of the pipeline cut, temperatures were elevated for Savantine Creek with the average stream temperature at 67.26° F (N=2,336), whereas the station located upstream of the pipeline cut had an average temperature of 63.53° F (N=2,335). These impacts to Savantine Creek were documented in the summer of 2014. These temperatures indicate sustained thermal impacts to the stream more than 2.5 years after the 300 upgrade had been functional.

Pinchot Brook had two temperature stations installed in the summer of 2014 after the NEUP project had been completed with 2,336 hourly temperature readings collected. Pinchot Brook was cut across by the TGP NEUP in 2013 – this segment of the upgrade was constructed and was functional by November 2013. Pinchot Brook had higher temperatures downstream of the pipeline cut, though not as pronounced as that of the Savantine Creek wetland complex. However, the elevated temperatures were documented downstream of the 2013 pipeline cut to this Exceptional Value waterbody. Downstream of the pipeline cut, the average water temperature was 63.75° F while the upstream station had a mean temperature of 62.77° F. There was no probe available to install directly in the pipeline cut for Pinchot Brook.

Upstream and downstream HOBO locations for both waterbody complexes were located in forested areas outside of the pipeline ROW. The pipeline cuts for both complexes involved clearing of trees and shrubs for the pipeline projects which led to increased solar radiation to the stream column. Pipeline construction results in the loss of riparian (streamside) vegetation.[vi] For each of the pipeline crossings studied there was a resulting loss of vegetation and foliage associated with clearing the stream banks and wetlands. Riparian vegetation is an important part of a healthy ecosystem and protects the land adjoining a waterway which in turn directly affects water quality, water quantity, and stream ecosystem health. A stream corridor is composed of several essential elements including the stream channel as well as associated wetlands and vernal ponds, floodplains, and forests. The body of scientific research indicates that stream buffers, particularly those dominated by woody vegetation that are a minimum 100 feet wide, are instrumental in providing numerous ecological and socioeconomic benefits. [vii] [viii] A reduction in streamside healthy and mature streamside vegetation reduces stream shading, increases stream temperature and reduces its suitability for incubation, rearing, foraging and escape habitat.

Both streams had increased algae growth documented with photo-monitoring after the pipeline cuts were completed, indicating another sign of cascading stream changes indicative of opening up the canopy for these smaller headwater tributaries. Such cascading impacts include elevated nutrient levels downstream of the pipeline cuts.[ix] These thermal impacts can alter benthic diversity and can diminish or negate the ecosystem affects during the time of damage including other longer lasting cascading affects to ecosystem services otherwise provided by the invertebrates – including as food for other dependent species, the water quality benefits provided by invertebrates helping with nutrient breakdown, and the breakdown of instream detritus creating food for other species. [x] Invasive plant species colonization, mostly *Phragmites australis*, and spreading were also documented; another indication of forest fragmentation and changes to the ecosystem due to older and recent pipeline crossings. Finally increased visual turbidity and bubbling of the wetland was evident and documented at Savantine wetland complex long after project completion on multiple occasions. Both of these water complexes, Pinchot Brook and Savantine Creek wetland complex, have some open herbaceous or scrub-

shrub wetlands in their headwaters and nearby in addition to having the impact of the pipeline cuts which may contribute to some of the overall temperature findings. Both complexes were important to vernal pool species reproduction which may be impacted by the pipeline construction and maintenance activities as evidenced during field visits when amphibian species were observed using these complexes. Leopard frogs, green frogs, red-spotted newts, and spring peepers were documented using or surrounding these complexes at various times of the year. Research indicates that vernal pool species usually return to the same vernal pool year after year.

At times low flow conditions were present during the summer of 2014. During these low flow events the HOBO probes were not immersed in water and were recording air temperatures, rather than water temperatures. The data obtained from upstream and downstream locations in the Savantine Brook Watershed Complex are especially indicative of this. While analyzing the data, outlier points due to air temperature exposures were calculated and can be seen in the first box and whisker plot above. A second box and whisker plot is included that does not include these air temperature readings. During analysis, a mean temperature was calculated for the sampling stations without including the outlier air temperatures. The mean values were not significantly different than the mean values for the entire datasets. Thus, for the sake of inclusivity and transparency, datasets were used in their entirety for calculations in the tables and graphs for each station.

References

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[vii] Pipeline Associated Watercourse Crossings, 3rd Edition, publication prepared for CAPP, CEPA, and CGA by Tera Environmental Consultants, 2005.

[viii] Sweeney, B. W., et al. 2004. Riparian deforestation, stream narrowing, and loss of stream ecosystem services, PNAS, September 2004; 101: 14132-14137.

[ix] Zenes, Nicole K., Effects of Pipeline Construction Clear-Cutting on Water Quality in Northeastern Headwater Streams, May 2015.

[x] Sweeney, B. W., et al. 2004. Riparian deforestation, stream narrowing, and loss of stream ecosystem services, PNAS, September 2004; 101: 14132-14137.