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**Sent:** Friday, April 9, 2021 9:08:16 AM

**To:** 'Walthall, Anita'

**Cc:** 'Peter Anderson'; Tiffany Haworth ([thaworth@danriver.org](mailto:thaworth@danriver.org)); 'Steven Pulliam'; Emily Sutton; Anita Royston ([naacppittsyco@gmail.com](mailto:naacppittsyco@gmail.com)); Elizabeth Kostelny; Ivy Main ([ivy.main@sierraclub.org](mailto:ivy.main@sierraclub.org))

**Subject:** Comments on Lambert Compressor Station Air Permit (Email 1 of 2)

**Importance:** Normal

**Attachments:**

[Comments of SELC et al. on Lambert Compressor Station Air Permit 4-9-21.pdf](#); [Exhibits 1-10.pdf](#);

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Ms. Walthall: Please find attached the comments of the Southern Environmental Law Center, Appalachian Voices, Dan River Basin Association, Good Stewards of Rockingham, Haw River Assembly, Pittsylvania County NAACP, Preservation Virginia, and Sierra Club Virginia Chapter on the proposed stationary source permit to Mountain Valley Pipeline, LLC to construct and operate the Lambert Compressor Station (Registration No. 21652). Exhibits 1-10 to our comments are also attached to this email. Exhibits 11-28 will follow in a second email.

Please feel free to contact me with any questions.

Mark

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April 9, 2021

*Via email to anita.walthall@deq.virginia.gov*

Ms. Anita Walthall  
Virginia Department of Environmental Quality  
Blue Ridge Regional Office  
901 Russell Drive  
Salem, VA 24153

**Re: Proposed Stationary Source Permit to Mountain Valley Pipeline, LLC to  
Construct and Operate Lambert Compressor Station (Registration No. 21652)**

Dear Ms. Walthall:

The Southern Environmental Law Center, Appalachian Voices, Dan River Basin Association, Good Stewards of Rockingham, Haw River Assembly, Pittsylvania County NAACP, Preservation Virginia, and Sierra Club Virginia Chapter hereby submit the following comments on the Department of Environmental Quality's ("DEQ's") draft minor new source permit to Mountain Valley Pipeline, LLC ("MVP") to construct and operate the Lambert Compressor Station in Pittsylvania County. The interests of our organizations and members would be directly and adversely affected by the issuance of the proposed permit.

The Lambert Compressor Station would be part of the MVP Southgate Project, a proposed 75-mile gas pipeline that would extend from Pittsylvania County to Alamance County, North Carolina. The proposed facility would feature two natural gas-fired combustion turbines providing approximately 27,756 horsepower ("hp") of compression, gas-fired micro combustion turbines to provide on-site energy, a gas-fired heater, two 10,000-gallon produced fluid tanks, and other equipment.<sup>1</sup>

As set forth below, DEQ and MVP have neglected to adequately address environmental justice concerns, performed an incomplete site suitability analysis, and failed to demonstrate compliance with applicable air permitting requirements for the Lambert Compressor Station. Through these fundamental flaws in the permitting process, DEQ has failed to ensure that issuing the permit would adequately maintain air quality and protect local residents—in particular, communities of color and low-income communities—from disproportionate adverse health impacts. We ask that the permit be submitted for consideration by the State Air Pollution Control Board ("Board"); request a public hearing so that the Board hears directly from affected

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<sup>1</sup> Mountain Valley Pipeline, LLC, Article 6 Air Permit Application for the Lambert Compressor Station – MVP Southgate Project 2 (rev. 2, June 2020) ("June 2020 Permit Application").

community members along with other members of the public; and urge the Board to deny the permit.

**I. The Permitting Process for the Lambert Compressor Station Has Failed to Provide for the Fair Treatment and Meaningful Involvement of Environmental Justice Communities.**

As the United States Court of Appeals for the Fourth Circuit observed in *Friends of Buckingham v. State Air Pollution Control Board*, “[t]here is evidence that a disproportionate number of environmental hazards, polluting facilities, and other unwanted land uses are located in communities of color and low-income communities.”<sup>2</sup> And under Virginia law, in considering whether to approve a permit for the construction and operation of a facility, the Board is “require[d] ... to consider the potential for disproportionate impacts to minority and low income communities.”<sup>3</sup>

That requirement is now even more prominently enshrined in Virginia law than it was at the time of the Fourth Circuit’s *Friends of Buckingham* decision. The 2020 enactment of the Virginia Environmental Justice Act (“VEJA”) made it “the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth, with a focus on environmental justice communities and fenceline communities.”<sup>4</sup> Accordingly, it is Virginia policy to afford environmental justice communities fair treatment and ensure that they do not “bear[] a disproportionate share of any negative environmental consequence resulting from an industrial, governmental, or commercial operation, program, or policy.”<sup>5</sup> Under the VEJA, environmental justice communities must also be given meaningful involvement in agency decision-making processes; they must “have access and opportunities to participate in the full cycle of the decision-making process about a proposed activity that will affect their environment or health”; and decision-makers must “seek out and consider” the participation of affected community members, “allowing the views and perspectives of community residents to shape and influence the decision.”<sup>6</sup> Separate legislation enacted in 2020 made it an express DEQ policy “to further environmental justice.”<sup>7</sup>

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<sup>2</sup> *Friends of Buckingham v. State Air Pollution Control Bd.*, 947 F.3d 68, 87 (4th Cir. 2020) (quoting Nicky Sheats, *Achieving Emissions Reductions for Environmental Justice Communities Through Climate Change Mitigation Policy*, 41 Wm. & Mary Env’tl. L. & Pol’y Rev. 377, 382 (2017)).

<sup>3</sup> *Friends of Buckingham*, 947 F.3d at 87 (quoting brief filed on Board’s behalf); *see also* Va. Code § 10.1-1307(E)(3) (requiring the Board, in weighing approval of a permit, to consider “[t]he suitability of the activity to the area in which it is located”).

<sup>4</sup> Va. Code § 2.2-235.

<sup>5</sup> *Id.* § 2.2-234.

<sup>6</sup> *Id.*

<sup>7</sup> *Id.* § 10.1-1183; *see also id.* § 10.1-1182 (defining “environmental justice”).

Yet the treatment of environmental justice concerns by MVP and DEQ resemble in many ways the handling of the minor new source permit for the Buckingham Compressor Station, a part of the now-abandoned Atlantic Coast Pipeline that was proposed to be sited in the historic, predominantly African American community of Union Hill. In January 2020, the Fourth Circuit vacated that permit, finding that DEQ and the Board had “failed to make any findings regarding the demographics of Union Hill that would have allowed for a meaningful assessment of the likelihood of disproportionate harm” and “fail[ed] to consider the disproportionate impact on those closest to the Compressor Station.”<sup>8</sup> Similar flaws in the environmental justice analysis performed by MVP and DEQ for the Lambert Compressor Station render the proposed permit unlawful under *Friends of Buckingham* and impede the fair treatment and meaningful involvement of affected communities of color and low-income communities.

**A. DEQ and MVP’s public outreach efforts have been inadequate—particularly with respect to communities of color.**

Ensuring the meaningful participation of those most directly affected by DEQ’s permitting decisions—often, the communities most likely to bear the health risks associated with increased air pollution—requires ensuring that relevant information reaches affected community members at a time and in a manner that it is useful to them, and ensuring that they have a full opportunity to provide input. To date, MVP’s outreach efforts have fallen woefully short of ensuring that relevant information reaches affected community members and ensuring their input—especially with regard to the African American and Indigenous communities that will face potential impacts.

First, as MVP’s consultant, Dr. Alexa Lawrence, acknowledged, the number of interviews she conducted with community members was so small as to “not reflect sufficient practices to meet the standards of academic inquiry.”<sup>9</sup> Between June 22, 2020, and August 31, 2020, Dr. Lawrence conducted interviews with “members of the identified Indigenous communities native to this amainechi” and “non-Indigenous community members resident within a 10-mile radius of the proposed Lambert Compressor Station.”<sup>10</sup> On August 26, 2020, Dr. Lawrence conducted the “only physical visit to Pittsylvania County and the proposed Station site (and surrounding towns, etc.),” which “did not entail any person-to-person contact.”<sup>11</sup> To better ensure the participation of community members and to garner the concerns of the potentially affected community, DEQ should require MVP to increase the number of community members interviewed as well as the number of site visits.

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<sup>8</sup> *Friends of Buckingham*, 947 F.3d at 87, 92.

<sup>9</sup> Land & Heritage Consulting, LLC, Updated Community Impact Assessment of Lambert Compressor Station 35 (Feb. 23, 2021) (“Updated Community Impact Assessment”). Dr. Lawrence reported that outreach was limited by the timeline of the environmental justice review, the COVID-19 pandemic, and George Floyd-related community protests. *Id.* at 3.

<sup>10</sup> *Id.* at 38.

<sup>11</sup> *Id.* at 15 (emphasis added).

Second, MVP's consultant interviewed only one member of the Blairs, an "African-American community composed of Freedmen descendants."<sup>12</sup> Dr. Lawrence identified "a present and thriving African-American community, many of whom are descendants of the original Freedmen families," and connected to the current Blairs, Virginia community.<sup>13</sup> However, her outreach to the Blairs resulted in only one full interview.<sup>14</sup> To ensure that "the specific and unique needs and concerns" of the Blairs are more completely understood, DEQ should require MVP to continue "targeted outreach to that community."<sup>15</sup>

Lastly, community members did not receive timely notice of the proposed Lambert Compressor Station. Even at the time of the consultant's interviews—two years after MVP initially applied to DEQ for an air permit for the Lambert Compressor Station—"a majority of [their] respondents were not familiar with the proposed Station."<sup>16</sup> The NAACP's Pittsylvania County Branch did not receive notice of the project until December 2020.<sup>17</sup> In addition, "Indigenous community members consistently expressed disappointment and frustration that [MVP] had not previously conducted appropriate or authentic outreach to their communities, and cited multiple failures and missed opportunities for in-depth communication."<sup>18</sup> Until now, MVP's notice to the potentially affected community has been far from sufficient. As the permitting process continues, and throughout all future phases of the process, DEQ must ensure that community members have adequate notice of the relevant informational briefings, comment periods, and public hearings.<sup>19</sup>

**B. MVP and DEQ have failed to adequately describe the character of the local population.**

The Fourth Circuit has emphasized that DEQ and the Board could not meet their statutory duty to consider environmental justice in weighing a proposed permit where they "failed to make any findings regarding the character of the local population."<sup>20</sup> The Fourth Circuit vacated the air

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<sup>12</sup> *Id.* at 4.

<sup>13</sup> *Id.* at 53.

<sup>14</sup> *Id.*

<sup>15</sup> *Id.* at 4.

<sup>16</sup> *Id.* at 40.

<sup>17</sup> *Pittsylvania NAACP Asks DEQ to Refer MVP Air Permit to Air Pollution Control Board*, Chatham Star-Tribune, Mar. 8, 2021, <https://bit.ly/3bvQDnR> (**Exhibit 1**); Transcript of Lambert Compressor Station Public Hearing at 15:7–10 (Feb. 8, 2021), <https://bit.ly/3bvRZ1W> (testimony of Pittsylvania County NAACP president Anita Royston).

<sup>18</sup> Updated Community Impact Assessment at 44.

<sup>19</sup> DEQ, Draft Engineering Analysis, MVP Southgate Project – Lambert Compressor Station 19 ("Draft Engineering Analysis").

<sup>20</sup> *Friends of Buckingham*, 947 F.3d at 86.

permit DEQ issued to the Buckingham Compressor Station due, in part, to DEQ and the Board's "fail[ure] to make any findings regarding the demographics of Union Hill that would have allowed for a meaningful assessment of the likelihood of disproportionate harm."<sup>21</sup> Because MVP's environmental justice review, approved by DEQ, similarly fails to describe the character of the local population sufficiently to allow for a meaningful assessment of disproportionate harm, it cannot support the issuance of the proposed permit.

First, to determine whether any environmental justice communities existed in the area around the compressor station, MVP "looked to the latest census block group data."<sup>22</sup> Within this 1-mile radius, MVP utilized the U.S. Environmental Protection Agency's ("EPA's") EJSCREEN tool to show that the minority population is 22%, thus not meeting the criteria of a "community of color" under the VEJA.<sup>23</sup> While one of the census block groups in proximity to the compressor station does "qualif[y] as a community of color," MVP downplayed this finding by stating that the 1-mile study area "contains one very small part of a census block group that qualifies as a community of color under VEJA."<sup>24</sup> DEQ seemed to accept MVP's claim that "no environmental justice community bears a disproportionate share" of impacts from the proposed Station.<sup>25</sup> However, the results of this EJSCREEN analysis by MVP are at odds with the Updated Community Impact Assessment of Lambert Compressor Station prepared for MVP by Land & Heritage Consulting, LLC. This updated impact assessment shows that within a 3-mile radius of the proposed compressor station, there were "four communities that meet the 'environmental justice community' parameters as defined in the Virginia Environmental Justice Act."<sup>26</sup>

While EJSCREEN can be a helpful "pre-decisional screening tool," EPA instructs that, due to its exclusive reliance on census data, EJSCREEN is not to be used "[a]s a means to identify or label an area as an 'EJ community'" or "[a]s a basis for agency decision-making or making a determination regarding the existence or absence of EJ concerns."<sup>27</sup> As EPA has cautioned, "[t]he fact that census data can only be disaggregated to certain prescribed levels (e.g., census tracts, census blocks) suggests that pockets of minority or low-income communities, including those that may be experiencing disproportionately high and adverse effects, may be

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<sup>21</sup> *Id.* at 87.

<sup>22</sup> Mountain Valley Pipeline, LLC, Supplemental Information on Environmental Justice: Supplement to Application for Article 6 Air Permit for the Lambert Compressor Station – MVP Southgate Project 9 (Sept. 2020) ("Supplemental Information on Environmental Justice").

<sup>23</sup> *Id.* at 10.

<sup>24</sup> *Id.* at 12.

<sup>25</sup> Draft Engineering Analysis at 16.

<sup>26</sup> Updated Community Impact Assessment at 1.

<sup>27</sup> EPA, *How Does EPA Use EJSCREEN?*, <https://bit.ly/3ds3cAm> (last visited Apr. 2, 2021) (**Exhibit 2**).

missed in a traditional census tract-based analysis.”<sup>28</sup> Even MVP acknowledges that “census data is only a starting point to ‘flag’ potential environmental justice communities” and that “local site visits and/or calls should be conducted to identify localized pockets of minority or low-income persons overlooked by census data.”<sup>29</sup> Yet, as discussed in Section I.A, above, MVP’s consultant made only a single site visit and interviewed only a small number of community members.

Second, *Friends of Buckingham* made clear that where there is “conflicting evidence about whether and how [a certain community] [is] a ‘minority’ environmental justice population,” it is DEQ and the Board’s responsibility to resolve this conflict.<sup>30</sup> Here, MVP’s EJSCREEN-based environmental justice analysis is at odds with the findings of its own consultant, which identified *four* environmental justice communities in close proximity to the proposed compressor station. DEQ has an obligation to address this conflict.

Third, in its revised application, MVP claimed that it “communicated with local leaders to determine whether any ‘localized pockets’ of minority persons have been overlooked by census data.”<sup>31</sup> These “communications” led MVP to conclude that “the African-American population present within the 1-mile study area is less than reflected in the census block groups as a whole, possibly as low as five to seven percent, and no distinct geographic areas within that area contain localized pockets of African-Americans or other populations.”<sup>32</sup> MVP went on to claim—again, based on “communicat[i]ons with local leaders”—that the 1-mile radius around the proposed compressor station site “contains one of the more affluent pockets within the affected census blocks.”<sup>33</sup> Yet MVP did not attribute this information to any particular individuals, nor did it offer any data to support them. DEQ should require MVP to substantiate these purported findings by identifying their sources and providing supporting data.

Fourth, MVP’s use of a 1-mile radius around the proposed compressor station as the outer geographic limit of its environmental justice analysis was unduly limited. MVP maintained that it selected the 1-mile radius “because it encompasses the population most likely to be impacted, if at all, by this minor source of air emissions.”<sup>34</sup> Additionally, MVP claimed that “[a]ir modeling confirms that use of a 1-mile radius is reasonable and appropriate.”<sup>35</sup> Yet MVP’s use of a 1-mile radius is at odds with the methodology of MVP’s own consultant, who utilized

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<sup>28</sup> EPA, *Final Guidance for Incorporating Environmental Justice Concerns in EPA’s NEPA Compliance Analyses* § 2.1.1 (1998), <https://bit.ly/3r7w7zj> (“NEPA EJ Guidance”).

<sup>29</sup> Supplemental Information on Environmental Justice at 5 (quoting VDOT, *Environmental Justice Guidelines* 7, <https://bit.ly/39tvfOo>).

<sup>30</sup> *Friends of Buckingham*, 947 F.3d at 87–88.

<sup>31</sup> Supplemental Information on Environmental Justice at 12.

<sup>32</sup> *Id.*

<sup>33</sup> *Id.* at 13.

<sup>34</sup> *Id.* at 9.

<sup>35</sup> *Id.*

3-mile, 5-mile, and 10-mile radii.<sup>36</sup> Dr. Lawrence acknowledged that the VEJA requires a focus on “fenceline communities” and used the term in her report as “referring to communities within a 3-mile radius of the station, consistent with definitions found in the environmental justice literature.”<sup>37</sup>

MVP’s arbitrary 1-mile radius is also inconsistent with technical guidance promulgated by EPA, which provides that when mapping the location of polluting sources, “[a]nalysts must decide what distance from the facility most accurately reflects the community’s exposure to a stressor; *no single specific distance is appropriate for all analyses*.”<sup>38</sup> Furthermore, EPA has noted that “proximity-based analyses may also vary with different geographic units of analysis,” and for this reason analysts “should explore alternative geographic units or distances when defining proximity to a source, and describe the choices and assumptions that are used in selecting particular buffers.”<sup>39</sup> Here, MVP has not “explore[d] alternative geographic units” or adequately described the choices and assumptions that led it to use a 1-mile radius. If MVP’s assertion that a 1-mile radius is appropriate “because it encompasses the population most likely to be impacted, if at all, by this minor source of air emissions,” it begs the question why MVP’s own consultant utilized significantly larger radii for her environmental justice review. Moreover, MVP’s claim that “[a]ir modeling confirms that use of a 1-mile radius is reasonable and appropriate” is as circular as it is conclusory, and is not adequately explained. DEQ should require MVP to justify its use of a 1-mile radius and explain why it is more appropriate than the 3-, 5-, and 10-mile radii used by its own consultant.

Finally, MVP has not adequately considered the impact of the proposed compressor station on Freedmen descendants associated with the Blairs community. In her updated impact assessment, MVP’s consultant noted “the presence of an extensive and continuous, yet dispersed, African-American community composed of Freedman descendants [the Blairs] ... located approximately 14 miles from the proposed Station site.”<sup>40</sup> The consultant met with a single member of the Blairs, reporting that she was “unable to interview any other members of that community for this report, either during our initial phase of outreach or during later outreach conducted in November 2020.”<sup>41</sup> Consistent with the recommendation of MVP’s consultant,

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<sup>36</sup> Updated Community Impact Assessment at 5.

<sup>37</sup> Land & Heritage Consulting, LLC, Community Impact Assessment of Lambert Compressor Station at 3–4 (Sept. 2020); *see also* Updated Community Impact Assessment at 2 (referring to “the immediate 3-mile ‘fenceline community’ radius reflected in currently published literature” and citing Env’tl. Just. Health All. for Chem. Pol’y Reform et al., *Life at the Fenceline: Understanding Cumulative Health Hazards in Environmental Justice Communities* (2018), <https://bit.ly/3sE6BT3> (**Exhibit 3**)).

<sup>38</sup> EPA, *Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* 50 (June 2016), <https://bit.ly/3fryDNK> (emphasis added).

<sup>39</sup> *Id.*

<sup>40</sup> *Id.*

<sup>41</sup> *Id.*

DEQ should require MVP to continue “targeted outreach to that community so that the specific and unique needs and concerns of its members are explicitly understood.”<sup>42</sup>

**C. MVP and DEQ have neglected to consider the potential for disproportionate adverse impacts on the affected community.**

The failure of MVP and DEQ to conduct an adequate study of the population potentially affected by the Lambert Compressor Station has prevented them from satisfying the other primary requirement of an environmental justice analysis clearly articulated in *Friends of Buckingham*: considering the potential for disproportionate adverse impacts on a community of color or low-income community most affected by the proposed compressor station.<sup>43</sup> In *Friends of Buckingham*, the Fourth Circuit faulted the Board for its “fail[ure] to make any findings regarding the demographics of Union Hill that would have allowed for a meaningful assessment of the likelihood of disproportionate harm.”<sup>44</sup> Here, as set forth in Sections I.A and I.B, above, MVP’s outreach was inadequate and its findings about the character of the local population were insufficient to support a meaningful assessment of disproportionate harm.

But the deficiencies in MVP’s consideration of disproportionate impacts, adopted by DEQ, go beyond the failure to adequately describe the character of the local population. MVP also claimed that no environmental justice community would bear disproportionate adverse health impacts “because *no* community will face any appreciable health risk as result of facility’s emissions, notwithstanding any particular sensitivities or vulnerabilities in the EJ community.”<sup>45</sup> MVP based this conclusion largely on the argument—rejected by the Fourth Circuit in *Friends of Buckingham*—that “compliance with the [National Ambient Air Quality Standards (“NAAQS”)] demonstrates no negative impacts on environmental justice communities.”<sup>46</sup> Because the Lambert Compressor Station would not cause or contribute to an exceedance of the NAAQS, MVP maintained, there could be no disproportionate health impacts on communities of color or low-income communities in the vicinity of the station. And DEQ accepted this claim, noting that MVP’s review “provides an evaluation of impacts from the proposed Station, and concludes that no environmental justice community bears a disproportionate share of any such impacts.”<sup>47</sup>

But it was precisely this line of reasoning that the Fourth Circuit dismissed in *Friends of Buckingham*. There, DEQ had expressed the view that “if ... all the health based standards are being complied with, then there really is no disproportionate impact, because everyone is being

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<sup>42</sup> *Id.*

<sup>43</sup> See *Friends of Buckingham*, 947 F.3d at 91–92.

<sup>44</sup> *Id.* at 87.

<sup>45</sup> Supplemental Information on Environmental Justice at 14.

<sup>46</sup> *Id.* at 17.

<sup>47</sup> Draft Engineering Analysis at 16.



subjected to the same air pollution but well below health-based standards.”<sup>48</sup> The Fourth Circuit squarely rejected this view, which the Board had adopted in approving the permit for the Buckingham Compressor Station:

Even if all pollutants within the county remain below state and national air quality standards, the Board failed to grapple with the likelihood that those living closest to the Compressor Station—an overwhelmingly minority population according to the Friends of Buckingham Survey—will be affected more than those living in other parts of the same county. ... [T]he Board’s failure to consider the disproportionate impact on those closest to the Compressor Station resulted in a flawed analysis.<sup>49</sup>

The Fourth Circuit had good reason to dismiss the notion that mere compliance with NAAQS means no disproportionate adverse health risks. Whether a facility would allow an area to comply with air quality standards is distinct from whether it would have a disproportionately high and adverse effect on environmental justice populations.<sup>50</sup> Otherwise, consideration of disproportionate harm would be required only for facilities that would contribute to a violation of air quality standards—and thus could not lawfully be built.

Such an approach would also ignore the fact that ozone—which results from the interaction of nitrogen oxides (“NO<sub>x</sub>”) and other atmospheric compounds—and fine particulate matter (“PM<sub>2.5</sub>”) cause adverse health effects even at levels below NAAQS.<sup>51</sup> Exposure to PM<sub>2.5</sub> increases the risk of asthma, heart attacks, and death—even at levels that do not exceed NAAQS.<sup>52</sup> These health effects are of particular concern given that African American populations have a greater prevalence of asthma, lung cancer, and other health issues exacerbated by the pollutants that would be emitted from the Lambert Compressor Station.<sup>53</sup>

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<sup>48</sup> *Friends of Buckingham*, 947 F.3d at 91 (quoting DEQ’s testimony at November 9, 2018 Board meeting).

<sup>49</sup> *Id.* at 91–92.

<sup>50</sup> NEPA EJ Guidance § 3.2.2 (explaining that even harms that are not “significant” in the NEPA context may disproportionately or severely harm environmental justice communities).

<sup>51</sup> *See Friends of Buckingham*, 947 F.3d at 92 (“any amount of PM<sub>2.5</sub> in the system is harmful”); *Am. Trucking Ass’n v. EPA*, 283 F.3d 355, 360 (D.C. Cir. 2002) (recognizing the “lack of a threshold concentration below which [particulate matter is] known to be harmless”); NAAQS for Particulate Matter, 78 Fed. Reg. 3086, 3098 (Jan. 15, 2013) (recognizing that there is “no population threshold, below which it can be concluded with confidence that PM<sub>2.5</sub>-related effects do not occur.”).

<sup>52</sup> *Friends of Buckingham*, 947 F.3d at 92.

<sup>53</sup> *See id.* at 88.

Accordingly, it was improper for MVP and DEQ to find no disproportionate impact merely on the basis that NAAQS were met. As the Fourth Circuit held in *Friends of Buckingham*, “blindly relying on ambient air standards is not a sufficiently searching analysis of air quality standards for an EJ community.”<sup>54</sup> MVP and DEQ must do more.

In addition, MVP asserts that the communities in the vicinity of the proposed Lambert Compressor Station “are ... not overburdened by other sources of pollution.”<sup>55</sup> Yet MVP acknowledges that the area within a 1-mile radius of the site is already above the state average for exposure to PM<sub>2.5</sub>,<sup>56</sup> even before the addition of a compressor station that would emit over 10 tons per year of PM<sub>2.5</sub>.<sup>57</sup> As a result, MVP has not substantiated its claim that the Lambert Compressor Station “will cause no cumulative overburdening effect in combination with other sources of pollution.”<sup>58</sup> For an area already facing a disproportionately high exposure to PM<sub>2.5</sub> as compared to the rest of the state, the potential for the station to exacerbate that disproportionate impact should have been assessed in MVP and DEQ’s analysis.

## **II. DEQ’s Site Suitability Analysis Fails to Consider Either the Reasonableness or the Social and Economic Costs of Operating a Substantial New Source of Greenhouse Gas Emissions.**

Under Va. Code § 10.1-1307(E), before approving an air permit such as the proposed permit for the Lambert Compressor Station, the Board (and, by extension, DEQ) “shall consider facts and circumstances relevant to the reasonableness of the activity involved ... including: ... (2) The social and economic value of the activity involved.”<sup>59</sup> According to MVP’s application, even with controls, operation of the Lambert Compressor Station would generate 125,377 tons per year carbon dioxide equivalent (“CO<sub>2</sub>e”), through emissions of carbon dioxide, methane, and nitrous oxide.<sup>60</sup>

With the passage of the Virginia Clean Economy Act, Virginia has committed to reduce carbon dioxide emissions from the power sector by 30% by 2030 and to eliminate carbon emissions from the power sector by 2050.<sup>61</sup> Authorizing a facility that amounts to a major new source of greenhouse gas emissions on a permanent basis would effectively negate a substantial portion of Virginia’s planned reductions in greenhouse gas emissions. This goes directly to the “reasonableness of the activity involved.” In the face of the significant steps Virginia is

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<sup>54</sup> *Id.* at 93.

<sup>55</sup> Supplemental Information on Environmental Justice at 27.

<sup>56</sup> *See id.* at 27, 28 tbl. 7.

<sup>57</sup> June 2020 Permit Application at 17 tbl. 3-3.

<sup>58</sup> Supplemental Information on Environmental Justice at 14.

<sup>59</sup> Va. Code § 10.1-1307(E).

<sup>60</sup> June 2020 Permit Application at 17 tbl. 3-3.

<sup>61</sup> 2020 Va. Acts chs. 1193, 1194, <https://bit.ly/3fDNPqX>.

otherwise taking to reduce greenhouse gas emissions, operating a major new source of such emissions would be an *unreasonable* activity—particularly if there is a question as to whether the MVP Southgate project would provide any countervailing energy benefits.

Further, the social cost of carbon—the costs of long-term climate harm from greenhouse gas emissions—has been well-documented, even if the precise values have been subject to debate.<sup>62</sup> The fact that the greenhouse gas emissions from the Lambert Compressor Station can be estimated to cost millions of dollars per year in climate-related damages should be highly relevant to DEQ and the Board’s evaluation of the “social and economic value of the activity involved.”

There is no indication in the permitting record that DEQ considered the Lambert Compressor Station’s expected greenhouse gas emissions, their reasonableness, or their social and economic costs in its evaluation of site suitability. DEQ must revisit its site suitability analysis in light of these considerations.

### **III. MVP and DEQ have not demonstrated compliance with applicable air permitting requirements for the Lambert Compressor Station.<sup>63</sup>**

#### **A. MVP and DEQ have failed to demonstrate that the Lambert Compressor Station would not prevent or interfere with the 1-hour National Ambient Air Quality Standard for nitrogen dioxide.**

Under 9 VAC 5-80-1180, to obtain a minor new source permit, a facility “shall be designed, built and equipped to operate without preventing or interfering with the attainment or maintenance of any applicable ambient air quality standard and without causing or exacerbating a violation of any applicable ambient air quality standard.”<sup>64</sup> The Lambert Compressor Station is proposed to be located within 4,000 feet of two other compressor stations operating with compressors powered by natural gas-fired turbines, Transcontinental Gas Pipeline Company (“Transco”) Stations 165 and 166.<sup>65</sup> It appears that compliance with the 1-hour nitrogen dioxide (“NO<sub>2</sub>”) NAAQS is a concern for the Transco stations’ operations, because in a recent permit for installation of new gas-fired compressor turbines at Transco Station 165,<sup>66</sup> DEQ required

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<sup>62</sup> See, e.g., Interagency Working Grp. on Soc. Cost of Greenhouse Gases, U.S. Gov’t, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Aug. 2016), <https://bit.ly/3rLnIX8>.

<sup>63</sup> The technical comments contained in Section III were prepared with the assistance of air quality expert Vicki Stamper. Ms. Stamper’s curriculum vitae is attached as **Exhibit 4**.

<sup>64</sup> 9 VAC 5-80-1180.

<sup>65</sup> See Draft Engineering Analysis at 2; June 2020 Permit Application at 5.

<sup>66</sup> DEQ, Stationary Source Permit to Construct and Operate: Transcontinental Gas Pipe Line Company LLC – Natural Gas Compressor Station 165, Condition 49 (Jan. 28, 2020) (“2020 Transco Station 165 Permit”) (**Exhibit 5**).

Transco to install and operate an NO<sub>2</sub> ambient monitor to “ensure continuing compliance with the 1-hour NO<sub>2</sub> NAAQS.”<sup>67</sup>

Before issuing a permit for a new source of NO<sub>x</sub> in the area, it is DEQ’s obligation to ensure that the new facility will not interfere with attainment or maintenance of the NAAQS. The 1-hour NO<sub>2</sub> modeling assessment for the January 2020 Transco permit predicted 1-hour NO<sub>2</sub> concentrations of 178.3 micrograms per cubic meter (“μg/m<sup>3</sup>”),<sup>68</sup> which is 95% of the 188 μg/m<sup>3</sup> NO<sub>2</sub> NAAQS. Thus, the Lambert Compressor Station’s proposed addition of NO<sub>x</sub> pollution to the area must be carefully evaluated to ensure that it would not cause or contribute to a violation of the 1-hour NO<sub>2</sub> NAAQS. As set forth below, based on our review of the permitting record, MVP’s modeling analysis does not provide this assurance.

**1. MVP has not justified the use of variable background NO<sub>2</sub> monitoring data in its 1-hour NO<sub>2</sub> NAAQS modeling.**

The 1-hour NO<sub>2</sub> NAAQS modeling in MVP’s initial permit application relied on background data from the nearest NO<sub>2</sub> monitoring site, located in Roanoke County, Virginia, about 69.8 kilometers (43 miles) from the proposed Lambert Compressor Station site.<sup>69</sup> The background 1-hour NO<sub>2</sub> concentration at the Roanoke County monitoring site was 33.3 μg/m<sup>3</sup>.<sup>70</sup>

In its June 2020 1-hour NO<sub>2</sub> NAAQS modeling, however, MVP relied not on the Roanoke County background NO<sub>2</sub> modeling data but on background data from a monitoring site in the area of Winston-Salem, North Carolina, 111.8 kilometers (69 miles) from the proposed site. MVP maintained that data from the more distant Winston-Salem monitor was “conservatively representative and appropriate” because the Winston-Salem area had more than double the NO<sub>x</sub> emissions and a much higher population than Pittsylvania County,<sup>71</sup> and identified the background 1-hour NO<sub>2</sub> concentration of the Winston-Salem monitoring site as 68 μg/m<sup>3</sup>.<sup>72</sup> But MVP did not actually use the 68 μg/m<sup>3</sup> background 1-hour NO<sub>2</sub> concentration from Winston-Salem in its 1-hour NO<sub>2</sub> modeling. Instead, MVP used a variable NO<sub>2</sub> background

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<sup>67</sup> Memorandum from Office of Air Quality Assessments, DEQ, to Paul Jenkins, DEQ, 3 (July 9, 2020) (included as Attachment 2 to Draft Engineering Analysis) (“Air Quality Analysis”).

<sup>68</sup> DEQ, Engineering Analysis, Transcontinental Gas Pipeline Company, LLC (Station 165) at 13 (Jan. 28, 2020) (“2020 Transco Station 165 Engineering Analysis”) (**Exhibit 6**).

<sup>69</sup> See TRC Env’tl. Corp., Air Quality Modeling Protocol for Article 6 Air Permit Application – Mountain Valley Pipeline, LLC, Lambert Compressor Station, Southgate Project 3-2 (Oct. 2018) 3-2 tbl. 3-1.

<sup>70</sup> *Id.*

<sup>71</sup> AECOM, Air Quality Dispersion Modeling Report – MVP Southgate Project: Lambert Compressor Station, Pittsylvania County, Virginia at 3-6 (June 2020) (included as App. G to June 2020 Permit Application) (“June 2020 Modeling Report”).

<sup>72</sup> *Id.* at 3-5 tbl. 3-5.

concentration from Winston-Salem that varied by season and by hour of day, based on taking the 98<sup>th</sup> percentile 1-hour monitor values from Winston-Salem averaged over three years by season and hour.<sup>73</sup>

In using variable background data, MVP relied on a 2011 EPA NO<sub>2</sub> modeling guidance.<sup>74</sup> EPA's guidance observes that "[m]any of the challenges and more controversial issues related to cumulative impact assessments arise in the context of how best to combine a monitored and modeled contribution to account for background concentrations."<sup>75</sup> In particular, the guidance cautions that "the question of how to appropriately combine monitored and modeled concentrations (temporally and spatially) to determine the cumulative impact depends on a clear understanding of what the ambient monitored data represents in relation to the modeled emissions inventory."<sup>76</sup> In contravention of this guidance, neither MVP nor DEQ has shown how the monitored Winston-Salem background concentrations used in the modeling relate to the modeled emissions from the Lambert Compressor Station. This failure is most apparent in MVP's use of variable background monitoring data.

When combining modeled concentrations with monitored background concentrations to determine the cumulative ambient impact, EPA's recommended "first tier" approach is to "add the overall highest hourly background NO<sub>2</sub> concentration (across the most recent three years) from a representative monitor."<sup>77</sup> According to EPA, refinements to the first-tier approach "may be considered on a case-by-case basis *with adequate justification and documentation*."<sup>78</sup> Notably, however, EPA's NO<sub>2</sub> modeling guidance expressly "do[es] not recommend" the use of background concentrations that vary by season and by hour of day, "except in rare cases of relatively isolated sources where the available monitor can be shown to be representative of the ambient concentration levels in the areas of maximum impact from the proposed new source."<sup>79</sup> MVP has not adequately justified or documented that the Winston-Salem NO<sub>2</sub> monitor is representative of the ambient concentrations in the areas of expected maximum impact from the proposed Lambert Compressor Station.

The Winston-Salem background data reflects a county with a population of 379,099;<sup>80</sup> according to 2019 U.S. Census Bureau estimates, the Winston-Salem metropolitan area alone has

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<sup>73</sup> *Id.* at 3-6 to 3-7.

<sup>74</sup> *Id.* at 3-1 (citing Memorandum from Tyler Fox, EPA, to Regional Air Division Directors at 18–21 (Mar. 1, 2011), <https://bit.ly/2PmziFA> ("Appendix W Clarification Memo")).

<sup>75</sup> Appendix W Clarification Memo at 13.

<sup>76</sup> *Id.* at 14.

<sup>77</sup> *Id.* at 17.

<sup>78</sup> *Id.* (emphasis added).

<sup>79</sup> *Id.* at 21.

<sup>80</sup> June 2020 Modeling Report at 3-6 (citing July 1, 2018 U.S. Census Bureau data).

a population of 247,945.<sup>81</sup> Pittsylvania County, in contrast, has a population of only 60,949.<sup>82</sup> Further, the Winston-Salem NO<sub>2</sub> concentrations are undoubtedly influenced by mobile source traffic, which tends to peak at certain hours of the day due to commuting traffic. MVP has not provided any analysis to demonstrate that similar emissions profiles are likely to occur in the proposed location of the Lambert Compressor Station. Indeed, it is unlikely that the background NO<sub>2</sub> concentrations around the Lambert Compressor Station would vary by hour to the same degree as they would in a metropolitan area with busy periods of commuting traffic (and accompanying spikes in NO<sub>x</sub> emissions) at certain hours of the day. In the absence of adequate justification, MVP should have used a more conservative background concentration: “the overall highest hourly background NO<sub>2</sub> concentration (across the most recent three years)” from the Winston-Salem monitor.<sup>83</sup>

EPA’s NO<sub>2</sub> modeling guidance also provides that the use of background concentrations that vary on an hour-by-hour basis could be justified

where the modeled emission inventory clearly represents the majority of emissions that could potentially contribute to the cumulative impact assessment and where inclusion of the monitored background concentration is intended to conservatively represent the potential contribution from minor sources and natural or regional background levels not reflected in the modeled inventory. In this case, *the key aspect which may justify the hour-by-hour pairing of modeled and monitored values is a demonstration of the overall conservatism of the cumulative assessment* based on the combination of modeled and monitored impacts. *Except in rare cases of relatively isolated sources*, a single ambient monitor, or even a few monitors, will not be adequately representative of hourly concentrations across the modeled domain to preclude the need to include emissions from nearby background sources in the modeled inventory.<sup>84</sup>

But MVP’s overall assessment was not “conservative.” Table 1, below, reproduces the hourly background data used in MVP’s modeling.

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<sup>81</sup> U.S. Census Bureau, *QuickFacts: Winston-Salem city, North Carolina*, <https://bit.ly/3cKF7FB> (last visited Apr. 2, 2021) (**Exhibit 7**).

<sup>82</sup> June 2020 Modeling Report at 3-6 (citing July 1, 2018 U.S. Census Bureau data).

<sup>83</sup> See Appendix W Clarification Memo at 17.

<sup>84</sup> *Id.* at 21 (emphasis added); see also *id.* at 12 (“The goal of the cumulative impact assessment should be to demonstrate with an adequate degree of confidence in the result that the proposed new or modified emissions will not cause or significantly contribute to violations of the NAAQS. In general, the more conservative the assumptions on which the cumulative analysis is based, the more confidence there will be that the goal has been achieved and the less controversial the review process will be from the perspective of the reviewing authority. As less conservative assumptions are implemented in the analysis, the more scrutiny those assumptions may require and the review process may tend to be lengthier and more controversial as a result.”).

**Table 1. MVP's 1-hour NO<sub>2</sub> Variable Season and Hour of Day Background Monitor Values (µg/m<sup>3</sup>) (Source: June 2020 Modeling Report at 3-7 tbl. 3-8)**

Hour of Day	Season			
	Winter	Spring	Summer	Fall
1	52.64	33.59	29.01	44.93
2	56.9	37.41	33.78	44.68
3	54.9	32.65	29.33	43.05
4	52.51	35.59	25.69	38.98
5	51.14	41.23	27.89	39.54
6	52.26	48.88	29.2	42.24
7	55.96	45.75	27.95	46.5
8	57.4	47.31	26.63	44.49
9	52.08	31.9	27.7	39.54
10	46.81	24.5	18.3	35.47
11	43.55	17.42	12.35	23.37
12	32.34	14.16	9.84	15.1
13	24.5	12.22	8.33	16.54
14	22.81	11.15	7.77	15.92
15	25.63	12.41	7.9	15.48
16	29.2	13.91	12.85	21.81
17	29.08	13.91	12.85	30.77
18	41.49	18.67	14.1	44.56
19	62.67	24.38	16.04	62.54
20	60.91	38.92	23	66.93
21	57.53	42.3	29.27	60.79
22	61.41	36.72	32.34	55.21
23	55.15	38.1	32.77	50.82
24	54.71	34.4	31.77	49.01

As set forth in this table, the hourly background values used in MVP's 1-hour NO<sub>2</sub> modeling ranged from 7.77 µg/m<sup>3</sup> to 66.93 µg/m<sup>3</sup>, with every value falling below MVP's claimed "conservative" background concentration of 68 µg/m<sup>3</sup>. Indeed, the median hourly background NO<sub>2</sub> concentration used was 33.18 µg/m<sup>3</sup>.

Further, the proposed Lambert Compressor Station would not be a “relatively isolated source[.]” MVP’s June 2020 modeling report identified 15 NO<sub>x</sub> sources over 5 counties and 2 cities that MVP included in its cumulative modeling.<sup>85</sup> Transco operates two compressor stations (Stations 165 and 166) located approximately 4,000 feet from the proposed Lambert Compressor Station. Transco Station 165 previously had gas-fired reciprocating internal combustion engines powering compressors but has since replaced them with two gas-fired combustion turbine-powered compressors. Transco Station 166 includes four gas-fired combustion turbine-powered compressors.<sup>86</sup> Despite the number of sources included in the 1-hour NO<sub>2</sub> modeling, it is not clear that the Lambert Compressor Station modeling incorporated “the majority of emissions that could potentially contribute to the cumulative impact assessment.”<sup>87</sup> In January 2020, Transco obtained a permit to make changes to Transco Station 165.<sup>88</sup> The permit allowed the construction of two new gas-fired compressor turbines.<sup>89</sup> According to DEQ’s Engineering Analysis for this permit, the 1-hour NO<sub>2</sub> modeling analysis showed a total modeled concentration of 178.3 µg/m<sup>3</sup>.<sup>90</sup>

What is not clear is whether the cumulative 1-hour NO<sub>2</sub> modeling conducted for the Lambert Compressor Station included worst-case emissions from the compressor turbines at both Stations 165 and 166. For the two new turbines at Transco Station 165, Transco’s application identified 150 startups and 150 shutdowns per turbine per year—events during which less stringent emission limits for NO<sub>x</sub> and other pollutants apply.<sup>91</sup> On average, that is nearly one startup or shutdown for every day of the year by each of the two new turbines at Transco Station 165. In addition, because startups and shutdowns from the four compressor turbines at Station 166 could also potentially affect hourly NO<sub>2</sub> concentrations, those startup and shutdown emissions should have been modeled. According to an August 2015 permit for Transco Station 166, Turbines 1 and 2 are allowed a total of 300 startup and shutdown events per year, and Turbines 3 and 4 are also allowed 300 startups and shutdowns per year.<sup>92</sup> And the draft permit for the Lambert Compressor Station would allow 17.32 hours per turbine per year for startups

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<sup>85</sup> June 2020 Modeling Report at 3-11.

<sup>86</sup> See 2020 Transco Station 165 Permit at 2; *see also* Memorandum from Allen Armistead, DEQ, to Air Permit File 1 (Aug. 20, 2015) (“2015 Transco Station 166 Engineering Analysis”) (**Exhibit 8**).

<sup>87</sup> See Appendix W Clarification Memo at 21.

<sup>88</sup> 2020 Transco Station 165 Permit.

<sup>89</sup> 2020 Transco Station 165 Engineering Analysis at 2.

<sup>90</sup> *Id.* at 13.

<sup>91</sup> *Id.* at 11.

<sup>92</sup> DEQ, Stationary Source Permit to Modify and Operate: Transcontinental Gas Pipe Line Co., LLC – Compressor Station 166, Conditions 4, 5 (Aug. 24, 2015) (“2015 Transco Station 166 Permit”) (**Exhibit 9**).



and 17.32 hours per turbine per year for shutdowns,<sup>93</sup> which, assuming 10-minute startup and shutdown durations, equates to approximately 104 startups and 104 shutdowns per year per turbine. On average, this represents a startup or shutdown every day and a half for each of the Lambert Compressor Station turbines.

Although it may seem unlikely for all six Transco turbines and the two planned Lambert Compressor Station turbines to be in startup or shutdown mode simultaneously, the existing Transco permits and draft Lambert Compressor Station permit all allow frequent startups and shutdowns of the compressor turbines. Given the high number of startups and shutdowns that both Transco and MVP have requested for their compressor stations, in characterizing the potential contribution to hourly NO<sub>2</sub> concentrations it is imperative that all of these compressor turbines be modeled assuming the potential hourly NO<sub>x</sub> emissions from each turbine in startup or shutdown mode.

Relatedly, all of the compressor turbines at the proposed Lambert Compressor Station and at Transco Stations 165 and 166 are Solar turbines equipped with SoLoNO<sub>x</sub> combustion controls that do not effectively reduce NO<sub>x</sub> emissions when temperatures are under 0°F.<sup>94</sup> The permit for Transco Station 165 does not require operation of SoLoNO<sub>x</sub> when ambient temperatures are below 0°F and neither does the draft permit for the proposed Lambert Compressor Station.<sup>95</sup> MVP represents that temperatures below 0°F are projected to occur for only five hours per year;<sup>96</sup> when such low temperatures do occur, however, it will significantly increase the NO<sub>x</sub> emissions from all of these compressor turbines equipped with SoLoNO<sub>x</sub>—turbines that are located in close proximity to each other.<sup>97</sup> Failing to consider an event likely to occur on at least one day per year fails to reflect the potential cumulative impact on 1-hour ambient NO<sub>2</sub> concentrations of all of these compressor turbines.

The draft permit for the Lambert Compressor Station allows NO<sub>x</sub> emissions of 14.42 to 21.28 pounds of NO<sub>x</sub> per hour for its two compressor turbines during periods of subzero temperatures—emission rates that are 16 times higher than the NO<sub>x</sub> emission limits applicable

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<sup>93</sup> DEQ, Draft Stationary Source Permit to Construct and Operate: Mountain Valley Pipeline, LLC – Lambert Compressor Station, Condition 4.g (Dec. 16, 2020) (“Draft Permit”).

<sup>94</sup> See 2020 Transco Station 165 Engineering Analysis at 2–3; 2015 Transco Station 166 Engineering Analysis at 1,3 (indicating that Station 166 uses Solar Taurus 70 compressor turbine with SoLoNO<sub>x</sub>); Leslie Witherspoon, Solar Turbines Incorporated, *SoLoNO<sub>x</sub> Products: Emissions in Non-SoLoNO<sub>x</sub> Modes*, PIL 167, at 2 (Dec. 1, 2016) (**Exhibit 10**) (cited in June 2020 Permit Application App. B tbls. B-3 (Solar Mars 100), B-5 (Solar Taurus 70)).

<sup>95</sup> See 2020 Transco Station 165 Permit, Condition 29 (establishing NO<sub>x</sub> limit for “Low Temp Mode (<0 °F)”); Draft Permit, Conditions 4.h, 20–24 (Conditions 22 and 23 establishing NO<sub>x</sub> limits for “Low Temp Mode (<0 °F)”).

<sup>96</sup> June 2020 Modeling Report at 2-2, 3-8.

<sup>97</sup> Given the proximity of Transco Stations 165 and 166 to the proposed Lambert Compressor Station, it is likely that ambient temperatures would be the same for all of these facilities.

during normal operation and 7 to 10 times higher than the blended startup/shutdown/100% load NO<sub>x</sub> rates MVP modeled for the Lambert Compressor Station units.<sup>98</sup> Similarly, the NO<sub>x</sub> emission limits for the two new compressor turbines at Transco Station 165 allow the units to emit almost five times as much during subzero temperatures as during normal operation.<sup>99</sup> Yet MVP did not consider emissions scenarios existing at subzero temperatures in its modeling.<sup>100</sup> Given the proximity of these facilities and the fact that modeling of much lower NO<sub>x</sub> emission rates for these units showed 1-hour NO<sub>2</sub> concentrations of 95% of the 1-hour NO<sub>2</sub> NAAQS, just five hours per year of emissions at these levels due to subzero temperatures could have significant impacts on 1-hour NO<sub>2</sub> concentrations. DEQ must thus require MVP to address emissions from these nearly co-located units during periods of subzero temperatures in assessing whether the Lambert Compressor Station will cause or contribute to a violation of the 1-hour NO<sub>2</sub> NAAQS.

In addition, with respect to other emissions sources included in MVP's modeling, it is unclear whether the modeling reflects "the majority of emissions that could potentially contribute to the cumulative impact assessment"<sup>101</sup> because MVP has neither identified the emission units and emission rates modeled for each of these facilities nor indicated whether actual or allowable emissions were modeled. MVP refers to the modeling files for the "complete set of modeled inputs,"<sup>102</sup> but making such data available only in computer model files does not help the public verify that sources were properly modeled. Further, DEQ has not posted the modeling files to its website containing documents regarding the draft permit for the Lambert Compressor Station.<sup>103</sup> DEQ should require MVP to disclose the emission rates modeled for each source (including which emission units were modeled) and the basis for the emissions that were modeled. The public should have the opportunity to review that data, to ensure that the modeling properly included all sources that would contribute to the NO<sub>2</sub> concentrations in the area impacted by the proposed Lambert Compressor Station.

All of this information is necessary to justify the use of background NO<sub>2</sub> monitoring data that varies by hour of day and season, in accordance with EPA's 2011 guidance. Because the Lambert Compressor Station would not be an "isolated facility," DEQ must ensure that MVP has modeled all emissions that could potentially contribute to cumulative impacts on the 1-hour NO<sub>2</sub> NAAQS to justify using variable background monitoring data. Based on the permit record's lack

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<sup>98</sup> Draft Permit, Conditions 20–23; *see also* June 2020 Modeling Report App. B tbl. B-5.

<sup>99</sup> 2020 Transco Station 165 Permit Conditions 27, 29.

<sup>100</sup> June 2020 Modeling Report at 3-8 ("the below 0° F case for the turbines was not considered in the 1-hour NO<sub>2</sub> NAAQS modeling analysis.").

<sup>101</sup> Appendix W Clarification Memo at 21.

<sup>102</sup> June 2020 Modeling Report at 3-11.

<sup>103</sup> *See* DEQ, *Air Public Notices*, <https://www.deq.virginia.gov/permits-regulations/public-notices/air> (last visited Apr. 2, 2021).

of information sufficient to verify the adequacy of MVP's modeling, MVP has not met its burden to justify its reliance on variable background monitoring data.

**2. DEQ must disclose the cumulative emission inventory modeled by MVP to determine whether the Lambert Compressor Station will cause or contribute to a violation of the 1-hour NO<sub>2</sub> NAAQS.**

DEQ must ensure that the Lambert Compressor Station will not prevent *or interfere with* attainment or maintenance of the NAAQS. However, as discussed in Section III.A.1, above, it is not clear that MVP has adequately modeled worst-case allowable NO<sub>x</sub> emissions from the proposed facility along with other sources in the area that could contribute to 1-hour NO<sub>2</sub> concentrations. A separate, but related, problem is that MVP has not provided in any of the application materials available on DEQ's public website for the proposed permit an identification of the emission units modeled for the other sources assessed in the cumulative analysis, the NO<sub>x</sub> emission rates modeled for those emission units, or the source for those emission rates—i.e., whether the source is permitted allowable emissions or some other basis for assumptions about short-term NO<sub>x</sub> emission rates.<sup>104</sup>

For Transco Station 165, DEQ recently issued a permit for the construction of two new compressor turbines. The 1-hour NO<sub>2</sub> modeling for that permit predicted cumulative 1-hour NO<sub>2</sub> concentrations of 178.3 µg/m<sup>3</sup>, which is 95% of the level of the 1-hour NO<sub>2</sub> NAAQS. DEQ subsequently required Transco to install and operate an ambient air monitoring network for NO<sub>2</sub> that is to also include meteorological monitoring.<sup>105</sup> This ambient air monitoring was required to begin operating beginning with the startup of either of the new combustion turbines.<sup>106</sup>

The fact that DEQ required Transco to install and operate an NO<sub>2</sub> monitoring network as part of its January 2020 permit for the new compressor turbines at Transco Station 165 would seem to indicate that DEQ was concerned with the area's ability to comply with the 1-hour NO<sub>2</sub> NAAQS—even before the addition of the proposed Lambert Compressor Station. Indeed, DEQ's July 9, 2020 Air Quality Analysis states that DEQ required Transco to install an NO<sub>2</sub> ambient monitor "to ensure continuing compliance with the 1-hour NO<sub>2</sub> NAAQS."<sup>107</sup> DEQ claims that the Lambert Compressor Station would only have a "relatively small impact" on the maximum modeled 1-hour NO<sub>2</sub> concentrations, referring to a table showing the proposed facility contributing 1.04 µg/m<sup>3</sup> to a total concentration of 178.8 µg/m<sup>3</sup>.<sup>108</sup> But DEQ either has not determined or has not explained whether this modeled concentration reflects the Lambert Compressor Station's projected startup or shutdown emission rates. Further, DEQ must disclose the significance of MVP's "voluntary" planned installation of selective catalytic reduction

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<sup>104</sup> See *id.*

<sup>105</sup> 2020 Transco Station 165 Permit, Condition 49.

<sup>106</sup> *Id.*

<sup>107</sup> Air Quality Analysis at 2–3.

<sup>108</sup> *Id.*

(“SCR”) at the compressor turbines to meet a NO<sub>x</sub> emission limit of 2.7 parts per million (“ppm”). It seems likely that these controls and the proposed NO<sub>x</sub> emission limit are intended to ensure that the proposed Lambert Compressor Station does not prevent or interfere with attainment or maintenance of the 1-hour NO<sub>2</sub> NAAQS. DEQ must clearly state as such.

### **3. DEQ has not ensured that all areas of ambient air have been modeled.**

To obtain its minor source permit, MVP must demonstrate that the Lambert Compressor Station will not prevent or interfere with attainment or maintenance of the NAAQS in all areas of “ambient air.” EPA regulations define “ambient air” as “that portion of the atmosphere, external to buildings, to which the general public has access.”<sup>109</sup> In order for an area *not* to be considered as ambient air, EPA generally requires that the public be precluded from access to the area through fencing or other physical barriers.<sup>110</sup> It is not clear that MVP has included modeling receptors in all areas where the public may have access.

MVP used two sets of receptor grids and source combinations in its modeling: (1) exclusion of receptors within Transco Station 165/166’s ambient boundary with all NAAQS sources, and (2) exclusion of Transco Station 165/166’s sources but receptors included within their ambient boundary.<sup>111</sup> Typically, modeling reports include figures of the ambient air boundary of the proposed facility and other facilities, along with identification of receptors used in the modeling. Based on our review, MVP has not included any such figures in its modeling report or modeling protocol. Given that the modeled impacts of the Lambert Compressor Station, Transco stations, and other sources in the area were so close to the 1-hour NO<sub>2</sub> NAAQS, it is important for the public to understand the extent of the Lambert Compressor Station’s potential impacts and its spatial relationship to Transco Stations 165 and 166.

MVP did not include modeling receptors within the boundaries of the property, claiming it will be fenced.<sup>112</sup> Yet the draft permit does not specifically require that property boundary be fenced or otherwise preclude public access. The requirement to preclude public access should be spelled out in the permit.

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<sup>109</sup> 40 C.F.R. § 50.1(e).

<sup>110</sup> *See, e.g.*, Letter from EPA Administrator Douglas M. Costle to Sen. Jennings Randolph (Dec. 19, 1980) <https://bit.ly/3ubLzeC>. EPA has recently recognized that a fence or physical barrier is not the only mechanism of barring public access and that other measures may be used to preclude access to the site. *See* Memorandum from EPA Administrator Andrew R. Wheeler to Regional Administrators (Dec. 2, 2019), <https://bit.ly/31BmwFS>. Notably, EPA states that it expects the air agency to determine that the “general public does not have access to property in order to exclude an area from ambient air.” *Id.* at 2.

<sup>111</sup> June 2020 Modeling Report at 4-2.

<sup>112</sup> *Id.* at 3-4.

Nor is it clear that the applicable air permits for Transco Stations 165 and 166 require fencing or otherwise preclude public access to effectively create an ambient air boundary. The January 28, 2020 Permit to Construct for the new compressor turbines at Transco Station 165 does not include any such requirements, nor does the August 24, 2015 Stationary Source Permit to Modify and Operate Transco Compressor Station 166.<sup>113</sup> If the property boundaries of the Transco Stations do not preclude public access, MVP's cumulative modeling must demonstrate compliance with the 1-hour NO<sub>2</sub> NAAQS within the property of the Transco stations. DEQ should ensure that MVP discloses the ambient air boundary of Transco Stations 165 and 166 relative to the MVP site boundary (including the receptor placement for Transco Stations 165 and 166) and identifies any enforceable provisions applicable to Transco Stations 165 and 166 that effectively prohibit public access to the area that MVP's modeling excludes from consideration as ambient air. If no such enforceable provisions exist, DEQ must require MVP's cumulative modeling to include receptors within the Transco property.

DEQ should also require MVP to provide isopleth maps showing the area of 1-hour NO<sub>2</sub> concentrations to which the Lambert Compressor Station would cause or contribute along with the properly defined ambient air boundaries for the station and the existing Transco Stations 165 and 166. Such information is necessary to inform the public of the extent of the Lambert Compressor Station's potential emissions impacts.

**4. DEQ's engineering analysis contains an unsupported background concentration value.**

In DEQ's July 9, 2020 Draft Engineering Analysis for the Lambert Compressor Station, Table 2 includes the source contribution analysis for the modeled cumulative concentration of 178.8 µg/m<sup>3</sup>. That table lists the background air quality as 60.86 µg/m<sup>3</sup>.<sup>114</sup> It is unclear where DEQ obtained this figure. A background concentration value of 60.86 µg/m<sup>3</sup> is not identified as any of the 1-hour NO<sub>2</sub> variable seasonal and hourly background concentration values presented in MVP's June 2020 Modeling Report.<sup>115</sup> DEQ must explain this discrepancy in stated background concentrations.

**B. DEQ cannot issue a permit for the Lambert Compressor Station without conducting a proper BACT analysis.**

MVP and DEQ made three overarching errors with respect to the Best Available Control Technology ("BACT") requirements for new stationary sources: (1) DEQ focused on the wrong emissions rate to conclude that the Lambert Compressor Station was exempt from applying BACT for NO<sub>x</sub>; (2) MVP and DEQ gave insufficient consideration to an available method of pollution control—the use of electric motors to power the compressors—that would eliminate

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<sup>113</sup> See 2015 Transco Station 166 Permit.

<sup>114</sup> Air Quality Analysis at 3 tbl. 2.

<sup>115</sup> See June 2020 Modeling Report at 3-7 tbl. 3-8.

almost all on-site air pollution from the Lambert Compressor Station; and (3) DEQ ultimately set a NO<sub>x</sub> emission limit that did not represent BACT.

**1. DEQ erroneously found that the Lambert Compressor Station would be exempt from BACT requirements for NO<sub>x</sub>.**

In reviewing an application for a new stationary source permit, DEQ is required to consider “the maximum degree of emission reduction for any pollutant” that DEQ, “taking into account energy, environmental and economic impacts and other costs, determines is achievable for the new stationary source or project through the application of production processes or available methods, systems and techniques ... for control of such pollutant.”<sup>116</sup>

A new stationary source like the Lambert Compressor Station must apply BACT for each regulated pollutant not exempted by the regulations.<sup>117</sup> The regulations exempt new stationary sources from the BACT requirement for any pollutant to be emitted by the station at an “uncontrolled emission rate” below the threshold that 9 VAC 5-50-1105(C)(1) sets for that pollutant. For nitrogen oxides (NO<sub>x</sub>), the threshold uncontrolled emission rate is 40 tons per year.<sup>118</sup>

DEQ determined that the proposed Lambert Compressor Station would be subject to the BACT requirements for PM<sub>2.5</sub> and formaldehyde but exempt from BACT for all other pollutants—including NO<sub>x</sub>.<sup>119</sup> DEQ based its determination that the BACT requirements did not apply to NO<sub>x</sub> on the finding that the Lambert Compressor Station’s uncontrolled emission rate for NO<sub>x</sub> was 34.73 tons per year, below the 40-tons-per-year threshold.<sup>120</sup> Because the emission rate of 34.73 tons per year was not the compressor station’s “uncontrolled emission rate” for NO<sub>x</sub>, DEQ’s determination was erroneous.

Under 9 VAC 5-80-1105(C)(1), a stationary source’s uncontrolled emission rate is the sum of the uncontrolled emission rates of the individual affected emission units.<sup>121</sup> “Uncontrolled emission rate” is defined as “the emission rate from an emissions unit when operating at maximum capacity without air pollution control equipment.”<sup>122</sup> “Air pollution control equipment” is further defined to “include[] control equipment which is not vital to its

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<sup>116</sup> 9 VAC 5-50-250(C).

<sup>117</sup> 9 VAC 5-50-260(B).

<sup>118</sup> 9 VAC 5-80-1105(C)(1); Draft Engineering Analysis at 10.

<sup>119</sup> Draft Engineering Analysis at 7.

<sup>120</sup> *See id.*; *see also* June 2020 Permit Application at 27 tbl. 4-3.

<sup>121</sup> 9 VAC 5-80-1105(C)(1).

<sup>122</sup> 9 VAC 5-80-1110(C).

operation, except that its use enables the source to conform to applicable air pollution control laws and regulations.”<sup>123</sup>

DEQ presumably determined that the SoLoNOx dry low NOx combustors for the station’s Solar turbines were vital to the combustion turbines’ operation as an inherent part of the turbines. But SoLoNOx combustors are available with different levels of NOx control. In its November 2018 permit application, MVP proposed to use SoLoNOx dry low NOx combustors to meet a NOx emission limit of 15 ppm.<sup>124</sup> MVP calculated the uncontrolled emission rate for NOx as 55.28 tons per year, exceeding the 40-tons-per-year threshold to trigger BACT for NOx.<sup>125</sup> In its April 2019 updated application, however, MVP reported that the combustion turbines would now be equipped with “Solar’s *Advanced SoLoNOx* dry low NOx combustor technology for NOx control,” which would reduce NOx emissions to 9 ppm.<sup>126</sup>

Even if the SoLoNOx combustors were considered “vital” to the operation of the turbines, however, there would be no basis to conclude that the “Ultra Low NOx” pollution controls of “Advanced SoLoNOx” were “vital” to the operation of the turbines. The manufacturer, Solar Turbines, describes these advanced controls as an “[u]pgrade” available for certain turbines.<sup>127</sup> MVP’s application points out that the advanced SoLoNOx controls that achieve 9 ppm NOx cost more than the baseline SoLoNOx controls that achieve 15 ppm NOx.<sup>128</sup> Therefore, DEQ cannot conclude that the “Ultra Low NOx” pollution controls of “Advanced SoLoNOx” are “vital” to the turbines’ operation—and the Lambert Compressor Station’s uncontrolled emission rate for NOx is the sum of the emission rates of the compressor turbines *without* the use of Advanced SoLoNOx technology along with all other NOx emission sources at the facility. Because the resulting uncontrolled emission rate for NOx exceeds the threshold of 40 tons per year set forth in 9 VAC 5-80-1105(C)(1), the Lambert Compressor Station is subject to BACT for NOx.

Separately, we note that MVP indicated that the 9 ppm NOx emission rate associated with the ultra-low NOx “Advanced SoLoNOx” controls is valid only for ambient temperatures

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<sup>123</sup> *Id.*

<sup>124</sup> TRC Env’tl. Corp., Article 6 Air Permit Application – Mountain Valley Pipeline, LLC, Lambert Compressor Station, Southgate Project at 4-10 (Nov. 2018).

<sup>125</sup> *Id.* at 4-2; *see also* June 2020 Permit Application App. E, NOx BACT Cost Analysis “Baseline Case” (calculating the uncontrolled NOx emission rate as 53.47 tons per year).

<sup>126</sup> TRC Env’tl. Corp., Article 6 Air Permit Application – Mountain Valley Pipeline, LLC, Lambert Compressor Station, Southgate Project at 4 (rev. 1, Apr. 2019) (“April 2019 Permit Application”).

<sup>127</sup> Solar Turbines, *SoLoNOx<sup>TM</sup> Upgrade*, <https://bit.ly/3sAhOE1> (last visited Apr. 2, 2021) (**Exhibit 11**).

<sup>128</sup> *See* June 2020 Permit Application at 49 tbl. 5-1 (indicating that “Ultra Low NOx” controls cost \$613,636 more in capital costs than “Baseline” NOx controls).

between 0°F and 100°F.<sup>129</sup> Yet MVP did not identify or account for uncontrolled NOx emissions (or uncontrolled emissions of any other pollutant) during periods when ambient temperatures are above 100°F.<sup>130</sup> MVP did not even quantify what the compressor turbines' emissions rate for NOx or other pollutants would be at ambient temperatures above 100°F.<sup>131</sup> To properly determine BACT applicability, DEQ must require MVP to quantify such emissions and include such emissions in the calculation of uncontrolled emission rates of NOx and other pollutants.

**2. BACT for NOx, PM<sub>2.5</sub>, and formaldehyde can be achieved at the Lambert Compressor Station through the use of electric motors to power the compressors.**

A determination of “best available control technology” (“BACT”) must consider “the nature and amount of the emissions, emission control efficiencies achieved in the industry for the source type, total cost-effectiveness, and where appropriate, the cost-effectiveness of the incremental emissions reduction achieved between control alternatives.”<sup>132</sup> By failing to adequately consider the use of electric compressor motors in place of gas-fired compressor turbines, MVP and DEQ did not fulfill their obligation to evaluate and apply BACT.<sup>133</sup>

The use of electric motors in lieu of gas-fired turbines to drive the compressors reflects the maximum degree of emission reduction of NOx, PM<sub>2.5</sub>, and formaldehyde for the Lambert Compressor Station, as well as for the other air pollutants the station would emit. In contrast to the planned gas-fired combustion turbines powering the compressors, electric motors would emit no pollutants in connection with the compression of gas. Compressors powered by electric motors also require significantly less maintenance than compressors powered by gas-fired turbines.<sup>134</sup> Less maintenance means less compressor downtime and, by extension, fewer

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<sup>129</sup> April 2019 Permit Application at 4.

<sup>130</sup> See June 2020 Modeling Report App. B tbl. B-2. MVP did account for emissions of NOx and other pollutants during periods of subzero ambient temperatures, which MVP claimed would likely occur for only five hours per year. See *id.* at 2-2, 3-8.

<sup>131</sup> See *id.* App. B tbl. B-2.

<sup>132</sup> 9 VAC 5-50-250(C).

<sup>133</sup> Despite claiming to be exempt from BACT for NOx, MVP did conduct a NOx BACT analysis “under the potential case that SoLoNOx would be considered air pollution control equipment and the assumption that turbines using conventional (Non-SoLoNOx) combustion burners or higher NOx emitting SoLoNOx turbines could result in emission rates above the [BACT] exemption emissions levels ....” June 2020 Permit Application at 41. Because, as set forth in Section III.B.1, above, the Lambert Compressor Station is subject to BACT for NOx in addition to PM<sub>2.5</sub> and formaldehyde—we include comments on the NOx BACT analysis that MVP performed in its application and DEQ referred to in its Draft Engineering Analysis.

<sup>134</sup> See EPA, PRO Fact Sheet No. 103, *Install Electric Compressors 2* (2011), <https://bit.ly/2PJw7HZ> (“PRO Fact Sheet No. 103”).



blowdown emissions. For the Lambert Compressor Station, reducing blowdown emissions would reduce emissions of methane as well as volatile organic compounds such as hexane that co-occur with the gas. Additional benefits of electric motors as compared to gas-fired turbines include increased efficiency and lower noise levels.<sup>135</sup>

**a. Electric compressor motors are an “available” control technology.**

Electric motors have long been recognized as a more efficient and cleaner alternative to gas turbines when it comes to powering compressor stations.<sup>136</sup> As a result, electric compressor motors have become commonplace in recent years, including along gas pipelines.<sup>137</sup>

DEQ claims that electric motors do not represent an “available” control technology for the Lambert Compressor Station because the “electrical transmission infrastructure required for the use of [electric motors] at the proposed Station does not exist.”<sup>138</sup> But a current lack of infrastructure should not eliminate the use of electric motors from consideration. As MVP demonstrated in its permit application, the necessary infrastructure—including new power lines and an additional substation at the Lambert site—can be built;<sup>139</sup> the question may be one of cost, but not of availability.<sup>140</sup> In the context of evaluating BACT under the federal prevention of significant deterioration (“PSD”) program, EPA considers control options as available if the control techniques have a “practical potential for application to the emissions unit and the regulated pollutant under evaluation.”<sup>141</sup> And it is generally more cost-effective to incorporate the best pollution control techniques at a facility before it has been constructed, rather than retrofitting a facility after it is in operation. DEQ cannot reasonably find that the use of electric

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<sup>135</sup> *Id.*

<sup>136</sup> See Jeffery B. Greenblatt, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-6990E, *Opportunities for Efficiently Improvements in the U.S. Natural Gas Transmission, Storage and Distribution System* 12–15 (May 2015), <https://bit.ly/2PGEFz7> (**Exhibit 12**); PRO Fact Sheet No. 103 at 2.

<sup>137</sup> See, e.g., Mark Iden, *Solar Power Station Helps to Power Gas Pipeline Compressor Station*, Pipeline Tech. J., Oct. 16, 2020, <https://bit.ly/3u4hAVY> (**Exhibit 13**) (describing Enbridge’s solar-powered Lambertville Compressor Station in West Amwell Township, New Jersey); N.M. Env’t Dep’t, Title V Operating Permit No. P154-R4 (Sept. 28, 2018) (permitting Transwestern’s Roswell Compressor Station No. 9 in Roswell, New Mexico) (**Exhibit 14**); Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* 29–30 (Jan. 26, 2009), <https://bit.ly/2QVsNd7> (**Exhibit 15**).

<sup>138</sup> Draft Engineering Analysis at 10.

<sup>139</sup> June 2020 Permit Application App. E.

<sup>140</sup> We address the cost-effectiveness of using electric motors in place of gas-fired turbines to power the compressors in Section III.B.4, below.

<sup>141</sup> EPA, *New Source Review Workshop Manual* B.5 (draft Oct. 1990), <https://bit.ly/3wj4yFW>.

compressor motors is not an available control technology for the Lambert Compressor Station—particularly considering the prevalence of compressors powered by electric motors at natural-gas-pipeline compressor stations.

**b. Electric compressor motors are an inherently lower-emitting process as compared to gas-fired compressor turbines.**

DEQ also dismisses the use of electric motors based on the markedly inconclusive finding that “[a]n electric compressor station may or may not be an inherently lower pollutant process than a natural gas-fired compressor station,” depending on the fuel source for the electric generation.<sup>142</sup> DEQ explains its statement as follows:

If the source of the electric compressor station’s electricity comes from a coal-fired power plant, the overall air pollution impact of the electric compressor station is worse than that of a natural gas-fired compressor station. However, if the electricity comes from a natural gas-fired power plant, the overall air pollution impact of an electric compressor station is likely to be approximately equal to that of a natural gas-fired compressor station.<sup>143</sup>

DEQ’s reasoning contains several erroneous assumptions. First, even assuming that using electric motors in place of gas-fired turbines would not lower overall emissions, it plainly would lessen the air pollution impact in the area of the compressor station. DEQ’s conclusion about the “overall air pollution impact” ignores the localized impacts of pollutant emissions on fenceline communities—an express focus of the Virginia Environmental Justice Act<sup>144</sup> and, as discussed in Section I.C, above, an essential element of DEQ’s required environmental justice analysis.

But using electric motors would likely lower overall emissions as well. DEQ’s second mistaken assumption is that electricity for the Lambert Compressor Station would come from a single power generating source. That is fundamentally not how electricity transmission operates, as electrons cannot be differentiated once put onto the grid.

A far more appropriate analysis would look at the statewide or regional generation sources from which the Lambert Compressor Station could draw electricity. Electricity for the Chatham, Virginia area can come from three different power companies: Appalachian Power Company, Mecklenburg Electric Cooperative, and Virginia Electric and Power Company

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<sup>142</sup> Draft Engineering Analysis at 10.

<sup>143</sup> *Id.*

<sup>144</sup> See Va. Code § 2.2-235 (“It is the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth, with a focus on environmental justice communities and fenceline communities.”).

(“Dominion”).<sup>145</sup> Those companies have a mix of power generating sources and can also purchase power from other generating sources. According to data from the U.S. Energy Information Administration, as of 2018, Virginia’s grid was powered by approximately 60% natural gas, 30% nuclear, and approximately 6% solar and biomass. Coal accounted for less than 4% of electricity generation.<sup>146</sup> Dominion’s most recent long-term planning document reported that in 2019 Dominion’s electricity was produced from 41% natural gas, 30% nuclear, and only 9% coal.<sup>147</sup> Even based on this high-level data, it is immediately apparent that an electric compressor station would likely produce less overall air pollution—including lower NO<sub>x</sub> emissions—than a gas-fired station, as only a tiny portion of electricity generated in Virginia is coal-fired, while a minimum of 30% is carbon-dioxide free (nuclear and solar).

Importantly, the percentage of electricity generated by carbon-free sources will necessarily and rapidly improve due to several recent legislative and regulatory changes. By 2024 and 2028, Dominion is required by law to retire several polluting facilities powered by coal, heavy oil, and biomass.<sup>148</sup> As one analysis put it, “the bulk of Virginia’s coal plants must shut down before 2025.”<sup>149</sup> Meanwhile, both major utilities—Dominion and Appalachian Power—must increase their renewable generation through the buildout and acquisition of wind and solar resources, with Dominion’s generation becoming 100% carbon-free by 2045 and Appalachian Power’s by 2050.<sup>150</sup> Legislatively required increases in energy-efficiency programs will further reduce emissions,<sup>151</sup> as will an increase from 1% to 6% of customers eligible for net metering (i.e., rooftop solar).<sup>152</sup>

And, as DEQ is well aware, Virginia is now a participant in the Regional Greenhouse Gas Initiative thanks to DEQ’s regulatory program.<sup>153</sup> With few exceptions, since January 1, 2021, power plant operators or owners must now purchase an allowance for every ton of carbon

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<sup>145</sup> See EPA, *eGRID Power Profiler*, <https://bit.ly/3rLK4T5> (last visited Apr. 2, 2021) (listing three utilities under “Select your utility” upon entry of “24531” under “Power Profiler – Enter zip code”).

<sup>146</sup> See U.S. Energy Info. Admin., *Virginia Energy Consumption Estimates, 2018*, <https://bit.ly/2OfnleL> (last visited Apr. 2, 2021) (**Exhibit 16**).

<sup>147</sup> Dominion Energy, *Virginia Electric and Power Company’s Report of Its Integrated Resource Plan* 78 fig. 5.1.1.3 (May 1, 2020), <https://bit.ly/39upv78> (Chapter 5 excerpted as **Exhibit 17**) (“2020 Dominion IRP”).

<sup>148</sup> Va. Code § 56-585.5(B)(1), (2); see also 2020 Dominion IRP at 83.

<sup>149</sup> Darren Sweeney, *Bulk of Virginia’s Coal Plants Must Shut Down Before 2025 Under New State Law*, S&P Global Platts, Apr. 13, 2020, <https://bit.ly/3uijCSE> (**Exhibit 18**).

<sup>150</sup> Va. Code § 56-585.5(B)(3), (C).

<sup>151</sup> Va. Code § 56-596.2(B).

<sup>152</sup> Va. Code § 56-594(E).

<sup>153</sup> See 9 VAC 5-140-6010 *et seq.*

dioxide their plant emits. The amount of available allowances decrease by 3% every year for an overall reduction of 30% from 2020 levels by 2030. The program is designed to drive down emissions while affording the power-plant operators flexibility to make cost-effective decisions to reduce their emissions over time. While Virginia has just started participating in the program, the Regional Greenhouse Gas Initiative has been tremendously successful. Over the first 10 years of the program, participating states saw their carbon dioxide emissions fall 90% faster than the rest of the country, for an overall reduction of 47%.<sup>154</sup> And the percentage of electricity generated by carbon-generating fossil fuels is only expected to decrease over the life of the proposed Lambert Compressor Station, which is projected to be 50 years or more.<sup>155</sup> Less reliance on fossil fuels to generate electricity going forward means even lower NOx emissions.

DEQ's equivocation over whether a compressor powered by electric motors would be a lower-emitting process than a compressor powered by gas-fired turbines relies on a third mistaken assumption: that overall emissions would likely be the same if the electricity for an electric Lambert Compressor Station came from a gas-fired power plant as if the Lambert Compressor Station were powered by gas-fired turbines.<sup>156</sup> This is incorrect. Gas-fired combined-cycle power plants—the gas-fired power plants used to meet base load for industrial sources like compressor stations—are more energy-efficient than gas-fired compressor turbines. A combined-cycle power system generally has an energy efficiency in the range of 50-60%.<sup>157</sup> MVP has indicated that the thermal efficiency of the gas-fired compressor turbines to be installed at the Lambert Compressor Station would have, at best, a thermal efficiency of 33-34% at 100% load.<sup>158</sup> One of the lower CO<sub>2</sub> BACT emission limits for a new combined-cycle power plant is 794 pounds per megawatt hour (“lb/MWh”), which applies to the Belle River Combined Cycle Power Plant in Michigan.<sup>159</sup> Assuming, as MVP did, that 25 megawatts (“MW”) needs to be produced at the power plant to power the Lambert Compressor Station,<sup>160</sup> this emission rate

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<sup>154</sup> Acadia Ctr., *The Regional Greenhouse Gas Initiative: 10 Years in Review*, Executive Summary (2019), <https://bit.ly/2PIVeAw> (**Exhibit 19**).

<sup>155</sup> See FERC, Southgate Project: Final Env'tl. Impact Statement, Dkt. No. CP19-14-000, at 4-1 (Feb. 2020) (indicating lifetime of 50 years or more for compressor station), <https://bit.ly/3dIBSnj> (“Final EIS”).

<sup>156</sup> Draft Engineering Analysis at 10.

<sup>157</sup> See IPIECA, *Combined Cycle Gas Turbines* (Apr. 10, 2013), <https://bit.ly/3sSg8FS> (**Exhibit 20**).

<sup>158</sup> See June 2020 Permit Application App. B tbls. B-3, B-5.

<sup>159</sup> EPA, *Pollutant Information*, <https://bit.ly/3fxFUM1> (last visited Apr. 2, 2021) (**Exhibit 21**) (listing “Emission Limit 2” for “Carbon Dioxide Equivalent (CO<sub>2</sub>e)” as “794.0000 LB/MW-H 12-OPER MO ROLL AVG”). To locate this information, go to EPA, *RACT/BACT/LAER Clearinghouse: Search by RBLC Identifier*, <https://bit.ly/39BIRs9>, enter “MI-0435” under “Enter RBLC ID(s),” select “Run search now,” select “FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2),” and select “Carbon Dioxide Equivalent (CO<sub>2</sub>e).”

<sup>160</sup> June 2020 Permit Application App. E.

would equate to maximum emissions of 86,943 tons per year of CO<sub>2</sub> from a gas-fired combined-cycle power plant to provide maximum power to the Lambert Compressor Station for a year. The compressors, microturbines, and fuel gas heater (which would no longer be needed if the station was electric) at the Lambert Compressor Station are identified as having potential CO<sub>2</sub> emissions at maximum capacity of 123,223 tons per year.<sup>161</sup> Thus, if the power for the Lambert Compressor Station came from a gas-fired combined-cycle power plant, CO<sub>2</sub> emissions would be 30% lower, and overall emissions would likewise be reduced.

In addition, combined-cycle power plants are more energy-efficient than gas-fired compressor turbines, making annual emissions of all pollutants from power plants lower than the projected annual emissions from a gas-powered Lambert Compressor Station. NO<sub>x</sub> BACT emissions for a gas-fired combined-cycle plant are typically 2 parts per million by volume, dry (“ppmvd”), carbon monoxide (“CO”) BACT emission limits are typically 1.0 ppmvd, and volatile organic compound emission limits are typically 0.7 ppmvd.<sup>162</sup> In comparison, draft permit for the Lambert Compressor Station identifies the controlled emission rates of the planned gas-fired compressor turbines as 2.7 ppmvd for NO<sub>x</sub>, 2.0 ppmvd for carbon monoxide, and 0.5 ppmvd for volatile organic compounds. Relying on DEQ’s permit documents for the proposed Chickahominy Power Station, a combined-cycle power plant, we calculate the following lb/MWh emission rates based on the above BACT limits: NO<sub>x</sub> – 0.053 lb/MWh, CO – 0.016 lb/MWh, and volatile organic compounds (“VOCs”) – 0.0065 lb/MWh.<sup>163</sup> Using these emission factors and an assumed 25 MW generation need at the power plant to power the Lambert Compressor Station at 100% capacity for a year, the emissions from the power plant for the Lambert Compressor Station load would be as follows: NO<sub>x</sub> – 5.83 tons per year (“tpy”) (compared to 12.37 tpy from the controlled gas-fired station); CO – 1.77 tpy (compared to 17.28 tpy from the controlled gas-fired station); and VOCs – 0.717 tpy (compared to the 3.33 tpy from the controlled gas-fired station).<sup>164</sup> Thus, the emissions from the power generated from a gas-fired combined cycle power plant to operate an electric Lambert Compressor Station would be far lower than the emissions from a gas-fired Lambert Compressor Station.

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<sup>161</sup> *Id.* App. B tbl. B-1.

<sup>162</sup> See generally EPA, *RACT/BACT/LAER Clearinghouse (RBLC) Basic Information*, <https://bit.ly/39AFW1J> (last visited Apr. 2, 2021). BACT determinations reviewed include determinations for such facilities as the Greenville Power Station (RBLC ID VA-0325), Killingly Energy Center (RBLC ID CT-0161), Chickahominy Power Station (RBLC ID VA-0332), and Novi Energy C4GT (RBLC ID VA-0328) (**Exhibit 22**).

<sup>163</sup> These emission rates were calculated based on the net generating capacity of one planned combined cycle unit at the Chickahominy Power Station of 550 MW and on the modeled hourly emission rates for each combined-cycle unit as identified in the November 2018 air permit application for the power station. See AECOM, *Air Permit Application: Chickahominy Combined-Cycle Power Plant Project*, Charles City County, Virginia 3-6 tbl. 3-7 (Nov. 2018) (Section 3 excerpted as **Exhibit 23**).

<sup>164</sup> The “controlled gas-fired station” emissions cited here are from June 2020 Permit Application App. B tbl. B-1, “CONTROLLED Potential Emissions Summary.”

**c. The law does not preclude DEQ from considering electric compressor motors as part of its BACT review.**

DEQ also appears to claim that even if the Lambert Compressor Station were subject to BACT for NO<sub>x</sub>, DEQ would not be required to evaluate whether the use of electric motors in place of gas-fired turbines represented BACT:

The parameters in question, electric turbines with electric transmission, are believed to fundamentally redefine the BACT approach for the proposed combustion turbines and therefore BACT does not apply. DEQ does not substitute alternative equipment for the affected emission units as part of the BACT review.<sup>165</sup>

It is unclear exactly what DEQ is arguing here, but none of the possible interpretations of DEQ's statement are legally valid.

DEQ's statement that considering electric compressor motors is "believed to fundamentally redefine the BACT approach for the proposed combustion turbines" has shades of EPA's "redefining the source" doctrine, which is applicable to projects certified under the prevention of significant deterioration ("PSD") program. Under this federal doctrine, the permitting authority need not consider a control alternative if it "redefines the source."<sup>166</sup> But the doctrine, developed to resolve a statutory ambiguity unique to the Clean Air Act's PSD program, does not apply to a non-PSD, minor source in a state permitting process.<sup>167</sup>

And even if the federal doctrine were applicable here, the use of electric motors in place of gas-fired turbines would not constitute "redefining the source" under EPA's test. To determine whether a given technology impermissibly redefines the source, EPA follows a two-step process. First, the applicant itself defines the facility's purpose. Second, EPA determines which elements of the facility as proposed can be changed to reduce emissions without disrupting the applicant's purpose.<sup>168</sup> MVP has defined the purpose of the compressor station as "to move gas from the beginning of the H-650 pipeline at milepost 0.0 in Pittsylvania County, Virginia, to the downstream delivery points along the pipeline ...."<sup>169</sup> There is no evidence that the engines that drive the compressors are inherent design elements that, if changed, would disrupt MVP's purpose for the compressor station in any way.

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<sup>165</sup> Draft Engineering Analysis at 10.

<sup>166</sup> *Friends of Buckingham*, 947 F.3d at 73 (quoting *Helping Hand Tools v. EPA*, 848 F.3d 1185, 1194 (9th Cir. 2016)).

<sup>167</sup> *See Friends of Buckingham*, 947 F.3d at 74 (observing that, to court's knowledge, federal redefining the source doctrine "has never been applied to a non-PSD, minor source by a state pollution board").

<sup>168</sup> *Helping Hand*, 848 F.3d at 1194.

<sup>169</sup> June 2020 Permit Application at 1.

To the extent DEQ attempts to invoke a Virginia doctrine or practice, we note that in *Friends of Buckingham*, DEQ and the Board made the same claim, and the Fourth Circuit found no such doctrine in Virginia law.<sup>170</sup> DEQ subsequently issued a guidance memorandum stating that the BACT requirement “does not provide for wholesale replacement of an emissions unit, or a fundamental alteration of the emissions unit in the application under review.”<sup>171</sup> But this claim—made without citation to any prior authority—is in conflict with established Virginia law.

Under Virginia’s regulations, BACT is evaluated, and required, *for the stationary source*. It is “[a] new *stationary source*” that must “apply best available control technology for each regulated pollutant for which there would be an uncontrolled emission rate equal to or greater than” specified levels.<sup>172</sup> BACT, in turn, is defined as “an emission limitation ... based on the maximum degree of emission reduction for any pollutant which would be emitted from a new stationary source or project which the board, on a case-by-case basis ... determines is achievable *for the new stationary source* or project ....”<sup>173</sup> And the regulations make clear that “stationary source shall include *all* of the pollutant-emitting activities that belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person or of persons under common control ....”<sup>174</sup> Categorically refusing to consider modified emission units is inconsistent with the obligation of DEQ to evaluate and apply BACT at the level of the stationary source.<sup>175</sup>

With the focus properly on the stationary source, Virginia law requires DEQ to assess “the maximum degree of emission reduction for any pollutant” that it determines “is achievable ... through the application of production processes or available methods, systems and techniques ... for control of such pollutant.”<sup>176</sup> Electric motors are “methods, systems [or] techniques” that can be applied to control pollutants—and thus must be considered. For DEQ to implement a policy that does not allow such consideration would be at odds with the goal of the BACT

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<sup>170</sup> See *Friends of Buckingham*, 947 F.3d at 83.

<sup>171</sup> DEQ, Air Permitting Guidance Memo No. APG-350-Ch8, at 2 (Aug. 31, 2020), <https://bit.ly/31Dk8hJ>.

<sup>172</sup> 9 VAC 5-50-260(B) (emphasis added).

<sup>173</sup> 9 VAC 5-50-250(C) (defining “‘Best available control technology’ or ‘BACT’”) (emphasis added).

<sup>174</sup> 9 VAC 5-80-1110(C) (defining “Stationary source”) (emphasis added).

<sup>175</sup> It is true that 9 VAC 5-50-260(A) prohibits emissions from any “affected facility” in excess of emissions limits representing BACT, and 9 VAC 5-50-240(A) clarifies that “[t]he affected facilities at stationary sources to which the provisions of this article apply are emissions units that are subject to the new source review program.” But these provisions merely confirm that BACT emission limits apply to individual emission units; BACT must still be determined “for the new stationary source.” 9 VAC 5-50-250(C).

<sup>176</sup> *Id.*

analysis: to evaluate the maximum achievable degree of emission reduction from the new stationary source.

**d. MVP's analysis of the cost-effectiveness of using electric compressor motors is flawed.**

Although DEQ never evaluated the cost-effectiveness of using electric motors in lieu of gas-fired turbines, MVP included such an analysis in its June 30, 2020 Application Update. MVP's analysis is deficient for several reasons.

First, MVP claimed that "it is not clear that the use of electric compression as an alternative technology for the Project would result in any reduction in emissions" and then provides emission increase estimates from the generation of electricity to meet the electricity needs of the Lambert Compressor Station.<sup>177</sup> As discussed in Section III.B.2.b, above, MVP's assessment of increased emissions from the source or sources of electricity for the compressor station are completely speculative, especially given the shift to carbon-free energy sources occurring in Virginia and nationally. In addition, BACT is evaluated for the stationary source,<sup>178</sup> which in this case is the Lambert Compressor Station and does not include any sources of electricity generation.

Second, MVP's cost-effectiveness analysis considered the costs for purchase of compressors powered by electric motors but failed to acknowledge (as the data in its June 2020 permit application indicated) that an electric compressor station would cost less than the planned gas-fired combustion turbines in terms of capital costs. This difference is shown in Table 2, below.

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<sup>177</sup> June 2020 Permit Application at 51, 55–56.

<sup>178</sup> 9 VAC 5-50-260(B), 5-50-250(C).



**Table 2. Comparison of MVP’s Capital Costs for Gas-Fired Turbine-Powered Compressors Turbines to MVP’s Capital Costs for Electric Motor-Powered Compressors (Source: June 2020 Permit Application App. E, NOx BACT Cost Analysis “Baseline Case” and “Case 4: Electric Turbines”)**

<b>Component of Compressor Station</b>	<b>Cost for Gas-Fired Turbines</b>	<b>Cost for Electric Motors</b>
11,460 hp compressor (Solar Taurus 70, 15 ppm SoLoNOx)	\$7,250,000	\$5,500,000
16,610 hp compressor (Solar Mars 100 compressor turbines (15 ppm SoLoNOx)	\$10,545,455	\$8,000,000
Primary Fuel Skid and System Piping (Common to Both Units)	\$250,000	\$0
Fuel Heater Installed (Common to Both Units)	\$100,000	\$0
C1000 Microturbine Installed (Common to Both Units)	\$1,600,000	\$0
Microturbine fuel skid and system piping	\$150,000	\$0
MCC Equipment inside of Station Installed	\$250,000	\$500,000
Utility Substation, 28 kVA, 13.8 kV-MVP Purchased	\$0	\$1,500,000
<b>Total</b>	<b>\$20,155,455</b>	<b>\$15,500,000</b>

As this table demonstrates, the capital costs of the compressor station would be about 25% lower (approximately \$4.7 million less) if electric motors were installed instead of gas-fired turbines. However, MVP also claimed additional costs for building a substation to bring electricity to the Lambert Compressor Station site.<sup>179</sup> MVP estimated that the substation capital costs (which include the substation upgrades and additional transmission line construction and upgrades listed in Section 5.6.1 of the June 2020 Permit Application) would be \$34,848,000,<sup>180</sup> but provides no supporting information regarding, among other things, (a) the existing electric system facilities and their capabilities, (b) the existing system’s current and projected loading levels in the absence of an electric Lambert Compressor Station, or (c) the projected loading that

<sup>179</sup> June 2020 Permit Application at 52–53, 57–58, App. E.

<sup>180</sup> *Id.* at 59, App. E (NOx BACT Cost Analysis “Case 4: Electric Turbines”).

would support an electric Lambert Compressor Station. MVP has not demonstrated that local electric facilities need to be upgraded from 69 kilovolts (“kV”) to 115 kV in order to serve the additional load associated with the compressor station. Further, it is not clear whether all of the substation costs would have to be covered by MVP or whether the utilities would provide some assistance, given that it would provide the utility with a customer for the 50-plus-year life of the compressor station. MVP assumed it would bear the entirety of the capital costs.

MVP also assumed that the total capital cost of electric motor-powered compressors would be the capital cost of electric motors plus the capital costs of a substation.<sup>181</sup> However, in determining cost-effectiveness, MVP should have taken into account the \$4.7 million in capital cost savings of using electric motor-powered compressors in lieu of gas-fired turbine-powered compressors and reduced the overall capital cost of electric motors and a substation by that amount.

In addition, MVP overstated annualized capital costs of electric motor-powered compressors by using too high of an interest rate and too short of a lifetime of the electric motors and substation. Specifically, MVP assumed a 6% interest rate and a 15-year life of the equipment.<sup>182</sup> The substation would likely have a lifetime equivalent to the expected 50-plus-year life of the compressor station.<sup>183</sup> The electric motors would likely have a useful life of 30 years or more.<sup>184</sup> Thus, assuming a 15-year life in determining annualized costs of controls greatly overstated the annualized capital costs, which can be amortized over at least 30 years and as much as 50 years for the substation. The assumed 6% interest rate is also far higher than the rate that EPA’s Control Cost Manual advises should be used in cost-effectiveness calculations. Specifically, EPA recommends using the current bank prime lending rate in amortizing capital costs of controls,<sup>185</sup> which is currently 3.25%.<sup>186</sup>

In addition, MVP appears to have overstated the operational costs for electricity for the electric motors. Specifically, MVP claimed the electricity demand for the Lambert Compressor

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<sup>181</sup> *Id.* at 59.

<sup>182</sup> *Id.*

<sup>183</sup> See Final EIS at 4-1 (indicating lifetime of 50 years or more for compressor station); see also, e.g., Kojiro Shimomugi et al., *How Transformers Age*, T&D World, Feb. 21, 2019, <https://bit.ly/3w1SELS> (**Exhibit 24**).

<sup>184</sup> This is based on the fact that many gas-fired turbine-powered compressors have been in operation for 30 years or more, and electric motor-powered compressors have less maintenance issues and lower maintenance requirements, which should ensure that the compressors last 30 years or more.

<sup>185</sup> EPA, *Control Cost Manual* § 1, ch. 2, at 16 (Nov. 2017), <https://bit.ly/31DkWmL>.

<sup>186</sup> See Bd. of Governors of Fed. Rsrv. Sys., *Selected Interest Rates (Daily) – H.15*, <https://bit.ly/3fBAorz> (Apr. 1, 2021) (**Exhibit 25**).

Station would be 25 MW.<sup>187</sup> However, converting the two compressor turbines' horsepower rating to MW rating equates to only 20.698 MW,<sup>188</sup> and adding in the five microturbines at 200 kW each<sup>189</sup> equates to a total maximum electricity need of 21.698 MW for the station.<sup>190</sup> Thus, MVP overstated the annual electricity usage at the Lambert Compressor Station and associated costs by approximately 14%. We calculate a maximum electricity usage of an electric compressor station of 190,074,480 kilowatt-hours per year ("kWh/yr") or, on average, 15,839,540 kilowatt-hours per month ("kWh/month").<sup>191</sup> In comparison, MVP assumed 216,000,000 kWh/yr or 18,000,000 kWh/month.<sup>192</sup> Using the same electricity cost numbers provided by MVP, we calculate the maximum annual cost for electricity at an electric compressor station as \$6,479,719 per year—more than \$1 million lower than MVP's estimate of \$7,514,280 per year.

With respect to the other annual maintenance costs, MVP's data shows that compressors powered by electric motors will have lower maintenance costs than gas-fired turbine-powered compressors. Specifically, MVP stated that the maintenance costs of gas-fired turbines will be \$1,567,753, whereas the maintenance costs for electric motors will be \$495,962.<sup>193</sup> Thus, overall, the use of electric motors would involve lower capital costs and lower maintenance costs than the use of gas-fired turbines.

It also bears noting that MVP estimated that the cost of the natural gas to run the proposed Lambert Compressor Station would be \$4,010,863 per year.<sup>194</sup> Not only would MVP avoid incurring that cost if it were to use electric motors, but the gas that would otherwise be used to power the compressors (1,682,464 million standard cubic feet per year<sup>195</sup>) would presumably be available for sale, allowing MVP to make a profit on top of its cost savings.

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<sup>187</sup> June 2020 Permit Application App. E.

<sup>188</sup> The horsepower rating of the two compressor turbines are 11,146 hp and 16,610 hp, or a total of 27,756 hp. *See id.* at 2. Conversions from horsepower to megawatt were based on 1 hp = 0.0007457 MW.

<sup>189</sup> *See id.*

<sup>190</sup> It must be noted that consumers of electricity generally pay for the cost of the kW-hrs they use, not the kW-hrs that have to be generated, considering losses along transmission lines.

<sup>191</sup> These totals were calculated assuming 21.698 MW maximum total compressor station need, assuming continual need at the maximum MW need throughout the year (i.e., 8,760 hours per year).

<sup>192</sup> June 2020 Permit Application App. E.

<sup>193</sup> *Id.*

<sup>194</sup> *Id.*

<sup>195</sup> *Id.*

Finally, MVP evaluated the cost-effectiveness of pollutant reductions from electrification on a pollutant-by-pollutant basis. Yet forgoing the use of natural gas to power the Lambert Compressor Station would eliminate emissions of *all* pollutants emitted as the result of gas combustion, including pollutants not being evaluated for BACT.

Below, in Table 3, we provide revised cost-effectiveness calculations for the use of electric compressor motors in lieu of gas-fired compressor turbines at the Lambert Compressor Station. Our costs are based on the following:

- We compared the difference in capital cost of an electric compressor station to that of a gas-fired compressor station, adding in MVP's unsubstantiated \$34,848,00 cost estimate for a substation.
- Those revised capital costs were amortized over 30 years, assuming a 3.25% interest rate.
- Annual operations and maintenance ("O&M") costs were based on net increase in O&M costs for use of an electric compressor station instead of a gas-fired compressor station.
- Cost-effectiveness was based on dividing the total of the revised annualized capital costs and revised annual O&M costs by the total air pollutants reduced per year from the gas-fired compressor station (both with and without considering CO<sub>2</sub>e emissions). Hazardous air pollutants were not included in the total, since it was not clear whether those emissions were included in the total of VOC emissions. We did not include any emission reductions from pigging or from blowdowns, although it must be noted that use of electric motors would decrease emissions from blowdowns due to less frequent maintenance required. We also did not account for reductions in fugitive emissions, although use of electric motors would result in no fugitive emissions associated with the fuel gas input to the compressors.

**Table 3. Revised Net Cost-Effectiveness of Using Electric Motors at Lambert Compressor Station**

Net Capital Cost of Using Electric Motors at Lambert Compressor Station	Annualized Capital Costs (3.25% Interest, 30-Year Life)	Net Annual O&M Costs of Electric Motors	Total Annual Costs of Electric Motors	Cost-Effectiveness Based on Reductions in All Air Emissions from Use of Electric Motors Excluding CO <sub>2e</sub> , <sup>196</sup> \$/Ton	Cost-Effectiveness Based on Reductions in All Air Emissions from Use of Electric Motors Including CO <sub>2e</sub> , <sup>197</sup> \$/Ton
\$30,192,545	\$1,591,147	\$1,047,849	\$2,638,996	\$14,798	\$21/ton

Cost-effectiveness is based on the total annualized costs of a pollution control option divided by the pollutants reduced by that option. By failing to reflect the capital and maintenance savings of using electric motors instead of gas-fired turbines, and assuming an unreasonably high interest rate and arbitrarily short life of controls, MVP calculated the total annualized costs of electric compressor motors as \$13,194,212 per year.<sup>198</sup> Using reasonable inputs and assumptions, as described above and illustrated in Table 3, the net total annualized costs of electric motors to power the Lambert Compressor Station’s compressors would be \$2,638,996—80% less than the total annualized cost figure put forth by MVP.

**3. Assuming the use of gas-fired compressor turbines, DEQ should apply BACT to require a NOx emission limit no higher than 2.5 ppmvd.**

Despite the significant benefits of using electric compressor motors described in Section III.B.2, above, DEQ’s draft permit does not require their use. We thus provide the following

<sup>196</sup> Total of Uncontrolled Emissions = 178.33 tpy, based on total of NOx, PM2.5, CO, SO<sub>2</sub>, and VOC emissions for gas-fired turbines, microturbines, and heaters from June 2020 Permit Application App. B tbl. B-1, “UNCONTROLLED” Potential Emissions Summary,” and 15 ppm NOx emissions from June 2020 Permit Application App. E, NOx BACT Cost Analysis “Baseline Case.”

<sup>197</sup> Total of Uncontrolled Emissions = 178.33 tpy + 123,351 tpy CO<sub>2e</sub>, based on June 2020 Permit Application App. B tbl. B-1, “UNCONTROLLED Potential Emissions Summary” (total uncontrolled CO<sub>2e</sub> emissions excluding emissions from “Produced Fluid Tanks,” “Blowdowns,” and “Station Fugitives”).

<sup>198</sup> June 2020 Permit Application at 59 tbl. 5-3.

comments on DEQ's proposed NO<sub>x</sub> BACT emission limits for the gas-fired turbine-powered compressors.

As discussed in Section III.B.1, above, the Lambert Compressor Station should be considered as subject to BACT based on its baseline NO<sub>x</sub> emissions of 15 ppm, for which the facility's uncontrolled NO<sub>x</sub> emissions would exceed DEQ's BACT applicability threshold of 40 tons per year. Because the advanced low-NO<sub>x</sub> combustors are not vital to the operation of the combustion turbines, it is not appropriate to consider those controls as inherently part of the compressors' uncontrolled emissions.

Further, while DEQ indicates that MVP has voluntarily proposed control measures to meet BACT for NO<sub>x</sub>—specifically, installation of SCR in addition to advanced ultra-low-NO<sub>x</sub> combustors—DEQ must also acknowledge that those controls are needed to ensure that the area does not violate the 1-hour NO<sub>2</sub> NAAQS. As discussed in Section III.A, above, the cumulative 1-hour NO<sub>2</sub> modeling for the Lambert Compressor Station showed concentrations of NO<sub>2</sub> at 95% of the 1-hour NO<sub>2</sub> NAAQS.<sup>199</sup> Given that SoLoNO<sub>x</sub> emission rates are not guaranteed at temperature above 100°F or at subzero temperatures,<sup>200</sup> the SoLoNO<sub>x</sub> controls alone are likely insufficient to ensure that the Lambert Compressor Station would not cause or contribute to a violation of the 1-hour NO<sub>2</sub> NAAQS. DEQ must thus make clear that it is relying on the NO<sub>x</sub> limitations it has proposed for the two compressor turbines to claim that the Lambert Compressor Station will not interfere with attainment or maintenance of the 1-hour NO<sub>2</sub> NAAQS. The importance of stating this clearly in the permit and engineering analysis is to ensure that a new 1-hour NO<sub>2</sub> modeling analysis is required before DEQ allows any relaxation of the permit's NO<sub>x</sub> emission limits in the future.

DEQ has proposed a NO<sub>x</sub> limit of 2.7 ppmvd@15% oxygen for the compressor turbines based on use of ultra-low NO<sub>x</sub> combustion controls (SoLoNO<sub>x</sub>) and SCR.<sup>201</sup> The 2.7 ppm NO<sub>x</sub> limit reflects an SCR NO<sub>x</sub> removal efficiency of 70% from the 9 ppm NO<sub>x</sub> rate that the advanced SoLoNO<sub>x</sub> will achieve. Yet SCR systems can achieve much higher NO<sub>x</sub> removal efficiencies than 70%. For example, BASF makes SCR catalysts that it claims can achieve up to 97% NO<sub>x</sub> reduction. The NOxCat™ ETZ catalyst is specifically designed for simple-cycle power generating turbines and other high temperature turbine applications.<sup>202</sup> The NOxCat™ VNX and ZNX catalysts can achieve up to 99% NO<sub>x</sub> reduction and are most effective at a temperature range of 550°F to 800°F.<sup>203</sup>

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<sup>199</sup> June 2020 Modeling Report at 4-2 tbl. 4-2.

<sup>200</sup> April 2019 Permit Application at 4.

<sup>201</sup> Draft Permit, Conditions 1, 20.

<sup>202</sup> See BASF, *NOxCat™ ETZ™ Catalysts*, <https://bit.ly/3fDkPzM> (last visited Apr. 2, 2021) (**Exhibit 26**).

<sup>203</sup> See BASF, *NOxCat™ VNX™ Catalysts*, <https://bit.ly/3mf1yG8> (last visited Apr. 2, 2021) (**Exhibit 27**).

In terms of operational characteristics, the compressor turbines are essentially the same as simple-cycle combustion turbines used for power generation, except that the turbine is used to drive a compressor rather than to generate electricity. SCR has been required as BACT and installed on numerous simple-cycle gas-fired combustion turbines that operate as peaking plants in the United States with varying load ranges. Compliance with those emission limits is typically required on a very short-term basis, with NO<sub>x</sub> emissions being monitored with continuous emissions monitoring systems (“CEMS”). For example, in a permit analysis for the Mariposa Energy Project to be located in Alameda County, California, the Bay Area Air Quality Management District provided numerous examples of simple-cycle gas turbines permitted in the District with 1-hour average NO<sub>x</sub> limits of 2.5 ppmvd@15% O<sub>2</sub> and required the new simple-cycle gas turbines of the Mariposa Energy Project to meet a NO<sub>x</sub> BACT limit of 2.5 ppmvd.<sup>204</sup> These example simple-cycle turbine NO<sub>x</sub> limits with SCR are provided in Table 4, below.

**Table 4. Simple-Cycle Turbines in California with NO<sub>x</sub> Limits with SCR of 2.5 ppmvd@15%O<sub>2</sub> (Source: Mariposa Energy Project Preliminary Determination at 38)**

Facility	NO <sub>x</sub> Limit Averaging Time
Panoche Energy Center	1-hour average
Walnut Creek Energy Park	1-hour average
Sun Valley Energy Project	1-hour average
CPV Sentinel Energy Project	1-hour average
Lambie Energy Center	1-hour average
Riverview Energy Center	1-hour average
Wolfskill Energy Center	1-hour average
Goosehaven Energy Center	1-hour average

A review of EPA’s RACT/BACT/LAER Clearinghouse shows numerous other simple-cycle combustion turbines with NO<sub>x</sub> BACT limits of 2.5 ppmvd, as shown in Table 5, below.

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<sup>204</sup> See Bay Area Air Quality Mgmt. Dist., Preliminary Determination of Compliance: Mariposa Energy Project at 38–39 (Aug. 2010), <https://bit.ly/3sIMvqt> (Sections 5.1 and 5.2 excerpted as **Exhibit 28**) (“Mariposa Energy Project Preliminary Determination”). These BACT determinations can also be found in the California Air Resources Board’s BACT Clearinghouse. See Cal. Air Res. Bd., *Technology Clearinghouse*, <https://bit.ly/3wgmwsK> (last visited Apr. 2, 2021).

**Table 5. Simple-Cycle Turbines in EPA’s RACT/BACT/LAER Clearinghouse with NOx Limits with SCR of 2.5 ppmvd@15%O<sub>2</sub><sup>205</sup>**

<b>Facility</b>	<b>RBLC ID</b>	<b>NOx Limit Averaging Time</b>
Bayonne Energy Center LLC	NJ-0086	3-hour average
Troutdale Energy Center	OR-0050	3-hour average
Vineland Municipal Electric Utility	NJ-0077	3-hour average
Bayonne Energy Center LLC	NJ-0075	Not given
PSEG Fossil LLC Kearny Generating Station	NJ-0076	3-hour rolling average
El Cajon Energy LLC	CA-1174	1-hour average
Orange Grove Project	CA-1176	1-hour average
Escondido Energy Center LLC	CA-1175	1-hour average

Based on all of this information, a NOx emission limit at least as low as 2.5 ppmvd should be considered as BACT for NOx for the compressor turbines at the Lambert Compressor Station. Not only would such a limit better reflect the capabilities of SCR, but a lower NOx limit would lower the Lambert Compressor Station’s impact on 1-hour NO<sub>2</sub> concentrations in the area, which would better prevent the facility from causing or contributing to a 1-hour NO<sub>2</sub> NAAQS violation given the other NOx sources in the area.

#### **IV. Conclusion**

To approve the proposed minor new source permit on this record would be to repeat ignore many of the missteps that led to the vacatur of the Buckingham Compressor Station permit a little over a year ago. As set forth in this letter, DEQ and MVP have neglected to adequately address environmental justice concerns, performed an incomplete site suitability analysis, and failed to demonstrate compliance with applicable air permitting requirements for the Lambert Compressor Station. These fundamental flaws in the permitting process require that the proposed permit be denied.

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<sup>205</sup> Specific information on each facility can be found by entering the specified RBLC identifier under “Enter RBLC ID(s)” at EPA, *Search by RBLC Identifier*, <https://bit.ly/39BIRs9> (last visited Apr. 2, 2021).



Ms. Anita Walthall

April 9, 2021

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Accordingly, we ask that the permit be submitted for consideration by the Board; request a public hearing so that the Board hears directly from affected community members along with other members of the public; and urge the Board to deny the permit.

Sincerely,



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## EXHIBITS TO COMMENTS

- Exhibit 1 *Pittsylvania NAACP Asks DEQ to Refer MVP Air Permit to Air Pollution Control Board*, Chatham Star-Tribune, Mar. 8, 2021, <https://bit.ly/3bvQDnR>
- Exhibit 2 EPA, *How Does EPA Use EJSCREEN?*, <https://bit.ly/3ds3cAm> (last visited Apr. 2, 2021)
- Exhibit 3 Env'tl. Just. Health All. for Chem. Pol'y Reform et al., *Life at the Fenceline: Understanding Cumulative Health Hazards in Environmental Justice Communities* (2018), <https://bit.ly/3sE6BT3>
- Exhibit 4 Curriculum Vitae of Vicki Stamper
- Exhibit 5 DEQ, Stationary Source Permit to Construct and Operate: Transcontinental Gas Pipe Line Company LLC – Natural Gas Compressor Station 165 (Jan. 28, 2020)
- Exhibit 6 DEQ, Engineering Analysis, Transcontinental Gas Pipeline Company, LLC (Station 165) (Jan. 28, 2020)
- Exhibit 7 U.S. Census Bureau, *QuickFacts: Winston-Salem city, North Carolina*, <https://bit.ly/3cKF7FB> (last visited Apr. 2, 2021)
- Exhibit 8 Memorandum from Allen Armistead, DEQ, to Air Permit File (Aug. 20, 2015)
- Exhibit 9 DEQ, Stationary Source Permit to Modify and Operate: Transcontinental Gas Pipe Line Co., LLC – Compressor Station 166 (Aug. 24, 2015)
- Exhibit 10 Leslie Witherspoon, Solar Turbines Incorporated, *SoLoNOx Products: Emissions in Non-SoLoNOx Modes*, PIL 167 (Dec. 1, 2016)
- Exhibit 11 Solar Turbines, *SoLoNOx<sup>TM</sup> Upgrade*, <https://bit.ly/3sAhOE1> (last visited Apr. 2, 2021)
- Exhibit 12 Jeffery B. Greenblatt, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-6990E, *Opportunities for Efficiently Improvements in the U.S. Natural Gas Transmission, Storage and Distribution System* (May 2015), <https://bit.ly/2PGEFz7>
- Exhibit 13 Mark Iden, *Solar Power Station Helps to Power Gas Pipeline Compressor Station*, Pipeline Tech. J., Oct. 16, 2020, <https://bit.ly/3u4hAVY>
- Exhibit 14 N.M. Env't Dep't, Title V Operating Permit No. P154-R4 (Sept. 28, 2018)

- Exhibit 15 Al Armendariz, *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements* (Jan. 26, 2009), <https://bit.ly/2QVsNd7>
- Exhibit 16 U.S. Energy Info. Admin., *Virginia Energy Consumption Estimates, 2018*, <https://bit.ly/2OfnIeL> (last visited Apr. 2, 2021)
- Exhibit 17 Dominion Energy, *Virginia Electric and Power Company's Report of Its Integrated Resource Plan* (May 1, 2020), <https://bit.ly/39upv78> (Chapter 5 excerpted)
- Exhibit 18 Darren Sweeney, *Bulk of Virginia's Coal Plants Must Shut Down Before 2025 Under New State Law*, S&P Global Platts, Apr. 13, 2020, <https://bit.ly/3uijCSE>
- Exhibit 19 Acadia Ctr., *The Regional Greenhouse Gas Initiative: 10 Years in Review* (2019), <https://bit.ly/2PIVeAw>
- Exhibit 20 IPIECA, *Combined Cycle Gas Turbines* (Apr. 10, 2013), <https://bit.ly/3sSg8FS>
- Exhibit 21 EPA, *Pollutant Information*, <https://bit.ly/3fxFUM1> (last visited Apr. 2, 2021)
- Exhibit 22 BACT determinations (NO<sub>x</sub>, CO, and VOCs) for Greenville Power Station (RBLC ID VA-0325), Killingly Energy Center (RBLC ID CT-0161), Chickahominy Power Station (RBLC ID VA-0332), and Novi Energy C4GT (RBLC ID VA-0328)
- Exhibit 23 See AECOM, Air Permit Application: Chickahominy Combined-Cycle Power Plant Project, Charles City County, Virginia (Nov. 2018) (Section 3 excerpted)
- Exhibit 24 Kojiro Shimomugi et al., *How Transformers Age*, T&D World, Feb. 21, 2019, <https://bit.ly/3wlSELS>
- Exhibit 25 Bd. of Governors of Fed. Rsrv. Sys., *Selected Interest Rates (Daily) – H.15*, <https://bit.ly/3fBAorz> (Apr. 1, 2021)
- Exhibit 26 BASF, *NO<sub>x</sub>Cat<sup>TM</sup> ETZ<sup>TM</sup> Catalysts*, <https://bit.ly/3fDkPzM> (last visited Apr. 2, 2021)
- Exhibit 27 BASF, *NO<sub>x</sub>Cat<sup>TM</sup> VNX<sup>TM</sup> Catalysts*, <https://bit.ly/3mf1yG8> (last visited Apr. 2, 2021)
- Exhibit 28 Bay Area Air Quality Mgmt. Dist., Preliminary Determination of Compliance: Mariposa Energy Project (Aug. 2010), <https://bit.ly/3sIMvqt> (Sections 5.1 and 5.2 excerpted)

Exhibits 1-10.pdf

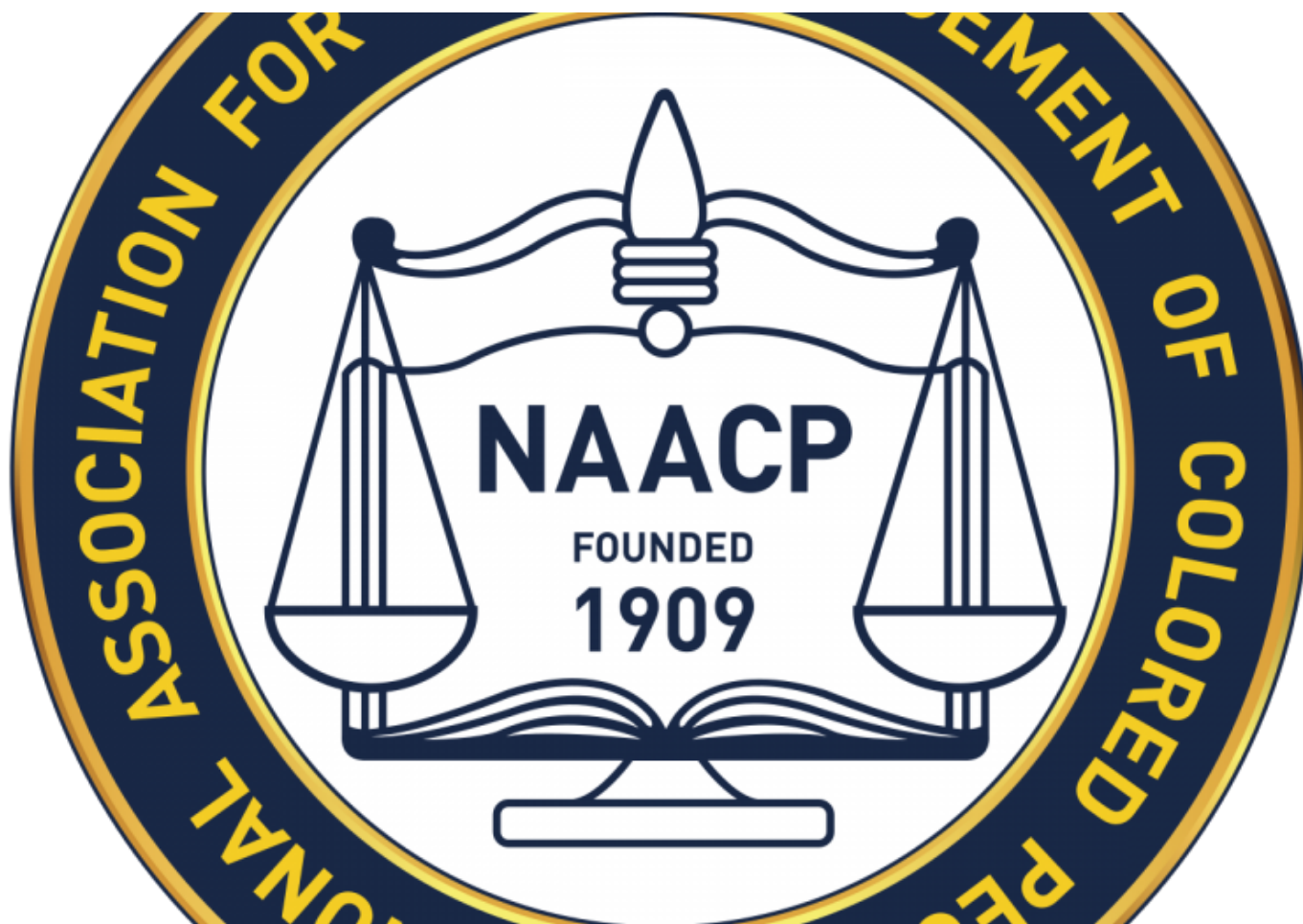
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# Exhibit 1

[https://www.chathamstartribune.com/news/article\\_52141b58-8018-11eb-9948-9bd1a8856f32.html](https://www.chathamstartribune.com/news/article_52141b58-8018-11eb-9948-9bd1a8856f32.html)

## Pittsylvania NAACP asks DEQ to refer MVP air permit to Air Pollution Control Board

Mar 8, 2021



The Pittsylvania County Branch of the NAACP, the National Association for the Advancement of Colored People, passed a resolution March 2 opposing immediate approval of an air permit requested by the Mountain Valley Pipeline (MVP) for its proposed Lambert Compressor Station, currently sited approximately two and a half miles east of Chatham. The group also approved a written comment to DEQ on the draft air permit.

The resolution and comment request that Virginia's Department of Environmental Quality refer the draft air permit to the citizen Air Pollution Control Board. The referral would allow time for

further consideration of air quality issues and concerns regarding environmental justice.

The Virginia Environmental Justice Act, adopted in 2020, defines environmental justice as “the fair treatment and meaningful participation of all people ... in the development, implementation, and enforcement of environmental laws, regulations, and policies. ... Meaningful participation requires that affected and vulnerable community residents have access and opportunities to participate in the full cycle of the decision-making process about a proposed activity that will affect their environment or health and decision makers will seek out and consider such participation, allowing the views and perspectives of community residents to shape and influence the decision.”

According to the group’s written comment to DEQ, “Despite MVP and DEQ having acknowledged that the Lambert Compressor Station has the potential to affect communities of color, MVP’s environmental justice consultant did not contact us, the local Pittsylvania Branch NAACP, at all, and neither MVP nor DEQ contacted us until December 2020. We strongly hold that affected and vulnerable community residents of Pittsylvania County have not had access and opportunities to participate in the full cycle of the decision-making process about the MVP Southgate project, including the Lambert Compressor Station.”

The Lambert Compressor Station is part of the MVP Southgate Extension, a pipeline project conditionally certified by the Federal Energy Regulatory Commission June 18, 2020, to transport fracked gas through Pittsylvania County to North Carolina for use in that state only.

The conditional FERC certificate requires that MVP obtain necessary approvals and permits for the MVP Mainline before beginning construction on the Southgate project. The MVP Mainline, if completed, would deliver fracked gas from Wetzel County, West Virginia, to Transcontinental Pipe Line Company, LLC’s (Transco) Compressor Stations 165 and 166 in Pittsylvania County for distribution to the Southeastern U.S.

Though some of the MVP Mainline has been constructed in northern Pittsylvania County, the company lacks key federal permits. Stop work orders prevent MVP from crossing streams or attempting to install pipe on steep mountain slopes in Virginia and West Virginia.

On Jan. 7, 2020, the fourth Circuit Court of Appeals revoked a similar air permit issued to Dominion Energy for a compressor station in the predominantly African American community of Union Hill in Buckingham County despite stringent air quality requirements, stating, “What matters is whether the (Air Pollution Control Board) has performed its statutory duty to determine whether this facility is suitable for this site, in light of [environmental justice] and potential health risks for the people of Union Hill. It has not.”

# Exhibit 2



An official website of the United States government.



## How Does EPA Use EJSCREEN?

### Environmental Justice Mapping and Screening at EPA

#### EJSCREEN Uses



EPA uses EJSCREEN as a preliminary step when considering environmental justice in certain situations. The agency uses it to screen for areas that may be candidates for additional consideration, analysis or outreach as EPA develops programs, policies and activities that may affect communities. In the past, the agency employed EJ screening tools in a wide variety of circumstances.

A few examples of what EJSCREEN supports across the agency include:

- Informing outreach and engagement practices
- Implementing aspects of the following programs:
  - permitting
  - enforcement
  - compliance
  - voluntary
- Developing retrospective reports of EPA work
- Enhancing geographically based initiatives

EJSCREEN is not used by EPA staff for any of the following:

- As a means to identify or label an area as an "EJ community"
- To quantify specific risk values for a selected area
- To measure cumulative impacts of multiple environmental factors
- As a basis for agency decision-making or making a determination regarding the existence or absence of EJ concerns

EPA hopes to refine our uses of EJSCREEN as we build upon lessons learned and as we receive feedback

from our stakeholders and governmental partners.

LAST UPDATED ON AUGUST 10, 2016

# Exhibit 3

ENVIRONMENTAL JUSTICE HEALTH ALLIANCE FOR CHEMICAL POLICY REFORM  
COMING CLEAN | CAMPAIGN FOR HEALTHIER SOLUTIONS

# LIFE AT THE FENCELINE

Understanding Cumulative Health Hazards  
in Environmental Justice Communities







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September 2018

ENVIRONMENTAL JUSTICE HEALTH ALLIANCE FOR CHEMICAL POLICY REFORM  
COMING CLEAN | CAMPAIGN FOR HEALTHIER SOLUTIONS

**Environmental Justice Health  
Alliance** for Chemical Policy Reform

coming **clean**

CAMPAIGN FOR  
**Healthier  
Solutions**

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## THIS REPORT WAS PRODUCED BY:

**Coming Clean** is a national environmental health and justice collaborative of 200 organizations working to reform the chemical and fossil fuels industries so they are no longer a source of harm, and to secure systemic changes that allow a safe chemical and clean energy economy to flourish. Learn more at [www.comingcleaninc.org](http://www.comingcleaninc.org).

**The Environmental Justice Health Alliance for Chemical Policy Reform** supports diverse movement towards safe chemicals and clean energy that leaves no community or worker behind. EJHA is a network of grassroots environmental justice organizations in communities that are disproportionately impacted by toxic chemicals, from old contaminated sites, ongoing exposure to polluting facilities, and toxic chemicals in household products and foods. Learn more at [www.ej4all.org](http://www.ej4all.org).

**The Campaign for Healthier Solutions**, hosted by Coming Clean and EJHA, is made up of interested organizations, dollar store customers, and investors who seek to work with discount retailers to help them protect their customers and the communities in which they operate, and also grow their business, by implementing corporate policies to identify and phase out harmful chemicals in the products they sell. Learn more at [www.nontoxicdollarstores.org](http://www.nontoxicdollarstores.org).

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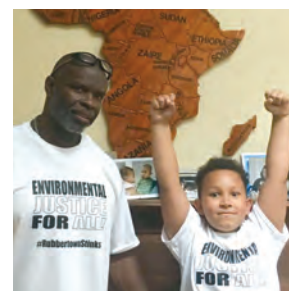
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## EXECUTIVE SUMMARY

**A**cross the United States, the health and safety of people who live, work, play, and learn near thousands of industrial and commercial facilities that use or store extremely dangerous chemicals is at risk of a major chemical release or explosion at any time. Compared to national averages, a significantly greater proportion of Blacks (African Americans), Latinos (Hispanics), and people at or near poverty levels tend to live in close proximity to the most hazardous facilities. Compounding these risks, a large and growing body of research has found that people of color and those living in poverty are exposed to higher levels of environmental pollution than Whites or people not living in poverty.

Exposure to toxic air pollution and stress related to fear of potential chemical disasters increase the health burden on these communities. These hazards are amplified by other negative socioeconomic and health factors, including higher rates of diseases such as diabetes and asthma; lack of access to healthy foods; exposure to toxic chemicals in products sold at discount retail stores; substandard housing; and stress from racism, poverty, unemployment, and crime; among other factors. Addressing the cumulative impacts of these various environmental health risks and social determinants of health on these overburdened communities is the foundation of Environmental Justice (EJ).

The research reported here builds on many previous reports and studies, as well as a robust and expanding body of scientific and technical literature, on Environmental Justice and social determinants of health. We examined who is potentially impacted, and their health risks from multiple chemical hazards and toxic air pollution exposures, in the following areas: Los Angeles, as well as Kern, Fresno, and Madera counties, CA; Houston and Dallas, TX; Louisville, KY; Albuquerque, NM; and Charleston, WV.



**Two-thirds of people in Louisville (pictured above) live near high-risk chemical facilities, a common situation in communities like those studied for this report.**

We looked at several interconnected issues:

- Who lives in close proximity to the most hazardous industrial and commercial facilities (and is therefore at greatest risk from a major chemical release or explosion)?
- What are the cancer risks and the potential for respiratory illness from toxic air pollution exposure for those living in a “fenceline zone” within 3 miles of a hazardous facility?
- Do these communities have access to healthy foods?
- Where are critical institutions—schools, hospitals, and discount retail (“dollar”) stores—located in these fenceline areas?

## OVERALL FINDINGS

The results of the analyses conducted for this report demonstrate that the health and safety of communities closest to some of the nation's most dangerous industrial and commercial facilities are at risk from multiple threats, including potential chemical releases or explosions, daily exposure to toxic air pollution, and poor nutrition from a lack of access to healthy foods (along with other hazards and impacts not specifically studied here). The population of these fenceline areas is disproportionately Black, Latino, and living in poverty. Many of these communities also rely heavily, or solely, on dollar stores for household necessities and in some cases food, making these retailers potential sources of either additional toxic exposures or safer products and healthier foods (depending on the corporate policies they implement or fail to adopt).

Analysis of the 9 areas studied for this report clearly shows that:

1. **In most of the areas researched, large majorities of the population live in fenceline zones around highly hazardous facilities, and most schools and medical institutions are located in these zones, at much greater rates than nationally.** In 7 of the 9 areas researched for this report, two-thirds of the population or more live in fenceline zones (much greater than the national rate of 39%). In most of the areas studied, at least two-thirds of all schools and 70% of medical facilities are located in fenceline zones (compared to 45% of US schools and 39% of US hospitals and nursing homes).
2. **Fenceline zones around hazardous facilities are disproportionately Black, Latino, and impoverished.** The percentage of Blacks or Latinos living within 3 miles of a Risk Management Plan (RMP) facility was higher than for the entire area in every study area, and often much higher than for the US as a whole. In 7 of the 9 areas researched, the percentage of people living in poverty within 3 miles of an RMP facility is higher than for those living in poverty in the entire area, and often much higher than for the US as a whole.
3. **People living in hazardous facility fenceline zones face multiple health hazards and risks.** In addition to the constant threat of catastrophic chemical releases or explosions, in every area researched for this report

fenceline zones face higher risk of cancer from toxic air pollution than the entire area (and often much higher than for the US as a whole). In 8 of the 9 areas, the potential for respiratory illness is higher in fenceline zones than for the entire area, and in every area is above the national rate. The percentage of fenceline zone residents who also live in a low-income/low food access area is higher than for the entire city or county in all 9 areas (and two to three times the national rate in most areas).

4. **The most vulnerable neighborhoods—areas that are both low-income and have low access to healthy foods—are even more heavily and disproportionately impacted.** In every area studied, low-income/low food access areas within fenceline zones have higher poverty rates, greater percentages of residents who are people of color, and higher cancer risk and respiratory hazard from toxic air pollution than for the whole fenceline zones or the entire city or county, often much higher.

In comparing data from the fenceline zone areas with the entire urban area or county, overall key findings for the 9 areas researched include:

- In 7 of the 9 areas, more than two-thirds of the population (over 67%) lives in a fenceline zone (within three miles of a facility that is part of the US Environmental Protection Agency's Risk Management Program for the most hazardous facilities), a much higher rate than the 39% of the US population that lives in such fenceline zones.
- In 7 of the 9 areas researched, the percentage of people living in poverty within 3 miles of an RMP facility is higher than for those living in poverty in the entire area (and in the other two areas the poverty rate is equal).
- In all of the communities studied, the percentage of people living in areas with Low Incomes and Low Access to healthy foods (LILA areas) within 3 miles of an RMP facility is higher than the percentage of residents of the entire community who live in low-income/low food access areas, and in some cases substantially higher.
- In 8 of the 9 areas studied, 71% to 100% of people who live in low-income areas that also have low access to healthy foods also live within a hazardous facility fenceline zone.





Members of Texas Environmental Justice Advocacy Services (tejas) and other organizations demand action to prevent chemical disasters at a federal Listening Session on chemical facility safety in Houston, TX.

**IN 8 OF THE 9 AREAS STUDIED,** 71% to 100% of people who live in low-income areas that also have low access to healthy foods also live within a hazardous facility fenceline zone.

- The percentage of Blacks or Latinos living within 3 miles of an RMP facility was higher than for the entire area in all of the study areas, and this difference rises significantly in areas with low incomes and low access to healthy foods within many fenceline zones.
- Cancer risks in fenceline zones are higher than for the entire area in all 9 areas studied, and the potential for suffering respiratory illness from exposure to toxic air pollution is higher in fenceline zones in 8 of the 9 areas. For people living in areas with low incomes and low access to healthy foods within fenceline zones, these risks increase further in all 9 areas studied.
- At least two-thirds of all schools are located within 3 miles of an RMP facility in 6 of the 9 areas.

- At least half of all medical facilities are located within 3 miles of an RMP facility in all but one area. At least 70% of medical facilities are located in these fenceline zones in 6 out of the 9 areas.

### NATIONAL FINDINGS

- About 124 million people, 39% of the U.S. population, live within three miles of approximately 12,500 high-risk chemical facilities (those in the RMP program).
- Almost half (45%) of the approximately 125,000 schools in the US are located within 3 miles of RMP facilities. This puts more than 24 million children as well as staff at these schools at particular risk from a catastrophic chemical facility incident.
- About 4 in 10 (39%) of the almost 11,000 medical facilities (hospitals and nursing homes) in the US are near RMP facilities. A major chemical facility incident near these medical facilities could have catastrophic impacts on patients and staff.
- Almost one-half (about 13,000) of the almost 27,000 dollar stores owned by the largest US chains are located within three miles of an RMP facility. Toxic chemicals in products and unhealthy foods available at these stores add to the potential health impacts on fenceline communities.

## KEY URBAN AREA OR COUNTY FINDINGS

### *Los Angeles, California*

- More than 8.7 million people, or 72% of people in Los Angeles, live within 3 miles of the area's 141 RMP facilities, which is 85% higher than the national rate.
- In areas with low incomes and low access to healthy foods within the fenceline zones around RMP facilities, Latinos make up more than two-thirds of the population, which is 42% greater than the percentage of Latinos in Los Angeles. Also, the percentage of Blacks in areas with low incomes and low access to healthy foods within the 3-mile zones is 44% greater than for the LA area as a whole.

### *Fresno County, California*

- Almost 637,000 people, or 68% of Fresno County residents, live within 3 miles of the 77 RMP facilities there, a 73% increase over the national rate.
- The percentage of Latinos in areas with low incomes and low access to healthy foods within fenceline zones is 23% greater than for Latinos in Fresno County overall.

### *Kern County, California*

- Almost 581,000 people, or 68% of Kern county residents, live within 3 miles of the county's 97 RMP facilities, a 74% increase over the national rate.
- While Latinos represent just over 50% of the county's population, 65% of people living in areas with low incomes and with low access to healthy foods within the 3-mile fenceline zones are Latino, which is 29% higher than the full county.

### *Madera County, California*

- 100% of people living in areas with low incomes and low access to healthy foods also live within 3 miles of an RMP facility, more than twice the percentage of Madera County residents who live within the fenceline zones (47%).
- The potential for suffering respiratory illness from toxic air pollution exposure is 33% higher for those living within 3 miles of an RMP facility compared to Madera County overall. Those in areas with low incomes and low access to healthy foods within the fenceline zones face a 24% higher cancer risk from air pollution, which is the highest risk of all 9 areas included in this report.

### *Louisville, Kentucky*

- More than 600,000 people, or 67% of Louisville residents, live within 3 miles of the area's 23 RMP facilities, a 72% increase over the national rate. Ninety-two percent of people living in areas with low incomes and low access to healthy foods live within these fenceline zones, a 37% increase compared to all Louisville residents living within 3 miles of an RMP facility.
- The percentage of people living in poverty in areas with low incomes and low access to healthy foods within 3 miles of an RMP facility is 94% greater than for Louisville overall. The percentage of Blacks living in low-income/low food access areas within fenceline zones is twice that of Louisville as a whole (39% compared to 18%).

### *Albuquerque, New Mexico*

- The potential for suffering respiratory problems from toxic air pollution exposure is 25% higher for those in areas with low incomes and low access to healthy foods within RMP facility fenceline zones compared to Albuquerque overall, while cancer risk from air pollution is 10% higher.
- The percentage of Latinos in areas with low incomes and low access to healthy foods within fenceline zones is 32% greater than for Albuquerque overall, and is more than twice the rate for whites in these areas.

### *Dallas, Texas*

- Almost 3.5 million people, or 72% of Dallas residents, live within 3 miles of the area's 108 RMP facilities, an 85% increase over the national rate.
- While Latinos make up less than one-third Dallas's population, more than half of people in areas with low incomes and low access to healthy foods within the 3-mile fenceline zones are Latino, a 62% increase. The percentage of Latinos in these areas is more than twice the rate for whites.

### *Houston, Texas*

- Almost 3.6 million people, or three-quarters of Houston residents, live within 3 miles of the 191 RMP facilities in the area, a 92% increase above the national rate.
- Seventy-eight percent of all Houston medical facilities and 72% of schools are within 3 miles of an RMP facility.

### *Charleston, West Virginia*

- Seventy percent of people in Charleston live within 3 miles of an RMP facility, an 80% increase over the national rate.
- People living in Charleston face the highest cancer risk from toxic air pollutants of all 9 areas included in this report. Those risks increase further for those living within 3 miles of an RMP facility in areas with low incomes and with low access to healthy foods.

## **RECOMMENDATIONS AND SOLUTIONS**

**Ensure that facilities that use or store hazardous chemicals adopt safer chemicals and processes.** Switching to inherently safer chemicals and technologies—which removes underlying hazards - is the most effective way to prevent deaths and injuries from chemical disasters (as well as eliminate ongoing emissions of the replaced chemicals).

**Ensure that facilities share information on hazards and solutions, and emergency response plans, with fenceline communities and workers.** Facility employees and fenceline communities can only participate effectively in their own protection if they have full access to information and meaningful access to decision-making processes. First responders must know what hazards they face.

**Require large chemical facilities to continuously monitor, report and reduce their fenceline-area emissions and health hazards.** Unplanned, smaller releases of toxic chemicals often precede more serious incidents at chemical facilities and may themselves directly impact the health of people living in nearby communities. Continuous, publicly available monitoring of air emissions will improve community knowledge of hazards and potentially help prevent minor issues from leading to major disasters.

**Prevent the construction of new or expanded chemical facilities near homes and schools, and the siting of new homes and schools near facilities that use or store hazardous chemicals.** The siting of new facilities that use or store hazardous chemicals, or expansion of existing ones, near homes, schools, or playgrounds significantly increases the possibility that a chemical release or explosion will result in a disaster. Similarly, new homes, schools, and playgrounds should not be sited near hazardous facilities.



Michele Roberts of Coming Clean and the Environmental Justice Health Alliance supports action to remove chemical hazards.

**Require publicly accessible, formal health-impact assessments and mitigation plans to gauge the cumulative impact of hazardous chemical exposures on fenceline communities.** Federal, state, and local agencies should assess, with full participation by the affected communities, the potential impact of unplanned chemical releases and the cumulative impacts of daily air-pollution exposures on the health of fenceline communities.

**Strengthen the enforcement of existing environmental and workplace health and safety regulations.** Congress should increase funding to the EPA, OSHA, and the states for expanding inspections and improving the enforcement of environmental and workplace health and safety laws, so that problems in chemical facilities can be identified before they lead to disasters.

**Dollar store chains should develop and implement broad policies to identify and remove hazardous chemicals from the products they sell, stock fresh and healthy foods, and source safer products and foods locally and regionally.** Given their presence in many communities of color and low-income fenceline communities, the largest dollar store chains are in a unique position to benefit the health and welfare of these communities where they operate, while growing and benefiting their own businesses, by providing safer products and healthier foods.



## CHAPTER ONE INTRODUCTION

**A**cross the United States, the health and safety of people who live, work, play, learn, and pray near thousands of industrial and commercial facilities that use or store extremely dangerous chemicals is at risk of a major chemical release or explosion at any time.

Approximately 124 million people across the United States, almost 40% of the US population, live within three miles of high-risk chemical facilities.<sup>1</sup> Their health, wellbeing, and even cultures are endangered by the threat of a catastrophic explosion or release, and other determinants of health, including lack of access to healthy foods, and daily exposure to toxic chemicals released into the air by industrial facilities, from everyday household products, and from building materials used to construct their homes.

Previous research found that these “fenceline” areas nearest hazardous facilities are often primarily composed of low-income people of color, especially Blacks (African Americans) and Latinos (Hispanics).<sup>2,3</sup> Exposure to toxic air pollution<sup>4</sup> and stress related to fear of potential chemical plant disasters

increase the health burden on these Environmental Justice (EJ) communities. These hazards are amplified by other negative socioeconomic and health factors, including higher rates of diseases such as diabetes and asthma, substandard housing, stress from racism, poverty, unemployment, and crime, among other factors.<sup>5</sup>

Adding to the health burden for these communities are harmful chemicals in foods and household products often found in discount retailers (“dollar stores”)<sup>6</sup> and lack of access to healthier foods.<sup>7</sup> Dollar stores are often located in small rural towns or in urban neighborhoods where they might be the only place to buy essential household items, including food. For example, Family Dollar has specifically targeted areas where they may be the only store selling food.<sup>8</sup> Many communities served by dollar stores are predominantly communities of color or low-income communities that have reduced access to quality medical care, fresh and healthy food, and public services, which are critical to overall health and to withstanding chemical exposures. Because of their presence in so many fenceline communities, dollar stores are in a unique position to either contribute to the health burden faced by these

### What is Environmental Justice?

**E**nvironmental Justice—as both a principle and a movement—arose in response to disproportionate exposure of communities of color and low-income communities (referred to as Environmental Justice communities) to harmful pollution, toxic sites and facilities, and other health and environmental hazards. While these people and communities have known about the hazards they face for a long time, beginning in the early 1980s new research helped document these harms and support action to address them. Grassroots leaders in many EJ communities began organizing and networking to address disproportionate toxic impacts wherever people live, work, play, learn, or worship. In 1991, the First National People

of Color Environmental Leadership Summit adopted 17 Principles of Environmental Justice. Over the past 40 years, EJ organizing has led to President Clinton’s Executive Order on Environmental Justice, to the establishment of EPA’s Office of Environmental Justice and National Environmental Justice Advisory Council, to the adoption of some form of EJ policies in many states, and to concrete actions to protect EJ communities from environmental health hazards. However, disproportionate toxic threats are still a daily fact of life in communities of color, low-income communities, and Indigenous communities across the United States, which Environmental Justice organizations work to address.



Residents of Wilmington, DE are campaigning for solutions to toxic air pollution and high-risk chemical facilities in their community.

communities, or help to provide solutions (by stocking healthier foods and safer products).\*

This report builds on a substantial body of previous Environmental Justice research. From its beginning, the Environmental Justice movement has worked to assess and address cumulative health, environmental, and social impacts<sup>9</sup> that disproportionately impact communities of color, low-income communities, and Indigenous communities. For more than twenty-five years, Environmental Justice researchers and organizers have documented disproportionate impacts and advocated for changes to address these inequities. Many reports and articles document their results and successes.<sup>10,11,12,13,14</sup>

In response to Environmental Justice organizing, in 1994 President Bill Clinton issued Executive Order 12898 on Environmental Justice (“Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations”) which directed each federal agency

to “make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations...”<sup>15</sup>

The EJ Executive Order continues to inform federal policy making and enforcement over twenty years later, despite attempts by the Administration of George W. Bush to remove race from consideration in US Environmental Protection Agency (EPA) environmental justice determinations.<sup>16</sup> EPA now defines Environmental Justice as “the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.”<sup>17</sup> However, the Agency also clarifies that “no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.”<sup>18</sup>

\* Throughout this report, “dollar stores” refers generally to discount retail stores, which are primarily those operated by the largest US discount retail chains (Dollar General and Dollar Tree, which also owns Family Dollar), and is not meant to indicate any one specific company. Any direct references to specific companies or their stores list the company by name.



EPA's current Environmental Justice Strategic Plan (EJ 2020 Action Agenda) recognizes disproportionate impacts on communities of color, low-income communities, and Indigenous communities, and commits the Agency to "achieving better environmental outcomes and reducing disparities in the nation's most overburdened communities."<sup>19</sup>

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**EJHA'S EFFORTS TO PREVENT** chemical disasters unite communities at the fenceline of hazardous chemical facilities with facility employees, supported by national advocates and experts. Key prevention measures include disclosure of information on hazards and alternatives, community and worker involvement, and transition to safer chemicals and processes.

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Responding to the urgent need for action to address the numerous hazards and harms that disproportionately affect people of color and low-income people, the Environmental Justice Health Alliance for Chemical Policy Reform (EJHA) has networked community organizations across the United States to organize and campaign for solutions. EJHA works to address the multiple harms caused by the hazardous chemical and energy industries—including waste, pollution, and health hazards—that disproportionately target and impact communities of color, Indigenous communities, and low-income communities. These communities along the "fenceline" of industry are exposed to multiple hazards at high rates, and have the least resources to influence and respond.

EJHA's efforts to prevent chemical disasters unite communities at the fenceline of hazardous chemical facilities with facility employees, supported by national advocates and experts. Key prevention measures include disclosure of information on hazards and alternatives, community and worker involvement, and transition to safer chemicals and processes. As the EJ movement has demonstrated, and EJHA agrees, these solutions can also help to mitigate the worsening climate crisis (which also disproportionately affects already overburdened communities).

EJHA's Campaign for Healthier Solutions (CHS) encourages discount retailers (dollar stores) to protect their customers, workers, and the communities in which they operate, and grow their businesses, through corporate policies to identify and phase out harmful chemical substances in the products they sell (which are often produced in countries such as China, and then transported to the US). The campaign asks dollar stores to stock safer products and healthier foods, especially when these can be sourced from local farms, community businesses, or cooperatives, in order to support the communities where their stores operate.

The research reported here builds on many previous reports and studies, as well as a robust and expanding body of scientific and technical literature on Environmental Justice and social determinants of health, including the 2014 EJHA report *Who's in Danger? Race, Poverty, and Chemical Disasters*. We examined the following areas: Los Angeles, as well as Kern, Fresno, and Madera counties, CA; Houston, TX; Dallas, TX; Louisville, KY; Albuquerque, NM; Charleston, WV. The areas selected for inclusion in this report have community-based advocacy efforts underway to address the large numbers of industrial and commercial facilities with hazardous chemicals, high environmental pollution levels, as well as the large numbers of dollar stores and lack of access to healthy foods in their communities.

In order to understand who is potentially impacted and the health risks from the multiple hazards and exposures in these communities, we looked at several interconnected issues:

- Who lives in close proximity to the most hazardous facilities? Specifically, what is the demographic profile of people living within 3 miles of high-risk chemical facilities included in the EPA Risk Management Plan (RMP) program?
- What are the cancer risks and the potential for respiratory illness from toxic air pollution exposure for those living within these 3-mile fenceline areas?
- Do these communities have access to healthy foods? What is the demographic profile of those living in areas within these fenceline zones that are considered low income and with low access to healthy foods?
- Where are critical institutions (schools, hospitals, and dollar stores) located within the fenceline areas in these communities?

Although the analysis for this report did not look specifically at the age or condition of housing in these communities,

previous research has extensively documented that many communities of color and low-income communities suffer from a lack of access to safe and quality housing, which in turn negatively impacts health. According to the US Surgeon General, “Many of the disparities in health status among subpopulations may be linked to poor access to safe and healthy homes, which is most prevalent among lower income populations, populations with disabilities, and minority populations.”<sup>20</sup>

Not only are “blacks and low-income people . . . more likely than the general population to be in housing that has extreme physical problems,”<sup>21</sup> it is also true that “low-income people and African Americans are much more likely to be exposed to, and therefore suffer, the effects of poor indoor air quality than the general population.”<sup>22</sup> Indoor toxic exposures may include chemicals such as formaldehyde or volatile organic compounds released from building materials; lead released from paint, water pipes, or other sources; and chemicals released from furniture and everyday household or consumer products.<sup>23</sup>

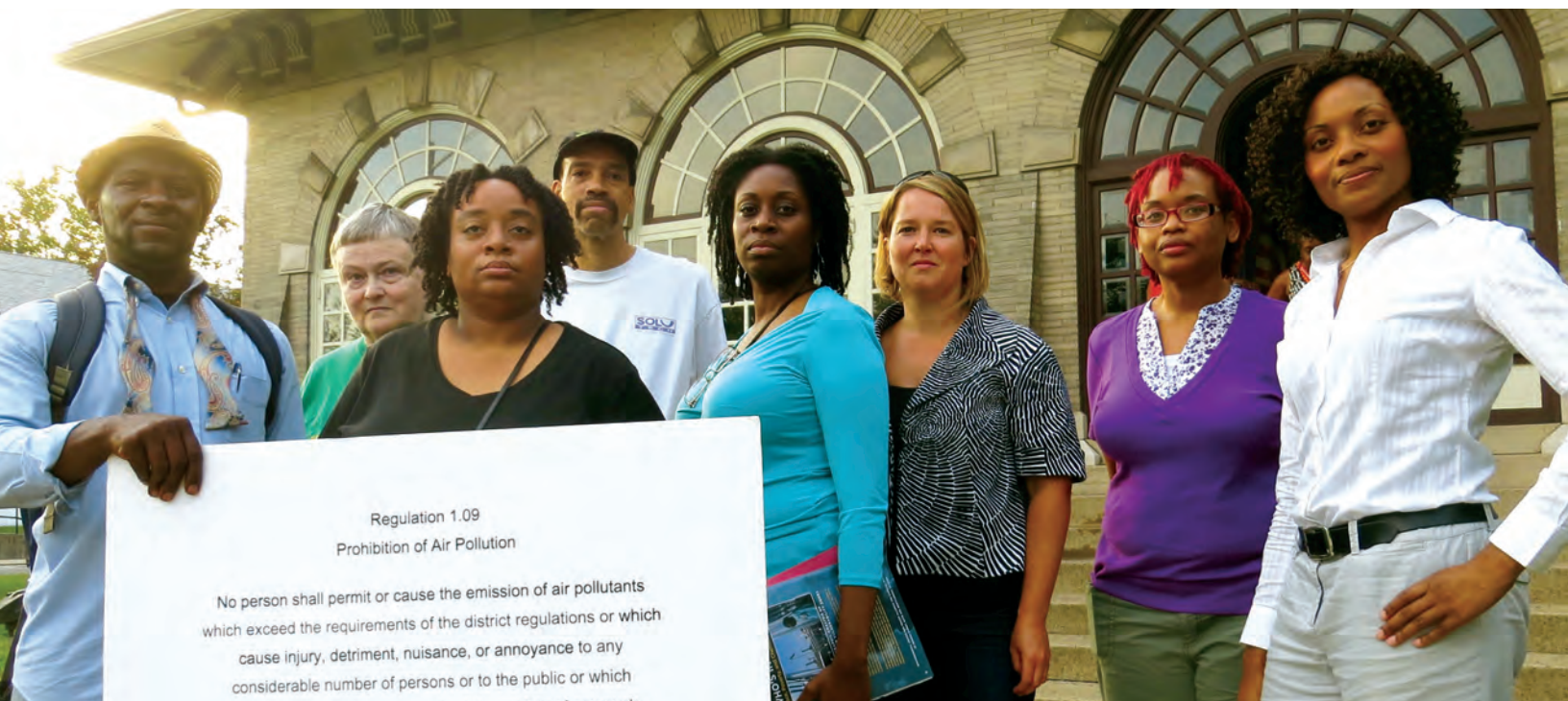
We encourage additional research into the multiple hazards and stressors that affect communities near the fenceline of hazardous facilities, and environmental justice communities in general, including the availability, quality, and safety of housing.

## **FENCELINE COMMUNITIES FACE MULTIPLE ENVIRONMENTAL HAZARDS AND HEALTH RISKS**

### *Hazardous Chemical Facilities*

Hazardous chemical releases from industrial and commercial facilities into surrounding communities are all too common. The EPA’s Risk Management Plan program (RMP) covers about 12,500 of the nation’s most high-risk facilities that produce, use, or store significant amounts of certain highly toxic or flammable chemicals. These facilities must prepare plans for responding to a worst-case incident such as a major fire or explosion that releases a toxic chemical into the surrounding community. The chemical disaster zones for these facilities often extend up to 25 miles or more and include hundreds of thousands of people, hundreds of schools, many hospitals, and thousands of small and large businesses. Collectively, these facilities endanger as many as 177 million people.<sup>24</sup>

The EPA estimates that about 150 “reportable” incidents of unplanned chemical releases (separate from the daily toxic emissions that are allowed under most operating permits) occur each year at RMP facilities. The EPA notes that these incidents “pose a risk to neighboring communities and workers because they result in fatalities, injuries, significant property damage, evacuations, sheltering in place, or environmental damage.”<sup>25</sup> EPA records show that from



**Members of Rubbertown Emergency ACTION (REACT) work to stop toxic air pollution in Louisville.**

**TABLE 1**  
**Top Five States with the Most RMP Facility Incidents Over Five Years**

State	RMP Facilities	Incidents	Injuries	Evacuated	Property Damage
Texas	1,457	178	185	12,277	\$644,367,042
Louisiana	327	118	222	9,706	\$216,709,465
California	863	75	15,098	75,526	\$9,081,573
Illinois	918	58	46	173	\$5,354,288
Oklahoma	304	57	20	54	\$36,270,405

Over 1 in 10 RMP facilities in the US are located in Texas. Over five years, Louisiana had 1 reported chemical incident for every three RMP facilities in the state.

Source: RTKNET. RMP facilities and accidents by state, compiled from data last released on January 31, 2017 obtained from EPA's Risk Management System database. <http://www.rtk.net/rmp/tables.php?tabtype=t3&subtype=a&sorttype=inc>, search done on May 15, 2018.

2004-2013 there were more than 1,500 chemical releases reportable under the RMP program, about 500 of which had off-site impacts (or about one release with off-site impacts every week). These incidents caused nearly 60 deaths, 17,000 injuries and requests for medical treatment, almost 500,000 people evacuated or sheltered-in-place, and more than \$2 billion in property damages, even though the decade studied did not include a truly catastrophic incident.<sup>26</sup> Chemical releases can also seriously disrupt local economies and cause severe economic damage. The Freedom Industries toxic spill into the Elk River near Charleston, WV, in January 2014 cost local businesses and the local economy \$19 million a day.<sup>27</sup>

In January 2017, the EPA adopted revisions to its chemical facility safety (RMP) rule that could prevent disasters and improve the ability of communities to prepare for—and respond to—incidents at these dangerous facilities.<sup>28</sup> However, implementation of the revised RMP rule was placed on hold by the Trump Administration EPA, which delayed the rule's implementation until February 19, 2019<sup>29</sup> and on May 17, 2018 proposed to roll back almost all of these modest safety improvements.<sup>30</sup>

People living nearest to these high-risk chemical facilities (known as the fenceline areas or zones), and the businesses, schools, and hospitals in these areas, are especially at risk from disasters. They are at greatest risk of immediate death or injury, are likely to be exposed to the highest level of toxic chemicals released, and have the least amount of time to evacuate or otherwise protect themselves. In 2012, a major explosion at the Chevron oil refinery in Richmond, California resulted in over 15,000 residents seeking medical attention over the next several weeks, including 20 people who were hospitalized.<sup>31</sup> According to the US Chemical Safety Board, a major release of highly toxic

**PEOPLE LIVING NEAREST TO**  
these high-risk chemical facilities (known as the fenceline areas or zones), and the businesses, schools, and hospitals in these areas, are especially at risk from disasters.

hydrogen fluoride gas into the densely populated community of Torrance, CA following an explosion at the Chevron refinery there in 2015 was only avoided by chance.<sup>32</sup>

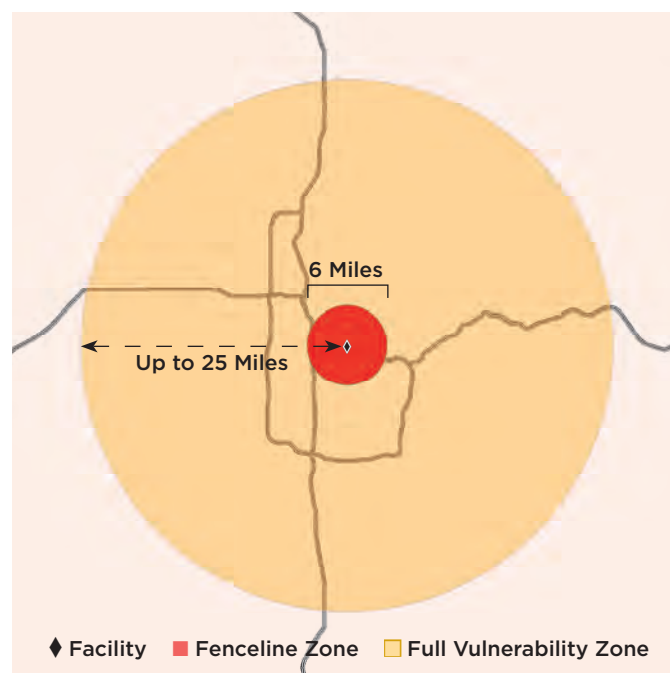
Several reports and studies have documented the disproportionate representation of low-income populations and people of color in fenceline communities around hazardous facilities. A 2001 study of chemical facilities in Florida found that a significantly large proportion of both non-White and impoverished individuals resided in areas potentially exposed to multiple accidental releases.<sup>33</sup> A 2004 study found that larger, more chemical-intensive facilities tend to be located in counties with larger Black populations and in counties with high levels of income inequality. It also found a greater risk of incidents at facilities in heavily Black counties.<sup>34</sup>

More recently, a 2014 report from the Environmental Justice Health Alliance examined the demographics of the populations in fenceline zones around 3,433 of the most hazardous RMP facilities. The report, *Who's in Danger?*, found that the percentage of Blacks in the fenceline zones around those facilities is 75% greater than for the US as a whole, while the percentage of Latinos in the fenceline zones is 60% greater than for the US as a whole. Additionally, the poverty rate in these zones is 50% higher



than for the US as a whole.<sup>35</sup> A 2016 report from the Center for Effective Government found that people of color are almost twice as likely as Whites to live within one mile of RMP facilities, with poor Black and Latino children more than twice as likely to live in these areas compared to white children who are living above the poverty line. The report also found that chemical facilities in communities of color have almost twice the rate of incidents compared to those in predominately white neighborhoods.<sup>36</sup>

**FIGURE 1**  
Sample Vulnerability Zone and Fenceline Zone



**BOX 1**  
“Fenceline Zones” in This Report

In this report, “fenceline zone” refers to areas within 3 miles of a facility included in the EPA’s Risk Management Plan (RMP) program. The full chemical disaster vulnerability zones for these facilities extend up to 25 miles. The vulnerability zones are calculated by the companies themselves as part of worst-case chemical release scenario analysis required under the RMP program. The scenarios are projections that the chemical facilities report to the EPA, and include the maximum area of potential serious harm from a worst-case release of chemicals. The people living or working closest to these hazardous facilities, and the institutions like schools and hospitals nearest to them, are at the greatest risk from a chemical release or explosion and have the least ability to quickly respond or evacuate.

### ***Toxic Air Pollution***

A large and expanding body of scientific literature has documented the disproportionate exposure of people of color, and particularly poor people of color, to high levels of toxic air pollution and resulting health impacts. A 2006 study found that cancer risks associated with toxic air pollution were highest in Census tracts located in 309 highly segregated metropolitan areas. Disparities in cancer risks between racial/ethnic groups were also wider in more segregated metropolitan areas.<sup>37</sup> A recent national study found that air pollution from industrial facilities is likely to disproportionately impact low-income and nonwhite communities, and that these disproportionalities become even greater when considering the smaller group of facilities that generate the majority of air pollution exposure risk (“the worst-of-the worst”).<sup>38</sup> Other studies have documented disproportionate cancer risks for low-income people of color from exposure to toxic air pollution in Baltimore,<sup>39</sup> Southern California,<sup>40</sup> and Houston,<sup>41</sup> among other locations. The higher air pollution exposure in EJ communities compounds the impact of the disproportionate underlying health status in these communities. For example, in the case of asthma, older Blacks are almost three times more likely than whites to die from asthma-related causes, and Black children die from asthma at eight times the rate of white children.<sup>42</sup>

While most studies have separately examined the demographics of fenceline communities at risk of chemical disasters or from daily toxic air pollution exposure, two recent studies focused on Houston looked at both of these hazards together. A 2014 study found that Houston neighborhoods with a higher percentage of Hispanic residents, lower percentage of homeowners, and higher income inequality face significantly greater exposure to both chronic and acute pollution risks.<sup>43</sup> A 2016 report from the Union of Concerned Scientists and the Texas Environmental Justice Advocacy Services (T.E.J.A.S.) found that a substantially larger percentage of people located within one mile of RMP facilities in two predominantly low-income Latino east Houston neighborhoods face higher cancer risks and potential respiratory illness when compared to two predominantly White and wealthier west Houston communities.<sup>44</sup>

### ***Toxic Chemicals in Household Products***

Extensive research over several decades (including testing of consumer and household products, household dust, indoor air, and testing of human blood, urine, and hair

samples) has proven that many chemicals used in everyday consumer products, household products such as furniture, building materials, cosmetics and personal care products, and even food packaging are released into homes and absorbed, ingested, or inhaled by people. Scientific studies have linked many of these chemicals to serious health problems, including cancer, learning disabilities and other neurodevelopmental issues, obesity, reproductive health effects, and more. Increasing pressure from consumers, communities, scientists, medical professionals, and businesses has led many states, the federal government, and even large retail companies like Walmart and Target to take concrete actions to identify and remove hazardous chemicals from everyday products.<sup>45</sup>

Most families buy consumer and household products, including food, from local retail stores. Almost 27,000 discount retail stores (“dollar stores”)<sup>46</sup> across the United States belonging to the major dollar store chains (the giants Dollar General and Dollar Tree/Family Dollar, and smaller chains like 99 Cents Only) often serve as the primary, or only, source of household products and food for many low-income communities. Many communities served by dollar stores are predominantly communities of color or low-income communities that are already



Residents of Albuquerque (pictured above) and many other fence-line communities depend on dollar stores for household products and food.

## INCREASING PRESSURE FROM

consumers, communities, scientists, medical professionals, and businesses has led many states, the federal government, and even large retail companies like Walmart and Target to take concrete actions to identify and remove hazardous chemicals from everyday products.

disproportionately exposed to chemical hazards, health effects linked to environmental pollution exposures, and substandard or hazardous housing conditions. As noted earlier, we looked at the presence of dollar stores in fence-line zones near high-risk facilities along with other data to better understand the range of hazards, health determinants, and possible solutions faced by these “hot spot” communities.

While retail competitors like Walmart<sup>47</sup> and Target<sup>48</sup> have adopted comprehensive policies to know, disclose, and address many chemicals of concern throughout their supply chains, the major dollar store chains have until recently lagged behind in their efforts to address toxic chemicals in the products they sell. Although the largest dollar store chains have taken some limited steps to address some toxic chemicals in their products mostly in response to federal and state requirements, analyses of a sample of products from these stores found high levels of toxic chemicals in many products. A 2012 report found that 39% of vinyl packaging sold by discount retailers contained levels of cadmium or lead that violate state laws.<sup>49</sup> The 2015 Campaign for Healthier Solutions report *A Day Late and a Dollar Short* found that 81% of the dollar store products tested contained at least one hazardous chemical above levels of concern, compared to established standards based on a sample of 164 products purchased from the major chains. At least 71% of the products tested from each dollar store chain contained one or more hazardous chemicals above levels of concern.<sup>50</sup>

In June 2017, Dollar Tree disclosed that the company had notified suppliers of its intent to eliminate seventeen hazardous chemicals from the products it stocks by 2020, including several chemicals not currently restricted by the federal or state governments. This action by Dollar Tree is

an important first step by a national discount retail chain, and we encourage other chains to adopt similar actions. Dollar Tree also needs to make its action more fully transparent to customers and shareholders by disclosing the letters it has sent to suppliers, and by publicly reporting on progress toward its goals.

### ***Lack of Access to Healthy Foods***

Dollar stores are often the only source of food in many low-income communities, including both urban and rural areas. A lack of supermarkets in these communities, and the typically limited availability of healthy foods offered in discount retail stores, result in restricted access to healthy foods.\* Nationally, an estimated 52.5 million people, or 17% of the US population, have low access to a supermarket.<sup>51</sup> A review of studies of neighborhood differences in access to food found that residents of neighborhoods who have better access to supermarkets and limited access to convenience stores tend to have healthier diets and lower levels of obesity, and that residents of low-income, minority, and rural neighborhoods are most often affected by poor access to supermarkets and healthful foods.<sup>52,53</sup> Conversely, a lack of access to healthy foods has been linked to higher levels of obesity<sup>54</sup> as well as hypertension and diabetes<sup>55</sup> and cancer.<sup>56</sup> Nationally, the occurrence of diabetes in Hispanic and Black people is 66% and 77% higher, respectively, compared to non-Hispanic Whites,<sup>57</sup> while obesity rates for Blacks and Hispanics are 47% and 30% higher.<sup>58</sup>

Research has found that communities comprised of low-income residents and people of color often lack access to the healthier foods available in supermarkets. A study of 28,000 US ZIP codes found that ZIP codes representing low-income areas had only 75% as many chain supermarkets available as ZIP codes representing middle-income areas. The availability of chain supermarkets in predominantly Black neighborhoods was found to be roughly one-half that in their counterpart white neighborhoods, with even less relative availability in urban areas. ZIP codes with higher proportions of Hispanic residents had only 32% as many chain supermarkets available as primarily non-Hispanic neighborhoods.<sup>59</sup> A review of studies on neighborhood disparities in access to fast-food outlets and convenience stores found that low-income neighborhoods offered greater access to those food sources that promote unhealthy eating.<sup>60</sup>

Ironically, agricultural workers may not only live in fence-line zones near hazardous facilities, and be exposed to toxic air pollution where they live as well as to hazardous pesticides on the job,<sup>61</sup> but also have low access to healthy foods, even though they work to plant or harvest fresh produce as farmworkers. For example, in the three central California counties studied in this report (which are heavily agricultural counties that contain many farms and large populations of agricultural workers), the percentage of low-income Latinos who live within 3 miles of a hazardous chemical facility and also have low access to healthy foods was 23% to 33% higher than the percentage of Latinos in the county as a whole.

### ***What We Studied***

The analysis conducted for this study examined the demographics of the populations, as well as locations of schools, medical facilities (hospitals and nursing homes), and dollar stores, in 9 metropolitan areas or counties potentially impacted by a toxic chemical release due to their close proximity to many hazardous chemical

#### **BOX 2**

##### **What is a “LILA” Area?**

Access to healthy foods is a critical factor for individual, family, and community health. The US Department of Agriculture’s (USDA) Economic Research Service notes that “limited access to supermarkets, supercenters, grocery stores, or other sources of healthy and affordable food may make it harder for some Americans to eat a healthy diet.” USDA defines Low Access to healthy food as “being far from a supermarket, supercenter, or large grocery store.”

Income is also an important factor in family and community health and wellbeing. The US Department of Treasury defines Low-Income areas as those with poverty rates of 20% or greater, or that meet other criteria.

Some communities have Low Access to healthy foods and are also Low Income. These Low-Access and Low-Income areas are called LILA areas. More background on LILA areas can be found at <https://www.ers.usda.gov/data-products/food-access-research-atlas/documentation>.

\* We used a US Department of Agriculture definition of “lack of access to healthy foods,” which is not living within ½ mile of a supermarket in urban areas, or within 10 miles of a supermarket in a rural area.



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## RECOGNIZING THAT CHILDREN

and those in medical facilities would be especially vulnerable during a chemical release or explosion nearby, and are especially vulnerable to toxic exposures, we assessed the number of schools and medical facilities within 3 miles of an RMP facility in these communities.

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facilities. We also assessed the additional health risks from toxic air pollution as well the demographic profile of the fenceline zones around hazardous facilities, and also in areas within fenceline zones that are considered Low Income and with Low Access to healthy foods (known as LILA areas).

Analysis of the data from the six urban areas and the three counties included in this report focused primarily on the demographics of people living within 3 miles of high-risk chemical facilities (i.e., fenceline areas). To assess additional health risks in these fenceline communities, we examined the cancer risks and respiratory hazards from toxic air pollution, dollar store locations for potential exposure to toxic chemicals from products (and as potential sources of safer products and healthy foods), as well as low access to healthy foods for those in low-income areas. Recognizing that children and those in medical facilities would be especially vulnerable during a chemical release or explosion nearby, and are especially vulnerable to toxic exposures, we assessed the number of schools and medical facilities within 3 miles of an RMP facility in these communities.

To assess the cancer risks and potential respiratory hazards from residents' exposure to toxic air pollution in the 9 areas, we used data from the EPA's National Air Toxics Assessment (NATA). The NATA was developed primarily as a tool to inform both national and more localized efforts to collect air toxics information and characterize emissions (e.g., to prioritize pollutants or geographical areas of interest for more refined data collection such as monitoring). The 2011 NATA data, the most recent available, include data for 140 toxic air pollutants from a broad spectrum

of sources including large industrial facilities, such as refineries and power plants, and smaller sources, such as gas stations, oil and gas wells, and chrome-plating operations. Other pollution sources include cars, trucks, and off-road sources such as construction equipment and trains, as well as pollution formed by chemical reactions in the atmosphere.

The EPA calculates the amount of air pollution faced by people at the census-tract level and then uses health benchmarks to estimate cancer risks and respiratory health hazards from the combined effect of those exposures. Cancer risks are expressed as the projected number of cancers per million people based on a 70-year lifetime of exposure. The national average cancer risk is 40 cancers per million people, based on the 2011 data. By comparison, when the EPA sets pollution control limits for individual toxic air pollutants under the Clean Air Act, the lifetime cancer risk target for the general population is one additional cancer per million people.

The Respiratory Hazard Index (RHI) represents the ratio of pollutant levels compared to EPA benchmarks established as not likely to cause non-cancer respiratory illnesses based on a lifetime of exposure. An index value greater than 1 indicates the potential for adverse health impacts, with increasing concern for suffering respiratory health effects as the value increases.

The cancer risk and respiratory hazard values are based on numerous modeled data and therefore should be viewed as estimates of average population risks and hazards rather than exact risk numbers for a particular person. Although NATA estimates cancer risks and non-cancer hazards for numerous toxic air pollutants, additional chemicals might exist that are not identified or for which data on these health impacts are unavailable. Therefore, these risk and hazard estimates represent only a subset of the total potential cancer and non-cancer risks associated with air toxics exposures. These risk estimates also do not consider ingestion or the breathing of indoor sources of air toxics as an additional exposure pathway. In other words, the actual cancer risk and respiratory hazard from toxic pollution faced by people living in the areas we researched is almost certainly greater than these limited data show.

A full description of data sources and methodology can be found in Appendix A.

## CHAPTER TWO

### KEY FINDINGS

**T**he results of the analyses conducted for this report demonstrate that the health and safety of communities closest to some of the nation's most dangerous industrial and commercial facilities are at risk from multiple threats, including potential chemical releases or explosions, daily exposure to toxic air pollution, and poor nutrition from a lack of access to healthy foods (along with other hazards and impacts not specifically studied here). The population of these fenceline areas is disproportionately Black, Latino, and living in poverty. Many of these communities also rely heavily, or solely, on dollar stores for household necessities and in some cases food, making these retailers potential sources of either additional toxic exposures or safer products and healthier foods (depending on the corporate policies they implement or fail to adopt).

Analysis of the 9 areas studied for this report clearly shows that:

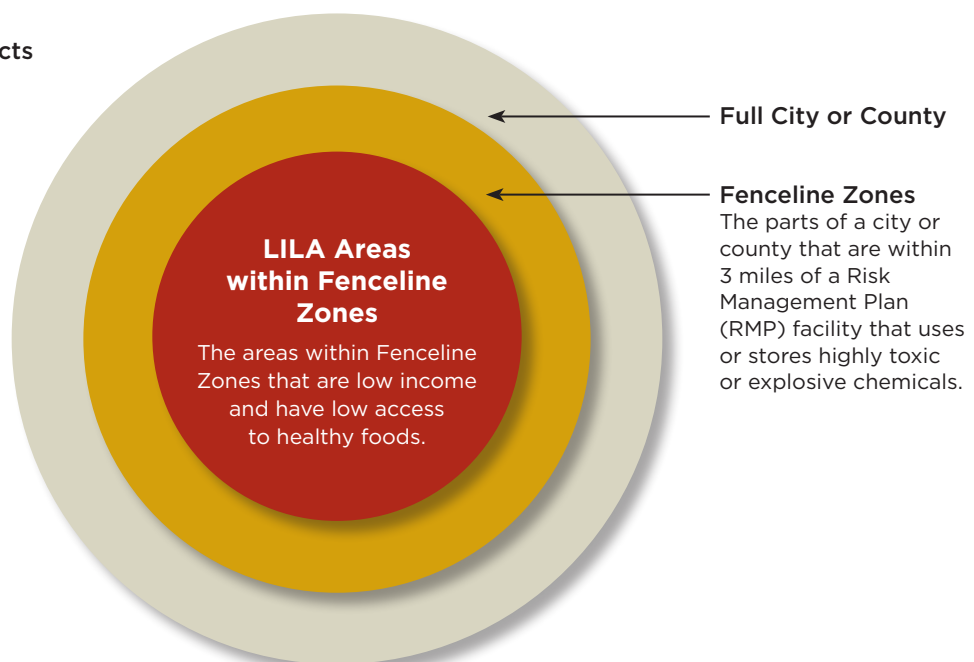
1. In most of the areas researched, large majorities of the population live in fenceline zones around highly

hazardous facilities, and most schools and medical institutions are located in these zones, at much greater rates than nationally. In seven of the nine areas researched for this report, two-thirds of the population or more live in fenceline zones (much greater than the national rate of 39%). In most of the areas studied, two-thirds of all schools and 70% of medical facilities are located in fenceline zones (compared to 45% of US schools and 39% of US hospitals and nursing homes).

2. Fenceline zones around hazardous facilities are disproportionately Black, Latino, and impoverished. The percentage of Blacks or Latinos living within 3 miles of an RMP facility was higher than for the entire area in every study area, and often much higher than for the US as a whole. In 7 of the 9 areas researched, the percentage of people living in poverty within 3 miles of an RMP facility is higher than for those living in poverty in the entire area, and often much higher than for the US as a whole.
3. People living in hazardous facility fenceline zones face multiple health hazards and risks. In addition

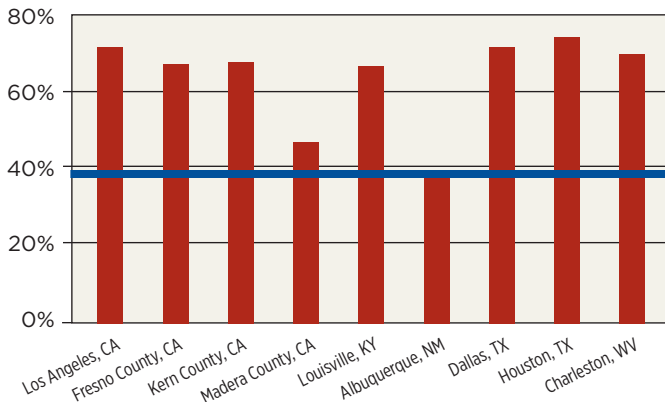
**FIGURE 2**  
Increasing Hazards and Impacts

Our research found that hazards and impacts become more severe and more disproportionate when moving from the whole US to the nine cities or counties studied, to the fenceline zones and low-income/low food access areas within those cities or counties, and especially to LILA areas (low-income areas with low access to healthy foods) within fenceline zones.



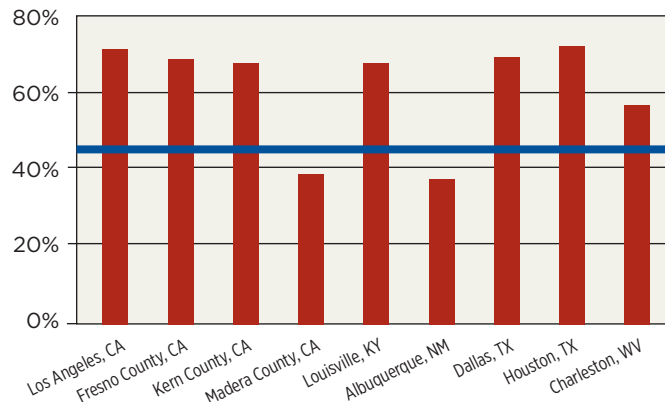


**FIGURE 3**  
Population in Fenceline Zones



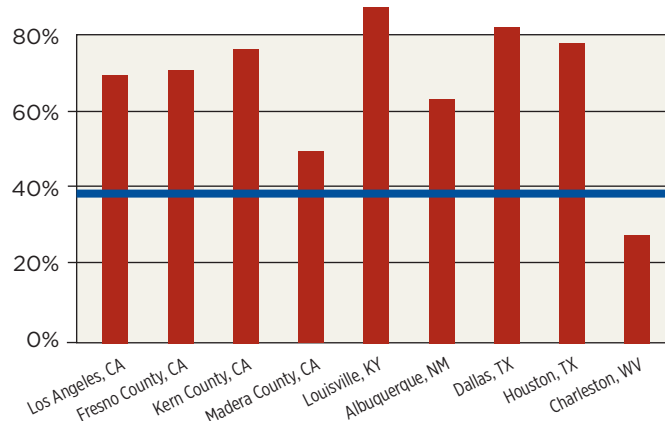
In 7 of the 9 areas researched for this report, two-thirds of the population or more live in fenceline zones near hazardous facilities (much greater than the national rate of 39%, marked by the blue horizontal line).

**FIGURE 4**  
Schools in Fenceline Zones



In 6 of the 9 areas studied, at least two-thirds of all schools are located within 3 miles of a hazardous RMP facility (much greater than the national rate of 45%, marked by the blue horizontal line).

**FIGURE 5**  
Medical Facilities in Fenceline Zones



In 6 of the 9 areas studied, at least 70% of hospitals and nursing homes are located in fenceline zones (much greater than the national rate of 39%, marked by the blue horizontal line).

to the constant threat of catastrophic chemical releases or explosions, in every area researched for this report fenceline zones face higher risk of cancer from toxic air pollution than the entire area (and often much higher than for the US as a whole). In 8 of the 9 areas, the potential for respiratory illness is higher in fenceline zones than for the entire area, and in every area is above the national rate. The percentage of fenceline zone residents who also live in a low-income/low food access area is higher than for the entire city or county in all 9 areas (and two to three times the national rate in most areas).

4. The most vulnerable neighborhoods—areas that are both low income and have low access to healthy foods—are even more heavily and disproportionately impacted. In every area studied, low-income/low food access areas within fenceline zones have higher poverty rates, greater percentages of residents who are people of color, and higher cancer risk and respiratory hazard rates from toxic air pollution than for the whole fenceline zones or the entire city or county, often much higher.

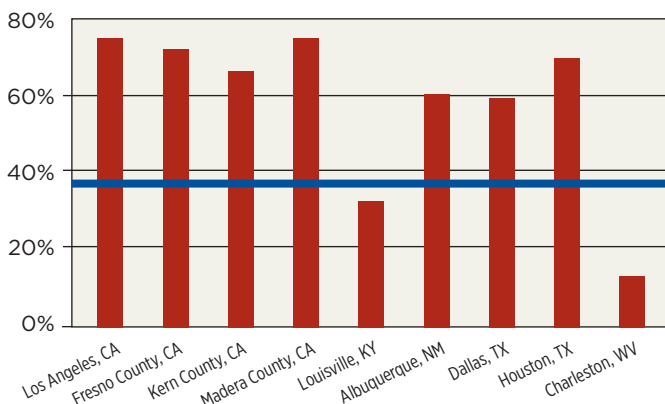
In comparing data from the fenceline zones with the entire urban area or county, key findings include:

- In 7 of the 9 areas we researched, more than two-thirds of the population (over 67%) lives in a fenceline zone within 3 miles of a facility that is part of the EPA's Risk Management Program (RMP), and sometimes in more than one such zone. Nationally, 39% of the US population lives within 3 miles of an RMP facility.
- In 7 of the 9 areas researched, the percentage of people living in poverty within 3 miles of an RMP facility is higher than for those living in poverty in the entire area (and in the other two areas the poverty rate is equal).
- In all of the communities studied, the percentage of people living in areas with Low Incomes\* and Low Access to healthy foods (known as LILA areas) within 3 miles of an RMP facility is higher than the percentage of residents of the entire community who live in low-income/low food access areas, and in some cases substantially higher.
- In 8 of the 9 areas studied, 71% to 100% of people who live in low-income areas that also have low access to healthy foods also live within a hazardous facility fenceline zone.

\* The US Department of Health and Human Services defines "low income" as incomes less than twice that of the national poverty income guideline (e.g., \$49,200 for a family of 4). Source: <https://aspe.hhs.gov/poverty-guidelines>.

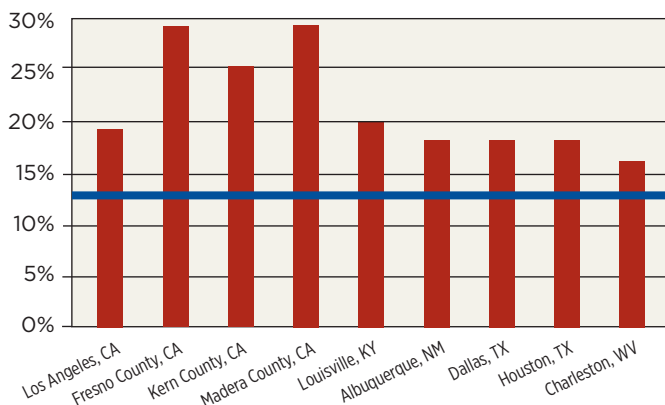
- The percentage of Blacks or Latinos living within 3 miles of an RMP facility was higher than for the entire area in all of the study areas, and this difference rises significantly in areas with low incomes and low access to healthy foods within many fenceline zones.
- Cancer risks in fenceline zones are higher than for the entire area in all 9 areas, and the potential for suffering respiratory illness from exposure to toxic air pollution is higher in fenceline zones in 8 of the 9 areas. For people living in areas with low incomes and low access to healthy foods within fenceline zones, these risks increase in all 9 areas.
- At least two-thirds of all schools are located within 3 miles of an RMP facility in 6 of the 9 areas (compared to 45% nationally).

**FIGURE 6**  
Race in Fenceline Zones



In 7 of the 9 areas studied, the percentage of fenceline zone residents who are people of color is much higher than the percentage of people of color in the whole US population.

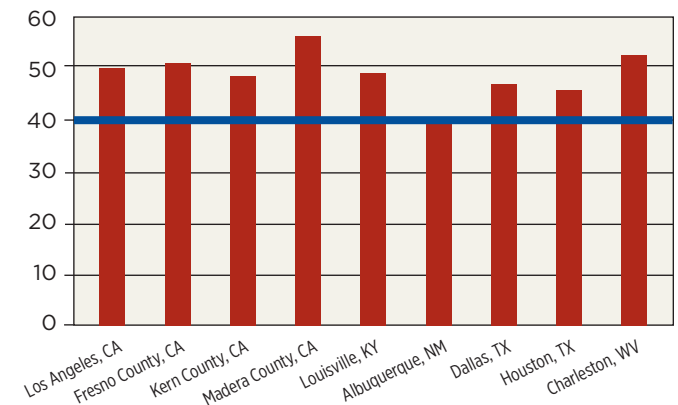
**FIGURE 7**  
Poverty in Fenceline Zones



The poverty rate within fenceline zones in all nine of the cities or counties we studied is higher than the national rate of 13.5% (marked by the horizontal blue line). In 7 of the 9 areas researched, the percentage of people living in poverty within 3 miles of an RMP facility is higher than for those living in poverty in the entire area, and often much higher than for the US as a whole.

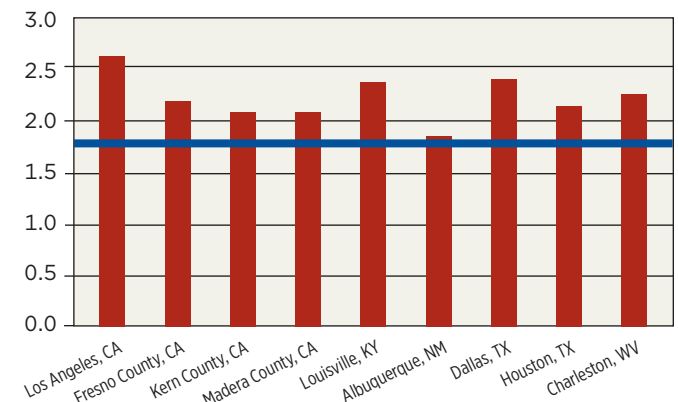
- At least half of all medical facilities (hospitals and nursing homes) are located within 3 miles of an RMP facility in all but one area. At least 70% of medical facilities are located in these fenceline zones in 6 out of the 9 areas. Nationally, only 39% of medical facilities are in fenceline zones.
- In 8 of the 9 areas, at least two-thirds (68%) of dollar stores are located within fenceline zones (compared to less than half of all dollar stores nationally).

**FIGURE 8**  
Cancer Risk from Air Pollution in Fenceline Zones



The EPA estimates that the national average risk of cancer from a lifetime of exposure to toxic air pollution at 2011 levels is 40 cancers per million people. Within fenceline zones in the 9 cities or counties we studied, the risk is the same or higher in every case, and often much higher. Cancer risks within fenceline zones in these cities or counties are higher than for the entire area in all 9 areas studied.

**FIGURE 9**  
Respiratory Hazard in Fenceline Zones



The EPA assesses risk of non-cancer respiratory illness from air pollution using its Respiratory Hazard Index (see Appendix A for more on RHI). In 8 of the 9 areas studied, the potential for respiratory illness is higher in fenceline zones than for the entire area. In every area studied, the RHI in fenceline zones is above the national index value of 1.8. It is important to note that even the national RHI is 80% greater than the level of toxic air pollution exposure that would represent no health concern (an index value of 1).

## CHAPTER THREE

### RESULTS

#### THE NATIONAL SCOPE

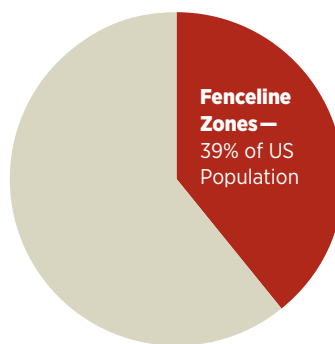
**E**PA's Risk Management Plan (RMP) program includes approximately 12,500 industrial and commercial facilities that produce, use, or store significant quantities of certain highly toxic and flammable chemicals. These facilities pose serious risk to nearby residents, workers, and businesses because a major incident would result in deaths, injuries, significant property damage, evacuations, sheltering in place, or environmental damage. Almost 124 million people (39% of the US population) live within 3 miles of an RMP facility.

Almost half (45%) of the approximately 125,000 schools in the US are located within 3 miles of RMP facilities.<sup>62</sup> This puts more than 24 million children as well as staff at these schools at particular risk from a catastrophic chemical facility incident. For example, the West Middle School in West, TX was severely damaged by an explosion at a fertilizer storage facility on April 17, 2013. A greater tragedy was averted only because the explosion happened during the night rather than during school hours.

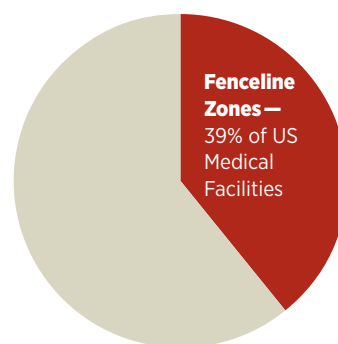
About 4 in 10 (39%) of the almost 11,000 medical facilities (hospitals/nursing homes) in the US, are near RMP facilities.<sup>63</sup> A major chemical facility incident near these medical facilities could have catastrophic impacts on patients and staff. Due to physical damage and/or chemical exposure, the facility may also be unable to accept patients from the surrounding community.

Almost one-half (about 13,000) of the almost 27,000 dollar stores in the US\* are located within three miles of an RMP facility.<sup>64</sup> Toxic chemicals in products and unhealthy foods available at these stores add to the potential health impacts on fenceline communities that also must contend with health risks from chemical facility releases, and often are exposed to high levels of toxic pollution and are poor with low access to healthy foods.

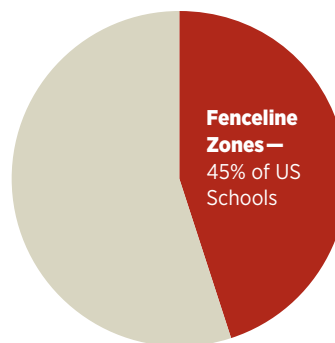
**FIGURE 10**  
124 Million US Residents  
Live within 3 Miles of  
an RMP Facility



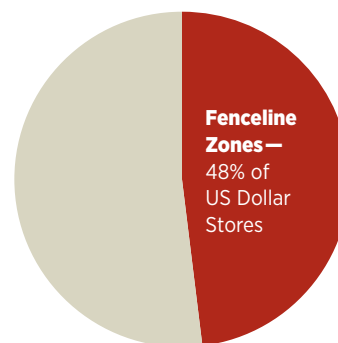
**FIGURE 12**  
4 of 10 Hospitals and  
Nursing Homes in the  
US are within 3 Miles  
of an RMP Facility



**FIGURE 11**  
24 Million Children  
Attend School within 3  
Miles of an RMP Facility



**FIGURE 13**  
13,000 of 27,000 Dollar  
Stores are within 3 Miles  
of an RMP Facility



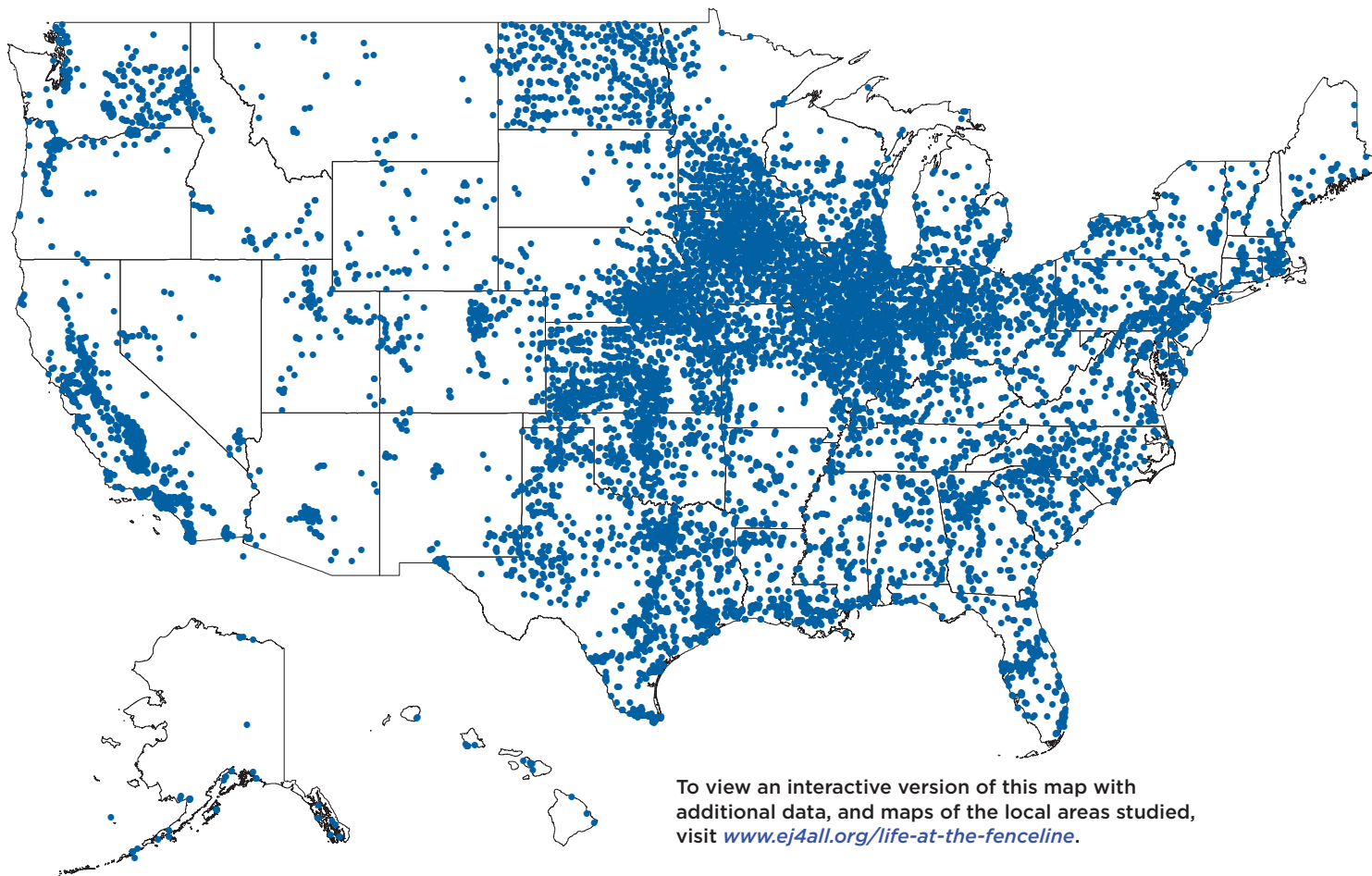
#### EPA'S RISK MANAGEMENT PLAN

program includes approximately 12,500 industrial and commercial facilities that produce, use, or store significant quantities of certain highly toxic and flammable chemicals.

\* The vast majority of these stores are operated by the largest chains: Family Dollar and Dollar Tree (now owned by the same parent company), and Dollar General.

**FIGURE 14**

**12,493 Active RMP Facilities in the US**



## RESULTS FOR STUDY AREAS

### *Population Demographics*

- In 7 of the 9 areas examined, more than two-thirds (67%) of the people in each area live within 3 miles of an RMP facility (compared to only 39% nationally).
- In 7 of the 9 areas, the percentage of people living within 3 miles of an RMP facility who are poor is disproportionately higher than for the entire area.
- In all but one of the areas, the percentage of people of color living within 3 miles of an RMP facility was higher than for the entire area, especially for Blacks and Latinos, and in 7 of 9 areas is much higher than the national rate (38%).
- In 7 of the 9 areas, average home values within 3 miles of an RMP facility are lower compared to the entire area.
- In all but one of the areas, average household incomes were lower, sometimes substantially, for those living within 3 miles of an RMP facility compared to the entire area.

- In all 9 areas, the percentage of people with a high school or less education was higher for those living within 3 miles of an RMP facility compared to the entire area. In all but one area, the percentage of people with a college degree or higher was lower for those living within 3 miles of an RMP facility compared to the entire area.

### *Health Risks*

- In all but 1 of the 9 areas, the cancer risk from toxic air pollution exposure for all people living in the entire area assessed was higher than the national average.
- For those living within 3 miles of an RMP facility, the cancer risk was higher than for the entire area in all 9 areas studied. The cancer risk for those living in areas with low incomes and low access to healthy foods within the fenceline zones was even higher in all 9 areas, in some cases substantially higher.

- In 6 of the 9 areas studied, the RHI (respiratory hazard) value from toxic air pollution exposure was greater than 2, indicating a significant potential for suffering respiratory illness.
- In 8 of 9 areas, the RHI values were higher for those living within 3 miles of an RMP facility than for the entire area, and increased further (to above 2) in all 9 areas for those living in parts of the fenceline zones with low incomes and low access to healthy foods.

**IN EVERY AREA**, the percentage of the population living in low-income/low food access areas is significantly higher than the national rate, and is at least twice as high in 5 of the 9 areas.

#### ***Low Income with Low Access to Healthy Foods***

- In every area, the percentage of the population living in low-income/low food access areas is significantly higher than the national rate, and is at least twice as high in 5 of the 9 areas.
- In all 9 areas, people living in areas with low incomes and low access to healthy foods within 3 miles of an RMP facility face higher health risks, and the percentage of people of color is greater, often substantially, compared to those living in parts of the 3-mile zones that are not low-income/low food access.

**TABLE 2**  
Demographic Data and Health Risks

	Albuquerque Totals/ 3 miles/3 miles LILA	Charleston Totals/ 3 miles/3 miles LILA	Dallas Totals/ 3 miles/3 miles LILA	Houston Totals/ 3 miles/3 miles LILA
<b>Weighted RHI</b>	1.74/1.86/2.17	2.39/2.26/2.40	2.37/2.40/2.48	2.09/2.13/2.29
<b>Weighted Cancer Risk</b>	38.25/39.45/41.91	50.83/52.04/54.01	46.25/46.58/47.67	44.74/45.57/47.26
<b>% Poverty</b>	18.4/18.4/28.0	15.7/15.6/22.5	16.3/17.7/27.2	17.2/18.4/28.5
<b>% White</b>	41.5/40.1/26.3	86.5/86.8/80.1	42.4/40.8/22.5	32.9/30.6/12.1
<b>% Black</b>	2.6/2.5/2.9	6.0/6.3/10.0	17.3/16.5/21.7	18.6/19.5/25.5
<b>% Hispanic</b>	48.4/50.1/64.0	1.1/0.9/0.9	31.5/34.7/51.0	39.0/40.2/56.1
<b>% Children</b>	23.3/23.0/24.3	19.7/20.5/19.9	26.9/26.9/29.4	27.1/26.7/28.8

	Fresno Totals/ 3 miles/ 3 miles LILA	Kern Totals/ 3 miles/ 3 miles LILA	Madera Totals/ 3 miles/ 3 miles LILA	Los Angeles Totals/ 3 miles/ 3 miles LILA	Louisville Totals/ 3 miles/ 3 miles LILA
<b>Weighted RHI</b>	2.06/2.19/2.37	1.91/2.07/2.24	1.56/2.07/2.11	2.59/2.63/2.83	2.26/2.37/2.46
<b>Weighted Cancer Risk</b>	48.62/50.57/52.02	45.69/48.20/49.60	46.37/56.32/57.27	50.17/50.22/52.06	47.35/48.85/50.86
<b>% Poverty</b>	27.6/29.4/37.8	23.4/24.7/34.1	22.3/28.6/35.2	17.6/18.6/24.8	16.0/19.6/31.1
<b>% White</b>	31.3/27.8/17.9	37.1/34.1/23.5	38.3/22.5/17.0	27.9/23.4/11.0	72.8/67.5/49.1
<b>% Black</b>	4.8/4.9/6.2	5.3/6.0/5.8	3.3/2.8/2.5	6.6/6.8/9.5	17.8/22.5/39.3
<b>% Hispanic</b>	51.7/54.2/63.4	50.6/52.6/65.3	52.8/70.0/75.8	47.3/52.4/67.4	4.5/4.8/6.1
<b>% Children</b>	29.0/29.8/31.6	29.3/29.9/32.6	27.4/32.1/34.5	23.1/24.0/26.9	22.6/22.3/23.9

**City/County Totals:** Result for the entire city or county.

**3 miles:** The Fenceline Zones within 3 miles of an RMP facility.

**3 miles LILA:** Low Income and Low Access to food areas within Fenceline Zones.

See Appendix A for explanations of RHI (Respiratory Hazard Index) and Cancer Risk.



**TABLE 3**

**RMP Facilities, Dollar Stores, Schools, and Medical Facilities in Study Areas**

	RMP Facilities	RMP Facilities With Dollar Stores Within 3 Miles	% of RMP Facilities With Dollar Stores Within 3 Miles	Schools	Schools Within 3 Miles of an RMP Facility	% of Schools Within 3 Miles of an RMP Facility	Medical Facilities	Medical Facilities Within 3 Miles of an RMP Facility	% of Med Facilities that are Within 3 Miles of an RMP Facility
Los Angeles, CA	141	137	97.2%	3,972	2,828	71.1%	148	103	69.6%
Louisville, KY	23	23	100.0%	343	230	67.1%	16	14	87.5%
Albuquerque, NM	7	7	100.0%	279	106	37.9%	11	7	63.6%
Charleston, WV	13	13	100.0%	83	47	56.6%	7	2	28.6%
Dallas, TX	108	103	95.4%	1,821	1,251	68.7%	78	65	83.3%
Houston, TX	191	176	92.1%	1,624	1,165	71.7%	51	40	78.4%
Fresno Co., CA	77	52	67.5%	389	266	68.3%	49	35	71.4%
Kern Co., CA	97	29	29.9%	306	206	67.3%	30	23	76.7%
Madera Co., CA	7	3	42.9%	90	35	38.9%	10	5	50.0%



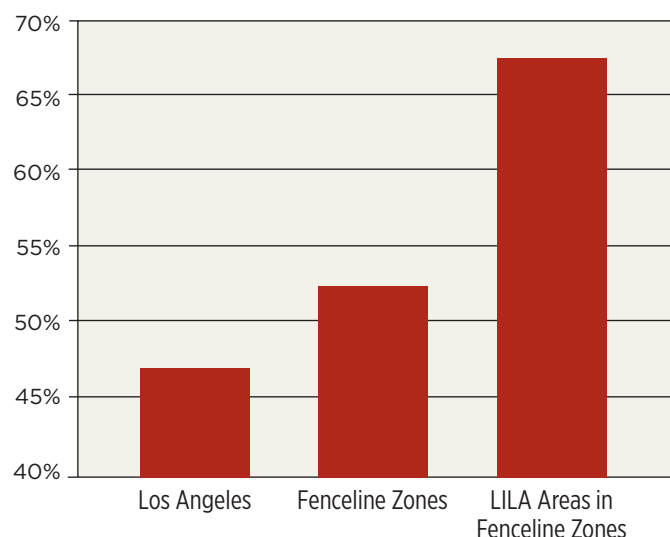
## RESULTS: LOS ANGELES, CALIFORNIA

Los Angeles, our nation's second most populous urban area, is home to 141 RMP facilities, second only to Houston of all the areas studied for this report.

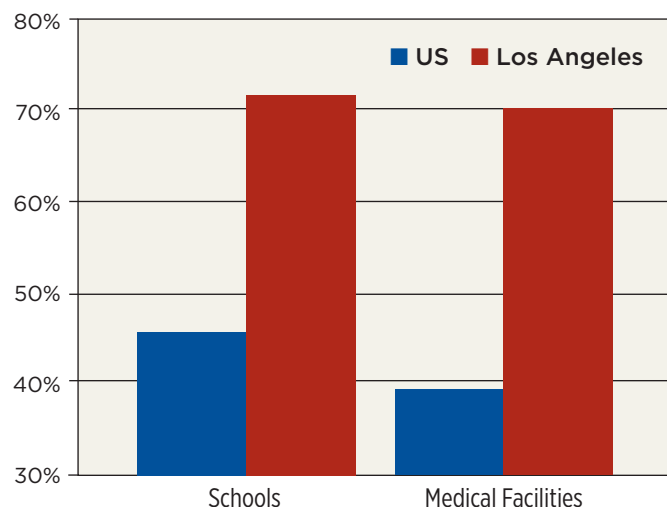
### KEY FINDINGS

- More than 8,760,000 people, or 72% of people in Los Angeles, live within 3 miles of an RMP facility, which is 85% higher than the national rate. Eighty-two percent of people who live in areas with low incomes and low access to healthy foods also live within 3 miles of an RMP facility.
- The percentage of Latinos (Hispanics) who live in 3-mile zones is 11% higher than for the entire urban area (52% compared to 47%). More striking however, Latinos make up more than two-thirds of the population in low-income/low food access areas within fenceline zones, which is 42% greater than the representation of Latinos in Los Angeles.
- The percentage of Blacks in areas with low incomes and low access to healthy foods in the 3-mile zones is 44% greater than for the LA area as a whole.
- The potential for suffering respiratory illness is 9% higher for those living in low-income/low food access areas with fenceline zones compared to the Los Angeles urban area overall, which already has the highest potential for respiratory illness from toxic air pollution (a Respiratory Hazard Index of 2.59) of all the areas included in the study.
- Seventy-one percent of LA schools are located within 3 miles of an RMP facility, as are 70% of medical facilities. This represents a 56% and 79% increase over national percentages for schools and medical facilities, respectively, in these zones.
- Seventy-nine percent of all dollar stores in Los Angeles are located in 3-mile fenceline zones around RMP facilities.

### Latino Population



### Schools and Medical Facilities in Fenceline Zones



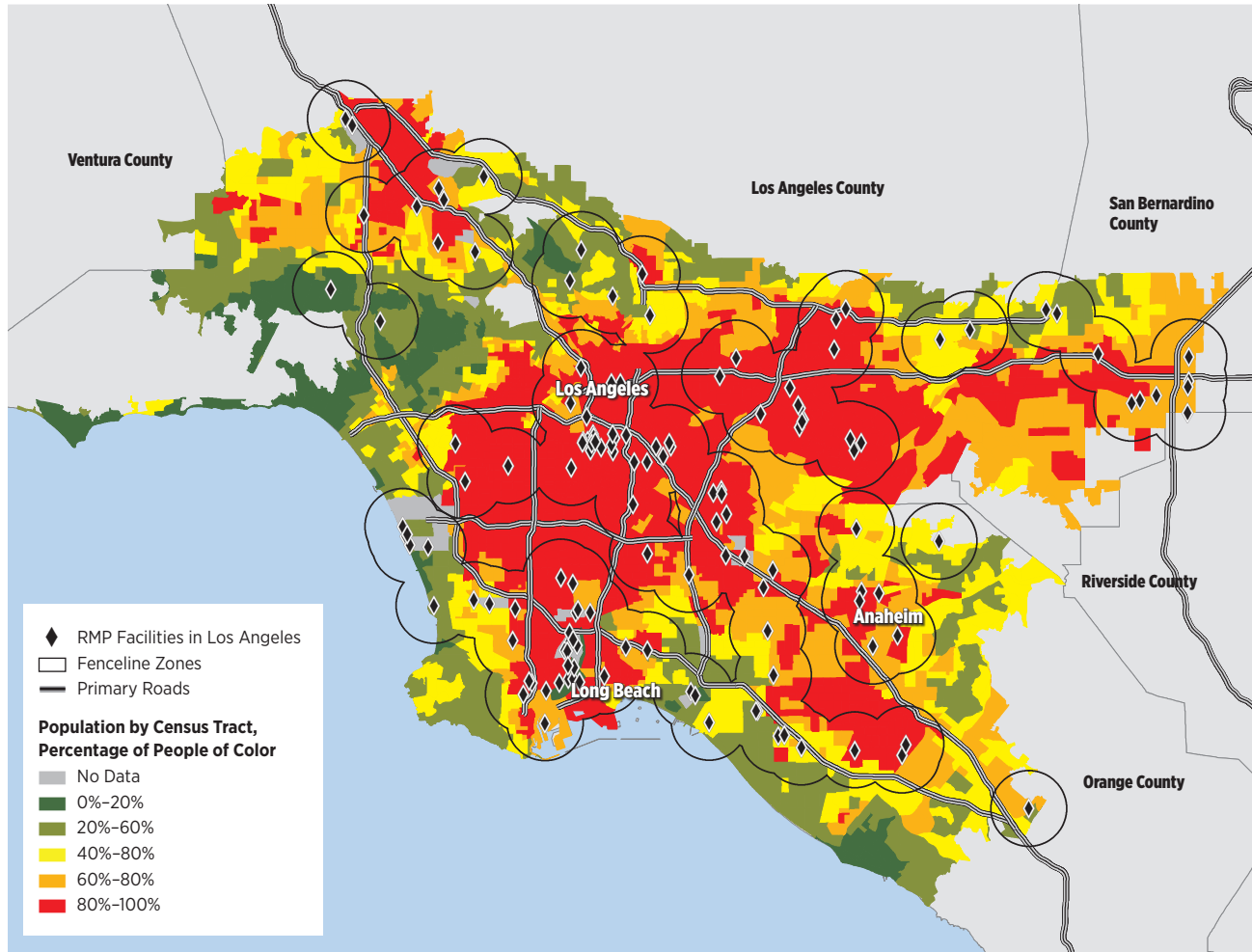
Jose Bravo of the Just Transition Alliance and Campaign for Healthier Solutions calls on EPA to prevent chemical disasters in Los Angeles.



**72% OF THE POPULATION OF** the Los Angeles Urban Area lives within 3 miles of an RMP facility.

## Hazardous Facilities and Race in Los Angeles

For additional maps and other information about Los Angeles, visit <https://ej4all.org/life-at-the-fenceline>.



## Los Angeles Data Summary

	Los Angeles Totals	Los Angeles 3 Mile Totals	Los Angeles 3 Mile LILA* Totals
<b>Weighted Cancer</b>	50.17	50.22	52.06
<b>Weighted RHI</b>	2.59	2.63	2.83
<b>Percent Black</b>	6.6%	6.8%	9.5%
<b>Percent Hispanic</b>	47.3%	52.4%	67.4%
<b>Percent White</b>	27.9%	23.4%	11.0%
<b>Percent Children</b>	23.1%	24.0%	26.9%
<b>Percent Poverty</b>	17.6%	18.6%	24.8%
<b>Average Household Income</b>	\$83,392	\$76,452	\$53,876
<b>Average Home Value</b>	\$550,046	\$475,194	\$314,249
<b>Percent HS Graduate or Less</b>	43.1%	47.4%	61.2%
<b>Percent College Degree or More</b>	28.0%	24.1%	13.7%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.



## RESULTS: FRESNO COUNTY, CALIFORNIA

There are 77 RMP facilities located in Fresno County.

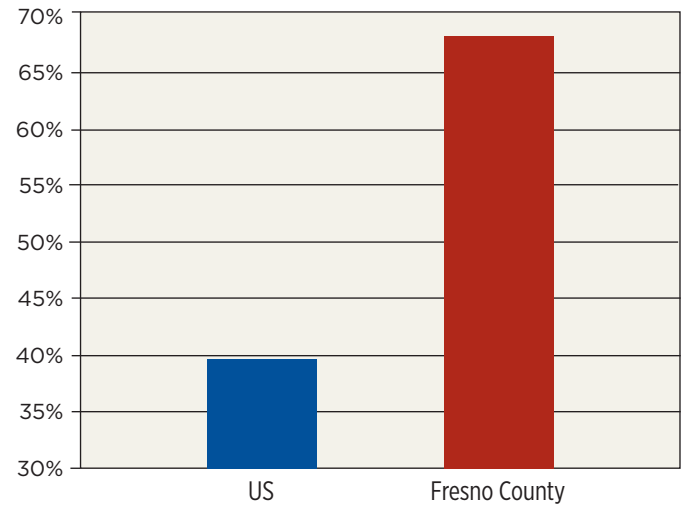
### KEY FINDINGS

- Almost 637,000 people, or 68% of Fresno County residents, live within 3 miles of an RMP facility, a 74% increase over the national rate.
- The percentage of Latinos in areas with low incomes and low access to healthy foods in fenceline zones is 23% greater than for Latinos in Fresno County overall.
- Average household income for those in areas with low incomes and low access to healthy foods is 29% less than for Fresno County overall.
- The potential for suffering respiratory illness from toxic air pollution exposure is 15% higher for those in areas with low incomes and low access to healthy foods within fenceline zones compared to Fresno County overall, while cancer risks are 7% greater.
- Sixty-eight percent of Fresno County schools and 71% of medical facilities are located within 3 miles of an RMP facility.
- Seventy-four percent of all dollar stores are within 3 miles of an RMP facility.

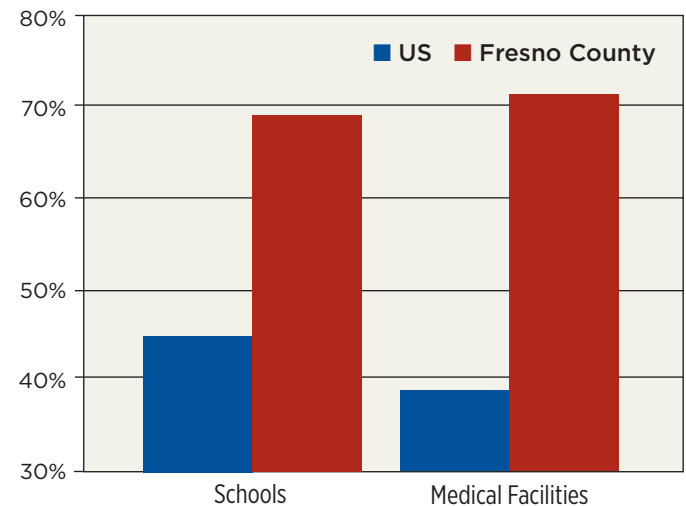


Members of Lideres Campesinas (which works in Fresno, Kern, and Madera Counties) call on dollar stores to remove toxic chemicals from the products they sell.

### Percent of Residents in Fenceline Zones Compared to National



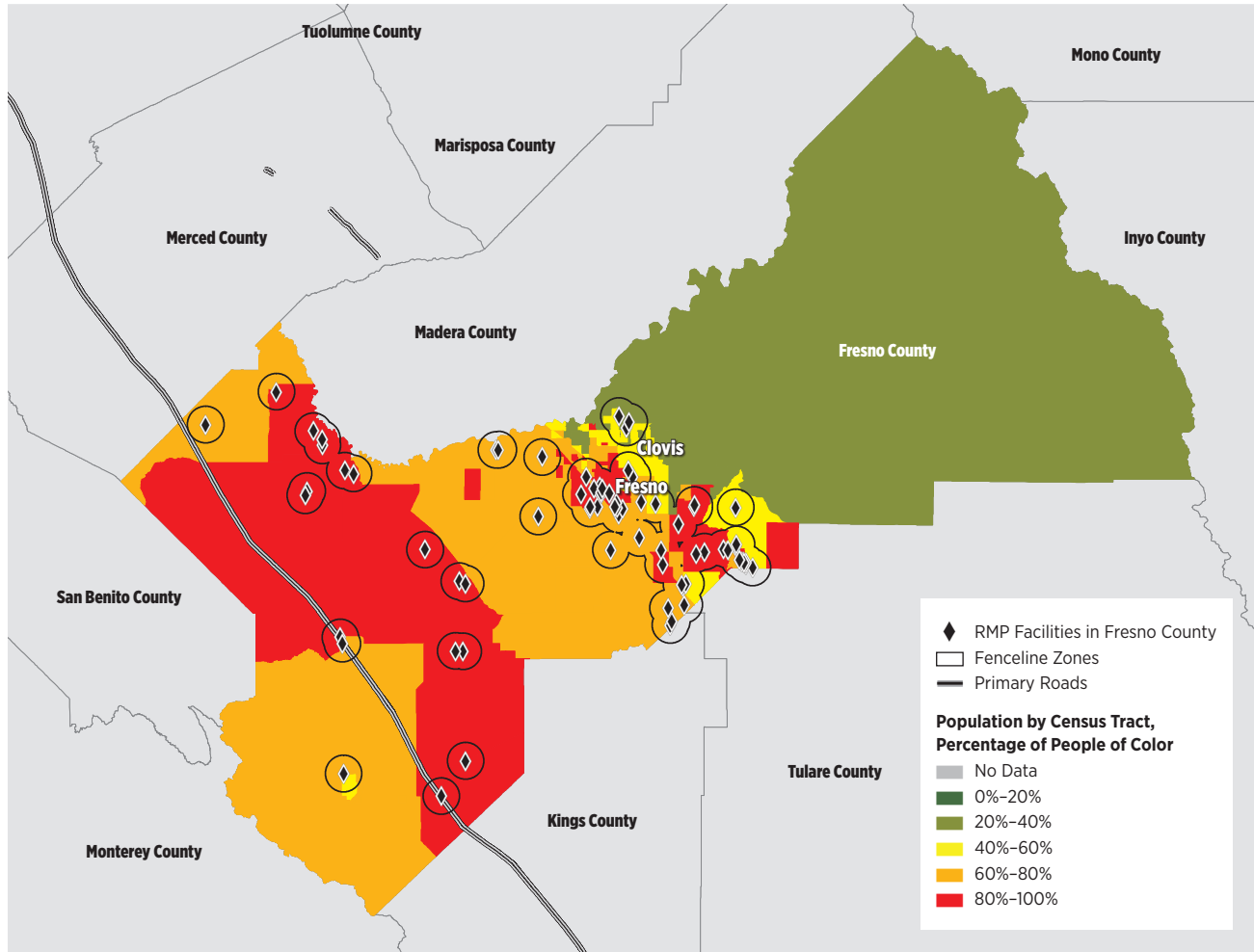
### Schools and Medical Facilities in Fenceline Zones



**68% OF THE POPULATION OF**  
Fresno County lives within 3 miles of an  
RMP facility.

## Hazardous Facilities and Race in Fresno County

For additional maps and other information about Fresno County, visit <https://ej4all.org/life-at-the-fenceline>.



## Fresno County Data Summary

	Fresno Co. Totals	Fresno Co. 3 Mile Totals	Fresno 3 Mile LILA* Totals
<b>Weighted Cancer</b>	48.62	50.57	52.02
<b>Weighted RHI</b>	2.06	2.19	2.37
<b>Percent Black</b>	4.8%	4.9%	6.2%
<b>Percent Hispanic</b>	51.7%	54.2%	63.4%
<b>Percent White</b>	31.3%	27.8%	17.9%
<b>Percent Children</b>	29.0%	29.8%	31.6%
<b>Percent Poverty</b>	27.6%	29.4%	37.8%
<b>Average Household Income</b>	\$62,411	\$59,806	\$44,332
<b>Average Home Value</b>	\$221,576	\$206,867	\$155,918
<b>Percent HS Graduate or Less</b>	49.9%	51.9%	62.8%
<b>Percent College Degree or More</b>	17.6%	16.6%	9.0%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.

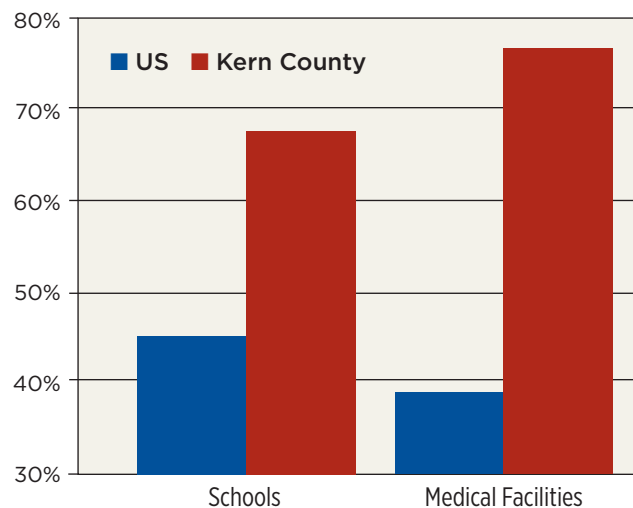
## RESULTS: KERN COUNTY, CALIFORNIA

There are 97 RMP facilities located in Kern County.

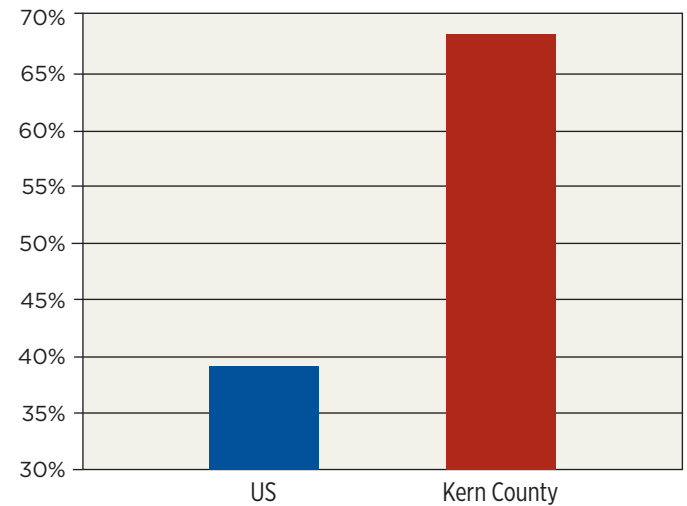
### KEY FINDINGS

- Almost 581,000 people, or 68% of Kern county residents, live within 3 miles of an RMP facility, a 74% increase over the national rate.
- While Latinos represent just over 50% of the county's population, 65% of people living in areas with low incomes and low access to healthy foods within the 3-mile fenceline zones are Latino, a 29% increase.
- The potential for suffering respiratory illness from toxic air pollution exposure is 17% higher for those living in low-income/low food access areas within fenceline zones compared to Kern County overall, while cancer risks are 9% greater.
- More than two-thirds of all Kern County schools and more than three-quarters of medical facilities are located within 3 miles of an RMP facility.
- Seventy-two percent of all dollar stores in Kern County are located within 3 miles of an RMP facility.

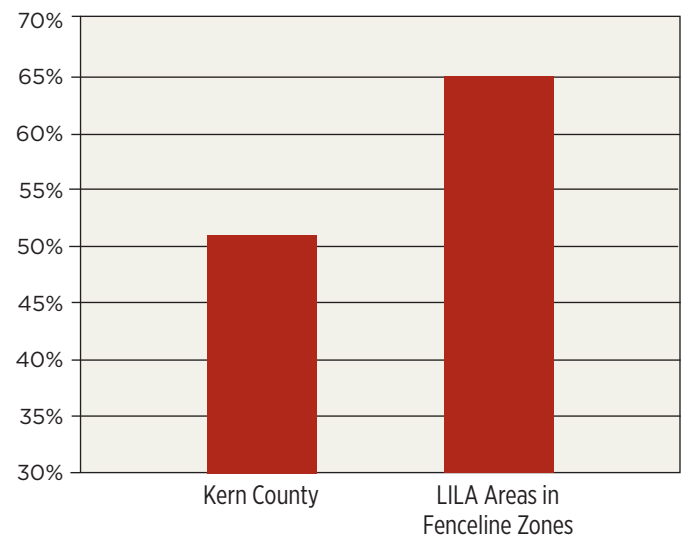
### Schools and Medical Facilities in Fenceline Zones



### Percent of Residents in Fenceline Zones Compared to National



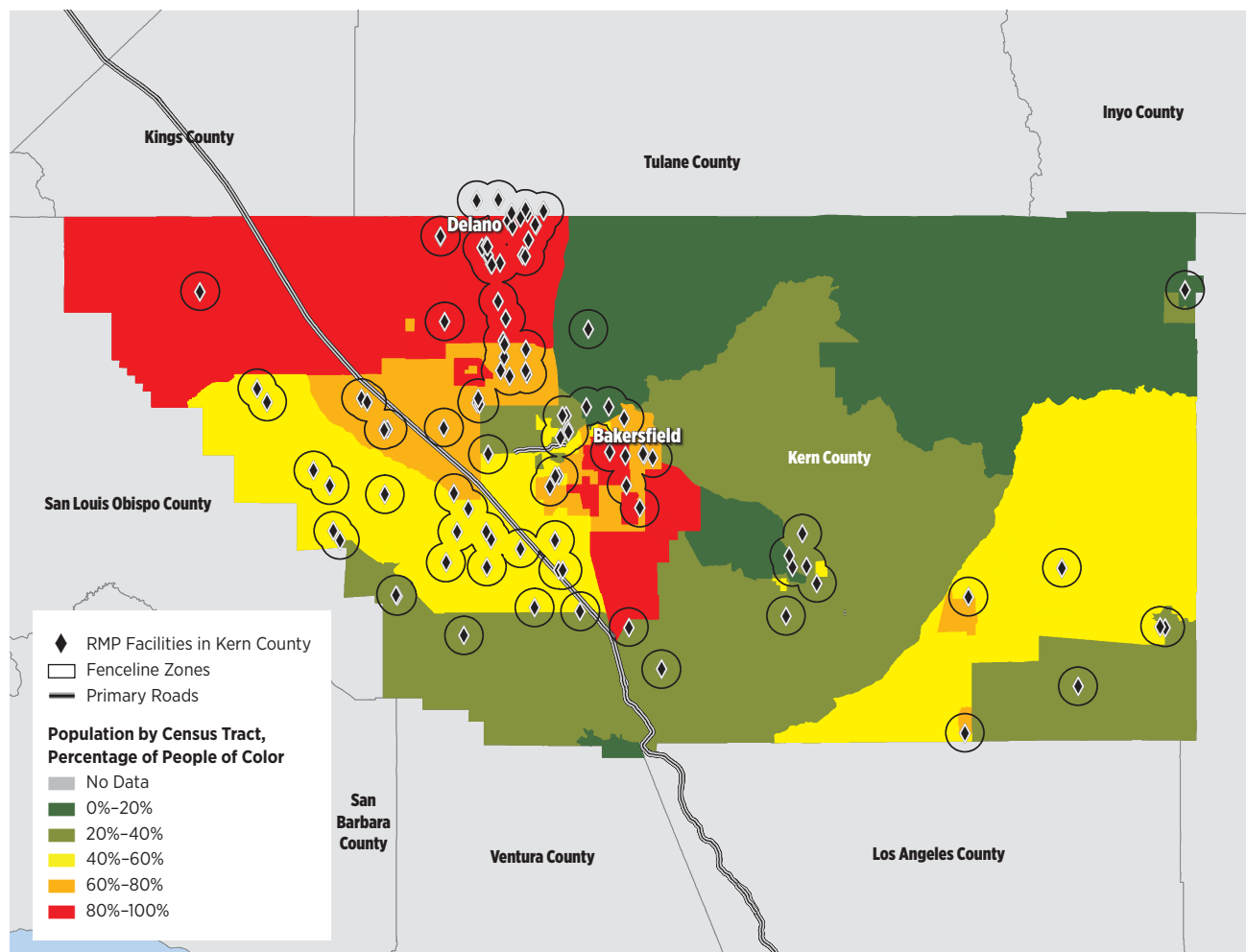
### Latino Population



**68% OF THE POPULATION** of Kern County lives within 3 miles of an RMP facility.

## Hazardous Facilities and Race in Kern County

For additional maps and other information about Kern County, visit <https://ej4all.org/life-at-the-fenceline>.



## Kern County Data Summary

	Kern Co. Totals	Kern Co. 3 Mile Totals	Kern County 3 Mile LILA* Totals
<b>Weighted Cancer</b>	45.69	48.20	49.60
<b>Weighted RHI</b>	1.91	2.07	2.24
<b>Percent Black</b>	5.3%	6.0%	5.8%
<b>Percent Hispanic</b>	50.6%	52.6%	65.3%
<b>Percent White</b>	37.1%	34.1%	23.5%
<b>Percent Children</b>	29.3%	29.9%	32.6%
<b>Percent Poverty</b>	23.4%	24.7%	34.1%
<b>Average Household Income</b>	\$65,432	\$63,516	\$46,082
<b>Average Home Value</b>	\$188,274	\$183,073	\$136,360
<b>Percent HS Graduate or Less</b>	53.5%	54.0%	65.8%
<b>Percent College Degree or More</b>	14.1%	13.8%	7.3%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.

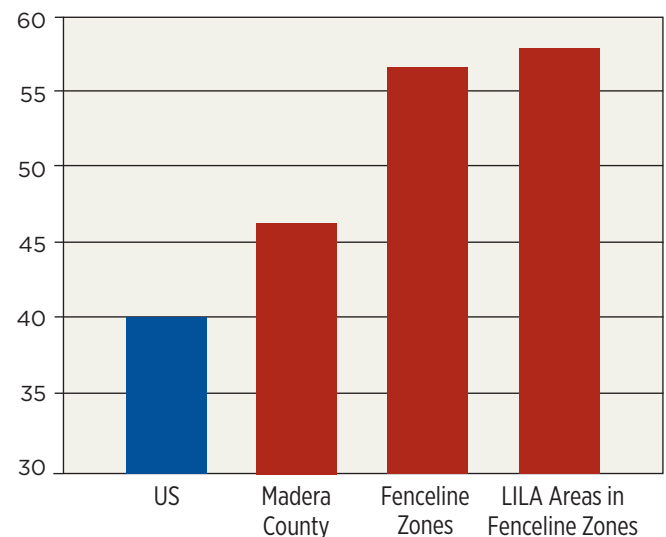
## RESULTS: MADERA COUNTY, CALIFORNIA

Madera County contains seven RMP facilities.

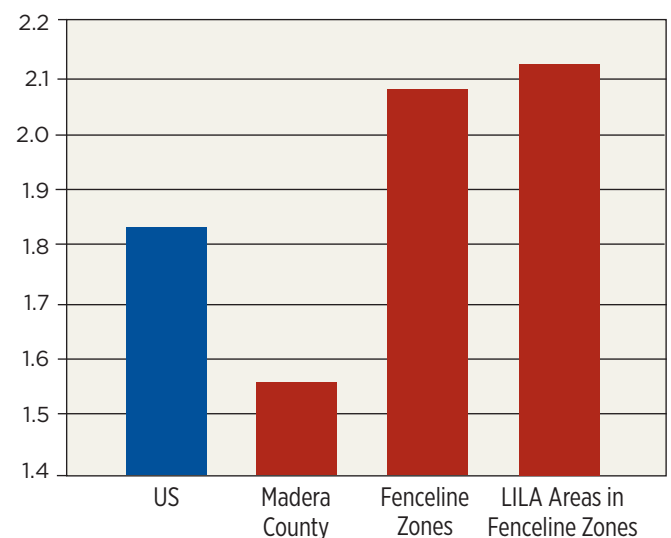
### KEY FINDINGS

- More than 77,000 people, or 47% of Madera County residents, live within 3 miles of an RMP facility, a 21% increase over the national rate.
  - Strikingly, almost 100% of those living in low-income/low food access areas in Madera County also live within 3 miles of an RMP facility, a rate that is more than twice the percent of county residents who live within fenceline zones (47%).
  - The potential for suffering respiratory illness from toxic air pollution exposure is 33% higher for those living within 3 miles of an RMP facility compared to Madera County overall, and those living in low-income/low food access areas within these fenceline zones face a 35% higher risk.
  - Cancer risk from exposure to toxic air pollution is 21% higher for those living within 3 miles of an RMP facility compared to Madera County overall. Those living in low-income/low food access areas within fenceline zones face a 24% higher cancer risk (about 57 cancers per million people), which is the highest risk of all 9 areas included in this report.
  - While Latinos make up about 53% of the county's population, 70% of people living within 3 miles of an RMP facility are Latino, a 33% increase over their overall county representation. Latinos make up 76% of the population in low-income/low food access areas within these fenceline zones, a 44% increase over their overall county representation.
  - The percentage of people living in poverty within 3 miles of an RMP facility is 28% greater than for Madera County overall. More strikingly, the poverty rate in low-income/low food access (LILA) areas within 3 miles of an RMP facility is 58% greater than for the country as a whole.
  - Twenty-seven percent of Madera County residents are children, but 35% of the residents of low-income/low food access areas within fenceline zones are children, a 26% increase.
  - The average household income for those living within 3 miles of an RMP facility is 17% lower than for Madera County overall. For those living in areas with low incomes and low access to healthy food, the drop in average household incomes doubles to 34%.
- Half of all medical facilities in Madera County are located within 3 miles of an RMP facility, as are 39% of schools.
  - Seventy-five percent of all dollar stores in Madera County are located within 3 miles of an RMP facility, and 43% of RMP facilities have a dollar store within 3 miles.

### Cancer Risk from Air Pollution

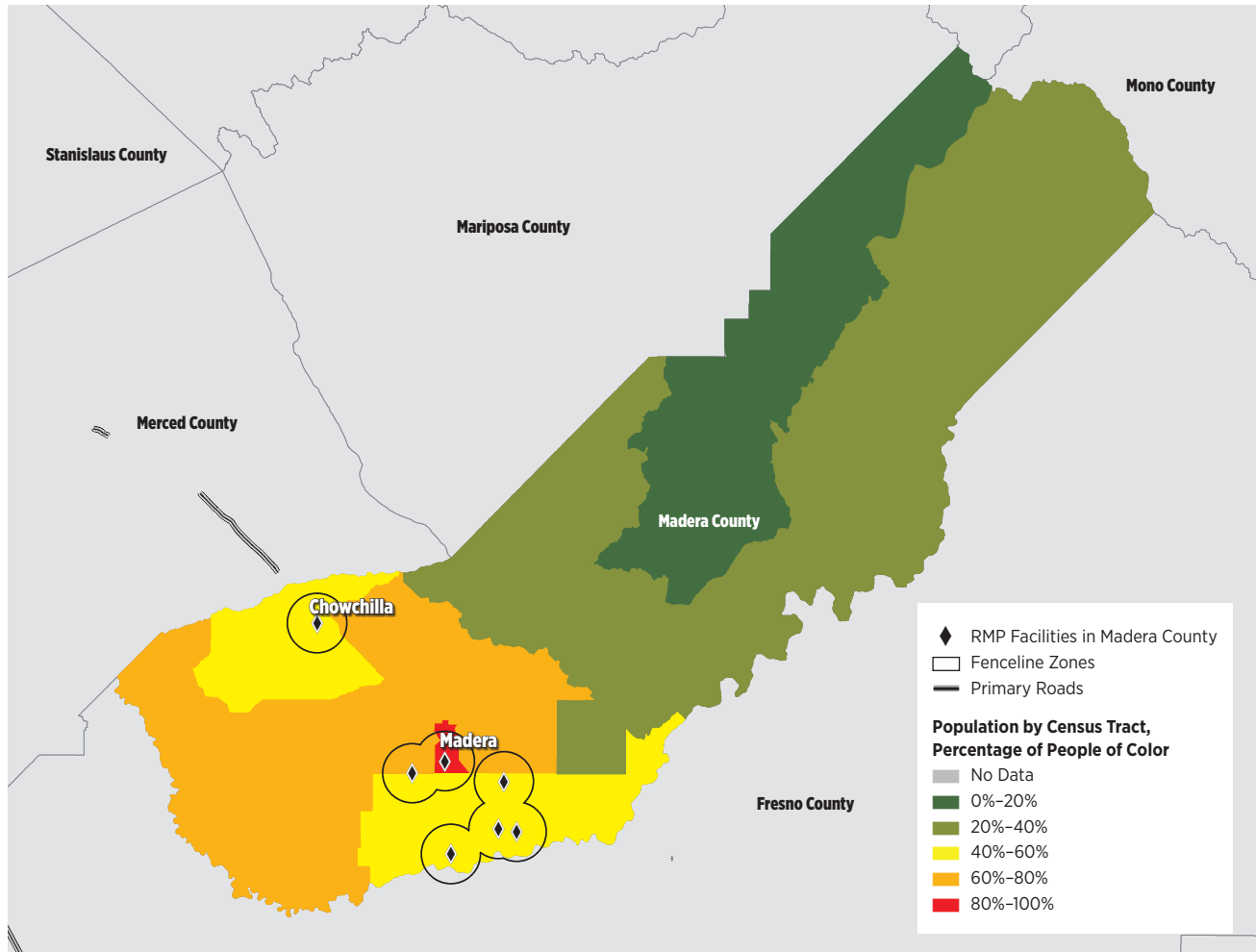


### Respiratory Hazard from Air Pollution



## Hazardous Facilities and Race in Madera County

For additional maps and other information about Madera County, visit <https://ej4all.org/life-at-the-fenceline>.



## Madera County Data Summary

	Madera Co. Totals	Madera Co. 3 Mile Totals	Madera County 3 Mile LILA* Totals
<b>Weighted Cancer</b>	46.37	56.32	57.27
<b>Weighted RHI</b>	1.56	2.07	2.11
<b>Percent Black</b>	3.3%	2.8%	2.5%
<b>Percent Hispanic</b>	52.8%	70.0%	75.8%
<b>Percent White</b>	38.3%	22.5%	17.0%
<b>Percent Children</b>	27.4%	32.1%	34.5%
<b>Percent Poverty</b>	22.3%	28.6%	35.2%
<b>Average Household Income</b>	\$63,832	\$52,779	\$42,043
<b>Average Home Value</b>	\$242,651	\$186,986	\$154,031
<b>Percent HS Graduate or Less</b>	51.7%	63.0%	71.2%
<b>Percent College Degree or More</b>	14.4%	9.3%	6.0%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.

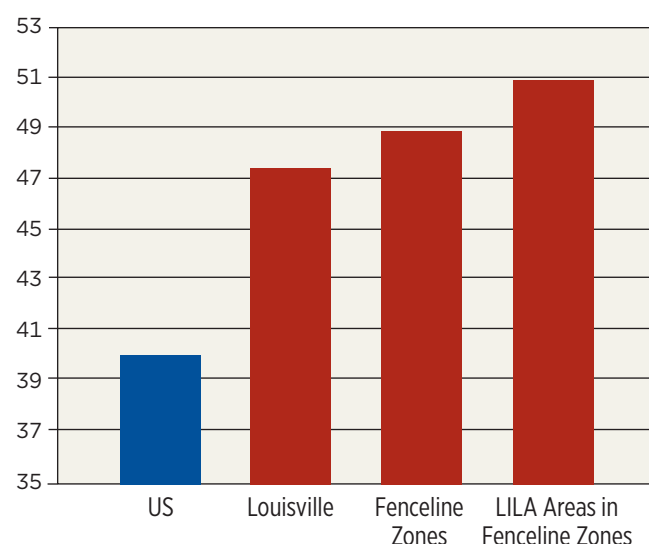
## RESULTS: LOUISVILLE, KENTUCKY

There are 23 RMP facilities located in Louisville.

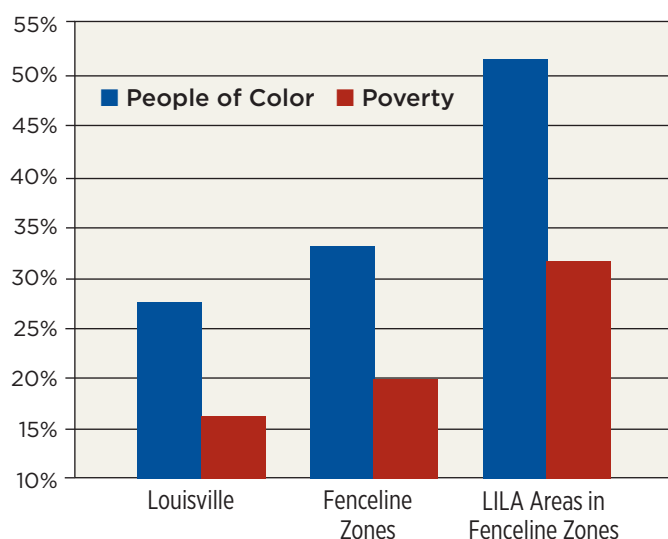
### KEY FINDINGS

- Almost 606,000 people, or 67% of Louisville residents, live within 3 miles of an RMP facility, a 72% increase over the national rate.
- Ninety-two percent of Louisville residents who live in low-income/low food access (LILA) areas also live within a fenceline zone, a rate 37% greater than for all residents.
- The potential for suffering respiratory illness from toxic air pollution exposure is 9% higher for those in low-income/low food access areas within fenceline zones compared to Louisville overall, while cancer risks for those living in these areas are 7% greater.
- The percentage of people living in poverty within 3 miles of an RMP facility is 23% greater than for Louisville overall. This difference increases substantially to 94% greater for low-income/low food access areas within the fenceline zones.
- The average household income for those living in low-income/low food access areas within fenceline zones is 41% lower than for all those living in Louisville.
- While Blacks make up 18% of Louisville's population, 23% of people living within 3 miles of an RMP facility are Black, a 28% increase over their overall county representation. Strikingly, in low-income/low food access areas within fenceline zones, Blacks make up 39% of the population, more than twice the city rate.
- All of Louisville's 23 RMP facilities have at least one dollar store located within 3 miles, and 73% of all dollar stores are located within 3 miles of an RMP facility.
- More than two-thirds (67%) of Louisville schools are located within 3 miles of an RMP facility, as are 88% of medical facilities.

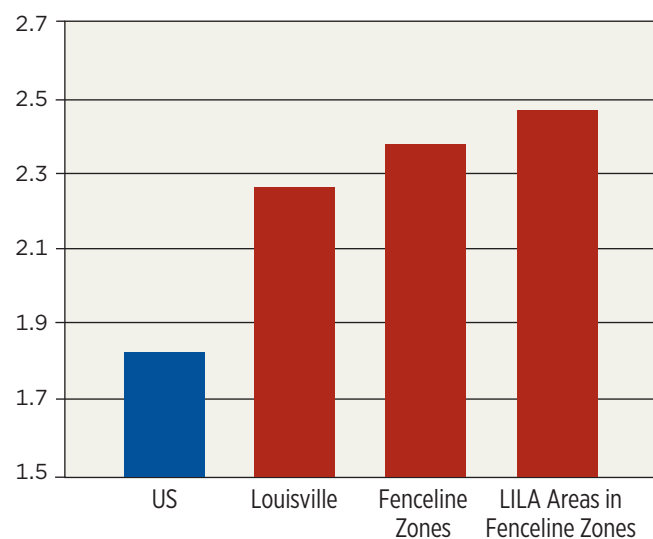
### Cancer Risk from Air Pollution



### Race and Poverty in Louisville

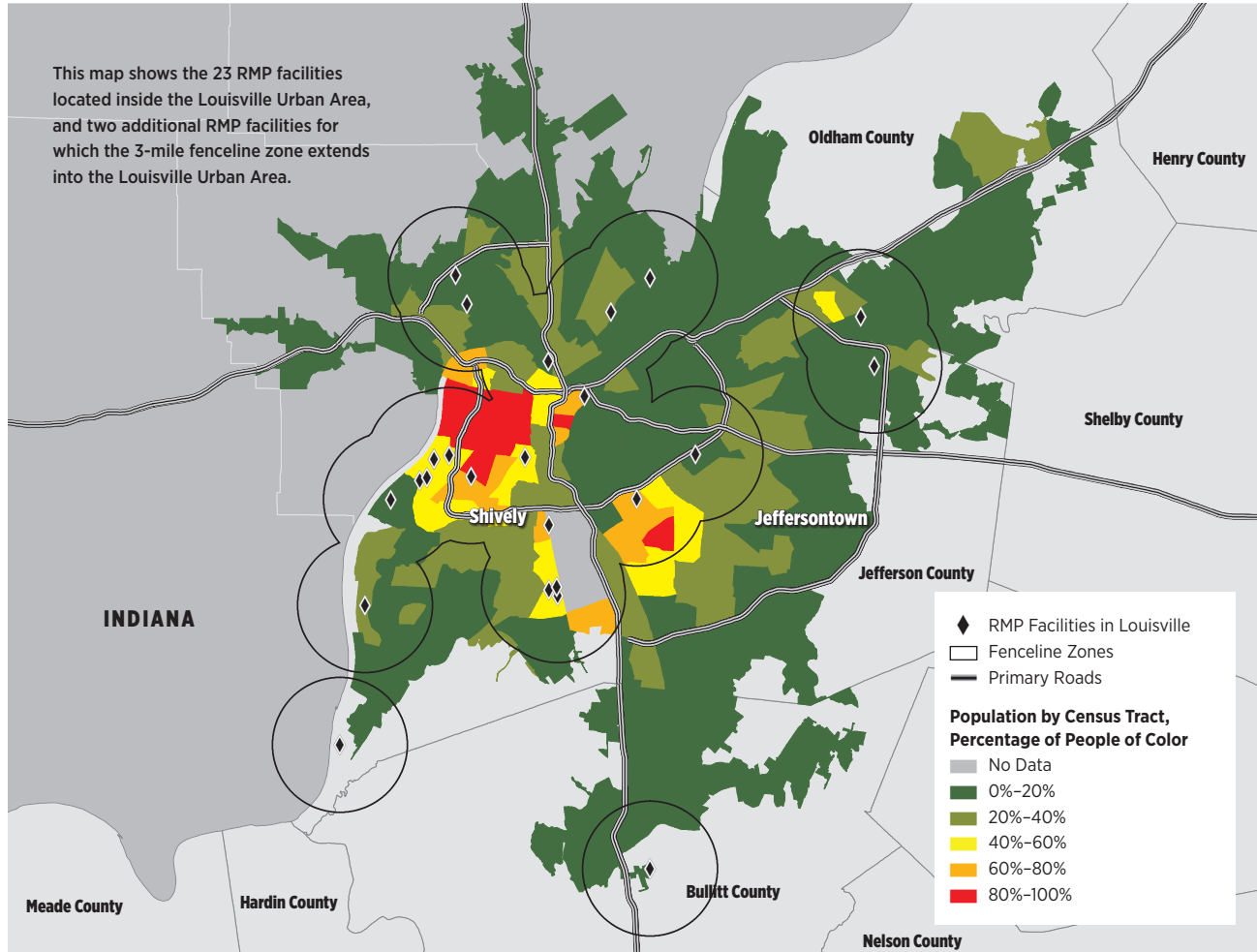


### Respiratory Hazard from Air Pollution



## Hazardous Facilities and Race in Louisville

For additional maps and other information about Louisville, visit <https://ej4all.org/life-at-the-fenceline>.



## Louisville Data Summary

	Louisville Totals	Louisville 3 Mile Totals	Louisville 3 Mile LILA* Totals
Weighted Cancer	47.35	48.85	50.86
Weighted RHI	2.26	2.37	2.46
Percent Black	17.8%	22.5%	39.3%
Percent Hispanic	4.5%	4.8%	6.1%
Percent White	72.8%	67.5%	49.1%
Percent Children	22.6%	22.3%	23.9%
Percent Poverty	16.0%	19.6%	31.1%
Average Household Income	\$66,720	\$60,889	\$39,452
Average Home Value	\$181,660	\$170,253	\$103,050
Percent HS Graduate or Less	40.8%	43.1%	54.4%
Percent College Degree or More	26.8%	24.8%	13.9%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.



## RESULTS: ALBUQUERQUE, NEW MEXICO

There are seven RMP facilities located in Albuquerque.

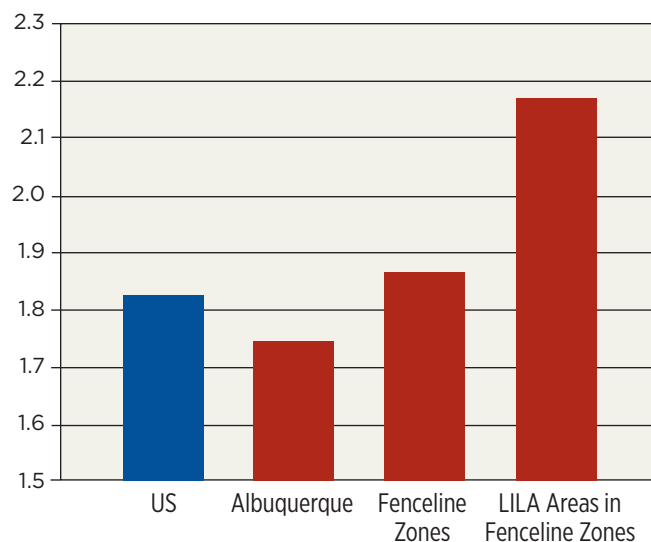
### KEY FINDINGS

- More than 268,000 people, or 39% of people living in Albuquerque, live within 3 miles of an RMP facility.
- The potential for suffering respiratory problems from toxic air pollution exposure is 25% higher for those in low-income/low food access areas within fenceline zones compared to Albuquerque overall, while cancer risk is 10% higher.
- The percentage of Latinos in low-income/low food access areas within fenceline zones is 32% greater than for Latinos in Albuquerque overall, and is more than twice the rate for whites in these areas.
- The average household income for those living in low-income/low food access areas within 3 miles of an RMP facility is 26% lower than for Albuquerque as a whole.
- The percentage of those living in areas with low incomes and low access to healthy foods who have a high school or less education is 36% greater than for Albuquerque overall. The percentage of those living in low-income/low food access areas with a college degree or more education is 39% lower than for Albuquerque overall.

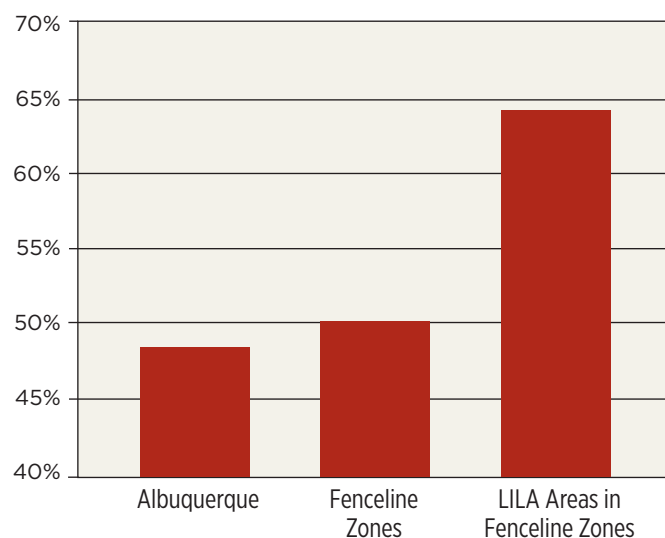


Leaders of the Campaign for Healthier Solutions, Los Jardines Institute, and allies call on dollar stores to sell healthier foods and safer products.

### Respiratory Hazard from Air Pollution



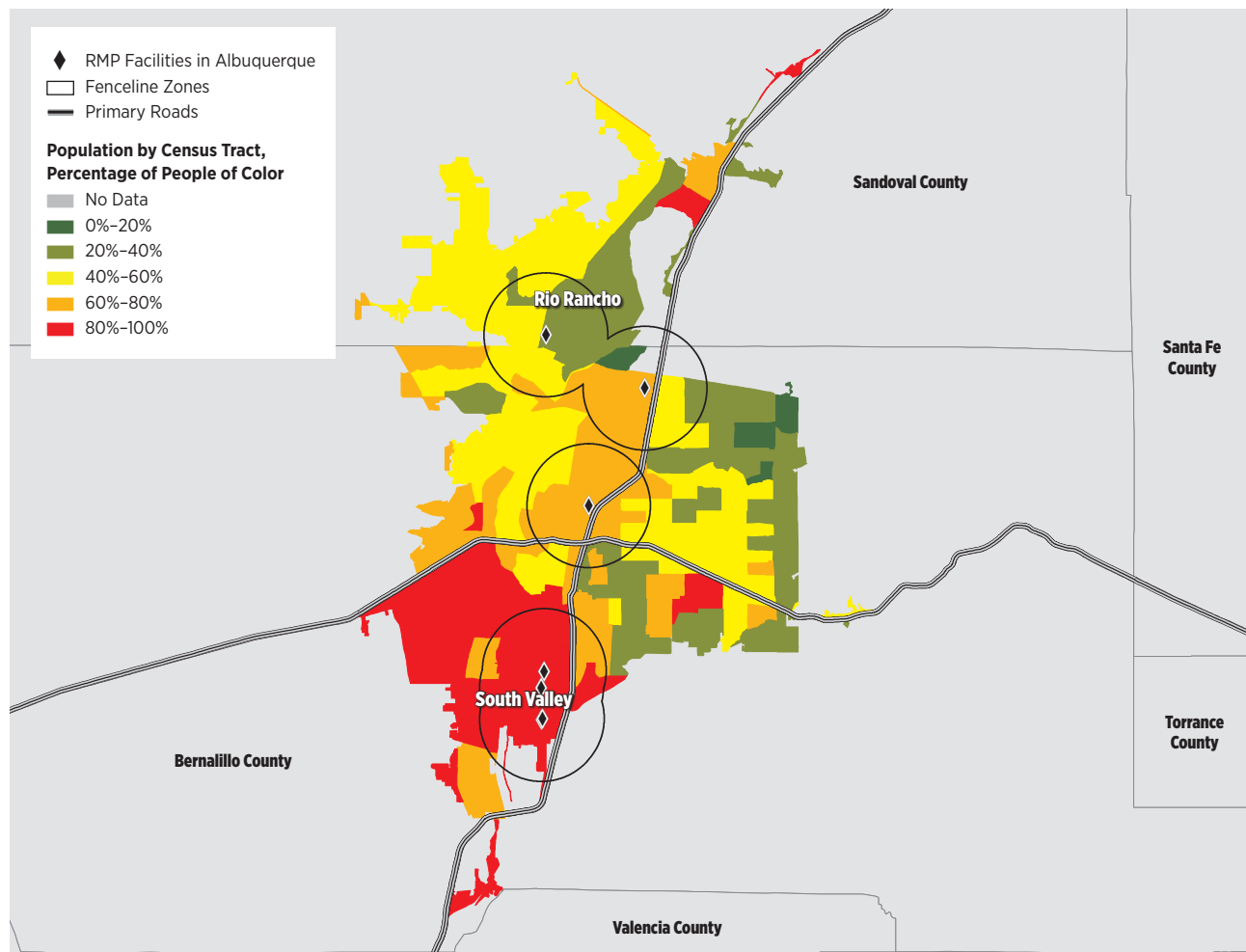
### Latino Population



**39% OF THE POPULATION OF**  
Albuquerque lives within 3 miles of an  
RMP facility.

## Hazardous Facilities and Race in Albuquerque

For additional maps and other information about Albuquerque, visit <https://ej4all.org/life-at-the-fenceline>.



## Albuquerque Data Summary

	Albuquerque Totals	Albuquerque 3 Mile Totals	Albuquerque 3 Mile LILA* Totals
<b>Weighted Cancer</b>	38.25	39.45	41.91
<b>Weighted RHI</b>	1.74	1.86	2.17
<b>Percent Black</b>	2.6%	2.5%	2.9%
<b>Percent Hispanic</b>	48.4%	50.1%	64.0%
<b>Percent White</b>	41.5%	40.1%	26.3%
<b>Percent Children</b>	23.3%	23.0%	24.3%
<b>Percent Poverty</b>	18.4%	18.4%	28.0%
<b>Average Household Income</b>	\$65,170	\$65,970	\$47,908
<b>Average Home Value</b>	\$209,745	\$219,400	\$150,054
<b>Percent HS Graduate or Less</b>	36.2%	37.4%	50.2%
<b>Percent College Degree or More</b>	29.4%	29.6%	18.9%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.

## RESULTS: DALLAS, TEXAS

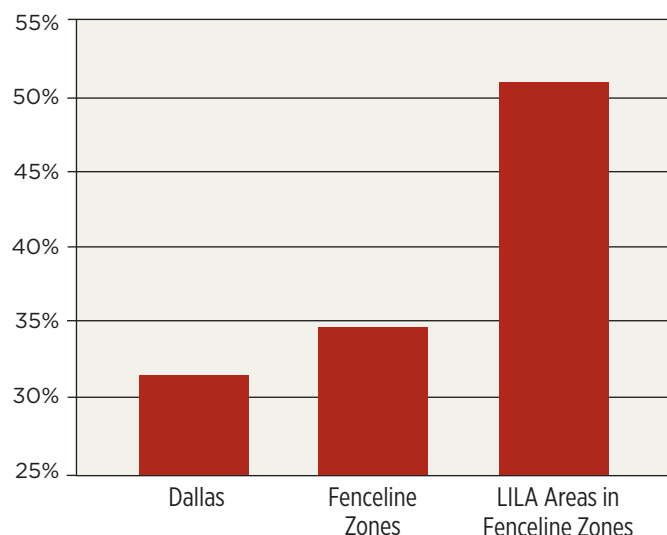
There are 108 RMP facilities located in Dallas.

### KEY FINDINGS

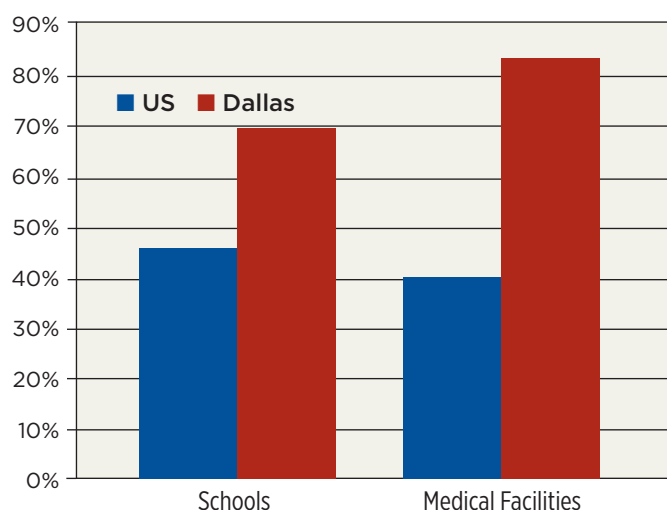
- Almost 3.5 million people, or 72% of Dallas residents, live within 3 miles of an RMP facility, an 85% increase over the national rate.
- Seventy-nine percent of people living in low-income/low food access areas in Dallas also live within 3 miles of an RMP facility.
- The percentage of people living in poverty in low-income/low food access areas within 3 miles of an RMP facility is 67% higher than for those in poverty in Dallas overall.
- The average household income for those living in low-income/low food access areas within 3 miles of an RMP facility is 39% lower than for all those living in Dallas.
- While Latinos make up less than one-third Dallas's population, more than half of people in low-income/low food access areas within 3 miles of an RMP facility are Latino, a 62% increase. The percentage of Latinos is more than twice the rate for whites in low-income/low food access areas within the fenceline zones.
- Blacks make up 17% of the Dallas population, but constitute 22% of people in areas with low incomes and low access to healthy foods within in the 3-mile fenceline zones, a 25% increase.
- More than 80% of all medical facilities in Dallas are located within 3 miles of an RMP facility, as are more than two-thirds of schools.
- Ninety-five percent of RMP facilities in Dallas have a dollar store within 3 miles, and 70% of dollar stores are located within 3 miles of an RMP facility.



### Latino Population



### Schools and Medical Facilities in Fenceline Zones

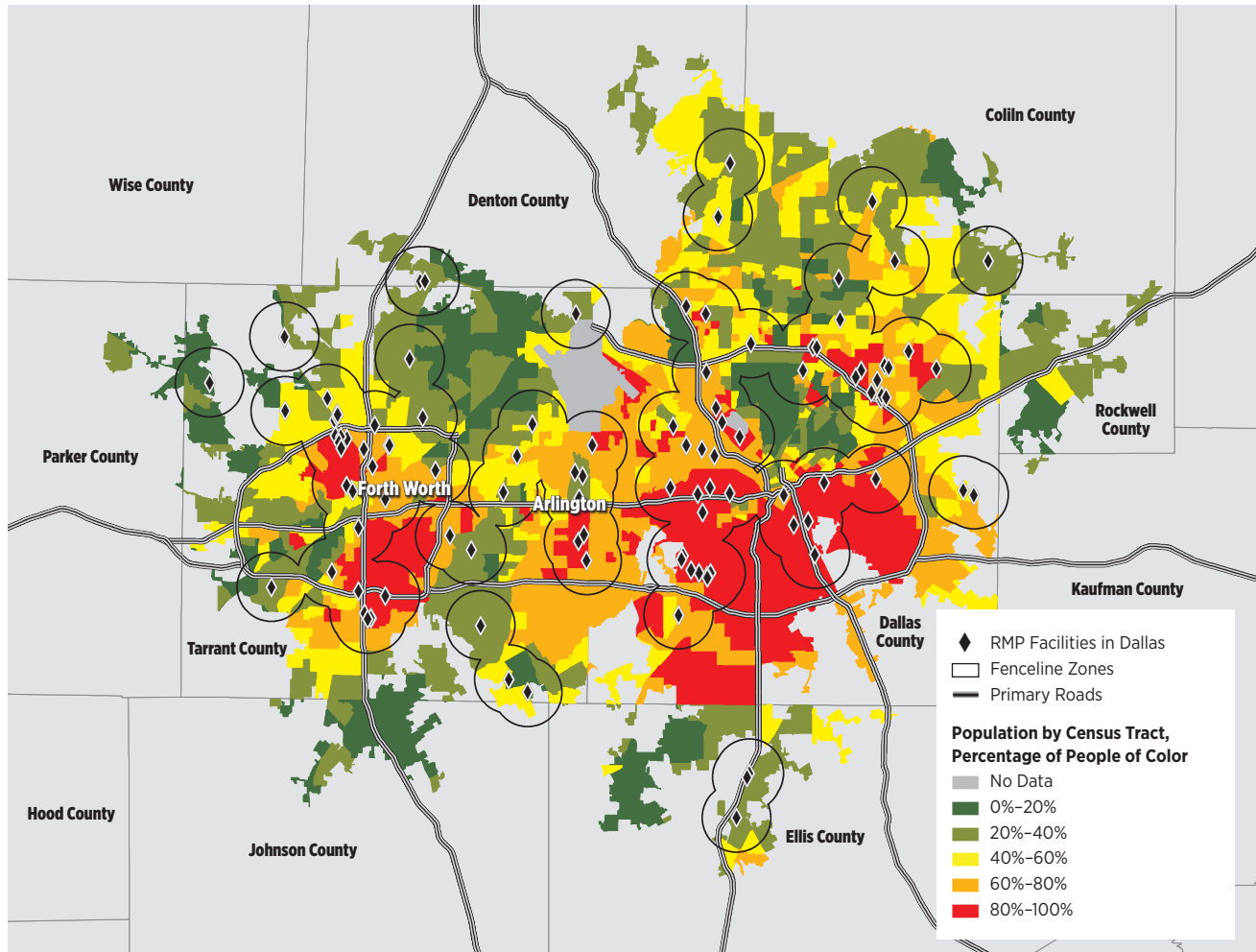


**72% OF THE POPULATION OF**  
the Dallas Urban Area lives within 3 miles  
of an RMP facility.

Left: A 2007 explosion at Southwest Industrial Gases in Dallas sent flaming debris onto highways and buildings.

## Hazardous Facilities and Race in Dallas

For additional maps and other information about Dallas, visit <https://ej4all.org/life-at-the-fenceline>.



## Dallas Data Summary

	Dallas Totals	Dallas 3 Mile Totals	Dallas 3 Mile LILA* Totals
Weighted Cancer	46.25	46.58	47.67
Weighted RHI	2.37	2.40	2.48
Percent Black	17.3%	16.5%	21.7%
Percent Hispanic	31.5%	34.7%	51.0%
Percent White	42.4%	40.8%	22.5%
Percent Children	26.9%	26.9%	29.4%
Percent Poverty	16.3%	17.7%	27.2%
Average Household Income	\$80,130	\$74,771	\$49,036
Average Home Value	\$204,060	\$189,682	\$114,414
Percent HS Graduate or Less	39.5%	42.6%	60.7%
Percent College Degree or More	30.6%	28.1%	14.4%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.

## RESULTS: HOUSTON, TEXAS

There are 191 RMP facilities located in Houston, the most of any of the areas included in this report.

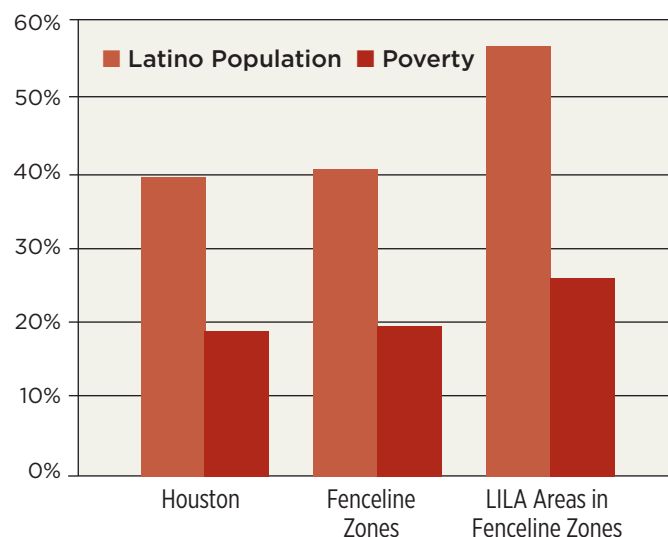
### KEY FINDINGS

- Almost 3.6 million people, or three-quarters of Houston residents, live within 3 miles of an RMP facility, a 92% increase above the national rate.
- Eighty-two percent of Houston residents who live in low-income/low food access areas also live within RMP facility fenceline zones.
- The percentage of people in poverty in low-income/low food access areas within 3 miles of an RMP facility is 66% higher than for those in poverty in Houston overall.
- The average household income for those living in low-income/low food access areas within the fenceline zones is 41% lower than for all those living in Houston.
- Latinos make up 39% of Houston's population but represent 56% of those living in low-income/low food access areas within 3 miles of an RMP facility (a 44% greater rate). Blacks comprise 19% of the Houston population, but make up 26% of those living in low-income/low food access areas within the fenceline zones (a 37% greater rate).
- Seventy-eight percent of all Houston medical facilities and 72% of schools are within 3 miles of an RMP facility.
- Ninety-two percent of RMP facilities in Houston have a dollar store within 3 miles and almost three-quarters of all dollar stores are located within 3 miles of an RMP facility.

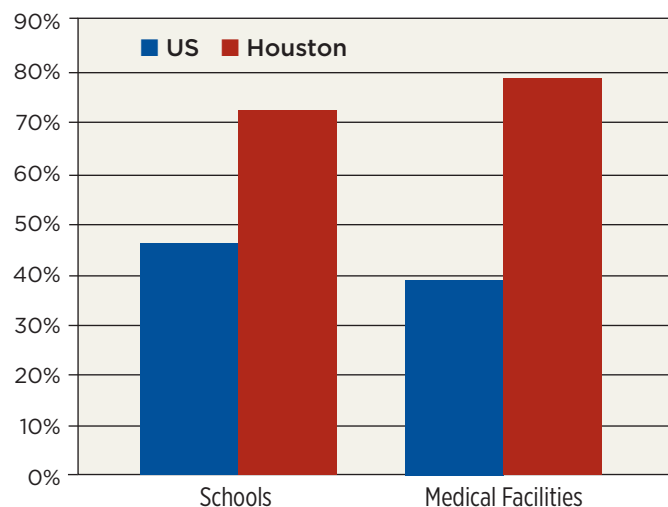


Houston contains 191 high-risk chemical facilities.

### Latino Population and Poverty in Houston



### Schools and Medical Facilities in Fenceline Zones

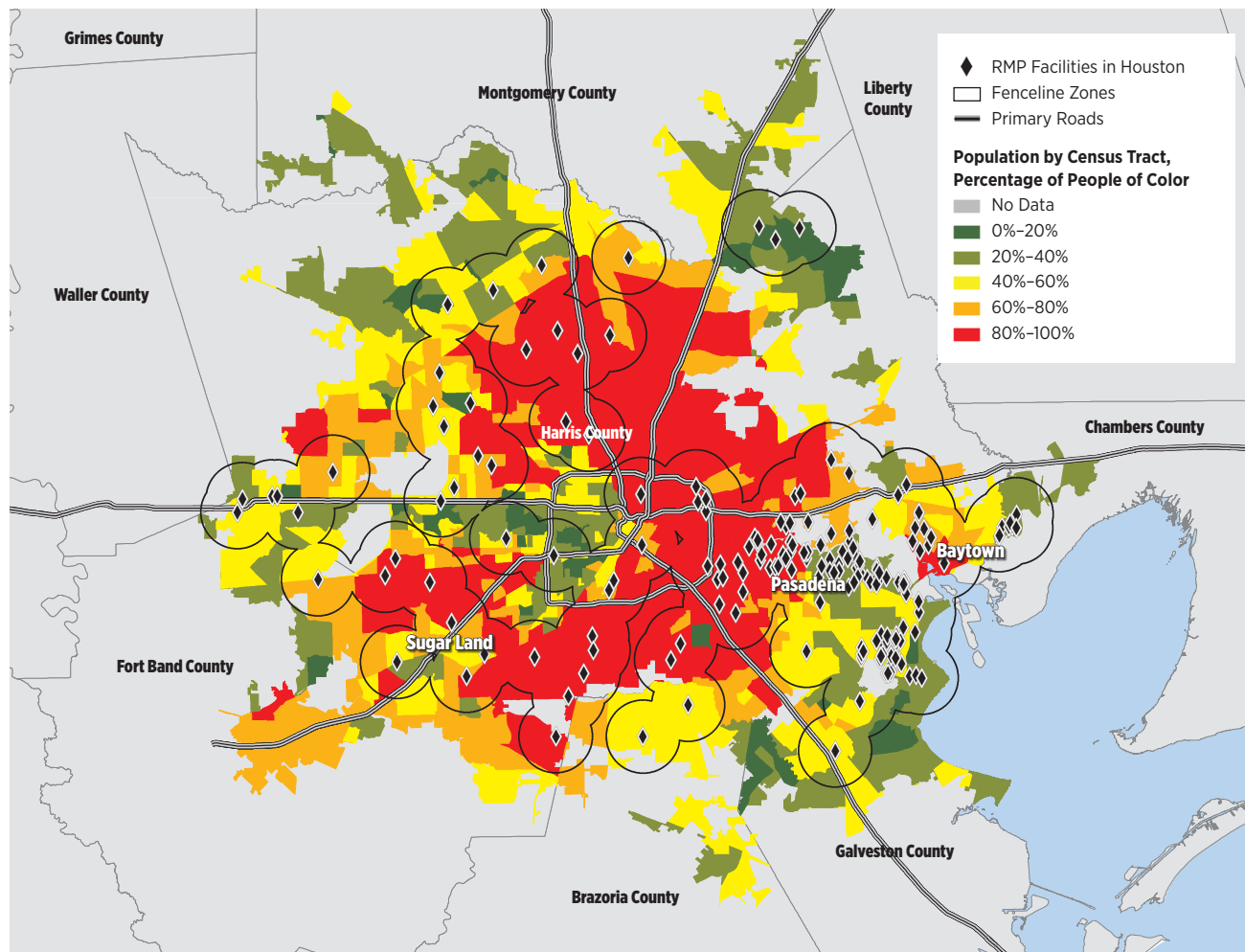


**75% OF THE POPULATION OF**  
Houston lives within 3 miles of an RMP facility.



## Hazardous Facilities and Race in Houston

For additional maps and other information about Houston, visit <https://ej4all.org/life-at-the-fenceline>.



## Houston Data Summary

	Houston Totals	Houston 3 Mile Totals	Houston 3 Mile LILA* Totals
<b>Weighted Cancer</b>	44.74	45.57	47.26
<b>Weighted RHI</b>	2.09	2.13	2.29
<b>Percent Black</b>	18.6%	19.5%	25.5%
<b>Percent Hispanic</b>	39.0%	40.2%	56.1%
<b>Percent White</b>	32.9%	30.6%	12.1%
<b>Percent Children</b>	27.1%	26.7%	28.8%
<b>Percent Poverty</b>	17.2%	18.4%	28.5%
<b>Average Household Income</b>	\$82,920	\$80,522	\$48,832
<b>Average Home Value</b>	\$197,888	\$201,040	\$105,512
<b>Percent HS Graduate or Less</b>	42.1%	43.2%	61.6%
<b>Percent College Degree or More</b>	28.8%	28.1%	13.9%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.

## RESULTS: CHARLESTON, WEST VIRGINIA

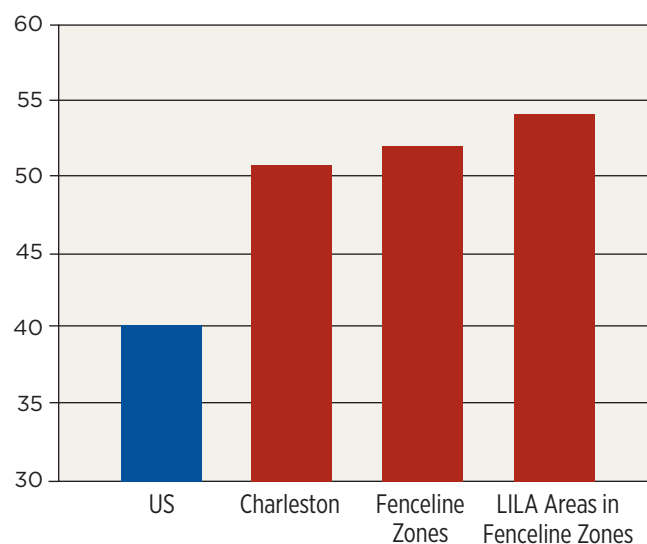
There are 13 RMP facilities located in Charleston.

### KEY FINDINGS

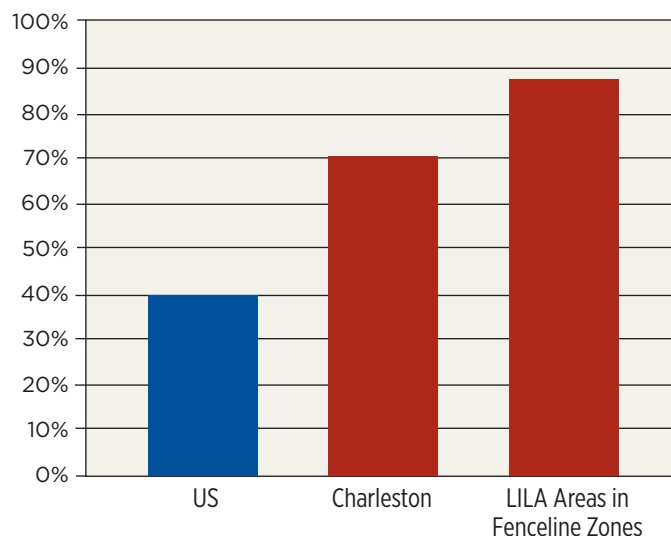
- Seventy percent of people in Charleston live within 3 miles of an RMP facility, an 80% increase over the national rate.
- Eighty-seven percent of Charleston residents who live in low-income/low food access areas also live in fenceline zones (more than twice the rate of all US residents who live in RMP facility fenceline zones, which is 39%).
- People living in Charleston face the highest cancer risk (approximately 51 cancers per million people) from toxic air pollutants of all 9 areas included in this report. Those risks increase further for those living in low-income/low food access areas within 3 miles of an RMP facility.
- The percentage of people in poverty in low-income/low food access areas within 3 miles of an RMP facility is 43% higher than for those in poverty in Charleston overall.
- The average household income for those living in low-income/low food access areas within 3 miles of an RMP facility is 28% lower than for all those living in Charleston.
- More than half of Charleston schools and almost 30% of medical facilities are located within 3 miles of an RMP facility.
- All of Charleston's 13 RMP facilities have at least one dollar store located within 3 miles, and two-thirds (68%) of all dollar stores are located within 3 miles of an RMP facility.



### Cancer Risk from Air Pollution



### Residents in Fenceline Zones

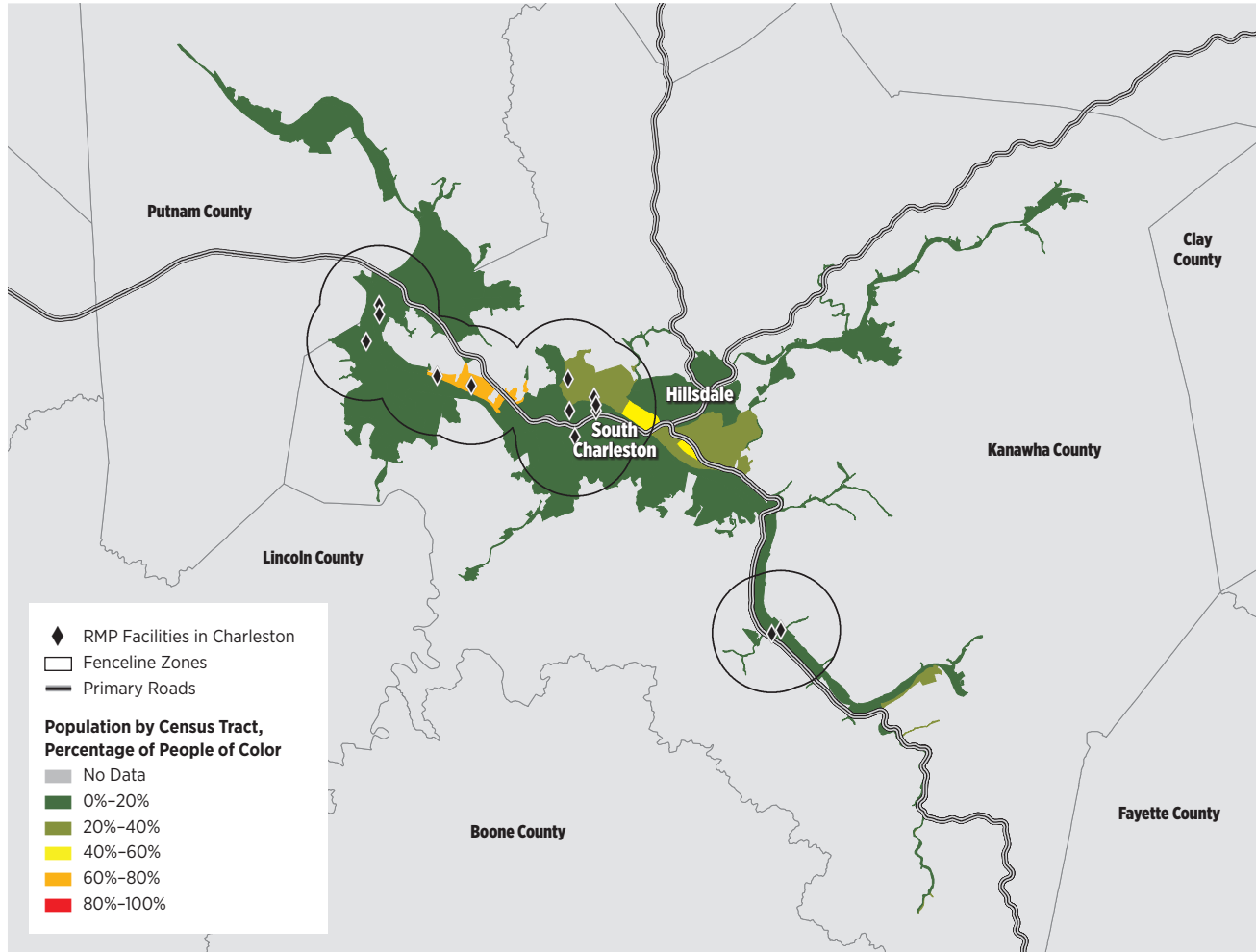


**70% OF THE POPULATION OF**  
the Charleston Urban Area lives within  
3 miles of an RMP facility.

Left: This rail car at the Axiall chemical facility in New Martinsville, WV released 90 tons of toxic chlorine gas in 2016.

## Hazardous Facilities and Race in Charleston

For additional maps and other information about Charleston, visit <https://ej4all.org/life-at-the-fenceline>.



## Charleston Data Summary

	Charleston Totals	Charleston 3 Mile Totals	Charleston 3 Mile LILA* Totals
<b>Weighted Cancer</b>	50.83	52.04	54.01
<b>Weighted RHI</b>	2.39	2.26	2.40
<b>Percent Black</b>	6.0%	6.3%	10.0%
<b>Percent Hispanic</b>	1.1%	0.9%	0.9%
<b>Percent White</b>	86.5%	86.8%	80.1%
<b>Percent Children</b>	19.7%	20.5%	19.9%
<b>Percent Poverty</b>	15.7%	15.6%	22.5%
<b>Average Household Income</b>	\$65,555	\$61,227	\$47,166
<b>Average Home Value</b>	\$145,940	\$132,790	\$97,039
<b>Percent HS Graduate or Less</b>	41.7%	43.6%	52.8%
<b>Percent College Degree or More</b>	26.7%	25.3%	16.2%

\* LILA—Areas with Low-Income populations with Low Access to healthy foods (see Box 2 on p.13).

Note: Highlighted numbers indicate a substantial difference from the full city or county, and the full 3-mile areas data.



## CHAPTER FOUR

# CONCLUSIONS

**T**he findings of this report demonstrate that the health and safety of communities closest to some of the nation's most dangerous industrial and commercial facilities are at risk from multiple threats, including potential chemical releases or explosions, daily exposure to toxic air pollution, and poor nutrition from a lack of access to healthy foods (along with other hazards and impacts not specifically studied here). The population of these “fenceline” areas is disproportionately Black, Latino, and living in poverty. Many of these communities also rely heavily, or solely, on dollar stores for household necessities and in some cases food, making these retailers potential sources of either additional toxic exposures or safer products and healthier foods (depending on the corporate policies they implement or fail to adopt).

**All of the areas researched for this report face serious health risks from hazardous chemical facilities, toxic air pollution, and lack of access to healthy food.** The 9 cities or counties researched for this report contain significant concentrations of industrial and commercial facilities that use or store highly hazardous chemicals, creating the constant threat of a catastrophic chemical release or explosion. The risk of cancer from toxic air pollution is greater than the national rate in all 9 areas, and the potential for respiratory illness from air pollution is substantial in all 9 areas. The percentage of city or county residents living in Low-Income areas that also have Low Access to healthy foods (LILA areas) is higher than for the US as a whole in all 9 areas, and is twice as high or greater in 5 of the 9 areas.

**Fenceline zones around hazardous facilities in these areas are disproportionately Black, Latino, and impoverished.** The percentage of Blacks or Latinos living within 3 miles of an RMP facility was higher than for the entire area in every study area, and often much higher than for the US as a whole. In 7 of the 9 areas researched, the

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### THE FINDINGS OF THIS REPORT

demonstrate that the health and safety of communities closest to some of the nation's most dangerous industrial and commercial facilities are at risk from multiple threats, including potential chemical releases or explosions, daily exposure to toxic air pollution, and poor nutrition from a lack of access to healthy foods.

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percentage of people living in poverty within 3 miles of an RMP facility is higher than for those living in poverty in the entire area, and often much higher than for the US as a whole.

**People living in hazardous facility fenceline zones face multiple health hazards and risks.** In 7 of the 9 areas researched for this report, two-thirds or more of the population live in fenceline zones around highly hazardous industrial or commercial facilities (much higher than the national rate of 39%). In all of the areas researched for this report, fenceline zones face higher risk of cancer from toxic air pollution than the entire city or county, and in 8 of the 9 areas the potential for respiratory illness is higher in fenceline zones. From 26% to 54% of the population of fenceline zones also live in low-income/low food access areas (compared to only 18% of the US population).

**Some neighborhoods are even more heavily and disproportionately impacted.** In 8 of the 9 areas studied, 71% to 100% of people who live in low-income areas that also have low access to healthy foods also live within a

hazardous facility fenceline zone. In every area studied, low-income/low food access areas within fenceline zones have higher poverty rates, greater percentages of residents who are people of color, and higher cancer risks and potential for respiratory illnesses from toxic air pollution than for the whole fenceline zones or the entire city or county, often much higher.

**Action to address these hazards is urgently needed.**

Significant and rapid improvements in public laws and regulations at the national, state, and municipal levels, and in corporate policies and practices, are urgently needed to protect the health and wellbeing of at-risk communities in the 9 areas we researched and elsewhere. The commonsense solutions identified below can address the cumulative health and safety risks to fenceline communities discussed in this report, including chemical facility disasters, chronic exposure to toxic air pollution, and toxic chemicals in household products.

**RECOMMENDATIONS AND SOLUTIONS**

The first four recommendations and proposed solutions that follow aim to improve the safety of high-risk industrial facilities, expand communities' access to information

about the hazards posed by nearby facilities, and improve community preparedness for responding to a toxic chemical release. They may have the additional benefit of reducing the daily load of toxic air pollution that affects these communities. The last three recommendations and proposed solutions address both the acute risks from unplanned chemical releases and the risks from daily chronic exposure to toxic air pollution, as well as exposure to toxic chemicals from dollar store products.

**1. Ensure that facilities that use or store hazardous chemicals adopt safer chemicals and processes.**

Switching to inherently safer chemicals and technologies—which removes underlying hazards—is the most effective way to prevent deaths and injuries from chemical disasters (as well as eliminate ongoing emissions of the replaced chemicals). Companies should seek out and adopt safer alternatives when possible. Government at all levels should require hazardous industrial and commercial facilities to assess whether they could use safer chemicals or processes, and adopt them whenever feasible, using the methods and systems already widely available.



Los Jardines Institute supports community gardens and other solutions to health and environmental hazards in Albuquerque.

2. **Ensure that facilities share information on hazards and solutions, and emergency response plans, with fenceline communities and workers.** Facility employees and fenceline communities can only participate effectively in their own protection if they have full access to information and meaningful access to decision-making processes. Federal, state, and local authorities should ensure that communities have access to information on hazards and emergency planning conducted under federal and state programs, and that they have information on facility hazards submitted to states under the Emergency Planning and Community Right-to-Know Act. Local residents, trained health care professionals, emergency responders, and health-care providers need this information to prepare for and effectively respond to chemical releases and explosions. Communities should be included in emergency response planning and implementation.
3. **Require large chemical facilities to continuously monitor, report and reduce their fenceline-area emissions and health hazards.** Unplanned, smaller releases of toxic chemicals often precede more serious incidents at chemical facilities and may themselves directly impact the health of people living in nearby communities. Fenceline community residents should be able to easily access information (based on continuous monitoring that is independently validated) on emissions coming from facilities that use or release hazardous chemicals, along with information about the chemicals' health hazards, and be easily able to participate in and act on response measures. The EPA should expand current requirements for benzene monitoring by oil refineries to include other toxic air pollutants and require air emissions monitoring at other types of major industrial facilities. This information will allow communities to understand hazards and participate in shaping solutions.
4. **Prevent the construction of new or expanded chemical facilities near homes and schools, or the siting of new homes and schools near facilities that use or store hazardous chemicals.** The siting of new facilities that use or store hazardous chemicals, or expansion of existing ones, near homes, schools, or playgrounds significantly increases the possibility that an unplanned chemical release will result in a disaster. Similarly, new homes, schools, and playgrounds should not be sited near hazardous facilities. Municipal authorities should

adopt and enforce local ordinances that require an assessment of the potential health and safety risks when siting homes, schools, and other public facilities. Authorities at all levels should reject new or expansion requests whenever there will not be an adequate safety buffer zone between the facility and homes, schools, or playgrounds. Requiring a buffer zone between these areas and polluting sources may also reduce residents' daily exposure to toxic chemical pollution.

5. **Require publicly accessible, formal health-impact assessments and mitigation plans to gauge the cumulative impact of hazardous chemical exposures on fenceline communities.** Federal and state agencies should assess the potential impact of unplanned chemical releases and the cumulative impacts of daily air-pollution exposures on the health of fenceline communities. Agencies and elected officials should provide affected communities with the tools and resources they need to fully engage in the assessment process, and the EPA should review hazard assessments of these communities. Permits for ongoing emissions should be strengthened where necessary to account for the cumulative impact of air pollution emissions from multiple sources on fenceline communities, and emissions limits should fully protect public health, including especially vulnerable populations such as the elderly, children, people with disabilities, and people with existing health conditions.

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## FEDERAL AND STATE AGENCIES

should assess the potential impact of unplanned chemical releases and the cumulative impacts of daily air-pollution exposures on the health of fenceline communities. Agencies and elected officials should provide affected communities with the tools and resources they need to fully engage in the assessment process, and the EPA should review hazard assessments of these communities.

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Communities like Houston (pictured above) face multiple health and environmental hazards and need solutions.

6. **Strengthen the enforcement of existing environmental and workplace health and safety regulations.** Congress should increase funding to the EPA, the Occupational Health and Safety Administration (OSHA), and the states for expanding inspections and improving the enforcement of environmental and workplace health and safety laws, so that problems in chemical facilities can be identified before they lead to disasters. Better oversight and enforcement will also help agencies and the public hold companies accountable if they fail to address identified hazards and emissions of toxic pollution. Communities that face some of the greatest threats from chemical facility incidents, toxic air pollution and contaminated sites need strong governmental policies to protect them, including strict permitting requirements and reliable inspection and enforcement of these requirements. If state and municipal governments are not providing adequate protection, it is essential that the EPA engage to defend these communities' right to a safe environment.
7. **Dollar store chains should develop and implement broad policies to identify and remove hazardous chemicals from the products they sell, stock fresh**

**and healthy foods, and source safer products and foods locally and regionally.** Given their presence in many communities of color and low-income fenceline communities, the largest dollar store chains are in a unique position to benefit the health and welfare of these communities where they operate, while growing and benefiting their own businesses, by providing safer products and healthier foods. Dollar Tree should fully disclose, and publicly report progress on, its positive action already underway to phase out seventeen toxic chemicals by 2020.<sup>65</sup> All the dollar store chains should adopt broad and transparent chemical management policies (including public reporting and continuous improvement) to identify and remove hazardous chemicals from all products in their stores, beginning with their house brands, and stock healthier foods including more fresh produce. They should source safer products and healthier foods locally and regionally whenever possible, to reduce climate change impacts from long-distance transportation, and to support the communities in which their stores operate. Agencies at all levels of government should ensure that discount retailers comply with all relevant laws and regulations, and provide technical assistance to support these transitions.

## APPENDIX A METHODOLOGY

### DATA COLLECTION & MAPPING

The demographic data were obtained from the US Census Bureau's American Community Survey (ACS). The Census Bureau's advanced American FactFinder interface (Census Bureau 2011-2015, <https://factfinder.census.gov/faces/nav/jsf/pages/index.xhtml>) was used to create tables of the data at the census tract level. This database is updated annually and summarized into one, three and five year spans. Per the recommendation of the Census Bureau (<https://www.census.gov/programs-surveys/acs/guidance/estimates.html>), the most recent 5-year span, 2011–2015, was selected.

Publicly available data from the Environmental Protection Agency's (EPA) Risk Management Program (RMP) as provided by the Right-to-Know Network (<http://rtk.net>) were used to determine the location of RMP facilities. Facilities were located based on their self-reported latitude/longitude codes. All other information about the facilities (e.g. number of accidents, number of injuries) was also obtained from the Right-to-Know Network's database and is self-reported by the facilities to EPA.

2011 National Air Toxics Assessment (NATA) cancer risk and respiratory hazard index data, as well as specific pollutant data, were obtained from the EPA's NATA website using the census tract identification <https://www.epa.gov/national-air-toxics-assessment/2011-nata-assessment-results>). See below for a more detailed explanation of this data.

The location of discount retail stores (which are primarily operated by Dollar General and Dollar Tree (which also owns Family Dollar), referred to as “dollar stores” in the report, was purchased from AggData ([www.aggdata.com](http://www.aggdata.com)).

Low Income and Low Access (LILA) to healthy food data were obtained from the US Department of Agriculture's Economic Research Database (<https://www.ers.usda.gov/data-products/food-access-research-atlas/download-the-data>). 2011 data, the most recent version available at the time the data was accessed, was selected.

Medical facilities data were obtained from the Medicare.gov website ([www.medicare.gov](http://www.medicare.gov)).

Public and private school data were downloaded from the US Department of Education National Center for Education Statistics (NCES) (<https://nces.ed.gov/ccd/pubsc-huniv.asp> public school data-national and <https://nces.ed.gov/ccd/elsi/tableGenerator.aspx> private school data-national). The most recent data (2014-2015 school year for the public school data, 2011-2012 school year for the private school data) was selected for both datasets.

All boundaries were mapped using publicly available TIGER line files (2016) from the Census Bureau (<https://www.census.gov/geol/maps-data/data/tiger-cart-boundary.html>).

### DEMOGRAPHIC CALCULATIONS AND DATA ON HEALTH RISKS AND HAZARDS

Demographics from the ACS for the census tracts were used as presented by Census. All NATA data were used as provided by EPA without further calculations.

We obtained cancer risk and respiratory hazard index data, as well as data on specific pollutants, from the 2011 National Air Toxics Assessment (NATA) using the census tract identification (EPA 2015). The 2011 NATA data, released in 2015, are the most recent available.

The NATA was developed primarily as a tool to inform both national and more localized efforts to collect air toxics information and characterize emissions (e.g., to prioritize pollutants or geographical areas of interest for more-refined data collection such as monitoring). The 2011 NATA dataset is based on data for 140 toxic air pollutants from a broad spectrum of sources including large industrial facilities, such as refineries and power plants, and smaller sources, such as gas stations, oil and gas wells, and chrome-plating operations. Other pollution sources include cars, trucks, and off-road sources such as construction equipment and trains, as well as pollution formed by chemical reactions of these emissions in the atmosphere. The numbers calculated by the EPA are intended to reflect toxic air pollution-related health hazards that are, in principle, controllable through better management practices by emitters.

#### ***What the Numbers Mean: How Cancer Risk and Respiratory Health Hazards Were Calculated***

The EPA calculates the amount of toxic air pollution faced by people at the census-tract level and uses health benchmarks to estimate cancer risks and the potential for respiratory health hazards from the combined effect of those exposures. Health risks and health hazards are distinct measures (see below), but both reflect the negative impacts on communities from exposure to toxic industrial facilities located near schools and homes.

The EPA generates data on the health risks from toxic air pollution using emission reports from industry and pollution dispersion models, combined with data from a limited number of pollution-monitoring stations. **Cancer risks** are expressed as the projected number of air pollution-related cancers per million people based on a 70-year lifetime of exposure. The EPA estimates that the national average risk of cancer from a lifetime of exposure to toxic air pollution at 2011 levels is 40 cancers per million people (EPA, n.d.). For comparison, when the EPA sets national toxic air pollution standards for industrial sources, its cancer risk target for the general population is one in one million (EPA 1999).

The **respiratory hazard index**, in contrast, does not speak to a direct effect on human health but rather is a measure of the amount of the hazardous substance in the environment (which, of course, has important effects on human health) compared to a health metric. The respiratory hazard index is the ratio of existing pollutant levels to levels established by the EPA as not likely to cause non-cancer respiratory illnesses based on a lifetime of exposure. If an existing pollutant level is the same as the non-concerning benchmark, the ratio is 1. An index value greater than 1 indicates the potential for adverse respiratory health impacts, with increasing concern as the value increases above 1.

Both health measures are based on a combination of monitored and modeled data and thus are estimates of average risks and hazards affecting a community rather than exact risks or hazards for a particular person. The lower the cancer risk and respiratory hazard index values, the lower the overall cancer risk and potential for respiratory illness. However, many other factors determine any given person's health; therefore, even relatively low values must be considered with caution.

#### ***Additional Risks Not Captured in This Analysis***

NATA's estimates include only chronic cancer risks for air toxics that the EPA is currently able to identify and quantify. Therefore, these risk estimates represent only a subset of the total potential cancer risk associated with air toxics exposures. Importantly, these risk estimates do not consider additional exposure pathways such as ingestion of toxic chemicals from foods or water, or breathing toxic air pollution from indoor sources, nor do they take into account the potential for combined or synergistic impacts from exposure to multiple chemicals. In addition, while the NATA risk data are based on exposure to outdoor air pollution, urban outdoor air pollution can also be an important contributor to indoor air quality, especially in highly ventilated homes or in homes near pollution sources (World Health Organization, [http://www.who.int/phe/health\\_topics/outdoorair/databases/background\\_information/en](http://www.who.int/phe/health_topics/outdoorair/databases/background_information/en)).

## APPENDIX B

# SUMMARY DATA TABLES

	Albuquerque Totals/ 3 miles/3 miles LILA	Charleston Totals/ 3 miles/3 miles LILA	Dallas Totals/ 3 miles/3 miles LILA	Houston Totals/ 3 miles/3 miles LILA
<b>Weighted RHI</b>	1.74/1.86/2.17	2.39/2.26/2.40	2.37/2.40/2.48	2.09/2.13/2.29
<b>Weighted Cancer</b>	38.25/39.45/41.91	50.83/52.04/54.01	46.25/46.58/47.67	44.74/45.57/47.26
<b>% Poverty</b>	18.4/18.4/28.0	15.7/15.6/22.5	16.3/17.7/27.2	17.2/18.4/28.5
<b>% White</b>	41.5/40.1/26.3	86.5/86.8/80.1	42.4/40.8/22.5	32.9/30.6/12.1
<b>% Black</b>	2.6/2.5/2.9	6.0/6.3/10.0	17.3/16.5/21.7	18.6/19.5/25.5
<b>% Hispanic</b>	48.4/50.1/64.0	1.1/0.9/0.9	31.5/34.7/51.0	39.0/40.2/56.1
<b>% Children</b>	23.3/23.0/24.3	19.7/20.5/19.9	26.9/26.9/29.4	27.1/26.7/28.8
<b>Avg Home Value</b>	209,745/219,400/ 150,054	145,940/132,790/ 97,039	204,060/189,682/ 114,414	197,888/201,040/ 105,512
<b>Avg Household Income</b>	65,170/65,970/47,908	65,555/61,227/47,166	80,130/74,771/49,036	82,920/80,522/48,832
<b>% HS or Less</b>	36.2/37.4/50.2	41.7/43.6/52.8	39.5/42.6/60.7	42.1/43.2/61.6
<b>% 4 Year or More Degree</b>	29.4/29.6/18.9	26.7/25.3/16.2	30.6/28.1/14.4	28.8/28.1/13.9

	Fresno Totals/ 3 miles/ 3 miles LILA	Kern Totals/ 3 miles/ 3 miles LILA	Madera Totals/ 3 miles/ 3 miles LILA	Los Angeles Totals/3 miles/ 3 miles LILA	Louisville Totals/ 3 miles/3 miles LILA
<b>Weighted RHI</b>	2.06/2.19/2.37	1.91/2.07/2.24	1.56/2.07/2.11	2.59/2.63/2.83	2.26/2.37/2.46
<b>Weighted Cancer</b>	48.62/50.57/52.02	45.69/48.20/49.60	46.37/56.32/57.27	50.17/50.22/52.06	47.35/48.85/50.86
<b>% Poverty</b>	27.6/29.4/37.8	23.4/24.7/34.1	22.3/28.6/35.2	17.6/18.6/24.8	16.0/19.6/31.1
<b>% White</b>	31.3/27.8/17.9	37.1/34.1/23.5	38.3/22.5/17.0	27.9/23.4/11.0	72.8/67.5/49.1
<b>% Black</b>	4.8/4.9/6.2	5.3/6.0/5.8	3.3/2.8/2.5	6.6/6.8/9.5	17.8/22.5/39.3
<b>% Hispanic</b>	51.7/54.2/63.4	50.6/52.6/65.3	52.8/70.0/75.8	47.3/52.4/67.4	4.5/4.8/6.1
<b>% Children</b>	29.0/29.8/31.6	29.3/29.9/32.6	27.4/32.1/34.5	23.1/24.0/26.9	22.6/22.3/23.9
<b>Avg Home Value</b>	221,576/206,867/ 155,918	188,274/183,073/ 136,360	242,651/186,986/ 154,031	550,046/475,194/ 314,249	181,660/170,253/ 103,050
<b>Avg Household Income</b>	62,411/59,806/ 44,332	65,432/63,516/ 46,082	63,832/52,779/ 42,043	83,392/76,452/ 53,876	66,720/60,889/ 39,452
<b>% HS or Less</b>	49.9/51.9/62.8	53.5/54.0/65.8	51.7/63.0/71.2	43.1/47.4/61.2	40.8/43.1/54.4
<b>% 4 Year or More Degree</b>	17.6/16.6/9.0	14.1/13.8/7.3	14.4/9.3/6.0	28.0/24.1/13.7	26.8/24.8/13.9

**City/County Totals:** Result for the entire city or county.

**3 miles:** The Fenceline Zones within 3 miles of an RMP facility.

**3 miles LILA:** Low Income and Low Access to food areas within Fenceline Zones.

See Appendix A for explanations of RHI (Respiratory Hazard Index) and Cancer Risk.



## APPENDIX C

### LOCAL ORGANIZATIONS IN STUDY AREAS

**T**hese member organizations of the Environmental Justice Health Alliance for Chemical Policy Reform work to address the problems documented in this report in their communities, and implement safe, just, and sustainable solutions. You can also learn more about these and other members of EJHA at [www.EJ4All.org](http://www.EJ4All.org).

In Albuquerque, NM, **Los Jardines Institute** (The Gardens Institute) works to build and support healthy and sustainable communities and spaces by providing opportunities that promote multi-generational, community-based models of learning, sharing, and building community. <https://www.losjardines.org>

In Charleston, WV, **People Concerned About Chemical Safety** (PCACS) promotes international human rights pertaining to environmental and chemical safety through education and advocacy, and serves as a watchdog to ensure existing chemical safety laws are upheld by facilities in our communities. <http://peopleconcernedaboutmic.com>

In Fresno County, Kern County, and Madera County, CA, **Lideres Campesinas** works to develop leadership among campesinas so that they serve as agents of political, social and economic change in the farmworker community. [www.liderescampesinas.org](http://www.liderescampesinas.org)

In Houston, TX, **Texas Environmental Justice Advocacy Services** (t.e.j.a.s.) works to promote environmental protection through education, policy development, community awareness, and legal action. Its guiding principle is that everyone, regardless of race or income, is entitled to live in a clean environment. [www.tejasbarrios.org](http://www.tejasbarrios.org)

In Los Angeles, CA, **Physicians for Social Responsibility** (PSR-LA), a physician and health advocate membership organization, works to protect public health from environmental toxins and nuclear threats. It brings the voices of health experts to the forefront of critical policy discussions, and works alongside health professionals, advocates, and policymakers to create solutions that improve the health and environment for all Californians. <http://www.psr-la.org>

In Louisville, KY, **Rubbertown Emergency Action** (REACT) works for strong laws to stop toxic air pollution from chemical plants; the protection of residents in the event of a leak, fire or explosion in a chemical plant or railcar, and full disclosure and easy access to information concerning the impact of hazardous facilities on residents living nearby. On Facebook as *REACT Rubbertown Emergency ACTION* at <https://www.facebook.com/groups/317041690234>.



## APPENDIX D

# GLOSSARY OF TERMS AND ABBREVIATIONS

### Fenceline Zone

In this report, fenceline zones are a 3-mile radius around RMP facilities (see more on RMP below), in which those affected are at most risk from a chemical release or explosion and least likely to be able to escape from a toxic or flammable chemical emergency, but not representing the outer bounds of potential harm. For example, while the fenceline zone around a facility is 3 miles in radius, the full vulnerability zone for a worst-case chemical release may be as large as 25 miles in radius. See Figure 3 on page 11 for a graphic representation of a sample vulnerability zone and fenceline zone.

### Hazardous Facility or High-Risk Facility

In this report, hazardous facility or high-risk facility refers to Risk Management Plan (RMP) facilities, which are defined below. Only facilities that use or store significant quantities of specific highly toxic or flammable chemicals are part of the US Environmental Protection Agency's RMP program. Many different types of industrial and commercial facilities—ranging from chemical manufacturing plants, oil refineries, and paper mills, to water treatment plants, food manufacturing and storage facilities, fertilizer distributors, and more—are included in the RMP program, which currently covers approximately 12,500 facilities. A worst-case chemical release at many of these facilities could endanger several million people over a radius as great as twenty-five miles.

### LILA Area

LILA stands for Low Income and Low Access to healthy foods. As the term is used by the US Department of Agriculture, and as we have used it in the research and findings for this report, low-income areas have poverty rates of 20% or greater (or meet other criteria), and low access to healthy food means being far from a supermarket, supercenter, or large grocery store. More background on LILA areas can be found at <https://www.ers.usda.gov/data-products/food-access-research-atlas/documentation>.

### RMP

RMP refers to Risk Management Plan, a plan prepared under the chemical incident prevention provisions of the Clean Air Act, section 112(r), and submitted to the US Environmental Protection Agency by a facility that produces, handles, processes, distributes, or stores more than a threshold amount of certain extremely hazardous substances (77 toxic or 63 flammable chemicals).

### Vulnerability Zone

An estimate made by a facility under EPA's Risk Management Plan program of the maximum possible area where people could be harmed by a worst-case release of certain toxic or flammable chemicals. The vulnerability zone is a radius (or circle) distance around the facility, of—for example—one mile, five miles, or 20 miles in all directions.

### Worst-Case Scenario

An estimate made by a facility under EPA's Risk Management Plan program of the largest potential chemical release from a single vessel or process under conditions that result in the maximum possible affected area.

## APPENDIX E

### ONLINE RESOURCES

*Many additional resources—including additional maps, community fact sheets, and data—are available on the Life at the Fenceline project home page at [www.ej4all.org/life-at-the-fenceline](http://www.ej4all.org/life-at-the-fenceline).*

The project pages online include:

- This full report
- Fact sheets about the study areas with more maps and information
- An interactive map of the US and all nine study areas
- Additional resources and data

#### *Other resources on chemical facility hazards and disproportionate impacts*

*Who's in Danger: Race, Poverty, and Chemical Disasters* (Environmental Justice Health Alliance for Chemical Policy Reform, May 2014) <https://comingcleaninc.org/whats-new/whos-in-danger-report>

*Living in the Shadow of Danger: Poverty, Race, and Unequal Chemical Facility Hazards* (Center for Effective Government, January 2016)

- Full report: <https://www.foreffectivegov.org/shadow-of-danger>
- State scorecards: <https://www.foreffectivegov.org/shadow-of-danger-factsheets>

*Blowing Smoke: Chemical Companies Say “Trust Us,” But Environmental and Workplace Safety Violations Belie Their Rhetoric* (Center for Effective Government, October 2015) <https://www.foreffectivegov.org/blowing-smoke>

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# LIFE AT THE FENCELINE

## Understanding Cumulative Health Hazards in Environmental Justice Communities



Across the United States, the health and safety of people who live, work, play, and learn near thousands of industrial and commercial facilities that use or store extremely dangerous chemicals is at risk of a major chemical release or explosion at any time. New research presented in this report studied who lives in the “fenceline” zones nearest high-risk facilities in nine Environmental Justice communities, what are the cancer risks and respiratory hazard from toxic air pollution in these areas, whether these communities have access to healthy foods, and where critical institutions (schools, hospitals, and dollar stores) are located.

The results find that the health and safety of communities closest to some of the nation’s most dangerous industrial and commercial facilities are at risk from multiple threats, including potential chemical releases or explosions, daily exposure to toxic air pollution, and poor nutrition from a lack of access to healthy foods (along with other hazards and impacts not specifically studied here). The population of these fenceline areas is disproportionately Black, Latino, and living in poverty. Many of these communities also rely heavily, or solely, on dollar stores for household necessities and in some cases food, making these retailers potential sources of either additional toxic exposures or safer products and healthier foods (depending on the corporate policies they implement or fail to adopt).

[WWW.EJ4ALL.ORG/LIFE-AT-THE-FENCELINE](http://WWW.EJ4ALL.ORG/LIFE-AT-THE-FENCELINE)

28 VERNON STREET, SUITE 434, BRATTLEBORO, VT 05301



# Exhibit 4

## Curriculum Vitae

**Vicki Stamper**

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Boise, Idaho 83707

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(208) 336-3947

### Areas of Expertise

***Comprehensive knowledge of the Clean Air Act*** - accomplished in the requirements for new source review (NSR) and prevention of significant deterioration (PSD) construction permits including review of Best Available Control Technology (BACT) determinations, Title V operating permits, Maximum Achievable Control Technology (MACT) Approvals, Class I area protection including regional haze plans and best available retrofit technology (BART) determinations, and state implementation plans for compliance with the national ambient air quality standards (NAAQS).

***Extensive experience with the air pollution issues related to fossil fuel-fired power plants*** – have evaluated numerous NSR and PSD air permit applications, best available control technology determinations, and best available retrofit technology determinations for the fossil fuel-fired electric utility industry.

### Professional Experience

Air Quality Consultant

Boise, ID 83707

April 2003 to

Present

I provide consulting services on numerous air quality issues such as:

- Reviewing/preparing comments on all aspects of air quality construction and operating permit applications and permits for various industrial sources.
- Providing technical expertise for the appeal of air quality permits that do not comply with federal or state clean air requirements.
- Investigating facility compliance with federal and state air quality regulations.
- Analyzing proposed or available mercury and other hazardous air pollutant controls for coal-fired power plants.
- Reviewing and commenting on Class I regional haze and visibility protection plans.
- Evaluating proposed best available retrofit technology determinations.
- Critiquing prevention of significant deterioration increment analyses.
- Evaluating and commenting on air quality analyses and environmental impact statements for proposed oil and gas development in the West.

## **Professional Experience (continued)**

### Environmental Engineer/Legal Assistant

Reed Zars, Attorney at Law  
Laramie, WY 82070

May 2001 to  
April 2003

#### *Responsibilities included:*

- Investigating industrial facilities' compliance with Clean Air Act requirements through review of public documents.
- Researching pollution reduction measures and effectiveness.
- Preparing comments on proposed air quality construction and operating permits
- Reviewing and preparing written comments on proposed EPA state implementation plan approvals regarding topics such as opacity regulations, emission limit exemptions, Class I area visibility plans and permitting regulations.

### New Source Review Program Manager

Air and Radiation Program  
U.S. Environmental Protection Agency, Region VIII  
Denver, Colorado 80202

December 1990  
to April 2001

#### *Responsibilities included:*

- Serving as the Region VIII lead for state rules regarding the new source review and prevention of significant deterioration programs, as well as other industrial source control measures.
- Reviewing all aspects of prevention of significant deterioration increment analyses.
- Reviewing state implementation plans for consistency with requirements of Clean Air Act.
- Preparing documents to justify EPA approval or disapproval of state submittals.
- Educating and assisting tribes in developing regulations for tribal implementation plans.
- Participating in workgroups to ensure national consistency and provide input on rulemakings.
- Reviewing state operating permit programs under Title V of the Clean Air Act.
- Researching and compiling the EPA-approved state implementation plans.
- Developing and reviewing state implementation plans for particulate matter nonattainment areas, as well as assisting in the preparation of requests to redesignate to attainment.
- Reviewing environmental impact statements for consistency with the Clean Air Act.
- Serving as primary contact for air quality issues in the state of Wyoming.

## **Professional Experience (continued)**

Environmental Engineer  
Envirometrics, Inc.  
Seattle, Washington 98103

August 1989-  
July 1990

### *Responsibilities included:*

- Designing components of research projects pertaining to pollution control systems.
- Developing testing criteria and measuring the effectiveness of these control systems.
- Preparing air pollution permit applications and related documentation for industrial sources.
- Compiling input data for modeling of ambient air quality impacts on Class I areas.
- Developing emission inventories.

## **Education**

Bachelor of Science Degree  
Civil Engineering, Michigan State University  
East Lansing, Michigan

## **Selected Reports and Papers**

- Stamper, V. & Megan Williams, Assessment of Cost Effectiveness Analyses for Controls Evaluated in Four-Factor Analyses for Oil and Gas Facilities for the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period, Prepared for National Parks Conservation Association, July 2, 2020.
- Stamper, V. & Megan Williams, Oil and Gas Sector, Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Engines, Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration; Prepared for National Parks Conservation Association, March 6, 2020
- Stamper, V., Technical Support Document to Comments of Conservation Organizations; Proposed Revisions to Arkansas Regional Haze State Implementation Plan, February 1, 2018.
- Stamper, V., Technical Support Document to Comments of Conservation Organizations; EPA Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Texas, May 3, 2017.
- Stamper, V., Technical Support Document in Support of NPCA and RE Comments on PSD Permit No. 16-0, BP West Coast Products LLC Cherry Point Refinery, December 15, 2016.

## Selected Reports and Papers (continued)

- Stamper, V., Technical Support Document to Comments of Conservation Organizations; EPA's Proposed Rulemaking Regarding Utah's Regional Haze Plan, March 14, 2016.
- Stamper, V., Technical Support Document to Comments of Conservation Organizations; EPA's Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, August 5, 2015.
- Stamper, V., Technical Support Document to Comments of Conservation Organizations; EPA's Proposed Reasonable Progress Measures for Texas and Oklahoma, April 27, 2015.
- Stamper, V., Technical Support Document to Comments of Conservation Organizations, Proposed Federal Implementation Plan to Address Regional Haze Requirements for Navajo Generating Station Units 1, 2 and 3, December 30, 2013.
- Stamper, V., Technical Support Document to Comments of Conservation Organizations, EPA's Proposed Action on Wyoming Regional Haze, August 21, 2013.
- Stamper, V., Technical Support Document to Comments of Conservation Organizations; Proposed Wyoming Regional Haze Partial SIP Approval and Partial FIP, August 1, 2012.
- Stamper, V., C. Copeland, M. Williams, and T. Spencer (contributing editor), *Poisoning the Great Lakes: Mercury Emissions from Coal-Fired Power Plants in the Great Lakes Region*, Natural Resources Defense Council Publication, June 2012.
- Fox, Phyllis and V. Stamper, Technical Support Document to Comments of Conservation Organizations: Proposed Montana Regional Haze FIP, June 15, 2012.
- Stamper, V., Evaluation of Whether the SO<sub>2</sub> Backstop Trading Program Proposed by the States of New Mexico, Utah and Wyoming and Albuquerque-Bernalillo County Will Result in Lower SO<sub>2</sub> Emissions than Source-Specific BART, May 25, 2012.
- Technical Support Attachment to Comments of Conservation Organizations; Minnesota Regional Haze SIP Proposed Approval – February 21, 2012.
- Stamper, V. and C. Copeland, *Stop the Rollbacks, Cleaner, Healthier Air for Colorado*, Environmental Defense publication, 2005.
- Banerjee, S. and V. Stamper, *Mercury Air Pollution: The Case for Rigorous MACT Standards For Subbituminous Coal*, prepared for Rocky Mountain Office of Environmental Defense and the Land and Water Fund of the Rockies, May 2003.

# Exhibit 5



*Commonwealth of Virginia*

***VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY***

**BLUE RIDGE REGIONAL OFFICE**

901 Russell Drive, Salem, Virginia 24153

(540) 562-6700 FAX (540) 562-6725

[www.deq.virginia.gov](http://www.deq.virginia.gov)

Matthew J. Strickler  
Secretary of Natural Resources

David K. Paylor  
Director  
(804) 698-4000

Robert J. Weld  
Regional Director

January 28, 2020

Mr. Glen Jasek  
VP Operations, Eastern Interstates  
Williams  
2800 Post Oak Blvd., Suite 900  
Houston, TX 77056-6147

Location: Pittsylvania County  
Registration No.: 30864

Dear Mr. Jasek:

Attached is a permit to construct and operate a project at a compressor station in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution.

In the course of evaluating the application and arriving at a final decision to approve the Southeastern Trail project, the Department of Environmental Quality (DEQ) deemed the application complete on January 27, 2020.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to construct and operate shall not relieve Transco of the responsibility to comply with all other local, state, and federal permit regulations.

The proposed turbines are subject to 40 CFR 60, New Source Performance Standard (NSPS), Subparts KKKK and 40 CFR 63 Maximum Achievable Control Technology (MACT), Subpart YYYY. Virginia has accepted delegation of these rules. In summary, the units may be required to comply with certain federal emission standards and operating limitations. The Department of



Environmental Quality (DEQ) advises you to review these regulations to ensure compliance with applicable emission and operational limitations. As the owner/operator you are also responsible for any monitoring, notification, reporting and recordkeeping requirements of the NSPS and MACT. Notifications shall be sent to Virginia DEQ.

The facility has emission units that may be subject to the following regulations: 40 CFR 60 Subparts JJJJ, OOOOa and 40 CFR 63 Subpart ZZZZ. Virginia has not accepted delegation of these rules. In summary, the units may be required to comply with certain federal emission standards and operating limitations. The Department of Environmental Quality (DEQ) advises you to review these regulations to ensure compliance with applicable emission and operational limitations. As the owner/operator you are also responsible for any monitoring, notification, reporting and recordkeeping requirements of the NSPS and MACT. Notifications shall be sent to both EPA, Region III and Virginia DEQ.

To review any federal rules referenced in the above paragraph or in the attached permit, the US Government Publishing Office maintains the text of these rules at [www.ecfr.gov](http://www.ecfr.gov), Title 40, Part 60 and 63 as applicable.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director  
Department of Environmental Quality  
P. O. Box 1105  
Richmond, VA 23218

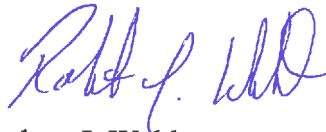
If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

A copy of the results of performance tests required by 40 CFR 60, Subparts KKKK shall to be sent to:

Associate Director  
Office of Air Enforcement and Compliance Assistance (3AP20)  
U.S. Environmental Protection Agency  
Region III  
1650 Arch Street  
Philadelphia, PA 19103-2029

If you have any questions concerning this permit, please contact Anita Walthall at (540)562-6769 or [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov).

Sincerely,



Robert J. Weld  
Regional Director

Attachments: Permit  
Source Testing Report Format

cc: Michael Callegari, Williams ([michael.c.callegari@williams.com](mailto:michael.c.callegari@williams.com))  
Mary Carder, ERM ([mary.carder@erm.com](mailto:mary.carder@erm.com))  
James Puckett, DEQ BRRO Air Compliance Inspector (electronic)



*Commonwealth of Virginia*

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Director  
(804) 698-4000

Robert J. Weld  
Regional Director

**STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE**

This permit includes designated equipment subject to  
New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia  
Regulations for the Control and Abatement of Air Pollution,

Transcontinental Gas Pipe Line Company, LLC  
2800 Post Oak Blvd., Suite 900  
Houston, TX 77056-6147  
Registration No.: 30864

is authorized to construct and operate

natural gas compressor station 165

located at

945 Transco Road in Chatham (Pittsylvania County), Virginia 24531

in accordance with the Conditions of this permit.

Approved on January 28, 2020.

A handwritten signature in blue ink, appearing to read "Robert J. Weld", written over a horizontal line.

Robert J. Weld  
Regional Director

Permit consists of 27 pages.

Permit Conditions 1 to 69.

Attachment - Source Testing Report Format, 1 page

## INTRODUCTION

This permit approval is based on the permit applications dated June 20, 2018, including supplemental information dated November 7, 2018, September 16, 2019, November 18, 2019, November 25, 2019, and January 27, 2020. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9VAC5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9VAC5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

**Equipment List** – Equipment at this facility covered by this permit consists of:

Equipment included in the project:

Reference No.	Equipment Description	Rated Capacity	Delegated Federal Requirements
TUR-05	Solar Titan Combustion Turbine Model 130-23502S	23,150 hp*	40 CFR 60, Subpart KKKK
TUR-06	Solar Titan Combustion Turbine Model 130-23502S	23,150 hp*	40 CFR 60, Subpart KKKK
AUX-04	Caterpillar G3512 Emergency Engine	1,468 hp (1000 kW)	---
FUGS	Fugitive natural gas leaks from fugitive emission components	---	---
M/L 11	Clark TCV-10 Compressor Engine	3,400 hp	---

\*Based on ambient temperature of 0°F and 100% operating load.

Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.

## PROCESS REQUIREMENTS

1. **Permanent Shutdown** – Upon start-up of either combustion turbine (TUR-05 or TUR-06) or (12) twelve months from the signature date of this permit, whichever occurs earlier, the ten (10) Clark TLA-6 reciprocating engines (M/L1 – M/L10) shall permanently cease operation. Restarting operation of M/L1 – M/L10 shall be considered equivalent to construction and operation of a new emissions unit and will be subject to the requirement to obtain a permit pursuant to the applicable provisions of 9VAC5 Chapter 80. The source may request an extension of the (12) twelve month time period by submitting the request the Blue Ridge Regional Office along with the justification for the extension within 30 days of the expiration of the time period.  
(9VAC5-20-220 and 9VAC5-80-1180)
2. **Emission Controls** – Nitrogen oxides (NO<sub>x</sub>) emissions from the combustion turbines (TUR-05, TUR-06) shall be controlled by dry low NO<sub>x</sub> (SoLoNO<sub>x</sub><sup>TM</sup>) combustion control technology and selective catalytic reduction (SCR). The SCR system shall be designed to reduce NO<sub>x</sub> emissions to an outlet concentration of 3.75 ppmvd as a 3-hour average when the compressor turbine's inlet air temperature is 0°F or greater. The SoLoNO<sub>x</sub><sup>TM</sup> technology shall be in operation at all times the respective combustion turbine is operating except during start-up and shutdown, as defined in Condition 5.
  - a. When a combustion turbine's inlet air temperature is less than 0°F, the SoLoNO<sub>x</sub><sup>TM</sup> technology must be operated to maximum extent possible, following the manufacturer's written protocol or best engineering practices for minimizing emissions. No compressor turbine shall operate below 50% load except during startup and shutdown.
  - b. Each combustion turbine shall be equipped with Pilot Active Control Logic (PACL) to minimize emissions when inlet air temperature is less than 0°F and the PACL shall be in operation when the respective combustion turbine is operating. Each SCR shall be in operation at all times the respective combustion turbine is operating, except during start-up and shutdown where operation shall be as described in Condition 5.e.  
(9VAC5-50-260 and 9VAC5-80-1180)
3. **Emission Controls** – Carbon Monoxide (CO) and Volatile Organic Compound (VOC) emissions from the combustion turbines (TUR-05, TUR-06) shall be controlled by an oxidation catalyst system. Each oxidation catalyst system shall be provided with adequate access for inspection and shall be in operation at all times the respective combustion turbine is operating, except during each unit start-up, as defined in Condition 5.  
(9VAC5-50-260 and 9VAC5-80-1180)
4. **Emission Controls** – Particulate emissions (PM, PM<sub>10</sub>, PM<sub>2.5</sub>) from the combustion turbines (TUR-05, TUR-06) shall be controlled by inlet air filters. Each filter shall be provided with adequate access for inspection and shall be in operation at all times the respective combustion turbine is operating.

(9VAC5-50-260<sup>1</sup> and 9VAC5-80-1180)

5. **Emission Controls** – The permittee shall operate and maintain each combustion turbine (TUR-05, TUR-06), all air pollution control equipment, and all monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during start-up, shutdown, and malfunction.
- a. For the purpose of this permit, start-up is defined as the period beginning with the first fuel fed to the combustion turbine and ending when the combustion turbine reaches 50% load.
  - b. For the purpose of this permit, shutdown is defined as the period beginning when the combustion turbine drops below 50% load for the purpose of ceasing operation and ends when fuel feeding stops.
  - c. For the purpose of this permit, an oxidation catalyst system shall be considered in operation when the catalyst bed inlet gas temperature is above 600°F or the minimum combustion chamber temperature derived from the most recent performance test that demonstrates compliance with this permit.
  - d. The oxidation catalyst system shall be in operation during the shutdown of the respective combustion turbine.
  - e. During start-up and shutdown, each combustion turbine SCR system (including ammonia injection) and oxidation catalyst system shall be operated in a manner to minimize emissions following the manufacturer's written protocol or best engineering practices for minimizing emissions. Written documentation shall be maintained explaining the sufficiency of the practices. If such practices are used in lieu of the manufacturer's protocol, the documentation shall justify why the practices are at least equivalent to manufacturer's protocols with respect to minimizing emissions.
  - f. Annual time in start-up of each combustion turbine shall not exceed 25 hours per year. Annual hours of start-up shall be calculated as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
  - g. Annual time in shutdown of each combustion turbine shall not exceed 25 hours per year. Annual hours of shutdown shall be calculated as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

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<sup>1</sup> 9VAC5-50-260 (BACT) applies to PM<sub>10</sub> and PM<sub>2.5</sub>.

- h. Each combustion turbine shall operate in “SoLoNOx mode” at all times except for start-up, shutdown, and when a combustion turbine’s inlet air temperature is less than 0°F. Operation not in “SoLoNOx mode” shall not exceed an annual total of 60 hours per combustion turbine, calculated as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

(9VAC5-50-260 and 9VAC5-80-1180)

- 6. **Emission Controls:** The emissions reduction requirements for the compressor engine (M/L 11) shall be met through engine combustion modifications (high pressure fuel injection).

(9VAC5-80-1180)

- 7. **Emission Controls** – Emissions from the emergency engine (AUX-04) shall be controlled by proper engine operation in accordance with the manufacturer’s written instructions, or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer in a manner consistent with good air pollution control practices for minimizing emissions.

(9VAC5-50-260 and 9VAC5-80-1180)

- 8. **Emission Controls** – The permittee shall implement the following work practices to reduce emissions from venting of natural gas from the facility.

- a. Emissions from each emergency shutdown (ESD) test shall be controlled by installation of a block valve directly following each ESD blowdown valve. The block valve shall be closed prior to initiating any ESD test and shall be opened only after the ESD blowdown valve has closed.
- b. Except as provided in Condition 8.f, the permittee shall control emissions from the shutdown of each combustion turbine by maintaining pressurized hold for the combustion turbine. Pressurized hold shall be achieved by maintaining sufficient differential pressure between the seal gas and combustion turbine case such that the dry seal maintains integrity for the entire duration of the shutdown. Sufficient differential pressure shall be determined for each combustion turbine during the tests required in Condition 44.
- c. Pig launching and recovery shall be limited to three events per 12-month period. Emissions from these events shall be limited to the gas contained in the pig launching or recovery chambers. The permittee shall have available written operating procedures to minimize emissions from pig launching and recovery. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.



- d. The permittee shall install a vent gas reduction system (VGRS) to ensure the sufficient differential pressure required in Condition 8.b is maintained. The VGRS shall be provided with adequate access for inspection and shall be in operation as necessary to ensure sufficient differential pressure between the seal gas and combustion turbine case such that the dry seal is maintained for the respective combustion turbine in compliance with Condition 8.f.
- e. The permittee shall continuously monitor and record the seal gas pressure and combustion turbine case pressure for each combustion turbine during pressurized holds.
- f. For each combustion turbine, the permittee shall vent gas no more than twelve (12) times per year, calculated monthly as the sum of each consecutive 12-month period. A combustion turbine may not vent gas unless the combustion turbine case pressure is less than or equal to 44.7 psia (30 psig). The permittee shall ensure isolation valves are closed and record the combustion turbine case pressure at the beginning of each combustion turbine shutdown venting event. The permittee shall minimize the amount of time for each combustion turbine start-up purge.

(9VAC5-50-260 and 9VAC5-80-1180)

9. **Emission Controls** – The permittee shall implement the following work practices to reduce emissions from leaks of natural gas from the facility.

- a. The permittee shall develop, maintain, and implement a fugitive emission component monitoring and repair plan. In developing this plan, the definition of “fugitive emissions component” shall be the same as contained in 40 CFR 60.5430a. This plan shall consist of a daily auditory/visual/olfactory (AVO) inspection program for all fugitive emissions components. The plan shall also consist of a quarterly leak detection survey. A leaking fugitive emissions component for the purpose of the quarterly survey shall be an instrument reading of 500 ppm or more using Method 21 or an optical gas imaging camera. The instrument utilized must be maintained, calibrated, and operated in accordance with Method 21 and the manufacturer’s specifications. The initial survey shall be conducted no later than 60 days after the facility start-up with subsequent surveys conducted no less frequently than every calendar quarter. Consecutive surveys shall be no less than 60 days apart.
- b. The first attempt to repair any fugitive emissions component found to be leaking during an AVO inspection or a quarterly survey shall be made as soon as practicable but no later than 3 days after discovery. The leaking fugitive emissions component shall be repaired within 15 days of discovery. The permittee shall maintain a list of difficult to repair fugitive emissions components, which when leaking, the repair requires facility shutdown or cannot otherwise be completed within 15 days of discovery; documentation justifying the inclusion of a fugitive emissions component on the list shall be included. If a leak is found that will emit more natural gas than the

required shutdown, the shutdown shall occur and the leak be repaired. If a leak is found that will emit less natural gas than a facility shutdown, repair may be delayed until the next facility shutdown unless the emissions from the total delayed repairs would exceed the emissions of the required shutdown. Records of the daily AVO inspection results, repair attempts, and the list of long-term leaking fugitive emissions components and reason for each delay shall be maintained on site.

- c. The monitoring plan shall be submitted to the Blue Ridge Regional Office for review and approval no later than 60 days prior to start-up of the facility.
- d. The fugitive emissions components on the VGRS shall be part of the daily AVO and quarterly leak detection survey.
- e. A summary of the results of the daily AVO and quarterly LDAR surveys shall be submitted with the quarterly reports required in Condition 51 detailing leaks detected, any corrective actions taken to address and minimize the leaks, and the dates of leak discovery and leak repair.

(9VAC5-50-260 and 9VAC5-80-1180)

10. **Monitoring Devices** – Each combustion turbine (TUR-05, TUR-06) shall be equipped with devices to continuously measure and record combustion turbine inlet air temperature, combustion turbine load, and “SoLoNOx” mode. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer’s written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the combustion turbine is operating.

(9VAC5-50-20 C and 9VAC5-80-1180)

11. **Monitoring Devices** – Each SCR system shall be equipped with devices to continuously measure and record ammonia injection rate, catalyst bed differential pressure, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer’s written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.

(9VAC5-50-20 C and 9VAC5-80-1180)

12. **Monitoring Devices** – Each combustion turbine shall be equipped with devices to continuously measure and record the seal gas pressure and the combustion turbine case pressure. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer’s written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation at all times.

(9VAC5-50-20 C and 9VAC5-80-1180)

13. **Monitoring Devices** – Each oxidation catalyst system shall be equipped with a device to continuously measure and record the gas temperature at the catalyst bed inlet and the catalyst bed differential pressure. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst system is operating.  
(9VAC5-50-20 C and 9VAC5-80-1180)
14. **Monitoring Device** – The emergency engine (AUX-04) shall be equipped with a non-resettable hour meter to continuously measure hours of operation. The monitoring device shall be installed, maintained, calibrated, and operated in accordance with approved procedures, which shall include, as a minimum, the manufacturer's written requirements or recommendations. The monitoring device shall be provided with adequate access for inspection and shall be in operation when the emergency engine is operating.  
(9VAC5-50-20 C and 9VAC5-80-1180)
15. **Monitoring Plan** – The permittee shall develop and operate in accordance with an approved monitoring plan for the monitoring devices identified in Conditions 10, 11, 12, and 13. The plan shall include ranges for each parameter. The range values shall be established during the initial performance tests required in Condition 35 and revalidated during the subsequent performance tests required in Condition 37. Ranges shall be 3-hour rolling averages. The monitoring plan shall be submitted to the Blue Ridge Regional Office with the test results as required in Condition 35.  
(9VAC5-50-20 C and 9VAC5-80-1180)
16. **Monitoring Device - A Parametric Monitoring Systems (PMS)** shall be installed on the compressor engine (M/L 11) to measure and record the operating performance indicators as analytical monitoring for NO<sub>x</sub> emissions. The PMS shall be installed, maintained, calibrated, and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the compressor engine (M/L 11) is operating. The PMS shall collect and record at a minimum four or more data points equally spaced over each hour the following parameters at the following frequencies:
  - (1) Fuel flow (FF<sub>SCFM</sub>) in standard cubic feet per minute (SCFM) on an hourly average basis
  - (2) Engine speed (RPM) on an hourly average basis
  - (3) Air manifold temperature (AMT) in degrees F on an hourly average basis
  - (4) Critical trapped equivalence ratio (TER<sub>C</sub>) on an hourly average basis
  - (5) Engine trapped volume (V<sub>TRAP</sub>) in cubic feet (ft<sup>3</sup>) on an hourly average basis
  - (6) Actual air manifold pressure (AMPACT) in inches of mercury (in Hg) on an hourly average basis

(7) Critical air manifold pressure (AMPC) in inches of mercury (in Hg) on an hourly average basis

- a. If the one (1) hour average actual air manifold pressure (AMPACT) of the compressor engine (M/L 11) is less than the calculated critical air manifold pressure (AMPC) for a one-hour period, the permittee shall report a deviation from normal operation.
- b. If any three (3) hour average of AMPACT of the compressor engine (M/L 11) is less than the calculated AMPC for that engine, the source shall take timely corrective action such that the affected engine resumes normal operation.
- c. If the three (3) hour average of AMPACT of the affected engine (M/L 11) is less than the calculated AMPC for that engine for three (3) times during the year, the permittee shall repeat the testing required in Condition 39 to re-establish the correlation between parameter levels that indicate proper operation of the compressor engine (M/L 11) and assure compliance with the NO<sub>x</sub> limit. Testing shall be completed and the results submitted to the Blue Ridge Regional Office within ninety (90) days of the third occurrence.

(9VAC5-80-1180)

17. **Monitoring Device** - At least once per year, the permittee shall test the compressor engine (M/L 11) with a portable analyzer to demonstrate the validity of the PMS and compliance to the NO<sub>x</sub> emission limit in Condition 24. The engine shall be tested in the "as found" condition. The engine shall not be adjusted or tuned prior to any test for the purpose of lowering emissions, then returned to previous setting or operating conditions after the test is completed. The permittee shall submit the testing protocol for approval to the Blue Ridge Regional Office at least 30 days prior to the scheduled testing. The portable analyzer shall be capable of measuring NO<sub>x</sub> emissions over the full range of expected engine operating conditions. The permittee shall calibrate the portable analyzer in accordance to the provisions of 40 CFR Part 60 Appendix A, Method 7E or alternative as approved by the Administrator and record the results in a logbook.

(9VAC5-80-1180)

## OPERATING LIMITATIONS

18. **Fuel** – The approved fuel for the combustion turbines (TUR-05, TUR-06) and emergency engine (AUX-04) is pipeline natural gas. A change in the fuel shall be considered a change in the method of operation of the combustion turbines (TUR-05, TUR-06) and emergency engine (AUX-04) and may require a new or amended permit. However, if a change in the fuel is not subject to new source review permitting requirements, this condition should not be construed to prohibit such a change.

(9VAC5-50-260 and 9VAC5-80-1180)

19. **Fuel** – The approved fuel for the compressor engine (M/L 11) is pipeline natural gas. A change in the fuel shall be considered a change in the method of operation of the compressor engine (M/L 11) and may require a new or amended permit.  
(9VAC5-80-1180)
20. **Fuel Specification** – The pipeline natural gas shall not exceed a sulfur content of 1.1 grains of sulfur per 100 standard cubic feet at any time.  
(9VAC5-80-1180)
21. **Fuel Monitoring** – The permittee shall use the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum total sulfur content for the natural gas being fired at the natural gas compressor station facility is 1.1 grains of sulfur or less per 100 standard cubic feet. In the alternative, the permittee may perform annual fuel analysis of on-site natural gas. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office no later than 60 days after test completion and shall conform to the test report format enclosed with this permit.  
(9VAC5-50-410 and 9VAC5-80-1180)
22. **Operating Hours** – The emergency engine (AUX-04) shall be operated for the purposes of maintenance, testing, and emergencies (as defined in 9VAC5-80-1110C) only. The emergency engine (AUX-04) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.  
(9VAC5-50-260 and 9VAC5-80-1180)
23. **Requirements by Reference** – Except where this permit is more restrictive than the applicable requirement, the combustion turbines (TUR-05, TUR-06) as described in the Introduction shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.  
(9VAC5-50-400, 9VAC5-50-410, and 9VAC5-80-1180)

## EMISSION LIMITS

24. **Emission Limits** – Emissions from the operation of the compressor engine (M/L 11) shall not exceed the limits specified below:

Nitrogen Oxides (as NO <sub>2</sub> )	19.20 lb/hr
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These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 6, 17, 19, 39 and 50.  
(9VAC5-80-1180)

25. **Emission Limits** – Emissions from the operation of the emergency engine (AUX-04) shall not exceed the limits specified below:

Nitrogen Oxides (as NO <sub>2</sub> )	2.0 g/hp-hr	1.62 ton/yr
Carbon Monoxide	4.0 g/hp-hr	3.24 ton/yr
Volatile Organic Compounds	1.0 g/hp-hr	0.81 ton/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 7, 22, 36, 38 and 50. (9VAC5-50-260 and 9VAC5-80-1180)

26. **Emission Limits** – During the first 12-month period of operation, emissions from the operation of each Solar Titan combustion turbine (TUR-05, TUR-06) shall not exceed the limits specified below<sup>2</sup>:

Nitrogen Oxides (as NO <sub>2</sub> )	5.00 ppmvd @15% O <sub>2</sub> *	3.45 lb/hr*	15.32 ton/yr
Carbon Monoxide	2.00 ppmvd @15% O <sub>2</sub> *	0.84 lb/hr*	5.47 ton/yr
Volatile Organic Compounds	2.50 ppmvd @15% O <sub>2</sub> *	0.60 lb/hr*	3.18 ton/ yr
PM (filterable)		1.33 lb/hr*	5.81 ton/yr
PM <sub>10</sub> (total)		1.33 lb/hr*	5.81 ton/yr
PM <sub>2.5</sub> (total)		1.33 lb/hr*	5.81 ton/ yr
Sulfur Dioxide		0.68 lb/hr*	2.98 ton/yr

\*Limits are a 3-hour average and do not apply during periods of start-up, shutdown, or when ambient temperatures are below 0°F. The emission rates for startup/shutdown periods and low temperature operating mode (< 0°F and ≥ 50% load) are listed in Condition 28.

These emissions are derived from the estimated overall emission contribution from operating limits. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period and shall include startup and shutdown periods, and when ambient temperatures are below 0 °F as applicable. Exceedance of the operating limits may

<sup>2</sup> 9VAC5-50-260 (BACT) refers to NO<sub>x</sub>, CO, VOC, PM<sub>10</sub> and PM<sub>2.5</sub> emissions for turbines TUR-05 and TUR-06.

be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 2, 3, 4, 5, 35 and 50. (9VAC5-50-260 and 9VAC5-80-1180)

27. **Emission Limits** – Beginning 12-months after start-up, during each 12-month period of operation, emissions from the operation of each Titan combustion turbine (TUR-05, TUR-06) shall not exceed the limits specified below<sup>1</sup>:

Nitrogen Oxides (as NO <sub>2</sub> )	3.75 ppmvd @15% O <sub>2</sub> *	2.59 lb/hr*	11.54 ton/yr
Carbon Monoxide	2.00 ppmvd @15% O <sub>2</sub> *	0.84 lb/hr*	5.47 ton/yr
Volatile Organic Compounds	2.50 ppmvd @15% O <sub>2</sub> *	0.60 lb/hr*	3.18 ton/yr
PM		1.33 lb/hr*	5.81 ton/yr
PM <sub>10</sub>		1.33 lb/hr*	5.81 ton/yr
PM <sub>2.5</sub>		1.33 lb/hr*	5.81 ton/yr
Sulfur Dioxide		0.68 lb/hr*	2.98 ton/yr

\*Limits are a 3-hour average and do not apply during periods of start-up, shutdown, or when ambient temperatures are below 0°F. The NO<sub>x</sub> emission rates for startup/shutdown periods and low temperature operating mode (< 0°F and ≥ 50% load) are listed in Condition 29.

These emissions are derived from the estimated overall emission contribution from operating limits. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period and shall include startup and shutdown periods, and when ambient temperatures are below 0°F as applicable. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 2, 3, 4, 5, **Error!**

**Reference source not found.**35, 37 and 50.

(9VAC5-50-260 and 9VAC5-80-1180)

28. **Emission Limits for Non-Standard Operating Modes** – During the first 12-month period of operation, emissions during start-up, shutdown, and low temperature mode from each Titan combustion turbine (TUR-05, TUR-06) shall not exceed the limits specified below:

	<u>Start-up</u>	<u>Shutdown</u>	<u>Low Temp Mode</u> (<0 °F)
Nitrogen Oxides (as NO <sub>2</sub> )	1.00 lb/event	1.00 lb/event	16.10 lb/hr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with this emission limit may be determined



as stated in Conditions 44 and 50.  
 (9VAC5-50-260 and 9VAC5-80-1180)

29. **Emission Limits for Non-Standard Operating Modes** – Beginning 12-months after start-up, during each 12-month period of operation, emissions during start-up, shutdown, and low temperature mode from each Titan combustion turbine (TUR-05, TUR-06) shall not exceed the limits specified below:

	<u>Start-up</u>	<u>Shutdown</u>	<u>Low Temp Mode (&lt;0 °F)</u>
Nitrogen Oxides (as NO <sub>2</sub> )	1.00 lb/event	1.00 lb/event	12.08 lb/hr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with this emission limit may be determined as stated in Conditions 44 and 50.  
 (9VAC5-50-260 and 9VAC5-80-1180)

30. **Emission Limits** – Volatile organic compounds emissions shall not exceed the limits specified below:

Fugitive Emissions Components	0.89 ton/yr
Combined Combustion Turbine Venting (Start-up and Shutdown)	0.38 ton/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 8, 9, **Error! Reference source not found.**43, and 50.  
 (9VAC5-50-260 and 9VAC5-80-1180)

31. **Visible Emission Limit** – Visible emissions from the each combustion turbine (TUR-05, TUR-06) shall not exceed 5% opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A).  
 (9VAC5-50-260 and 9VAC5-80-1180)
32. **Visible Emission Limit** – Visible emissions from the emergency engine (AUX-04) shall not exceed 5% opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A).  
 (9VAC5-50-260 and 9VAC5-80-1180)
33. **Visible Emission Limit** – Visible emission observations from combustion turbines (TUR-05, TUR-06) shall be conducted at least once a week. If visible emissions are observed, the permittee shall take timely corrective action such that the equipment resumes operation with no visible emissions or perform a visible emission evaluation (VEE) in accordance with 40 CFR 60, Appendix A, Method 9 to assure visible emissions from the emission unit is less than five (5) percent opacity. A record of the date, time, observer, cause and

corrective measures taken shall be made. If no visible emissions were observed, a record of the date, time and observer shall be made. These records shall be maintained on site by the permittee for the most recent 5-year period.

(9VAC5-80-1180)

## TESTING

34. **Emissions Testing** – The facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. Sampling ports, safe sampling platforms, and access shall be provided when requested.  
(9VAC5-50-30 F and 9VAC5-80-1180)
35. **Stack Test** – Initial performance tests shall be conducted for CO, VOC, PM<sub>10</sub>, and PM<sub>2.5</sub> from each combustion turbine (TUR-05, TUR-06) to determine compliance with the emission limits contained in Condition 26. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 40CFR Part 51 Appendix M or 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility and shall conform to the test report format enclosed with this permit.  
(9VAC5-50-30 and 9VAC5-80-1200)
36. **Stack Test** – Initial performance tests shall be conducted for NO<sub>x</sub>, CO, and VOC from the emergency engine (AUX-04) to determine compliance with the emission limits contained in Condition 25. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility and shall conform to the test report format enclosed with this permit.  
(9VAC5-50-30 and 9VAC5-80-1200)
37. **Stack Test** – The permittee shall repeat the performance tests contained in Condition 35 every two years to determine compliance with the emission limits contained in Condition 27. Subsequent tests shall be performed no later than 26 months after the previous test.

The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office no later than 60 days after test completion and shall conform to the test report format enclosed with this permit. (9VAC5-50-30 and 9VAC5-80-1200)

38. **Stack Test** – The permittee shall repeat the performance tests contained in Condition 36 every 8,760 hours of operation or 36 months, whichever is earlier. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office no later than 60 days after test completion and shall conform to the test report format enclosed with this permit. (9VAC5-50-30 and 9VAC5-80-1200)
39. **PMS Relative Accuracy Test** – Unless previously completed, the permittee shall perform a minimum of nine (9) emissions tests runs to establish a correlation between the engine operating parameters in Condition 16 and NO<sub>x</sub> emissions in Condition 24 from the compressor engine (M/L 11) using the following equation and constants A, B, and C referenced below:

$$AMP_C = \frac{\{AF_{ST} \times (0.0765 \times FSG) \times \frac{FF_{SCFM}}{RPM} \times (AMT + 460)\}}{(2.699 \times TER_C \times V_{TRAP})} - 14.73 \times 2.036$$

Where:

AMP <sub>C</sub>	= critical air manifold pressure in inches of mercury (in Hg)
AF <sub>ST</sub>	= stoichiometric air/fuel ratio
FSG	= fuel gas specific gravity
FF <sub>SCFM</sub>	= unit fuel flow rate in standard cubic feet per minute (SCFM)
RPM	= unit speed in revolutions per minute
AMT	= air manifold temperature in °F
TER <sub>C</sub>	= critical trapped equivalence ratio
V <sub>TRAP</sub>	= engine trapped volume in cubic feet (ft <sup>3</sup> )

And:

$$TER_C = A \times \frac{(FF_{SCFM})^2}{(RPM)^2} + B \times \frac{(FF_{SCFM})}{(RPM)} + C$$

Where:

A, B, and C = constants determined based upon initial performance testing of affected unit.

(9VAC5-80-1180)

40. **Test Protocol and Results** - Tests for compressor engine (M/L 11) shall be conducted and reported and data reduced as set forth in 9VAC5-50-30 and the test methods and procedures contained in each applicable section listed in 40 CFR Part 60, Appendix A or alternative as approved by the Administrator. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to the scheduled testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 45 days after test completion and shall conform to the test report format enclosed with this permit.  
(9VAC5-80-1180)
41. **Future Testing** - If the compressor engine (M/L 11) is changed in a manner that results in significant changes in the parameters established in Condition 39, the permittee shall repeat the testing required in Condition 39 to re-establish the correlation between parameter levels that indicate proper operation of the affected engine (Ref. M/L 11) and assure compliance with the NOx limit. Testing shall be completed and the results submitted to the Blue Ridge Regional Office within ninety (90) days of the engine change.  
(9VAC5-80-1180)
42. **Visible Emissions Evaluation** – Concurrently with the initial performance tests in Conditions 35 and 36 and subsequent performance tests in Conditions 37 and 38, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall also be conducted by the permittee. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The initial test shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Should conditions prevent concurrent opacity observations, the Blue Ridge Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility and shall conform to the test report format enclosed with this permit.  
(9VAC5-50-30 and 9VAC5-80-1200)
43. **VGRS Evaluation** - The permittee shall ensure proper operation and maintenance of the pressurized hold required in Condition 8.b by performing an evaluation for each combustion turbine by quantitative analysis of leaks during a pressurized hold using Method 21 or an optical gas imaging camera. The seal gas pressure and the combustion turbine case pressure shall be monitored during this evaluation to ensure continued proper operation of the VGRS and shall form acceptable ranges for on-going operation. The initial evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Subsequent annual

evaluations shall be performed, reported, and demonstrate compliance thereafter at a period not to exceed 13 months from the preceding evaluation. The test report shall conform to the test report format enclosed with this permit and shall include the established pressure ranges.

(9VAC5-50-30 and 9VAC5-80-1200)

## **CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)**

44. **CEMS** - Continuous Emission Monitoring Systems, meeting the design specifications of 40 CFR Part 60, Appendix B, shall be installed to measure and record the emissions of nitrogen oxides (NO<sub>x</sub>) and the oxygen content of the exhaust gas from the compressor turbine stack as ppmvd corrected to 15% O<sub>2</sub>. Except where otherwise approved by the DEQ, the CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 60.13, 40 CFR 60, Subpart KKKK and 40 CFR 60, Appendices B and F. Data shall be reduced to 3-hour rolling averages, using procedures approved by the Blue Ridge Regional Office.

(9VAC5-50-40 and 9VAC5-80-1180)

45. **CEMS Performance Evaluations** - Performance evaluations of the CEMS shall be conducted in accordance with 40 CFR Part 60, Appendix B, and shall take place during the performance tests required by Conditions 35 and 37 or within 30 days thereafter. One copy of the performance evaluations report shall be submitted to the DEQ within 45 days of the evaluation. The CEMS shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of the CEMS performance, and subsequent notifications, shall be submitted to the Blue Ridge Regional Office.

(9VAC5-80-1180 and 9VAC5-50-40)

46. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60 Appendix F shall be implemented for all continuous emissions monitoring systems.

(9VAC5-80-1180 and 9VAC5-50-40)

47. **CEMS Excess Emissions and Monitor Downtime for NO<sub>x</sub>** - For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 48 are defined as follows:

- a. An excess emission is any unit operating period in which the 3-hour rolling average NO<sub>x</sub> emission rate exceeds the applicable emission limit in Conditions 26 or 27 and
- b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO<sub>x</sub> concentration, O<sub>2</sub> concentration and fuel flow rate.

(9VAC5-50-50 and 9VAC5-50-410)

48. **CEMS Reports** - The permittee shall furnish written reports to the DEQ of excess emissions from any process monitored by a CEMS with the quarterly report required in Condition 51. These reports shall include, but are not limited to the following information:
- a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;
  - b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;
  - c. The date(s) and time(s) identifying each period during which the CEMS was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and
  - d. When no excess emissions have occurred or the CEMS have not been inoperative, repaired or adjusted, such information shall be stated in that report.

(9VAC5-80-1180 and 9VAC5-50-50)

#### **ADDITIONAL REQUIREMENTS**

49. **Ambient Air Quality Monitoring** – The permittee shall conduct ambient air monitoring for NO<sub>2</sub> beginning with the startup of either combustion turbine (TUR-05, TUR-06). No later than 180 days prior to startup of the combustion turbines (TUR-05, TUR-06), the permittee shall submit an Ambient Air Quality Monitoring Quality Assurance Project Plan (QAPP) for approval by the Blue Ridge Regional Office. The Quality Assurance Project Plan shall be developed consistent with the requirements of EPA's "Guide to Writing Quality Assurance Project Plans for Ambient Air Monitoring Networks" (EPA-454/8-18-006). The permittee shall not certify ambient monitoring data without an approved QAPP. The plan shall include, at a minimum, all the elements described in EPA-454/8-18-006 in addition to the following elements:
- a. Description of the site selection process for air quality and meteorological monitors;
  - b. Description of procedures for all aspects of the operation of monitoring equipment including maintenance, data processing, data validation, data reporting and data certification. These procedures shall be developed consistent with the requirements described in EPA's "Guidance for Preparing Standard Operating Procedures (SOPs)" (EPAQA/G-6). The SOPs shall be submitted to the Blue Ridge Regional Office for approval with the QAPP.

- c. All monitoring and associated tasks shall conform to, at a minimum, the applicable requirements of 40 CFR Parts 50, 53, 58, and any other requirements specified by the Blue Ridge Regional Office.
- d. Performance Evaluations (PE) for all monitoring equipment installed consistent with these conditions shall be performed by the permittee or their designated representative. These PEs shall be performed consistent with the requirements of 40 CFR Part 58, Appendix A Section 3. Results of the PE shall be submitted to the Blue Ridge Regional Office 3 months after the performance date of the PE. The permittee shall be responsible for submitting the results of the PE to the EPA Air Quality Subsystem database. If the PE does not meet the requirements of the 40 CFR Part 58 Section 3, the Blue Ridge Regional Office shall be notified prior to the submittal of the data to the AQS database. This notification is to include any remedial action taken or planned to be taken by the permittee to bring the system into compliance with the requirements of 40 CFR Part 58 Section 3.

The Blue Ridge Regional Office will approve the monitoring location(s) based on EPA's siting criteria and the proximity to the maximum modeled impact from the compressor station for each pollutant. Completion of ambient air monitoring subject to approval by the Blue Ridge Regional Office.  
(9VAC5-80-1180)

## RECORDS AND REPORTING

50. **On Site Records** – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Blue Ridge Regional Office. These records shall include, but are not limited to:
- a. Monthly and annual consumption of natural gas for the turbines (TUR-05, TUR-06) and emergency engine (AUX-04). Annual throughput shall be calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
  - b. Operation and control device monitoring records as required in Conditions 8, 9, 10, 11, 12, 13, 14, and 21.
  - c. Records for each event when a combustion turbine does not operate in "SoLoNOx mode" shall include event duration, event reason, and annual hours. Annual hours shall be calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.



- d. Documentation from Solar for all parameters and their ranges that are relevant to the "SoLoNOx mode" determination.
- e. Records of fuel quality characteristics to demonstrate compliance with Condition 21.
- f. Monthly emissions calculations for NO<sub>x</sub>, CO, VOC, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, and SO<sub>2</sub> from the combustion turbines (TUR-05, TUR-06) and emergency engines (AUX-04) using calculation methods approved by the Blue Ridge Regional Office to demonstrate compliance with the annual emission limitations in Conditions 25, 26, 27, and 30.
- g. Scheduled and unscheduled maintenance and operator training.
- h. Records of actual piping pressure prior to venting gas from that section of piping, the clock time for the opening and closing of any vent valve, the amount of gas vented during the event, and any mitigation measures used. These records include the ESD testing, combustion turbine start-up purge, and combustion turbine shutdown venting.
- i. Records of the time, date, and duration of each combustion turbine start-up and shutdown event.
- j. Records of the operating time and reason for each operation of the emergency engine (AUX-04)
- k. Results of all stack test data, VGRS evaluations, and visible emissions evaluations.
- l. CEMS calibrations, calibration checks, percent operating time, and excess emissions.
- m. The occurrence and duration of any periods during which a CEMS is inoperative.
- n. Periodic monitoring records for the compressor engine (M/L 11) necessary to demonstrate compliance with the NO<sub>x</sub> emission limit in Condition 24.
- o. Calculations for the compressor engine (M/L 11) demonstrating compliance with the NO<sub>x</sub> emissions limit listed in Condition 24.
- p. A summary of any corrective maintenance taken.
- q. Records of the portable analyzer calibration for the compressor engine (M/L 11).

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.

(9VAC5-80-1180 and 9VAC5-50-50)

51. **Reporting** - The permittee shall submit a certification of compliance with all terms and conditions of this permit, including emission limitation standards or work practices, as well as any other applicable requirement to the Blue Ridge Regional Office no later than March

1 and September 1 of each calendar year. This report must be signed by a responsible official, consistent with 9VAC5-20-230. The time periods to be addressed are January 1 to June 30 and July 1 to December 31. Each report shall include the following information:

- a. Exceedances of emissions limitations or operational restrictions;
- b. Excursions from control device operating parameter requirements, as documented by continuous emission monitoring;
- c. Failure to meet monitoring, recordkeeping, or reporting requirements contained in this permit;
- d. Summary results of the daily AVO and quarterly LDAR surveys required in Condition 9; and
- e. Excess emission reports required in Condition 48.

If there were no deviations from permit conditions during the time period, the permittee shall include a statement in the report that "no deviations from permit requirements occurred during this semi-annual reporting period." These reports shall be maintained and shall be current for the most recent five years.

(9VAC5-80-1180 and 9VAC5-50-50)

## NOTIFICATIONS

52. **Initial Notifications** – The permittee shall furnish written notification to the Blue Ridge Regional Office of:

- a. The actual date on which construction of the combustion turbines (TUR-05 and TUR-06) and the emergency engine (AUX-04) commenced within 30 days after such date.
- b. The actual date on which shutdown of the Clark TLA-6 reciprocating engines (M/L1 – M/L10) occurred within 15 days of such date.
- c. The anticipated start-up date of the combustion turbines (TUR-05 and TUR-06) and the emergency engine (AUX-04) postmarked not more than 60 days nor less than 30 days prior to such date.
- d. The actual start-up date of the combustion turbines (TUR-05 and TUR-06) and the emergency engine (AUX-04) within 15 days after such date.
- e. The anticipated date of performance tests postmarked at least 30 days prior to such date.
- f. Copies of the written notification referenced in items 52.a, and 52.c through 52.e above are to be sent to:

Associate Director  
Office of Air Enforcement and Compliance Assistance (3AP20)  
U.S. Environmental Protection Agency  
Region III  
1650 Arch Street  
Philadelphia, PA 19103-2029

(9VAC5-50-50 and 9VAC5-80-1180)

## GENERAL CONDITIONS

53. **Permit Invalidity** – This permit to construct the combustion turbines (TUR-05 and TUR-06) and the emergency engine (AUX-04) shall become invalid, unless an extension is granted by the DEQ, if:

- a. A program of continuous construction is not commenced within 18 months from the date of this permit.
- b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

(9VAC5-80-1210)

54. **Permit Suspension/Revocation** – This permit may be suspended or revoked if the permittee:

- a. Knowingly makes material misstatements in the permit application or any amendments to it;
- b. Fails to comply with the conditions of this permit;
- c. Fails to comply with any emission standards applicable to a permitted emissions unit;
- d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or
- e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emissions limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9VAC5-80-1210 G)

55. **Right of Entry** – The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

- a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;
- b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;
- c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and
- d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.  
(9VAC5-170-130 and 9VAC5-80-1180)

56. **Maintenance/Operating Procedures** – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

- a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.
- b. Maintain an inventory of spare parts.
- c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.
- d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.  
(9VAC5-50-20 E and 9VAC5-80-1180 D)

57. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown, or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.  
(9VAC5-20-180 J and 9VAC5-80-1180 D)
58. **Notification for Facility or Control Equipment Malfunction** – The permittee shall furnish notification to the Blue Ridge Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour. Such notification shall be made no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Blue Ridge Regional Office.  
(9VAC5-20-180 C and 9VAC5-80-1180)
59. **Violation of Ambient Air Quality Standard** – The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.  
(9VAC5-20-180 I and 9VAC5-80-1180)
60. **Change of Ownership** – In the case of a transfer of ownership of the stationary source, the new owner shall abide by any current minor NSR permit issued to the previous owner. The new owner shall notify the Blue Ridge Regional Office of the change of ownership within 30 days of the transfer.  
(9VAC5-80-1240)
61. **Permit Copy** – The permittee shall keep a copy of this permit on the premises of the facility to which it applies.  
(9VAC5-80-1180)

#### **STATE-ONLY ENFORCEABLE (SOE) REQUIREMENTS**

The following terms and conditions are included in this permit to implement the requirements of 9VAC5-40-130 et seq., 9VAC5-50-130 et seq., 9VAC5-60-200 et seq. and/or 9VAC5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

62. **(SOE) Operating Limit** – The testing of either Station 166 emergency engine (ENG1, ENG2) shall not coincide with the startup or shutdown of any Station 165 or 166 turbine (TUR-01 - TUR-06).  
(9VAC5-60-320, 9VAC5-80-1120F, and 9VAC5-80-1180)

63. **(SOE) Emission Limits** – Formaldehyde (CAS# 50-00-0) emissions from the facility shall not exceed the limits specified below:

TUR-05	0.30 lb/hr*	0.29 lb/hr**	1.66 ton/yr
TUR-06	0.30 lb/hr*	0.29 lb/hr**	1.66 ton/yr
AUX-04	0.64 lb/hr		0.16 ton/yr
Total Facility	1.24 lb/hr		3.48 ton/yr

\* Limit applies only when ambient temperatures are below 0°F and the turbine is operating at greater than or equal to 50% load – not during start-up or shutdown.

\*\* Limit applies only when ambient temperatures are greater than or equal to 0°F and the turbine is operating at greater than or equal to 50% load – not during start-up or shutdown.

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 3, 5, 7, 8, 22, 66, 67, and 69. (9VAC5-60-320, 9VAC5-80-1120F, and 9VAC5-80-1180)

64. **(SOE) Emission Limits** – Start-up and shutdown emissions of Formaldehyde (CAS# 50-00-0) from TUR-05 and TUR-06, shall not exceed the limits specified below:

Start-up	2.90 lb/event	3.15 lb/hr
Shutdown	2.40 lb/event	2.65 lb/hr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 3, 5, 7, 22, 66, 67, and 69. (9VAC5-60-320, 9VAC5-80-1120F, and 9VAC5-80-1180)

65. **(SOE) Emission Limits** – Hexane (CAS# 110-54-3) emissions from venting events at the facility shall not exceed the limits specified below:

TUR-05	0.24 lb/hr
TUR-06	0.24 lb/hr

Compliance with these limits may be determined as stated in Conditions 8, 68, and 69. (9VAC5-60-320, 9VAC5-80-1120F, and 9VAC5-80-1180)

66. **(SOE) Stack Test** – Concurrently with the performance tests in Condition 35 and 37, initial performance tests shall be conducted for formaldehyde from the compressor turbines (TUR-05, TUR-06) to determine compliance with the emission limits contained in Condition 63. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-60-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-60-100. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility and shall conform to the test report format enclosed with this permit.  
(9VAC5-60-30, 9VAC5-80-1120F, and 9VAC5-80-1180)
67. **(SOE) Stack Test** – Concurrently with the performance tests in Conditions 36 and 38, initial performance tests shall be conducted for formaldehyde from the emergency engine (AUX-04) to determine compliance with the emission limit contained in Condition 63. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-60-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-60-100. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility and shall conform to the test report format enclosed with this permit.  
(9VAC5-60-30, 9VAC5-80-1180, and 9VAC5-80-1120F)
68. **(SOE) Fuel Monitoring** – The permittee shall use the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying the maximum hexane content for the natural gas being fired at the natural gas compressor station facility. In the alternative, the permittee may perform annual fuel analysis of on-site natural gas. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office no later than 60 days after test completion and shall conform to the test report format enclosed with this permit.  
(9VAC5-80-1120F and 9VAC5-80-1180)
69. **(SOE) On Site Records** – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content



and format of such records shall be arranged with and approved by the Blue Ridge Regional Office. These records shall include, but are not limited to:

- a. Hourly, monthly, and annual emissions (in pounds and tons) of formaldehyde and hexane, including hexane emissions exhausted during any venting event, to demonstrate compliance with the emissions limitations in Conditions 63, 64, and 65. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
- b. Results of all stack test data.
- c. Equipment status to demonstrate compliance with Condition 62.
- d. Hexane analysis results to demonstrate compliance with Condition 68.

These records shall be available for inspection by the Blue Ridge Regional Office and shall be current for the most recent five years.

(9VAC5-60-50, 9VAC5-80-1120F and 9VAC5-80-1180)

## SOURCE TESTING REPORT FORMAT

### Report Cover

1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

### Certification

1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. \*Signed by reviewer

### Copy of approved test protocol

### Summary

1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. \*For each emission unit, a table showing:
  - a. Operating rate
  - b. Test Methods
  - c. Pollutants tested
  - d. Test results for each run and the run average
  - e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

### Source Operation

1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

### Test Results

1. Detailed test results for each run
2. \*Sample calculations
3. \*Description of collected samples, to include audits when applicable

### Appendix

1. \*Raw production data
2. \*Raw field data
3. \*Laboratory reports
4. \*Chain of custody records for lab samples
5. \*Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

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\* Not applicable to visible emission evaluations


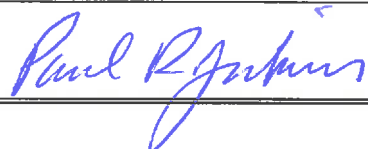
# Exhibit 6

**VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY**

**Blue Ridge Regional Office**

**INTRA-AGENCY MEMORANDUM**

**Engineering Analysis**

<b>Permit Writer</b>	Anita Walthall		
<b>Air Permit Manager</b>	Paul Jenkins		
<b>Memo To</b>	Air Permit File	<b>Date</b>	1/28/2020
<b>Facility Name</b>	Transcontinental Gas Pipeline Company, LLC (Station 165)		
<b>Registration Number</b>	<b>30864</b>	<b>Application #</b>	<b>13</b>
<b>Date Fee Paid</b>	6/26/2018	<b>Amount (\$)</b>	63,000.00
<b>Distance to Class I Areas</b>	142.08	<b>SNP (km)</b>	87.1
		<b>JRF (km)</b>	
<b>FLM Notification (Y/N)</b>	Y	<b>Required if less than 10K (minor), 100K (state major)</b>	
<b>Application Fee Classification</b> (Title V, Synthetic Minor, True Minor)	Title V	<b>Before permit action</b>	Title V After permit action
<b>Permit Writer Signature</b>			
<b>Permit Manager Signature</b>			

**I. Introduction & Background**

Transcontinental Gas Pipe Line Company, LLC ("Transco") submitted an application dated June 20, 2018 to construct a project at its natural gas compressor Transco Station 165 ("Station 165"). The station is part of Transcontinental's interstate gas transmission system. Station 165 is located at 945 Transco Road in Chatham, VA (Pittsylvania County). Transco submitted supplemental application information dated November 7, 2018, September 16, 2019, November 18, 2019, and January 27, 2020; modeling protocol dated September 16, 2019 and revised November 25, 2019; and modeling report dated October 3, 2019 and updated on November 25, 2019. The permit application was deemed complete on January 27, 2020.

Transco is a Title V major source of NOx, CO, VOC, and formaldehyde (HAP). A minor NSR permit for Station 165 was issued September 29, 2011 (amended on June 14, 2012 and February 28, 2013) to govern the operation of a combustion engine (M/L 12) and an emergency generator (AUX-03). The remaining engines (M/L1 – M/L11) at Station 165 are existing (pre-1972) and not covered by the minor NSR permit program. A second station on the premises (Station 166) has a minor NSR permit dated August 24, 2015. The facility is located in an attainment area for all pollutants and is a PSD major source. Transco is also subject to a state operating permit (SOP) dated January 24, 2007, which is a source specific State Implementation Plan (SIP) revision to implement Phase II of the NOx SIP Call.

The most recent on-site inspection conducted on August 9, 2018, determined the facility to be in compliance with its requirements. A Local Governing Body Certification form authorized on June 19, 2018 was later determined as not required for this permit action.

There are abundant regulatory and technical considerations in the application review and drafting of the air permit that require significant technical education and experience. Attachment 1 is provided as an attempt to convey a number of standard concepts and terms within the field. The information in the attachment does not reflect all of the statutory, regulatory, and legal implications but is provided as a basic explanation of some of the technical terms associated with air permit application reviews.

## **II. Emission Units / Process Description**

The Chatham facility consists of two compressor stations, 165 and 166. Station 165 has been in operation since 1957 and uses natural gas-fired, (internal combustion) reciprocating compressor engines to power the compressors. Station 166 is a newer station that operates natural gas-fired gas turbine powered compressors. Each station is equipped with emergency generators to maintain operations in the event of power interruption. Since the compressor stations are adjacent, use the same SIC code, and have common ownership, they are registered as one stationary source (30864).

For this permit action, the changes to Station 165 include the following emissions/emission units:

### Combustion Turbines

To provide pressure for this station, Transco is proposing to construct and operate the following natural gas-fired compressor turbines:

- 23,150 hp (171.9 MMBtu/hr), Solar Titan Model 130-23502S combustion turbine (TUR-05)
- 23,150 hp (171.9 MMBtu/hr), Solar Titan Model 130-23502S combustion turbine (TUR-06)

**Note:** The horsepower rating and LHV fuel heat rate (MMBtu/hr) of the turbines listed here are based on ambient temperature of 0°F and 100% operating load.

Combustion turbines work by converting the energy in the fuel gas to mechanical energy that then powers the pipeline gas compressors. The compressors increase the pressure of the pipeline gas to enable it to move from one location to another, as the gas will flow from higher pressure to lower pressure in the pipeline. The turbines will generate mechanical energy from the combustion of natural gas fuel. Fresh atmospheric air flows through an air compressor, bringing it to higher pressure. Energy is then added by spraying fuel (pipeline natural gas) into the compressed air and igniting it so the combustion generates a high-temperature flow. This high-temperature, high-pressure gas enters a turbine, where it expands, turning a shaft that powers both the turbine's air compressor and other large centrifugal compressors that pressurize the pipeline gas.

The proposed lean-premix staged turbines are equipped with Solar's dry low-NOx combustion system, SoLoNOx™, which limits the formation of NOx by pre-mixing air and fuel prior to combustion. This system limits NOx emissions when the turbine is operating at an ambient temperature of 0 °F or greater and at a load equal to or greater than 50%. This technology reduces nitrogen oxide (NOx) emissions by operating a lean burn fuel ratio (fuel to air ratios of less than 1:1). The SoLoNOx™ system does not operate during start-up or shutdown. SoLoNOx™ efficiency is diminished at low loads (less than 50% of capacity), as well as at loads greater than or

equal to 50% for ambient temperatures below 0 °F. SoLoNOx™ is operating optimally when the “pilot operating mode” is in “minimum pilot mode,” which is explained in Solar’s PIL-220 dated August 31, 2017. Transco cannot operate below 50% load, except during start-up or shutdown.

In addition to the use of SoLoNOx™, Transco agreed to the installation of add-on controls to further reduce emissions: selective catalytic reduction (SCR) for NOx control, and use of an oxidation catalyst system to control CO, VOC, and organic HAPs such as formaldehyde. An SCR reduces NOx emissions by injecting ammonia (NH<sub>3</sub>) into the exhaust gas upstream of a catalyst. The compounds NOx, NH<sub>3</sub>, and O<sub>2</sub> react on the catalyst surface to form nitrogen (N<sub>2</sub>) and water (H<sub>2</sub>O). Oxidation catalyst systems are typically used on turbines to achieve a reduction in CO and VOC emissions. The oxidation catalyst system promotes the oxidation of CO and VOC to carbon dioxide (CO<sub>2</sub>) and water (H<sub>2</sub>O) as the emission stream passes through the catalyst bed. Catalyst systems need to operate above minimum temperatures to achieve the intended reactions for NOx, CO, or VOC. Neither catalyst system will be at temperature during start-up. During shutdown, the oxidation catalyst system will remain above the reaction temperature (until the temperature of the turbine and associated equipment begins to cool). The SCR system is more complicated (i.e., requires ammonia injection at the correct stoichiometric rate as well as higher temperatures) and will not operate during shutdown.

Due to the technical considerations for operating the SoLoNOx™ system and the inability to operate the control systems during start-up and shutdown<sup>1</sup>, there are three operating modes for the turbines:

- Normal operating mode (50%-100%), at or above 0°F inlet air temperature (Steady-state)
- Low temperature mode, operating at temperatures below 0°F (Low Temperature)
- Start-up and Shutdown mode, when power is being energized or de-energized (SUSD)

#### Compressor Fugitive Emissions (FUGS)

The proposed project will include fugitive emissions from piping components (i.e., valves, flanges, pumps, etc.). Because piping components have a potential for leaks, the constituents in natural gas namely, VOCs and toxic pollutants are also expected to be released into the atmosphere.

#### Venting and Blowdowns

Natural gas blowdown events occur as a result of depressurization activities associated with compression turbine start-ups and shutdowns. The cause for depressurization results in releases of natural gas during turbine start-up, turbine shutdown, and site-wide emergency shutdown (ESD) testing. VOCs and toxic pollutants are released into the atmosphere during these events.

#### Emergency Engine

A 1,468 bhp (1,000 kW) Caterpillar G3512 natural gas-fired emergency engine (AUX-04) will provide back-up power in the event that grid power is unavailable. The engine is a 4SLB unit with a 2011 manufacture year with a 2020 planned construction year. The pollutants expected to be emitted from the emergency engine are NOx, CO, VOC, SO<sub>2</sub>, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, and toxics.

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<sup>1</sup> The oxidation catalyst will operate above the minimum temperature for the entirety of the shutdown sequence. Therefore, control of emissions will occur during that period.

### Tanks

Three liquid storage tanks will be installed at the facility. TANK-03 rated at 4,265 gallons will store pipeline natural gas condensate liquids and TANK-04 will contain oily wastewater at the same capacity. TANK-05, rated at 10,000-gallon capacity, will store aqueous ammonia for use by each turbine's SCR control system. The pollutants expected to be emitted from the tanks are VOC and ammonia.

### Shutdown Existing Engines

Transco plans to permanently shut down 10 existing Clark reciprocating internal combustion engines (M/L1 - M/L10), at Station 165 upon startup of the first turbines (TUR-05 and TUR-06) covered by this permit action.

## III. Emission Calculations

The primary pollutants emitted by combustion turbines are NO<sub>x</sub>, CO and unburned hydrocarbons (UHC). Sulfur dioxide (SO<sub>2</sub>), particulate matter (PM, PM<sub>10</sub>, and PM<sub>2.5</sub>) and trace levels of HAPs are a function of fuel content.<sup>2</sup> Emissions rates for NO<sub>x</sub>, CO, and unburned hydrocarbons (UHC) are guaranteed by the vendor. Emission estimates for VOC (and methane) emissions are 20% of the UHC emissions<sup>3</sup>. The supplemental application includes an update to baseline actual emission calculations for the Station 165 project. Those calculations have been reviewed by DEQ and no other changes to the calculations are necessary (see Appendix C). The project's uncontrolled emissions and modification emissions are evaluated in Sections IVA and B.

Based on the proposed operating scenarios for the turbines, the annual permitted emissions are calculated using the following basis:

- turbines operating at 8,700 hours per year (each) in steady-state mode
- low temperature emissions (for temperatures below 0°F) are estimated to total 10 hours per year (or 5 hours each turbine), and
- SUSD emissions having a total duration of approximately 50 hours (25 hour each turbine).<sup>4</sup>

## IV. Regulatory Review

### A. 9VAC5 Chapter 80, Part II, Article 6 – Minor New Source Review

The provisions of Article 6 apply throughout Virginia to (i) the construction of any new stationary source, (ii) the construction of any project (which includes the affected emissions units), and (iii) the reduction of any stack outlet elevation at any stationary source.

#### *9VAC5-80-1105 B through D:*

Transco seeks approval for a project that includes affected emissions units. The proposed project's equipment emissions are evaluated against the project emission rates found in 9VAC5-80-1110 D.1. To be exempt from permitting, the regulations provide that a project must be exempt under the provisions of 9VAC5-80-1105 B through D as a group, and according to provisions of 9VAC5-80-1105 E and F. In light of the proposed equipment, the storage tanks are exempt from permitting. TANK-03 is exempt under 9VAC5-80-1105B.4.b, as a volatile organic

<sup>2</sup> <https://www.netl.doe.gov/sites/default/files/gas-turbine-handbook/3-2-1-2.pdf>.

<sup>3</sup> Solar Turbines P1L 168.

<sup>4</sup> SUSD combined emissions = 300 events x 10 min/event x 1hr/60min = 50 hrs.



compound storage tank of 40,000 gallons or less storage capacity. TANK-04 is also exempt, according to 9VAC5-80-1105 B.8.e (1), as a petroleum liquids storage vessel of 40,000 gallons or less storage capacity. TANK-05 is exempt from permitting as ammonia is not a regulated air pollutant.

For minor NSR permit applicability, the uncontrolled emission rate increase (UER) of criteria pollutants for a project is the sum of the new uncontrolled emissions (NUE) minus the sum of the current uncontrolled emissions (CUE) for each unit included in the project ( $UER = NUE - CUE$ ) and cannot be less than zero. The combined UER is compared to the criteria pollutant exemptions levels in 9VAC5-80-1105 D. If the UER exceeds the exemption level for any one criteria pollutant, the project is subject to the permitting requirements of 9VAC5 Chapter 80, Article 6. For new emissions unit CUE equals zero. The emission from the new units (turbines and emergency engine) are reviewed to determine the UER for the project.

#### Compressor Turbines (TUR-05, TUR-06)

The proposed compressor turbines are new emission units at an existing source. NUE is based on manufacturer data for NO<sub>x</sub>, CO, and VOC using worst case emissions for these pollutants at maximum load and 0°F. Emissions of PM, PM<sub>10</sub>, PM<sub>2.5</sub> and SO<sub>2</sub> are determined using emission factors from AP-42, Table 3.1-2a, and assumes the maximum load in MMBtu/hr using the higher heating value (HHV). The NUE for all pollutants are based on 8,760 hours per year.

#### Emergency Engine (AUX-04)

The NUE for pollutants emitted by the emergency engine is based on 500 hours of operation a year since this unit is delegated for emergency use only. Emissions of NO<sub>x</sub>, CO, and VOC are based on New Source Performance Standards (NSPS), 40 CFR 60 Subpart JJJJ, and maximum rated capacity of the engine. Emissions of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> are based on emission factors from AP-42 Table 3.2-2 for four stroke, lean burn engines.

The data shown below summarizes the projects uncontrolled emissions. The UER for CO, NO<sub>x</sub> PM<sub>10</sub>, PM<sub>2.5</sub> and VOC exceed the respective exemption rates, therefore the project is subject to permitting requirements of Article 6. State BACT applies to each affected pollutant (see Section V).

**Project Uncontrolled Emission Rate (UER)<sup>5</sup>**

<b>Pollutant</b>	<b>UER (tpy)</b>	<b>Exemption Rate (tpy)</b>	<b>Exempt? (Y/N)</b>
Carbon Monoxide	102.09	100	N
Nitrogen Oxides	56.44	10	N
Sulfur Dioxide	5.97	10	Y
PM	11.64	15	Y
PM <sub>10</sub>	11.64	10	N
PM <sub>2.5</sub>	11.64	6	N

<sup>5</sup> Table 5.1 of November 19, 2019 application.

Volatile Organic Compounds <sup>6</sup>	20.90	10	N
Lead	<0.06	0.6	Y

*9VAC5-80-1105E&F:*

Unless the equipment (source) is subject to §112 of the CAA, new and modified sources that emit toxic pollutants must be evaluated according to the requirements of Virginia's toxic program (9VAC5-60-300C). The turbines and emergency engine are in a source category whose toxic pollutants are exempt from this rule.<sup>7</sup> The project's emission of all other toxic pollutants are less than the respective exemption thresholds. See section VIIB for discussion and additional modeling performed.

**B. 9VAC5 Chapter 80, Part II, Article 8 and Article 9 – PSD Major New Source Review and Non-Attainment Major New Source Review**

The Prevention and Significant Deterioration (PSD) permit program is for major stationary sources (defined in the Regulations) located in areas that are in compliance with the National Ambient Air Quality Standards (NAAQS). Areas that are meeting the NAAQS are designated as "PSD areas". Areas that have ambient air concentrations higher than the NAAQS are designated as "nonattainment areas". An area's classification is determined for each pollutant with a NAAQS. These pollutants are referred as "criteria pollutants". The PSD program also applies to certain other pollutants that are regulated under the Clean Air Act.<sup>8</sup>

Pittsylvania County is a PSD area for all pollutants as designated in 9VAC5-20-205. Transco is not in a source category with a 100-tpy PSD threshold; therefore, the applicable major stationary source threshold is 250 tpy. The facility is an existing major source with a PTE for at least one regulated NSR pollutant greater than 250 tpy. As a major source, the proposed project is evaluated to determine whether a major modification is initiated.

A major modification causes two types of emission increases: a significant emissions increase (SEI) and a significant net emission increase (SNEI). The procedure for calculating whether a SEI occurs depend on the type of emissions units being modified. The application utilized the emissions test contained in 9VAC5-80-1605 G.4 since the project involves new emissions units. This test calculates the difference between baseline actual emissions (BAE) to future potential emissions for each new unit.

The initial step is to sum all of the emission increases associated with the project for each pollutant. If the result for a pollutant is less than the significant emissions rate, a significant increase has not occurred and that pollutant has not resulted in a major modification. For pollutants that exceed the significant emissions rate, a second step (emission evaluation) is required to determine if a significant net emissions increase has also occurred.

<sup>6</sup> Value includes emissions from non-exempt project equipment and fugitives releases (leaking components and venting).

<sup>7</sup> 40 CFR 63 (Subparts YYYY and ZZZZ).

<sup>8</sup> BACT review for GHG emissions is required if a PSD permit is required for a criteria pollutant (6/23/14 SCOTUS decision).

As new units that have not commenced operation, the BAE for each unit is zero. Therefore, the future PTE for each unit is totaled and summarized in the table below. The PTE for the project has emissions of PM<sub>2.5</sub> and GHG greater than the PSD significance levels.

**Step 1: Emission Increase**

<b>Pollutant</b>	<b>Total Project Increase (tpy)</b>	<b>PSD Significance Threshold (tpy)</b>	<b>PSD Netting Required?</b>
CO	14.18	100	No
NO <sub>x</sub>	24.71	40	No
PM	11.64	25	No
PM <sub>10</sub>	11.64	15	No
PM <sub>2.5</sub>	11.64	10	Yes
SO <sub>2</sub>	5.97	40	No
VOC	8.45	40	No
Lead	<0.6	0.6	No
GHG (as CO <sub>2</sub> e)	207,901.53	75,000	Yes

Step 2 involves summing all of the SEIs associated with the project with all of the other creditable increases and decreases in actual emissions made at the facility during the contemporaneous period (September 2014 through the date that the increase from the particular change occurs). If the result is greater than the significant emission rate, a major modification would occur and the project is subject to PSD permitting.

The main decreases will result from the shutdown of ten (10) reciprocating engines. In addition, Transco identified a project for Station 166 during the contemporaneous period that involved the installation of four combustion turbines and two emergency engines. The Station 166 contemporaneous project increase emissions for PM<sub>2.5</sub> and GHG are added to the current project emissions to determine net emissions increase (NEI). As summarized in the following table, the proposed project changes does not meet the definition of a major modification, as there is no significant net emission increases for PM<sub>2.5</sub>. The project is exempt from Article 8 permitting requirements. The decreases associated with shutting down ML-1/ - ML-10 are enforceable as a practical matter and is included in the permit (9VAC5-80-1615(f)).

**Step 2: Net Emission Increase**

<b>Pollutant</b>	<b>Project Increases (tpy)</b>	<b>Contemporaneous Increases (tpy) Decreases (tpy)</b>		<b>NEI (tpy)</b>	<b>Significant Value (tpy)</b>	<b>PSD Permitting Required?</b>
PM <sub>2.5</sub>	11.64	8.46	(12.68)	7.42	10	No
GHG (CO <sub>2</sub> e)	207,901.53	157,227.00	(38,692.73)	326,435.79	75,000	PM <sub>2.5</sub> Contingent

Greenhouse Gases (9VAC5 Chapters 80 and 85)

As of January 2, 2011, GHG is subject to regulation for a major modification if the project causes a SEI and SNEI for GHG in addition to one other criteria pollutant.<sup>9</sup> The Station 165 project does not have a criteria pollutant to exceed the SNEI threshold, therefore, GHG is not subject to the regulations as a NSR pollutant for the purpose of PSD applicability.

C. 9VAC5 Chapter 50, Part II, Article 5 – NSPS

Requirements of NSPS Subparts JJJJ, KKKK, OOOOa are applicable to the affected equipment (or process) as identified in this section. These rules contain federally enforceable requirements that a source must comply with, regardless of their inclusion in a permit.

The emergency engine (AUX4) is subject to 40 CFR 60, Subpart JJJJ being spark ignition fired and having a manufacture date after April 1, 2006. The engine is subject to a BACT requirement that is at least as stringent as the requirements in this rule (see Section V). Virginia has not accepted delegation of this NSPS rule and therefore it is not incorporated into this permit.

The proposed combustion turbines (TUR-05 and TUR-06) are subject to 40 CFR 60, Subpart KKKK “Standards of Performance for Stationary Combustion Turbines”. This subpart establishes emission standards and compliance schedules for the control of NO<sub>x</sub> and SO<sub>2</sub> emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005 (§60.4300-§60.4420). NSPS Subpart KKKK requires a NO<sub>x</sub> emission limit of 15 ppm @15% O<sub>2</sub> (§60.4320) for each turbine. The permit’s BACT requirement is more stringent than the subpart’s 15 ppm limit (see Section V). Monitoring, testing, and recordkeeping requirements for NO<sub>x</sub> are required (§60.4333, §60.4340). The turbines are also subject to the fuel sulfur monitoring requirements (§60.4360).

NSPS Subpart OOOOa, “Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced after September 18, 2015” (§60.5360a-§60.5432a) applies to select equipment for the collection of fugitive emissions (60.5365a(j)). This subpart sets standards for GHGs and VOCs that require leak testing for methane and other VOC emissions. NSPS OOOOa requires a fugitive emissions monitoring plan (§60.5397a(b) through (j)); monitoring surveys (§60.5397a(f) and §60.5397a(g)(2)) and repair/replacement timeframes (§60.5397a(h)). The monitoring plan required by this permit is at least as stringent as the requirements in this rule (see Section V). Virginia has not accepted delegation of this NSPS rule and therefore it is not incorporated into this permit.

The affected facilities have been designed to comply with the applicable requirements of these rules. Applicable requirements of NSPS JJJJ, KKKK, and OOOOa will be included in the source’s Title V permit.

D. 9VAC5 Chapter 60, Part II, Article 1 – NESHAPS

The facility is not subject to any Part 61 (40 CFR 61) emission standards.

E. 9VAC5 Chapter 60, Part II, Article 2 – MACT

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<sup>9</sup> CO<sub>2</sub>e is the emission rate of each GHG species multiplied by its respective global warming potential (40CFR Part 98).

As a major source for HAPs, the requirements of 40 CFR 63 Subparts YYYY (4Y) and ZZZZ (4Z) apply to equipment identified in this section. These rules contain federally enforceable requirements for compliance, regardless of their inclusion in a permit. Applicable requirements of MACT 4Y and 4Z will be included in the source's Title V permit.

The natural gas-fired turbines (TUR-05, TUR-06) are subject to the requirements of MACT 4Y (§63.6080). The affected facility only required to comply with the standard for initial notification (§63.6095(d)). Currently, no other requirements of this subpart apply to the turbines. Pending EPA's final action to lift the stay for this subcategory, additional standards may be applicable at that time. Virginia has accepted delegation of MACT 4Y, however, MACT requirements are not included in minor NSR permits.

The emergency engine (AUX04) is subject to the requirements of Part 63 4Z, also known as the "RICE MACT" (§63.6585). The engine must meet the definition of an emergency stationary RICE with specific requirements for operation (§63.6640(f)) and initial notification (§63.6645(f)). Virginia has not accept delegation of this rule.

The affected facilities have been designed to comply with the applicable requirements of these rules.

**F. State Only Enforceable (SOE) Requirements (9VAC5-80-1120 F)**

This section of the permit contains conditions to address operating scenarios, emission limitations and performance testing as necessary to regulate State Toxic emissions. For 1-hr formaldehyde concerns, simultaneous testing of Station 166 emergency engines (ENG1, ENG2) cannot occur during the startup and shutdown events of any turbine at Station 165 or 166 (TUR01 – TUR-06). Facility-wide formaldehyde and hexane emission limitations are included based on modeling protocols. The hexane content in pipeline natural gas, must be tested once a year to demonstrate compliance with the worst-case concentration indicated in the application (0.2 wt%). Transco will be required to maintain records to show operating scenarios, emission data, and fuel characteristics (hexane content) were not violated.

**V. Best Available Control Technology Review (BACT)**

BACT is a requirement to reduce emissions through the use of available reduction techniques (i.e., control devices, adjustments to prevent pollution formation, work practices, etc.) as applied to each affected emissions unit in the project proposed by the applicant (see 9VAC5-80-1190.1.a, 9VAC5-50-240A, and 9VAC5-50-260). For this application, the two primary affected emissions units are the two natural gas-fired combustion turbines. Any consideration of electric motor driven compressors (ECs) would represent a fundamentally different unit in the project; for example, no air permit application would be required at all for such units. BACT is applied to the affected emissions unit and is not a mechanism for replacement of the affected emissions unit in the proposed project. In the particular case of the current Station 165 project, Transco provided DEQ with supplemental information, dated January 27, 2020, evaluating the feasibility of using ECs instead of combustion turbines. This information demonstrates that the electrical transmission infrastructure required for the use of ECs at Station 165 does not exist. Therefore, even if the substitution of ECs for the proposed combustion turbines was considered to be a control technique

that could be applied to the project in the context of a BACT determination, the use of ECs at Station 165 is not an available option and thus cannot be considered the best available control technology. Finally, it is important to note that an electric compressor station may or may not result in lower overall regional emissions of air pollutants than a natural gas-fired compressor station, depending on the source of electric generation on the grid from which electric compressor station receives its electricity. If the source of the electric compressor station's electricity comes from a coal-fired power plant, the overall air pollution impact of the electric compressor station is worse than that of a natural gas-fired compressor station. If, on the other hand, the electricity comes from a natural gas-fired power plant, the overall air pollution impact of an electric compressor station is likely to be roughly equal to that of a natural gas fired compressor station. For this reason, it cannot be said that an electric compressor is superior to a natural gas-fired compressor station from an overall air pollution standpoint. This requirement considers whether an emission reduction is BACT using various factors including the cost of the control system divided by the amount of pollutant reduced; called 'cost effectiveness'. BACT review is relative to a specific pollutant and a specific type of operation. Generally, for BACT, modifications undergo a review to compare the relative level of control with other similar Virginia sources. Based on the potential impacts to the surrounding communities, the modification was also related to similar projects in other states.

Each affected emissions unit emitting a pollutant that is subject to permitting shall apply BACT for that pollutant (9VAC5-50-260C). Under the minor NSR program, BACT is applicable for NO<sub>x</sub>, CO, PM<sub>10</sub>, PM<sub>2.5</sub>, and VOC emissions. Transco provided a "top down" control technology approach for NO<sub>x</sub>, CO, VOC, PM<sub>2.5</sub>, and PM<sub>10</sub>. While the project does not require this level of BACT review, DEQ considers the control technology selected in the application to be valid. Transco submitted a BACT review for the pollutants subject to permitting (see Section 5 of the current application).

#### **Turbines:**

Transco proposes to use SoLoNO<sub>x</sub><sup>TM</sup>, a dry low-NO<sub>x</sub> combustion system and SCR technology on the turbines (TUR-05, TUR-06) to control NO<sub>x</sub> emissions. A review of permits issued in Virginia for similar compressor stations indicates most turbines are uncontrolled with emission values of 15 ppm NO<sub>x</sub>. Two recently issued permits with SCR requirements were found, both of which are compressor stations (one in another state) associated with the Atlantic Coast Pipeline (ACP). Transco originally proposed 9 ppmvd and no SCR as a controlled emission rate from each turbine. A review to determine if a lower concentration was appropriate included a draft permit for a gas compressor station in Charles County, Maryland and a new construction permit for a station in Buckingham County, Virginia. One of the units at the Buckingham compressor station is similar in size and make to the units proposed for construction at Transco's Station 165. Its NO<sub>x</sub> emission rate of 3.75 ppmvd has not been verified. Based on a comparison of the costs incurred between 5 ppm and 3.75 ppm and the feasibility of such control for the similar model's size turbine, DEQ concludes BACT is an exhaust concentration of 3.75 ppmvd NO<sub>x</sub>.

Proper equipment design (SoLoNO<sub>x</sub><sup>TM</sup> technology) also aids to reduce CO and unburned hydrocarbon emissions (UHC).<sup>10</sup> Moreover, Transco proposes an oxidation catalyst system as BACT for control of CO and VOC emissions at 92 and 50 percent respectively. A review of issued

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<sup>10</sup> Solar Turbine PIL 167. VOC emission are a subpart of the UHC (Solar PIL 168).

permits in Virginia for similar compressor stations indicates most turbines are uncontrolled with emission values of 25 ppm CO and 5 ppm VOC. A recent permit with oxidation catalyst requirements included a lower controlled VOC emission rate from a compressor station associated with ACP. Control of CO and VOC emissions by oxidation catalyst system is considered BACT. Transco revised the application's initial control efficiency for CO emissions and maintains the vendor's guaranteed uncontrolled VOC emission rate of 5 ppm (Solar Turbines PIL-168). Consequently, the proposed turbines will have a controlled exhaust emission concentration of 2.0 ppm CO and 2.5 ppm VOC.

Transco proposes to use clean burning low sulfur fuel; employ good combustion practices; and use high efficiency filters on the air inlet to control particulate emissions (PM<sub>10</sub>, PM<sub>2.5</sub>) from the turbines (TUR-05, TUR-06). DEQ considers the use of clean burning fuel (low sulfur) results in minimal formation of particulate matter less than 10 micron during combustion. The use of high-efficiency filtration on the inlet air will minimize the entrainment of particulate matter into the turbine exhaust stream, and the use of good combustion practices as BACT for PM<sub>10</sub> / PM<sub>2.5</sub>. The permit establishes a visible emissions limit of less than 5% from the natural gas combustion turbine.

#### **Emergency Engine:**

The emergency engine will emit NO<sub>x</sub>, CO, VOC, PM<sub>10</sub>, and PM<sub>2.5</sub>. The unit is not categorically exempt in accordance with 9VAC5-80-1105B. Based on the emergency classification and the low annual hours of operation, the numeric standards equivalent to the NSPS JJJJ are considered as BACT for NO<sub>x</sub>, CO, and VOC (2.0 g/hp-hr, 4.0 g/hp-hr, 1.0 g/hp-hr, respectively). While these numeric standards are identical to the NSPS values, BACT, not the NSPS, is the regulatory authority for these limits. Virginia has not accepted delegation of this NSPS rule and therefore it is not incorporated into this permit. Visible emissions less than 5%, efficient generator design, pipeline quality natural gas, and good combustion practices is considered BACT for PM<sub>10</sub> / PM<sub>2.5</sub>.

#### **Fugitive Leak Components:**

Natural gas contains VOC, which is subject to BACT. A daily auditory/visual/olfactory (AVO) and quarterly LDAR checks in accordance with Method 21 (or an optical gas-imaging camera) is considered BACT. While these requirements may be similar or identical with the requirements of NSPS OOOOa, the regulatory authority for these conditions is BACT. Virginia has not accepted delegation of this NSPS rule and therefore it is not incorporated into this permit.

#### **Natural Gas Venting (Blowdown):**

Natural gas contains VOC, which is subject to BACT. Station 165 has three anticipated activities or events that result in releases of natural gas: turbine start-up; turbine shutdown; and site-wide emergency shutdown (ESD) testing. Transco's application included 150 startups and 150 shutdowns per turbine per year (600 total events for both turbines) utilizing electric starters during turbine start-ups (no natural gas venting); a seal gas booster system to keep the units in a "pressurized hold" during shutdown operations and one site-wide ESD testing event per year.<sup>11</sup> DEQ reviewed the emissions from these operational practices and requested Transco to review additional controls for emissions generated during blowdown operations. Based on Transco's review of start-up and shutdown, flaring, and other control options, the facility proposes a vent gas

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<sup>11</sup> Emission calculations assume one event per year for potential to emit.

reduction system (VGRS) to reduce emissions of VOC due to turbine venting related to start-up and shutdown. Transco revised the PTE emission estimates for planned depressurization events. Maintaining the estimated 600 startup and shutdowns combustion events, Transco agrees to performing only 24 blowdowns (12 each turbine) after startup, shutdown, or maintenance activity and “assumes” the use of vent gas reduction (VGR). The VGRS is capable of reducing the system pressure to 30 psig prior to atmospheric depressurization. Transco proposed capped tests using a double-valve system as a control for ESD testing, additionally VOC emissions are minimized through the use of a compressor dry gas boosting system for maintaining pressurized holds. The use of VGRS and capped ESD testing can decrease emissions by approximately 99% for VOC alone.<sup>12</sup>

Additional Controls Not Required by BACT (9VAC5-50-260)

Although not required by BACT the facility also proposes the following control measure:

A sulfur content of the natural gas of 1.1 grains per 100 scf has been established as a limitation in the permit for the natural gas quality. The limitation is used as a means of demonstrating compliance with the sulfur dioxide emission limitations established in the permit.

## VI. Summary of Potential Emissions Increase

The facility’s change in PTE is shown in the following table:

Pollutant	Past PTE (tpy)	Future PTE (tpy)	PTE Change (tpy)
NO <sub>x</sub>	3,746.1	548.8	-3,197.2
CO	1,026.4	372.6	-653.8
VOC	251.2	100.7	-150.5
PM/PM <sub>10</sub> /PM <sub>2.5</sub>	60.3	35.9	-24.4
SO <sub>2</sub>	10.1	13.9	+3.8
NH <sub>3</sub>	0	21.5	+21.5
HAP (total)	73.5	24.1	-49.4

Detailed calculations provided by Transco are included in the source application as Appendix C.

## VII. Dispersion Modeling

### A. Criteria Pollutants

A cumulative air quality analysis via dispersion modeling was conducted to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) for NO<sub>2</sub> (1-hour and annual averaging periods), CO (1-hour and 8-hour averaging periods), PM<sub>10</sub> (24-hour averaging period) and PM<sub>2.5</sub> (24-hour and annual averaging periods).

For the impact of the VOC emissions, a quantitative analysis was performed in accordance

<sup>12</sup> While not the subject of Article 6 permitting, a reduction in venting emissions also significantly reduces the amount of methane emitted from 6,011.34 tpy to 251.8 tpy (as CO<sub>2</sub>e).



with current EPA guidance.

Modeling was completed by Transco and the protocol submitted to the Office of Air Quality Assessments for analysis. The NAAQS analysis included emissions from Station 165, emissions from existing sources from Virginia, and representative ambient background concentrations of NO<sub>2</sub>, CO, PM<sub>10</sub>, and PM<sub>2.5</sub>. The modeling analysis was approved on December 9, 2019 and demonstrated compliance with the applicable NAAQS. The results are summarized below:

Pollutant (averaging period)	Total Modeled Concentration (µg/m <sup>3</sup> )	Ambient Background Concentration (µg/m <sup>3</sup> )	Total Concentration (µg/m <sup>3</sup> )	NAAQS (µg/m <sup>3</sup> )
NO <sub>2</sub> (1-hr)	178.3	---	178.3	188
NO <sub>2</sub> (annual)	21.6	13.2	34.8	100
CO (1-hr)	2,151	2,300	4,451	40,000
CO (8-hr)	1,106	1,380	2,486	10,000
PM <sub>2.5</sub> (24-hr)	5.5	17	22.7	35
PM <sub>2.5</sub> (annual)	1.0	7.2	8.2	12
PM <sub>10</sub> (24-hr)	7.9	31	38.9	150

#### B. Toxic Pollutants

Modeling is also required if potential toxic air pollutant emissions after issuance of the permit exceed the exemption thresholds included in 9VAC5-60-300 C. Based on toxic pollutant emission calculations submitted and applicability to §112 regulatory requirements, there are no toxic pollutants from the proposed project whose emissions exceeded exemption thresholds or that require modeling. However, due to Virginia's recent permit activities for compressor stations, DEQ requested Transco to include a modeling analysis for formaldehyde and n-hexane in order to determine the Predicted Ambient Air Concentration (PAAC) and to compare those values against their respective Significant Ambient Air Concentration (SAAC).

Modeling was completed by Transco and protocol submitted to the Office of Air Quality Assessments for review. The modeling analysis was approved on December 9, 2019 and demonstrates compliance with the applicable SAAC. The results are summarized below:

Toxic Pollutant (averaging period)	Scenario	Modeled Concentration (PAAC) (µg/m <sup>3</sup> )	SAAC (µg/m <sup>3</sup> )
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Formaldehyde (1-hour)	50% Load	29.4	62.5
Formaldehyde (1-hour)	75% Load	29.4	62.5
Formaldehyde (1-hour)	100% Load	29.4	62.5
Formaldehyde (1-hour)	Startup (blended with 75% load)	47.7	62.5
Formaldehyde (1-hour)	Shutdown (blended with 75% load)	36.8	62.5
Formaldehyde (annual)	50% Load	1.25	2.4
Formaldehyde (annual)	75% Load	1.25	2.4
Formaldehyde (annual)	100% Load	1.24	2.4
Hexane (1-hour)	Unit Blowdown (with Pigging)	236.1	8,800
Hexane (1-hour)	Emergency Shutdown (with Pigging)	168.0	8,800
Hexane (annual)	Unit Blowdown (with Pigging)	0.03	352
Hexane (annual)	Emergency Shutdown (with Pigging)	0.03	352

The air toxics modeling analysis for formaldehyde (1-hour) assumes the simultaneous testing of the Station 166 engines (ENG1 and ENG2) must not coincide with the startup and shutdown operations of any one of combination of Station 165 or 166 turbines (TUR-01 – TUR-06).

#### C. Other Modeling Considerations - Ozone:

An assessment to estimate the impact on ozone from the proposed modified facility's NO<sub>x</sub> and VOC emissions was conducted. The monitored ozone design value for the area is approximately 61 ppb for the period 2016 through 2018. This results in a total design value equal to 61.23 ppb which is well below the 8-hour ozone NAAQS of 70 ppb.

To assure compliance with the NAAQS, modeling endorses the NO<sub>x</sub> hourly emission rate for the existing engine (M/L 11) to be 19.20 lb/hr at all times. Additionally, an operating scenario for Station 166 engines (ENG1, ENG2) is required to restrict testing of these units during times when any of the Station 165 or 166 turbines (TUR01 – TUR06) are in startup or shutdown mode. A copy of the Air Quality Analysis Memorandum is provided as Attachment 2.

### VIII. Compliance Demonstration

#### Turbines (TUR-05, TUR-06)

For proper operation of the SCR system, the permit requires monitoring of the turbine inlet air temperature, ammonia injection rate, catalyst bed inlet gas temperature, pilot operating point, turbine load, and catalyst bed differential pressure. For the oxidation catalyst system, the permit requires monitoring of catalyst bed inlet temperature and catalyst bed differential pressure.

Transco must develop a monitoring plan for the turbine monitoring parameters. The turbines must also be tested bi-annually for CO, PM<sub>10</sub>, PM<sub>2.5</sub> and VOC. The time between bi-annual tests must not exceed 26 calendar months. Transco is required to validate the monitoring ranges during each

performance test. Continuous emission monitoring system (CEMS) will be used to demonstrate NOx emissions. Performance evaluations of the CEMS shall be conducted in accordance with 40 CFR Part 60, Appendix B, and take place during the performance test or within 30 days thereafter. The inlet filters will be maintained in accordance with the manufacturer's recommendations.

The VGRS allows for 'pressurized hold' by maintaining a seal gas pressure sufficiently higher than the compressor case pressure. A test to determine the appropriate range for each turbine is required using Method 21 or an optical gas imaging camera to ensure no leakage. Records of the daily AVO and quarterly LDAR surveys are also required, as well as corrective actions taken.

#### Emergency Engine (AUX04)

The engine must be equipped with a non-resettable hour meter. A log containing the reason for operation of the engine and the amount of time operated is required. An initial performance test is required to demonstrate compliance with the emission limits for NOx, CO, and VOC, with subsequent tests being performed every 8,760 hours of operation or 36 months, whichever is less. Records of engine maintenance are also required.

#### Other Records

Transco must maintain records to demonstrate compliance with emission limits, operating parameters, inspections/observations and maintenance activities. Records of the shutdown of Clark engines (M/L-1 – M/L-10) is also required. Records must be maintained for exempt equipment in accordance with 9VAC5-80-1105A.4.

### **IX. Title V Review – 9VAC5 Chapter 80 Part II Article 1 or Article 3**

Transco Compressor Station is classified as a Title V major source. The facility currently operates under a Title V permit with an effective date of September 30, 2008 having an expiration date of November 25, 2013. Transco's Title V renewal application is currently under application shield. Changes made to the facility as a result of this minor NSR permit require a modification to the Title V permit (9VAC5-80-230 A.2.).

The applicable requirements pertaining to the NSPS Part 60 (subparts 4J, 4K, 4Oa) and NESHAP Part 63 (subparts 4Y and 4Z) regulations will be incorporated into the source's Title V permit as required by the Air Regulations.

### **X. Site Suitability**

Based on a review of the application, the air quality analysis, and resulting draft permit, the proposed facility complies with all regulatory requirements. Air Quality modeling results indicate compliance with all applicable ambient air quality standards. Therefore, the site is deemed suitable from an air quality perspective.

### **XI. Public Participation and Notifications**

There are no public participation requirements associated with the proposed project.

### **XII. Other Considerations**

None.

### **XIII. Recommendations**

Approval of the draft permit is recommended.

### **Attachments**

- Attachment 1 – Frequently Used Permitting Terms
- Attachment 2 – Air Quality Analysis Memorandum

## ATTACHMENTS

## Frequently Used Terms

@15% O<sub>2</sub> – A notation indicating that the concentration is mathematically corrected from the actual stack conditions to a comparable set of conditions. This prevents a source from adding additional ambient air just prior to the testing instrumentation to dilute the concentration of the pollutant being measured. This is not an issue with a mass emission rate since dilution does not change the mass of the pollutant emitted. The pound per million (ppm) limitations for Station 165 are corrected to 15% O<sub>2</sub>.

Blowdown – A venting event where piping at the facility must be emptied of natural gas; a site-wide blowdown is when all piping at the facility must be emptied.

Catalyst – A substance that changes the reaction speed but does not participate in the reaction.

CO – Carbon monoxide, a pollutant with a NAAQS.

Fugitive – Describes a type of emissions that occur but cannot be reasonably collected.

CO<sub>2</sub>e – “Carbon dioxide equivalent”, a term to describe different greenhouse gases in a common unit. For any quantity and type of greenhouse gas, CO<sub>2</sub>e signifies the amount of CO<sub>2</sub> which would have the equivalent global warming impact.

GHG – “Greenhouse gas”, gases consisting of carbon dioxide, methane, nitrous oxide and fluorinated compounds that trap heat in the atmosphere. The proposed Titan 130 combustion turbines will emit CO<sub>2</sub>, CH<sub>4</sub>, and N<sub>2</sub>O.

ISO conditions – Properties of a gas change based on the gas temperature and pressure exerted on the gas. In order to have a meaningful discussion regarding any gases, these variables must be defined. While several methods exist to define these variables, the International Organization for Standardization (ISO) defines the conditions as 59°F and 14.7 pounds per square inch (psi).

LDAR – Leak Detection and Repair – usually refers to a program a source uses to monitor various pieces of equipment at a facility that may be prone to leaking and fix leaks as detected

MACT – Maximum Achievable Control Technology; federal regulations for certain types of equipment; used in this analysis to refer to such standards promulgated in 40 CFR Part 63, which are technology based.

MMBtu – Million British thermal units – a measure of energy

NAAQS – National Ambient Air Quality Standard; a federal standard for the maximum concentration of a certain air pollutant in the ambient air in the country that is protective of human health. CO, O<sub>3</sub>, NO<sub>2</sub>, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, and lead are the pollutants with NAAQS.

NESHAPS – National Emission Standards for Hazardous Air Pollutants; federal regulations for certain types of equipment; used in this analysis to refer to such standards promulgated

in 40 CFR Part 61, which are risk based.

**NO<sub>x</sub>** – Nitrogen oxides or oxides of nitrogen – a surrogate for the amount of NO<sub>2</sub> (a pollutant with a NAAQS) being emitted; a pollutant that forms ozone when the atmosphere has favorable conditions (hot and dry with enough VOC).

**NSPS** – New Source Performance Standard; federal regulations for certain types of equipment.

**Open flare** – A stack-like device with a continuous flame at the tip, such that when a flammable gas flows, the ‘pilot flame’ ignites the gas prior to exiting the flare stack; also described as a candlestick flare for its similarity in appearance to a large candle.

**Pigging** – The method of removing liquids from the piping; liquids can be generated due to the high pressure of the gas causing some components to condense in the piping. No pigging operations are performed at this site.

**PM** – Particulate matter of a certain size that only includes the portion that can be filtered when emitted.

**PM<sub>10</sub> and PM<sub>2.5</sub>** – Particulate matter of a certain size that includes both the portion that can be filtered when emitted and the portion that is a gas when emitted and later condenses; both pollutants have a NAAQS.

**pph, lb/hr** – pound per hour – a short-term mass emission rate

**ppm** – parts per million – A concentration that can be converted to a mass emission rate.

**ppmvd** – parts per million, volumetric dry.

**PSD** – Prevention of Significant Deterioration; a pre-construction permitting program that applies to large sources.

**PTE** – potential to emit – the maximum ability of a source to emit pollutants considering permit limitations

**Stoichiometric** – Chemical reactions rely on the correct amount of each chemical. The ideal amount of each chemical is the ‘stoichiometric’ amount or ratio.

**TPY, tpy, ton/yr** – ton per year – a long-term mass emission rate

**Vent Gas Reduction System (VGRS)** – A system, including an electrically-driven compressor, which reduces the amount of natural gas released to the atmosphere during combustion turbine shutdowns by maintain sufficient pressure to ensure that the compressor seal remains intact during combustion turbine shutdowns.

**VOC** – Volatile Organic Compounds – A group of chemicals that form ozone when the atmosphere has favorable conditions (hot and dry with enough NO<sub>x</sub>).

## AQM Modelling Report

## MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY  
*Office of Air Quality Assessments*1111 East Main Street, Richmond, VA 23219  
22<sup>nd</sup> Floor

804/698-4900

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To: Paul Jenkins, Air Permit Manager (BRRO)

From: Office of Air Quality Assessments (AQA)

Date: December 9, 2019

Subject: Air Quality Analysis – Transco Compressor Station 165

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**I. Project Background**

Transcontinental Gas Pipe Line Company, LLC (Transco) operates two adjacent compressor stations (Stations 165 and 166) in the town of Chatham, Pittsylvania County, Virginia. These stations (hereafter referred to as the facility) are considered a single source for air permitting and compliance and are currently permitted to operate the following equipment:

- Eleven (11) Clark reciprocating internal combustion engines (RICE) used for natural gas compression (ID M/L 1 – M/L 11) [165];
- One (1) Caterpillar RICE used for natural gas compression (ID M/L 12) [165];
- Three (3) emergency generators (ID AUX 1 – AUX 3) [165];
- Four (4) Solar Taurus 70 turbines (ID TUR1 – TUR4) [166];
- Two (2) emergency generators (ID ENGI – ENG2) [166];
- Fugitive emission sources from piping components;
- Natural gas venting/blowdowns for compressor unit start-up, shutdown, maintenance, and emergency shutdown (ESD) safety testing; and
- Multiple sources considered insignificant activities.

As part of its Southeastern Trail Project, Transco is proposing to modify Station 165 that includes the following:

- Installing two (2) Solar Titan 130-23502S turbines each rated at 23,502 horsepower (hp) (ISO) (ID TUR05 - TUR06);



- Installing one (1) 1,468 hp emergency generator (ID AUX-04);
- Installing two (2) 4,265-gallon above ground storage tanks for natural gas condensate liquids and oily wastewater (ID TANK-03 – TANK-04);
- Installing one (1) 10,000-gallon above ground storage tank for aqueous ammonia (ID TANK-05)
- Providing natural gas venting/blowdowns for compressor unit start-up, shutdown, maintenance, and emergency shutdown (ESD) safety testing (ID BDS-05 and BDS-06);
- Fugitive emissions from new piping components (ID FUGS); and
- Removing ten (10) of the eleven (11) existing Clark reciprocating internal combustion engines (RICE) used for natural gas compression (ID M/L 1 – M/L 10).

The proposed changes are subject to the permitting requirements contained in 9 VAC 5 Chapter 80, Article 6 (Permits for New and Modified Stationary Sources) of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution. The DEQ required an air quality analysis in order to assess the potential impacts to ambient air quality. Modeling was conducted for nitrogen dioxide (NO<sub>2</sub>), carbon monoxide (CO), particulate matter having an aerodynamic diameter equal to or less than 2.5 microns (PM-2.5), and particulate matter having an aerodynamic diameter equal to or less than 10 microns (PM-10).

Toxics modeling was also conducted for hourly and annual formaldehyde and hexane emissions to demonstrate compliance with their respective Significant Ambient Air Concentrations (SAAC) as defined in 9 VAC 5 Chapter 60, Article 5 (Emission Standards for Toxic Pollutants from New and Modified Sources) of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution (9 VAC 5-60-300 et al).

## II. Modeling Methodology

The air quality modeling analysis conforms to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and was performed in accordance with approved modeling methodology. The air quality model used for the analyses was AERMOD (Version 19191). AERMOD is the preferred EPA-approved regulatory model for near-field applications.

Additional details on the modeling methodology are available in the applicant's November 2019 air dispersion modeling report.

## III. Modeling Results

### A. NAAQS Analysis

A cumulative modeling analysis was conducted to assess compliance with the National Ambient Air Quality Standards (NAAQS) for NO<sub>2</sub> (1-hour and annual averaging periods), CO (1-hour and 8-hour averaging periods), PM-2.5 (24-hour and annual averaging periods), and PM-10 (24-hour averaging period). The NAAQS analysis included emissions from the proposed modified facility, emissions from existing sources from Virginia, and representative ambient background concentrations of NO<sub>2</sub>.

CO, PM-2.5, and PM-10. The results of the analysis are presented in Table 1 and demonstrate modeled compliance with the applicable NAAQS.

Table 1  
 NAAQS Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Total Modeled Concentration ( $\mu\text{g}/\text{m}^3$ )	Ambient Background Concentration ( $\mu\text{g}/\text{m}^3$ )	Total Concentration ( $\mu\text{g}/\text{m}^3$ )	NAAQS ( $\mu\text{g}/\text{m}^3$ )
NO <sub>2</sub>	1-hour	178.3	— <sup>(1)</sup>	178.3	188
NO <sub>2</sub>	Annual	21.6	13.2	34.8	100
CO	1-hour	2,151	2,300	4,451	40,000
CO	8-hour	1,106	1,380	2,486	10,000
PM-2.5	24-hour	5.5	17	22.7 <sup>(2)</sup>	35
PM-2.5	Annual	1.0	7.2	8.2 <sup>(2)</sup>	12
PM-10	24-hour	7.9	31	38.9	150

<sup>(1)</sup> Season and hour of day varying.

<sup>(2)</sup> Total concentration includes the contribution from secondary PM-2.5 formation.

#### B. Toxics Analysis

The modified facility is subject to the state toxics regulations at 9 VAC 5-60-300 et al. An analysis was conducted in accordance with the regulations and the predicted concentrations for each modeled toxic pollutant were below their respective SAAC. Table 2 summarizes the toxic pollutant modeling analysis results.

Table 2  
 Toxics Analysis Maximum Predicted Concentrations

Toxic Pollutant	Averaging Period	Scenario	Modeled Concentration ( $\mu\text{g}/\text{m}^3$ )	SAAC ( $\mu\text{g}/\text{m}^3$ )
Formaldehyde	1-hour	50% Load	29.4	62.5
Formaldehyde	1-hour	75% Load	29.4	62.5
Formaldehyde	1-hour	100% Load	29.4	62.5
Formaldehyde	1-hour	Startup (blended with 75% load)	47.7	62.5
Formaldehyde	1-hour	Shutdown (blended with 75% load)	36.8	62.5
Formaldehyde	Annual	50% Load	1.25	2.4
Formaldehyde	Annual	75% Load	1.25	2.4
Formaldehyde	Annual	100% Load	1.24	2.4

Toxic Pollutant	Averaging Period	Scenario	Modeled Concentration ( $\mu\text{g}/\text{m}^3$ )	SAAC ( $\mu\text{g}/\text{m}^3$ )
Hexane	1-hour	Unit Blowdown (with Pigging)	236.1	8,800
Hexane	1-hour	Emergency Shutdown (with Pigging)	168.0	8,800
Hexane	Annual	Unit Blowdown (with Pigging)	0.03	352
Hexane	Annual	Emergency Shutdown (with Pigging)	0.03	352


### C. Other Modeling Considerations

#### *Ozone*

An assessment to estimate the impact on ozone from the proposed modified facility's  $\text{NO}_x$  and VOC emissions was conducted. The conservatively calculated ozone impact from the modified facility is approximately 2.21 parts per billion (ppb). In addition, the net actual emissions reductions of  $\text{NO}_x$  and VOC, resulting from the removal of older units, decreases ozone impacts by 1.98 ppb. Therefore, the net change in ozone concentration for the overall project is 0.23 ppb. The monitored ozone design value for the area is approximately 61 ppb for the period 2016 through 2018. This results in a total design value equal to 61.23 ppb which is well below the 8-hour ozone NAAQS of 70 ppb.

# Exhibit 7

**QuickFacts****Winston-Salem city, North Carolina**QuickFacts provides statistics for all states and counties, and for cities and towns with a **population of 5,000 or more**.**Table**

All Topics	Winston-Salem city, North Carolina
Population estimates, July 1, 2019, (V2019)	247,945
 PEOPLE	
Population	
Population estimates, July 1, 2019, (V2019)	247,945
Population estimates base, April 1, 2010, (V2019)	229,627
Population, percent change - April 1, 2010 (estimates base) to July 1, 2019, (V2019)	8.0%
Population, Census, April 1, 2010	229,617
Age and Sex	
Persons under 5 years, percent	▲ 6.5%
Persons under 18 years, percent	▲ 23.8%
Persons 65 years and over, percent	▲ 14.1%
Female persons, percent	▲ 53.1%
Race and Hispanic Origin	
White alone, percent	▲ 56.6%
Black or African American alone, percent (a)	▲ 34.9%
American Indian and Alaska Native alone, percent (a)	▲ 0.3%
Asian alone, percent (a)	▲ 2.5%
Native Hawaiian and Other Pacific Islander alone, percent (a)	▲ 0.1%
Two or More Races, percent	▲ 2.8%
Hispanic or Latino, percent (b)	▲ 15.0%
White alone, not Hispanic or Latino, percent	▲ 45.7%
Population Characteristics	
Veterans, 2015-2019	12,647
Foreign born persons, percent, 2015-2019	9.9%
Housing	
Housing units, July 1, 2019, (V2019)	X
Owner-occupied housing unit rate, 2015-2019	53.5%
Median value of owner-occupied housing units, 2015-2019	\$147,900
Median selected monthly owner costs -with a mortgage, 2015-2019	\$1,171
Median selected monthly owner costs -without a mortgage, 2015-2019	\$423
Median gross rent, 2015-2019	\$806
Building permits, 2019	X
Families & Living Arrangements	
Households, 2015-2019	94,957
Persons per household, 2015-2019	2.46
Living in same house 1 year ago, percent of persons age 1 year+, 2015-2019	84.2%
Language other than English spoken at home, percent of persons age 5 years+, 2015-2019	17.3%
Computer and Internet Use	
Households with a computer, percent, 2015-2019	89.5%
Households with a broadband Internet subscription, percent, 2015-2019	79.0%
Education	
High school graduate or higher, percent of persons age 25 years+, 2015-2019	88.2%
Bachelor's degree or higher, percent of persons age 25 years+, 2015-2019	34.5%
Health	
With a disability, under age 65 years, percent, 2015-2019	6.8%
Persons without health insurance, under age 65 years, percent	▲ 14.2%
Economy	
In civilian labor force, total, percent of population age 16 years+, 2015-2019	60.5%
In civilian labor force, female, percent of population age 16 years+, 2015-2019	56.6%
Total accommodation and food services sales, 2012 (\$1,000) (c)	564,907
Total health care and social assistance receipts/revenue, 2012 (\$1,000) (c)	1,958,944
Total manufacturers shipments, 2012 (\$1,000) (c)	4,016,976
Total merchant wholesaler sales, 2012 (\$1,000) (c)	2,266,381
Total retail sales, 2012 (\$1,000) (c)	4,067,779
Total retail sales per capita, 2012 (c)	\$17,358
Transportation	
Mean travel time to work (minutes), workers age 16 years+, 2015-2019	20.9

**Income & Poverty**

Median household income (in 2019 dollars), 2015-2019	\$45,750
Per capita income in past 12 months (in 2019 dollars), 2015-2019	\$28,821
Persons in poverty, percent	▲ 20.7%

**BUSINESSES****Businesses**

Total employer establishments, 2018	X
Total employment, 2018	X
Total annual payroll, 2018 (\$1,000)	X
Total employment, percent change, 2017-2018	X
Total nonemployer establishments, 2018	X
All firms, 2012	18,681
Men-owned firms, 2012	9,246
Women-owned firms, 2012	7,507
Minority-owned firms, 2012	6,071
Nonminority-owned firms, 2012	11,551
Veteran-owned firms, 2012	1,868
Nonveteran-owned firms, 2012	15,604


**GEOGRAPHY****Geography**

Population per square mile, 2010	1,733.6
Land area in square miles, 2010	132.45
FIPS Code	3775000

About datasets used in this table

Value Notes

 Estimates are not comparable to other geographic levels due to methodology differences that may exist between different data sources.

Some estimates presented here come from sample data, and thus have sampling errors that may render some apparent differences between geographies statistically indistinguishable. Click the Quick Info  icon to the left of each row in TABLE view to learn about sampling error.

The vintage year (e.g., V2019) refers to the final year of the series (2010 thru 2019). *Different vintage years of estimates are not comparable.*

Fact Notes

- (a) Includes persons reporting only one race
- (c) Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data
- (b) Hispanics may be of any race, so also are included in applicable race categories

Value Flags

- Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest or upper interval of an open ended distribution.
- F Fewer than 25 firms
- D Suppressed to avoid disclosure of confidential information
- N Data for this geographic area cannot be displayed because the number of sample cases is too small.
- FN Footnote on this item in place of data
- X Not applicable
- S Suppressed; does not meet publication standards
- NA Not available
- Z Value greater than zero but less than half unit of measure shown

QuickFacts data are derived from: Population Estimates, American Community Survey, Census of Population and Housing, Current Population Survey, Small Area Health Insurance Estimates, Small Area Income and Poverty Estimates, State and County Housing Unit Estimates, County Business Patterns, Nonemployer Statistics, Economic Census, Survey of Business Owners, Building Permits.

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# Exhibit 8



**VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY**  
**Blue Ridge Regional Office**

INTRA-AGENCY MEMORANDUM

Permit Writer	Allen Armistead			
Memo To	Air Permit File	Date	8/20/2015	
Facility Name	Transcontinental Gas Pipeline Company, LLC			
Registration Number	30864			
County-Plant I.D.	143-00120			
UTM Coordinates (Zone 17)	604.2	Easting (km)	4076.9	Northing (km)
Elevation (feet)	660			
Distance to Class I Areas	>100	SNP (km)	87.1	JRF (km)
FLM Notification (Y/N)	N	Required if less than 10K (minor), 100K (state major)		
NET Classification (A, SM, B)	A	Before permit action	A	After permit action
Title V Major Pollutants	NOx, VOC, CO, HAPs	Before permit action	NOx, VOC, CO, HAPs	After permit action
PSD Major Source (Y/N)	Y	Before permit action	Y	After permit action
PSD Major Pollutants	NOx, VOC, CO	Before permit action	NOx, VOC, CO	After permit action

## I. Introduction

Transcontinental Gas Pipe Line Corporation (Transco) is an interstate natural gas transmission company. Transco's compressor stations are used to compress and move the gas along the system. Transco currently operates a facility located at 945 Transco Road near Chatham, VA in Pittsylvania County. The facility consists of two compressor stations, Compressor Station #165 and #166. Station #165 has been in operation since 1957 and uses natural gas-fired, internal combustion, reciprocating compressor engines to power the compressors for the station. Station #166 is a newer station that uses natural gas-fired gas turbine powered compressors. Each station also has emergency generators associated with it. Because the stations are adjacent, under the same SIC code, and have common ownership, these two stations are considered to be one stationary source.

On March 18, 2015, this office received an application dated March 11, 2015, requesting a permit to install two additional gas turbine powered compressors and an additional emergency generator at Station #166. After completion of the project outlined in this application Station #166 will consist of four gas turbine powered compressors and two emergency generators. Additional information was received on June 2, 2015; June 22, 2015; and July 9, 2015, before the application was considered complete.

Transco's Chatham facility is a Title V major source of NO<sub>x</sub>, CO, VOC, and hazardous air pollutants (HAPs) and is covered by the Title V permit effective November 26, 2008. A Title V renewal application was received on May 21, 2013. A minor NSR permit for Station #165 was issued September 29, 2011, with amendments issued June 14, 2012 and February 28, 2013, covers one compressor and an emergency generator. The other engines at Station #165 are not covered by a minor NSR permit. Station #166 was issued a permit on November 12, 2013. This source is located in an attainment area for all pollutants and is a PSD major source. Transco is subject to a state operating permit (SOP) dated January 24, 2007, which is a source specific SIP revision to implement Phase II of the NO<sub>x</sub> SIP Call.

The last on site inspection of the facility was June 12, 2014. Transco was judged to be in compliance with its requirements.

## II. Emission Unit(s) / Process Description(s)

Additions to Compressor Station No. 166 will be two Solar Taurus 70-10802S gas turbine powered

natural gas compressors, each with a maximum rated capacity of 11,585 HP (85.14 MMBtu/hr)<sup>1</sup>, and a Waukesha-Pearce Model No. L5794LT 4 cycle spark ignited, rich burn (4SRB) emergency generator rated at 1,208 HP (10.03 MMBtu/hr [900 kW / 1208 HP])..

Fuel for the compressors and generator will be pipeline natural gas. These units emit mainly NO<sub>x</sub> and CO, with lesser amounts of particulate, VOC, SO<sub>2</sub>, and HAPs.

### **III. Regulatory Review**

#### **A. 9VAC5 Chapter 80, Part II, Article 6 – Minor New Source Review**

The proposed change meets the definition of project contained in 9VAC5-80-1110 C. For a project to be exempt from permitting, the regulations provide that a project must be exempt under both the provisions of 9VAC5-80-1105 B through D as a group and the provisions of 9VAC5-80-1105 E and F.

Equipment associated with the project is not listed in 9VAC5-80-1105 B. In determining if a project is exempt under 9VAC5-80-1105 D, a calculation of uncontrolled emission increase (UEI) is required. UEI is the difference between the new (after the project) uncontrolled emission rate (NUE) and the current (before the project) uncontrolled emission rate (CUE). Since the proposed equipment is new to the facility, the CUE for each of the units is zero.

Calculations were submitted by the permittee and revised by DEQ (see Attachment A). Calculations<sup>2</sup> for the turbine emissions show that the NUE, and UEI, for each turbine is 22.43 tons/yr for NO<sub>x</sub>. This is greater than the exemption threshold in 9VAC5-80-1105 D of 10 tons/yr for NO<sub>x</sub>. All of the other criteria pollutants are less than their respective exemption thresholds. Because the UEI for NO<sub>x</sub> is greater than its exemption threshold, a permit is required for the project.

Using the hourly emissions for the emergency generator engine in Attachment A, and extrapolating to 500 hours of emergency operation, yields a UEI for NO<sub>x</sub> of 1.33 tons/yr, for CO of 2.66 tons/yr, and for VOCs of 0.67 tons/yr.

Included with the application, and included in Attachment A. are estimated potential fugitive emissions of VOCs from the project of 0.91 tons/yr. These emissions are from operations at the facility separate from the emissions from the turbines and generator including: venting and piping components for the turbines and generator.

The toxic pollutants associated with operation of the turbines will be emitted at less than their respective exemption levels under 9VAC5-60-300. In addition, the turbines are in a MACT source category, 40 CFR 63 Subpart YYYYY, but there are currently only notification requirements for natural gas fired units such as those in this project. The emergency generator is covered by a MACT standard (40 CFR 63 Subpart ZZZZ). Therefore, the toxic emissions for the project are exempt from the state toxics rule under 9VAC5-60-300 and from review under Article 6.

#### **B. 9VAC5 Chapter 80, Part II, Article 8 and Article 9 – PSD Major New Source Review and Non-Attainment Major New Source Review**

Pittsylvania County is a PSD area for all pollutants as designated in 9VAC5-20-205. The facility is a PSD major source. The permittee proposes to limit the fuel throughput for the turbines and to limit the hours of operation of the generator to 500 hours. This will limit all emissions to less than the significant thresholds in 9VAC5-80-1615. Therefore, Article 8 and 9 will not be applicable.

Beginning July 1, 2011, greenhouse gases (GHG) is a pollutant that must be considered for regulation as a “regulated NSR pollutant” for projects that occur at any stationary source. Following the US Supreme Court decision on June 23, 2014, GHG may not be used to trigger a PSD permit by itself. If

<sup>1</sup> Based on a lower heating value (LHV) of 924.9 Btu/scf, in calculations provided by the manufacturer of the turbines.

<sup>2</sup> The calculations use emission factors and other data provided by the turbine manufacturer for NO<sub>x</sub>, CO, and VOC emissions. The other criteria pollutant emissions are based on AP-42 factors.

another regulated pollutant triggers PSD, then if the project causes an increase in CO<sub>2</sub> equivalents<sup>3</sup> (CO<sub>2</sub>e) of at least 75,000 tons per year GHG would be subject to PSD requirements as well. Therefore, Article 8 is not applicable to GHG for this project.

C. 9VAC5 Chapter 50, Part II, Article 5 – NSPS

The project turbines are subject to 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines. The emission factor for NO<sub>x</sub> submitted with the application is less than the emission standard listed in Subpart KKKK. Applicable requirements from Subpart A and Subpart KKKK have been included in the permit. NO<sub>x</sub> emissions in the permit are based on an emissions standard that is less than the emission standard in Subpart KKKK. Sulfur content of the fuel will be demonstrated with gas contract documentation. The permittee has chosen to show continuous compliance with the NO<sub>x</sub> standard by performing annual performance tests.

The emergency generator engine is subject to 40 CFR 60 Subpart JJJJ; Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. The NO<sub>x</sub>, CO, and VOC emissions calculations for the engine in Attachment A are based on the standards for an emergency engine in Subpart JJJJ. However, Transco is subject to Title V and any applicable requirements will be incorporated into the Title V permit.

D. 9VAC5 Chapter 60, Part II, Article 1 – NESHAPS

No applicable standards in 40CFR Part 61.

E. 9VAC5 Chapter 60, Part II, Article 2 – MACT

The emergency generator engine is subject to the major source requirements of 40 CFR 63 Subpart ZZZZ (RICE MACT). The application indicates that Transco is aware that the engine is subject to Subpart ZZZZ, and intends to comply with the requirements of the subpart. These applicable requirements will be incorporated into the source's Title V permit as required by the Air Regulations.

The turbines are covered by 40 CFR 63 Subpart YYYY (Stationary Combustion Turbines). Under §63.6095 (d) natural gas fired units, like those in this project, are currently only subject to initial notification requirements.

F. State Only Enforceable (SOE) Requirements (9VAC5-80-1120 F)

No SOE requirements are necessary.

#### **IV. Best Available Control Technology Review (BACT)**

BACT applicability for a project subject to permitting is a pollutant-by-pollutant evaluation. All units in a project that emit a pollutant that has an increase in uncontrolled emissions equal to or greater than its exemption threshold in 9VAC5-80-1105.D shall apply BACT for that pollutant. As discussed in Section III.A the NO<sub>x</sub> emissions from the turbines is greater than its threshold in 9VAC5-80-1105.D. Therefore, NO<sub>x</sub> emissions from the turbines and NO<sub>x</sub> emissions from the emergency generator are subject to BACT.

BACT for the turbines to minimize NO<sub>x</sub> emissions is the use of SoLoNO<sub>x</sub> technology<sup>4</sup>, which, for the proposed units, uses an emission factor of 15 ppm at 15% O<sub>2</sub> as compared to the NSPS Subpart KKKK standard of 25 ppm at 15% O<sub>2</sub>. Monitoring is required in the permit to show when each turbine is and is not operating in low-NO<sub>x</sub> mode. The source will conduct annual stack test to assure continuing compliance with the limit. The permit contains a limit on the amount of fuel that can be burned by the turbines on a 12-month rolling basis. Additionally, the permit contains a limit on the number of startups

<sup>3</sup> CO<sub>2</sub>e is the emission rate of each GHG species multiplied by its respective global warming potential (GWP) from 40CFR Part 98.

<sup>4</sup> A control system developed by Solar® turbines that is a dry low emissions technology that utilizes lean-premixed combustion technology to ensure uniform air/fuel mixture and to minimize formation of regulated pollutants.

and shutdowns for the turbines<sup>5</sup>. During the startups and shutdowns<sup>6</sup> there are transition times that the SoLoNOx technology does not function effectively. The permit, as a provision of NSPS Subpart KKKK, requires that the turbines be stack tested on an annual basis.

BACT for NOx on the emergency generator is limiting operation to less than 500 hours on a 12-month rolling basis. In addition, the emergency generator being a new unit that is subject to NSPS Subpart JJJJ, has an emissions standard for NOx that it is required to meet.

## V. Summary of Actual Emissions Increase

Emissions as a result of the project are shown in the table below.

Pollutant	Turbines (tons/yr)	Emergency Generator (tons/yr)	Tanks & Fugitives (tons/yr)	Project Total (tons/yr)	“Significant” Value (TPY)
NOx	37.0	1.33	-	38.33	40
CO	37.5	2.66	-	40.16	100
VOC	4.31	0.67	0.91	5.89	40
SO <sub>2</sub>	1.93	0.0015	-	1.93	40
PM	4.51	0.025	-	4.54	25
PM <sub>10</sub>	4.51	0.025	-	4.54	15
PM <sub>2.5</sub>	4.51	0.025	-	4.54	10

## VI. Dispersion Modeling

### A. Regulated Pollutants

As shown in the table in Section V, the project does not cause an increase in emissions for any criteria pollutant greater than the respective significant thresholds in 9VAC 5-80-1615 C. Therefore, by policy modeling is not required.

### B. Toxic Pollutants

Modeling is not required for a project that is exempt from the state toxics rule (See Section III.A).

## VII. Boilerplate Deviations

The current permit for Station #166 and the most recent Skeleton, Generic, and Testing boilerplates were used to prepare the proposed permit. There were no deviations.

## VIII. Compliance Demonstration

Hours of operation records are required for the emergency generator. Records of fuel consumption, fuel specifications, and startups/shutdowns are required for the turbines as well as annual testing as a requirement of NSPS Subpart KKKK.

## IX. Title V Review – 9VAC5 Chapter 80 Part II Article 1

The facility is a Title V major source due to a potential to emit (PTE) greater than 100 tons per year for at least one regulated pollutant. A complete application for a significant modification to the Title V permit is due no later than 12 months after beginning operation.

## X. Other Considerations

As part of the calculations submitted by the source, for this application, emissions estimates are given

<sup>5</sup> The annual number of startups and shutdowns was submitted by the source as part of the application.

<sup>6</sup> For this model of turbine each startup and each shutdown takes about 10 minutes.

for startup/shutdown periods. These estimates are not included in the permit because the fuel used during the startup/shutdown periods is part of the fuel limit for the project, and, with the exception of CO, the estimated emissions are relatively small. Fees are not paid for CO emissions and the addition of the CO emissions to those listed in the permit would not trigger any additional permitting threshold.

#### **XI. Recommendations**

Approval of the draft permit is recommended.

#### **Attachments**

Attachment A – Emissions Calculations

#### **Addendum**

In Transco's comments on the draft permit, Transco noted that the tank installed for NG pipeline condensate (Ref. Tnk1) has a capacity of 8,820 instead of the 4,200 gallons listed in the 11/12/13 permit. The tank installed is below the exemption level capacity in 9VAC5-80-1105 B and is below the applicability capacity for NSPS Kb. The Equipment List was changed to list the correct capacity for the tank.

# Exhibit 9



# COMMONWEALTH of VIRGINIA

Molly Joseph Ward  
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY  
Blue Ridge Regional Office  
[www.deq.virginia.gov](http://www.deq.virginia.gov)

David K. Paylor  
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Lynchburg, Virginia 24502  
(434) 582-5120  
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**Roanoke Office**  
3019 Peters Creek Road  
Roanoke, Virginia 24019  
(540) 562-6700  
Fax (540) 562-6725

August 24, 2015

Mr. Michael C. Callegari  
Manager, Environmental Compliance  
Transcontinental Gas Pipe Line Co., LLC  
P.O. Box 1396  
Houston, TX 77251-1396

Location: Pittsylvania County  
Registration No.: 30864

Dear Mr. Callegari:

Attached is a permit to modify and operate a compressor station in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. This permit supersedes your permit dated November 12, 2013.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on July 9, 2015.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to modify and operate shall not relieve Transcontinental Gas Pipe Line Co., LLC of the responsibility to comply with all other local, state, and federal permit regulations.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever

Mr. Michael C. Callegari  
August 24, 2015  
Page 2

occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director  
Department of Environmental Quality  
P. O. Box 1105  
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

A copy of the results of performance tests required by 40 CFR 60, Subpart KKKK shall to be sent to:

Associate Director  
Office of Air Enforcement and Compliance Assistance (3AP20)  
U.S. Environmental Protection Agency  
Region III  
1650 Arch Street  
Philadelphia, PA 19103-2029

If you have any questions concerning this permit, please contact Allen Armistead at 434-582-6202 or the regional office at 434-582-5120.

Sincerely,



Robert J. Weld  
Regional Director

RJW/EAA

Attachments: Permit  
NSPS, Subpart KKKK (find at <http://www.ecfr.gov>)  
Source Testing Report Format

cc: Manager/Inspector, Air Compliance





# COMMONWEALTH of VIRGINIA

Molly Joseph Ward  
Secretary of Natural Resources

DEPARTMENT OF ENVIRONMENTAL QUALITY  
Blue Ridge Regional Office  
[www.deq.virginia.gov](http://www.deq.virginia.gov)

David K. Paylor  
Director

Robert J. Weld  
Regional Director

**Lynchburg Office**  
7705 Timberlake Road  
Lynchburg, Virginia 24502  
(434) 582-5120  
Fax (434) 582-5125

**Roanoke Office**  
3019 Peters Creek Road  
Roanoke, Virginia 24019  
(540) 562-6700  
Fax (540) 562-6725

## STATIONARY SOURCE PERMIT TO MODIFY AND OPERATE This permit includes designated equipment subject to New Source Performance Standards (NSPS).

This permit supersedes your permit dated November 12, 2013.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia  
Regulations for the Control and Abatement of Air Pollution,

Transcontinental Gas Pipe Line Co., LLC  
P.O. Box 1396  
Houston, TX 77251-1396  
Registration No.: 30864

is authorized to modify and operate

compressor station 166

located at

945 Transco Rd, Chatham, VA 24531

in accordance with the Conditions of this permit.

Approved on August 24, 2015.

Robert J. Weld  
Regional Director

Permit consists of 14 pages.  
Permit Conditions 1 to 38.

## **INTRODUCTION**

This permit approval is based on and combines permit terms and conditions in accordance with 9 VAC 5-80-1255 from the following permit approvals and the respective permit applications:

minor new source review permit approval dated August 24, 2015 based on the permit application dated March 11, 2015, and supplemental information dated June 2, 2015; June 22, 2015; and July 9, 2015;

minor new source review permit approval dated November 12, 2013 based the permit application dated February 5, 2013, and supplemental information dated March 11, 2013; April 8, 2013; April 23, 2013; June 7, 2013; and July 16, 2013

Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9VAC5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9VAC5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

**Equipment List** - Equipment at this facility consists of the following:

<b>Equipment included in the project</b>				
<b>Reference No.</b>	<b>Equipment Description</b>	<b>Rated Capacity</b>	<b>Federal Requirements</b>	
Tur3	Solar Taurus 70-10802S Turbine	85.14 MMBtu/hr (LHV)*	40 CFR 60 Subpart KKKK	
Tur4	Solar Taurus 70-10802S Turbine	85.14 MMBtu/hr (LHV)	40 CFR 60 Subpart KKKK	
Eng2	Emergency Generator – Waukesha-Pearce Industries, Inc. Model No. L5794LT	900 kW / 1208 HP	40 CFR 60 Subpart JJJJ	

<b>Equipment Previously Permitted</b>				
<b>Reference No.</b>	<b>Equipment Description</b>	<b>Rated Capacity</b>	<b>Federal Requirements</b>	<b>Permit Date</b>
Tur1	Solar Taurus 70-10802S Turbine	80.38 MMBtu/hr (LHV)*	40 CFR 60 Subpart KKKK	11/12/13
Tur2	Solar Taurus 70-10802S Turbine	80.38 MMBtu/hr (LHV)	40 CFR 60 Subpart KKKK	11/12/13
Eng1	Emergency Generator – Waukesha-Pearce Industries, Inc. Model No. L5794LT	900 kW / 1208 HP	40 CFR 60 Subpart JJJJ	11/12/13

<b>Equipment Exempt from Permitting</b>				
<b>Reference No.</b>	<b>Equipment Description</b>	<b>Rated Capacity</b>	<b>Exemption Citation</b>	<b>Exemption Date</b>
Tnk1	Tank for NG pipeline condensate	8,820 gal	9VAC5-80-1105 B.8	11/12/13, Revised 8/24/2015
Tnk2	Tank for Oil/Water mixture	4,200 gal	9VAC5-80-1105 B.8	11/12/13

\* - LHV means Lower Heating Value

Specifications included in the above tables are for informational purposes only and do not form enforceable terms or conditions of the permit.

### **PROCESS REQUIREMENTS**

1. **Emission Controls** – Nitrogen Oxides (NO<sub>x</sub>) emissions from the four turbines (Tur1 thru Tur4) shall be controlled by Solar Turbine's SoLoNO<sub>x</sub> technology. The turbines shall be provided with adequate access for inspection, and the SoLoNO<sub>x</sub> technology shall be in operation when the turbines are operating.  
(9VAC5-80-1180 and 9VAC5-50-260)[8/24/2015]
2. **Emission Controls** – Carbon Monoxide (CO) and Volatile Organic Compound (VOC) emissions from the four turbines (Tur1 thru Tur4) shall be controlled by operating and maintaining the turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Maintenance shall be done in accordance with the manufacturer recommendations.  
(9VAC5-80-1180 and 9VAC5-50-410) [8/24/2015]

### **OPERATING LIMITATIONS**

3. **Operating Hours** - The emergency generator engines (Eng1 & Eng2) shall each not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.  
(9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]

4. **Operating Practice** - The two turbines (Tur1 & Tur2) shall not have more than 300 total startup/shutdown events per year, not to exceed 100 hours per year for startup/shutdown events, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.  
(9VAC5-80-1180 and 9VAC5-50-260)[11/12/13]
5. **Operating Practice** - The two turbines (Tur3 & Tur4) shall not have more than 300 total startup/shutdown events per year, not to exceed 100 hours per year for startup/shutdown events, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.  
(9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]
6. **Monitoring Devices** - The emergency generator engines (Eng1 & Eng2) shall each be equipped with a non-resettable hour meter to continuously measure hours of operation.  
Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the emergency generator engine is operating.  
(9VAC5-80-1180 D and 9VAC5-50-260) [8/24/2015]
7. **Monitoring Devices** – Each of the four turbines (Tur1 thru Tur4) shall be equipped with a continuous monitoring system to monitor the appropriate parameters as recommended by the manufacturer to determine whether the units are operating to control NOx emissions using the SoLoNOx technology. The permittee shall keep a log of the operating time when the SoLoNOx technology is not operating to control NOx emissions, including startups and shutdowns. The log shall include the cause when the SoLoNOx technology is not controlling NOx emissions and the associated emissions during the non-control period.  
Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when either of the four turbines (Tur1 thru Tur4) is operating.  
(9VAC5-80-1180 D and 9VAC5-50-260) [8/24/2015]
8. **Fuel** - The approved fuel for the four turbines (Tur1 thru Tur4) and the emergency generators (Eng1 & Eng2) is natural gas. A change in the fuel may require a permit to modify and operate.  
(9VAC5-80-1180) [8/24/2015]

9. **Fuel Specifications** - The natural gas shall meet the specifications below:
- a. It shall meet the definition as specified in 40 CFR 60.4420, and
  - b. It shall meet the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract for the fuel as described in 40 CFR 60.4365. This documentation shall specify that the total sulfur content for the natural gas is 0.003% or less.  
(9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]
10. **Fuel Throughput** - The two turbines (Tur1 & Tur2) shall consume no more than  $1,170 \times 10^6$  standard cubic feet per year, calculated monthly as the sum of each consecutive 12-month period. Standard conditions shall be as specified in 40 CFR 72.2 (68°F and 29.92 in Hg). Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.  
(9VAC5-80-1180 and 9VAC5-50-260) [11/12/13]
11. **Fuel Throughput** - The two turbines (Tur3 & Tur4) shall consume no more than  $1,330 \times 10^6$  standard cubic feet per year, calculated monthly as the sum of each consecutive 12-month period. Standard conditions shall be as specified in 40 CFR 72.2 (68°F and 29.92 in Hg). Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.  
(9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]
12. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the four turbines (Tur1 thru Tur4) shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.  
(9VAC5-80-1180, 9VAC5-50-400, and 9VAC5-50-410) [8/24/2015]
13. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the two emergency generators (Eng1 and Eng2) shall be operated in compliance with the requirements of 40 CFR 60, Subpart JJJJ.  
(9VAC5-80-1180, 9VAC5-50-400, and 9VAC5-50-410) [8/24/2015]

#### **EMISSION LIMITS**

14. **Process Emission Limits** - Emissions from the operation of each of the two turbines Tur1 & Tur2 shall not exceed the limits specified below:
- |                                                       |             |
|-------------------------------------------------------|-------------|
| Particulate Matter (PM)<br>(including condensable PM) | 0.59 lbs/hr |
| PM-10                                                 | 0.59 lbs/hr |
| PM-2.5                                                | 0.59 lbs/hr |

Sulfur Dioxide	0.25 lbs/hr	
Nitrogen Oxides (as NO <sub>2</sub> )	15.0 ppmvd @ 15% O <sub>2</sub>	0.060 lb/MMBtu (LHV)
Carbon Monoxide	25.0 ppmvd @ 15% O <sub>2</sub>	0.061 lb/MMBtu (LHV)
Volatile Organic Compounds	0.57 lbs/hr	

Compliance with these emission limits may be determined as stated in Conditions 8 and 9. These limits apply at all times except during startup, shutdown, and malfunction. (9VAC5-80-1180 and 9VAC5-50-260) [11/12/13]

**15. Process Emission Limits** - Emissions from the operation of both of the two turbines Tur1 & Tur2 combined shall not exceed the limits specified below:

Particulate Matter (PM) (including condensable PM)	3.9 tons/yr
PM-10	3.9 tons/yr
PM-2.5	3.9 tons/yr
Sulfur Dioxide	1.7 tons/yr
Nitrogen Oxides (as NO <sub>2</sub> )	32.2 tons/yr
Carbon Monoxide	32.7 tons/yr
Volatile Organic Compounds	3.7 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits, excluding startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition(s) 8, 9, and 10. (9VAC5-80-1180 and 9VAC5-50-260) [11/12/13]

**16. Process Emission Limits** - Emissions from the operation of each of the two turbines Tur3 & Tur4 shall not exceed the limits specified below:

Particulate Matter (PM) (including condensable PM)	0.62 lbs/hr	
PM-10	0.62 lbs/hr	
PM-2.5	0.62 lbs/hr	
Sulfur Dioxide	0.27 lbs/hr	
Nitrogen Oxides (as NO <sub>2</sub> )	15.0 ppmvd @ 15% O <sub>2</sub>	0.060 lb/MMBtu (LHV)

Carbon Monoxide	25.0 ppmvd @ 15% O <sub>2</sub>	0.061 lb/MMBtu (LHV)
Volatile Organic Compounds	0.60 lbs/hr	

Compliance with these emission limits may be determined as stated in Conditions 8 and 9. These limits apply at all times except during startup, shutdown, and malfunction.  
 (9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]

**17. Process Emission Limits** - Emissions from the operation of both of the two turbines Tur3 & Tur4 combined shall not exceed the limits specified below:

Particulate Matter (PM) (including condensable PM)	4.5 tons/yr
PM-10	4.5 tons/yr
PM-2.5	4.5 tons/yr
Sulfur Dioxide	1.9 tons/yr
Nitrogen Oxides (as NO <sub>2</sub> )	37.0 tons/yr
Carbon Monoxide	37.5 tons/yr
Volatile Organic Compounds	4.3 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits, excluding startup and, shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition(s) 8, 9, and 11.  
 (9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]

**18. Process Emission Limits** - Emissions from the operation of the emergency generator (Eng1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO <sub>2</sub> )	5.33 lbs/hr	1.3 tons/yr
Carbon Monoxide	10.65 lbs/hr	2.7 tons/yr
Volatile Organic Compounds	2.66 lbs/hr	0.7 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 3, 8, and 9.  
 (9VAC5-80-1180 and 9VAC5-50-260) [11/12/13]

19. Emissions from the operation of the emergency generator (Eng2) shall not exceed the limits specified below:

Nitrogen Oxides (as NO <sub>2</sub> )	5.33 lbs/hr	1.3 tons/yr
Carbon Monoxide	10.65 lbs/hr	2.7 tons/yr
Volatile Organic Compounds	2.66 lbs/hr	0.7 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 3, 8, and 9.

(9VAC5-80-1180 and 9VAC5-50-260) [8/24/2015]

20. **Visible Emission Limit** - Visible emissions from each of the four turbines (Tur1 thru Tur4) shall not exceed five (5) percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.

(9VAC5-80-1180) [8/24/2015]

21. **Visible Emission Limit** - Visible emissions from each of the emergency generators (Eng1 & Eng2) shall not exceed five (5) percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.

(9VAC5-80-1180) [8/24/2015]

## **RECORDS**

22. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Blue Ridge Regional Office. These records shall include, but are not limited to:

- Annual hours of operation of each of the emergency generator engines (Eng1 & Eng2), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- The annual number of startup/shutdown events by the two turbines Tur1 & Tur2 and the total amount of time associated with the startup/shutdown events, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.



- c. The annual number of startup/shutdown events by the two turbines Tur3 & Tur4 and the total amount of time associated with the startup/shutdown events, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- d. Annual consumption of natural gas by the two turbines Tur1 & Tur2, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- e. Annual consumption of natural gas by the two turbines Tur3 & Tur4, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- f. Monthly and annual emissions calculations for NOx from the two turbines Tur1 & Tur2 using calculation methods approved by the Blue Ridge Regional Office to verify compliance with the ton/yr emissions limitations in Condition 15. Annual emissions shall be calculated monthly as the sum of each consecutive 12 month period. The consecutive 12-month period sum shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- g. Monthly and annual emissions calculations for NOx from the two turbines Tur3 & Tur4 using calculation methods approved by the Blue Ridge Regional Office to verify compliance with the ton/yr emissions limitations in Condition 17. Annual emissions shall be calculated monthly as the sum of each consecutive 12 month period. The consecutive 12-month period sum shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
- h. Documentation of the average monthly Btu value for the natural gas consumed by the four turbines (Tur1 thru Tur4) in both Lower Heating Value and Higher Heating Value, along with any methodologies used in any conversions.
- i. Records to verify that the natural gas fuel meets the specifications as required in Condition 9.
- j. Results of all performance tests, and results of DEQ requested visible emission evaluations.

- k. Records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the four turbines (Tur1 thru Tur4) or any malfunction of the air pollution control equipment. This includes the log required by Condition 7.
- l. Scheduled and unscheduled maintenance, and operator training.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.

(9VAC5-80-1180, 9VAC5-50-50, 9VAC5-50-410, and 40 CFR 60.7) [8/24/2015]

### **TESTING**

23. **Emissions Testing** - The compressor station shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.  
(9VAC5-50-30 F and 9VAC5-80-1180) [8/24/2015]

24. **Stack Test (Initial Compliance - NO<sub>x</sub>)** - Initial performance tests shall be conducted for NO<sub>x</sub> from the two turbines Tur1 & Tur2 in accordance with the requirements of 40 CFR 60.4400 to determine compliance with the emission limit contained in Condition 14. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within the time period specified above or within 60 days after test completion, whichever is earlier, and shall conform to the test report format enclosed with this permit.

The parameters indicating that the SoLoNO<sub>x</sub> technology is operating in low-NO<sub>x</sub> mode, as addressed in Condition 7, shall be monitored and recorded during the performance tests.  
(9VAC5-50-30, 9VAC5-80-1200, 9VAC5-50-410, and 40 CFR 60.4400) [11/12/13]

25. **Stack Test (Initial Compliance - NO<sub>x</sub>)** - Initial performance tests shall be conducted for NO<sub>x</sub> from the two turbines Tur3 & Tur4 in accordance with the requirements of 40 CFR 60.4400 to determine compliance with the emission limit contained in Condition 16. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within the time period specified above or within 60 days

after test completion, whichever is earlier, and shall conform to the test report format enclosed with this permit.

The parameters indicating that the SoLoNOx technology is operating in low-NOx mode, as addressed in Condition 7, shall be monitored and recorded during the performance tests. (9VAC5-50-30, 9VAC5-80-1200, 9VAC5-50-410, and 40 CFR 60.4400) [8/24/2015]

26. **Stack Test (Continuous Compliance - NO<sub>x</sub>)** – NO<sub>x</sub> performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test) on the four turbines (Tur1 thru Tur4) in accordance with the requirements of 40 CFR 60.4400 to determine compliance with the emission limit contained in Condition 14 and 16. If the NO<sub>x</sub> emission result from the performance test is less than or equal to 75 percent of the NO<sub>x</sub> emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO<sub>x</sub> emission limit for the turbine, you must resume annual performance tests. Tests shall be conducted and reported and data reduced as set forth in 9VAC5-50-30, and the test methods and procedures contained in each applicable section or subpart listed in 9VAC5-50-410. The details of the tests are to be arranged with the Blue Ridge Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Blue Ridge Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.

The parameters indicating that the SoLoNOx technology is operating in low-NOx mode, as addressed in Condition 7, shall be monitored and recorded during the performance tests. (9VAC5-50-30, 9VAC5-80-1200, 9VAC5-50-410, and 40 CFR 60.4340 & 60.4400) [8/24/2015]

27. **Performance Test (Compliance - Sulfur)** - Each time a test is conducted as outlined in Conditions 24, 25, and 26 a SO<sub>2</sub> performance test shall be conducted for the turbines in accordance with the requirements of 40 CFR 60.4415. (9VAC5-50-30, 9VAC5-80-1200, 9VAC5-50-410, and 40 CFR 60.4415) [8/24/2015]

## **NOTIFICATIONS**

28. **Initial Notifications** - The permittee shall furnish written notification to the Blue Ridge Regional Office of:
- a. The actual date on which construction of the two turbines (Tur3 & Tur4) and emergency generator (Eng2) commenced within 30 days after such date.
  - b. The actual start-up date of the two turbines (Tur1 & Tur2) and emergency generator (Eng1) within 15 days after such date.
  - c. The actual start-up date of the two turbines (Tur3 & Tur4) and emergency generator (Eng2) within 15 days after such date.

- d. The anticipated date of performance tests of the compressor station postmarked at least 30 days prior to such date.
- e. An Initial Notification for the two turbines (Tur3 & Tur4) in accordance with the requirements of 40 CFR 63.6145.

Copies of the written notification referenced in items a through e above are to be sent to:

Associate Director  
Office of Air Enforcement and Compliance Assistance (3AP20)  
U.S. Environmental Protection Agency  
Region III  
1650 Arch Street  
Philadelphia, PA 19103-2029

(9VAC5-50-50, 9VAC5-80-1180, 9VAC5-50-410, 40 CFR 60.7, 9VAC5-60-100, and 40 CFR 63.9) [8/24/2015]

### **GENERAL CONDITIONS**

**29. Permit Invalidity** – This permit to construct the two turbines Tur1 & Tur2 and emergency generator engine Eng1 shall become invalid, unless an extension is granted by the DEQ, if:

- a. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of a phased construction project.  
(9VAC5-80-1210) [11/12/13]

**30. Permit Invalidity** – This permit to construct the two turbines Tur3 & Tur4 and emergency generator engine Eng2 shall become invalid, unless an extension is granted by the DEQ, if:

- a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit;
- b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of a phased construction project.  
(9VAC5-80-1210) [8/24/2015]

**31. Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

- a. Knowingly makes material misstatements in the permit application or any amendments to it;
- b. Fails to comply with the conditions of this permit;
- c. Fails to comply with any emission standards applicable to a permitted emissions unit;

- d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or
  - e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.
- (9VAC5-80-1210 F)

**32. Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

- a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;
- b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;
- c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and
- d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.  
(9VAC5-170-130 and 9VAC5-80-1180)

**33. Maintenance/Operating Procedures** – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to the four turbines (Tur1 thru Tur4) and two emergency generator engines (Eng1 & Eng2):

- a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.
- b. Maintain an inventory of spare parts.
- c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.
- d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such

equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.  
(9VAC5-50-20 E and 9VAC5-80-1180 D) [8/24/2015]

34. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.  
(9VAC5-20-180 J and 9VAC5-80-1180 D)
35. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Blue Ridge Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Blue Ridge Regional Office.  
(9VAC5-20-180 C and 9VAC5-80-1180)
36. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.  
(9VAC5-20-180 I and 9VAC5-80-1180)
37. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Blue Ridge Regional Office of the change of ownership within 30 days of the transfer.  
(9VAC5-80-1240)
38. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.  
(9VAC5-80-1180)

## SOURCE TESTING REPORT FORMAT

### Report Cover

1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

### Certification

1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. \*Signed by reviewer

### Copy of approved test protocol

### Summary

1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. \*For each emission unit, a table showing:
  - a. Operating rate
  - b. Test Methods
  - c. Pollutants tested
  - d. Test results for each run and the run average
  - e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

### Source Operation

1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

### Test Results

1. Detailed test results for each run
2. \*Sample calculations
3. \*Description of collected samples, to include audits when applicable

### Appendix

1. \*Raw production data
2. \*Raw field data
3. \*Laboratory reports
4. \*Chain of custody records for lab samples
5. \*Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

\* Not applicable to visible emission evaluations

# Exhibit 10



## **SoLoNO<sub>x</sub> Products: Emissions in Non-SoLoNO<sub>x</sub> Modes**

**Leslie Witherspoon**  
Solar Turbines Incorporated

### **PURPOSE**

Solar's gas turbine dry low NO<sub>x</sub> emissions combustion systems, known as SoLoNO<sub>x</sub><sup>™</sup>, have been developed to provide the lowest emissions possible during normal operating conditions. In order to optimize the performance of the turbine, the combustion and fuel systems are designed to reduce NO<sub>x</sub>, CO and unburned hydrocarbons (UHC) without penalizing stability or transient capabilities. At very low load and cold temperature extremes, the SoLoNO<sub>x</sub> system must be controlled differently in order to assure stable operation. The required adjustments to the turbine controls at these conditions cause emissions to increase.

The purpose of this Product Information Letter is to provide emissions estimates, and in some cases warrantable emissions for NO<sub>x</sub>, CO and UHC, at off-design conditions.

The expected emissions values that follow are typically used to estimate emissions for annual emissions inventory purposes, for New Source Review applicability determinations, for air dispersion modeling, and for air permitting.

### **EMISSIONS ESTIMATES IN NON-SOLONOX MODE (LOW LOAD)**

At operating loads < ~50%<sup>1</sup> on natural gas fuel and < ~65%<sup>2</sup> on liquid fuels, SoLoNO<sub>x</sub> engines are controlled to increase stability and transient response capability. The control steps that are required affect emissions in two ways: 1) pilot fuel flow is increased, increasing NO<sub>x</sub> emissions, and 2) airflow through the combustor is increased, increasing CO emissions. Engine controls are triggered either by power output for single-shaft engines or gas producer speed for two-shaft engines.

Emissions at lower loads vary by model and by the generation of control system. NO<sub>x</sub> can range from 40 to 70 ppm (raw) and CO and UHC emissions can vary from 25 to 10000 ppm (raw).

**For emissions estimates at part-load conditions (idle to SoLoNO<sub>x</sub> mode) contact Solar's Environmental Programs Group (Anthony Pocengal 858.505.8554 or Leslie Witherspoon 858.694.6609).**

As an alternative, a conservative method for estimating emissions of NO<sub>x</sub> at low loads is to use the applicable New Source Performance Standard (NSPS): 40CFR60 subpart GG or KKKK. For projects that commence construction after February 18, 2005, subpart KKKK is the applicable NSPS and contains a NO<sub>x</sub> level of 150 ppm @ 15% O<sub>2</sub> for operating loads less than 75%.

---

<sup>1</sup> <~40% load for the *Titan 250*

<sup>2</sup> < ~80% load for *Centaur 40*

## COLD AMBIENT EMISSIONS ESTIMATES

Solar's standard temperature range warranty for gas turbines with SoLoNOx combustion is  $\geq 0^{\circ}\text{F}$ . At ambient temperatures below  $0^{\circ}\text{F}$ , Solar's turbine models are controlled to increase pilot fuel which improves flame stability but leads to higher emissions. Without the increase in pilot fuel at temperatures below  $0^{\circ}\text{F}$  the turbine may exhibit combustor rumble, as operation may be near the lean stability limit. The *Titan*™ 250 is an exception, with a lower standard warranty at  $\geq -20^{\circ}\text{F}$ .

If a cold ambient emissions warranty is requested, the turbine must be configured with the appropriate combustion hardware and software. For new production hardware this refers to the inclusion of "Pilot Active Control Logic". Pilot Active Control Logic employs active oscillations feedback to increase pilot and reduce oscillations.

A cold ambient emissions warranty is only available on gas turbines being fired on natural gas and is not offered for ambient temperatures below  $-20^{\circ}\text{F}$ . Standard natural gas as defined in Solar's fuel spec, ES9-98, is required to offer a cold ambient warranty, but non-standard fuels on a project basis can be reviewed by Solar to determine applicability. Cold ambient emissions warranties cannot be offered for the *Centaur*® 40 turbine. In addition, a cold ambient warranty cannot be offered for liquid fuel operation at this time.

Table 1 provides expected and warrantable cold ambient emissions levels for Solar's SoLoNOx combustion turbines. Refer to Product Information Letter 205 for *Mercury*™ 50 turbine emissions estimates.

**Table 1.** *Expected and/or Warrantable Emissions Between  $0^{\circ}\text{F}$  and  $-20^{\circ}\text{F}$  for Turbines Equipped with Pilot Active Control Logic*  
Natural Gas Fuel  
NOx ppm values corrected to 15% O<sub>2</sub>

Turbine Model	Fuel System	Fuel	Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
<i>Centaur</i> 50	Gas Only	Gas	50 to 100% load	42	100	50
	Dual Fuel	Gas	50 to 100% load	72	100	50
<i>Taurus</i> ™ 60	Gas Only or Dual Fuel	Gas	50 to 100% load	42	100	50
<i>Taurus</i> 65	Gas Only	Gas	50 to 100% load	42	100	50
<b><i>Taurus</i> 70</b>	<b>Gas Only or Dual Fuel</b>	<b>Gas</b>	<b>50 to 100% load</b>	<b>42</b>	<b>100</b>	<b>50</b>
<i>Mars</i> ® 90	Gas Only	Gas	50 to 100% load	42	100	50
<b><i>Mars</i> 100</b>	<b>Gas Only or Dual Fuel</b>	<b>Gas</b>	<b>50 to 100% load</b>	<b>42</b>	<b>100</b>	<b>50</b>
<i>Titan</i> 130	Gas Only or Dual Fuel	Gas	50 to 100% load	42	100	50
<i>Titan</i> 250	Gas Only	Gas	40 to 100% load	25	50	25
	Gas Only	Gas	40 to 100% load	15	25	25

A cold ambient warranty is available for new equipment and will expire along with the new equipment warranty. A cold ambient warranty is available for existing equipment if the cold ambient upgrade is done at the time of overhaul. If an existing eligible turbine undergoes a "field retrofit" of the Pilot Active Control Logic, emissions values as shown in Table 1 are "expected" but not warranted. A warranty can be activated at the next engine overhaul and will expire along with the engine overhaul warranty. **Not all legacy models/ratings will have a cold ambient warranty option.**

**For information on the availability and approvals for cold ambient temperature emissions warranties, please contact Solar's sales representatives.**

Table 2 summarizes “expected” emissions levels for ambient temperatures below 0°F for Solar’s SoLoNOx turbines that are not equipped with the Pilot Active Control Logic or do not have the a generation of hardware that can be equipped with Pilot Active Control Logic. The emissions levels are extrapolated from San Diego factory tests and may vary at extreme temperatures and as a result of variations in other parameters, such as fuel composition, fuel quality, etc.

Table 3 summarizes “expected” emissions levels for ambient temperatures below –20°F for the *Titan 250*.

**Table 2. Expected Emissions below 0°F for SoLoNOx Combustion Turbines without Pilot Active Control Logic**

*NOx ppm values corrected to 15% O<sub>2</sub>*

Turbine Model	Fuel	Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
<i>Centaur 40</i>	Gas	50 to 100% load	120	150	50
<i>Centaur 50</i>	Gas	50 to 100% load	120	150	50
	Gas	50 to 100% load	120	150	50
<i>Taurus 60</i>	Gas	50 to 100% load	120	150	50
<i>Taurus 65</i>	Gas	50 to 100% load	120	150	50
<i>Taurus 70</i>	Gas	50 to 100% load	120	150	50
<i>Mars 90</i>	Gas	50 to 100% load	120	150	50
<i>Mars 100</i>	Gas	50 to 100% load	120	150	50
<i>Titan 130</i>	Gas	50 to 100% load	120	150	50
<i>Centaur 40</i>	Liquid	80 to 100% load	150	150	75
<i>Centaur 50</i>	Liquid	65 to 100% load	150	150	75
<i>Taurus 60</i>	Liquid	65 to 100% load	150	150	75
<i>Taurus 70</i>	Liquid	65 to 100% load	150	150	75
<i>Mars 100</i>	Liquid	65 to 100% load	150	150	75
<i>Titan 130</i>	Liquid	65 to 100% load	150	150	75

**Table 3. Expected Emissions below –20°F for the Titan 250 SoLoNOx Combustion Turbine**

*NOx ppm values corrected to 15% O<sub>2</sub>*

Turbine Model	Fuel	Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
<i>Titan 250</i>	Gas	40 to 100% load	70	150	50

For a more conservative NOx emissions estimate than shown in Table 2 or 3, customers can refer to the NSPS 40CFR60, Subpart KKKK, where the allowable NOx emissions level for ambient temperatures < 0°F is 150 ppm NOx at 15% O<sub>2</sub>. For pre-February 18, 2005, SoLoNOx combustion turbines subject to 40CFR60 subpart GG, a conservative estimate is the appropriate subpart GG emissions level. Subpart GG levels range from 150 to 214 ppm NOx at 15% O<sub>2</sub> on natural gas (and 150-210 on liquid fuel) depending on the turbine model.

**COLD AMBIENT PERMITTING STRATEGY OPTIONS**

When permitting in cold ambient climates, customers can use a “tiered emissions” permitting approach, choose to permit a single emission rate over all temperatures, use 40CFR60 Subpart KKKK, or develop another strategy to satisfy air permitting requirements.

In a “tiered” approach, a digital thermometer is installed to record ambient temperature. The amount of time is recorded that the ambient temperature falls below 0°F. The amount of time below 0°F is then used with the emissions estimates shown in Tables 1 and 2 to estimate “actual” emissions during sub-zero operation.

For customers who wish to permit at a single emission rate over all ambient temperatures, inlet air heating can be used to raise the engine inlet air temperature ( $T_1$ ) above 0°F. With inlet air heating to keep  $T_1$  above 0°F, standard emission warranty levels may be offered. Inlet air heating technology options include an electric resistance heater, an inlet air to exhaust heat exchanger and a glycol heat exchanger.

A conservative alternative to using the NO<sub>x</sub> values in Tables 1, 2 and 3 is to reference 40CFR60 subpart KKKK, which allows 150 ppm NO<sub>x</sub> at 15% O<sub>2</sub> for sub-zero operation.

Solar Turbines Incorporated  
9330 Sky Park Court  
San Diego, CA 92123-5398

This information is intended as a general overview and is not intended to be, and should not be used as, a substitute for obtaining legal advice in any specific situation. This document is accurate as of the publication date. Therefore, any discussion of a particular regulatory issue may become outdated. If specific legal advice is required, the reader should consult with an attorney.

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**Archived:** Monday, April 12, 2021 8:01:14 AM

**From:** [Mark Sabath](#)

**Sent:** Friday, April 9, 2021 9:10:45 AM

**To:** 'Walthall, Anita'

**Cc:** 'Peter Anderson'; Tiffany Haworth ([thaworth@danriver.org](mailto:thaworth@danriver.org)); 'Steven Pulliam'; Emily Sutton; Anita Royston ([naacppittsyco@gmail.com](mailto:naacppittsyco@gmail.com)); Elizabeth Kostelny; Ivy Main ([ivy.main@sierraclub.org](mailto:ivy.main@sierraclub.org))

**Subject:** Comments on Lambert Compressor Station Air Permit (Email 2 of 2)

**Importance:** Normal

**Attachments:**

[Exhibits 11-28.pdf](#);

---

Ms. Walthall: Please find attached Exhibits 11-28 to the comments submitted with the email below.

Mark

---

**From:** Mark Sabath

**Sent:** Friday, April 09, 2021 9:06 AM

**To:** 'Walthall, Anita'

**Cc:** 'Peter Anderson'; Tiffany Haworth ([thaworth@danriver.org](mailto:thaworth@danriver.org)); 'Steven Pulliam'; Emily Sutton; Anita Royston ([naacppittsyco@gmail.com](mailto:naacppittsyco@gmail.com)); Elizabeth Kostelny; Ivy Main ([ivy.main@sierraclub.org](mailto:ivy.main@sierraclub.org))

**Subject:** Comments on Lambert Compressor Station Air Permit (Email 1 of 2)

Ms. Walthall: Please find attached the comments of the Southern Environmental Law Center, Appalachian Voices, Dan River Basin Association, Good Stewards of Rockingham, Haw River Assembly, Pittsylvania County NAACP, Preservation Virginia, and Sierra Club Virginia Chapter on the proposed stationary source permit to Mountain Valley Pipeline, LLC to construct and operate the Lambert Compressor Station (Registration No. 21652). Exhibits 1-10 to our comments are also attached to this email. Exhibits 11-28 will follow in a second email.

Please feel free to contact me with any questions.

Mark

**Mark Sabath**

Senior Attorney | Southern Environmental Law Center

201 West Main St., Suite 14 | Charlottesville, VA 22902-5065

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# Exhibit 11

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# SoLoNOx<sup>TM</sup> Upgrade

## Low Emission Gas Turbine Solutions

Solar's SoLoNOx technology is a sustainable solution that reduces NOx and CO emissions. Since its introduction in 1992, Solar has shipped more than 2800 turbines equipped with SoLoNOx low emissions technology, reducing NOx emissions by over 6 million tons. Now, Solar is introducing the next generation of this innovative



technology. Advances in combustor liner, fuel injector, and bleed shield design, along with primary zone temperature control are some of the advancements allowing Solar to offer a robust 9ppm NO<sub>x</sub>, 15ppm CO, and 15 ppm UHC emissions warranty for natural gas fuel. This standard production option is now available for the Taurus 70- 10800, with other models and selected ratings to follow.



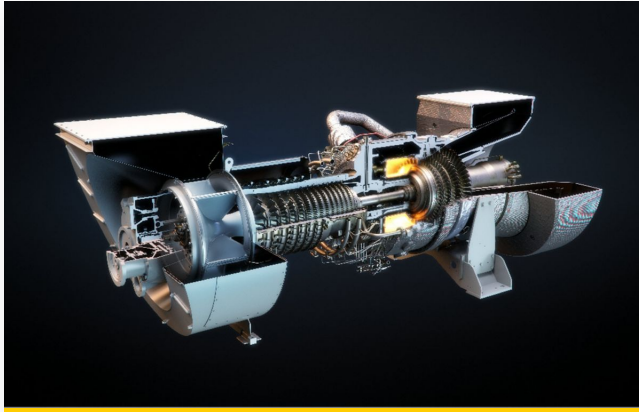
1 of 3

# SoLoNOx Upgrade Provides Increased Production And Better Emissions Controls

Downtime means lost production. Your exchange engine can also include a SoLoNOx conversion to minimize interruption to your production. By converting to Solar's SoLoNOx combustion system you can reduce emissions at your site, giving you more permitting options while helping improve local air quality.

[LEARN MORE](#)

## Case Studies And Solutions



## Combustion Technology

Solar has a long history of installing gas turbines around the world using a broad range of gaseous and liquid fuels, while at the same time reducing emissions.



## Will Lower Emissions Fit My Needs?

Solar's goal for Asset Optimization is to respond to our customers' needs when their operation requires the use of existing assets, have footprint constraints, or ...

[VIEW ALL CASE STUDIES](#)

## Would You Like Us To Evaluate Your Potential Savings?

Contact us and we'll evaluate the cost savings you can achieve with Solar Turbines solutions.

[GET IN TOUCH](#)

## Explore The Solar Turbines Difference

**Products For Every**

[Explore >](#)

**Optimizing Equipment Innovations For**

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## Solution, In Every Industry

Solar Turbines provides best in class energy solutions with turbomachinery for power generation and motor driven compression products and packages. Our wide range of solutions maximize availability, reliability and value throughout your equipment's life cycle.

## Value, Anywhere And Anytime

Customer support extends beyond maintenance and repairs to include broad offerings that help enhance performance and safety, extend equipment life and prevent obsolescence.

## Energy Solutions


Solar Turbines has been innovating the energy industry for more than 60 years and we will continue to push what is possible.



### Social Media

 Facebook

 LinkedIn

 YouTube

 Twitter

 Instagram

### Energy Solutions

Oil And Gas

Power Generation

Digital Solutions

Carbon Reduction

Industry Applications

Modular Solutions

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Gas Compressors

Gas Compressor Packages

Mechanical Drive Packages

Oil And Gas Power Generation

Industrial Power Generation

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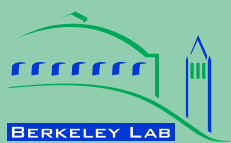
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# Exhibit 12





**ERNEST ORLANDO LAWRENCE  
BERKELEY NATIONAL LABORATORY**

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# **Opportunities for Efficiency Improvements in the U.S. Natural Gas Transmission, Storage and Distribution System**

**Jeffery B. Greenblatt**

**Energy Technologies Area**

**May 2015**

This work was supported by the Office of Energy Policy and Systems Analysis (EPSA) of the U.S. Department of Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231



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# **Opportunities for Efficiency Improvements in the U.S. Natural Gas Transmission, Storage and Distribution System**

Jeffery B. Greenblatt  
Lawrence Berkeley National Laboratory

## **Executive Summary**

This report provides an in-depth review of the U.S. natural gas transmission, storage and distribution system, from gas gathering at wellheads to final delivery to consumers, with a focus on energy efficiency opportunities. Drawing upon several resources published by the U.S. government and the natural gas industry, as well as a number of research papers and company publications, this report provides an overview of system components, historical and potential future trends, technical efficiency opportunities, cost estimates, and a final synthesis. While not comprehensive, a number of general conclusions can be drawn from the available information. There are a number of technical efficiency opportunities located throughout the natural gas infrastructure system that have yet to be fully realized. This includes improvements in compressors, prime movers (gas engines/turbines and electric motors), and capacity/operational choices; pipeline sizing, layout, cleaning, and interior coatings; and opportunities for waste heat recovery. While the natural gas gathering, processing, and transmission infrastructure being built as part of efforts to expand natural gas system capacity will generally be more efficient than existing natural gas infrastructure currently in place, there are opportunities to improve the efficiency of existing equipment (e.g. pipelines and compressor systems) through replacement and/or upgrades.

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## Abbreviations

AGA, American Gas Association  
BGA, BlueGreen Alliance  
BPC, Bipartisan Policy Center  
Bscf, billion scf  
Btu, British thermal unit (~1,055 J)  
CAGI, Compressed Air and Gas Institute  
DC, direct current  
DOE, U.S. Department of Energy  
EPSA, Office of Energy Policy and Systems Analysis (an office within DOE)  
EIA, Energy Information Administration (an office within DOE)  
FERC, Federal Energy Regulatory Commission  
GHG, greenhouse gas  
HHV, higher heating value  
hp, horsepower (~746 W)  
INGAA, Interstate Natural Gas Association of America  
IUPAC, International Union of Pure and Applied Chemists  
LHV, lower heating value  
LNG, liquefied natural gas  
MAOP, maximum allowable operating pressure (of pipeline)  
Mhp, million horsepower (~746 MW)  
MMtCO<sub>2e</sub>, million metric tons of CO<sub>2</sub> equivalent  
MMscf, million scf  
NARUC, National Association of Regulatory Utility Commissioners  
NETL, National Energy Technology Laboratory  
psi, pounds per square inch (~6,895 Pa)  
rpm, revolutions per minute  
RPS, renewable portfolio standard  
scf, standard cubic feet of gas (at 60°F and 14.73 psi). For natural gas, this is ~932 Btu LHV or ~1,033 Btu HHV (the precise value depends on the composition of natural gas, which can vary). Mass density is ~20.86 g/scf (GREET, 2010).<sup>i</sup>  
SMYS, specified maximum yield strength (of pipeline)  
SWRI, Southwest Research Institute  
TS&D, transmission, storage and distribution  
U.S., United States  
WHR, waste heat recovery

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<sup>i</sup> Converted from conditions presented in GREET (2010) (0°C and 101.325 kPa; former IUPAC standard) by scaling values by 1.0545 scf per IUPAC ft<sup>3</sup> (IUPAC, 1997).

# 1. Overview

## A. High-level description

With the oldest long-distance pipeline completed in 1929, the U.S. natural gas transmission network is about 85 years old (INGAA, 2010a, p. 13), with ~320,000 miles (DOT, 2014a)<sup>1</sup> of wide-diameter, high-pressure pipelines (EIA, 2008a). The distribution network constitutes the majority of pipeline distances (~2.15 million miles) (DOT, 2014b)<sup>2</sup> and while it contains some legacy pipeline, is overall newer than the transmission network (EIA, 2014a).

The modern natural gas transmission, storage and distribution (TS&D) infrastructure consists of a vast network of production wells, processing plants, pipelines, compressors, storage facilities and liquefaction plants, delivering about 73 Bscf of natural gas per day (~27,000 Bscf annually) in 2014. Seasonal demand varies between ~60 and ~100 Bscf/day (EIA, 2015a). Most natural gas that is consumed in the U.S. is produced domestically. About 10% is imported from Canada, with a very small portion imported from Mexico.<sup>3</sup> The U.S. also exports a small percentage of its domestic production, resulting in net imports of 8% in 2011 (EIA, 2011) and ~4% projected for 2015 (EIA, 2015a). Overall, 99% of natural gas used in the U.S. is produced in North America (APGA, 2012).

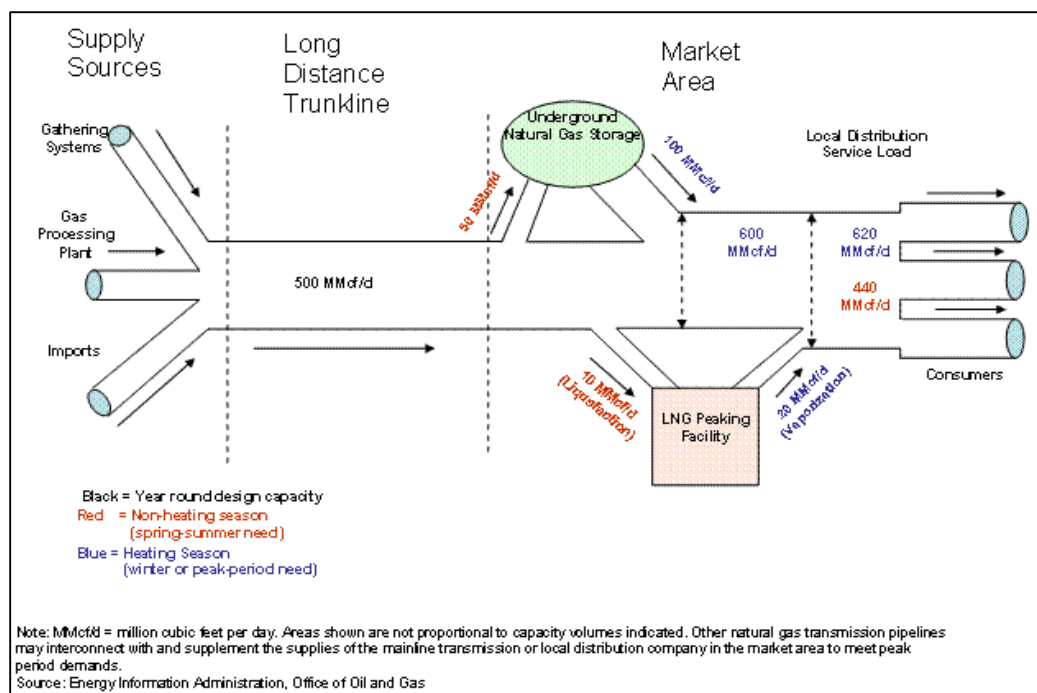
The EIA provides a useful schematic overview of the TS&D network, subdividing the system into gas gathering from production wells, gas processing, and imports; long-distance transmission pipelines; gas storage and LNG facilities (also mainly used for peaking storage); and distribution to end users (EIA, 2007; EIA, 2008b). Compression is used throughout the system (CAGI, 2012, p. 388; AGA, 2015a). See Figure 1. Except for the small amount of natural gas provided by LNG (EIA, 2015a), virtually all natural gas consumed is transported by pipeline; transport by rail or other vehicle is not considered economically feasible (INGAA, 2010b).

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<sup>1</sup> This total includes 17,000 miles of gathering pipelines: small-diameter pipelines that move natural gas from wells to processing plants or transmission interconnections (EIA, 2008a).

<sup>2</sup> There is some confusion over what constitutes a distribution pipeline. DOT (2012, 2014b) breaks distribution into “mains” (distribution lines that serve as a common source of supply for more than one service line) and “service” (distribution lines that transport gas from a common source of supply, e.g., mains, to a customer meter or the connection to a customer's piping). Mains encompass ~1.25 million miles and service lines account for the remaining ~900,000 miles (DOT, 2014b). Both EIA (2014a) and BGA (2014) report 1.2 million miles of distribution pipelines, consistent with the DOT estimate for mains. It seems that the service portion of the distribution network was not included in the EIA and BGA definitions of “distribution.”

<sup>3</sup> The U.S. imports from Mexico have been declining since 2007, reaching 0.3 Bscf in 2012 and 1.1 Bscf in 2013, as opposed to ~3,000 Bscf/yr from Canada between 2005-2013, though imports have been decreasing (EIA, 2014b).



**Figure 1. Schematic overview of natural gas pipeline TS&D network**

Source: EIA (2008b)

The outline of this report is as follows. Section 1-B provides a detailed description of system components, while Section 1-C describes historical and potential future trends. Section 2 discusses technical opportunities for efficiency improvement in each part of the system, including costs (Section 2-C) and system-level trade-offs (Section 2-D). Finally, Section 3 provides a synthesis.

## B. Description of system components

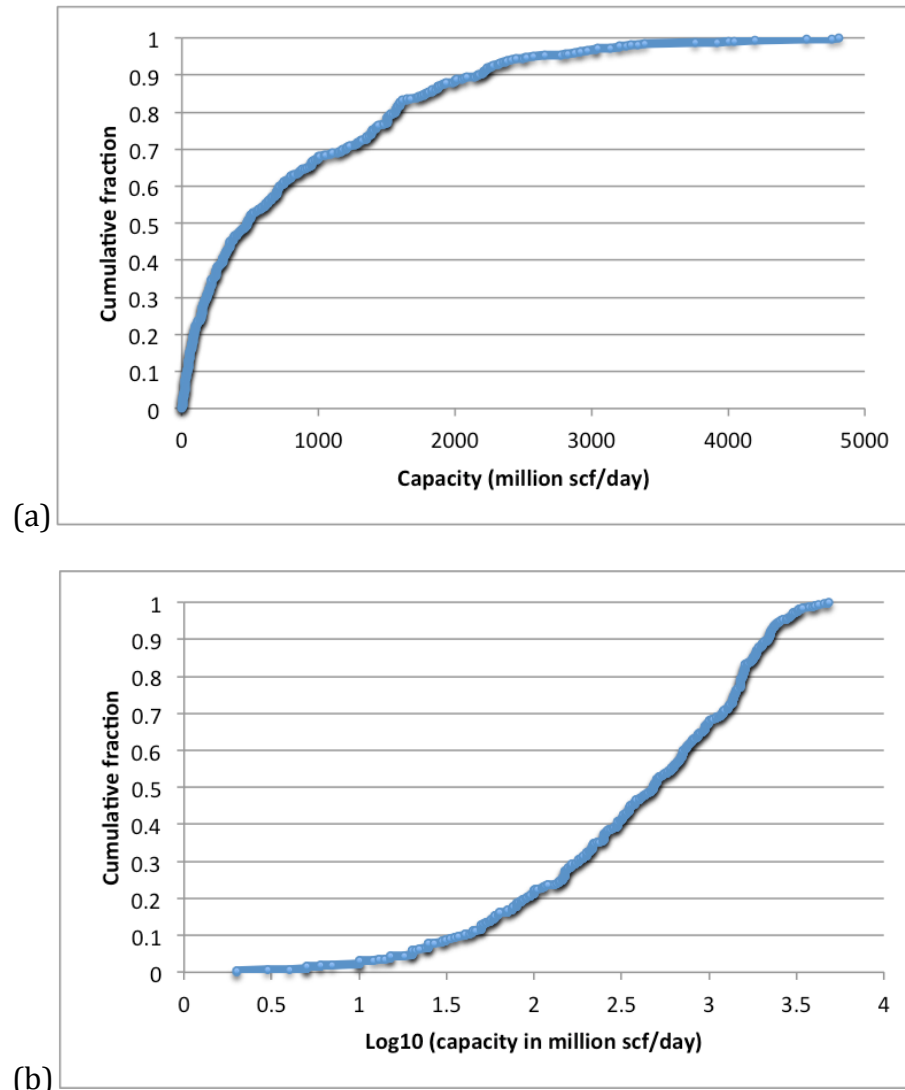
### i. Pipelines

#### a. Transmission and Gathering

There are ~17,000 miles of small-diameter gathering pipelines that move natural gas from wells to processing plants or transmission interconnections (EIA, 2008a). There was very little additional information about natural gas gathering pipelines.

The current high-pressure, inter- and intrastate transmission portion of the natural gas pipeline network consists of ~300,000 miles of pipelines organized into more than 210 individual pipeline systems (DOT, 2014a; EIA, 2007). As of 2008, about 70% of transmission pipeline mileage was interstate (EIA, 2008c). Pipe diameters range up to 48 inches and pressures vary between 200 and 1,750 psi (INGAA, 2010a, p. 18; CAGI, 2012, p. 423; AGA, 2015a; BPC, 2014). Approximately 27% of interstate pipeline diameters are 16 inches or smaller (EIA, 2008c). Pipeline flow rates vary tremendously, depending on what part of the delivery system is involved and local demand. Using flow rate capacities on ~530 individual pipelines in 2013 (EIA, 2014c), an analysis of the data indicates a range

from 2 MMscf/day to almost 5 Bscf/day; median and average capacities were 480 and 840 MMscf/day, respectively; see Figure 2.



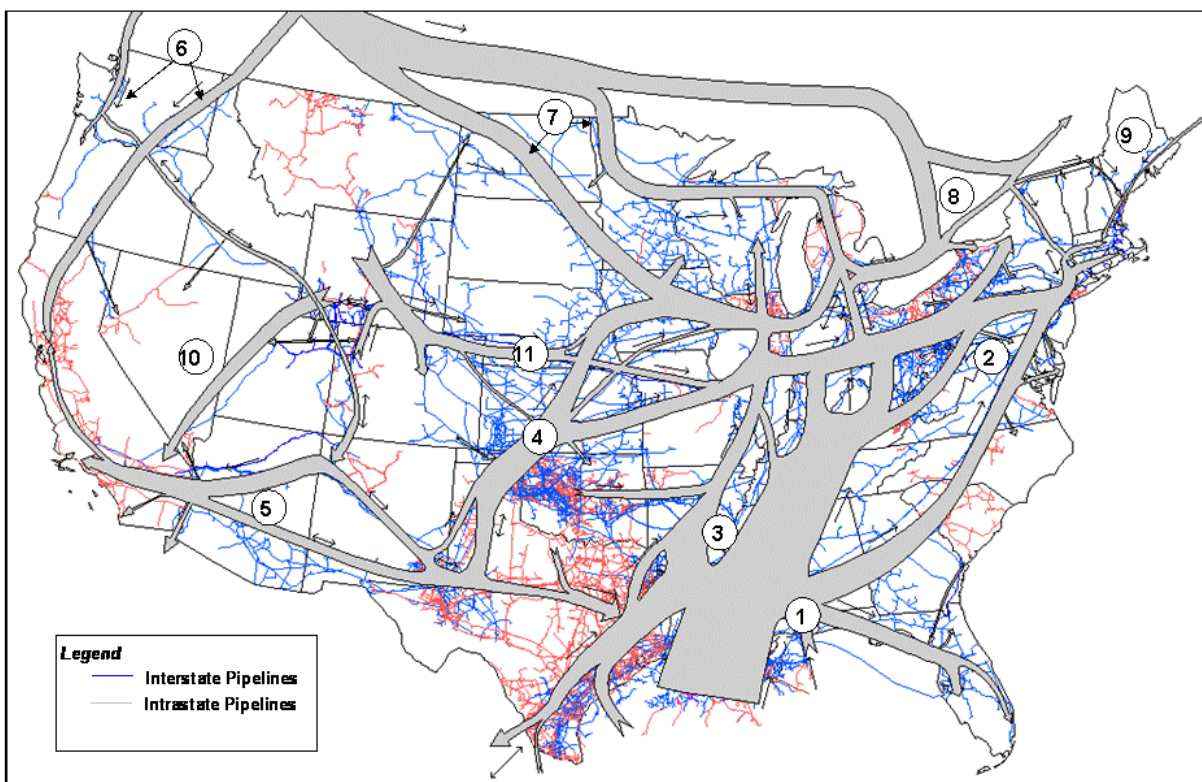
**Figure 2. Cumulative distribution of pipeline capacities in the U.S. in 2013: (a) normal scale (b) log scale**

Source: EIA (2014c) data analyzed by the author

Many major interstate pipelines are "looped" (two or more lines running in parallel). The pipeline rights-of-way are usually 100 feet wide (AGA, 2015a).

The major flow of natural gas in the U.S. has historically been from the Gulf region into the rest of the country, though the growth of shale gas is beginning to change this picture (see Section 1-C-i). Moreover, there are several regional sources of natural gas and many subtleties to the network. A schematic diagram showing major pathways is reproduced from EIA (2008d) and shown in Figure 3.

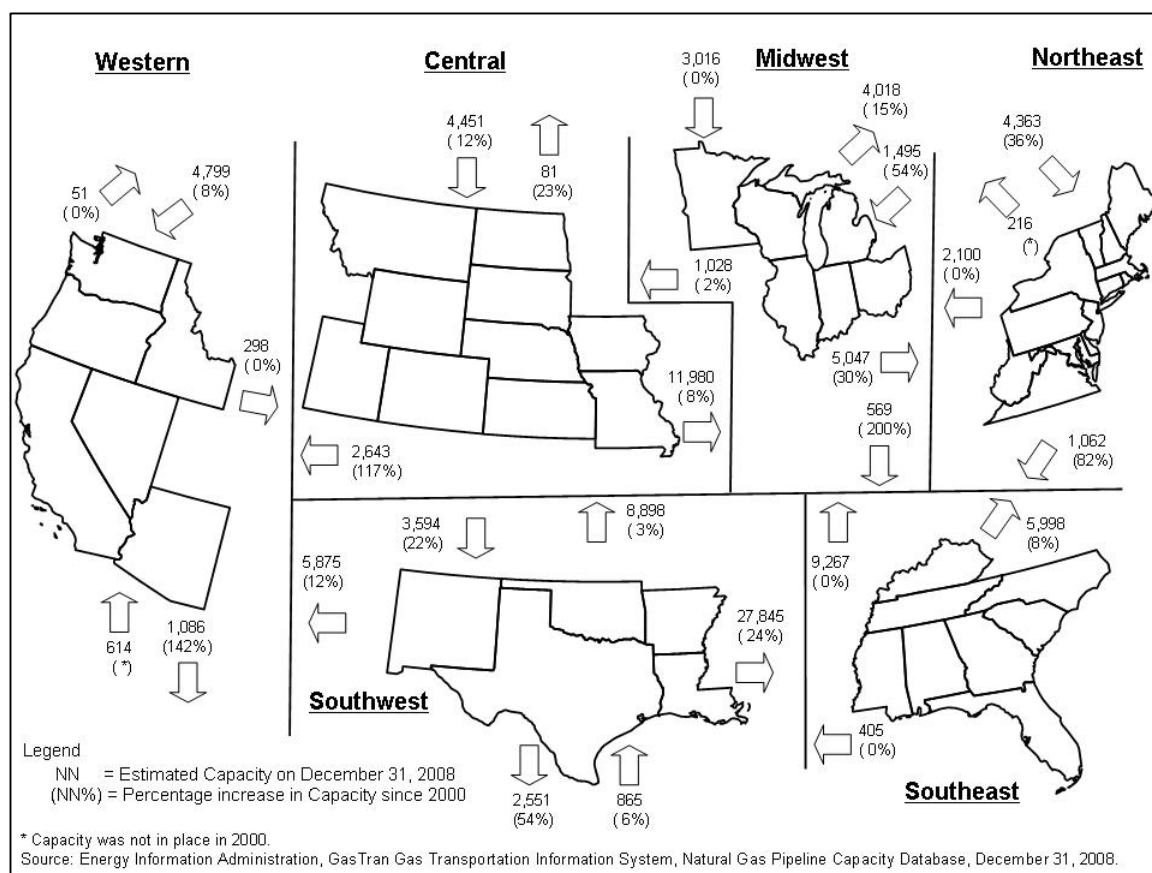




**Figure 3. Major natural gas flows in the U.S.**

Source: EIA (2008d)

Natural gas also flows in multiple directions between regions. A map showing flow rates among six U.S. regions is reproduced from EIA (2008e) and shown in Figure 4.



**Figure 4. Regional natural gas flows as of December 31, 2008**

Source: EIA (2008e)

### **b. Distribution**

Approximately 87% of the natural gas pipeline network mileage is used for distribution, with ~2.15 million miles currently in existence (DOT, 2014b). When the natural gas reaches a local gas utility, it normally passes through a gate station, which reduces the pressure in the line to between 0.25 psi and 400 psi (CAGI, 2012, p. 423; AGA, 2015a). Generally, reciprocating compressors are utilized for this function (CAGI, 2012, p. 423). (See Section 2-A-iv for a discussion of the use of turboexpanders to extract energy during this step-down process.) It is at this stage that an odorant is added. From the gate station, natural gas then moves into distribution lines or mains that range in diameter from 2 to 42 inches (AGA, 2015a; BPC, 2014).

The final stage in the gas delivery system is the service line to the building end user. Diameters typically range from 0.5 to 2 inches (BPC, 2014) and pressures range from 60 psi to as low as 0.25 psi (AGA, 2015a).

## ii. Compressor systems

Compressor systems consist of two main components: the compressor itself and the prime mover (also called the compressor driver). There are several major technology options for each component, and the choice of components will depend upon trade-offs among multiple features.

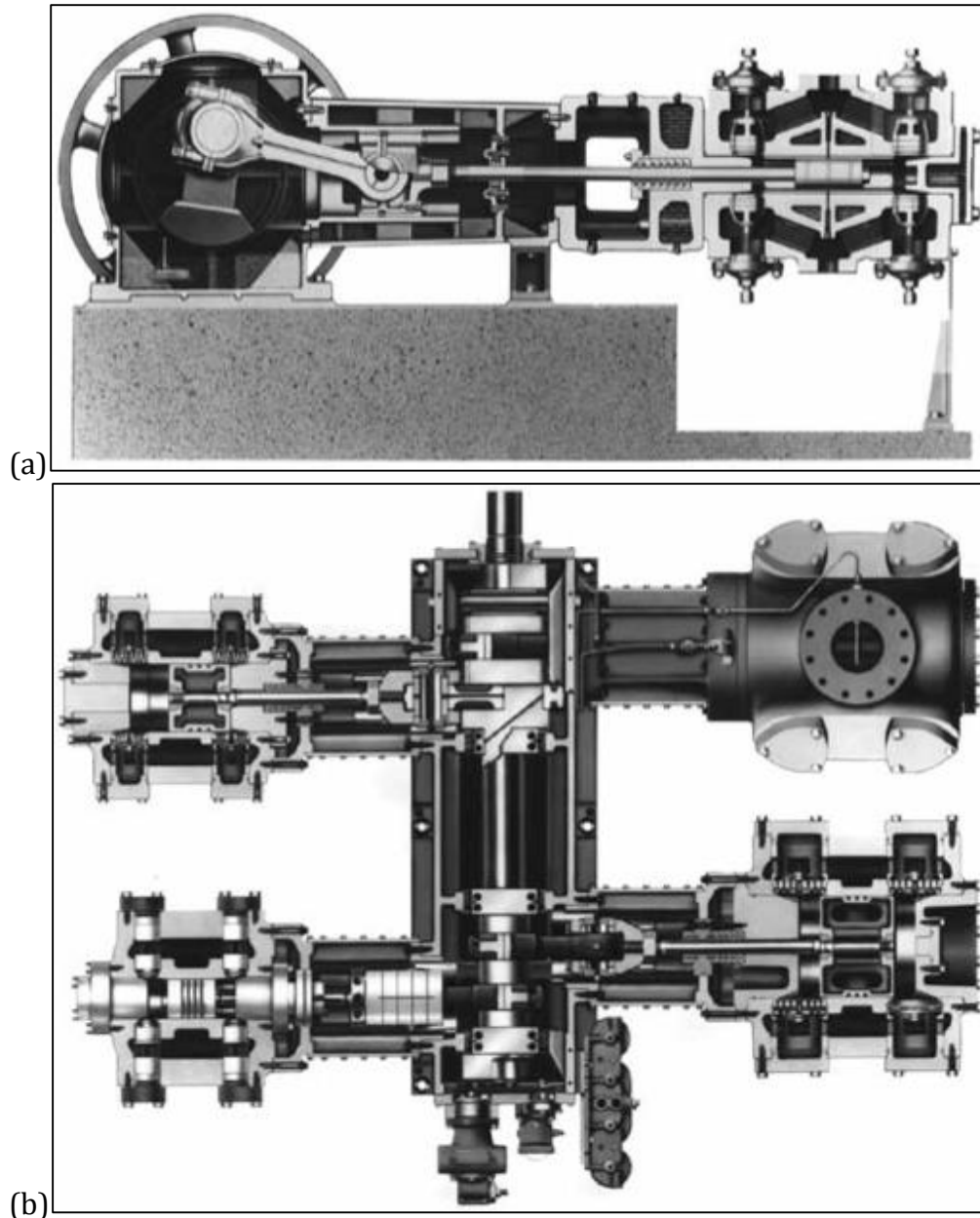
### a. Compressors

Major types of compressors are reciprocating, centrifugal and axial. (Other types of compressors exist as well but are not commonly used for natural gas compression).

**Reciprocating compressors** work by compressing gas in a cylinder via piston movement. Capacities vary from fractional hp to more than 20,000 hp per unit. Pressures range from low vacuum at the inlet (or suction) side to 30,000 psi and higher at the discharge side.

Reciprocating compressors come in two main configurations:

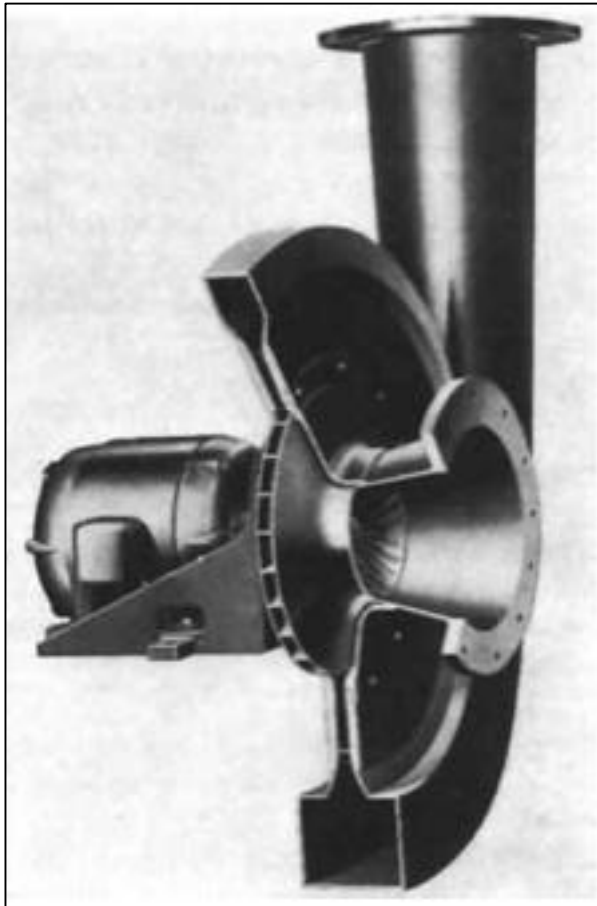
- Single-throw, horizontal or vertical arrangement: a single cylinder or multiple tandem cylinders are used with a single crank; the unbalanced inertia forces must be absorbed by the skid (baseplate) and foundation; see illustration reproduced from CAGI (2012, p. 450) in Figure 5(a).
- Multi-throw horizontal, balanced-opposed frame: Two or more cylinders with equal reciprocating weights are located on opposite sides of a frame and are powered by a double-throw crankshaft with cranks set at 180°. All primary and secondary inertia forces mutually cancel each other; however, there are unbalanced forces that cause mechanical vibrations and can result in alignment, piping, or vibration problems. As many as five pairs of crank throws can be arranged on one compressor frame. Figure 5(b) shows an illustration reproduced from CAGI (2012, p. 451).



**Figure 5. Examples of (a) single-throw and (b) multi-throw centrifugal compressors**  
Source: CAGI (2012, pp. 450–451)

Reciprocating compressors are built as either single- or multi-stage units. The number of stages is determined by the overall compression ratio. The compression ratio per stage (and valve life) is generally limited by the discharge temperature and usually does not exceed four, although small-sized units (used for intermittent duty) are furnished with a compression ratio as high as eight. On multi-stage machines, intercoolers (heat exchangers that remove the heat of compression from the gas, reducing the temperature to close to that of the compressor intake) are sometimes used between stages. Intercooling reduces the volume of gas going to the high-pressure cylinders, reducing the horsepower required for compression (CAGI, 2012, p. 474).

A **centrifugal compressor** uses the centrifugal force from a rotating gas flow to provide pressure to compress the gas. In its simplest form, a centrifugal compressor is a single-stage, single-flow unit with the impeller (the rotating part that imparts kinetic energy to the fluid) overhung on a motor CAGI (2012, p. 551); see the cut-away illustration reproduced from CAGI (2012, p. 552) shown in Figure 6. The gas enters the centrifugal compressor through the inlet nozzle (at right), which is proportioned to minimize turbulence as the gas enters the impeller. The rotating impeller (driven by an engine or motor) dynamically compresses the gas and also sets it in motion, giving it a velocity somewhat less than the tip speed of the impeller. The diffuser surrounds the impeller and serves to gradually reduce this velocity by increasing the pressure. A volute casing surrounds the diffuser and collects the gas, further reducing its velocity and further increasing the pressure. The gas exits at the top of the illustration (CAGI, 2012, p. 551).



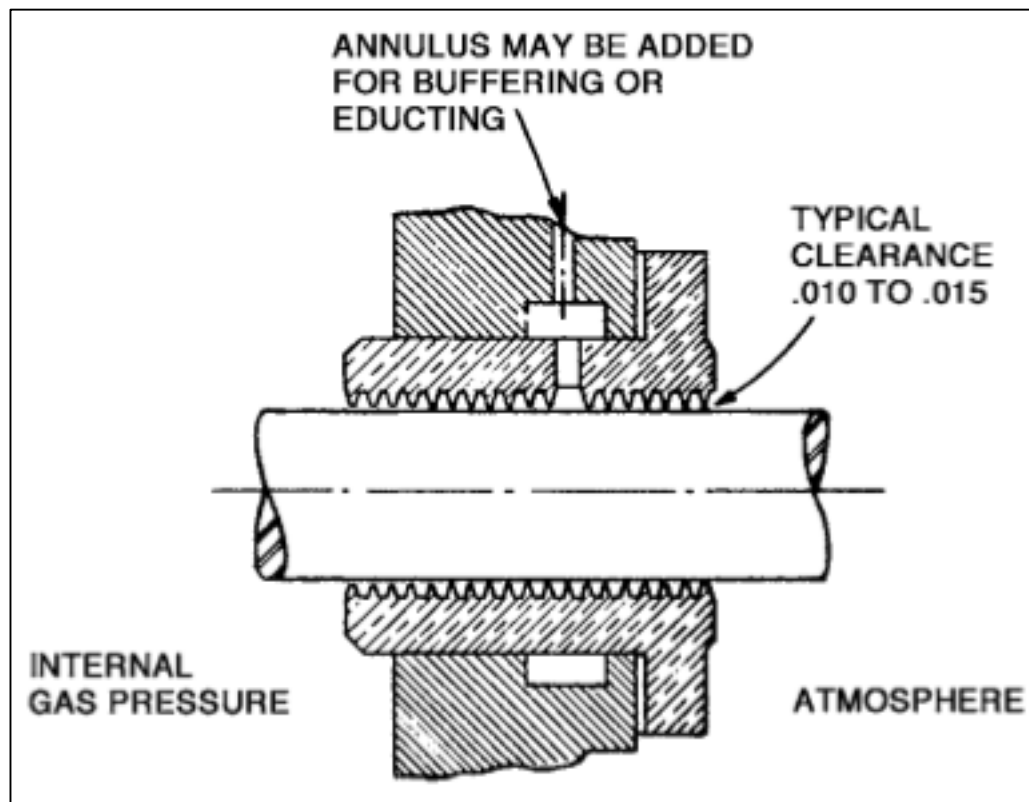
**Figure 6. Cut-away view of a single-stage centrifugal compressor**

Note: gas flow inlet is at right and outlet is at top.

Source: CAGI (2012, p. 552)

A multi-stage centrifugal compressor is a machine having two or more stages. Such compressors may be described as in-line (all impellers are on a single shaft and in a single casing) or integrally geared (impellers are mounted singly at one or both ends of each pin-

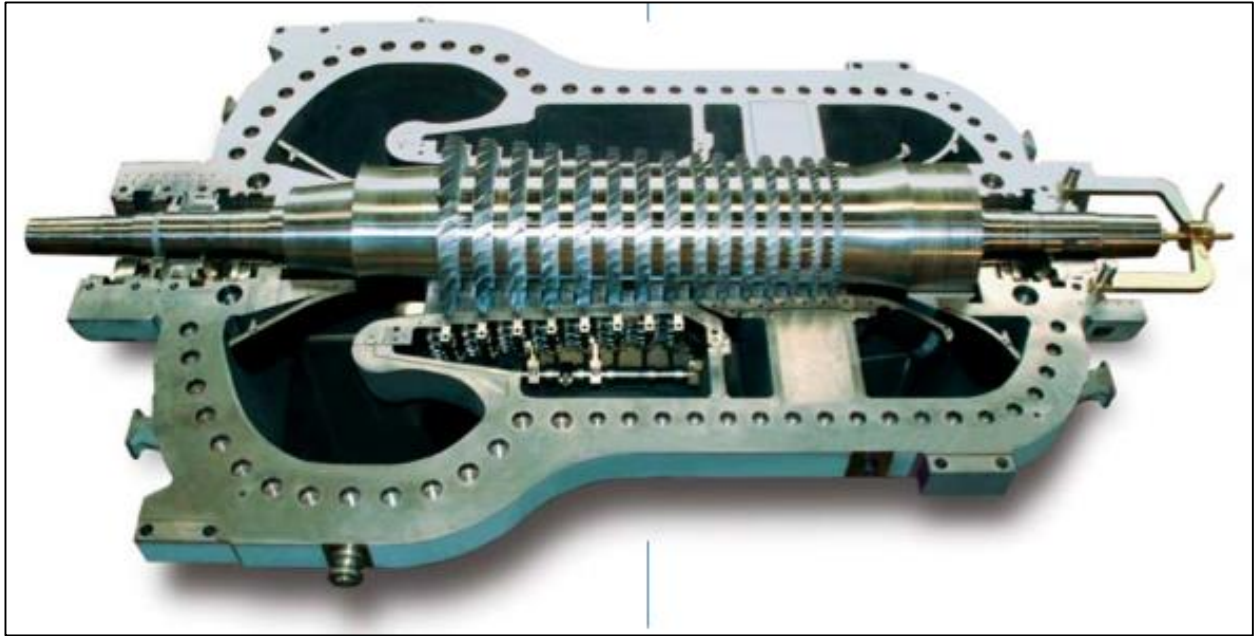
ion, and each impeller has its own separate casing). Integrally geared centrifugal compressors are normally used only on air and nitrogen service. Gas flow between stages is facilitated by inter-stage diaphragms, connecting the discharge of one impeller to the inlet of the next impeller. Sealing between stages is accomplished using labyrinth ring seals, which impose restriction on the flow between impellers at the shaft, at the impeller eye, and at the balancing drum (CAGI, 2012, pp. 545–552). An illustration of a labyrinth seal is reproduced from CAGI (2012, p. 595) in Figure 7.



**Figure 7. Labyrinth seal of centrifugal compressor**

Source: CAGI (2012, p. 595)

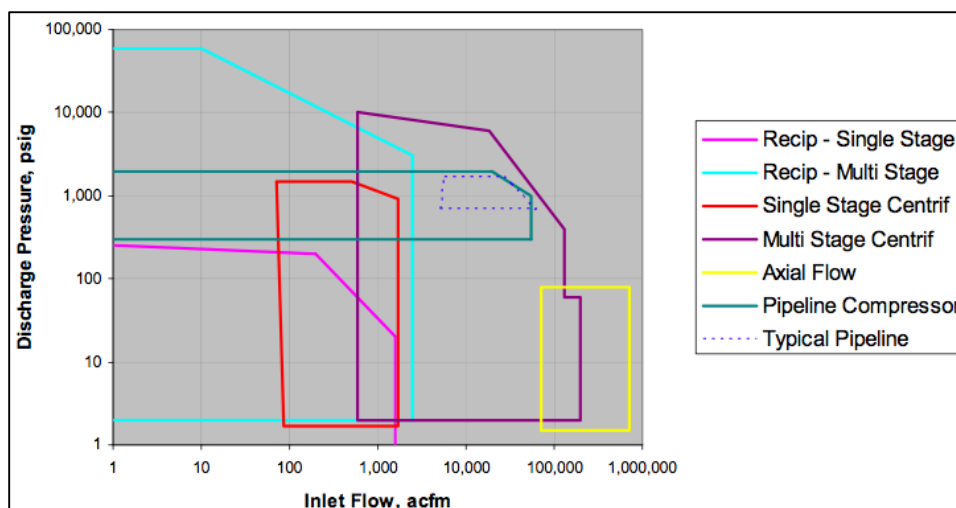
**Axial compressors** are more reminiscent of gas turbines, compressing the gas through a series of rotating blades arranged along a common shaft; see reproduction from GE (2005, p. 13) in Figure 8. They are primarily used for low pressure, high-flow applications (INGAA, 2010a, p. B-1), and as such, are seldom used in the natural gas TS&D system except for producing LNG (GE, 2013, p. 5). They are characterized by roughly constant inlet flow over a considerable range of discharge pressure (CAGI, 2012, p. 559). Shaft-end seals can be labyrinth, oil films or dry, depending on service requirements (GE, 2013, p. 13).



**Figure 8. Cut-away view of an axial compressor**

Source: GE (2013)

**Comparison of compressor types.** There are a great deal of overlapping characteristics among compressor technologies, as seen in Figure 9 reproduced from INGAA (2010a, p. B-1). As a rule, reciprocating compressors are generally used for lower flow applications (up to  $\sim 2,000$  scf/min.), while centrifugal compressors are used at higher flow rates ( $\sim 100$  to  $\sim 100,000$  scf/min.). Axial compressors, used for very high flow rates ( $>100,000$  scf/min.), are not generally encountered in pipeline operations.



**Figure 9. Discharge pressure versus inlet flow for different compressor technologies**

Source: INGAA (2010a, p. B-1)

As can be seen from the above figure, the pressure and flow rate conditions in most pipeline operations fall into a region that overlaps with both reciprocal and centrifugal



compressors. Among these two main types of compressors, reciprocating are more effective in situations with varying pressure ratios (i.e., where the ratio of discharge to suction pressure varies substantially), while centrifugal are more effective in situations with generally higher flow rates, some flow variability, and relatively constant pressure ratios. According to CAGI (2012, p. 474), the advantages of centrifugal over reciprocating compressors are:

- Lower installed first cost where pressure and volume conditions are favorable
- Lower maintenance expense
- Greater continuity of service and dependability
- Less operating attention required
- Greater volume capacity per unit of plot area
- Adaptability to high-speed, low maintenance cost prime movers

Conversely, the advantages of reciprocating over centrifugal compressors (CAGI, 2012, p. 474) are:

- Greater flexibility in capacity and pressure range
- Higher compressor efficiency and lower power cost
- Capability of delivering higher pressures
- Capability of handling smaller volumes
- Less sensitive to changes in gas composition and density

Differences in efficiency are discussed in Section 2-A.

#### ***b. Prime movers***

Among prime movers, there are three main choices in use in the natural gas TS&D system: gas engines, gas turbines and electric motors.

**Gas engines.** Similar to an internal combustion engine used in a vehicle, the gas engine (sometimes called a reciprocating engine) uses a chamber, filled with combusting natural gas, to drive a piston. While modern gas engines are quite efficient, they do have power limitations, and can have high vibration issues that affect reliability. Also, certain components may require frequent maintenance (INGAA, 2010a, p. 34). These issues are discussed more thoroughly in Sections 1-C-ii and 2-A.

Gas engines are normally divided into two general categories related to speed. These categories are slow-speed engines ( $\leq 600$  rpm) and medium-speed engines (600–2,100 rpm). There are also two basic types of gas engine designs: the two-stroke cycle and four-stroke cycle. Either type can be turbocharged. The two-cycle engines require less displacement for the same rating. The differences in performance between these engine types are small, especially with turbocharging (CAGI, 2012, p. 448).

Slow speed engines are in common use in integral gas engine compressors. “Integral” indicates the use of a common crankshaft to drive both the power cylinders and the compressor. Integral machines are typically subdivided according to power output: small (25–800 hp) and large (800–7,000 hp). Small integral engines are used in oil field services



(gas gathering, gas injection, small gas processing plants). Larger integral engines are used in process plants, main line gas transmission, gas injection, and large gas plants (CAGI, 2012, p. 518).

Medium-speed gas engines (600–2,100 rpm) are generally used for non-integral (separable) oil field compressors. Power sizes range from 5 to 3,600 hp, with the smaller end of the range (5–400 hp) generally operating at medium speed (1,400–1,800 rpm), while the larger end (300–3,600 hp) are generally directly connected and operate at lower speeds (600–1,200 rpm). Across the industry, the trend is toward higher driver speeds to keep pace with increasing compressor speeds (CAGI, 2012, p. 519).

Legacy internal combustion, slow speed gas engines have significantly less sophisticated controls and lower fuel efficiencies than state-of-the-art engines (INGAA, 2010a, p. 34).

**Gas turbines** use hot exhaust gases produced from the discharge of a gas generator to drive a power turbine. Two types of turbines are used: 1. aeroderivative engines, based on gas turbines developed for the aviation industry, and 2. industrial turbines, which are designed specifically for industrial use. Aviation industry developments have contributed to performance improvements in both types of turbines (INGAA, 2010a, p. 34).

Gas turbines have limited application in the process and oil and gas industry as prime movers. The gas turbine is relatively new compared to the gas engine, steam turbine or electric motor (see Section 1-C-ii). However, there are some applications where gas turbines (typically driving reciprocating compressors) are more common. One application is offshore compression, where weight is a concern. Another application is refineries or process plants, where turbine exhaust heat can be utilized to improve overall plant efficiency (CAGI, 2012, p. 527). Smaller plants (<10,000 hp) will typically choose a gas engine over gas turbines, unless the waste heat can be utilized (see also discussion of waste heat recovery in Section 2-A-iv). Gas engines have inherently better efficiency compared to smaller gas turbines (CAGI, 2012, p. 435). Efficiency trade-offs will be discussed further in Section 2-A.

**Electric motors** are more reliable and more efficient as stand-alone pieces of equipment than either gas engines or gas turbines. They are able to ramp up more rapidly than gas-driven prime movers. They also have an advantage where air quality regulations are an issue because they do not emit nitrogen oxides and CO<sub>2</sub> at the point of use. There are a number of competing factors, however, that affect the suitability of electric motors over gas-based technology. One is the requirement for variable speed, while the other is the availability and proximity of a suitable electric power supply or substation. Reliability of the grid is also a concern, particularly in remote locations (INGAA, 2010a, pp. 34–35). While natural gas drivers are the primary technology for oil and gas field operations, electric motors are increasingly being used due to environmental considerations (CAGI, 2012, p. 520).

There are three types of electric motors: induction, synchronous and DC. Each is described briefly below.

**Induction** is the most common type of electric motor. Induction motors generally have good efficiency and excellent starting torque, but rather high inrush current<sup>4</sup> requirements. Induction motor efficiencies lie in the high 80% to low 90% range, depending on power. Smaller power induction motors are generally less efficient (CAGI, 2012, p. 522).

**Synchronous** motors are the most common type of driver used for high-power applications, e.g., above 700 hp for speeds greater than about 450 rpm, or above 200 hp for lower speeds. These motors are typically more efficient than induction motors, with efficiencies in the range of 93%–97%. Synchronous motors must be carefully analyzed because of their lower torque characteristics, however (CAGI, 2012, pp. 521–522).

The use of **DC motors** as oil field compressor drivers has increased in popularity in recent years. The reasons for this increase are threefold: 1. Availability of DC traction motors, 2. Variable-speed capability of DC motors to control compressor capacity, and 3. Economic considerations of motor drive versus engine drive. However, when utilizing DC motors in a hazardous atmosphere, it is necessary to provide a continuous positive air pressure in the motor enclosure to assure that no gas can get into the motor and be ignited. Offshore oil field compressors are using more DC motor drivers because of the added speed flexibility, lower initial cost, and projected lower maintenance costs (CAGI, 2012, p. 523). However, it appears that these are not used much in gas compression applications.

The improvement in electronics control has greatly increased the potential for motors to be utilized as compressor drivers, especially in oil field applications. This has happened because of technological advances in motor controls. It is now economical to buy induction motors or synchronous motors with variable-speed controls to adjust the compressor operating speed. DC motors, having inherent variable-speed capability, already provide the needed variable speed with little further equipment needed. Variable speed to control compressor performance is a very desirable characteristic of a compressor prime mover (CAGI, 2012, p. 524).

**Other types of drivers** include steam turbines, hydraulic turbines, and diesel or gasoline engines. All of these technologies are rarely used in the oil and gas industry. About these technologies, CAGI (2012, pp. 524–528) says:

- Steam turbines are typically used to drive positive-displacement compressors where steam is available as a power source. However, it is generally not economical to use steam unless it is already available as part of a process, e.g., in refineries or natural gas processing plants.
- A hydraulic turbine is like a centrifugal pump operating in reverse. This type of turbine is found in specialty situations where plentiful high-pressure liquid already exists, e.g., in a refinery or processing plant (as in the situation for steam turbines). “By decreasing the liquid pressure across the turbine, the pressure of the liquid is

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<sup>4</sup> Inrush current is the instantaneous current drawn by the motor when first turned on.

reduced to a desirable level and power is recovered. When high-pressure liquid is available, this type of driver offers essentially free energy” (CAGI, 2012, p. 528).

- Diesel engines are used infrequently in the oil and gas industry, but there are some applications where they are economical, such as “air drilling compressors, kick-off compressors (used to start an oil field gas lift), fire floods, or standby compressors” (CAGI, 2012, p. 525). Also, there are dual-fuel configurations that allow the operator to select the most economical fuel (diesel or natural gas).
- Gasoline engines are also used rarely because of high fuel costs. They are primarily used with standby compressors. Operating and application characteristics of gasoline engines resemble those of natural gas and diesel engines.

#### *c. Pairing of prime movers with compressors*

Compressor selection usually dictates the choice of the prime mover. Gas engines are generally limited to driving reciprocating compressors, while gas turbines generally drive centrifugal compressors. Electric motors, on the other hand, may be used with either compressor technology, and pipeline companies have begun using electric motors to power centrifugal compressors on a more widespread basis than reciprocating compressors (INGAA, 2010a, p. 35).

#### *d. Preferred technologies by application*

**Gathering systems** typically need one or more field compressors (AGA, 2015a).

Compressors are used to provide suction to lift gas from underground reservoirs, with inlet pressures ranging from 25 to 65 psi and discharge pressures from 800 to 1,200 psi.

Compression is also used to reinject gas into reservoirs to maintain pressure, with discharge pressures from 3,000 to 4,000 psi (CAGI, 2012, pp. 421–423). CAGI estimates that gas-gathering applications account for the majority of installed reciprocating compressor capacity in the oil and gas industry; however, some centrifugal technology is used in low-pressure applications. Gas compression for lift service is typically utilized where electricity is not practical or economical, and gas is readily available (CAGI, 2012, p. 422). Oil and gas field applications require compressor systems that are compact and can be easily moved from one location to another. The normal drivers for these compressors are coupled gas engines or electric motors. These units are called “separables” (CAGI, 2012, pp. 447).

**Pipeline evacuation** involves the transfer of gas from a static section of pipeline to an active section of pipeline. This is accomplished by reciprocating compressors that can handle wide variation in suction pressures while compressing against a constant discharge pressure. Packaged compressor systems specifically designed for this application feature multiple compression stages that can maintain high driver loading throughout a wide range of compression ratios. Most such units are driven by gas engines. Typical conditions are intake pressures ranging from 850 psi initially, down to a final pressure of 50 psi, and a constant discharge pressure of 850 psi (CAGI, 2012, p. 424).

For **gas storage**, the compressor must not only be able to handle filling the reservoir but also the return of the gas. This dual service requires operating pressure flexibility and is provided best by the reciprocating compressor. Typical pressure conditions are suction from 35 to 600 psi during injection, 300 to 800 psi during withdrawal, and discharge from 600 to 4,000 psi during the injection phase and 700 to 1,000 psi as the gas is withdrawn from the reservoir and fed to the transmission line (CAGI, 2012, p. 425).

Reciprocating compressors are also often used to increase the pressure of the gas used as fuel for operating engines or turbines, known as **fuel gas boosting**. Suction pressures range from 10 psi (e.g., landfill gathering systems) to 50 psi (refinery or utility distribution headers), and discharge pressures range from 40 psi (engines) to 400 psi (turbines) (CAGI, 2012, pp. 427–428).

Compressor requirements for **gas processing** plants vary widely depending on the type and size of the plant (100–1,000 MMscf/day) and the composition of the gas stream. Performance flexibility and plant energy balance are much more important than first cost when determining the type of compression to be used. Larger plants tend to use centrifugal compressors with turbines, either gas or steam, as drivers. Large-capacity and relatively stable gas conditions make the choice of centrifugal compressors practical on the basis of efficiency and installed cost. Internal combustion engines powered with natural gas typically used as prime movers, though environmental (mainly air quality) concerns are causing electric motors to become more prevalent (CAGI, 2012, pp. 433–434).

#### **e. Apportionment of compression systems**

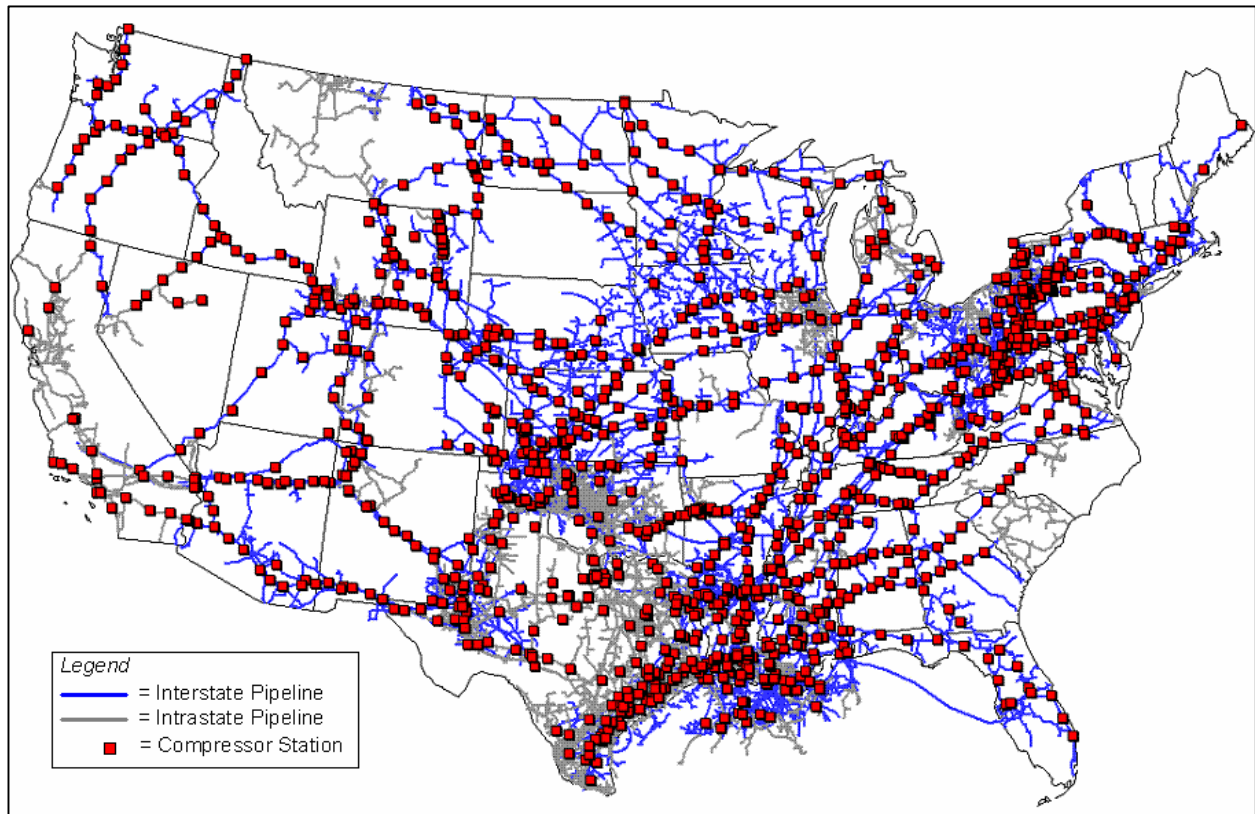
In terms of prime mover technology, the natural gas industry operated over 6,000 gas engines, 1,000 gas combustion turbines, and 200 electric motors in 2010 (INGAA, 2010a, p. 42), though Hedman (2008) notes that electric motor populations may be growing quickly. The average capacity of a gas engine is 1,700 hp, while gas turbines tend to be much larger (6,600 hp on average) (Hedman, 2008), with electric motors being even larger (average of 7,800 hp) (Boss, 2015). Large (>15,000 hp) gas turbines account for >25% of total gas turbine capacity, even though they constitute <9% of total units. Based on data in Hedman (2008), gas engines represent about 60% of total prime mover capacity (expressed in hp), with the balance supplied overwhelmingly by gas turbines. ICF (2009) contains historical compressor additions back to 1999 and projected additions through 2030, and indicates that between 2010 and 2013, capacity grew by ~1.8 million hp (Mhp). Putting these data together, it is estimated that total compressor capacity in 2013 was 20.2 Mhp.<sup>5</sup>

The actual number of compressor stations is far fewer than the number of compressor units, because multiple units typically are grouped at a single compressor station (INGAA, 2010a, p. 42). There are more than 1,400 compressor stations that maintain pressure on

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<sup>5</sup> Average capacity of electric motors was unknown but estimated to be similar to gas turbines. The 2009 reference capacity was calculated as (6,000 engines x 1,700 hp) + (1,000 turbines x 6,600 hp) + (200 motors x 7,800 hp) = 18.4 Mhp, based on INGAA (2010a, p. 42). Additions between 2010–2013 (ICF, 2009) bring the total estimate to 20.2 Mhp.

the natural gas pipeline network and assure continuous forward movement of supplies (EIA, 2007). About 2.4% of compressor units are electric-drive, but these constitute ~5% of total compressor horsepower (Boss, 2015). Multiple compressors are increasingly common at larger compressor capacities (e.g., >1,000 hp) (FERC, 2014). Figure 10 reproduces the EIA map of compressor station locations (EIA, 2008f).



**Figure 10. Natural gas compressor station locations**

Source: EIA (2008f)

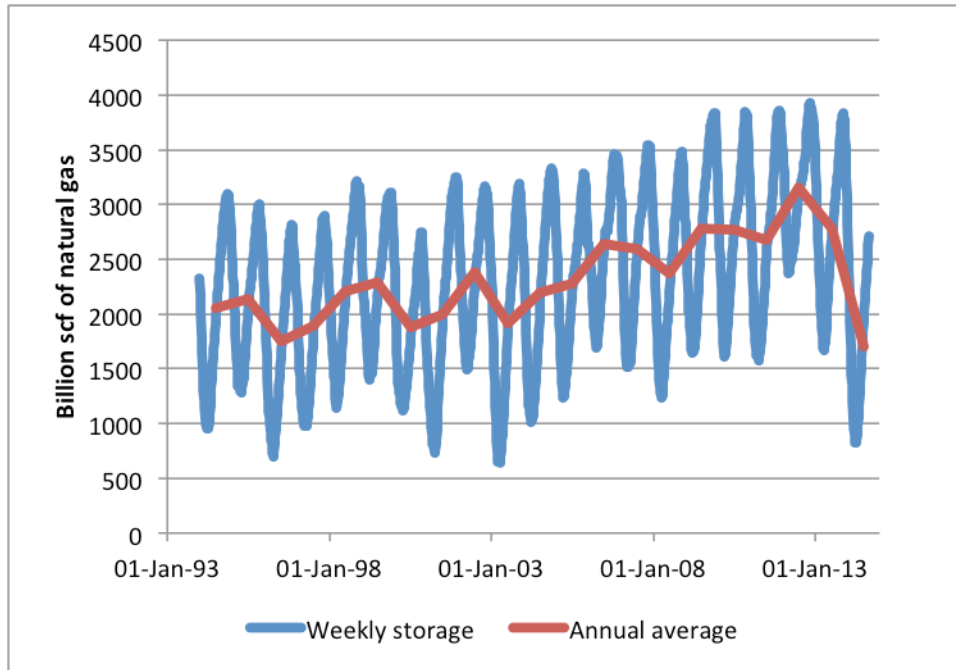
Based on data from 2004 (Hedman, 2008) and 2010 (INGAA, 2010a), much of the gas engine capacity is quite old, with ~45% having been in service for more than 50 years, an additional ~15% installed before 1970, ~20% installed between 1970 and 1990, and the remaining ~20% installed since 1990.<sup>6</sup> Information on the distributions of gas turbines and electric motors was not available, but they are both newer additions to the TS&D system (see Section 1-C-ii).

### iii. Storage and LNG

There are more than 400 underground storage facilities for natural gas (EIA, 2010). Total working gas storage capacity has increased from ~4,200 Bscf in 2008 to ~4,750 Bscf in 2013 (EIA, 2015b). Gas in storage undergoes strong seasonal and, to a lesser extent,

<sup>6</sup> Values in text have been adjusted to reflect a ~10% growth in gas engine capacity between 2004 and 2010 (INGAA, 2010a, p. 42).

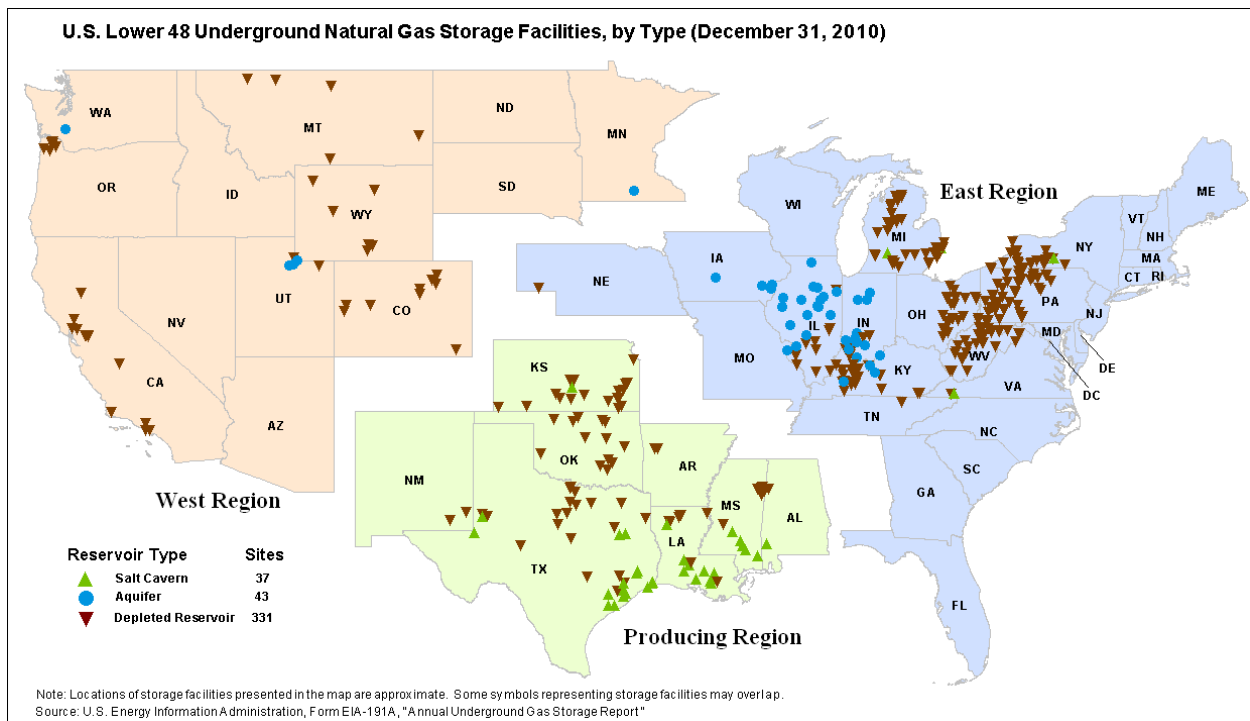
interannual variability; see Figure 11.<sup>7</sup> In recent years, the low point typically occurs in winter at around 1,500 Bscf, but in March 2014, it dipped to 822 Bscf (EIA, 2014d). However, a high level of storage injection brought supplies back to reasonable levels (~2,700 Bscf as of August 29, 2014) (EIA, 2014d).



**Figure 11. Weekly storage capacity in lower 48 states, December 1994-August 2014**  
Source: EIA (2014d) data analyzed by the author

A map of storage facilities as of 2010 is provided by EIA and reproduced in Figure 12 (EIA, 2010).

<sup>7</sup> EIA has data extending back to 1949, providing a useful picture of interannual supply variation (EIA, 2011).

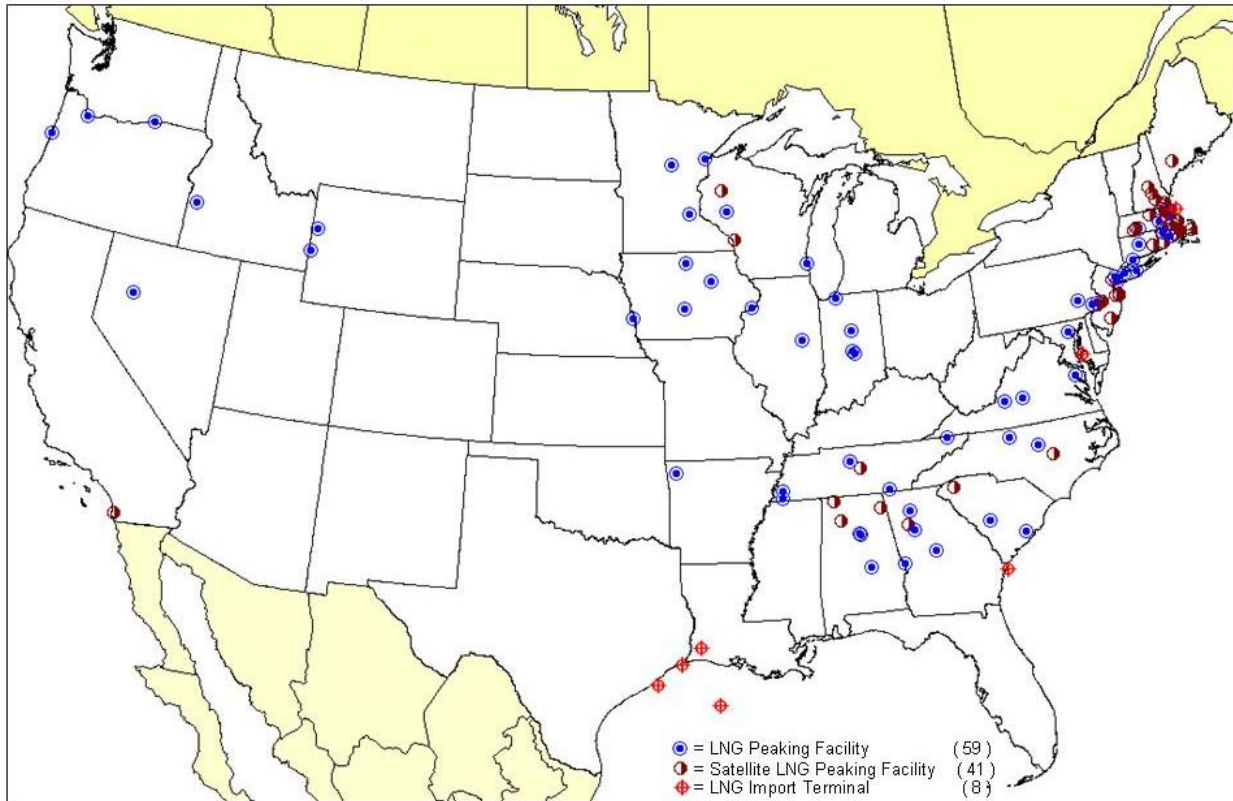


**Figure 12. Underground natural gas storage facilities as of 2010**

Source: EIA (2010)

There are 12 LNG regasification terminals as of August 15, 2014 (FERC, 2015a) and over 100 LNG peaking facilities (used to supplement stored natural gas during high demand periods) (EIA, 2008g); see Figure 13. A number of new LNG facilities are planned; see Section 1-C-i for a discussion.





**Figure 13. LNG facilities for import and peaking**

Source: EIA (2008g). Note that four additional LNG import terminals have been added since publication of this map (see text and FERC, 2015a).

In addition to the dedicated storage facilities described above, natural gas companies routinely raise and lower the pressure in pipeline segments to achieve short-term gas storage during periods when there is less demand at the end of the pipeline. This technique is called “line packing” and may allow pipeline operators to meet higher demand for short durations (AGA, 2015a).<sup>8</sup> Sometimes this involves raising the capacity of a line above its rated capacity, but pressure remains within safety limits (EIA, 2007).

## C. Historical and potential future trends

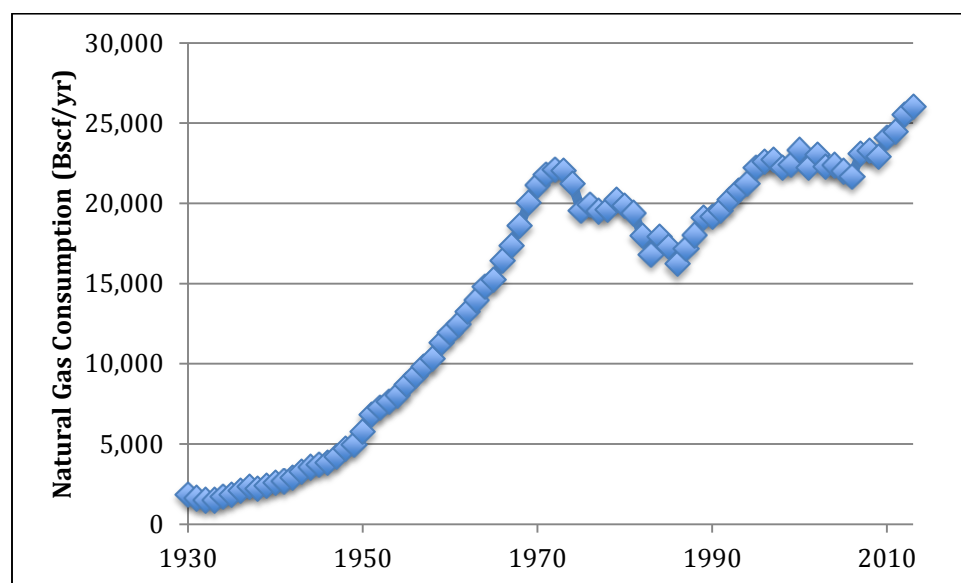
### i. Natural gas supply and demand

Demand for natural gas has increased steadily over time, but went through a period of dramatic growth from the mid-1930s to late 1960s, growing from 1,500 Bscf/yr in 1933 to 20,000 Bscf/yr in 1969, and has remained roughly at this level through the mid-2000s (EIA, 2001; EIA, 2014e). See Figure 14. Subsequently, demand began to grow again with the development of horizontal drilling and hydraulic fracturing technologies that have enabled

<sup>8</sup> “Line pack” is the inventory of gas in a pressurized section of a pipeline network (NWGA, 2012). It is the volume of gas that must be maintained within the line at all times in order to maintain pressure and insure an uninterrupted flow of transportation of natural gas through the pipeline. Line packing is not a substitute for traditional underground gas storage facilities and pipeline operations.



the U.S. to economically extract hydrocarbon resources from unconventional shale gas reservoirs. Total domestic natural gas production was about 23,000 Bscf/yr (63 Bscf/day) in 2011 (EIA, 2011), and reached a record high of 77 Bscf/day in November 2014, in step with growing demand (EIA, 2015a). Under INGAA auspices, ICF (2014) published a projected expansion of U.S. natural gas production of 40 Bscf/day between 2014 and 2035 (and 3.0 Bscf/day from Canada).<sup>9</sup> Most of this U.S. expansion (23 Bscf/day) is expected by 2020. Total consumption for natural gas (including exports of 5 Bscf/day to Mexico and 9 Bscf/day as LNG) is projected to grow to 120 Bscf/day by 2035.



**Figure 14. Historical natural gas consumption in the U.S.**

Sources: EIA (2001) and EIA (2014e) data analyzed by the author

As stated earlier in Section 1-A, most natural gas is produced within the U.S., with about 15% imported from Canada, and about 5% is exported. However, the rise in shale gas is causing large changes in the natural gas industry: not just growth in demand, but also dramatic shifts in how pipelines are utilized. Some existing natural gas transmission pipelines are reversing flow, while new pipelines are being rerouted to accommodate gas supplies on newly-constructed pipelines, as shale gas supplies are often not located in North America's most prolific supply basins. The increasing competition between natural gas supply basins and demand regions is changing the direction of natural gas flows on pipeline infrastructure across the country. According to NARUC, "the rapid growth of shale gas production redraws the map for pipeline flows across North America" (Honorable, 2012).

Increasing shale gas production, and in turn comparatively low U.S. natural gas prices, has led to interest in exporting LNG. As of February 5, 2015, five U.S. export facilities have been approved and are under construction, with total capacity of 9.2 Bscf/day (FERC, 2015b). An

<sup>9</sup> In addition, ICF (2014) projects 3.1 Bscf/day of natural gas liquids capacity will be added in the U.S. between 2014 and 2035, and 0.5 Bscf/day in Canada, roughly doubling current production.

additional 14 U.S. sites have been proposed to FERC (FERC, 2015c) and there are 13 more potential sites identified by project sponsors (FERC, 2015d). However, ICF (2014) projects that LNG export capacity will expand by only 9.3 Bscf/day by 2035, with a low-growth case projecting only 4.0 Bscf/day.

DOE is in the midst of changing its framing of the approval process for LNG export terminals (DOE, 2014; Rosner, 2014). While no site currently under consideration has a capacity larger than 3.2 Bscf/day, the DOE is currently assessing how the construction of larger LNG export facilities (between 12 and 20 Bscf/day) would affect the public interest (DOE, 2014). It also released a life-cycle assessment of the GHG impacts of exporting LNG to other countries to displace coal for electricity generation, concluding that while LNG has lower life-cycle GHG emissions than coal, the details of the results depend on assumptions (NETL, 2014).

## ii. Compressor systems

*Note: Information on compressor systems (compressors plus prime movers) was mainly limited to one data source: INGAA (2010a). Additional sources of data, including details on compressor system age, capacity, manufacturer, efficiency, technology type, etc. would be extremely useful.*

The current network includes 30- to 50-year-old “legacy” compressor engines that are “relatively large, robust, and slow speed (300 rpm) machines designed to operate continuously for years without a shutdown” (INGAA, 2010a, p. 12). The use of these older compressors has declined with increases in steel and construction costs. After World War II, the system expanded substantially due to advances in metallurgy, steel pipe, welding techniques and compressor technology (INGAA, 2010a, pp. 12-13).

In the 1950s, the main compressor technology was a slow-speed “integral” reciprocating compressor where a single design encompassed compressor and gas engine, producing smaller, more compact systems with lower installation costs. Centrifugal compressors driven by gas turbines began to dominate the market in the 1960s and 1970s, because they cost less to install and maintain than integral reciprocating compressors. Pipeline companies could also purchase large centrifugal units at significant cost savings compared to purchasing multiple smaller (reciprocating) compressor units (INGAA, 2010a, pp. 13-15).

Electric motors began to be used with larger, reciprocating compressors in the 1990s. Although technology enabling high power, high voltage, variable speed systems became available in the 1980s, synchronous and induction motor technology and variable-frequency drive systems did not emerge until the late 1990s (INGAA, 2010a, p. 16). However, the majority of engine technology is still gas-driven (see Section 1-B-ii-e).

Reciprocating compressors reemerged in the 1990s for low-flow applications with the development of high-speed systems that became available at lower cost. High-speed internal combustion gas engines were developed to match these compressors and offered

higher thermal efficiencies and thus lower fuel usage than older, low-speed systems (INGAA, 2010a, p. 16).

New technology has not come without a cost. Vibration and pulsation problems cause a number of maintenance issues. Researchers at SWRI have been developing solutions to these problems, such as a tapered cylinder nozzle to reduce vibration and boost efficiency, and a semi-active electromagnetic plate valve to extend valve life roughly 10-fold. As compressor valves are the single largest maintenance cost item for reciprocating compressors, this improvement appears to be a significant advance (Deffenbaugh et al., 2005). Since 2005, SWRI won an R&D Magazine “R&D100” award for this technology (SWRI, 2007) and a patent was filed in 2010 (US Patent Office, 2010).

As of 2013, total compressor capacity (of all types) was ~20 Mhp (see Section 1-B-ii-e) and near-term planned expansion totaled 450,000 hp (Smith, 2013a). ICF’s (2014) projected compressor capacity expansion between 2014 and 2035 estimated an additional 12.8 Mhp would be required,<sup>10</sup> with 66% of this capacity attributed to natural gas gathering, and the remainder to transmission pipelines. Total compressor capacity is therefore likely to grow to ~29-33 Mhp by 2035. In addition, 661,000 hp of compression would be needed to transport natural gas liquids (ICF, 2014).

### iii. Pipelines

The natural gas network consists of ~2.5 million miles of pipeline, of which 320,000 miles are large diameter, high-pressure gathering and transmission pipelines, while the remainder (~87%) are distribution pipelines. About 142,000 miles of the current transmission network were installed in the 1950s and 1960s, as natural gas demand exploded following World War II. A large portion of the 2.15 million miles of local distribution pipelines was also installed in the same period. However, the greatest growth in the local distribution network occurred in the 1990s during a period of low prices, where more than 225,000 miles of new distribution pipelines were installed to provide natural gas to many new residential and commercial facilities (DOT, 2014a, 2014b; EIA, 2014a, 2014f).

#### a. Gathering systems

Almost no information was available about pipelines for natural gas gathering, other than total mileage: ~11,000 miles onshore and ~6,000 miles offshore (DOT, 2014a). DOT (2012) provides an age distribution for natural gas transmission and gathering pipelines combined, which is almost identical to data provided by Kiefner and Rosenfeld (2012) (see Section 1-C-iii-b). From this data, it appears that the distribution of natural gas gathering pipeline ages is similar to that of the natural gas transmission network.

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<sup>10</sup> ICF (2014) also explored a low demand case with only 8.9 Mhp of compressor expansion by 2035. The older ICF (2009) study made even lower projections, estimating an expansion of between 2.5 and 6.5 Mhp through 2030 (after subtracting estimated Canadian additions of 0.8-1.3 Mhp).

ICF (2014) projects that an additional 303,000 miles of gathering lines will be needed between 2014 and 2035, greatly expanding current capacity. The average diameter of these new lines is 3.6 inches.<sup>11</sup>

#### *b. Transmission pipelines*

As noted previously, the oldest long-distance pipeline in the U.S. was completed in 1929 (INGAA, 2010a, p. 13), marking the genesis of the modern natural gas network. Since the 1950s, the general practice has been to build pipelines using the combination of pipeline diameter and compression to transport gas for the lowest delivered cost, but not necessarily at the highest efficiency (INGAA, 2010a, p. 13).

“Beginning in the 1960s, improved metallurgy and manufacturing practices permitted the construction of larger diameter pipeline with higher strength steel to transport natural gas longer distances at higher operating pressures with less compression and at lower costs. Pipeline companies also began experimenting with new, higher cost, internal coating technology that reduced friction” (INGAA, 2010a, p. 14); this is discussed in more detail in Section 2-B-iii.

Accompanying the growth in natural gas demand has been the construction since 1996 of more than 34,000 miles of new natural gas transmission pipeline, representing more than 200 Bscf/day of capacity (EIA, 2014g)—about three times the total current demand of ~73 Bscf/day; see Section 1-A. Most growth supported access to new supply sources such as imports from Canada, expanding production from new shale gas fields, and increased demand from new natural-gas-fired electric power plants. Most trunk expansions were on the order of 1 Bscf/day, though there were some significantly larger local expansions, including Canadian gas pipelines (2.6 Bscf/day), the Gulf offshore region (~5 Bscf/day), projects in the Powder River, Green River, Piceance, and Uintah basins of Wyoming, Colorado, and Utah to access coal-bed methane and tight-sands natural gas production (more than 14 Bscf/day), and new intrastate headers and laterals (6 Bscf/day) (EIA, 2008h). More recent major pipeline projects on the horizon (2015 onward) amount to 81 Bscf/day and 9,145 miles (EIA, 2014g).

ICF (2014) projects that new transmission pipeline requirements will amount to 18,600 miles between 2014 and 2035. An additional 17,100 miles of “laterals to/from power plants, storage field and processing plants” is projected, as well as 15,100 miles of transmission for natural gas liquids.

Diameters of long-distance transmission pipelines have increased steadily over the years, with maximum diameters of 24 inches in the oldest pipelines and up to 48 inches since 2000 (INGAA, 2010a, p. 19). As noted in Section 1-B-a, as of 2008, only 27% of interstate pipelines had diameters of 16 inches or less. The increase in pipe diameter has been

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<sup>11</sup> ICF (2014) reports 1,095,000 inch-miles and 303,100 miles of gathering lines; the quotient gives average diameter. Similar calculations were used for calculating average diameter of mainlines, laterals and natural gas liquids transmission (see Section 1-C-iii-b).

accompanied by increases in maximum allowable operating pressures (MAOP) from 720 psi in pre-1950 pipelines to more than a doubling to 1,750 psi today. This has been achieved through the development of high strength steels, enabling pipelines to be built and operated at higher pressures economically. As shown in Table 1 reproduced from INGAA (2010a, p. 19), available pipeline steel specified maximum yield strengths (SMYS) have increased from 42,000 psi before 1940 to 100,000 psi in 2010. Advances in steel strength continue to this day. Also, improved quality control in manufacturing, transportation, installation and testing of new pipe has allowed the operating pressure of some new pipe installations to increase from 72% to 80% of its SMYS (INGAA, 2010a, p. 18).

**Table 1. Trends in pipeline technology over time**

Decade of Construction	Available Maximum Diameter	Available Maximum Operating Pressure	Available Pipeline Steel Yield Strength (psi )	Available Maximum Stress Levels (% of SMYS)	Available Internal Coating	Piggable Pipelines
<1940	24"	720 psig	42,000	72%	No	No
40-49	28"	720 psig	46,000	72%	No	No
50-59	30"	860 psig	52,000	72%	No	No
60-69	36"	860 psig	60,000	72%	No	No
70-79	36"	1020 psig	65,000	72%	No	No
80-89	42"	1440 psig	70,000	72%	Yes	Yes
90-99	42"	1440 psig	80,000	72%	Yes	Yes
00-09	48"	1600 psig	100,000	72%	Yes	Yes
Present	48"	1750 psig	100,000	80%, 72%	Yes	Yes

Source: INGAA (2010a, p. 19)

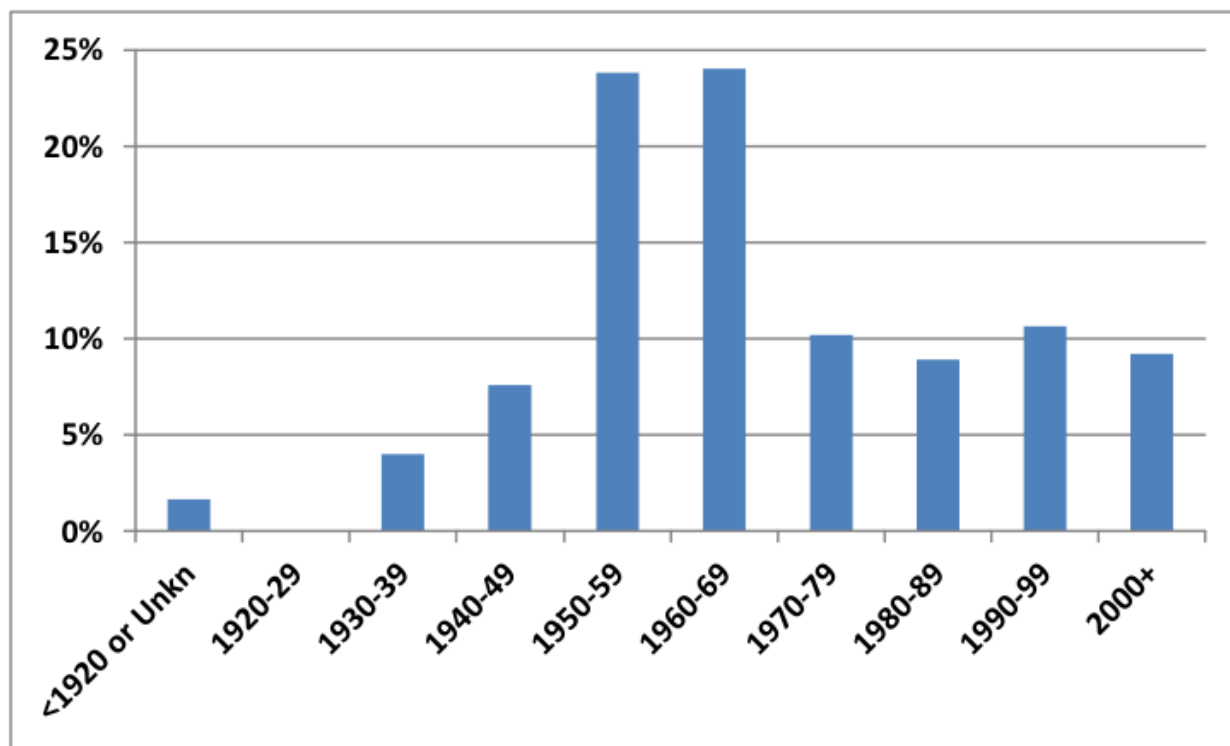
Based on author calculations of data from (ICF, 2014), projected expansion between 2014 and 2035 indicates an average pipe diameter for new transmission lines of 30.5 inches, and 16.3 inches for laterals.

BPC (2014) reports on materials comprising transmission pipelines. About 97% of pipeline miles consists of cathodically protected, coated steel,<sup>12</sup> with other steels (cathodically unprotected, uncoated or both) comprising ~2.5%. The remaining portion (~0.4%) is mainly plastic.

Pipeline ages were reported by an INGAA Foundation-sponsored report (Kiefner and Rosenfeld, 2012) based on DOT data provided in 2009. Approximately 60% of pipeline

<sup>12</sup> According to BPC (2014), "Proper coating on the exterior of steel pipelines inhibits the reaction of the metal with its environment, and cathodic protection imparts a direct current to the pipeline to further prevent the corrosion process." Surface coating typically uses fusion-bond epoxy; older systems used coal tar epoxy. A direct current can be achieved through the use of a sacrificial material such as magnesium, which has a different electrochemical potential than steel, as well as through an applied external voltage (INGAA, 2010b).

miles are at least 45 years old, with almost 50% built between 1950 and 1969. See Figure 15 for more details.



**Figure 15. Age of U.S. natural gas transmission pipeline by decade**

Source: Kiefner and Rosenfeld (2012)

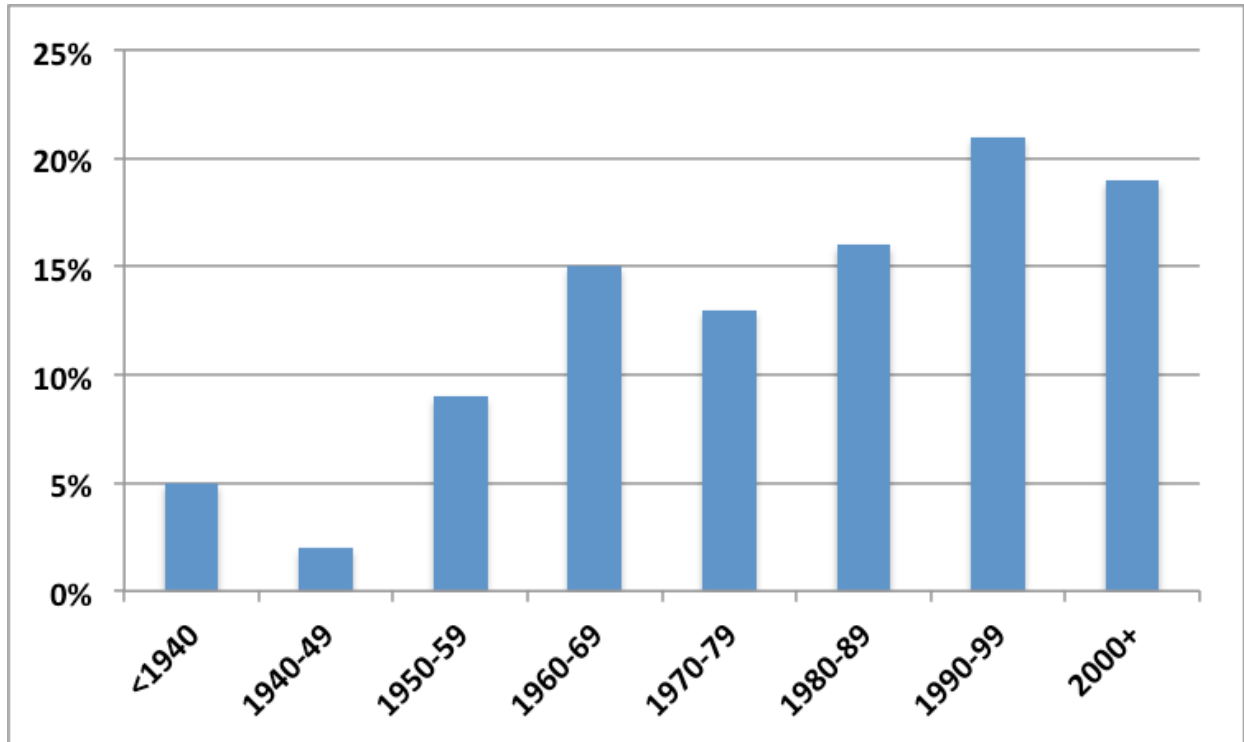
### *c. Distribution systems*

Distribution pipelines are constructed from a variety of materials, including various types of steel, cast iron, plastic (mainly polyethylene), and copper, though plastic has become the material of choice over the past 30 years (DOT, 2011; AGA, 2015b; BGA, 2014; BPC, 2014), comprising 52-54% of the ~1.25 million miles of distribution mains pipelines (BGA, 2014; BPC, 2014).<sup>13</sup> Advantages of plastic pipe include flexibility, corrosion resistance, and low installation cost—particularly because it can often be inserted into existing lines or through soil without the trenching that is often required for other materials (AGA, 2015b). Protected coated steel is the second most common material, comprising nearly 40% of distribution pipeline miles. The remaining ~9% consists of cast or wrought iron (~3%),<sup>14</sup> bare steel (~5%) and unprotected coated steel (~1%) (BGA, 2014; BPC, 2014). According to BGA (2014), this latter ~9% constitutes the most leak-prone portion of the distribution network, while BPC (2014) puts this number at closer to 7%. Although the portion of leak-prone miles fell 43% between 1990 and 2011, these materials are estimated to be 18 times more leak-prone than plastic and 57% more leak-prone than treated steel (BGA, 2014).

<sup>13</sup> BPC (2014) also estimated that distribution service lines consist of 68.7% plastic, 21.5% cathodically protected, coated steel, 3.4% bare steel, 2.4% unprotected, coated steel, 1.4% copper and 2.4% other.

<sup>14</sup> The iron pipe was built more than 50 years ago (DOT, 2012; BGA, 2014).

The age profile of distribution system is given by decade from DOT (2012) in Figure 16. Compared to transmission pipeline ages, the ages of distribution pipelines are much younger, with nearly 70% less than 45 years old.



**Figure 16. Age of U.S. natural gas distribution pipeline by decade**  
Source: DOT (2012)

#### iv. Storage and processing facilities

Little data were available on natural gas storage and processing facilities. ICF (2014) projected expansion of working gas storage by 823 Bscf between 2014 and 2035 (current capacity is ~4,800 Bscf; see Section 1-B-iii).

ICF (2014) also projected increases in natural gas processing facility capacity of 34.2 Bscf/day between 2014 and 2035, nearly as large as projected growth in production (~40 Bscf/day).

## 2. Technical efficiency opportunities

### A. Compressor systems

As partly covered in Section 1-B-ii, compressor systems vary in efficiency depending on choice of compressor and prime mover technology, power, speed, compression ratio and load factor. Moreover, the most efficient compressor is often not the most economical



choice from the perspective of the pipeline company. Costs and cost trade-offs are discussed in Section 2-C.

### i. Compressors

According to INGAA (2010a, pp. B-2 to B-5), the efficiencies of modern centrifugal and reciprocating compressors are similar (between approximately 75% and 90%), though small ( $\leq 20$  MW) centrifugal and high-speed reciprocating compressors tend to be at the less efficient end of this range, with larger centrifugal and lower-speed reciprocating compressors at the high end. Centrifugal compressor efficiencies also vary more strongly with compression ratio than reciprocating compressors, becoming much less efficient ( $< 65\%$ ) at compression ratios of 1.3 or less. Note that these values assume constant gas flow rates; the efficiency of reciprocating compressors will suffer more than centrifugal ones when flow rates are changing. What is perhaps surprising is that older (“legacy”) low-speed reciprocating compressors generally have *higher* efficiencies (between approximately 80% and 95%) than today’s systems, but they have less flow rate flexibility (ability to maintain high efficiency while accommodating a wide range of flow rates) and are far more expensive, so these are no longer commercially available as new systems.

Figure 17 reproduces a chart from INGAA (2010a, p. B-2) showing a comparison of compressor efficiencies by type and compression ratio.

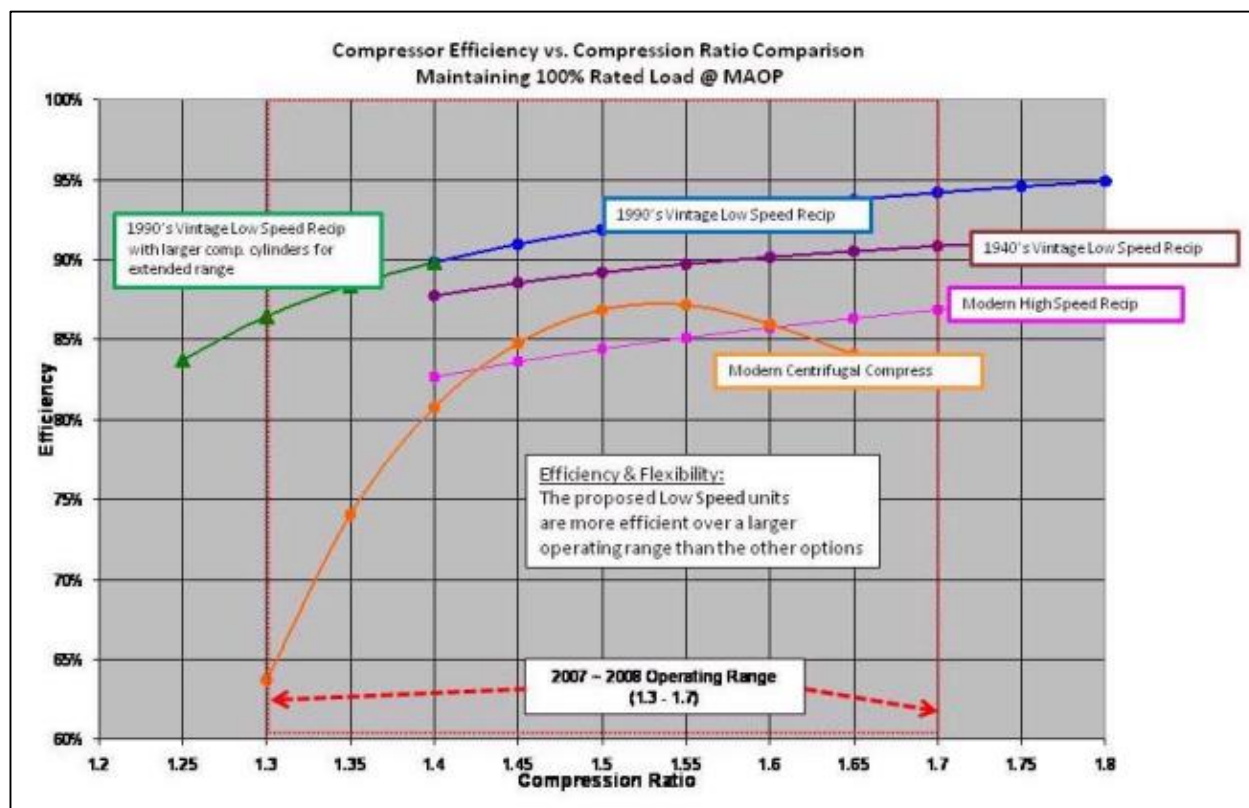


Figure 17. Compressor efficiency versus compression ratio for different compressor technologies



Source: INGAA (2010a, p. B-2)

INGAA also provides a table detailing a wide variety of compressor-prime mover combinations and characteristics, with efficiency estimates of each component as well as overall system efficiency under design conditions; this is reproduced in Table 2 (INGAA, 2010a, p. B-5).

**Table 2. Comparison of compressor technology efficiencies**

Prime Mover Technology	Prime Mover Efficiency (percent)	Compressor Type	Compressor Efficiency (percent)	Unit Efficiency (percent)	Advantages	Issues
Reciprocating Compressors						
Legacy slow speed IC engine (200-400 RPM)	27-30	Integral reciprocating	80-92	22-28	–	<ul style="list-style-type: none"><li>Waste heat recovery not economic</li><li>Less efficient and higher maintenance cost than legacy slow speed engines</li></ul>
Legacy slow speed + low emissions retrofit (200-400 RPM)	33-35	Integral reciprocating	80-92	26-32	<ul style="list-style-type: none"><li>Compact units</li></ul>	<ul style="list-style-type: none"><li>Waste heat recovery not economic; heat dispersed between exhaust gases and cooling</li><li>No longer manufactured</li></ul>
New slow speed IC engine (200-400 RPM)	30-43	Slow speed separable reciprocating	80-92	24-40	<ul style="list-style-type: none"><li>Multi-engine compressor station responds to demand variability more efficiently</li><li>Higher partial load efficiencies than turbines</li><li>More responsive to varying pressure ratios than centrifugal compressors</li><li>Slow speed unit are established infrastructure base with legacy of reliability</li><li>May be skid mounted for lower installed cost</li><li>Can be variable speed to maintain flexibility</li></ul>	<ul style="list-style-type: none"><li>Larger compressor cylinder design (and more costly) required for similar throughput to high speed machine</li></ul>
Medium speed engine (500-900 RPM)	32-46	Medium speed separable reciprocating	75-90	24-39		<ul style="list-style-type: none"><li>Higher initial unit cost than turbine units</li><li>Waste heat recovery not economic</li><li>Higher maintenance cost than legacy slow speed engines</li></ul>
High speed recip (900-1200 RPM)	32-43	Separable high speed reciprocating	70-82	22-35		<ul style="list-style-type: none"><li>Lower initial cost than slow speed reciprocating engine</li><li>Losses in valves and pulsation bottles are high</li></ul>
Synchronous speed electric motor (360 RPM)	25-46*	Slow speed separable reciprocating	80-92	20-42		<ul style="list-style-type: none"><li>No on-site emissions, simplifies permits</li></ul> <ul style="list-style-type: none"><li>Requires access to power</li><li>Torsional considerations</li><li>Speed fixed at 360 RPM (60 Hz)</li></ul>
Centrifugal Compressors						
Legacy gas turbine	22-27	Legacy centrifugal (1950-1980)	71-80	16-22	<ul style="list-style-type: none"><li>- only available technology at time for large power</li></ul>	<ul style="list-style-type: none"><li>No longer manufactured</li></ul>
Turbine (< 5 MW)	24-31	Centrifugal	75-88	18-27	<ul style="list-style-type: none"><li>Lower initial cost than reciprocating compressors</li><li>Waste Heat concentrated in exhaust gasses; CHP applications if a thermal host is nearby</li></ul>	<ul style="list-style-type: none"><li>Heat recovery for electric generation requires 11+ MW</li><li>Lower partial load driver efficiency</li><li>Lower ofload compressor efficiency</li></ul>
Turbine (5 - 20 MW)	27-36	Centrifugal	75-88	20-32		
Large Turbine (>20 MW)	29-40	Centrifugal	80-88	23-35		
Large Turbine with waste heat recovery (ORC) for electric power generation	33-47	Centrifugal	80-88	26-41	<ul style="list-style-type: none"><li>Electricity may provide revenue stream</li><li>Demand for “green” power</li><li>Organic Rankine Cycle is more compact with no fluid condensation</li></ul>	<ul style="list-style-type: none"><li>Requires large turbine (11+ MW)</li><li>Requires high load factor</li><li>Requires close grid access</li><li>Possible revenue pass-through requirements</li><li>Capital investment requires long-term contract with utility</li><li>Regulatory and permit complications.</li><li>ORC is less efficient than a steam cycle</li></ul>
Large Turbine with waste heat recovery (steam-based) for electric power generation	34-55	Centrifugal	80-88	26-48	<ul style="list-style-type: none"><li>Electricity may provide revenue stream</li><li>Demand for “green” power</li><li>Increases efficiency</li></ul>	<ul style="list-style-type: none"><li>Issues listed above for ORC system</li><li>Freeze-up in cold weather</li><li>Require 24/7 steam operator</li><li>Capital investment requires long-term contract with utility</li></ul>
Large Electric motor driven off electrical grid (3600 RPM)	25-46*	Centrifugal	80-88	20-40	<ul style="list-style-type: none"><li>No on-site emissions, simplifies permits</li><li>Low capital cost</li><li>Low maintenance for motor</li></ul>	<ul style="list-style-type: none"><li>Requires access to power</li><li>Cost associated with interconnection and transformer</li><li>Power provider may have minimum demand charge</li><li>Supply reliability</li><li>Generation of electricity at power plant may produce high emissions</li><li>Transmission of power also involves high losses especially if distances are great</li></ul>
*Heavily depends on source power generation losses. Electric motor site efficiency can reach 90 to 95 percent efficiency.						

Source: INGAA (2010a, p. B-5)

According to CAGI (2012, p. 478), energy losses from valves (see Section 1-C-ii) in high-speed ( $\geq 1000$  rpm) compressors can be as much as 20%, suggesting that improvements in valve performance may have a significant impact on efficiency. As mentioned in Section 1-C-ii, SWRI researchers successfully demonstrated a proof-of-concept approach to reducing energy losses arising from vibration and pulsation in high-speed reciprocating compressors by about 6% (Deffenbaugh et al., 2005). The same authors claimed that overall compressor efficiencies of 90% can now be achieved, and expressed optimism for increasing the efficiency of slow-speed compressors to as much as 95%.

For reciprocating compressors, compressor cylinder can be replaced with improved designs that are rated for higher pressures or designed to accommodate changes in load. The pulsation control system can also be modified to increase efficiency. Both of these are retrofit opportunities that do not require replacing the compressor (INGAA, 2010a, p. 41).

## ii. Prime movers

Laurenzi and Jersey (2013, pp. 26–27) analyzed heat rates of gas prime movers manufactured by Caterpillar, reporting mean heat rates and standard deviations of both gas engines and turbines. See Table 3. The range of capacities spanned by this data is very large: 95 to 8,180 hp<sup>15</sup> (Caterpillar, 2014). Laurenzi and Jersey (2013) also examined data from Siemens, reporting that efficiencies were similar in both mean value and variation.

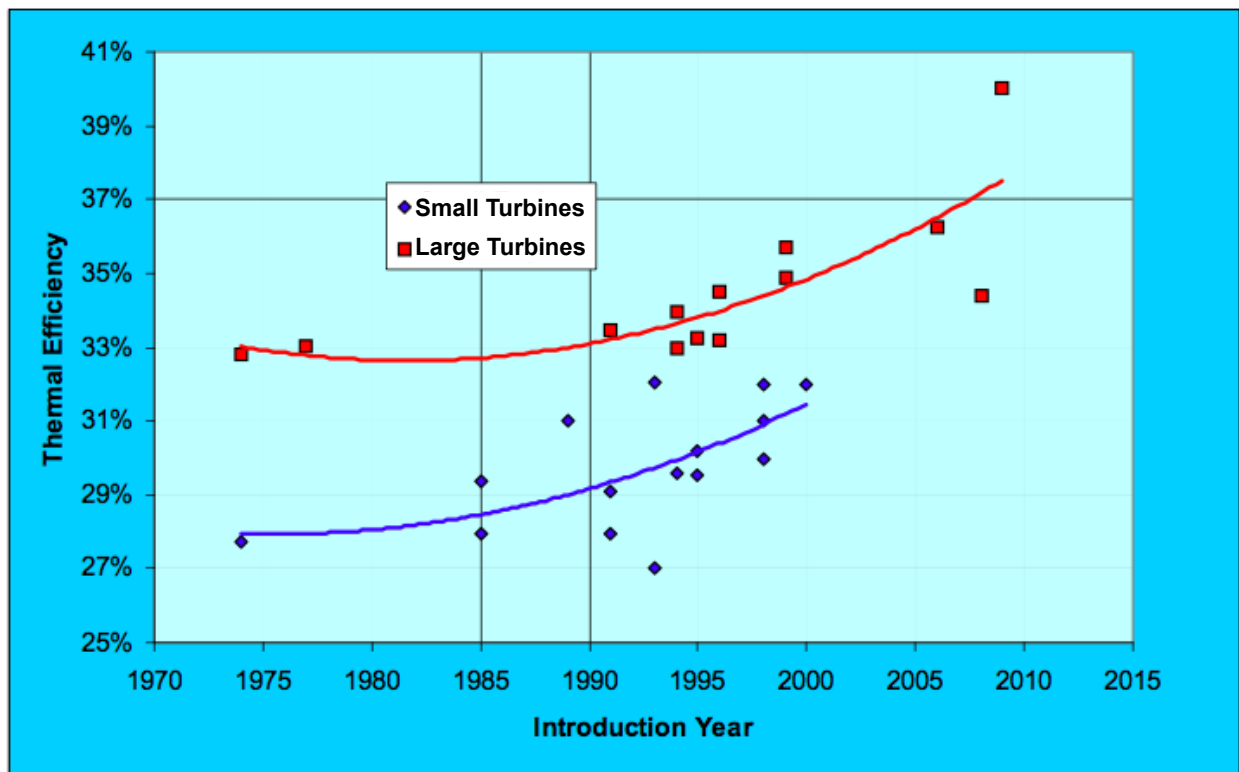
**Table 3. Heat rates of Caterpillar gas engines and turbines**

<b>Technology</b>	<b>Mean heat rate</b>	<b>Standard deviation</b>	<b>Mean efficiency (calculated)</b>	<b>Standard deviation of efficiency (calculated)</b>
	<i>Btu/hp-hr (HHV)</i>		<i>% (HHV)</i>	
Gas engines	6,825	38.7	37.28	0.21
Gas turbines	8,772	797	29.01	2.65

Source: Laurenzi and Jersey (2013)

Dividing the standard deviation by the mean efficiency gives one estimate of the efficiency improvement potential for gas prime movers, resulting in 0.6% for gas engine technology, and 9.1% for gas turbine technology. However, these estimates may be overly conservative, as INGAA (2010a, p. 19) claimed enormous improvement in recent years among large ( $>20,000$  hp) gas turbines, from 27% to 40% thermal efficiency (9,426 to 6,362 Btu/hp-hr). Smaller turbines have seen similar efficiency improvements, but operate slightly less efficiently (approximately 31% to 38%—see Figure 18) than the largest turbines. Note that the smaller ( $<10,000$  hp) turbine efficiency data stops in 2000. As stated in Section 1-B-ii-e, Hedman (2008) reported that large ( $>15,000$  hp) gas turbines account for  $>25\%$  of total gas turbine capacity.

<sup>15</sup> Some references use the notation “bhp” (brake horsepower) while others simply use “hp” (horsepower). According to the American Heritage Dictionary (2013), bhp is the “actual or useful horsepower of an engine, usually determined from the force exerted on a friction brake or dynamometer connected to the drive shaft.” However, the terms bhp and hp are interchangeable (Bruzek, 2008).



**Figure 18. Thermal efficiency of gas turbines over time**

Source: INGAA (2010a, p. 19). Note: Chart was modified to correct mislabeled legend. “Small” is defined as <10,000 hp; “large” is >10,000 hp.

Engine controls can be added to increase thermal efficiency in some older gas engines. Also, a gas engine can be replaced with an electric motor to accommodate a wider throughput range more efficiently (through speed variation) than other techniques (INGAA, 2010a, p. 41).

Electric motor efficiency is far higher, between ~90% and 97% (CAGI, 2012, p. 522), with the upper end corresponding to synchronous motors. However, it is difficult to compare electric motor efficiency with that of gas-based technology (INGAA, 2010a, p. B-5), because one must consider efficiencies of motor, transmission (6% on average; EIA, 2014h) and electricity production (for natural gas, this ranges from 40% to 60%; COSPP, 2010) as a system, and electricity can also be made using non-combustion methods, such as hydropower, wind or solar. INGAA estimates that system efficiency for electric motors varies between 25% and 46% (INGAA, 2010a, p. B-5). Even if system efficiency is lower than that of natural gas, electric motors may have lower GHG emissions if the GHG intensity of the generated electricity is sufficiently low. However, the choice of electric vs. gas may be increasingly driven by air quality concerns (INGAA, 2010a, p. 24). Electric motors do appear to be a more efficient choice than gas engines when flow rates vary substantially (see Section 1-ii-b).

### iii. Combined systems

For combined systems (prime mover plus compressor), for gas turbine-driven centrifugal compressors, the overall design efficiency of new systems has increased 50% since ca. 1990, and is now close to 33%. Gas engine-driven reciprocating compressors have improved as well: since 1995, their overall efficiency has increased from 42%–46% at peak thermal efficiency (100% load) (INGAA, 2010a, p. 20), representing a ~10% improvement.

Moreover, it is becoming more common to power high horsepower, low speed, reciprocating compressors (80%–92% efficiency) with either gas engines (30–43% efficiency) or electric motors (90%–97% efficiency),<sup>16</sup> to improve overall compressor system efficiency (INGAA, 2010a, p. 20).

### iv. Waste heat recovery

INGAA published a pair of reports (Hedman, 2008, 2009) documenting technical and economic opportunities for waste heat recovery from natural gas TS&D systems. Three types of heat recovery options were considered:

- Waste heat recovery from prime mover exhaust in compressor systems
- Use of turboexpanders (compressors “run in reverse”) to recover energy during gas expansion to lower pressure, usually when gas enters the distribution network
- Inlet air cooling to increase turbine efficiency in hot weather

The reports found that waste heat recovery from compressor systems is economical under certain circumstances, but the other two options did not appear to be viable under current economic conditions.<sup>17</sup> The economic opportunity for waste heat recovery is much greater for gas turbines than gas engines, because of the higher temperature and larger quantity of heat available in turbine exhaust. However, economically viable opportunities are currently limited to large systems ( $\geq 15,000$  hp) with high annual load factors ( $>60\%$ ). About 90–100 compressor stations in the U.S. were identified as meeting these criteria, representing a potential of 500–600 MW in generation capacity (Hedman, 2008). This potential represents ~10% of gas compressor turbine capacity and 4%–5% of total gas compressor prime mover capacity, but a small fraction (~0.2%) of U.S. gas-based power generation (EIA, 2014i).

As of November 2009, eight waste heat recovery projects have been installed on pipeline gas turbine compressor drivers in the U.S., with seven more in Canada; together these provide about 75 MW of electric generating capacity. Ten more projects are planned, with four in the U.S. representing an additional 22.5 MW. All projects are located in states with an RPS program or other incentive to favor waste heat recovery (Hedman, 2009). These

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<sup>16</sup> Note caveats about comparing electric and gas efficiencies; see Section 2-A-ii.

<sup>17</sup> Turboexpanders have been successfully installed in LNG and gas processing plants, where they are sometimes economical, but outside of this, only four demonstration plants were built in the 1980s representing a total of 3.8 MW capacity, but all were deemed uneconomical and eventually shut down. Turbine inlet air cooling appears to suffer from a net efficiency penalty, and so does not make economic sense at present (Hedman, 2008).

programs tend to increase the value of electricity sold by 0.5–1.0 ¢/kWh, which is a significant increment over the typical wholesale electricity price of 3.5–5.0 ¢/kWh (Hedman, 2008). All projects have also been installed on gas turbine compressors (Hedman, 2009).

## **B. Pipelines**

### **i. Pipe diameter and gas pressure**

Viewed in equivalent energy terms and equivalent transport distances, natural gas pipelines consume an average of 2%–3% of throughput to overcome frictional losses (INGAA, 2010a, p. 1). To improve the hydraulic efficiency of their systems, pipeline companies use the largest diameter pipelines and highest pressures possible while still being cost-effective (INGAA, 2010a, p. 18). Doubling the pipeline diameter will allow four times the gas flow with virtually the same operating cost (INGAA, 2010a, p. A-2), while conversely, doubling the gas flow in a fixed-diameter pipe will quadruple the energy needed to compress it (INGAA, 2010a, p. 28).

While not explicitly stated in the above sources, it appears that the energy required by compressors scales with the inverse fourth power of pipe diameter for a fixed flow rate. This conclusion is consistent with standard engineering texts (e.g., Lindeburg, 2011) as well as equations specific to the natural gas industry (Coelho and Pinho, 2007; Brikić, 2011), some forms of which suggest that the scaling relationship may be even stronger, e.g., inverse fifth power of pipe diameter. However, other limiting factors (e.g., economics) must come into play as pipe diameter increases, so that the maximum diameter used by the pipeline industry today (48 inches) presumably represents an economic balance point. Nonetheless, it may be worth exploring whether significant increases in energy cost (e.g., through a price on carbon) could push the industry to adopt larger pipe diameters than those used in current practice in order to reduce compressor fuel usage. This may particularly be the case for smaller-diameter pipelines. This point will be reiterated in Section 3.

As discussed in Section 1-C-iii, significant improvements have been possible through advancements in materials and compressor technology. New trunk pipelines are typically built with a larger diameter pipe than will be needed initially, but with compression capacity limited to meeting current needs, as compressors can be added later (either at new or existing stations) to increase capacity as demand increases (EIA 2007).

Increasing the MAOP increases gas throughput and reduces compressor fuel consumption, increasing efficiency. The Department of Transportation's Pipeline and Hazardous Materials Safety Administration determines the MAOP of pipelines (INGAA, 2010a, p. 39).

## ii. Pipe inspection and cleanliness

In the 1980s, companies expanded the use of advanced pipeline maintenance and inline inspection (ILI) technologies to clean and inspect the pipeline wall (“pigging”),<sup>18</sup> further reducing friction (INGAA, 2010a, pp. 14–19). Recently, there has also been an effort to “digitize” the pipeline network, providing real-time information on gas flows, leaks, and hazards through various types of sensors (including those mounted on wheeled or airborne robotic platforms), data analytics, visualization and advanced simulation (Accenture, 2014a). On September 8, 2014 GE and Accenture jointly announced their “industrial internet” solution for better pipeline management, to be implemented within the Marcellus and Utica shale gas production regions (Accenture, 2014b). The emphasis of these efforts is on increasing reliability and safety, reducing operational costs, and prevention of and/or rapid recovery from failures. A gain in efficiency from better system operation, or having a smoother interior surface is a side-benefit (Roberts, 2009a).

For cleaning, both mechanical (dry) scrubbing as well as a variety of liquid (surfactant, acid, gel) methods can be used. A combination of mechanical and liquid cleaning is generally considered superior. However, quantitative data on efficiency improvement from cleaning are lacking, though the claim is that liquid-based cleaning “should more than pay for itself” (Roberts, 2009b).

Additionally, shorter and straighter lengths of pipe, and avoidance of obstacles such as valves and flow meters in the pipeline (INGAA, 2010a, p. A-1 to A-2), as well as removal of debris such as “hard hats, wooden skids, pig bars, chill rings, welding rods, and electric grinders” (Roberts, 2009a) that are occasionally left in pipelines, will increase efficiency.

As discussed in Section 1-C-iii-c, replacing leak-prone pipes in the distribution network would save 23 Bscf/yr (BGA, 2014), or ~0.1% of total natural gas consumption. Such repairs would also have important safety and reliability benefits.

## iii. Internal surface coatings

As noted in Section 1-C-iii, pipeline companies began experimenting with internal coatings to reduce friction and increase system efficiency in the 1960s; however, internally coated pipes only became widely available starting in the 1990s.<sup>19</sup> The use of internal coatings has, according to one coatings manufacturer, become “standard industry practice” (Jotun, 2014). Others similarly claim that internal coatings are becoming “widely applied in gas pipelines and a remarkable economic benefit has been achieved” (Deyuan et al., 2011); many European countries and China have adopted coating technologies, with dramatic

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<sup>18</sup> “Legend has it they are called pigs because the early internal cleaning devices were made a [sic] leather cover stuffed with batting materials which made a sound much like a pig as line pressure pushed the device through the line. Maintenance pigs come in a variety of configurations including elastomeric spheres or devices consisting of a mandrel with elastomeric cups, discs, pigs, and brushes fastened to it. Some even have magnets to attract iron sulfide (rust)” (INGAA, 2010b).

<sup>19</sup> There are a variety of coating materials available, including fusion bond epoxy coatings (INGAA, 2010a, p. 30), but there was no additional information available in the references examined on the chemical composition of these coatings.

improvements in gas transmission rates, in some cases up to 30% (Deyuan et al., 2011). However, the U.S. is curiously absent from the list, suggesting the practice may be less widespread here.

Internal coatings are most effective at high flow rates, where flow is often turbulent. However, for a sufficiently low surface roughness, a laminar film can be formed at the pipe wall-fluid interface, reducing friction between the fluid and the pipe with a concomitant reduction in pressure drop and reduced amount of power needed to maintain pressure at a given throughput. An internal coating can form a more even coating on the inner pipe wall, reducing surface roughness (INGAA, 2010a, p. 30; Collet and Chizet, 2013). Typical values of average absolute roughness (maximum peak to valley height) for uncoated steel pipe are 20–50  $\mu\text{m}$  (with the latter corresponding to corroded pipe) and 1–5  $\mu\text{m}$  for coated pipe (Deyuan et al., 2011; Collet and Chizet, 2013). INGAA provided an example of an 11% reduction in fuel use compared to bare steel pipe when using an internal coating (INGAA, 2010a, p. C-1). Other researchers have reported increased flow rates between 5% and 27% (Pipelines International, 2011; Collet and Chizet, 2013), so coatings can make a significant impact on efficiency. A reduction in compression power can therefore be achieved with the same gas flow rate (Collet and Chizet, 2013).

A new innovation is the use of microgrooves to further reduce friction below that which can be achieved simply by making an internal surface as smooth as possible. Initially explored in the 1970s by Michael Walsh at NASA Langley, this so-called biomimetic drag-reducing coating “...completely broke through the traditional way of thinking,” and has recently been realized experimentally by a group at Beijing University (Deyuan et al., 2011). Using a groove of 135  $\mu\text{m}$  width and 100  $\mu\text{m}$  height on a coated surface that already possessed very low (5.5  $\mu\text{m}$ ) surface roughness, a further improvement of 6% in gas transport efficiency was achieved (Deyuan et al., 2011).

## C. Cost estimates

Cost data was difficult to obtain and only a handful of data points were available. More detailed information on the costs of various system components and their cost trade-offs are critically needed to help evaluate efficiency opportunities.

### i. Compressor systems

While slow speed, integral reciprocating compressors are typically more efficient than modern high-speed compressors, they are “...generally no longer commercially available because they are cost-prohibitive to manufacture and install,” (Deffenbaugh et al., 2005). The trend has been toward larger, more flexible machinery that can handle large swings in gas flow rates necessary in modern operations. Therefore, a return to earlier technology appears infeasible.

“Assuming the same configuration and location, two smaller compressor units will have a higher cost per horsepower compared to a larger unit due to economies of scale,” (INGAA, 2010a, p. 32).



For low-speed reciprocating compressors, gas engines are the most expensive option in terms of upfront cost, while gas turbines and electric motors have approximately the same installed cost. Between 1995 and 2010, the installed cost of compressor units has approximately doubled (INGAA, 2010a, p. 42). Typical installation costs for a greenfield mid-sized (~15,000 hp) compressor powered by a gas turbine were between \$2,500 and \$3,500 per hp in 2010 (INGAA, 2010a, p. 36), but more efficient compressors can cost 25% more, and if multiple compressors are chosen to increase flexibility, cost can be as much as 50% higher (INGAA, 2010a, p. 42).

Information on the relative costs of reciprocating versus centrifugal compressors was very limited. What information was available was hampered by a lack of “apples to apples” comparisons; an example is provided in Table 4, reproduced from INGAA (2010a, p. 36). In general, the author observes that the cost of a centrifugal vs. reciprocating compressor could be very similar (central three cases shown in Table), but taken across all data points, reciprocating compressors appear to be somewhat more expensive.

**Table 4. Relative driver/compressor cost comparison for a 14,400 hp unit**

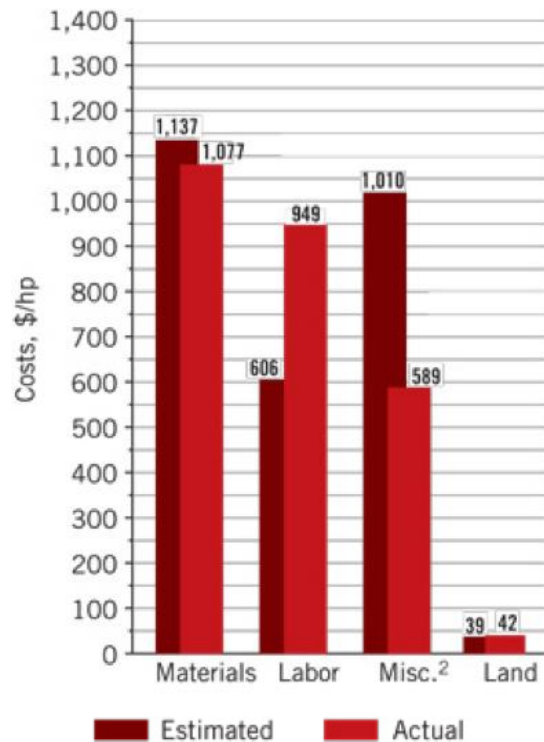
	Estimate for Initial Cost on Site				
	Single GT Turbine / Centrifugal Compressor	Multiple GT Turbines / Centrifugal Compressors	Electric Motor / High Speed Reciprocating Compressor	High Speed Engine / Reciprocating Compressor	Slow Speed Engine / Reciprocating Compressor
Total Installed Cost	100%	129%	130%	132%	154%

Source: INGAA (2010a, p. 36)

In terms of compressor costs across technology types, Smith (2013) provided cost information that broke costs down by materials, labor, land and miscellaneous expenses<sup>20</sup> and also as a function of compressor power. Actual average cost for July 1, 2012 to June 30, 2013 was \$2,657/hp, with compressor materials as the dominant actual cost item (41% of total), followed by labor (36%) and miscellaneous (22%). See Figure 19. These figures are comparable to averages derived from ICF (2014) for projected compression costs between 2014 and 2035: \$2,640/hp for transmission and storage compression, and \$2,800/hp for gathering system compression.<sup>21</sup>

<sup>20</sup> This category includes “surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction, and FERC fees” (Smith, 2013).

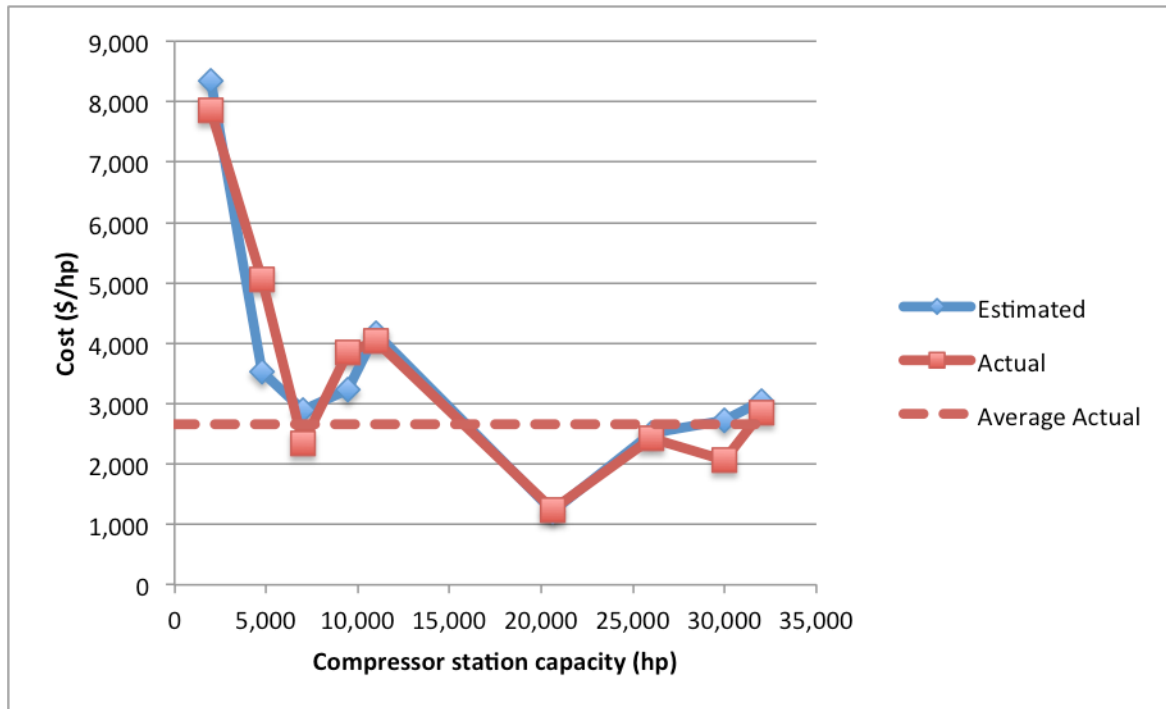
<sup>21</sup> Specifically, ICF (2014) projected total compressor capital expenditures (in 2012 dollars) between 2014 and 2035: \$11.6 billion for transmission and storage, and \$23.5 billion for gathering. Dividing by total projected expansion capacity from the same source produced the reported averages.



**Figure 19. Estimated and actual compressor cost breakdown for 2012–2013**

Source: Smith (2013).

Total compressor cost vs. capacity (in hp) is shown in Figure 20, where a downward trend with increasing hp is evident. Data for individual compressor projects in 2012–2013 (Smith, 2013) exhibit considerably more variability than these averages, however.



**Figure 20. Estimated and actual total compressor costs vs. capacity for 2012–2013**  
Source: Author calculations using data from Smith (2013)

## ii. Waste heat recovery

As discussed in Section 2-A-iv, waste heat recovery from compressor systems can sometimes be economical. Hedman (2008) estimated that the capital cost of such systems on large (>15,000 hp) gas turbines is \$2,000–\$2,500/kW.<sup>22</sup> With reasonable assumptions about equipment life and financing,<sup>23</sup> the annualized capital cost is about 3.1 ¢/kWh, on top of which an additional 0.5 ¢/kWh is added to pay the pipeline operator for the value of the heat, and an additional ~0.2 ¢/kWh is added to pay for operations and maintenance (range: 0.1–0.5 ¢/kWh). Given that current prices for wholesale power range between 3.5–5.0 ¢/kWh for long-term (20–30 year) purchase agreements, such systems can be favorable when capacity factors are sufficiently high. Green incentives (~0.5–1.0 ¢/kWh) can create a strong additional financial incentive (Hedman, 2008).

Although deemed uneconomical under current circumstances, the report did estimate capital costs for turboexpander systems as well: between \$600 and \$2,300/kW (in 1987 dollars), with the lower figure reflecting the considerable economy of scale inherent for a larger system (3.8 MW). Operational costs are also high: in addition to fuel for gas heating, the maintenance of the turboexpander is estimated to be 0.1–0.5 ¢/kWh (Hedman, 2008).

<sup>22</sup> Hedman (2009) updated this estimate to \$2,500–3,500/kW. However, the 2008 values are retained here in order to provide a consistent calculation.

<sup>23</sup> Assumptions: 20-year equipment life, 8% financing and 95% capacity factor; lower capacity factors will drive up cost considerably (Hedman, 2008).

### iii. Pipelines

Little information was available about pipeline construction costs. INGAA states that doubling the pipeline diameter will allow four times the gas flow, “yet costs only about twice as much to construct and costs virtually the same to operate” (INGAA, 2010a, p. A-2). Conversely, doubling the gas flow in a fixed-diameter pipe will quadruple the energy needed to compress it (INGAA, 2010a, p. 28). Clearly, maximizing pipe diameter will reduce operating costs.

BPC (2014) provided two sets of natural gas pipeline infrastructure cost estimates, based on data from ICF (2009) and CPUC (2012). The ICF data was for 30–36 inch diameter pipes, and ranged from \$30,000 to \$100,000 per inch-mile between 1993 and 2007; the cost calculated for a 36-inch pipe was \$1,080,000 to \$3,600,000 per mile. The CPUC data provided estimates for pipes ranging from 10 to 36 inches in diameter and was intentionally inflated by 40% from expected costs; the cost range spanned non-congested to highly-congested areas. Table 5 shows the data, reproduced from BPC (2014). For 36-inch pipes, the data is approximately twice as high as the ICF data, after correcting for the 40% inflation factor. According to BPC (2014), the difference may be partially due to a combination of cost overestimation, and real cost inflations between the times that two studies were published.

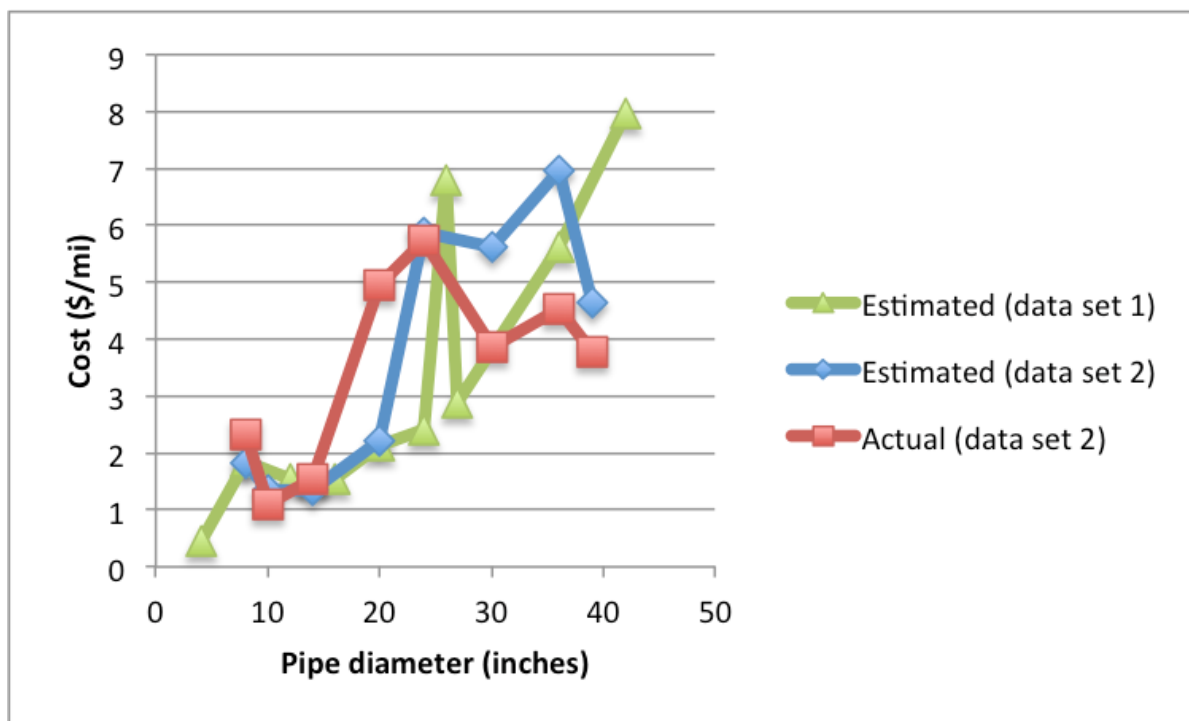
**Table 5. Estimated pipeline installation costs.**

PIPE SIZE RANGE	COST (MILLIONS OF DOLLARS PER MILE)		
	NON-CONGESTED AREAS	SEMI-CONGESTED AREAS	HIGHLY CONGESTED AREAS
10"	\$0.6	\$1.3	\$2.1
16"	\$1.1	\$2.0	\$3.2
24"	\$2.0	\$3.4	\$5.2
36"	\$4.0	\$6.2	\$8.9

Source: CPUC (2012)

Another recent report (BGA, 2014) provided a range of distribution pipeline replacement cost of between \$1.5 and \$5.0 million per mile, depending on diameter and other factors. These numbers appear to be roughly consistent with the (inflated) CPUC data, at least over the pipeline diameter range of 24 to 36 inches. BGA estimated that replacing the entire leak-prone portion of the distribution network (112,600 miles) would cost \$275 billion, implying an average cost of ~\$2.4 million per mile.

Oil and Gas Journal reported pipeline costs based on FERC data filed between July 1, 2012 and June 30, 2013 (Smith, 2013). Two sets of estimated costs were presented, as well as actual costs for one of the data sources. While considerable disparity exists among the three datasets cited, trends are generally in line with recent data presented above from CPUC (2012) and BGA (2014). See Figure 23.



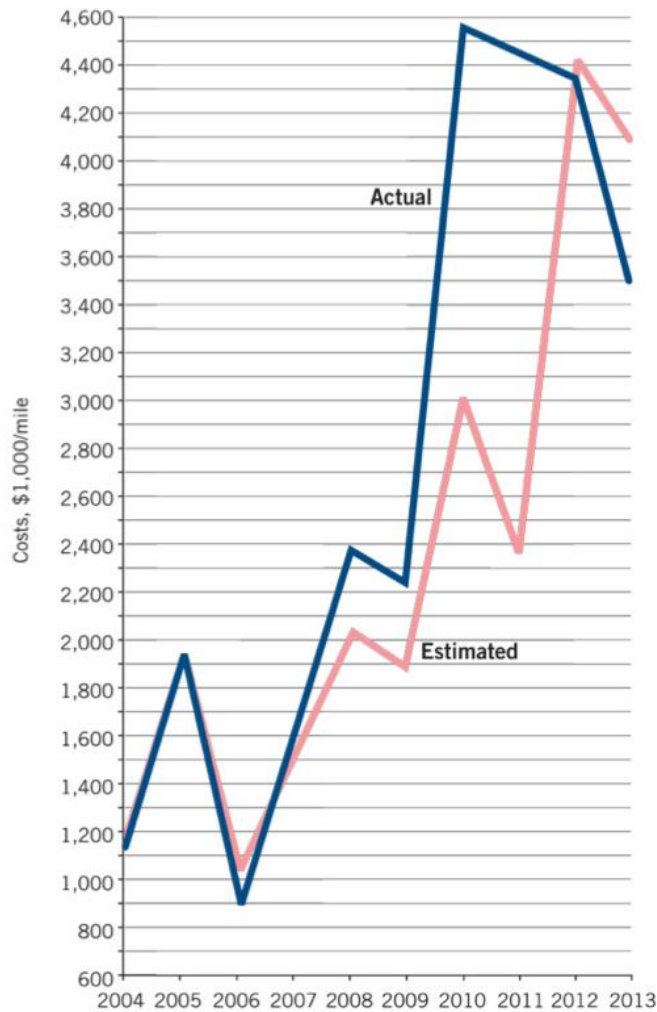
**Figure 21. Estimated and actual total pipeline costs vs. diameter for 2012-2013**

Source: Author analysis of data from Smith (2013, Tables 4 and 7)

ICF (2014) provided total projected capital expenditures (in 2012 dollars) between 2014 and 2035 for gathering, mainline transmission and lateral lines. These three categories of pipelines varied widely in average diameter (see Sections 1-C-iii-a and 1-C-iii-b for details). Using this data, the author derived an average cost per mile of \$117,000/mi for gathering pipelines (average diameter 3.6 inches), \$2.64 million/mi for laterals<sup>24</sup> (average diameter 16.3 inches), and \$4.69 million/mi for transmission pipelines (average diameter 30.5 inches). These results are broadly consistent with other studies.

Smith (2013) also examined estimated and actual total average pipeline construction costs over the past decade, showing a dramatic rise since the early 2000s. Actual costs for 2013 (\$3.49 million/mi.) were approximately three times that of 2004. See Figure 22.

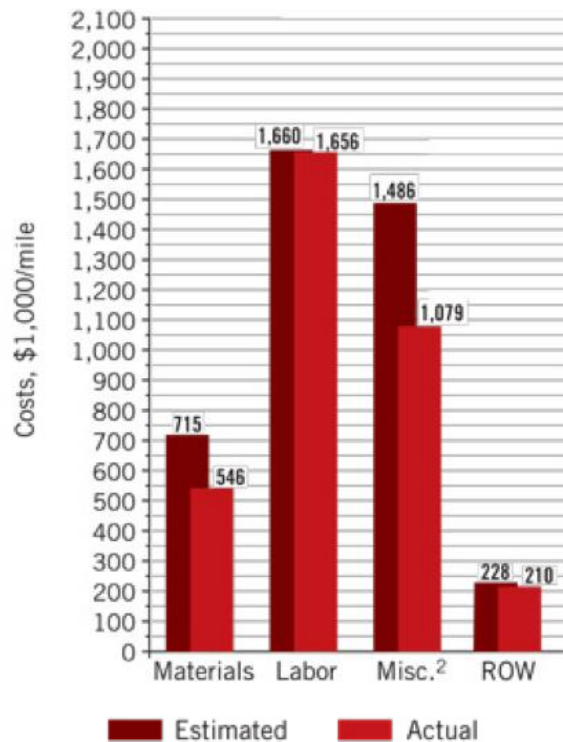
<sup>24</sup> See definition in Section 1-C-iii-b.



**Figure 22. Estimated and actual total pipeline cost trends, 2004–2013**

Source: Smith (2013). Note: While there were sometimes large annual differences between estimated and actual costs, the overall trends of both are significantly upward.

Finally, as for compressors, Smith (2013) provides a cost breakdown for compressor construction by component. Labor constitutes the most significant (47%) component of actual cost, followed by miscellaneous (31%) and materials (16%). See Figure 23.



**Figure 23. Estimated and actual pipeline cost breakdown for 2012-2013**

Note: ROW = rights-of-way (land).

Source: Smith (2013)

#### iv. Cleaning (pigging)

No useful cost information was available about pigging for efficiency improvement, other than the claim that liquid-based cleaning “should more than pay for itself” (Roberts, 2009b). There is also a cost distinction between “online” (pipeline continues to operate) versus “offline” (pipeline out of service and depressurized) pigging. “As a rule, offline cleaning can be twice as expensive as online and the cost is compounded by the loss of gas revenues,” (Roberts, 2009a). Pigging costs are higher offline due to a number of factors: slower pig velocity, more cleaning runs, the need for pressurized nitrogen and air to propel the cleaning equipment, and the fuel cost to generate pressurization over the duration of cleaning. In the case where natural gas at low pressure can be used as a propellant, some cost savings may be realized (Roberts, 2009a).

#### v. Internal coatings

According to INGAA, because it involves a substantial expense, internal coatings are not cost-effective in many circumstances (for instance, at light load capacities). When coatings are economically justified, they are most often used for future expansions, pipeline replacements or as a trade-off against the expense of higher compressor power (INGAA, 2010a, p. 30).

INGAA provides a cost estimate range of between \$2–\$8/ft. depending on pipe diameter and type of coating (INGAA, 2010a, p. C-1), though coating materials other than fusion bond epoxy were not specified. If the factory producing the pipe is unable to coat it, it must be shipped to another location for coating, costs could be higher and possibly result in construction delays. According to INGAA, replacing old steel pipe with new, internally coated pipe would typically be cost prohibitive because efficiency gains would not justify the cost (INGAA, 2010a, p. C-1).

Fogg and Morse (2005) provided a few cost estimates that consist of a mixture of absolute and relative values. One study they cited reported savings of \$20 million for a 530 km length pipe with a flow of 5.6 MMscf/day; the pipe diameter was not specified. Another study reported 5% cost savings due to a reduction in pipe diameter from 26 to 24 inches (outer diameter) while using the same compressors to achieve the same flow. A third study calculated cost savings of 7%–14% relative to uncoated steel pipe with little corrosion (20 µm roughness), increasing to 15%–25% savings when the pipe was heavily corroded (50 µm roughness).

Collet and Chizet (2013) provided even more optimistic estimates of cost savings, citing a 2002 examine from Argentina where a 1,200 km length of coated pipe incurred 27% lower compressor costs than uncoated pipe, among the highest savings cited in the literature. The source goes on to claim that reduced energy costs from internal coatings often have a financial payback of 3-5 years, with even further savings possible if the number of compressor stations and/or compressor capacity is reduced.

For the microgrooved pipe coating with an estimated efficiency improvement of 6%, the researchers estimate that the cost of such a coating is (Chinese) ¥10 (about \$1.60) per m<sup>2</sup> of internal pipe surface (Deyuan et al., 2011). Using their assumed internal diameter of 40 inches, this translates into \$5,100/km or \$1.55/ft. of pipe distance.

#### **vi. Storage, processing and LNG**

Only one source of information was available to estimate costs of new natural gas storage, processing and LNG plants: ICF (2014). This source provided total projected capital expenditures (in 2012 dollars) in these categories between 2014 and 2035, along with projected capacity additions (see Sections 1-C-i and 1-C-iv). By dividing these two quantities, average costs per unit of capacity were obtained:

- Natural gas storage: \$14.6 million per Bscf
- Natural gas processing plant: \$801 million per Bscf/day
- LNG export facility: \$4.70 billion per Bscf/day

#### **D. System-level trade-offs**

*Note: All information in this section comes from a single industry source (INGAA, 2010a). Additional sources of information or perspective would be useful to verify and update this information in the future.*



INGAA sums up the types of trade-offs that pipeline manufacturers must make when deciding whether to invest in efficiency: “When the cost of innovations exceeds what customers are willing to pay under their transportation contract with their pipeline company, there is little incentive for pipelines to assume the risk association with such investments.... Pipeline companies strive to be as efficient as possible, yet must balance efficiency with the need to provide reliable and flexible service to customers” (INGAA, 2010a, pp. 2–5).

As gas delivery contracts have become shorter (<15 years; INGAA, 2010a, p. 21), pipeline companies have faced considerable risk that their capital investments cannot be fully recovered. Moreover, competition between pipeline companies has placed more bargaining power in the hands of gas customers, creating a split-incentive situation where customers will only tend to pay for efficiency improvements that directly benefit them (INGAA, 2010a, pp. 4–5).

Because peak flow is required for only a small portion of the year, “the pipeline company may select compressor units with the lowest cost that provide the greatest flexibility” (INGAA, 2010a, p. 31), which means that they will often be operating away from the most efficient design point. There are some remedies for this situation, however: flow simulation software now allows for real-time modeling to help pipelines to operate more efficiently, usually through increasing pipeline pressures (“line packing”) (INGAA, 2010a, p. 39).

While two smaller compressors will have a higher cost per unit of compressor capacity (e.g. in hp) compared to a larger unit due to economies of scale, “operating multiple, smaller compressors can achieve better overall fuel efficiency than a single larger compressor,” if the pipeline generally operates with less than the maximum rated gas flow (INGAA, 2010a, p. 32).

INGAA (2010a, p. 43) provides a payback example for a 10,000 hp replacement, which is reproduced in Table 6. With the assumptions provided therein, the payback time for a 33% more efficient compressor (6,000 versus 8,000 Btu/hp-hr) is nearly 16 years, representing perhaps an length of time longer than some pipeline company would be willing to wait for full investment recovery (INGAA, 2010a, p. 42).

**Table 6. Cost comparison example for replacement of a 10,000 hp compressor**

Gas Cost	\$4.00/Dth		
Compressor size	10,000 hp		
	<b>Heat rate</b>	<b>Annual Fuel Cost</b>	<b>Capital Cost</b>
<b>Average efficiency</b>	8,000 Btu/hp-hr	\$2,242,560	\$35,000,000
<b>Best efficiency</b>	6,000 Btu/hp-hr	\$1,681,920	\$43,750,000
<b>Annual savings</b>		\$560,640	\$8,750,000
<b>Payout in years if unit operates at 80%</b>		15.6 years	

Note: Dth = decatherm.

Source: INGAA (2010a, p. 43)

The location and spacing of compressor stations is another important factor in overall system optimization. Pipeline companies now use advanced simulation software to determine optimal compressor station placement, considering cost, physical space availability, permitting, and reliability. INGAA provides an example of the trade-off between delivered transportation cost for natural gas vs. pipeline mileage that illustrates optimal compressor spacing. A smaller, 30-inch diameter pipeline requires shorter spacing (approximately 60 miles) between compressors stations because of the increased pressure drop associated with higher velocities in a smaller diameter pipe. Larger 36-inch and 42-inch diameter pipelines have lower pressure drops and therefore optimal spacing between stations is wider (80 miles and 100 miles, respectively). However, additional considerations including environmental, landowner, and other siting needs often force deviations away from an economically optimal spacing design (INGAA, 2010a, p. D-1).

According to INGAA, “As a rule of thumb, in a new pipeline design, a pipeline company can spend two to four times more initial capital on pipeline than on compression to achieve the same delivered cost of gas.” In fact, pipeline companies explicitly calculate the economic trade-offs between larger diameter pipelines versus the additional compression needed to achieve a desired flow rate. As stated earlier in Section 2-B, another important consideration is the nonlinear relationship between pipeline diameter and compression, where a doubling of gas flow for a given pipe diameter quadruples total fuel usage (INGAA, 2010a, p. 28).

Another trade-off concerns compressor valves, which must be replaced frequently and is the single largest cause of unscheduled downtime for reciprocating compressors. “There are trade-offs between valve types such as durability, efficiency, maintenance requirements, and cost.” (INGAA, 2010a, p. 40) As discussed in Section 1-C-ii, advanced valve designs such as those being developed by SWRI appear to offer good cost-saving opportunities and may increase efficiency slightly as well.

As mentioned in Section 2-C-v, internal pipe coatings may not be cost-effective in many circumstances, so they are often used in the context of future expansion, pipeline

replacement, or as a trade-off with increased compressor power (INGAA, 2010a, p. 30). However, compared to uncoated pipe, coatings appear to offer significant efficiency improvement.

### 3. Synthesis

All estimates presented here are drawn from material in Section 2.

**Compressors.** By choosing larger compressors with good pulsation control and advanced valve technology, it appears that both reciprocating and centrifugal compressors may be technically capable of reaching 90% thermal efficiency at their design point, and perhaps as high as 95% eventually. However, off-design operation is increasingly the norm for compressors, in order to accommodate large swings in demand. While not mentioned by INGAA, one solution may be to install multiple smaller compressors, so that capacity can be switched on or off modularly, maintaining high efficiency in operating units; however, such a choice usually increases cost. Therefore, due to cost considerations, an efficiency of  $\geq 90\%$  may not always be achievable in practice. Still, compared to typical design efficiencies of existing reciprocating and centrifugal systems ( $\sim 80\%$ ), there appears to be a potential for perhaps a  $\sim 10\%$  average efficiency improvement in compressor equipment. A number of these efficiency options can be implemented in a retrofit fashion, so virtually all existing compressors are potentially eligible.

Older **prime mover** technology is less efficient than modern (2010 era) equipment, which for gas engines and large ( $>10,000$  hp) gas turbines are all close to 40% efficiency, so choosing one technology over the other may be unimportant from an efficiency perspective. It is difficult to compare electric motor efficiency with that of gas-based technology, however, because one must consider efficiencies of motor, transmission and electricity production as a system, and electricity can also be made using non-combustion methods. In some circumstances, the system efficiency of electric motors can be higher than that of gas-based technology, and even if efficiency is lower, electric motors may sometimes reduce GHG emissions. The choice of electric vs. gas may be increasingly driven by air quality concerns. Electric motors do appear to be a more efficient choice than gas engines when flow rates vary substantially.

Meanwhile, the efficiency of new gas-based prime mover equipment continues to improve. Compared to average efficiencies of 20–30 or more years ago, which represent the majority of existing installed equipment, improvement of 10%–30% appears possible, with the largest gains corresponding to larger horsepower systems ( $>20,000$  hp). For older gas engines, engine control technology can be added in a retrofit fashion, improving efficiency.

**Waste heat recovery (WHR)** in gas turbine systems may be economical, particularly in states with “green” incentives, such as an RPS target that gives credits for WHR. While not directly improving the efficiency of the compressor system itself, waste heat recovery provides inexpensive supplemental electricity without burning additional fuel, and thus

offsets other electricity generation. About 90–100 compressor stations in the U.S. (~7% of total stations and 4%–5% of total prime mover power capacity) are estimated to be economical, and this number may grow as the price of electricity increases, through green policies or other changes.

**Pipelines.** Larger diameter pipelines are desirable, as they lower compressor energy use very significantly (energy use appears to scale with the inverse fourth or fifth power of pipe diameter at fixed flow rate). Therefore, according to the author’s calculations, a 10% increase in pipe diameter could reduce compressor energy use by 40%–50%, though this is an inference and needs to be verified by those in the industry. It is evident that pipeline diameters are currently limited to 48 inches through an economic trade-off among pipeline capital cost, compressor capital cost, and compressor energy use. However, it is the author’s view that the largest-diameter pipelines may not always be used, especially among smaller pipe diameters. If incentives (e.g., a price on carbon) materialized to favor higher-efficiency systems, pipeline diameters would probably be increased.

Pipeline pressures can be increased, sometimes in combination with obtaining a higher MAOP certification, though the latter often requires newer high-strength steels to handle the higher pressure, so this is usually only an option for new pipelines. Improvement potential could be large if a pipeline is currently not operating near its MAOP rating. Boosting the MAOP level from 1,600 to 1,750 psi as illustrated in the example in Section 1-C-iii would provide an additional ~10% increase in efficiency.

Good pipeline layout (e.g., minimizing unnecessary bends and overall length) as well as keeping protruding equipment in the pipes to a minimum can further enhance efficiency. Regular cleaning not only improves reliability but can boost efficiency as well.

**Interior coatings** also appear to make a significant improvement in efficiency, ranging from 5% to 27% compared with uncoated pipe. The use of a new microgrooved coating developed by Deyuan et al. (2011) appears promising, providing an additional efficiency improvement potential of ~6%.

Table 7 summarizes the efficiency opportunities in the U.S. natural gas TS&D system, based on sources cited earlier in the report. Estimates of the overall potential for efficiency improvement is difficult, however, due to lack of data about the efficiency distribution of the existing fleet.

**Table 7. Summary of efficiency opportunities in the U.S. natural gas TS&D system**

<b>Category</b>	<b>Equipment type</b>	<b>Description of action</b>	<b>Efficiency</b>
Compressors	Reciprocating and centrifugal	Base efficiency (modern designs)	75%–90%
		Base efficiency (legacy designs)	80%–95%
		Larger capacity	+15%*
		Pulsation control	+6%
		Overall potential (high speed)	90%
		Overall potential (slow speed)	95%
		Pulsation control system retrofit	No quantitative data available
	Reciprocating	Cylinder replacement with improved designs	No quantitative data available
Prime movers	Gas turbine (>20,000 hp)	Base efficiency (>20,000 hp, 1980 era)	27%
		Base efficiency (2010 era)	40%
	Gas turbine (10,000–20,000 hp)	Base efficiency (1974 era)	31%
		Base efficiency (2010 era)	38%
	Gas turbine (<10,000 hp)	Base efficiency (1974 era)	28%
		Base efficiency (2000 era)	31%
	Gas turbines (≥15,000 hp)	Waste heat recovery (~10% of gas turbine capacity)	Savings of 0.2% in U.S. natural gas electricity generation
	Gas engine	Base efficiency (2014 era)	37%
		Engine control retrofit, replace gas engine with electric motor	No quantitative data available
	Electric motor	Base efficiency (2010 era)	90%–95%
Compressor systems	Gas turbine, centrifugal compressor	Base efficiency (1990 era)	22%
		Base efficiency (2010 era)	33%
	Gas engine, reciprocating compressor	Base efficiency (1995)	42%
		Base efficiency (2010 era)	46%
Pipelines	All	Base efficiency (average)	97%–98%
		Increase pipeline diameter 10%	40%–50% savings
		Reduce pressure 10%	20% savings
		Pipe cleaning (pigging)	No quantitative data available but

			“should more than pay for itself”
		Conventional interior coatings	5%–27%
		Microgrooved interior coating	6%
	Distribution	Replace leak-prone pipes (9% of total network miles)	~0.1%

\* When starting from low end of range. From high end of range, efficiency improvement is reduced toward zero.

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# Exhibit 13





Pipeline Technology Journal

# Solar Power Station Helps to Power Gas Pipeline Compressor Station

🕒 Fri, 10/16/2020 - 15:37

📁 Posted in: PIPELINE BUSINESS , PROJECTS

💬 0 comments



Lambertville Solar Project (copyright by Merit SI)

Merit SI, a leading sustainable infrastructure company based in Houston, announced that it has started building the nation's first solar power plant for an interstate natural gas pipeline compressor station.



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The station, which is located in New Jersey, is owned by the Canadian pipeline company Enbridge Energy and will serve Texas Eastern Transmission LP, a subsidiary of Enbridge.

As reported in the Houston Chronicle, the 2.25 MW AC project, located in West Amwell Township, N.J., at Texas Eastern's Lambertville Compressor Station, is estimated to reduce associated GHG emission by 58,500 metric tons over its operating life and ease the electric transmission grid during high demand, higher cost, summer months.

"Powering our compressor stations in part with behind-the-meter solar helps us manage electricity costs and improve our environmental performance. Additionally, these projects bring incremental economic development into the communities we serve," said Caitlin Tessin, Director of Market Innovation at Enbridge.

Tom Kuster, Merit SI C.E.O., stated, "Enbridge is at the forefront of integrating renewable energy infrastructure into its existing pipeline network, and we are honored to have partnered with them on this important demonstration of its midstream energy industry leadership."

#### **Source / More Information**

Hart Energy

Houston Chronicle



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# Exhibit 14



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BUTCH TONGATE  
CABINET SECRETARY

**Air Quality Bureau  
TITLE V OPERATING PERMIT  
Issued under 20.2.70 NMAC**

Certified Mail No: 7018 0040 0000 1909 7851  
Return Receipt Requested

<b>Operating Permit No:</b>	P154-R4
<b>Facility Name:</b>	Roswell Compressor Station No9
<b>Permittee Name:</b>	Transwestern Pipeline Company
<b>Mailing Address:</b>	6381 North Main Street Roswell, NM 88201
<b>TEMPO/IDEA ID No:</b>	10 - PRT20170001
<b>AIRS No:</b>	35-005-0008
<b>Permitting Action:</b>	Renewal
<b>Source Classification:</b>	Title V Major and PSD Major
<b>Facility Location:</b>	544,900 m E by 3,707,500 m N; Zone 13; Datum NAD 83
<b>County:</b>	Chaves
<b>Air Quality Bureau Contact:</b>	Joseph H. Mashburn
<b>Main AQB Phone No.</b>	(505) 476-4300

**TV Permit Expiration Date:**

**SEP 28 2023**

**TV Renewal Application Due:**

**SEP 28 2022**

Liz Bisbey-Kuehn  
Bureau Chief  
Air Quality Bureau

**SEP 28 2018**

**Date**



**SUSANA MARTINEZ**  
GOVERNOR

**JOHN A. SANCHEZ**  
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**BUTCH TONGATE**  
CABINET SECRETARY

**Air Quality Bureau**  
**TITLE V OPERATING PERMIT**  
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Certified Mail No: 7018 0040 0000 1909 7851

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**TV Permit Expiration Date:** September 28, 2023

**TV Renewal Application Due:** September 28, 2022

\_\_\_\_\_  
**Liz Bisbey-Kuehn**  
**Bureau Chief**  
**Air Quality Bureau**

\_\_\_\_\_  
September 28, 2018  
**Date**

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## **PART A     FACILITY SPECIFIC REQUIREMENTS**

### **A100   Introduction**

- A.    Not Applicable

### **A101   Permit Duration (expiration)**

- A.    The term of this permit is five (5) years. It will expire five years from the date of issuance. Application for renewal of this permit is due twelve (12) months prior to the date of expiration. (20.2.70.300.B.2 and 302.B NMAC)
- B.    If a timely and complete application for a permit renewal is submitted, consistent with 20.2.70.300 NMAC, but the Department has failed to issue or disapprove the renewal permit before the end of the term of the previous permit, then the permit shall not expire and all the terms and conditions of the permit shall remain in effect until the renewal permit has been issued or disapproved. (20.2.70.400.D NMAC).

### **A102   Facility: Description**

- A.    This facility is a natural gas compressor station, providing compression of natural gas along a pipeline that transports the gas from production and processing areas to end users.
- B.    This facility is located approximately 5 miles north of Roswell, New Mexico in Chaves County. (20.2.70.302.A(7) NMAC)
- C.    This renewal consists of the following. The description of this renewal is for informational purposes only and is not enforceable:
- This Title V renewal incorporates the following equipment listed within NSR Permit 6742, issued May 27, 2016, into operating permit P154-R4: Two MIST extractors (MIST-1 and MIST-2) and six condensate tanks TK-1, TK-30, TK-31, TK-32, TK-33, and TK-34.
  - This permit's allowable hourly NOx emission limits for Units 903, 904, and 921 are returned to those modeled for the 2009 Title V permit.
  - The allowable annual operating hours for Units 903 and 904 are increased from the previous combined 13,248 total hours of operation per year to 8,760 hours of operation per year per engine.
  - The allowable annual operating hours for Unit 921 is increased from 2,680 to 4,500 hours.



- D. Tables 102.A and Table 102.B show the potential to emit (PTE) from this facility for information only. This is not an enforceable condition and excludes insignificant or trivial activities.

**Table 102.A: Total Potential to Emit (PTE) from Entire Facility**

Pollutant	Emissions (tons per year)
Nitrogen Oxides (NO <sub>x</sub> )	1,122.5
Carbon Monoxide (CO)	160.3
Volatile Organic Compounds (VOC) *	116.5
Sulfur Dioxide (SO <sub>2</sub> )	0.8
Total Suspended Particulates (TSP)	4.0
Particulate Matter 10 microns or less (PM <sub>10</sub> )	4.0
Particulate Matter 2.5 microns or less (PM <sub>2.5</sub> )	4.0
Greenhouse Gas (GHG) as CO <sub>2</sub> e	72,123

\* VOC total includes emissions from Fugitives, SSM and Malfunctions

**Table 102.B: Total Potential to Emit (PTE) for \*Hazardous Air Pollutants (HAPs) that exceed 1.0 ton per year**

Pollutant	Emissions (tons per year)
Acetaldehyde	3.2
Acrolein	2.0
Formaldehyde	19.9
Total HAPs **	27.7

\* HAP emissions are already included in the VOC emission total.

\*\* The total HAP emissions may not agree with the sum of individual HAPs because only individual HAPs greater than 1.0 tons per year are listed here.

### **A103 Facility: Applicable Regulations and Non-Applicable Regulations**

- A. The permittee shall comply with all applicable sections of the requirements listed in Table 103.A.

**Table 103.A: Applicable Requirements**

Applicable Requirements	Federally Enforceable	Unit No.
NSR Permit No: <b>1776M1 &amp; 1777M1</b> (Per 20.2.72 NMAC)	X	SVE-1 and SVE-2
NSR Permit No: <b>6742</b> (Per 20.2.72 NMAC)	X	MIST-1 MIST-2; TK-1, TK-30, TK-31, TK-32, TK-33 and TK-34
20.2.1 NMAC General Provisions	X	Entire Facility
20.2.7 NMAC Excess Emissions	X	Entire Facility



**Table 103.A: Applicable Requirements**

<b>Applicable Requirements</b>	<b>Federally Enforceable</b>	<b>Unit No.</b>
20.2.61 NMAC Smoke and Visible Emissions	X	903, 904, 921, SVE-1 and SVE-2
20.2.70 NMAC Operating Permits	X	Entire Facility
20.2.71 NMAC Operating Permit Emission Fees	X	Entire Facility
20.2.72 NMAC Construction Permit	X	Entire Facility
20.2.73 NMAC Notice of Intent and Emissions Inventory Requirements	X	Entire Facility
20.2.74 NMAC Permits – Prevention of Significant Deterioration (PSD)	X	Entire Facility
20.2.82 NMAC MACT Standards for Source Categories of HAPS	X	921
40 CFR 50 National Ambient Air Quality Standards	X	Entire Facility
40 CFR 63, Subpart A, General Provisions	X	921
40 CFR 63, Subpart ZZZZ	X	921
40 CFR 63, Subpart GGGGG, Site Remediation	X	SVE-1 and SVE-2

- B. Table 103.B lists requirements that are **not** applicable to this facility. This table only includes those requirements cited in the application as applicable and determined by the Department to be not applicable, or the Department determined that the requirement does not impose any conditions on a regulated piece of equipment.

**Table 103.B: Non-Applicable Requirements**

<b>Non-Applicable Requirements</b>	<b>(1)</b>	<b>(2)</b>	<b>Justification For Non-Applicability</b>
N/A			

1. Not Applicable for This Facility: No existing or planned operation/activity at this facility triggers the applicability of these requirements.
2. No Requirements: Although these regulations may apply, they do not impose any specific requirements on the operation of the facility as described in this permit.

- C. Compliance with the terms and conditions of this permit regarding source emissions and operation demonstrate compliance with national ambient air quality standards specified at 40 CFR 50, which were applicable at the time air dispersion modeling was performed for the facility's NSR Permit P154-R2M1.

#### **A104 Facility: Regulated Sources**

- A. Table 104.A lists the emission units authorized for this facility. Emission units identified as insignificant or trivial activities (as defined in 20.2.70.7 NMAC) and/or equipment not regulated pursuant to the Act are not included.

**Table 104.A: Regulated Sources List**

<b>Unit No.</b>	<b>Source Description</b>	<b>Make</b>	<b>Model</b>	<b>Serial No.</b>	<b>Construction/Reconstruct Date</b>	<b>Manuf. Date</b>	<b>Manufacturer Rated Capacity /Permitted Capacity</b>
903	4SLB RICE	Cooper-Bessemer	LSV-16SSG	7030	1959	1959	4500 hp / 4500 hp
904	4SLB RICE	Cooper-Bessemer	LSV-16SSG	7029	1959	1959	4500 hp / 4500 hp
921	4SRB RICE Generator	Ingersoll-Rand	PSVG-6	6BPSC280	1959	1959	408 hp /408 hp
MIST-1	Mist Extractor Tank	N/A	N/A	N/A	1980	1980	1,140 gal/ 365 bbl /y Combined MIST-1 & MIST-2
MIST-2	Mist Extractor Tank	N/A	N/A	N/A	2006	2006	50 gal/ 365 bbl /y Combined MIST-1 & MIST-2
TK-1	Tank - Above Ground	N/A	N/A	N/A	1980	1980	500 bbl/ 365 bbl /y Combined 6 Tanks
TK-30	Tank - Above Ground	N/A	N/A	N/A	2006	2006	2,500 gal/ 365 bbl /y Combined 6 Tanks
TK-31	Tank - Above Ground	N/A	N/A	N/A	2006	2006	2,500 gal
TK-32	Tank - Above Ground	N/A	N/A	N/A	2006	2006	1,000 gal/ 365 bbl /y Combined 6 Tanks
TK-33	Tank - Above Ground	N/A	N/A	N/A	2006	2006	1,000 gal/ 365 bbl /y Combined 6 Tanks
TK-34	Tank - Above Ground	N/A	N/A	N/A	2006	2006	1,000 gal/ 365 bbl /y Combined 6 Tanks
SVE-1	Soil Vapor Extractor & Thermal Oxidizer	Baker Furnace	200 CFM	286	2003	1996	200 CFM
SVE-2	Soil Vapor Extractor & Thermal Oxidizer	Baker Furnace	200 CFM	285	2003	1996	200 CFM
SSM/M	Startup, Shutdown, Maintenance, and Malfunctions	N/A	N/A	N/A	N/A	N/A	N/A

1. All TBD (to be determined) units and like-kind engine replacements must be evaluated for applicability to NSPS and MACT requirements.

**A105 Facility: Control Equipment**

- A. Table 105.A lists all the pollution control equipment required for this facility. Each emission point is identified by the same number that was assigned to it in the permit application.

**Table 105.A: Control Equipment List:**

Control Equipment Unit No.	Control Description	Pollutant being controlled	Control for Unit No. <sup>1</sup>
SVE-1	Thermal Oxidizer	VOCs & HAPs	SVE-1
SVE-2	Thermal Oxidizer	VOCs & HAPs	SVE-2

1 Control for unit number refers to a unit number from the Regulated Equipment List

- B. Thermal Oxidizer (Units SVE-1 and SVE-2)

**Requirement:**

- (1) The off-gas from the SVE Systems shall be controlled by the Thermal Oxidizer.  
 (2) The permittee shall maintain the units according to manufacturer's or supplier's recommended maintenance. (NSR Permits 1776M1 and 1777M1, condition A200.B)

**Monitoring**

- (1) The thermal oxidizer shall be operated in accordance with manufacturer's or supplier's recommendations and parameters. The SVE System shall not be operated without the thermal oxidizer except for periods of startup and shutdown as recommended by manufacturer or supplier. The permittee shall monitor times of maintenance and type of maintenance that occurred.  
 (2) The permittee shall monitor the total hours of operation in either thermal or catalytic modes.

**Recordkeeping:** The permittee shall record the hours of operation in each mode daily and maintain records in accordance with Section B109.

**Reporting:** The permittee shall report in accordance with Section B110.

**A106 Facility: Allowable Emissions**

- A. The following Section lists the emission units, and their allowable emission limits. (40 CFR 50; 40 CFR 63, Subparts A and ZZZZ, GGGGG, Paragraphs 1, 7, and 8 of 20.2.70.302.A NMAC; NSR Permits 1776M1, 1777M1, and 6742).

**Table 106.A: Allowable Emissions**

Unit No.	<sup>1</sup> NO <sub>x</sub> pph	NO <sub>x</sub> tpy	CO pph	CO tpy	VOC pph	VOC tpy
903	125.0	547.5	16.5	72.3	9.9	43.4
904	125.0	547.5	16.5	72.3	9.9	43.4

**Table 106.A: Allowable Emissions**

Unit No.	<sup>1</sup> NO <sub>x</sub> ppb	NO <sub>x</sub> tpy	CO ppb	CO tpy	VOC ppb	VOC tpy
921	12.0	27.0	6.8	15.3	<	<
MIST 1&2; TK-1, TK-30, TK-31, TK-32, TK-33, and TK-34	-	-	-	-	11.3	13.3
SVE-1	0.06	0.27	0.05	0.23	0.42	1.83
SVE-2	0.06	0.27	0.05	0.23	0.42	1.83

- 1 Nitrogen dioxide emissions include all oxides of nitrogen expressed as NO<sub>2</sub>.
  - 2 Title V annual fee assessments are based on the sum of allowable tons per year emission limits in Sections A106 and A107.
  - 3 To report excess emissions for sources with no pound per hour and/or ton per year emission limits, see condition B110.E.
- “-” indicates the application represented emissions are not expected for this pollutant.
- “<” indicates that the application represented the uncontrolled mass emission rates are less than 1.0 ppb or 1.0 tpy for this emissions unit and this air pollutant. The Department determined that allowable mass emission limits were not required for this unit and this pollutant.

#### **A107 Facility: Allowable Startup, Shutdown, & Maintenance (SSM) and Malfunction Emissions**

- A. The maximum allowable SSM and Malfunction emission limits for this facility are listed in Table 107.A and were relied upon by the Department to determine compliance with applicable regulations.

**Table 107.A: Allowable SSM and Malfunction Units, Activities, and Emission Limits**

Unit No.	Description	VOC (tpy)
SSM/M from [901, 902, 903, 904, 921]	<sup>1</sup> Compressor & Associated Piping Blowdowns during Routine and Predictable Startup, Shutdown, and/or Maintenance (SSM); and Malfunctions.	10.0

1. This authorization does not include VOC combustion emissions.
2. Units 901 and 902 are electric engines that drive compressors and the emissions here are from the blow down of the compressors.
3. To report excess emissions for sources with no pound per hour and/or ton per year emission limits, see condition B110.E.

B. The authorization of emission limits for startup, shutdown, maintenance, and malfunction does not supersede the requirements to minimize emissions according to Conditions B101.C and B107.A.

C. Combined SSM and Malfunction Emissions (VOCs)

**Requirement:**

**(1) Compliance Method**

The permittee shall perform a facility inlet gas analysis once every year and, on a monthly basis, complete the following monitoring and recordkeeping to demonstrate compliance with the allowable emission limits in Table 107.A for routine or predictable startup, shutdown, and maintenance (SSM); and/or malfunctions (M) herein referred to as SSM/M.

**(2) Emissions included in Permit Limit and/or Reported as Excess Emissions**

(a) All emissions due to routine or predictable startup, shutdown, and/or maintenance (SSM) must be included under and shall not exceed the 10 tpy SSM/M emission limit in this permit. For emissions due to malfunctions, the permittee has the option to report these as excess emissions of the pound per hour limits in Table 106.A (or the pound per hour limits in condition B110E, if applicable), in accordance with 20.2.7 NMAC, or include the emissions under the 10 tpy limit.

(b) Once emissions from a malfunction event are submitted in the final report (due no later than ten days after the end of the excess emissions event) per 20.2.7.110.A(2) NMAC, the event is considered an excess emission and cannot be applied toward the 10 tpy SSM/M limit in this permit.

**(3) Emissions Exceeding the Permit Limit**

If the monthly rolling 12-month total of SSM/M exceeds the 10 tpy emission limit, the permittee shall report the emissions as excess emissions in accordance with 20.2.7.110 NMAC.

**(4) Emissions Due to Preventable Events**

Emissions that are due entirely or in part to poor maintenance, careless operation, or any other preventable equipment breakdown shall not be included under the 10 tpy SSM/M emission limit. These emissions shall be reported as excess emissions of the pound per hour limits in Table 106.A (or the pound per hour limits in condition B110E, if applicable) in accordance with 20.2.7 NMAC.

**Monitoring:** The permittee shall monitor all SSM/M events.

**Recordkeeping:**

**(1) Compliance Method**

(a) Each month records shall be kept of the cumulative total of all VOC emissions related to SSM/M during the first 12 months and, thereafter of the monthly rolling 12-month

total of SSM/M VOC emissions. Any malfunction emissions that have been reported in a final excess emissions report per 20.2.7.110.A(2) NMAC, shall be excluded from this total.

(b) Records shall also be kept of the inlet gas analysis, the percent VOC of the gas based on the most recent gas analysis, and of the volume of total gas vented in MMscf used to calculate the VOC emissions.

(c) The permittee shall identify the equipment or activity and shall describe the event that is the source of emissions.

**(2) Emissions included Under Permit Limit or Reported as Excess Emissions**

The permittee shall record whether emissions are included under the 10 tpy permit limit for SSM/M or if the event is included in a final excess emissions report per 20.2.7.110.A(2) NMAC.

**(3) Condition B109 Records**

The permittee shall keep records in accordance with Condition B109 of this permit except for the following:

(a) The requirement to record the start and end times of SSM/M events shall not apply to venting of known quantities of VOCs as long as the emissions do not exceed the SSM/M emission limit.

(b) The requirement to record a description of the cause of the event shall not apply to SSM/M events as long as the emissions do not exceed the SSM/M emission limit.

**Reporting:** The permittee shall report in accordance with Section B110.

**A108 Facility: Hours of Operation**

A. This facility is authorized for continuous operation. Monitoring, recordkeeping, and reporting are not required to demonstrate compliance with continuous hours of operation.

**A109 Facility: Reporting Schedules (20.2.70.302.E NMAC)**

A. A Semi-Annual Report of monitoring activities is due within 45 days following the end of every 6-month reporting period. The six-month reporting periods start on September 1<sup>st</sup> and March 1<sup>st</sup> of each year.

B. The Annual Compliance Certification Report is due within 30 days of the end of every 12-month reporting period. The 12-month reporting period starts on September 1<sup>st</sup> of each year.

**A110 Facility: Fuel and Fuel Sulfur Requirements****A. Fuel and Fuel Sulfur Requirements (Units 903, 904 and 921)**

**Requirement:** All combustion emission units shall combust only natural gas containing no more than 0.75 grains of total sulfur per 100 dry standard cubic feet.

**Monitoring:** None. Compliance is demonstrated through records.

**Recordkeeping:**

- (1) The permittee shall demonstrate compliance with the natural gas or fuel oil limit on total sulfur content by maintaining records of a current, valid purchase contract, tariff sheet or transportation contract for the gaseous or liquid fuel, or fuel gas analysis, specifying the allowable limit or less.
- (2) If fuel gas analysis is used, the analysis shall occur not less than 9 months and not greater than 15 months since the previous analysis.

**Reporting:** The permittee shall report in accordance with Section B110.

**A111 Facility: 20.2.61 NMAC Opacity****A. 20.2.61 NMAC Opacity Requirements (Units 903, 904, 921, SVE-1 and SVE-2)**

**Requirement:** Visible emissions from all stationary combustion emission stacks shall not equal or exceed an opacity of 20 percent in accordance with the requirements at 20.2.61.109 NMAC.

**Monitoring:**

- (1) Use of natural gas fuel constitutes compliance with 20.2.61 NMAC unless opacity equals or exceeds 20% averaged over a 10-minute period. When any visible emissions are observed during operation other than during startup mode, opacity shall be measured over a 10-minute period, in accordance with the procedures at 40 CFR 60, Appendix A, Reference Method 9 (EPA Method 9) as required by 20.2.61.114 NMAC, or the operator will be allowed to shut down the equipment to perform maintenance/repair to eliminate the visible emissions. Following completion of equipment maintenance/repair, the operator shall conduct visible emission observations following startup in accordance with the following procedures:
  - (a) Visible emissions observations shall be conducted over a 10-minute period during operation after completion of startup mode in accordance with the procedures at 40 CFR 60, Appendix A, Reference Method 22 (EPA Method 22). If no visible emissions are observed, no further action is required.
  - (b) If any visible emissions are observed during completion of the EPA Method 22 observation, subsequent opacity observations shall be conducted over a 10-minute period, in accordance with the procedures at EPA Method 9 as required by 20.2.61.114 NMAC.

For the purposes of this condition, *Startup mode* is defined as the startup period that is described in the facility's startup plan.

**Recordkeeping:**

- (1) If any visible emissions observations were conducted, the permittee shall keep records in accordance with the requirements of Section B109 and as follows:
- (a) For any visible emissions observations conducted in accordance with EPA Method 22, record the information on the form referenced in EPA Method 22, Section 11.2.
  - (b) For any opacity observations conducted in accordance with the requirements of EPA Method 9, record the information on the form referenced in EPA Method 9, Sections 2.2 and 2.4.

**Reporting:** The permittee shall report in accordance with Section B110.

## **EQUIPMENT SPECIFIC REQUIREMENTS**

### **OIL AND GAS INDUSTRY**

#### **A200 Oil and Gas Industry**

- A. This section has common equipment related to most Oil and Gas Operations.

#### **A201 Engines**

- A. Maintenance and Repair Monitoring (Units 903, 904 and 921)

**Requirement:** Compliance with the allowable emission limits in Table 106.A shall be demonstrated by properly maintaining and repairing the units.

**Monitoring:** Maintenance and repair shall meet the minimum manufacturer's or permittee's recommended maintenance schedule. Activities that involve maintenance, adjustment, replacement, or repair of functional components with the potential to affect the operation of an emission unit shall be documented as they occur for the following events:

- (1) Routine maintenance that takes a unit out of service for more than two hours during any twenty-four-hour period.
- (2) Unscheduled repairs that require a unit to be taken out of service for more than two hours in any twenty-four-hour period.

**Recordkeeping:** The permittee shall maintain records in accordance with Section B109, including records of maintenance and repairs activities and a copy of the manufacturer's or permittee's recommended maintenance schedule.

**Reporting:** The permittee shall report in accordance with Section B110.



**B. Periodic Emissions Testing (Units 903 and 904)**

**Requirement:** Compliance with the allowable emission limits in Table 106.A shall be demonstrated by completing periodic emission tests during the monitoring period.

**Monitoring:** The permittee shall test using a portable analyzer or EPA Reference Methods subject to the requirements and limitations of Section B108, General Monitoring Requirements. Emission testing is required for NO<sub>x</sub> and CO and shall be carried out as described below.

Test results that demonstrate compliance with the CO emission limits shall also be considered to demonstrate compliance with the VOC emission limits.

For units with g/hp-hr emission limits, in addition to the requirements stated in Section B108, the engine load shall be calculated by using the following equation:

$$\text{Load(Hp)} = \frac{\text{Fuel consumption (scfh)} \times \text{Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

(1) The testing shall be conducted as follows:

a. Testing frequency shall be once per year.

b. The monitoring period is defined as a calendar year.

(2) The tests shall continue based on the existing testing schedule.

(3) All subsequent monitoring shall occur in each succeeding monitoring period. No two monitoring events shall occur closer together in time than 25% of a monitoring period.

(4) The permittee shall follow the General Testing Procedures of Section B111. Due to the unique operation of this facility as a "peaking station", the Department exempts the permittee from the 30-day notification stated in General Condition B111.D(1). The permittee shall notify the department as soon as possible prior to the test.

(5) Performance testing required by 40 CFR 60, Subpart JJJJ or IIII or 40 CFR 63, Subpart ZZZZ may be used to satisfy these periodic testing requirements if they meet the requirements of this condition and are completed during the specified monitoring period.

**Recordkeeping:** The permittee shall maintain records in accordance with Section B109, B110, and B111.

**Reporting:** The permittee shall report in accordance with Section B109, B110, and B111.

**C. Hours of Operation (Unit 921)**

**Requirement:** Compliance with the allowable TPY emission limits in Table 106.A shall be demonstrated by limiting the hours of operation of Unit 921 to 4,500 hours per year.

**Monitoring:** The permittee shall monitor the dates and hours of operation for the unit. The monitoring period shall be annually on a calendar basis. To demonstrate compliance during the first 12 months of monitoring, each month the permittee shall calculate the cumulative total of hours operated per unit, and after the first 12 months of monitoring the permittee shall calculate and sum the total hours of operation on a monthly rolling 12-month basis.

**Recordkeeping:** The permittee shall record the hours of operation daily for the unit in accordance with Section B109.

<b>Reporting:</b> The permittee shall report in accordance with Section B110.
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D. 40 CFR 63, Subpart ZZZZ (Unit 921)

<b>Requirement:</b> The unit is subject to 40 CFR 63 Subpart ZZZZ and the permittee shall comply with all applicable requirements of Subpart A and Subpart ZZZZ.
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<b>Monitoring:</b> The permittee shall comply with all applicable monitoring requirements of 40 CFR 63, Subpart A and Subpart ZZZZ.
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<b>Recordkeeping:</b> The permittee shall comply with all applicable recordkeeping requirements of 40 CFR 63, Subpart A and Subpart ZZZZ, including but not limited to 63.6655 and 63.10.
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<b>Reporting:</b> The permittee shall comply with all applicable reporting requirements of 40 CFR 63, Subpart A and ZZZZ, including but not limited to 63.6645, 63.6650, 63.9, and 63.10.
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**A202 Glycol Dehydrators – not required**

**A203 Tanks**

A. Tank Throughput and Separator Pressure (Units TK-1, TK-30, TK-31, TK-32, TK-33, and TK-34) [with flash emissions]

<b>Requirement:</b> Compliance with the allowable emission limits in Table 106.A shall be demonstrated by limiting the monthly rolling 12-month total condensate throughput to the units to 15,330 gallons per year (365 barrels/year) and limiting the monthly rolling 12-month average separator pressure to less than 1,008 psig.
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<b>Monitoring:</b> The permittee shall monitor the monthly total throughput and the upstream separator pressure once per month.
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<b>Recordkeeping:</b> The permittee shall record:
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- |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"> <li>(1) the monthly total throughput of liquids and,</li> <li>(2) the monthly separator pressure.</li> <li>(3) Each month the permittee shall use these values to calculate and record: <ul style="list-style-type: none"> <li>(a) during the first 12 months of monitoring, the cumulative total liquid throughput and after the first 12 months of monitoring, the monthly rolling 12-month total liquid throughput and,</li> <li>(b) during the first 12 months of monitoring, the average separator pressure, and after the first 12 months of monitoring, the monthly rolling 12-month average separator pressure.</li> </ul> </li> </ul> |
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Tank breathing and working emissions were calculated using methods found in AP-42 Section 7.1[or more current] and tank flashing emissions using the Vasquez-Beggs equation. Emission rates computed using the same parameters, but with a different Department approved algorithm, that exceed these values will not be deemed non-compliance with this permit.
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Records shall be maintained in accordance with Section B109.
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<b>Reporting:</b> The permittee shall report in accordance with Section B110.
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**B. Mist Eliminators (Units MIST-1 and MIST-2)**

<b>Requirement:</b> Compliance with the allowable emission limits in Table 106.A shall be demonstrated by limiting the monthly rolling 12-month total condensate throughput to the combined units to 15,330 gallons per year (365 barrels/year) and limiting the monthly rolling 12-month average separator pressure to less than 1,008 psig.
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<b>Monitoring:</b> The permittee shall monitor the monthly total throughput for the mist eliminators and the upstream separator pressure once per month.
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<b>Recordkeeping:</b> The permittee shall record:
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- |                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                   |
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| <ol style="list-style-type: none"> <li>(1) the monthly total throughput of liquids and,</li> <li>(2) the monthly separator pressure.</li> <li>(3) Each month the permittee shall use these values to calculate and record: <ol style="list-style-type: none"> <li>(a) during the first 12 months of monitoring, the cumulative total liquid throughput and after the first 12 months of monitoring, the monthly rolling 12-month total liquid throughput and,</li> <li>(b) during the first 12 months of monitoring, the average separator pressure, and after the first 12 months of monitoring, the monthly rolling 12-month average separator pressure.</li> </ol> </li> </ol> |
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Tank breathing and working emissions were calculated using methods found in AP-42 Section 7.1[or more current] and tank flashing emissions using the Vasquez-Beggs equation. Emission rates computed using the same parameters, but with a different Department approved algorithm that exceed these values will not be deemed non-compliance with this permit.
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Records shall be maintained in accordance with Section B109.
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<b>Reporting:</b> The permittee shall report in accordance with Section B110.
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**A204 Heaters/Boilers – not required**

**A205 Turbines – not required**

**A206 Flares/Incinerators**

**A. 40 CFR 63, Subpart GGGGG (Units SVE-1 and SVE-2)**

<b>Requirement:</b> The permittee shall comply with the applicable requirements of 40 CFR 63, Subpart GGGGG.
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<b>Monitoring:</b> The permittee shall comply with the applicable monitoring requirements of 40 CFR 63, Subpart GGGGG.
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<b>Recordkeeping:</b> The permittee shall comply with the applicable recordkeeping requirements of 40 CFR 63, Subpart GGGGG.
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<p><b>Reporting:</b> The permittee shall comply with the applicable reporting requirements of 40 CFR 63, Subpart GGGGG.</p>
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**PART B      GENERAL CONDITIONS (Attached)**

**PART C      MISCELLANEOUS: Supporting On-Line Documents; Definitions;  
Acronyms (Attached)**

**Air Quality Bureau**  
**TITLE V OPERATING PERMIT**  
**Issued under 20.2.70 NMAC**

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## **PART B    GENERAL CONDITIONS**

### **B100   Introduction**

A.    Not Applicable

### **B101   Legal**

A.    Permit Terms and Conditions (20.2.70 sections 7, 201.B, 300, 301.B, 302, 405 NMAC)

- (1)    The permittee shall abide by all terms and conditions of this permit, except as allowed under Section 502(b)(10) of the Federal Act, and 20.2.70.302.H.1 NMAC. Any permit noncompliance is grounds for enforcement action, and significant or repetitious noncompliance may result in termination of this permit. Additionally, noncompliance with federally enforceable conditions of this permit constitutes a violation of the Federal Act. (20.2.70.302.A.2.a NMAC)
- (2)    Emissions trading within a facility (20.2.70.302.H.2 NMAC)
  - (a)    The Department shall, if an applicant requests it, issue permits that contain terms and conditions allowing for the trading of emissions increases and decreases in the permitted facility solely for the purpose of complying with a federally enforceable emissions cap that is established in the permit in addition to any applicable requirements. Such terms and conditions shall include all terms and conditions required under 20.2.70.302 NMAC to determine compliance. If applicable requirements apply to the requested emissions trading, permit conditions shall be issued only to the extent that the applicable requirements provide for trading such increases and decreases without a case-by-case approval.
  - (b)    The applicant shall include in the application proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable and enforceable. The Department shall not include in the emissions trading provisions any emissions units for which emissions are not quantifiable or for which there are no replicable procedures to enforce the emissions trades. The permit shall require compliance with all applicable requirements.
- (3)    It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. (20.2.70.302.A.2.b NMAC)
- (4)    If the Department determines that cause exists to modify, reopen and revise, revoke and reissue, or terminate this permit, this shall be done in accordance with 20.2.70.405 NMAC. (20.2.70.302.A.2.c NMAC)

- (5) The permittee shall furnish any information the Department requests in writing to determine if cause exists for reopening and revising, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. This information shall be furnished within the time period specified by the Department. Additionally, the permittee shall furnish, upon request by the Department, copies of records required by the permit to be maintained by the permittee. (20.2.70.302.A.2.f NMAC)
- (6) A request by the permittee that this permit be modified, revoked and reissued, or terminated, or a notification by the permittee of planned changes or anticipated noncompliance, shall not stay any conditions of this permit. (20.2.70.302.A.2.d NMAC)
- (7) This permit does not convey property rights of any sort, or any exclusive privilege. (20.2.70.302.A.2.e NMAC)
- (8) In the case where an applicant or permittee has submitted information to the Department under a claim of confidentiality, the Department may also require the applicant or permittee to submit a copy of such information directly to the Administrator of the EPA. (20.2.70.301.B NMAC)
- (9) The issuance of this permit, or the filing or approval of a compliance plan, does not relieve the permittee from civil or criminal liability for failure to comply with the state or Federal Acts, or any applicable state or federal regulation or law. (20.2.70.302.A.6 NMAC and the New Mexico Air Quality Control Act NMSA 1978, Chapter 74, Article 2)
- (10) If any part of this permit is challenged or held invalid, the remainder of the permit terms and conditions are not affected and the permittee shall continue to abide by them. (20.2.70.302.A.1.d NMAC)
- (11) A responsible official (as defined in 20.2.70.7.AE NMAC) shall certify the accuracy, truth and completeness of every report and compliance certification submitted to the Department as required by this permit. These certifications shall be part of each document. (20.2.70.300.E NMAC)
- (12) Revocation or termination of this permit by the Department terminates the permittee's right to operate this facility. (20.2.70.201.B NMAC)
- (13) The permittee shall continue to comply with all applicable requirements. For applicable requirements that will become effective during the term of the permit, the permittee shall meet such requirements on a timely basis. (Sections 300.D.10.c and 302.G.3 of 20.2.70 NMAC)

B. Permit Shield (20.2.70.302.J NMAC)

- (1) Compliance with the conditions of this permit shall be deemed to be compliance with any applicable requirements existing as of the date of permit issuance and

identified in [Table 103.A](#). The requirements in [Table 103.A](#) are applicable to this facility with specific requirements identified for individual emission units.

- (2) The Department has determined that the requirements in [Table 103.B](#) as identified in the permit application are not applicable to this source, or they do not impose any conditions in this permit.
  - (3) This permit shield does not extend to administrative amendments (Subsection A of 20.2.70.404 NMAC), to minor permit modifications (Subsection B of 20.2.70.404 NMAC), to changes made under Section 502(b)(10), changes under Paragraph 1 of subsection H of 20.2.70.302 of the Federal Act, or to permit terms for which notice has been given to reopen or revoke all or part under 20.2.70.405 and 20.2.70.302J(6).
  - (4) This permit shall, for purposes of the permit shield, identify any requirement specifically identified in the permit application or significant permit modification that the department has determined is not applicable to the source, and state the basis for any such determination. (20.2.70.302.A.1.f NMAC)
- C. The owner or operator of a source having an excess emission shall, to the extent practicable, operate the source, including associated air pollution control equipment, in a manner consistent with good air pollutant control practices for minimizing emissions. (20.2.7.109 NMAC). The establishment of allowable malfunction emission limits does not supersede this requirement.

#### **B102 Authority**

- A. This permit is issued pursuant to the federal Clean Air Act ("Federal Act"), the New Mexico Air Quality Control Act ("State Act") and regulations adopted pursuant to the State and Federal Acts, including Title 20, New Mexico Administrative Code, Chapter 2, Part 70 (20.2.70 NMAC) - Operating Permits.
- B. This permit authorizes the operation of this facility. This permit is valid only for the named permittee, owner, and operator. A permit modification is required to change any of those entities.
- C. The Department specifies with this permit, terms and conditions upon the operation of this facility to assure compliance with all applicable requirements, as defined in 20.2.70 NMAC at the time this permit is issued. (20.2.70.302.A.1 NMAC)
- D. Pursuant to the New Mexico Air Quality Control Act NMSA 1978, Chapter 74, Article 2, all terms and conditions in this permit, including any provisions designed to limit this facility's potential to emit, are enforceable by the Department. All terms and conditions are enforceable by the Administrator of the United States Environmental Protection Agency ("EPA") and citizens under the Federal Act, unless the term or condition is specifically



designated in this permit as not being enforceable under the Federal Act. (20.2.70.302.A.5 NMAC)

- E. The Department is the Administrator for 40 CFR Parts 60, 61, and 63 pursuant to the Modification and Exceptions of Section 10 of 20.2.77 NMAC (NSPS), 20.2.78 NMAC (NESHAP), and 20.2.82 NMAC (MACT).

**B103 Annual Fee**

- A. The permittee shall pay Title V fees to the Department consistent with the fee schedule in 20.2.71 NMAC - Operating Permit Emission Fees. The fees will be assessed and invoiced separately from this permit. (20.2.70.302.A.1.e NMAC)

**B104 Appeal Procedures**  
(20.2.70.403.A NMAC)

- A. Any person who participated in a permitting action before the Department and who is adversely affected by such permitting action, may file a petition for a hearing before the Environmental Improvement Board ("board"). The petition shall be made in writing to the board within thirty (30) days from the date notice is given of the Department's action and shall specify the portions of the permitting action to which the petitioner objects, certify that a copy of the petition has been mailed or hand-delivered, and attach a copy of the permitting action for which review is sought. Unless a timely request for a hearing is made, the decision of the Department shall be final. The petition shall be copied simultaneously to the Department upon receipt of the appeal notice. If the petitioner is not the applicant or permittee, the petitioner shall mail or hand-deliver a copy of the petition to the applicant or permittee. The Department shall certify the administrative record to the board. Petitions for a hearing shall be sent to:

For Mailing:

Administrator, New Mexico Environmental Improvement Board  
P.O. Box 5469  
Santa Fe, NM 87502-5469

For Hand Delivery:

Administrator, New Mexico Environmental Improvement Board  
1190 St. Francis Drive, Harold Runnels Bldg.  
Santa Fe, New Mexico 87505

**B105 Submittal of Reports and Certifications**

- A. Stack Test Protocols and Stack Test Reports shall be submitted electronically to [Stacktest.AQB@state.nm.us](mailto:Stacktest.AQB@state.nm.us) or as directed by the Department.

- B. Excess Emission Reports shall be submitted as directed by the Department. (20.2.7.110 NMAC)
- C. Compliance Certification Reports, Semi-Annual monitoring reports, compliance schedule progress reports, and any other compliance status information required by this permit shall be certified by the responsible official and submitted to the mailing address below, or as directed by the Department:
- D. Compliance Certification Reports shall also be submitted to the Administrator at the address below (20.2.70.302.E.3 NMAC):

Manager, Compliance and Enforcement Section  
New Mexico Environment Department  
Air Quality Bureau  
525 Camino de los Marquez Suite 1  
Santa Fe, NM 87505-1816

Chief, Air Enforcement Section  
US EPA Region-6, 6MM-AP  
1445 Ross Avenue, Suite 1200  
Dallas, TX 75202-2733

**B106 NSPS and/or MACT Startup, Shutdown, and Malfunction Operations**

- A. If a facility is subject to a NSPS standard in 40 CFR 60, each owner or operator that installs and operates a continuous monitoring device required by a NSPS regulation shall comply with the excess emissions reporting requirements in accordance with 40 CFR 60.7(c).
- B. If a facility is subject to a NSPS standard in 40 CFR 60, then in accordance with 40 CFR 60.8(c), operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
- C. If a facility is subject to a MACT standard in 40 CFR 63, then the facility is subject to the requirement for a Startup, Shutdown and Malfunction Plan (SSM) under 40 CFR 63.6(e)(3), unless specifically exempted in the applicable subpart. (20.2.70.302.A.1 and A.4 NMAC)

**B107 Startup, Shutdown, and Maintenance Operations**

- A. The establishment of permitted startup, shutdown, and maintenance (SSM) emission limits does not supersede the requirements of 20.2.7.14.A NMAC. Except for operations or equipment subject to Condition B106, the permittee shall establish and implement a plan to minimize emissions during routine or predictable start up, shut down, and scheduled

maintenance (SSM work practice plan) and shall operate in accordance with the procedures set forth in the plan. (20.2.7.14.A NMAC)

**B108 General Monitoring Requirements**  
(20.2.70. 302.A and C NMAC)

- A. These requirements do not supersede or relax requirements of federal regulations.
- B. The following monitoring and/or testing requirements shall be used to determine compliance with applicable requirements and emission limits. Any sampling, whether by portable analyzer or EPA reference method, that measures an emission rate over the applicable averaging period greater than an emission limit in this permit constitutes noncompliance with this permit. The Department may require, at its discretion, additional tests pursuant to EPA Reference Methods at any time, including when sampling by portable analyzer measures an emission rate greater than an emission limit in this permit; but such requirement shall not be construed as a determination that the sampling by portable analyzer does not establish noncompliance with this permit and shall not stay enforcement of such noncompliance based on the sampling by portable analyzer.
- C. If the emission unit is shutdown at the time when periodic monitoring is due to be completed, the permittee is not required to restart the unit for the sole purpose of conducting the monitoring. Using electronic or written mail, the permittee shall notify the Department's Compliance and Enforcement Section of a delay in emission tests prior to the deadline for completing the tests. Upon recommencing operation, the permittee shall submit pre-test notification(s) to the Department's Compliance and Enforcement Section and shall complete the monitoring.
- D. The requirement for monitoring during any monitoring period is based on the percentage of time that the unit has operated. However, to invoke monitoring period exemptions at B108.D(2), hours of operation shall be monitored and recorded.
  - (1) If the emission unit has operated for more than 25% of a monitoring period, then the permittee shall conduct monitoring during that period.
  - (2) If the emission unit has operated for 25% or less of a monitoring period then the monitoring is not required. After two successive periods without monitoring, the permittee shall conduct monitoring during the next period regardless of the time operated during that period, except that for any monitoring period in which a unit has operated for less than 10% of the monitoring period, the period will not be considered as one of the two successive periods.
  - (3) If invoking the monitoring period exemption in B108.D(2), the actual operating time of a unit shall not exceed the monitoring period required by this permit before the required monitoring is performed. For example, if the monitoring period is annual, the operating hours of the unit shall not exceed 8760 hours before

monitoring is conducted. Regardless of the time that a unit actually operates, a minimum of one of each type of monitoring activity shall be conducted during the five year term of this permit.

- E. For all periodic monitoring events, except when a federal or state regulation is more stringent, three test runs shall be conducted at 90% or greater of the unit's capacity as stated in this permit, or in the permit application if not in the permit, and at additional loads when requested by the Department. If the 90% capacity cannot be achieved, the monitoring will be conducted at the maximum achievable load under prevailing operating conditions except when a federal or state regulation requires more restrictive test conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions and shall be included with the monitoring report.
- F. When requested by the Department, the permittee shall provide schedules of testing and monitoring activities. Compliance tests from previous NSR and Title V permits may be re-imposed if it is deemed necessary by the Department to determine whether the source is in compliance with applicable regulations or permit conditions.
- G. If monitoring is new or is in addition to monitoring imposed by an existing applicable requirement, it shall become effective 120 days after the date of permit issuance. For emission units that have not commenced operation, the associated new or additional monitoring shall not apply until 120 days after the units commence operation. All pre-existing monitoring requirements incorporated in this permit shall continue to apply from the date of permit issuance. All monitoring periods, unless stated otherwise in the specific permit condition or federal requirement, shall commence at the beginning of the 12 month reporting period as defined at condition A109.B.
- H. Unless otherwise indicated by Specific Conditions or regulatory requirements, all instrumentation used to measure parameters including but not limited to flow, temperature, pressure and chemical composition, or used to continuously monitor emission rates and/or other process operating parameters, shall be subject to the following requirements:
  - (1) The owner or operator shall install, calibrate, operate and maintain monitoring instrumentation (monitor) according to the manufacturer's procedures and specifications and the following requirements.
    - (a) The monitor shall be located in a position that provides a representative measurement of the parameter that is being monitored.
    - (b) At a minimum, the monitor shall complete one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
    - (c) At a minimum, the monitor shall be spanned to measure the normal range +/- 5% of the parameter that is being monitored.
    - (d) At least semi-annually, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion.

- (e) Recalibrate the monitor in accordance with the manufacturer's procedures and specifications at the frequency specified by the manufacturer, or every two years, whichever is less.
  - (2) Except for malfunctions, associated repairs, and required quality assurance or control activities (including calibration checks and required zero and span adjustments), the permittee shall operate and maintain all monitoring equipment at all times that the emissions unit or the associated process is operating.
  - (3) The monitor shall measure data for a minimum of 90 percent of the time that the emissions unit or the associated process is in operation, based on a calendar monthly average.
  - (4) The owner or operator shall maintain records in accordance with Section B109 to demonstrate compliance with the requirements in B108H (1)-(3) above, as applicable.
- I. The permittee is not required to report a deviation for any monitoring or testing in a Specific Condition if the deviation was authorized in this General Condition [B108](#).

**B109 General Recordkeeping Requirements**

(20.2.70.302.D NMAC)

- A. The permittee shall maintain records to assure and verify compliance with the terms and conditions of this permit and any applicable requirements that become effective during the term of this permit. The minimum information to be included in these records is as follows (20.2.70.302.D.1 NMAC):
- (1) Records required for testing and sampling:
    - (a) equipment identification (include make, model and serial number for all tested equipment and emission controls)
    - (b) date(s) and time(s) of sampling or measurements
    - (c) date(s) analyses were performed
    - (d) the qualified entity that performed the analyses
    - (e) analytical or test methods used
    - (f) results of analyses or tests
    - (g) operating conditions existing at the time of sampling or measurement
  - (2) Records required for equipment inspections and/or maintenance required by this permit:
    - (a) equipment identification number (including make, model and serial number)
    - (b) date(s) and time(s) of inspection, maintenance, and/or repair
    - (c) date(s) any subsequent analyses were performed (if applicable)

- (d) name of the person or qualified entity conducting the inspection, maintenance, and/or repair
  - (e) copy of the equipment manufacturer's or the owner or operator's maintenance or repair recommendations (if required to demonstrate compliance with a permit condition)
  - (f) description of maintenance or repair activities conducted
  - (g) all results of any required parameter readings
  - (h) a description of the physical condition of the equipment as found during any required inspection
  - (i) results of required equipment inspections including a description of any condition which required adjustment to bring the equipment back into compliance and a description of the required adjustments
- B. The permittee shall keep records of all monitoring data, equipment calibration, maintenance, and inspections, Data Acquisition and Handling System (DAHS) if used, reports, and other supporting information required by this permit for at least five (5) years from the time the data was gathered or the reports written. Each record shall clearly identify the emissions unit and/or monitoring equipment, and the date the data was gathered. (20.2.70.302.D.2 NMAC)
- C. If the permittee has applied and received approval for an alternative operating scenario, then the permittee shall maintain a log at the facility, which documents, contemporaneously with any change from one operating scenario to another, the scenario under which the facility is operating. (20.2.70.302.A.3 NMAC)
- D. The permittee shall keep a record describing off permit changes made at this source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under this permit, and the emissions resulting from those changes. (20.2.70.302.I.2 NMAC)
- E. Unless otherwise indicated by Specific Conditions, the permittee shall keep the following records for malfunction emissions and routine and predictable emissions during startup, shutdown, and scheduled maintenance (SSM):
  - (1) The owner or operator of a source subject to a permit, shall establish and implement a plan to minimize emissions during routine or predictable startup, shutdown, and scheduled maintenance through work practice standards and good air pollution control practices. This requirement shall not apply to any affected facility defined in and subject to an emissions standard and an equivalent plan under 40 CFR Part 60 (NSPS), 40 CFR Part 63 (MACT), or an equivalent plan under 20.2.72 NMAC - Construction Permits, 20.2.70 NMAC - Operating Permits, 20.2.74 NMAC - Permits - Prevention of Significant Deterioration (PSD), or 20.2.79 NMAC - Permits - Nonattainment Areas. (20.2.7.14.A NMAC) The permittee shall keep

records of all sources subject to the plan to minimize emissions during routine or predictable SSM and shall record if the source is subject to an alternative plan and therefore, not subject to the plan requirements under 20.2.7.14.A NMAC.

- (2) If the facility has allowable SSM emission limits in this permit, the permittee shall record all SSM events, including the date, the start time, the end time, a description of the event, and a description of the cause of the event. This record also shall include a copy of the manufacturer's, or equivalent, documentation showing that any maintenance qualified as scheduled. Scheduled maintenance is an activity that occurs at an established frequency pursuant to a written protocol published by the manufacturer or other reliable source. The authorization of allowable SSM emissions does not supersede any applicable federal or state standard. The most stringent requirement applies.
- (3) If the facility has allowable malfunction emission limits in this permit, the permittee shall record all malfunction events to be applied against these limits. The permittee shall also include the date, the start time, the end time, and a description of the event. **Malfunction means** any sudden and unavoidable failure of air pollution control equipment or process equipment beyond the control of the owner or operator, including malfunction during startup or shutdown. A failure that is caused entirely or in part by poor maintenance, careless operation, or any other preventable equipment breakdown shall not be considered a malfunction. (20.2.7.7.E NMAC) The authorization of allowable malfunction emissions does not supersede any applicable federal or state standard. The most stringent requirement applies. This authorization only allows the permittee to avoid submitting reports under 20.2.7 NMAC for total annual emissions that are below the authorized malfunction emission limit.
- (4) The owner or operator of a source shall meet the operational plan defining the measures to be taken to mitigate source emissions during malfunction, startup or shutdown. (20.2.7.203.A(5) NMAC)

**B110 General Reporting Requirements**  
(20.2.70.302.E NMAC)

- A. Reports of required monitoring activities for this facility shall be submitted to the Department on the schedule in section A109. Monitoring and recordkeeping requirements that are not required by a NSPS or MACT shall be maintained on-site or (for unmanned sites) at the nearest company office, and summarized in the semi-annual reports, unless alternative reporting requirements are specified in the equipment specific requirements section of this permit.
- B. Reports shall clearly identify the subject equipment showing the emission unit ID number according to this operating permit. In addition, all instances of deviations from permit

requirements, including those that occur during emergencies, shall be clearly identified in the reports required by section A109. (20.2.70.302.E.1 NMAC)

- C. The permittee shall submit reports of all deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. These reports shall be submitted as follows:
- (1) Deviations resulting in excess emissions as defined in 20.2.7.7 NMAC (including those classified as emergencies as defined in section B114.A) shall be reported in accordance with the timelines specified by 20.2.7.110 NMAC and in the semi-annual reports required in section A109. (20.2.70.302.E.2 NMAC)
  - (2) All other deviations shall be reported in the semi-annual reports required in section A109. (20.2.70.302.E.2 NMAC).
- D. The permittee shall submit reports of excess emissions in accordance with 20.2.7.110.A NMAC.
- E. Allowable Emission Limits for Excess Emissions Reporting for Flares and Other Regulated Sources with No Pound per Hour (pph) and/or Ton per Year (tpy) Emission Limits.
- (1) When a flare has no allowable pph and/or tpy emission limits in Sections A106 and/or A107, the authorized allowable emissions include only the combustion of pilot and/or purge gas. Compliance is demonstrated by limiting the gas stream to the flare to only pilot and/or purge gas.
  - (2) For excess emissions reporting as required by 20.2.7 NMAC, the allowable emission limits are 1.0 pph and 1.0 tpy for each regulated air pollutant (except for H<sub>2</sub>S) emitted by that source as follows:
    - (a) For flares, when there are no allowable emission limits in Sections A106 and/or A107.
    - (b) For regulated sources with emission limits in Sections A106 or A107 represented by the less than sign (“<”).
    - (c) For regulated sources that normally would not emit any regulated air pollutants, including but not limited to vents, pressure relief devices, connectors, etc.
  - (3) For excess emissions reporting as required by 20.2.7 NMAC for H<sub>2</sub>S, the allowable limits are 0.1 pph and 0.44 tpy for each applicable scenario addressed in paragraph (2) above.
- F. Results of emission tests and monitoring for each pollutant (except opacity) shall be reported in pounds per hour (unless otherwise specified) and tons per year. Opacity shall be reported in percent. The number of significant figures corresponding to the full accuracy inherent in the testing instrument or Method test used to obtain the data shall be used to calculate and



report test results in accordance with 20.2.1.116.B and C NMAC. Upon request by the Department, CEMS and other tabular data shall be submitted in editable, MS Excel format.

- G. At such time as new units are installed as authorized by the applicable NSR Permit, the permittee shall fulfill the notification requirements in the NSR permit.
- H. Periodic Emissions Test Reporting: The permittee shall report semi-annually a summary of the test results.
- I. The permittee shall submit an emissions inventory report for this facility in accordance with the schedule in subparagraph (5), provided one or more of the following criteria is met in subparagraphs (1) to (4): (20.2.73 NMAC)
  - (1) The facility emits, or has the potential to emit, 5 tons per year or more of lead or lead compounds, or 100 tons per year or more of PM10, PM2.5, sulfur oxides, nitrogen oxides, carbon monoxide, or volatile organic compounds.
  - (2) The facility is defined as a major source of hazardous air pollutants under 20.2.70 NMAC (Operating Permits).
  - (3) The facility is located in an ozone nonattainment area and which emits, or has the potential to emit, 25 tons per year or more of nitrogen oxides or volatile organic compounds.
  - (4) Upon request by the department.
  - (5) The permittee shall submit the emissions inventory report by April 1 of each year, unless a different deadline is specified by the current operating permit.
- J. Emissions trading within a facility (20.2.70.302.H.2 NMAC)
  - (1) For each such change, the permittee shall provide written notification to the department and the administrator at least seven (7) days in advance of the proposed changes. Such notification shall state when the change will occur and shall describe the changes in emissions that will result and how these increases and decreases in emissions will comply with the terms and conditions of the permit.
  - (2) The permittee and department shall attach each such notice to their copy of the relevant permit.

### **B111 General Testing Requirements**

Unless otherwise indicated by Specific Conditions or regulatory requirements, the permittee shall conduct testing in accordance with the requirements in Sections B111A, B, C, D and E, as applicable.

- A. Initial Compliance Tests

The permittee shall conduct initial compliance tests in accordance with the following requirements:

- (1) Initial compliance test requirements from previous permits (if any) are still in effect, unless the tests have been satisfactorily completed. Compliance tests may be re-imposed if it is deemed necessary by the Department to determine whether the source is in compliance with applicable regulations or permit conditions. (20.2.72 NMAC Sections 210.C and 213)
- (2) Initial compliance tests shall be conducted within sixty (60) days after the unit(s) achieve the maximum normal production rate. If the maximum normal production rate does not occur within one hundred twenty (120) days of source startup, then the tests must be conducted no later than one hundred eighty (180) days after initial startup of the source.
- (3) The default time period for each test run shall be at least 60 minutes and each performance test shall consist of three separate runs using the applicable test method. For the purpose of determining compliance with an applicable emission limit, the arithmetic mean of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Department approval, be determined using the arithmetic mean of the results of the two other runs.
- (4) Testing of emissions shall be conducted with the emissions unit operating at 90 to 100 percent of the maximum operating rate allowed by the permit. If it is not possible to test at that rate, the source may test at a lower operating rate
- (5) Testing performed at less than 90 percent of permitted capacity will limit emission unit operation to 110 percent of the tested capacity until a new test is conducted.
- (6) If conditions change such that unit operation above 110 percent of tested capacity is possible, the source must submit a protocol to the Department within 30 days of such change to conduct a new emissions test.

#### B. EPA Reference Method Tests

The test methods in Section B111.B(1) shall be used for all initial compliance tests and all Relative Accuracy Test Audits (RATAs), and shall be used if a permittee chooses to use EPA test methods for periodic monitoring. Test methods that are not listed in Section B111.B(1) may be used in accordance with the requirements at Section B111.B(2).

- (1) All compliance tests required by this permit shall be conducted in accordance with the requirements of CFR Title 40, Part 60, Subpart A, General Provisions, and the following EPA Reference Methods as specified by CFR Title 40, Part 60, Appendix A:

- (a) Methods 1 through 4 for stack gas flowrate
  - (b) Method 5 for particulate matter (PM) (TSP)
  - (c) Method 6C for SO<sub>2</sub>
  - (d) Method 7E for NO<sub>x</sub> (test results shall be expressed as nitrogen dioxide (NO<sub>2</sub>) using a molecular weight of 46 lb/lb-mol in all calculations (each ppm of NO/NO<sub>2</sub> is equivalent to 1.194 x 10<sup>-7</sup> lb/SCF)
  - (e) Method 9 for visual determination of opacity
  - (f) Method 10 for CO
  - (g) Method 19 for particulate, sulfur dioxide and nitrogen oxides emission rates. In addition, Method 19 may be used in lieu of Methods 1-4 for stack gas flowrate. The permittee shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months prior to the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report.
  - (h) Method 7E or 20 for Turbines per §60.335 or §60.4400
  - (i) Method 22 for visual determination of fugitive emissions from material sources and smoke emissions from flares
  - (j) Method 25A for VOC reduction efficiency
  - (k) Method 29 for Metals
  - (l) Method 30B for Mercury from Coal-Fired Combustion Sources Using Carbon Sorbent Traps
  - (m) Method 201A for filterable PM<sub>10</sub> and PM<sub>2.5</sub>
  - (n) Method 202 for condensable PM
  - (o) Method 320 for organic Hazardous Air Pollutants (HAPs)
- (2) Permittees may propose test method(s) that are not listed in Section B111.B(1). These methods may be used if prior approval is received from the Department.

C. Periodic Monitoring and Portable Analyzer Requirements for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters

Periodic emissions tests (periodic monitoring) shall be conducted in accordance with the following requirements:

- (1) Periodic emissions tests may be conducted in accordance with EPA Reference Methods or by utilizing a portable analyzer. Periodic monitoring utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. However, if a facility has met a previously

approved Department criterion for portable analyzers, the analyzer may be operated in accordance with that criterion until it is replaced.

- (2) The default time period for each test run shall be **at least** 20 minutes.  
Each performance test shall consist of three separate runs. The arithmetic mean of results of the three runs shall be used to determine compliance with the applicable emission limit.
- (3) Testing of emissions shall be conducted in accordance with the requirements at Section B108.E.
- (4) During emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing Reference Method 19. This information shall be included with the test report furnished to the Department.
- (5) Stack gas flow rate shall be calculated in accordance with Reference Method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The permittee shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months prior to the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using EPA Reference Methods 1-4.
- (6) The permittee shall submit a notification and protocol for periodic emissions tests upon the request of the Department.

#### D. Initial Compliance Test and RATA Procedures

Permittees required to conduct initial compliance tests and/or RATAs shall comply with the following requirements:

- (1) The permittee shall submit a notification and test protocol to the Department's Program Manager, Compliance and Enforcement Section, at least thirty (30) days before the test date and allow a representative of the Department to be present at the test. Proposals to use test method(s) that are not listed in Section B111.B(1) (if applicable) shall be included in this notification.
- (2) Contents of test notifications, protocols and test reports shall conform to the format specified by the Department's Universal Test Notification, Protocol and Report Form and Instructions. Current forms and instructions are posted to NMED's Air Quality web site under Compliance and Enforcement Testing.
- (3) The permittee shall provide (a) sampling ports adequate for the test methods applicable to the facility, (b) safe sampling platforms, (c) safe access to sampling platforms and (d) utilities for sampling and testing equipment.
- (4) Where necessary to prevent cyclonic flow in the stack, flow straighteners shall be installed

**E. General Compliance Test Procedures**

The following requirements shall apply to all initial compliance and periodic emissions tests and all RATAs:

- (1) Equipment shall be tested in the "as found" condition. Equipment may not be adjusted or tuned prior to any test for the purpose of lowering emissions, and then returned to previous settings or operating conditions after the test is complete.
- (2) The stack shall be of sufficient height and diameter and the sample ports shall be located so that a representative test of the emissions can be performed in accordance with the requirements of EPA Reference Method 1 or the current version of ASTM D 6522, as applicable.
- (3) Test reports shall be submitted to the Department no later than 30 days after completion of the test.

**B112 Compliance**

- A. The Department shall be given the right to enter the facility at all reasonable times to verify the terms and conditions of this permit. Required records shall be organized by date and subject matter and shall at all times be readily available for inspection. The permittee, upon verbal or written request from an authorized representative of the Department who appears at the facility, shall immediately produce for inspection or copying any records required to be maintained at the facility. Upon written request at other times, the permittee shall deliver to the Department paper or electronic copies of any and all required records maintained on site or at an off-site location. Requested records shall be copied and delivered at the permittee's expense within three business days from receipt of request unless the Department allows additional time. Required records may include records required by permit and other information necessary to demonstrate compliance with terms and conditions of this permit. (NMSA 1978, Section 74-2-13)
- B. A copy of the most recent permit(s) issued by the Department shall be kept at the permitted facility or (for unmanned sites) at the nearest company office and shall be made available to Department personnel for inspection upon request. (20.2.70.302.G.3 NMAC)
- C. Emissions limits associated with the energy input of a Unit, i.e. lb/MMBtu, shall apply at all times unless stated otherwise in a Specific Condition of this permit. The averaging time for each emissions limit, including those based on energy input of a Unit (i.e. lb/MMBtu) is one (1) hour unless stated otherwise in a Specific Condition of this permit or in the applicable requirement that establishes the limit. (20.2.70.302.A.1 and G.3 NMAC)
- D. The permittee shall submit compliance certification reports certifying the compliance status of this facility with respect to all permit terms and conditions, including applicable requirements. These reports shall be made on the pre-populated Compliance Certification Report Form that is provided to the permittee by the Department, and shall be submitted to

the Department and to EPA at least every 12 months. For the most current form, please contact the Compliance Reports Group at: [submittals.aqb@state.nm.us](mailto:submittals.aqb@state.nm.us). For additional reporting guidance see <https://www.env.nm.gov/air-quality/compliance-submittal-forms/> (20.2.70.302.E.3 NMAC)

- E. The permittee shall allow representatives of the Department, upon presentation of credentials and other documents as may be required by law, to do the following (20.2.70.302.G.1 NMAC):
- (1) enter the permittee's premises where a source or emission unit is located, or where records that are required by this permit to be maintained are kept;
  - (2) have access to and copy, at reasonable times, any records that are required by this permit to be maintained;
  - (3) inspect any facilities, equipment (including monitoring and air pollution control equipment), work practices or operations regulated or required under this permit; and
  - (4) sample or monitor any substances or parameters for the purpose of assuring compliance with this permit or applicable requirements or as otherwise authorized by the Federal Act.

### **B113 Permit Reopening and Revocation**

- A. This permit will be reopened and revised when any one of the following conditions occurs, and may be revoked and reissued when A(3) or A(4) occurs. (20.2.70.405.A.1 NMAC)
- (1) Additional applicable requirements under the Federal Act become applicable to a major source three (3) or more years before the expiration date of this permit. If the effective date of the requirement is later than the expiration date of this permit, then the permit is not required to be reopened unless the original permit or any of its terms and conditions has been extended due to the Department's failure to take timely action on a request by the permittee to renew this permit.
  - (2) Additional requirements, including excess emissions requirements, become applicable to this source under Title IV of the Federal Act (the acid rain program). Upon approval by the Administrator, excess emissions offset plans will be incorporated into this permit.
  - (3) The Department or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the terms and conditions of the permit.
  - (4) The Department or the Administrator determines that the permit must be revised or revoked and reissued to assure compliance with an applicable requirement.

- B. Proceedings to reopen or revoke this permit shall affect only those parts of this permit for which cause to reopen or revoke exists. Emissions units for which permit conditions have been revoked shall not be operated until new permit conditions have been issued for them. (20.2.70.405.A.2 NMAC)

**B114 Emergencies**  
(20.2.70.304 NMAC)

- A. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the permittee, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, or careless or improper operation.
- B. An emergency constitutes an affirmative defense to an action brought for noncompliance with technology-based emission limitations contained in this permit if the permittee has demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:
- (1) An emergency occurred and that the permittee can identify the cause(s) of the emergency;
  - (2) This facility was at the time being properly operated;
  - (3) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit; and
  - (4) The permittee submitted notice of the emergency to the Department within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirement of 20.2.70.302.E.2 NMAC. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.
- C. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.
- D. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

**B115 Stratospheric Ozone**  
(20.2.70.302.A.1 NMAC)

- A. If this facility is subject to 40 CFR 82, Subpart F, the permittee shall comply with the following standards for recycling and emissions reductions:
- (1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices, except for motor vehicle air conditioners (MVAC) and MVAC-like appliances. (40 CFR 82.156)
  - (2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment. (40 CFR 82.158)
  - (3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program. (40 CFR 82.161)

**B116 Acid Rain Sources**  
(20.2.70.302.A.9 NMAC)

- A. If this facility is subject to the federal acid rain program under 40 CFR 72, this section applies.
- B. Where an applicable requirement of the Federal Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Federal Act, both provisions are incorporated into this permit and are federally enforceable.
- C. Emissions exceeding any allowances held by the permittee under Title IV of the Federal Act or the regulations promulgated thereunder are prohibited.
- D. No modification of this permit is required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit modification under any other applicable requirement.
- E. The permittee may not use allowances as a defense to noncompliance with any other applicable requirement.
- F. No limit is placed on the number of allowances held by the acid rain source. Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Federal Act.
- G. The acid rain permit is an enclosure of this operating permit.

**B117 Risk Management Plan**  
(20.2.70.302.A.1 NMAC)

- A. If this facility is subject to the federal risk management program under 40 CFR 68, this section applies.



- B. The owner or operator shall certify annually that they have developed and implemented a RMP and are in compliance with 40 CFR 68.
- C. If the owner or operator of the facility has not developed and submitted a risk management plan according to 40 CFR 68.150, the owner or operator shall provide a compliance schedule for the development and implementation of the plan. The plan shall describe, in detail, procedures for assessing the accidental release hazard, preventing accidental releases, and developing an emergency response plan to an accidental release. The plan shall be submitted in a method and format to a central point as specified by EPA prior to the date specified in 40 CFR 68.150.b.

**PART C MISCELLANEOUS****C100 Supporting On-Line Documents**

- A. Copies of the following documents can be downloaded from NMED's web site under Compliance and Enforcement or requested from the Bureau.
- (1) Excess Emission Form (for reporting deviations and emergencies)
  - (2) Compliance Certification Report Form
  - (3) Universal Stack Test Notification, Protocol and Report Form and Instructions

**C101 Definitions**

- A. **"Daylight"** is defined as the time period between sunrise and sunset, as defined by the Astronomical Applications Department of the U.S. Naval Observatory. (Data for one day or a table of sunrise/sunset for an entire year can be obtained at <http://aa.usno.navy.mil/>. Alternatively, these times can be obtained from a Farmers Almanac or from <http://www.almanac.com/rise/>).
- B. **"Decommission"** and **"Decommissioning"** applies to units left on site (not removed) and is defined as the complete disconnecting of equipment, emission sources or activities from the process by disconnecting all connections necessary for operation (i.e. piping, electrical, controls, ductwork, etc.).
- C. **"Exempt Sources"** and **"Exempt Activities"** is defined as those sources or activities that are exempted in accordance with 20.2.72.202 NMAC. Note; exemptions are only valid for most 20.2.72 permitting action.
- D. **"Fugitive emission"** means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. (20.2.70.7M NMAC)
- E. **"Insignificant Activities"** means those activities which have been listed by the department and approved by the administrator as insignificant on the basis of size, emissions or production rate. (20.2.70.7Q NMAC)
- F. **"Malfunction"** for the requirements under 20.2.7 NMAC, means any sudden and unavoidable failure of air pollution control equipment or process equipment beyond the control of the owner or operator, including malfunction during startup or shutdown. A failure that is caused entirely or in part by poor maintenance, careless operation, or any other preventable equipment breakdown shall not be considered a malfunction.

- G. **“Natural Gas”** is defined as a naturally occurring fluid mixture of hydrocarbons that contains 20.0 grains or less of total sulfur per 100 standard cubic feet (SCF) and is either composed of at least 70% methane by volume or has a gross calorific value of between 950 and 1100 Btu per standard cubic foot. (40 CFR 60.331)
- H. **“Natural Gas Liquids”** means the hydrocarbons, such as ethane, propane, butane, and pentane, that are extracted from field gas. (40 CFR 60.631)
- I. **“National Ambient Air Quality Standards”** means the primary (health-based) and secondary (welfare-related) federal ambient air quality standards promulgated by the US EPA pursuant to Section 109 of the Federal Act. (20.2.72.7Q NMAC)
- J. **“NO<sub>2</sub>”** or **“Nitrogen dioxide”** means the chemical compound containing one atom of nitrogen and two atoms of oxygen, for the purposes of ambient determinations. The term **“nitrogen dioxide,”** for the purposes of stack emissions monitoring, shall include nitrogen dioxide (the chemical compound containing one atom of nitrogen and two atoms of oxygen), nitric oxide (the chemical compound containing one atom of nitrogen and one atom of oxygen), and other oxides of nitrogen which may test as nitrogen dioxide and is sometimes referred to as NO<sub>x</sub> or NO<sub>2</sub>. (20.2.2.7U NMAC)
- K. **“NO<sub>x</sub>”** see NO<sub>2</sub>
- L. **“Paved Road”** is a road with a permanent solid surface that can be swept essentially free of dust or other material to reduce air re-entrainment of particulate matter. To the extent these surfaces remain solid and contiguous they qualify as paved roads: concrete, asphalt, chip seal, recycled asphalt and other surfaces approved by the Department in writing.
- M. **“Potential Emission Rate”** means the emission rate of a source at its maximum capacity to emit a regulated air contaminant under its physical and operational design, provided any physical or operational limitation on the capacity of the source to emit a regulated air contaminant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its physical and operational design only if the limitation or the effect it would have on emissions is enforceable by the department pursuant to the Air Quality Control Act or the Federal Act. (20.2.72.7Y NMAC)
- N. **“Restricted Area-Non Military”** is an area to which public entry is effectively precluded. Effective barriers include continuous fencing, continuous walls, or other continuous barriers approved by the Department, such as rugged physical terrain with a steep grade that would require special equipment to traverse. If a large property is completely enclosed by fencing, a restricted area within the property may be identified with signage only. Public roads cannot be part of a Restricted Area.

- O. **"Shutdown"** for requirements under 20.2.72.7BB NMAC, means the cessation of operation of any air pollution control equipment, process equipment or process for any purpose, except routine phasing out of batch process units.
- P. **"SSM"** for requirements under 20.2.7 NMAC, means routine or predictable startup, shutdown, or scheduled maintenance.
- (1) **"Shutdown"** for requirements under 20.2.7.7H NMAC, means the cessation of operation of any air pollution control equipment or process equipment.
  - (2) **"Startup"** for requirements under 20.2.7.7I NMAC, means the setting into operation of any air pollution control equipment or process equipment.
- Q. **"Startup"** for requirements under 20.2.72.7DD NMAC, means the setting into operation of any air pollution control equipment, process equipment or process for any purpose, except routine phasing in of batch process units.

## C102 Acronyms

2SLB .....	2-stroke lean burn
4SLB .....	4-stroke lean burn
4SRB .....	4-stroke rich burn
acfm .....	actual cubic feet per minute
AFR .....	air fuel ratio
AP-42 .....	EPA Air Pollutant Emission Factors
AQB .....	Air Quality Bureau
AQCR .....	Air Quality Control Region
ASTM .....	American Society for Testing & Materials
Btu .....	British thermal unit
CAA .....	Clean Air Act of 1970 and 1990 Amendments
CEM .....	continuous emissions monitoring
cfh .....	cubic feet per hour
cfm .....	cubic feet per minute
CFR .....	Code of Federal Regulation
CI .....	compression ignition
CO .....	carbon monoxide
COMS .....	continuous opacity monitoring system
EIB .....	Environmental Improvement Board
EPA .....	United States Environmental Protection Agency
gr/100 cf .....	grains per one hundred cubic feet
gr/dscf .....	grains per dry standard cubic foot
GRI .....	Gas Research Institute
H <sub>2</sub> S .....	hydrogen sulfide
HAP .....	hazardous air pollutant
hp .....	horsepower
IC .....	Internal Combustion

KW/hr .....	kilowatts per hour
lb/hr .....	pounds per hour
lb/MMBtu .....	pounds per million British thermal unit
MACT .....	Maximum Achievable Control Technology
MMcf/hr .....	million cubic feet per hour
MMscf .....	million standard cubic feet
N/A .....	not applicable
NAAQS .....	National Ambient Air Quality Standards
NESHAP .....	National Emission Standards for Hazardous Air Pollutants
NG .....	natural gas
NGL .....	natural gas liquids
NMAAQs .....	New Mexico Ambient Air Quality Standards
NMAC .....	New Mexico Administrative Code
NMED .....	New Mexico Environment Department
NMSA .....	New Mexico Statutes Annotated
NO <sub>x</sub> .....	nitrogen oxides
NSCR .....	non-selective Catalytic Reduction
NSPS .....	New Source Performance Standard
NSR .....	New Source Review
PEM .....	parametric emissions monitoring
PM .....	particulate matter (equivalent to TSP, total suspended particulate)
PM <sub>10</sub> .....	particulate matter 10 microns and less in diameter
PM <sub>2.5</sub> .....	particulate matter 2.5 microns and less in diameter
pph .....	pounds per hour
ppmv .....	parts per million by volume
PSD .....	Prevention of Significant Deterioration
RATA .....	relative accuracy test assessment
RICE .....	reciprocating internal combustion engine
rpm .....	revolutions per minute
scfm .....	standard cubic feet per minute
SI .....	spark ignition
SO <sub>2</sub> .....	sulfur dioxide
SSM .....	Startup Shutdown Maintenance (see SSM definition)
TAP .....	Toxic Air Pollutant
TBD .....	to be determined
THC .....	total hydrocarbons
TSP .....	Total Suspended Particulates
tpy .....	tons per year
ULSD .....	ultra-low sulfur diesel
USEPA .....	United States Environmental Protection Agency
UTM .....	Universal Transverse Mercator Coordinate System
UTMH .....	Universal Transverse Mercator Horizontal
UTMV .....	Universal Transverse Mercator Vertical

VHAP .....volatile hazardous air pollutant  
VOC ..... volatile organic compounds

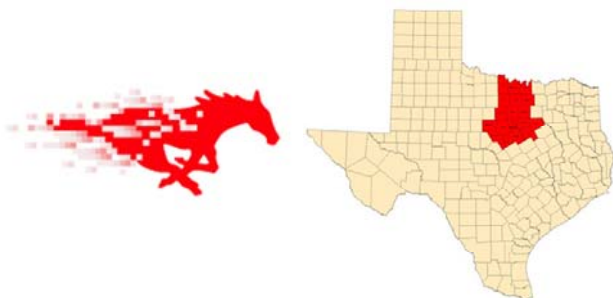
# Exhibit 15

# **Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements**

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## 1.0 EXECUTIVE SUMMARY

Natural gas production in the Barnett Shale region of Texas has increased rapidly since 1999, and as of June 2008, over 7700 oil and gas wells had been installed and another 4700 wells were pending. Gas production in 2007 was approximately 923 Bcf from wells in 21 counties. Natural gas is a critical feedstock to many chemical production processes, and it has many environmental benefits over coal as a fuel for electricity generation, including lower emissions of sulfur, metal compounds, and carbon dioxide. Nevertheless, oil and gas production from the Barnett Shale area can impact local air quality and release greenhouse gases into the atmosphere. The objectives of this study were to develop an emissions inventory of air pollutants from oil and gas production in the Barnett Shale area, and to identify cost-effective emissions control options.

Emission sources from the oil and gas sector in the Barnett Shale area were divided into point sources, which included compressor engine exhausts and oil/condensate tanks, as well as fugitive and intermittent sources, which included production equipment fugitives, well drilling and fracing engines, well completions, gas processing, and transmission fugitives. The air pollutants considered in this inventory were smog-forming compounds ( $\text{NO}_x$  and VOC), greenhouse gases, and air toxic chemicals.

For 2009, emissions of smog-forming compounds from compressor engine exhausts and tanks were predicted to be approximately 96 tons per day (tpd) on an annual average, with peak summer emissions of 212 tpd. Emissions during the summer increase because of the effects of temperature on volatile organic compound emissions from storage tanks. Emissions of smog-forming compounds in 2009 from all oil and gas sources were estimated to be approximately 191 tpd on an annual average, with peak summer emissions of 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 165 tpd during the summer.

For comparison, 2009 emission inventories recently used by state and federal regulators estimated smog-forming emissions from all airports in the Dallas-Fort Worth metropolitan area to be 16 tpd. In addition, these same inventories had emission estimates for on-road motor vehicles (cars, trucks, etc.) in the 9-county Dallas-Fort Worth metropolitan area of 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties.

The emission rate of air toxic compounds (like benzene and formaldehyde) from Barnett Shale activities was predicted to be approximately 6 tpd on an annual average, and 17 tpd during peak summer days. The largest contributors to air toxic emissions were the condensate tanks, followed by the engine exhausts.

In addition, predicted 2009 emissions of greenhouse gases like carbon dioxide and methane were approximately 33,000 tons per day of  $\text{CO}_2$  equivalent. This is roughly equivalent to the expected greenhouse gas impact from two 750 MW coal-fired power plants. The largest contributors to the Barnett Shale greenhouse gas impact were  $\text{CO}_2$  emissions from compressor engine exhausts and fugitive  $\text{CH}_4$  emissions from all source types.

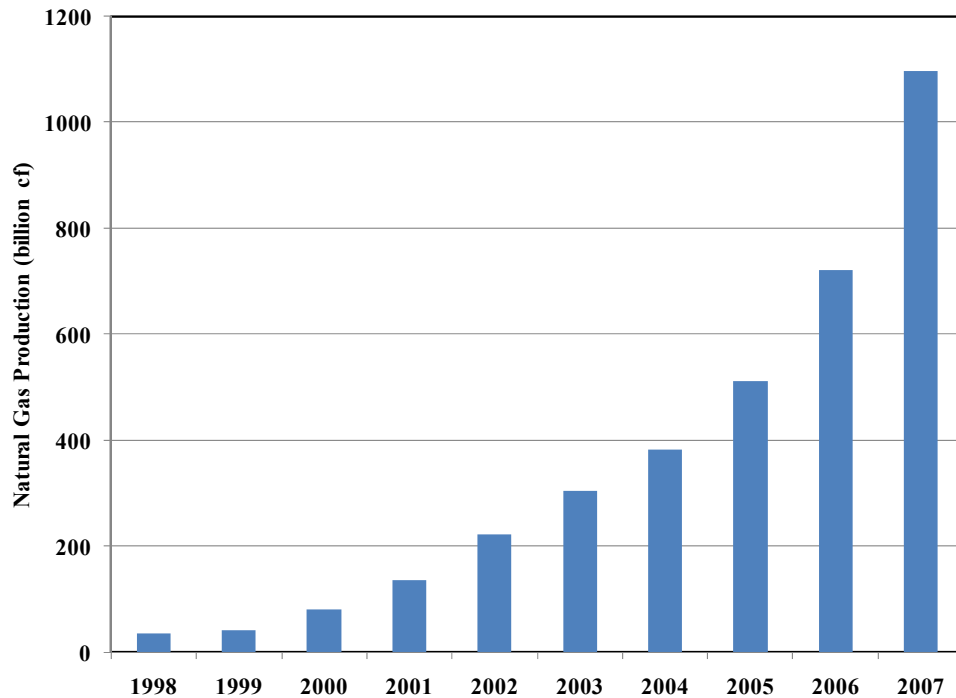
Cost effective control strategies are readily available that can substantially reduce emissions, and in some cases, reduce costs for oil and gas operators. These options include:

- use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in electric motors as an alternative to internal-combustion engines to drive compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

## 2.0 BACKGROUND

### 2.1 Barnett Shale Natural Gas Production

The Barnett Shale is a geological formation that the Texas Railroad Commission (RRC) estimates to extend 5000 square miles in parts of at least 21 Texas counties. The hydrocarbon productive region of the Barnett Shale has been designated as the Newark East Field, and large scale development of the natural gas resources in the field began in the late 1990's. Figure 1 shows the rapid and continuing development of natural gas from the Barnett Shale over the last 10 years.<sup>(1)</sup>



**Figure 1. Barnett Shale Natural Gas Production, 1998-2007.**

In addition to the recent development of the Barnett Shale, oil and gas production from other geologic formations and conventional sources in north central Texas existed before 1998 and continues to the present time. Production from the Barnett Shale is currently the dominant source of hydrocarbon production in the area from oil and gas activities in the area. Emission sources for all oil and gas activities are considered together in this report.

The issuance of new Barnett Shale area drilling permits has been following the upward trend of increasing natural gas production. The RRC issued 1112 well permits in 2004, 1629 in 2005, 2507 in 2006, 3657 in 2007, and they are on-track to issue over 4000 permits in 2008. The vast majority of the wells and permits are for natural gas production, but a small number of oil wells are also in operation or permitted in the area, and some oil wells co-produce casinghead gas. As of June 2008, over 7700 wells had been registered with the RRC, and the permit issuance rates are summarized in Table 1-1.<sup>(1)</sup> Annual oil, gas, condensate, and casinghead gas production rates for 21 counties in the Barnett Shale area are shown in Table 1-2.<sup>(1)</sup> The majority of Barnett Shale wells and well permits are located in six counties near the city of Fort Worth: Tarrant, Denton, Wise, Parker, Hood, and Johnson Counties. Figure 2 shows a RRC map of wells and well permits in the Barnett Shale.<sup>(2)</sup>

The top three gas producing counties in 2007 were Johnson, Tarrant and Wise, and the top three condensate producing counties were Wise, Denton, and Parker.

Nine (9) counties surrounding the cities of Fort Worth and Dallas have been designated by the U.S. EPA as the D-FW ozone nonattainment area (Tarrant, Denton, Parker, Johnson, Ellis, Collin, Dallas, Rockwall, and Kaufman ). Four of these counties (Tarrant, Denton, Parker, and Johnson) have substantial oil or gas production. In this report, these 9 counties are referred to as the D-FW metropolitan area. The areas outside these 9-counties with significant Barnett Shale oil or gas production are generally more rural counties to the south, west, and northwest of the city of Fort Worth. The counties inside and outside the D-FW metropolitan area with oil and gas production are listed in Table 1-3.

**Table 1-1. Barnett Shale Area Drilling Permits Issued, 2004-2008.<sup>(1)</sup>**

year	new drilling permits
2004	1112
2005	1629
2006	2507
2007	3657
2008	4000+

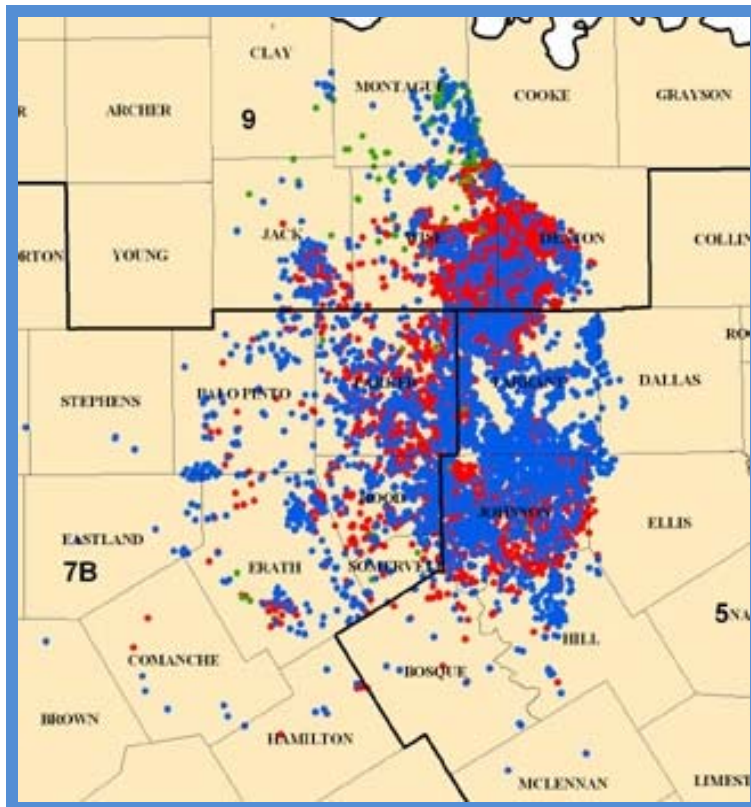
**Table 1-2. Hydrocarbon Production in the Barnett Shale Area in 2007.<sup>(1)</sup>**

County	Gas Production (MCF)	Condensate (BBL)	Casinghead Gas (MCF)	Oil Production (BBL)
Johnson	282,545,748	28,046	0	0
Tarrant	246,257,349	35,834	0	0
Wise	181,577,163	674,607	6,705,809	393,250
Denton	168,020,626	454,096	934,932	52,363
Parker	80,356,792	344,634	729,472	11,099
Hood	32,726,694	225,244	40,271	526
Jack	16,986,319	139,009	2,471,113	634,348
Palo Pinto	12,447,321	78,498	1,082,030	152,685
Stephens	11,149,910	56,183	3,244,894	2,276,637
Hill	7,191,823	148	0	0
Erath	4,930,753	11,437	65,425	5,073
Eastland	4,129,761	130,386	754,774	259,937
Somervell	4,018,269	6,317	0	0
Ellis	1,715,821	0	17,797	10
Comanche	560,733	1,584	52,546	7,055
Cooke	352,012	11,745	2,880,571	2,045,505
Montague	261,734	11,501	3,585,404	1,677,303
Clay	261,324	12,046	350,706	611,671
Hamilton	162,060	224	0	237
Bosque	135,116	59	0	0
Kaufman	0	0	3,002	61,963

**Table 1-3. Relationship Between the D-FW Metropolitan Area and Counties Producing Oil/Gas in the Barnett Shale Area**

<b>D-FW 9-County Metropolitan Area</b>	<b>D-FW Metro. Counties Producing Barnett Area Oil/Gas</b>	<b>Rural Counties Producing Barnett Area Oil/Gas</b>
Tarrant	Tarrant	Wise
Denton	Denton	Hood
Parker	Parker	Jack
Johnson	Johnson	Palo Pinto
Ellis	Ellis	Stephens
Collin		Hill
Dallas		Eastland
Rockwall		Somervell
Kaufman		Comanche
		Cooke
		Montague
		Clay
		Hamilton
		Bosque

**Figure 2. Texas RRC Map of Well and Well Permit Locations in the Barnett Shale Area (red = gas wells, green = oil wells, blue = permits. RRC district 5, 7B, & 9 boundaries shown in black.)**



## 2.2 Air Pollutants and Air Quality Regulatory Efforts

Oil and gas activities in the Barnett Shale area have the potential to emit a variety of air pollutants, including greenhouse gases, ozone and fine particle smog-forming compounds, and air toxic chemicals. The state of Texas has the highest greenhouse gas (GHG) emissions in the U.S., and future federal efforts to reduce national GHG emissions are likely to require emissions reductions from sources in the state. The three anthropogenic greenhouse gases of greatest concern, carbon dioxide, methane, and nitrous oxide, are emitted from oil and gas sources in the Barnett Shale area.

At present, air quality monitors in the Dallas-Fort Worth area show the area to be in compliance with the 1997 fine particulate matter (PM<sub>2.5</sub>) air quality standard, which is 15 micrograms per cubic meter (µg/m<sup>3</sup>) on an annual average basis. In 2006, the Clean Air Scientific Advisory Committee for EPA recommended tightening the standard to as low as 13 µg/m<sup>3</sup> to protect public health, but the EPA administrator kept the standard at the 1997 level. Fine particle air quality monitors in the Dallas-Fort Worth area have been above the 13 µg/m<sup>3</sup> level several times during the 2000-2007 time period, and tightening of the fine particle standard by future EPA administrators will focus regulatory attention at sources that emit fine particles or fine particle-forming compounds like NO<sub>x</sub> and VOC gases.

## 2.3 Primary Emission Sources Involved in Barnett Shale Oil and Gas Production

There are a variety of activities that potentially create air emissions during oil and gas production in the Barnett Shale area. The primary emission sources in the Barnett Shale oil and gas sector include compressor engine exhausts, oil and condensate tank vents, production well fugitives, well drilling and hydraulic fracturing, well completions, natural gas processing, and transmission fugitives. Figure 3 shows a diagram of the major machinery and process units in the natural gas system.<sup>(3)</sup>

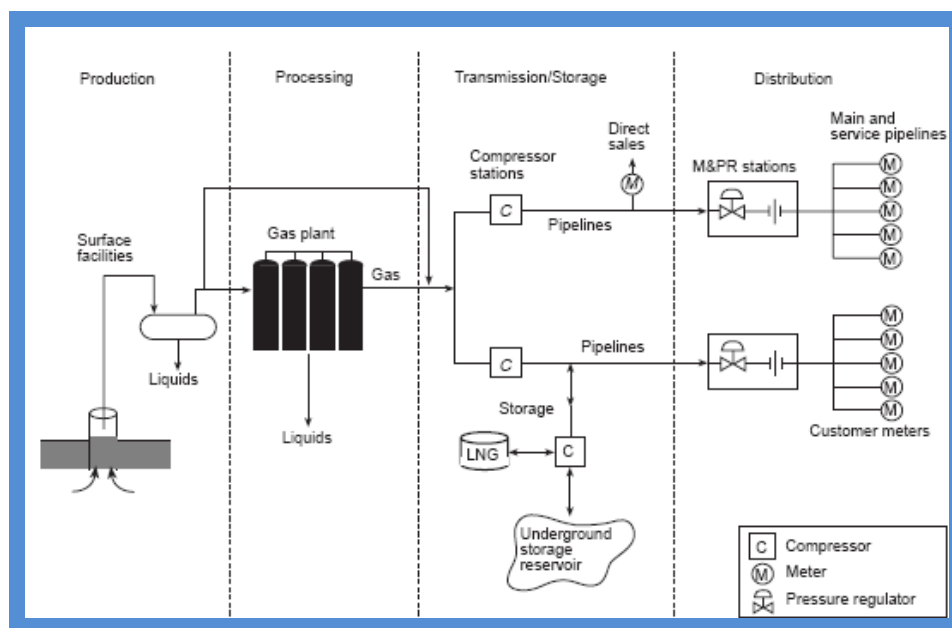
### 2.3.1 – Point Sources

#### *i. Compressor Engine Exhausts*

Internal combustion engines provide the power to run compressors that assist in the production of natural gas from wells, pressurize natural gas from wells to the pressure of lateral lines, and power compressors that move natural gas in large pipelines to and from processing plants and through the interstate pipeline network. The engines are often fired with raw or processed natural gas, and the combustion of the natural gas in these engines results in air emissions. Most of the engines driving compressors in the Barnett Shale area are between 100 and 500 hp in size, but some large engines of 1000+ hp are also used.

#### *ii. Condensate and Oil Tanks*

Fluids that are brought to the surface at Barnett Shale natural gas wells are a mixture of natural gas, other gases, water, and hydrocarbon liquids. Some gas wells produce little or no condensate, while others produce large quantities. The mixture typically is sent first to a separator unit, which reduces the pressure of the fluids and separates the natural gas and other gases from any entrained water and hydrocarbon liquids. The gases are collected off the top of the separator, while the water and hydrocarbon liquids fall to the bottom and are then stored on-site in storage tanks. The hydrocarbon liquid is known as condensate.



**Figure 3. Major Units in The Natural Gas Industry From Wells to Customers.** <sup>(3)</sup>

The condensate tanks at Barnett Shale wells are typically 10,000 to 20,000 gallons and hydrocarbons vapors from the condensate tanks can be emitted to the atmosphere through vents on the tanks. Condensate liquid is periodically collected by truck and transported to refineries for incorporation into liquid fuels, or to other processors. At oil wells, tanks are used to store crude oil on-site before the oil is transported to refiners. Like the condensate tanks, oil tanks can be sources of hydrocarbon vapor emissions to the atmosphere through tank vents.

### 2.3.2 – Fugitive and Intermittent Sources

#### *i. Production Fugitive Emissions*

Natural gas wells can contain a large number of individual components, including pumps, flanges, valves, gauges, pipe connectors, compressors, and other pieces. These components are generally intended to be tight, but leaks are not uncommon and some leaks can result in large emissions of hydrocarbons and methane to the atmosphere. The emissions from such leaks are called "fugitive" emissions. These fugitive emissions can be caused by routine wear, rust and corrosion, improper installation or maintenance, or overpressure of the gases or liquids in the piping. In addition to the unintended fugitive emissions, pneumatic valves which operate on pressurized natural gas leak small quantities of natural gas by design during normal operation. Natural gas wells, processing plants, and pipelines often contain large numbers of these kinds of pneumatic valves, and the accumulated emissions from all the valves in a system can be significant.

#### *ii. Well Drilling, Hydraulic Fracturing, and Completions*

Oil and gas drilling rigs require substantial power to form wellbores by driving drill bits to the depths of hydrocarbon deposits. In the Barnett Shale, this power is typically provided by transportable diesel engines, and operation of these engines generates exhaust from the burning of diesel fuel. After the wellbore is formed, additional power is needed to operate the pumps that move large quantities of water,

sand/glass, or chemicals into the wellbore at high pressure to hydraulically fracture the shale to increase its surface area and release natural gas.

After the wellbore is formed and the shale fractured, an initial mixture of gas, hydrocarbon liquids, water, sand, or other materials comes to the surface. The standard hardware typically used at a gas well, including the piping, separator, and tanks, are not designed to handle this initial mixture of wet and abrasive fluid that comes to the surface. Standard practice has been to vent or flare the natural gas during this "well completion" process, and direct the sand, water, and other liquids into ponds or tanks. After some time, the mixture coming to the surface will be largely free of the water and sand, and then the well will be connected to the permanent gas collecting hardware at the well site. During well completions, the venting/flaring of the gas coming to the surface results in a loss of potential revenue and also in substantial methane and VOC emissions to the atmosphere.

### *iii. Natural Gas Processing*

Natural gas produced from wells is a mixture of a large number of gases and vapors. Wellhead natural gas is often delivered to processing plants where higher molecular weight hydrocarbons, water, nitrogen, and other compounds are largely removed if they are present. Processing results in a gas stream that is enriched in methane at concentrations of usually more than 80%. Not all natural gas requires processing, and gas that is already low in higher hydrocarbons, water, and other compounds can bypass processing.

Processing plants typically include one or more glycol dehydrators, process units that dry the natural gas. In addition to water, the glycol absorbent usually collects significant quantities of hydrocarbons, which can be emitted to the atmosphere when the glycol is regenerated with heat. The glycol dehydrators, pumps, and other machinery used in natural gas processing can release methane and hydrocarbons into the atmosphere, and emissions also originate from the numerous flanges, valves, and other fittings.

### *iv. Natural Gas Transmission Fugitives*

Natural gas is transported from wells in mostly underground gathering lines that form networks that can eventually collect gas from hundreds or thousands of well locations. Gas is transported in pipeline networks from wells to processing plants, compressor stations, storage formations, and/or the interstate pipeline network for eventual delivery to customers. Leaks from pipeline networks, from microscopic holes, corrosion, welds and other connections, as well as from compressor intake and outlet seals, compressor rod packing, blow and purge operations, pipeline pigging, and from the large number of pneumatic devices on the pipeline network can result in large emissions of methane and hydrocarbons into the atmosphere and lost revenue for producers.

## 2.4 Objectives

Barnett Shale area oil and gas production can emit pollutants to the atmosphere which contribute to ozone and fine particulate matter smog, are known toxic chemicals, or contribute to climate change. The objectives of this study were to examine Barnett Shale oil and gas activities and : (1) estimate emissions of volatile organic compounds, nitrogen oxides, hazardous air pollutants, methane, carbon dioxide, and nitrous oxide; (2) evaluate the current state of regulatory controls and engineering techniques used to control emissions from the oil and gas sector in the Barnett Shale; (3) identify new approaches that can be taken to reduce emissions from Barnett Shale activities; and (4) estimate the emissions reductions and cost effectiveness of implementation of new emission reduction methods.

### 3.0 TECHNICAL APPROACH

#### 3.1 Pollutants

Estimates were made of 2007 and 2009 emissions of smog forming, air toxic, and greenhouse gas compounds, including nitrogen oxides ( $\text{NO}_x$ ), volatile organic compounds (VOCs), air toxics a.k.a. hazardous air pollutants (HAPs), methane ( $\text{CH}_4$ ), nitrous oxide ( $\text{N}_2\text{O}$ ), and carbon dioxide ( $\text{CO}_2$ ). Volatile organic compounds are generally carbon and hydrogen-based chemicals that exist in the gas phase or can evaporate from liquids. VOCs can react in the atmosphere to form ozone and fine particulate matter. Methane and ethane are specifically excluded from the definition of VOC because they react slower than the other VOC compounds to produce ozone and fine particles, but they are ozone-causing compounds nonetheless. The HAPs analyzed in this report are a subset of the VOC compounds, and include those compounds that are known or believed to cause human health effects at low doses. An example of a HAP compound is benzene, which is an organic compound known to contribute to the development of cancer.

Emissions of the greenhouse gases  $\text{CO}_2$ ,  $\text{CH}_4$ , and  $\text{N}_2\text{O}$  were determined individually, and then combined as carbon dioxide equivalent tons ( $\text{CO}_2\text{e}$ ). In the combination,  $\text{CH}_4$  tons were scaled by 21 and  $\text{N}_2\text{O}$  tons by 310 to account for the higher greenhouse gas potentials of these gases.<sup>(4)</sup>

Emissions in 2009 were estimated by examining recent trends in Barnett Shale hydrocarbon production, and where appropriate, extrapolating production out to 2009.

State regulatory programs are different for compressor engines inside the D-FW 9-county metropolitan area compared to outside. Engine emissions were determined separately for the two groups.

#### 3.2 Hydrocarbon Production

Production rates in 2007 for oil, gas, casinghead gas, and condensate were obtained from the Texas Railroad Commission for each county in the Barnett Shale area.<sup>(5)</sup> The large amount of production from wells producing from the Barnett Shale, as well as the smaller amounts of production from conventional formations in the area were taken together. The area was analyzed in whole, as well as by counties inside and outside the D-FW 9-county metropolitan area. Production rates in 2009 were predicted by plotting production rates from 2000-2007 and fitting a 2<sup>nd</sup>-order polynomial to the production rates via the least-squares method and extrapolating out to 2009.

#### 3.3 Compressor Engine Exhausts - Emission Factors and Emission Estimates

Emissions from the natural-gas fired compressor engines in the Barnett Shale were calculated for two types of engines: the generally large engines that had previously reported emissions into the TCEQ's Point Source Emissions Inventory (PSEI) prior to 2007 (a.k.a. PSEI Engines), and the generally smaller engines that had not previously reported emissions (a.k.a. non-PSEI Engines). Both these engine types are located in the D-FW 9-county metropolitan area (a.k.a. D-FW Metro Area), as well as in the rural counties outside the metropolitan area (a.k.a. Outside D-FW Metro Area). The four categories of engines are summarized in Figure 4 and the methods used to estimate emissions from the engines are described in the following sections.



**Figure 4. Engine Categories.**

<b>Non-PSEI Engines in D-FW Metro Area</b>	<b>PSEI Engines in D-FW Metro Area</b>	<b>PSEI Engines Outside D-FW Metro Area</b>	<b>Non-PSEI Engines Outside D-FW Metro Area</b>
--------------------------------------------	----------------------------------------	---------------------------------------------	-------------------------------------------------

*i. Non-PSEI Engines in D-FW Metropolitan Area*

Large natural gas compressor engines, located primarily at compressor stations and also some at well sites, have typically reported emissions to the Texas Commission on Environmental Quality (TCEQ) in annual Point Source Emissions Inventory (PSEI) reports. However, prior to 2007, many other stationary engines in the Barnett Shale area had not reported emissions to the PSEI and their contribution to regional air quality was unknown. In late 2007, the TCEQ conducted an engine survey for counties in the D-FW metropolitan area as part as efforts to amend the state clean air plan for ozone. Engine operators reported engine counts, engine sizes, NO<sub>x</sub> emissions, and other data to TCEQ. Data summarized by TCEQ from the survey was used for this report to estimate emissions from natural gas engines in the Barnett Shale area that had previously not reported emissions into the annual PSEI.<sup>(6)</sup> Data obtained from TCEQ included total operating engine power in the metropolitan area, grouped by rich vs. lean burn engines, and also grouped by engines smaller than 50 hp, between 50 - 500 hp, and larger than 500 hp.

Regulations adopted by TCEQ and scheduled to take effect in early 2009 will limit NO<sub>x</sub> emissions in the D-FW metropolitan area for engines larger than 50 horsepower.<sup>(7)</sup> Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. For this report, emissions in 2009 from the engines in the metropolitan area subject to the new rules were estimated assuming 97% compliance with the upcoming rules and a 3% noncompliance factor for engines continuing to emit at pre-2009 levels.

Emissions for 2007 were estimated using NO<sub>x</sub> emission factors provided by operators to TCEQ in the 2007 survey.<sup>(6)</sup> Emissions of VOCs were determined using TCEQ-determined emission factors, and emissions of HAPs, CH<sub>4</sub>, and CO<sub>2</sub> were determined using emission factors from EPA's AP-42 document.<sup>(8,9)</sup> In AP-42, EPA provides emission factors for HAP compounds that are created by incomplete fuel combustion. For this report only those factors which were judged by EPA to be of high quality, "A" or "B" ratings, were used to estimate emissions. Emission factors for the greenhouse gas N<sub>2</sub>O were from an emissions inventory report issued by the American Petroleum Institute.<sup>(10)</sup>

Beginning in 2009, many engines subject to the new NO<sub>x</sub> limits are expected to reduce their emissions with the installation of non-selective catalytic reduction units (NSCR), a.k.a. three-way catalysts. NSCR units are essentially modified versions of the "catalytic converters" that are standard equipment on every gasoline-engine passenger vehicle in the U.S.

A likely co-benefit of NSCR installation will be the simultaneous reduction of VOC, HAP, and CH<sub>4</sub> emissions. Emissions from engines expected to install NSCR units were determined using a 75% emissions reduction factor for VOC, HAPs, and CH<sub>4</sub>. Conversely, NSCR units are known to increase N<sub>2</sub>O emissions, and N<sub>2</sub>O emissions were estimated using a 3.4x factor increase over uncontrolled emission factors.<sup>(10)</sup> Table 2 summarizes the emission factors used to calculate emissions from the compressor engines identified in the 2007 survey.

**Table 2. Emission Factors for Engines Identified in the D-FW 2007 Engine Survey**

Table 2-1. Emission Factors for 2007 Emissions

engine type	engine size	NO <sub>x</sub> (g/hp-hr) <sup>a</sup>	VOC (g/hp-hr) <sup>b</sup>	HAPs (g/hp-hr) <sup>c</sup>	CH <sub>4</sub> (g/hp-hr) <sup>d</sup>	CO <sub>2</sub> (g-hp-hr) <sup>e</sup>	N <sub>2</sub> O (g-hp-hr) <sup>f</sup>
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	13.6	0.43	0.088	0.89	424	0.0077
rich	>500	0.9	0.43	0.088	0.89	424	0.0077
lean	<500	6.2	1.6	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

Table 2-2. Emission Factors for 2009 Emissions

engine type	engine size	NO <sub>x</sub> (g/hp-hr) <sup>i</sup>	VOC (g/hp-hr) <sup>j</sup>	HAPs (g/hp-hr) <sup>k</sup>	CH <sub>4</sub> (g/hp-hr) <sup>l</sup>	CO <sub>2</sub> (g-hp-hr) <sup>m</sup>	N <sub>2</sub> O (g-hp-hr) <sup>n</sup>
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	0.5	0.11	0.022	0.22	424	0.026
rich	>500	0.5	0.11	0.022	0.22	424	0.026
lean <sup>g</sup>	<500	0.62	1.6	0.27	4.8	424	0.012
lean <sup>h</sup>	<500	0.5	1.6	0.27	4.8	424	0.012
lean <sup>g</sup>	>500	0.7	1.45	0.27	4.8	424	0.012
lean <sup>h</sup>	>500	0.5	1.45	0.27	4.8	424	0.012

notes:

a: email from TCEQ to SMU, August 1, 2008, summary of results from 2007 engine survey (reference 6).

b: email from TCEQ to SMU, August 6, 2008 (reference 8).

c: EPA, AP-42, quality A and B emission factors; rich engine HAPs = benzene, formaldehyde, toluene; lean engine HAPs = acetaldehyde, acrolein, xylene, benzene, formaldehyde, methanol, toluene, xylene (reference 9).

d: EPA, AP-42 (reference 9).

e: EPA, AP-42 (reference 9).

f: API Compendium Report (reference 10).

g: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

h: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

i: rich (<50) factor from email from TCEQ to SMU, August 1, 2008 (reference 6); rich (50-500), rich (>500), lean (<500, post-2007), lean (>500, pre-2007), and lean (>500, post-2007) from TCEQ regulatory limits (reference 7); lean (<500, pre-2007) estimated with 90% control.

j: rich (<50) from email from TCEQ to SMU (reference 8); rich (50-500) and rich (>500) estimated with 75% NSCR control VOC co-benefit; lean EFs from email from TCEQ to SMU (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.

k: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.

l: EPA, AP-42 (reference 9); rich (50-500) and rich (>500) estimated with 75% control co-benefit.

m: EPA, AP-42 (reference 9).

n: API Compendium Report (reference 10); rich (50-500) and rich (>500) estimated with 3.4x N<sub>2</sub>O emissions increase over uncontrolled rate.

Annual emissions from the engines identified in the 2007 survey were estimated using the pollutant-specific emission factors from Table 1 together with Equation 1,

$$M_{E,i} = 1.10E-06 * E_i * P_{cap} * F_{hl} \quad (1)$$

where  $M_{E,i}$  was the mass emission rate of pollutant  $i$  in tons per year,  $E_i$  was the emission factor for pollutant  $i$  in grams/hp-hr,  $P_{cap}$  is installed engine capacity in hp, and  $F_{hl}$  is a factor to adjust for annual hours of operation and typical load conditions.

Installed engine capacity in 2007 was determined for six type/size categories using TCEQ estimates from the 2007 engine survey - two engine types (rich vs. lean) and three engine size ranges (<50, 50-500, >500 hp) were included.<sup>(6)</sup> TCEQ estimates of the average engine sizes and the numbers of engines in each size category were used to calculate the installed engine capacity for each category, as shown in Table 3. The  $F_{hl}$  factor was used to account for typical hours of annual operation and average engine loads. A  $F_{hl}$  value of 0.5 was used for this study, based on 8000 hours per year of average engine operation ( $8000/8760 = 0.91$ ) and operating engine loads of 55% of rated capacity, giving an overall hours-load factor of  $0.91 \times 0.55 = 0.5$ .<sup>(11)</sup>

**Table 3. Installed Engine Capacity in 2007 D-FW Engine Survey by Engine Type and Size**

engine type	engine size (hp)	number of engines <sup>q</sup>	typical size <sup>q</sup> (hp)	installed capacity <sup>r</sup> (hp)
rich	<50	12	50	585
rich	50-500	724	140	101,000
rich	>500	200	1400	280,000
lean <sup>o</sup>	<500	14	185	2540
lean <sup>p</sup>	<500	13	185	2400
lean <sup>o</sup>	>500	103	1425	147,000
lean <sup>p</sup>	>500	103	1425	147,000

notes:

o: engines installed or moved before June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

p: engines installed or moved after June 2007 - TCEQ regulations establish different regulatory limits for engines installed or moved before or after June 2007 (reference 7).

q: rich (<50) installed capacity based on HARC October 2006 H68 report which found that small rich burn engines comprise no more than 1% of engines in East Texas; rich (50-500) and rich (>500) installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6); lean burn installed capacity from email TCEQ to SMU in August 1, 2008 (reference 6) along with RRC data suggesting that 50% of engines in 2009 will be subject to the post-June 2007 NOx rule.

r: installed capacity = number of engines x typical size

## ii. PSEI Engines in D-FW Metropolitan Area

In addition to the engines identified in the 2007 TCEQ survey of the D-FW 9-county metropolitan area, many other stationary engines are also in use in the area. These include engines that had already been reporting annual emissions to TCEQ in the PSEI, which are principally large engines at compressor stations.<sup>(12)</sup>

Emissions of NO<sub>x</sub> from large engines in the D-FW metropolitan area that were reporting to the TCEQ PSEI were obtained from the 2006 Annual PSEI, the most recent calendar year available.<sup>(12)</sup> Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production and compression needs from 2006-2009. For NO<sub>x</sub> emissions in 2006 and 2007, an average emission factor of 0.9 g/hp-hr was obtained from TCEQ.<sup>(8)</sup> Emissions in 2009 were adjusted by accounting for the 0.5 g/hp-hr TCEQ regulatory limit scheduled to take effect in early 2009 for the D-FW metropolitan area.<sup>(7)</sup>

Unlike NO<sub>x</sub> emission, emissions of VOC were not taken directly from the PSEI. Estimates of future VOC emissions required accounting for the effects that the new TCEQ engine NO<sub>x</sub> limits will have on future VOC emissions. A compressor engine capacity production factor of 205 hp/(MMcf/day) was obtained from TCEQ that gives a ratio of installed horsepower capacity to the natural gas production. The 205 hp/(MMcf/day) factor was based on previous TCEQ studies of gas production and installed large engine capacity. The factor was used with 2006 gas production values to estimate installed PSEI engine capacities for each county in the Barnett Shale area.<sup>(8)</sup> Engine capacities were divided between rich burn engines smaller and larger than 500 hp, and lean burn engines. To estimate 2009 emissions, rich burn engines smaller than 500 hp are expected to have NSCR units by 2009 and get 75% VOC, HAP, and CH<sub>4</sub> control. Table 4 summarizes the VOC, HAP, and greenhouse gas emission factors used for the PSEI engines in the D-FW metropolitan area. Table 5 summarizes the estimates of installed engine capacity for each engine category.

**Table 4. VOC, HAP, GHG Emission Factors for PSEI Engines in D-FW Metropolitan Area**

Table 4-1. Emission Factors for 2007 Emissions

engine type	engine size	VOC EFs (g/hp-hr) <sup>s</sup>	HAPs EF (g/hp-hr) <sup>t</sup>	CH <sub>4</sub> EF (g/hp-hr) <sup>u</sup>	CO <sub>2</sub> EF (g/hp-hr) <sup>v</sup>	N <sub>2</sub> O (g/hp-hr) <sup>w</sup>
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.6	0.27	4.8	424	0.012

Table 4-2. Emission Factors for 2009 Emissions

engine type	engine size	VOC EFs (g/hp-hr) <sup>s</sup>	HAPs EF (g/hp-hr) <sup>t</sup>	CH <sub>4</sub> EF (g/hp-hr) <sup>u</sup>	CO <sub>2</sub> EF (g/hp-hr) <sup>v</sup>	N <sub>2</sub> O (g/hp-hr) <sup>w</sup>
rich	<500	0.11	0.022	0.22	424	0.026
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.47	0.27	4.8	424	0.012

notes:

s: email from TCEQ to SMU, August 6, 2008; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.47 to account for the effects of NSPS JJJJ rules on VOC emissions.

t: EPA, AP-42 (reference 9); 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

u: EPA, AP-42 (reference 9) ; 75% reductions applied to 2007 rich (>500), 2009 rich (>500) and 2009 rich (<500) engines (reference 9).

v: EPA, AP-42 (reference 9).

w: API Compendium Report; 2007 rich (>500), and 2009 rich (>500) and 2009 rich (<500) engines estimated with 3.4x N<sub>2</sub>O emissions increase over uncontrolled rate (reference 10).

**Table 5. Installed Engine Capacity in 2007 for PSEI Engines Inside D-FW Metropolitan Area**

engine type	engine size (hp)	installed capacity (%) <sup>x</sup>	installed capacity (hp) <sup>y</sup>
rich	<500	0.14	59,500
rich	>500	0.52	221,000
lean	all	0.34	144,000

notes:

x: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).

y: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

### *iii. PSEI Engines Outside D-FW Metropolitan Area*

Emissions of NO<sub>x</sub> from large engines outside the D-FW metropolitan area reporting to the TCEQ were obtained from the 2006 PSEI.<sup>(12)</sup> Emissions for 2007 and 2009 were estimated by extrapolating 2006 emissions upward to account for increases in gas production from 2006-2009. Unlike engines inside the metropolitan area, the engines outside the metropolitan area are not subject to the new D-FW engine rules scheduled to take effect in 2009.

In addition to the D-FW engine rules, in 2007 the TCEQ passed the East Texas Combustion Rule that limited NO<sub>x</sub> emissions from rich-burn natural gas engines larger than 240 hp in certain east Texas counties. Lean burn engines and engines smaller than 240 hp were exempted. The initial proposed rule would have applied to some counties in the Barnett Shale production area, including Cooke, Wise, Hood, Somervell, Bosque, and Hill, but in the final version of the rule these counties were removed from applicability, with the exception of Hill, which is still covered by the rule. Since gas production from Hill County is less than 3.5% of all the Barnett Shale area gas produced outside the D-FW metropolitan area, the East Texas Combustion Rule has limited impact to emissions from Barnett Shale area activity.

Emissions of VOC, HAPs, and greenhouse gases for large engines outside the D-FW metropolitan area were not obtained from the 2006 PSEI. A process similar to the one used to estimate emissions from large engines inside the metropolitan area was used, whereby the TCEQ compressor engine capacity production factor, 205 hp/(MMcf/day), was used along with actual 2007 production rates to estimate total installed engine capacity as well as installed capacity in each county for different engine categories. Pollutant-specific emission factors were applied to the capacity estimates for each category to estimate emissions. Table 6 summarizes the emission factors used to estimate emissions from engines in the PSEI outside the D-FW metropolitan area. The engine capacities used to estimate emissions are shown in Table 7.

**Table 6. VOC, HAP, GHG Emission Factors for PSEI Engines Outside D-FW Metropolitan Area**

engine type	engine size	VOC (g/hp-hr) <sup>z</sup>	HAPs (g/hp-hr) <sup>aa</sup>	CH <sub>4</sub> (g/hp-hr) <sup>aa</sup>	CO <sub>2</sub> (g-hp-hr) <sup>bb</sup>	N <sub>2</sub> O (g-hp-hr) <sup>cc</sup>
rich	<500	0.43	0.088	0.89	424	0.0077
rich	>500	0.11	0.022	0.22	424	0.026
lean	all	1.45	0.27	4.8	424	0.012

notes:

z: email from TCEQ to SMU, August 6, 2008; 75% control applied to rich (>500) engines (reference 8). Large lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.

aa: EPA, AP-42; 75% control applied to rich (>500) engines (reference 9).

bb. EPA, AP-42 (reference 9).

cc. API Compendium Report; rich (>500) engines estimated with 3.4x N<sub>2</sub>O emissions increase over uncontrolled rate (reference 10).

**Table 7. Installed Engine Capacity in 2007 for PSEI Engines Outside D-FW Metropolitan Area**

engine type	engine size (hp)	installed capacity (%) <sup>dd</sup>	installed capacity (hp) <sup>ee</sup>
rich	<500	0.14	17,000
rich	>500	0.52	62,000
lean	all	0.34	41,000

notes:

dd: distribution of engine types and sizes estimated from October 2006 HARC study (reference 13).

ee: estimated as the installed capacity (%) x the total installed capacity based on the TCEQ compressor engine capacity production factor of 205 hp/(MMcf/day) (references 5,8).

*iv. Non-PSEI Engines Outside the D-FW Metropolitan Area*

The Point Source Emissions Inventory (PSEI) only contains emissions from a fraction of the stationary engines in the Barnett Shale area, principally the larger compressor engines with emissions above the PSEI reporting thresholds. The 2007 TCEQ engine survey of engines inside the D-FW metropolitan area demonstrated that the PSEI does not include a substantial fraction of total engine emissions. Most of the missing engines in the metropolitan area were units with emissions individually below the TCEQ reporting thresholds, but the combined emissions from large numbers of smaller engines can be substantial. The results of the 2007 survey indicated that there were approximately 680,000 hp of installed engine capacity in the D-FW metropolitan area not previously reporting to the PSEI.<sup>(6)</sup>

Natural gas and casinghead gas production from metropolitan counties in 2007 was approximately 1,000 Bcf. A "non-PSEI" compressor engine capacity production factor of 226 hp/(MMcf/day) was determined for the Barnett Shale area. This capacity factor accounts for all the small previously hidden engines that the 2007 survey showed come into use in oil and gas production activities in the area. This production factor was used along with 2007 gas production rates for the counties outside the D-FW metropolitan area to estimate non-PSEI engine emissions from these counties. The new production factor accounts for the fact that counties outside the metro area likely contain previously unreported engine capacity in the same proportion to the unreported engine capacity that was identified during the 2007 engine survey inside the metro area. Without a detailed engine survey in the rural counties of the same scope as the 2007 survey performed within the D-FW metropolitan counties, use of the non-PSEI production factor provides a way to estimate emissions from engines not yet in state or federal inventories. The capacity of non-PSEI reporting engines in the rural counties of the Barnett Shale was determined by this method to be 132,000 hp. Emission factors used to estimate emissions from these engines, and the breakdown of total installed engine capacity into engine type and size categories, are shown in Tables 8 and 9.

**Table 8. Emission Factors for Non-PSEI Engines Outside D-FW Metropolitan Area**

engine type	engine size	NO <sub>x</sub> (g/hp-hr) <sup>ff</sup>	VOC (g/hp-hr) <sup>gg</sup>	HAPs (g/hp-hr) <sup>hh</sup>	CH <sub>4</sub> (g/hp-hr) <sup>hh</sup>	CO <sub>2</sub> (g-hp-hr) <sup>ii</sup>	N <sub>2</sub> O (g-hp-hr) <sup>jj</sup>
rich	<50	13.6	0.43	0.088	0.89	424	0.0077
rich	50-500	10.3	0.43	0.088	0.89	424	0.0077
rich	>500	0.89	0.11	0.022	0.22	424	0.026
lean	<500	5.2	1.45	0.27	4.8	424	0.012
lean	>500	0.9	1.6	0.27	4.8	424	0.012

notes:

ff: email from TCEQ to SMU, August 1, 2008 (reference 6). Rich burn engines 50-500 hp NO<sub>x</sub> emission factor adjusted from 13.6 to 10.3 to account for the effects of NSPS JJJJ rules on NO<sub>x</sub> emissions and the effect of the TCEQ East Texas Combustion Rule on Hill County production. Rich burn engines >500 adjusted from 0.9 to 0.89 to account for the effect of the TCEQ East Texas Combustion Rule on Hill County production. Lean burn <500 hp engine post-2007 emission factor adjusted from 6.2 to 5.15 to account for the effects of NSPS JJJJ rules on NO<sub>x</sub> emissions.

gg: email from TCEQ to SMU, August 6, 2008; rich (>500) based on 75% control (reference 8). Small lean engine VOC emission factor adjusted from 1.6 to 1.45 to account for the effects of NSPS JJJJ rules on VOC emissions.

hh: EPA, AP-42; rich (>500) based on 75% control (reference 9).

ii: EPA, AP-42 (reference 9).

jj: API Compendium Report; rich (>500) estimated with 3.4x N<sub>2</sub>O emissions increase over uncontrolled rate (reference 10).

**Table 9. Installed Engine Capacity for Non-PSEI Engines Outside Metropolitan Area by Engine Type/Size**

engine type	engine size (hp)	installed capacity (%)	installed capacity (hp)
rich	<50	0.01	110
rich	50-500	15	20,000
rich	>500	41	55,000
lean	<500	0.73	970
lean	>500	43	57,000

### 3.2 Condensate and Oil Tanks - Emission Factors and Emission Estimates

Condensate and oil tanks can be significant emitters of VOC, methane, and HAPs. A report was published in 2006 by URS Corporation which presented the results of a large investigation of emissions from condensate and oil tanks in Texas.<sup>(14)</sup> Tanks were sampled from 33 locations across East Texas, including locations in the Barnett Shale area. Condensate tanks in the Barnett Shale were sampled in Denton and Parker Counties, and oil tanks were sampled in Montague County. The results from the URS investigation were used in this study to calculate Barnett Shale-specific emission factors for VOC, CH<sub>4</sub>, HAPs, and CO<sub>2</sub>, instead of using a more general Texas-wide emission factor. The URS study was conducted during daylight hours in July 2006, when temperatures in North Texas are significantly above the annual average. Therefore, the results of the URS investigation were used to calculate "Peak Summer" emissions. The HAPs identified in the URS study included n-hexane, benzene, trimethylpentane, toluene, ethylbenzene, and xylene. The emission factors used to calculate peak summer emissions from Barnett

Shale condensate and oil tanks are shown in Table 10-1. Figure 5 shows a condensate tank battery from the 2006 URS study report.

**Figure 5. Example Storage Tank Battery (left), Separators (right), and Piping.<sup>(14)</sup>**



Computer modeling data were provided during personal communications with a Barnett Shale gas producer who estimated VOC, CH<sub>4</sub>, HAPs, and CO<sub>2</sub> emissions from a number of their condensate tanks.<sup>(15)</sup> The tanks were modeled with ambient temperatures of 60 F, which the producer used to represent annual hourly mean temperatures in the D-FW area. These modeling results were used in this report to predict annual average condensate tank emission factors for the Barnett Shale area. The annual average emission factors are shown in Table 10-2.



**Table 10. Condensate and Oil Tank Emission Factors for the Barnett Shale.**

Table 10-1. Peak Summer Emission Factors.<sup>(14)</sup>

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH <sub>4</sub> (lbs/bbl)	CO <sub>2</sub> (lbs/bbl)
condensate	48	3.7	5.6	0.87
oil	6.1	0.25	0.84	2.7

Table 10-2. Annual Average Emission Factors.<sup>(15)</sup>

	VOC (lbs/bbl)	HAPs (lbs/bbl)	CH <sub>4</sub> (lbs/bbl)	CO <sub>2</sub> (lbs/bbl)
condensate	10	0.20	1.7	0.23
oil	1.3	0.013	0.26	0.70

Emissions for 2007 were calculated for each county in the Barnett Shale area, using condensate and oil production rates from the RRC.<sup>(5)</sup> Emissions for 2009 were estimated with the extrapolated 2000-2007 production rates for the year 2009. Emissions were calculated with Equation 2,

$$M_{T,i} = E_i * P_c * C / 2000 \quad (2)$$

where  $M_{T,i}$  was the mass emission rate of pollutant  $i$  in tons per year,  $E_i$  was the emission factor for pollutant  $i$  in lbs/bbl,  $P_c$  was the production rate of condensate or oil, and  $C$  was a factor to account for the reduction in emissions due to vapor-emissions controls on some tanks. For this report, the use of vapor-emissions controls on some tanks was estimated to provide a 25% reduction in overall area-wide emissions.

### 3.3 Production Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from production wells vary from well to well depending on many factors, including the tightness of casing heads and fittings, the age and condition of well components, and the numbers of flanges, valves, pneumatic devices, or other components per well. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.<sup>(15)</sup> Fugitive emissions of natural gas from the entire natural gas network were estimated to be 1.4% of gross production. Production fugitives, excluding emissions from condensate tanks (which are covered in another section of this report), were estimated by the GRI/EPA study to be approximately 20% of total fugitives, or 0.28% of gross production.

Production fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.28% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Volume emissions were converted to mass emissions with a density of 0.0483 lb/scf. Multiple Barnett Shale gas producers provided gas composition, heat content data, and area-wide maps of gas composition. The area-wide maps of gas composition were used to estimate gas composition for each producing county. These county-level data were weighted by the fraction of total area production that originated from each county to calculate area-wide emission factors. Table 11 presents the production fugitives emission factors.

**Table 11. Production Fugitives Emission Factors for the Barnett Shale.**

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH <sub>4</sub> (lbs/MMcf)	CO <sub>2</sub> (lbs/MMcf)
11	0.26	99	1.9

Emissions were calculated with Equation 3,

$$M_{F,i} = E_i * P_g / 2000 \quad (3)$$

where  $M_{F,i}$  was the mass emission rate of pollutant  $i$  in tons per year,  $E_i$  was the emission factor for pollutant  $i$  in lbs/MMcf, and  $P_g$  was the production rate of natural and casinghead gas. The area-wide unprocessed natural gas composition based on data from gas producers was 74% CH<sub>4</sub>, 8.2% VOC, 1.4% CO<sub>2</sub>, and 0.20% HAPs, on a mass % basis. HAPs in unprocessed natural gas can include low levels of n-hexane, benzene, or other compounds.

### 3.4 Well Drilling, Hydraulic Fracturing Pump Engines, and Well Completions - Emission Factors and Emission Estimates

Emissions from the diesel engines used to operate well drilling rigs and from the diesel engines that power the hydraulic fracturing pumps were estimated based on discussions with gas producers and other published data. Well drilling engine emissions were based on 25 days of engine operation for a typical well, with 1000 hp of engine capacity, a load factor of 50%, and operation for 12 hours per day. Hydraulic fracturing engine emissions were based on 4.5 days of operation for a typical well, with 1000 hp of capacity, a load factor of 50%, and operation for 12 hours per day. Some well sites in the D-FW are being drilled with electric-powered rigs, with electricity provided off the electrical grid. Engines emission estimates in this report were reduced by 25% to account for the number of wells being drilled without diesel-engine power.

In addition to emissions from drilling and fracing engines, previous studies have examined emissions of natural gas during well completions. These studies include one by the Williams gas company, which estimated that a typical well completion could vent 24,000 Mcf of natural gas.<sup>(18)</sup> A report by the EPA Natural Gas Star program estimated that 3000 Mcf could be produced from typical well completions.<sup>(19)</sup> A report by ENVIRON published in 2006 describes emission factors used in Wyoming and Colorado to estimate emissions from well completions, which were equivalent to 1000 to 5000 Mcf natural gas/well.<sup>(20)</sup> Another report published in the June 2005 issue of the Journal of Petroleum Technology estimated that well completion operations could produce 7,000 Mcf.<sup>(21)</sup> Unless companies bring special equipment to the well site to capture the natural gas and liquids that are produced during well completions, these gases will be vented to the atmosphere or flared.

Discussions with Barnett Shale gas producers that are currently employing “green completion” methods to capture natural gas and reduce emissions during well completions suggests that typical well completions in the Barnett Shale area can release approximately 5000 Mcf of natural gas/well. This value, which is very close to the median value obtained from previous studies (References 18-21), was used to estimate well completion emissions in this report.

The number of completed gas wells reporting to the RRC was plotted for the Feb. 2004 – Feb. 2008 time period.<sup>(22)</sup> A least-squares regression line was fit to the data, and the slope of the line provides the

approximate number of new completions every year. A value of 1042 completions/year was relatively steady throughout the 2004-2008 time period (linear  $R^2 = 0.9915$ ). Emissions in 2007 and 2009 from well completions were estimated using 1000 new well completions/year for each year. Emission estimates were prepared for the entire Barnett Shale area, as well as inside and outside the D-FW metropolitan area. The data from 2004-2008 show that 71 percent of new wells are being installed in the D-FW metropolitan area, 29 percent of new wells are outside the metropolitan area, and the rate of new completions has been steady since 2004. Emissions of VOC, HAPs, CH<sub>4</sub>, and CO<sub>2</sub> were estimated using the same natural gas composition used for production fugitive emissions.

Some gas producers are using green completion techniques to reduce emissions, while others destroy natural gas produced during well completions by flaring. To account for the use of green completions and control by flaring, natural gas emission estimates during well completions were reduced by 25% in this report.

### 3.5 Processing Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from natural gas processing will vary from processing plant to processing plant, depending on the age of the plants, whether they are subject to federal rules such as the NSPS Subpart KKK requirements, the chemical composition of the gas being processed, the processing capacity of the plants, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.<sup>(15)</sup> Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Processing fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 9.7% of total fugitives, or 0.14% of gross production.

Processing fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.14% of the portion of gas production that is processed, estimated as 519 Bcf/yr. Emission factors for VOC, HAPs, CH<sub>4</sub>, and CO<sub>2</sub> were estimated with an area-wide natural gas composition, excluding the gas from areas of the Barnett Shale that does not require any processing. Volume emissions were converted to mass emissions with a natural gas density of 0.0514 lb/scf. Table 12 presents the processing fugitives emission factors.

**Table 12. Processing Fugitives Emission Factors for the Barnett Shale.**

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH <sub>4</sub> (lbs/MMcf)	CO <sub>2</sub> (lbs/MMcf)
14	0.3	45	1.0

Processing fugitive emissions were calculated with Equation 4,

$$M_{P,i} = E_i * P_g / 2000 \quad (4)$$

where  $M_{P,i}$  was the mass emission rate of pollutant  $i$  in tons per year,  $E_i$  was the emission factor for pollutant  $i$  in lbs/MMcf, and  $P_g$  was the production rate of natural and casinghead gas. The composition of the natural gas produced in the Barnett Shale that is processed was estimated to be 65% CH<sub>4</sub>, 1.5% CO<sub>2</sub>, 20% VOC, and 0.48% HAPs, on a mass % basis. Not all natural gas from the Barnett Shale area requires processing.

### 3.6 Transmission Fugitives - Emission Factors and Emission Estimates

Fugitive emissions from the transmission of natural gas will vary depending on the pressure of pipelines, the integrity of the piping, fittings, and valves, the chemical composition of the gas being transported, the tightness of compressor seals and rod packing, the frequency of blow down events, and other factors. A previous study published by the Gas Research Institute and U.S. EPA investigated fugitive emissions from the natural gas industry, including emissions from production wells, processing plants, transmission pipelines, storage facilities, and distribution lines.<sup>(15)</sup> Fugitive emissions of natural gas from the entire natural gas industry were estimated to be 1.4% of gross production. Transmission fugitives, excluding compressor engine exhaust emissions that were previously addressed in this report, were estimated to be approximately 35% of total fugitive emissions, or 0.49% of gross production. Transmission includes the movement of natural gas from the wells to processing plants, and the processing plants to compressor stations. It does not include flow past the primary metering and pressure regulating (M&PR) stations and final distribution lines to customers. Final distribution of gas produced in the Barnett Shale can happen anywhere in the North American natural gas distribution system, and fugitive emissions from these lines are beyond the scope of this report.

Transmission fugitive emissions from Barnett Shale operations in 2007 were estimated as 0.49% of gross natural gas and casinghead gas production of 1098 Bcf/yr. Emission factors for VOC, HAPs, CH<sub>4</sub>, and CO<sub>2</sub> were developed considering that a significant portion of the gas moving through the network does not require processing, while the portion of the gas with higher molecular weight compounds will go through processing. In addition, all gas will have a dry (high methane) composition after processing as it moves to compressor stations and then on to customers. Overall area-wide transmission fugitive emissions were calculated with a gas composition of 76% CH<sub>4</sub>, 5.1% VOC, 1.4% CO<sub>2</sub>, and 0.12% HAPs, by mass %. Table 13 presents the transmission fugitives emission factors.

**Table 13. Transmission Fugitives Emission Factors for the Barnett Shale.**

VOC (lbs/MMcf)	HAPs (lbs/MMcf)	CH <sub>4</sub> (lbs/MMcf)	CO <sub>2</sub> (lbs/MMcf)
12	0.28	175	3.3

Transmission fugitive emissions were calculated with Equation 5,

$$M_{tr,i} = E_i * P_g / 2000 \quad (5)$$

where  $M_{tr,i}$  was the mass emission rate of pollutant  $i$  in tons per year,  $E_i$  was the emission factor for pollutant  $i$  in lbs/MMcf, and  $P_g$  was the production rate of natural and casinghead gas.

## 4.0 RESULTS

### 4.1 Point Sources

#### *i. Compressor Engine Exhausts*

Emissions from compressor engines in the Barnett Shale area are summarized in Tables 14 and 15. Results indicate that engines are significant sources of ozone and particulate matter precursors (NO<sub>x</sub> and VOC), with 2007 emissions of 66 tpd. Emissions of NO<sub>x</sub> are expected to fall 50% from 32 to 16 tpd for engines in the Dallas-Fort Worth metropolitan area because of regulations scheduled to take effect in 2009 and the installation of NSCR units on many engines. Large reductions are unlikely because of the growth in natural gas production. For engines outside the D-FW metropolitan area counties, NO<sub>x</sub> emissions will rise from 19 tpd to 30 tpd because of the projected growth in natural gas production and the fact that engines in these counties are not subject to the same regulations as those inside the metropolitan area.

Emissions of volatile organic compounds are expected to increase from 15 to 21 tpd from 2007 to 2009, because of increasing natural gas production. The 2009 engine regulations for the metropolitan area counties do have the effect of reducing VOC emissions from some engines, but growth in production compensates for the reductions and VOC emissions from engines as a whole increase.

HAP emissions, which include toxic compounds such as formaldehyde and benzene, are expected to increase from 2.7 to 3.6 tpd from 2007 to 2009.

Greenhouse gas emissions from compressor engines are shown in Table 15. Emissions in 2007 as carbon dioxide equivalent tons were approximately 8900 tpd, and emissions are estimated to increase to nearly 14,000 tpd by 2009. Carbon dioxide contributed the most to the greenhouse gas emissions, accounting for approximately 90% of the CO<sub>2</sub> equivalent tons. The methane contribution to greenhouse gases was smaller for the engine exhausts than for the other sources reviewed in this report.

**Table 14. Emissions from Compressor Engine Exhausts.**

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
D-FW Metro Engines	32	13	2.2	35	7261	16	16	2.9	49	11294
Outside Metro Engines	19	2.5	0.45	7.4	1649	30	3.8	0.70	12	2583
<b>Engines Total</b>	<b>51</b>	<b>15</b>	<b>2.7</b>	<b>43</b>	<b>8910</b>	<b>46</b>	<b>19</b>	<b>3.6</b>	<b>61</b>	<b>13877</b>

**Table 15. Greenhouse Gas Emissions Details.**

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	CO2	CH4	N2O	CO2e	CO2	CH4	N2O	CO2e
D-FW Metro Engines	6455	35	0.20	7261	10112	49	0.28	11294
Outside Metro Engines	1475	7.4	0.062	1649	2310	12	0.10	2583
<b>Engines Total</b>	<b>7930</b>	<b>43</b>	<b>0.26</b>	<b>8910</b>	<b>12422</b>	<b>61</b>	<b>0.38</b>	<b>13877</b>

## ii. Oil and Condensate Tanks

Emissions from condensate and oil tanks are shown in Tables 16-1 and 16-2. Annual average emissions are shown in Table 16-1, and peak summer emissions are shown in Table 16-2.

On an annual average, emissions of VOCs from the tanks were 19 tpd in 2007, and emissions will increase to 30 tpd in 2009. Because of the effects of temperature on hydrocarbon liquid vapor pressures, peak summer emissions of VOC were 93 tpd in 2007, and summer emissions will increase to 146 tpd in 2009.

Substantial HAP emissions during the summer were determined for the tanks, with 2007 emissions of 7.2 tpd and 2009 emissions of 11 tpd. Greenhouse gas emissions from the tanks are almost entirely from CH<sub>4</sub>, with a small contribution from CO<sub>2</sub>. Annual average greenhouse gas emissions were 95 tpd in 2007, and will increase to 149 tpd in 2009.

**Table 16. Emissions from Condensate and Oil Tanks.**

Table 16-1. Annual Average Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e
D-FW Metro Tanks	8.9	0.18	2.1	44	14	0.28	3.2	69
Outside Metro Tanks	10	0.21	2.4	51	16	0.32	3.8	80
<b>Tanks Total</b>	<b>19</b>	<b>0.39</b>	<b>4.5</b>	<b>95</b>	<b>30</b>	<b>0.60</b>	<b>7.0</b>	<b>149</b>

Table 16-2. Peak Summer Tank Emissions

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e
D-FW Metro Tanks	43	3.3	6.7	142	67	5.2	10	222
Outside Metro Tanks	50	3.8	7.8	166	79	6.0	12	261
<b>Tanks Total</b>	<b>93</b>	<b>7.2</b>	<b>15</b>	<b>308</b>	<b>146</b>	<b>11</b>	<b>23</b>	<b>483</b>

## 4.2 Fugitive and Intermittent Sources

### i. Production Fugitives

Emissions from fugitive sources at Barnett Shale production sites are shown in Table 17. Production fugitives are significant sources of VOC emissions, with VOC emissions expected to grow from 2007 to 2009 from 17 to 26 tpd. Production fugitives are also very large sources of methane emissions, leading to large CO<sub>2</sub> equivalent greenhouse gas emissions. Greenhouse gas emissions were 3100 tpd in 2007 and will be 4900 tpd in 2009.

**Table 17. Emissions from Production Fugitives.**

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e
D-FW Metro Production Fugitives	11	0.27	102	2147	18	0.43	160	3363
Outside Metro Production Fugitives	5.2	0.12	46	971	8.1	0.19	72	1521
<b>Production Fugitives Total</b>	<b>17</b>	<b>0.40</b>	<b>148</b>	<b>3118</b>	<b>26</b>	<b>0.62</b>	<b>232</b>	<b>4884</b>

## ii. Well Drilling, Hydraulic Fracturing, and Well Completions

Emissions from well drilling engines, hydraulic fracturing pump engines, and well completions are shown in Table 18. These activities are significant sources of the ozone and fine particulate precursors, as well as very large sources of greenhouse gases, mostly from methane venting during well completions.

Greenhouse gas emissions are estimated to be greater than 4000 CO<sub>2</sub> equivalent tons per year. Based on 2000-2007 drilling trends, approximately 71% of the well drilling, fracing, and completion emissions will be coming from counties in the D-FW metropolitan area, with the remaining 29% coming from counties outside the metropolitan area.

**Table 18. Emissions from Well Drilling, Hydraulic Fracturing, and Well Completions.**

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e	NOx	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e
D-FW Metro Well Drilling and Well Completion	3.9	15	0.35	130	2883	3.9	15	0.35	130	2883
Outside Metro Well Drilling and Well Completions	1.6	6.1	0.14	53	1178	1.6	6.1	0.14	53	1178
<b>Well Drilling and Completions Emissions Total</b>	<b>5.5</b>	<b>21</b>	<b>0.49</b>	<b>183</b>	<b>4061</b>	<b>5.5</b>	<b>21</b>	<b>0.49</b>	<b>183</b>	<b>4061</b>

## iii. Natural Gas Processing

Processing of Barnett Shale natural gas results in significant emissions of VOC and greenhouse gases, which are summarized in Table 19. Emissions of VOC were 10 tpd in 2007 and are expected to increase to 15 tpd by 2009. Greenhouse gas emissions, largely resulting from fugitive releases of methane, were approximately 670 tpd in 2007 and will be approximately 1100 tpd in 2009.

**Table 19. Emissions from Natural Gas Processing.**

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e
D-FW Metro Processing Fugitives	6.7	0.16	22	464	10	0.26	35	727
Outside Metro Processing Fugitives	3.0	0.07	10	210	4.7	0.12	16	329
<b>Processing Fugitives Total</b>	<b>10</b>	<b>0.24</b>	<b>32</b>	<b>674</b>	<b>15</b>	<b>0.37</b>	<b>50</b>	<b>1056</b>

## iv. Transmission Fugitives

Transmission of Barnett Shale natural gas results in significant emissions of greenhouse gases and VOC. Greenhouse gas emissions from transmission fugitives are larger than from any other source category except compressor engine exhausts. Emissions of VOC in 2007 from transmission were approximately 18 tpd in 2007 and are estimated to be 28 tpd in 2009. Greenhouse gas emissions from methane fugitives result in emissions of approximately 5500 tpd in 2007 and 8600 tpd in 2009. Emissions are summarized in Table 20.

**Table 20. Emissions from Natural Gas Transmission Fugitives.**

	2007 Pollutant (tpd)				2009 Pollutant (tpd)			
	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e	VOC	HAPs	CH <sub>4</sub>	CO <sub>2</sub> e
D-FW Metro Transmission Fugitives	12	0.29	181	3799	19	0.46	283	5952
Outside Metro Transmission Fugitives	5.5	0.13	82	1718	8.6	0.21	128	2691
<b>Transmission Fugitives Total</b>	<b>18</b>	<b>0.43</b>	<b>262</b>	<b>5517</b>	<b>28</b>	<b>0.67</b>	<b>411</b>	<b>8643</b>

### 4.3 All Sources Emission Summary

Emissions from all source categories in the Barnett Shale area are summarized in Table 21-1 on an annual average basis, and are summarized in Table 12-2 on a peak summer basis. Annual average emissions for 2009 of ozone and particulate precursors (NO<sub>x</sub> and VOC) were approximately 191 tpd, and peak summer emissions of these compounds were 307 tpd. The portion of those emissions originating from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 133 tpd during the summer (Tarrant, Denton, Parker, Johnson, and Ellis).

Estimates of greenhouse gas emissions from the sector as a whole were quite large, with 2009 emissions of approximately 33,000 tpd. The greenhouse gas contribution from compressor engines was dominated by carbon dioxide, while the greenhouse gas contribution from all other sources was dominated by methane. Emissions of HAPs were significant from Barnett Shale activities, with emissions in 2009 of 6.4 tpd in 2009 on an annual average, and peak summer emissions of 17 tpd.

**Table 21. Emissions Summary for All Source Categories.**

Table 21-1. Annual Average Emissions from All Sources.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	19	0.39	4.5	95	0	30	0.60	7.0	149
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
<b>Total Daily Emissions (tpd)</b>	<b>56</b>	<b>100</b>	<b>4.6</b>	<b>673</b>	<b>22375</b>	<b>51</b>	<b>139</b>	<b>6.4</b>	<b>945</b>	<b>32670</b>

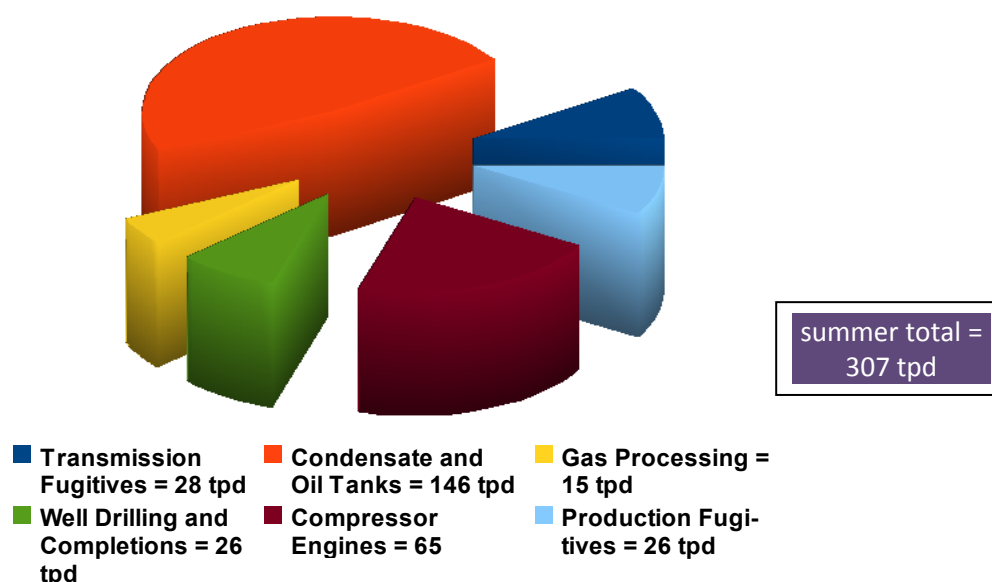
Table 21-2. Peak Summer Emissions from All Sources.

	2007 Pollutant (tpd)					2009 Pollutant (tpd)				
	NOx	VOC	HAPs	CH4	CO2e	NOx	VOC	HAPs	CH4	CO2e
Compressor Engine Exhausts	51	15	2.7	43	8910	46	19	3.6	61	13877
Condensate and Oil Tanks	0	93	7.2	15	308	0	146	11	23	483
Production Fugitives	0	17	0.40	148	3118	0	26	0.62	232	4884
Well Drilling and Completions	5.5	21	0.49	183	4061	5.5	21	0.49	183	4061
Gas Processing	0	10	0.24	32	674	0	15	0.37	50	1056
Transmission Fugitives	0	18	0.43	262	5517	0	28	0.67	411	8643
<b>Total Daily Emissions (tpd)</b>	<b>56</b>	<b>174</b>	<b>11</b>	<b>683</b>	<b>22588</b>	<b>51</b>	<b>255</b>	<b>17</b>	<b>961</b>	<b>33004</b>

Emissions of nitrogen oxides from oil and gas production in the Barnett Shale were dominated by emissions from compressor engines, with a smaller contribution from well drilling and fracing pump engines. All source categories in the Barnett Shale contributed to VOC emissions, but the largest group of VOC sources was condensate tank vents. Figure 6 presents the combined emissions of NO<sub>x</sub> and VOC during the summer from all source categories in the Barnett Shale.



**Figure 6. Summer Emissions of Ozone & Fine Particulate Matter Precursors (NO<sub>x</sub> and VOC) from Barnett Shale Sources in 2009.**



#### 4.4 Perspective on the Scale of Barnett Shale Air Emissions

Barnett Shale oil and gas production activities are significant sources of air emissions in the north-central Texas area. To help put the levels of Barnett Shale emissions into context, recent government emissions inventories for the area were reviewed, and emission rates of smog precursor emissions were examined.

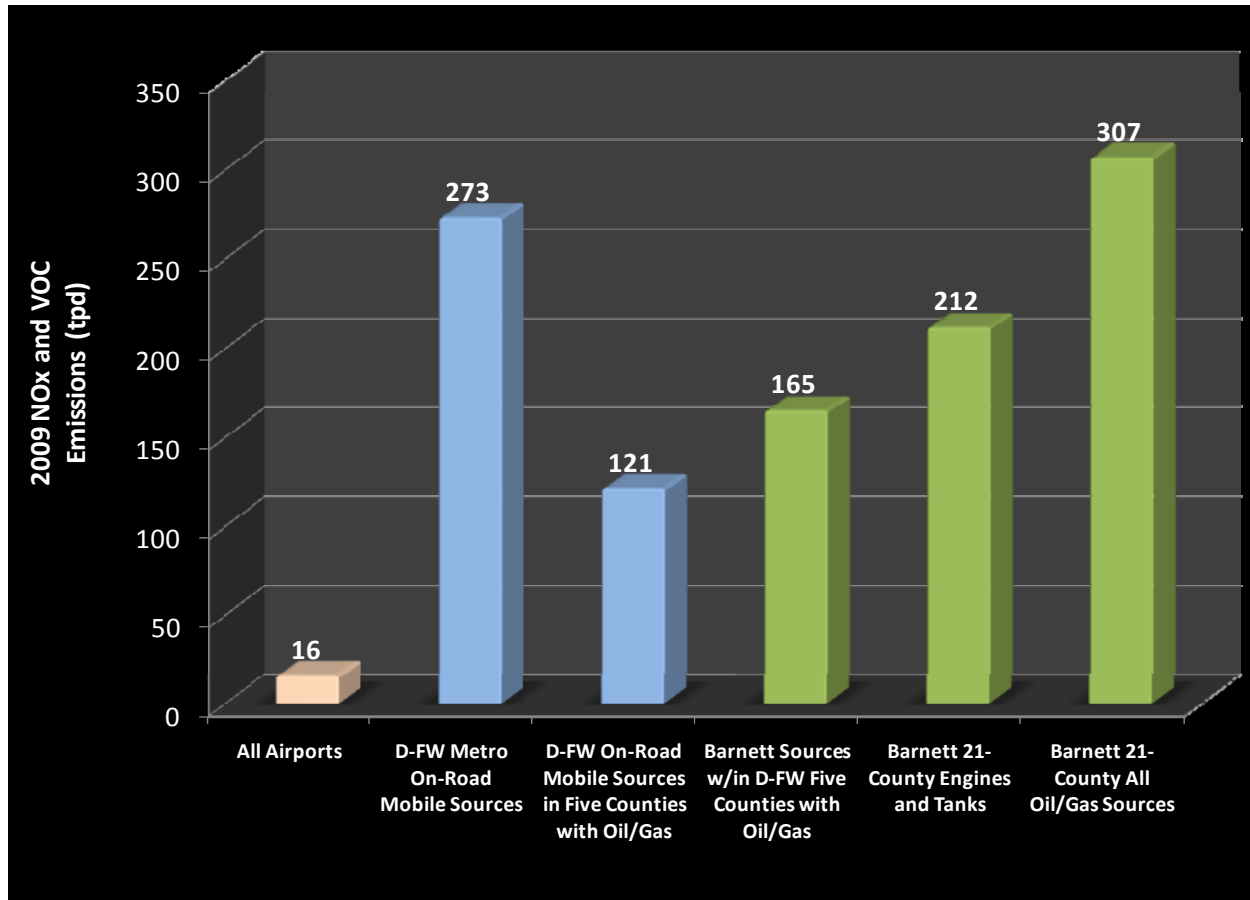
The Dallas-Fort Worth area is home to two large airports, Dallas Love Field and Dallas-Fort Worth International Airport, plus a number of smaller airports. A recent emissions inventory has estimated 2009 NO<sub>x</sub> emissions from all area airports to be approximately 14 tpd, with VOC emissions at approximately 2.6 tpd, resulting in total ozone and particulate matter precursor emissions of approximately 16 tpd.<sup>(22-24)</sup> For comparison, emissions of VOC + NO<sub>x</sub> in summer 2009 from just the compressor engines in the Barnett Shale area will be approximately 65 tpd, and summer condensate tanks emissions will be approximately 146 tpd. In 2009, even after regulatory efforts to reduce NO<sub>x</sub> emissions from certain compressor engine types, Barnett Shale oil and gas emissions will be many times the airports' emissions.

Recent state inventories have also compiled emissions from on-road mobile sources like cars, trucks, etc., in the 9-county D-FW metropolitan area.<sup>(25)</sup> By 2009, NO<sub>x</sub> + VOC emissions from mobile sources in the 9-county area were estimated by the TCEQ to be approximately 273 tpd. The portion of on-road motor vehicle emissions from the 5-counties in the D-FW metropolitan area with significant oil and gas production was 121 tpd (Denton, Tarrant, Parker, Johnson, and Ellis). As indicated earlier, summer oil and gas emissions in the 5-counties of the D-FW metropolitan area with significant oil and gas production was estimated to be 165 tpd, indicating that the oil and gas sector likely has greater emissions than motor vehicles in these counties (165 vs. 121 tpd).

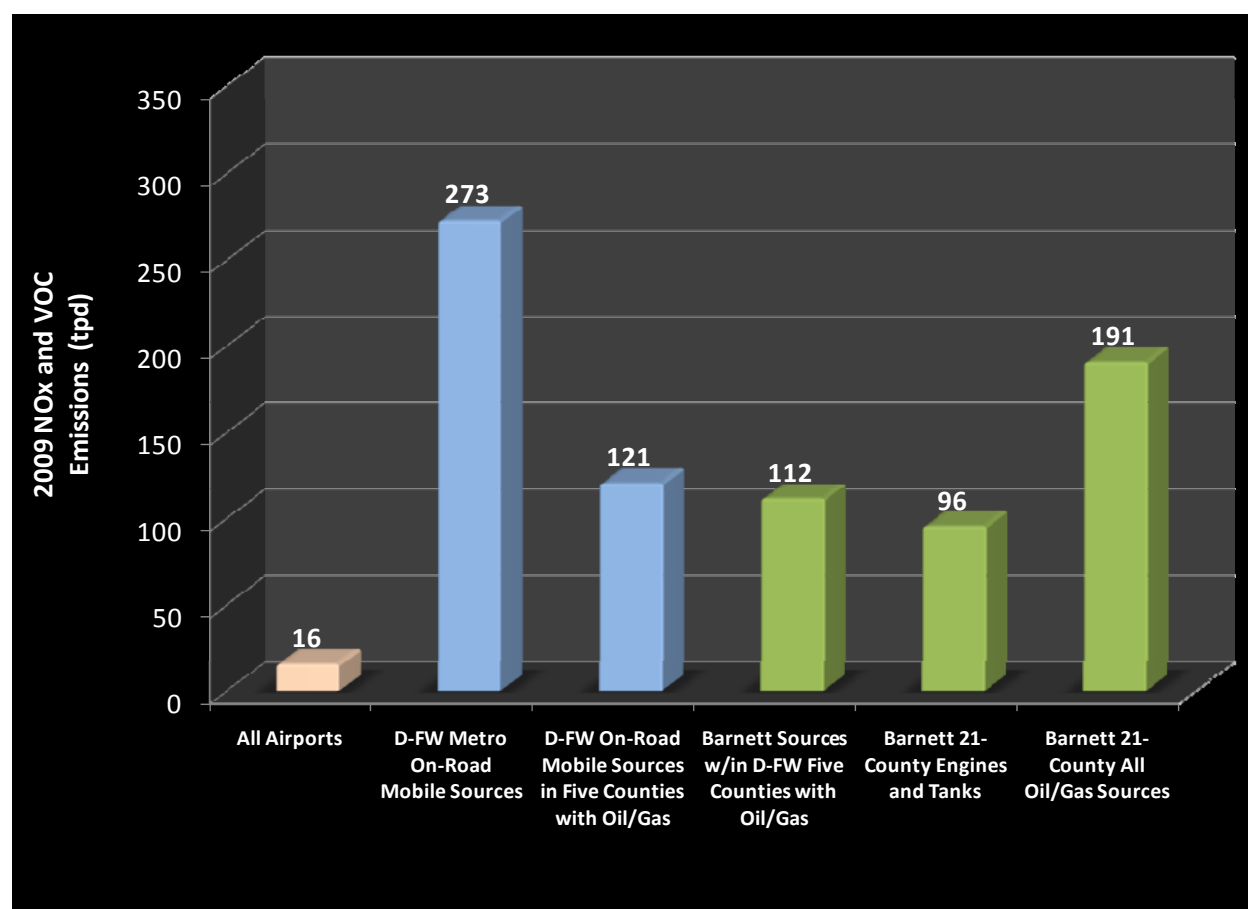
Emissions of NO<sub>x</sub> and VOC in the summer of 2009 from all oil and gas sources in the Barnett Shale 21-county area will exceed emissions from on-road mobile sources in the D-FW metropolitan area by more than 30 tpd (307 vs. 273 tpd).

Figure 7 summarizes summer Barnett Shale-related emissions, plus TCEQ emission estimates from the airports and on-road mobile sources. Figure 8 presents annual average emissions from these sources.

**Figure 7. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Summer 2009 Emissions).**



**Figure 8. Barnett Shale Activity, D-FW Area Airports, & Mobile Sources (Annual Average 2009 Emissions).**



## 5.0 EMISSIONS REDUCTION OPPORTUNITIES

The previous sections of this report have estimated the emission rates of ozone and particulate matter precursor compounds, air toxic compounds, and greenhouse gases from different oil and gas sources in the Barnett Shale area. For several of these source categories, off-the-shelf options are available which could significantly reduce emissions, resulting in important air quality benefits. Some of these emissions reductions would also result in increased production of natural gas and condensate, providing an economic payback for efforts to reduce emissions.

### 5.1 Compressor Engine Exhausts

Compressors in oil and gas service in the Barnett Shale perform vital roles, to either help get oil and gas out of the shale, to increase pressures of gas at the surface, and to provide the power for the large interstate pipeline systems that move high volumes of gas from production to processing and to customers. At present, most of the work to operate the compressors comes from natural gas-fired internal combustion engines, and these engines can be significant sources of emissions.

New TCEQ rules are scheduled to become effective in early 2009 and they will reduce NO<sub>x</sub>, VOC, and other emissions from a subset of the engines in the Barnett Shale – those that are currently in the D-FW metropolitan area that had typically not reported into the Texas point source emissions inventory for major sources. These rules are a good first step in addressing emissions from these sources, which had previously gone unnoticed in state emission inventory and regulatory efforts.

However, engines outside the D-FW metropolitan area are not subject to the rule. And even within the metropolitan area, the rule will not have the effect of greatly reducing emissions in 2009 compared to 2007 levels, since growth in oil and gas production (and the new engines that are going to be required to power the growth) will begin to overtake the benefits that come from reducing emissions from the pre-2009 fleet (see Table 14).

Two available options for reducing emissions from engines in the Barnett Shale area are: (1) extending the TCEQ 2009 engine regulation to all engines in the Barnett Shale, and (2) replacing internal combustion engines with electric motors as the sources of compression power.

#### *i. Extending the 2009 Engine Rule to Counties Outside the D-FW Metropolitan Area*

Regulations adopted by TCEQ for the D-FW metropolitan area and scheduled to take effect in early 2009 will limit NO<sub>x</sub> emissions from engines larger than 50 horsepower.<sup>(7)</sup> Rich burn engines will be restricted to 0.5 g/hp-hr, lean burn engines installed or moved before June 2007 will be restricted to 0.7 g/hp-hr, and lean burn engines installed or moved after June 2007 will be limited to 0.5 g/hp-hr. Applying these rules to engines outside the metropolitan area would reduce 2009 NO<sub>x</sub> emissions from a large number of engines, in particular, rich burn engines between 50 to 500 hp. Emissions of NO<sub>x</sub> in 2009 from the engines outside the metropolitan area would drop by approximately 6.5 tpd by extending the D-FW engine rule, an amount greater than mobile source emissions in all of Johnson County (4 tpd), or more than 50% of the emissions from Dallas-Fort Worth International Airport (12.6 tpd).

Extending the D-FW engine rule to counties outside the metropolitan area would likely result in many engine operators installing NSCR systems on rich burn engine exhausts. These systems would not only reduce emissions of NO<sub>x</sub>, but they would also be expected to reduce emissions of VOC, the other ozone and particulate matter precursor, by approximately 75% or greater.<sup>(26a)</sup> Additional co-benefits of NSCR installations would include lower emissions of organic HAP compounds like benzene and formaldehyde, lower emissions of methane, and lower emissions of carbon monoxide. The level of HAP, methane, and

carbon monoxide control would also be expected to be 75% or greater with typical NSCR installations.<sup>(26a)</sup>

Analyses of NSCR installations and operating costs by numerous agencies have indicated that the technology is very cost effective. For example, the Illinois Environmental Protection Agency estimated in 2007 that NSCR could control NO<sub>x</sub> from 500 hp engines at approximately \$330/ton.<sup>(26b)</sup> The U.S. EPA in 2006 estimated that NSCR could control NO<sub>x</sub> from 500 hp engines at approximately \$92 to 105/ton.<sup>(27)</sup> A 2005 report examining emissions reductions from compressor engines in northeast Texas estimated NO<sub>x</sub> cost effectiveness for NSCR at \$112-183/ton and identified VOC reductions as an important co-benefit.<sup>(28)</sup> These costs are well under the cost effectiveness values of \$10,000 to \$20,000 per ton often used as upper limits in PM<sub>2.5</sub>, ozone, and regional haze (visibility) regulatory programs. The simultaneous HAPs and methane removal that would occur with NSCR use provide further justification for extending the D-FW engine rule to counties outside the metropolitan area.

## *ii. Electric Motors Instead of Combustion Engines for Compressor Power*

When considering NO<sub>x</sub>, VOC, HAPs, and greenhouse gas emissions from compressor engines, it is important to understand that the work to move the gas in the pipelines is performed by the compressors, which by themselves produce no direct combustion emissions. The emissions come from the exhaust of the internal combustion engines, which are fueled with a small amount of the available natural gas. These engines provide the mechanical power to run the compressors. The 2007 TCEQ engine survey and the most recent point source emissions inventory indicate that installed compressor engine capacity throughout the Barnett Shale was approximately 1,400,000 hp in 2007, and capacity is likely to increase to over 2,100,000 hp by 2009.

As an alternative to operating the compressors in the Barnett Shale with millions of hp of natural gas burning-engines, the compressors could be operated with electrically-driven motors. The electrification of the wellhead and compressor station engine fleet in the Barnett Shale area has the potential to deliver significant reductions in emissions in North Central Texas. The use of electric motors instead of internal combustion engines to drive natural gas compressors is not new to the natural gas industry, and numerous compressors driven by electric motors are operational throughout Texas. Unfortunately, current regulations have not yet required their use in the Barnett Shale.

A few of the many examples of electrically-driven natural gas compressors, positive technical assessments, and industrial experience with their use in Texas and throughout the U.S., include:

- The Interstate Natural Gas Association of America: "One advantage of electric motors is they need no air emission permit since no hydrocarbons are burned as fuel. However, a highly reliable source of electric power must be available, and near the station, for such units to be considered for an application."<sup>(29)</sup>
- The Williams natural gas company: "The gas turbine and reciprocating engines typically use natural gas from the pipeline, where the electric motor uses power from an electric transmission line. Selection of this piece of equipment is based on air quality, available power, and the type of compressor selected. Typically electric motors are used when air quality is an issue."<sup>(30)</sup>
- JARSCO Engineering Corp.: "The gas transmission industry needs to upgrade equipment for more capacity. The new high-speed electric motor technology provides means for upgrading, at a fraction of the life cycle costs of conventional gas powered equipment."<sup>(31)</sup>
- Pipeline and Gas Journal, June 2007: "Important factors in favor of electric-driven compressor stations that should be considered in the feasibility analysis include the fact that the fuel gas for

gas turbine compressor stations will be transformed into capacity increase for the electrically-driven compressor station, and will therefore add revenue to this alternative..."<sup>(32)</sup>

- Prime mover example: Installations in 2007 at Kinder Morgan stations in Colorado of +10,000 hp electric-driven compressor units.<sup>(33)</sup>
- Wellhead example: Installations in Texas of wellhead capacity (5 to 400 hp) electrically-driven compressors.<sup>(34,35)</sup>
- Mechanical Engineering Magazine, December 1996: "Gas pipeline companies historically have used gas-fired internal-combustion engines and gas turbines to drive their compressors. However, this equipment emits nitrogen oxides....According to the Electric Power Research Institute, it is more efficient to send natural gas to a combined-cycle power plant to generate electricity transmitted back to the pipeline compressor station than to burn the natural gas directly in gas-fired compressor engines."<sup>(36)</sup>
- The Dresser-Rand Corporation: "New DATUM-C electric motor-driven compressor provides quiet, emissions free solution for natural gas pipeline applications – An idea whose time had come."<sup>(37)</sup>
- Occidental Oil and Gas Corporation: "Converting Gas-Fired Wellhead IC Engines to Electric Motor Drives: Savings \$23,400/yr/unit."<sup>(38)</sup>

The use of an electric motor instead of a gas-fired engine to drive gas compression eliminates combustion emissions from the wellhead or compressor station. Electric motors do require electricity from the grid, and in so far as electricity produced by power plants that emits pollutants, the use of electric motors is not completely emissions free. However, electric motor use does have important environmental benefits compared to using gas-fired engines.

Modern gas-fired internal-combustion engines have mechanical efficiencies in the 30-35% range, values that have been relatively static for decades. It is doubtful that dramatic increases in efficiency (for example, to 80 or 90%) are possible anytime in the near future. This means that carbon dioxide emissions from natural gas-fired engines at wellheads and compressor stations are not likely to drop substantially because of efficiency improvements. In addition, the scrubbing technology that is used in some large industrial applications to separate CO<sub>2</sub> from other gases also is unlikely to find rapid rollout to the thousands of comparatively-smaller exhaust stacks at natural gas wellheads and compressor stations. The two facts combined suggest that the greenhouse gas impacts from using internal combustion engines to drive compressors are likely to be a fixed function of compression demand, with little opportunity for large future improvements.

In contrast, the generators of grid electric power are under increasing pressure to lower greenhouse gas emissions. Wind energy production is increasing in Texas and other areas. Solar and nuclear power projects are receiving renewed interest from investors and regulators. As the electricity in the grid is produced by sources with lower carbon dioxide emissions, so then the use of electric motors to drive natural gas pipelines becomes more and more climate friendly.

Stated another way, carbon dioxide emissions from gas-fired engines are unlikely to undergo rapid decreases in coming years, whereas the electricity for operating electric motors is at a likely carbon-maximum right now. Electric-powered compression has a long-term potential for decreased climate impact, as non-fossil fuel alternatives for grid electricity generation expand in the future.

Costs: Estimates were made of the costs were switching from IC engines to electric motors for compression. Costs at sites in the Barnett Shale are highly time and site specific, depending on the cost of electricity and the value of natural gas, the numbers of hours of operation per year, the number and sizes of compressors operated, and other factors.

For this report, sample values were determined for capital, operating and maintenance, and operating costs of 500 hp of either IC engine capacity or electric motor capacity for a gas compressor to operate for 8000 hours per year at a 0.55 load factor. Electric power costs were based on \$8/month/kW demand charge, \$0.08/kWh electricity cost, and 95% motor mechanical efficiency. Natural gas fuel costs were based on \$7.26/MMBtu wellhead natural gas price and a BSFC of 0.0085 MMBtu/hp-hr.

With these inputs, the wellhead value of the natural gas needed to operate a 500 hp compressor with an IC engine for 1 year is approximately \$136,000. This is lower than the costs for electricity to run a comparable electric motor, which would be approximately \$174,000. In addition to these energy costs, it is important to also consider operating and maintenance (O&M) and capital costs. With an IC engine O&M cost factor of \$0.016/hp in 2009 dollars, O&M costs would be approximately \$35,000. With an electric motor O&M cost factor of \$0.0036/kWh in 2009 dollars, O&M costs would be approximately \$6200, providing a savings of nearly \$30,000 per year in O&M costs for electrical compression, nearly enough to compensate for the additional energy cost incurred from the additional price premium on electricity in Texas compared to natural gas.

With an IC engine capital cost factor of \$750/hp in 2009 dollars, the cost of a 500 hp compressor engine would be approximately \$370,000. With an electric motor cost factor of \$700/kW, the cost of 500 hp of electrically-powered compression would be approximately \$260,000.

The combined energy (electricity or natural gas), O&M, and capital costs for the two options are shown in Table 22, assuming a straight 5-year amortization of capital costs. The data show that there is little cost difference in this example, with a slight cost benefit of around \$12,000/year for generating the compression power with an electric motor instead of an IC engine. While this estimate would vary from site to site within the Barnett Shale, there appears to be cost savings, driven mostly by reduced initial capital cost, in favor of electrical compression in the Barnett Shale. In addition to the potential cost savings of electrical compression over engine compression, the lack of an overwhelming economic driver one way or the other allows the environmental benefits of electric motors over combustion engines to be the deciding factor on how to provide compression power in the area.

**Table 22. Costs of IC Engine and Electric Motor Compression  
[example of 500 hp installed capacity].**

	IC Engine (\$/year)	Electric Motor (\$/year)
energy (NG or electricity)	136,000	174,000
O&M	35,000	6,200
capital	74,000	52,000
<b>Total</b>	<b>245,000</b>	<b>232,000</b>

## 5.2 Oil and Condensate Tanks

Oil and condensate tanks in the Barnett Shale are significant sources of multiple air pollutants, especially VOC, HAPs, and methane. Multiple options exist for reducing emissions from oil and condensate tanks, including options that can result in increased production and revenue for well operators.<sup>(14)</sup> This section will discuss two of these options: flares and vapor recovery units.

### *i. Vapor Recovery Units*

Vapor recovery units (VRU) can be highly effective systems for capturing and separating vapors and gases produced by oil and condensate tanks. Gases and vapors from the tanks are directed to the inlet side of a compressor, which increases the pressure of the mixture to the point that many of the moderate and higher molecular weight compounds recondense back into liquid form. The methane and other light gases are directed to the inlet (suction) side of the well site production compressors to join the main flow of natural gas being produced at the well. In this way, VRU use increases the total production of gas at the well, leading to an increase in gas available for metering and revenue production. In addition, liquids produced by the VRU are directed back into the liquid phase in the condensate tank, increasing condensate production and the income potential from this revenue stream. Vapor recovery units are estimated to have control efficiencies of greater than 98%.<sup>(14)</sup>

The gases and vapors emitted by oil and condensate tanks are significant sources of air pollutants, and the escape of these compounds into the atmosphere also reduces income from hydrocarbon production. With a wellhead value of approximately \$7/MMBtu, the 7 tpd of methane that is estimated to be emitted in 2009 from condensate tanks in the Barnett Shale have a value of over \$800,000 per year. Even more significantly, a price of condensate at \$100/bbl makes the 30 tpd of VOC emissions in 2009 from the tanks in the Barnett Shale potentially worth over \$10 million per year.

While flaring emissions from tanks in the Barnett Shale would provide substantial environmental benefits, especially in terms of VOC and methane emissions, capturing these hydrocarbons and directing them into the natural gas and condensate distribution systems would provide both an environmental benefit and a very large potential revenue stream to oil and gas producers.

### *ii. Enclosed Flares*

Enclosed flares are common pollution control and flammable gas destruction devices. Enclosed flares get their name because the flame used to ignite the gases is generated by burner tips installed within the stack well below the top. The flames from enclosed flares are usually not visible from the outside, except during upset conditions, making them less objectionable to the surrounding community compared to open (unenclosed) flares.

Using a flare to control emissions from tanks involves connecting the vents of a tank or tank battery to the bottom of the flare stack. The vapors from oil and condensate tanks are sent to the flare, and air is also added to provide oxygen for combustion. The vapors and air are ignited by natural gas pilot flames, and much of the HAP, VOC, and methane content of the tank vapors can be destroyed. The destruction efficiency for flares can vary greatly depending on residence time, temperature profile, mixing, and other factors. Properly designed and operated flares have been reported to achieve 98% destruction efficiencies.

Applying 98% destruction efficiency to the Barnett Shale oil and condensate tanks emissions estimates shown in Table 16 results in potential emission reductions of 30 tpd of VOC, 0.6 tpd of HAPs, and 7 tpd of methane. These reductions are substantial and would provide large benefits to the ozone and PM precursor, HAPs, and greenhouse gas emission inventory of the Barnett Shale area. The use of flares,



however, also has several drawbacks. One of these is that tank vapor flares need a continuous supply of pilot light natural gas, and reports have estimated pilot light gas consumption at around 20 scfh/flare.<sup>(14)</sup>

Table 23 presents a summary of the results of an economic analysis performed in 2006 by URS Corporation for using flares or vapor recovery units to control emissions from a tank battery in Texas.<sup>(14)</sup> Capital costs were estimated by URS with a 5-year straightline amortization of capital. Flow from the tank battery was 25Mscf/day and VOC emissions were approximately 211 tpy. Costs were in 2006 dollars.

**Table 23. Economics of Flares and Vapor Recovery Units.**

Control Option	Total Installed Capital Cost (\$)	Annual Installed Operating Cost (\$/yr)	Operating Cost (\$/yr)	Value Recovered (\$/yr)	VOC Destruction Cost Effectiveness (\$/ton VOC)
Enclosed Flare	40,000	8000	900	NA	40
VRU	60,000	12000	11,400	91,300	(\$320)*

\*VRU produces positive revenue, resulting in zero cost for VOC control, after accounting for value of recovered products.

The URS analysis indicated that flares were able to cost effectively reduce VOC emissions at \$40/ton, while VRU units produced no real costs and quickly generated additional revenue from the products recovered by VRU operation. There was a less-than 1 year payback on the use of a VRU system, followed by years of the pollution control device becoming steady revenue source.

### 5.3 Well Completions

Procedures have been developed to reduce emissions of natural gas during well completions. These procedures are known by a variety of terms, including "the green flowback process" and "green completions."<sup>(39,40)</sup> To reduce emissions, the gases and liquids brought to the surface during the completion process are collected, filtered, and then placed into production pipelines and tanks, instead of being dumped, vented, or flared. The gas cleanup during a "green" completion is done with special temporary equipment at the well site, and after a period of time (days) the gas and liquids being produced at the well are directed to the permanent separators, tanks, and piping and meters that are installed at the well site. Green completion methods are not complex technology and can be very cost effective in the Barnett Shale. The infrastructure is well-established and gathering line placement for the initial collection of gas is not a substantial risk since wells are successfully drilled with a very low failure rate.

Emissions during well completions depend on numerous site-specific factors, including the pressure of the fluids brought to the surface, the effectiveness of on-site gas capturing equipment, the control efficiency of any flaring that is done, the chemical composition of the gas and hydrocarbon liquids at the drill site, and the duration of drilling and completion work before the start of regular production.

Some recent reports of the effectiveness of green completions in the U.S. are available, including one by the U.S. EPA which estimated 70% capture of formerly released gases with green completions, and another report by Williams Corporation which found that 61% to 98% of gases formerly released during well completions were captured with green completions.<sup>(40-41)</sup> Barnett Shale producer Devon Energy is using green completions on its wells, and they reported \$20 million in profits from natural gas and condensate recovered by green completed wells in a 3 year period.<sup>(42)</sup>

If green completion procedures can capture 61% to 98% of the gases formerly released during well completions, the process would be a more environmentally friendly alternative to flaring of the gases, since flaring destroys a valuable commodity and prevents its beneficial use. Green completions would also certainly be more beneficial than venting of the gases, since this can release very large quantities of

methane and VOCs to the atmosphere. Another factor in favor of capturing instead of flaring is that flaring can produce carbon dioxide (a greenhouse gas), carbon monoxide, polycyclic aromatic hydrocarbons, and particulate matter (soot) emissions.

#### 5.4 Fugitive Emissions from Production Wells, Gas Processing, and Transmission

Fugitive emissions from the production wells, gas processing plants, gas compressors, and transmission lines in the Barnett Shale can be minimized with aggressive efforts at leak detection and repair. Unlike controlling emissions from comparatively smaller numbers of engines or tanks (numbering in the hundreds or low thousands per county), fugitive emissions can originate from tens of thousands of valves, flanges, pump seals, and numerous other leak points. While no single valve or flange is likely to emit as much pollution as a condensate tank or engine exhaust stack, the cumulative mass of all these fugitives can be substantial. There are readily-available measures that can reduce fugitive emissions.

##### *i. Enhanced Leak Detection and Repair Program*

The federal government has established New Source Performance Standards for natural gas processing plants a.k.a. NSPS Subpart KKK.<sup>(43)</sup> These standards require regularly scheduled leak detection, and if needed, repair activities for items such as pumps, compressors, pressure-relief valves, open-ended lines, vapor recovery systems, and flares. The NSPS applies to plants constructed or modified after January 20, 1984. The procedures and standards in the processing plant NSPS are generally based on the standards developed for the synthetic organic manufacturing chemicals industry.<sup>(44)</sup>

Fugitive emissions from oil and gas wells, separators, tanks, and metering stations are not covered by the processing plant NSPS. Nonetheless, the leak detection and repair protocols established in the NSPS could certainly be used to identify fugitive emissions from these other items. Leak detection at processing plants covered by the NSPS is performed using handheld organic vapor meters (OVMs), and inspections are required to be done on a specified schedule. These same procedures could be used at every point along the oil and gas system in the Barnett Shale to identify and reduce emissions of VOCs and methane. Doing so would reduce emissions, and by doing so, increase production and revenue to producers.

It is difficult to estimate the exact degree of emission reductions that are possible with fugitive emission reduction programs. The large and varied nature of fugitive emission points (valves, fittings, etc.) at production wells, processing plants, and transmission lines means that each oil and gas related facility in the Barnett Shale will have different options for reducing fugitive emissions. In general, leak detection and repair programs can help identify faulty units and greatly reduce their emissions.

##### *ii. Eliminating Natural Gas-Actuated Pneumatic Devices*

The State of Colorado is currently adopting and implementing VOC control strategies to reduce ambient levels of ozone in the Denver metropolitan area and to protect the numerous national parks and wilderness areas in the state. As part of this effort, the state investigated the air quality impacts of oil and gas development, including the impacts of the pneumatically-controlled valves and other devices that are found throughout gas production, processing, and transmission systems. The State of Colorado confirmed the basic conclusions arrived at earlier by EPA and GRI in 1995, that these pneumatic devices can be substantial sources of CH<sub>4</sub>, VOC, and HAP emissions.<sup>(45,46)</sup> Much of the following information on these devices and the strategies to control emissions is based on a review of the recent work in Colorado.

Valves and similar devices are used throughout the oil and gas production, processing, and transmission systems to regulate temperature, pressure, flow, and other process parameters. These devices can be operated mechanically, pneumatically, or electrically. Many of the devices used in the natural gas sector

are pneumatically operated. Instrument air (i.e. compressed regular air) is used to power pneumatic devices at many gas processing facilities, but most of the pneumatic devices at production wells and along transmission systems are powered by natural gas.<sup>(46)</sup> Other uses of pneumatic devices are for shutoff valves, for small pumps, and with compressor engine starters.

As part of normal operation, most pneumatic devices release or “bleed” gas to the atmosphere. The release can be either continuously or intermittently, depending on the kind of device. In 2003 U.S. EPA estimated that emissions from the pneumatic devices found throughout the production, processing, and transmission systems were collectively one of the largest sources of methane emissions in the natural gas industry. Some U.S. natural gas producers have reduced natural gas emissions significantly by replacing or retrofitting “high-bleed” pneumatic devices. High-bleed pneumatic devices emit at least 6 standard cubic feet gas per hour.<sup>(46)</sup> Actual field experience is demonstrating that up to 80 percent of all high-bleed devices in natural gas systems can be replaced or retrofitted with low-bleed equipment.

The replacement of high-bleed pneumatic devices with low-bleed or no-bleed devices can reduce natural gas emissions to atmosphere by approximately 88 or 98 percent, respectively.<sup>(21, 47)</sup> Anadarko Petroleum Corporation estimated that VOC emissions from their pneumatic devices will be reduced by 464 tpy once 548 of their pneumatic controllers are retrofitted in Colorado.<sup>(46)</sup>

It may not be possible, however, to replace all high-bleed devices with low or no bleed alternatives. In the state of Colorado, it was estimated that perhaps up to 20 percent of high-bleed devices could not be retrofitted or replaced with low-bleed devices. Some of these included very large devices requiring fast and/or precise responses to process changes which could not yet be achieved with low-bleed devices.

But even for these devices that appear to require high-bleed operation, alternatives are available. Natural gas emissions from both high bleed and low bleed devices can be reduced by routing pneumatic discharge ports into a fuel gas supply line or into a closed loop controlled system. Another alternative is replacing the natural gas as the pneumatic pressure fluid with pressurized air. Instrument pressurized air systems are sometimes installed at facilities that have a high concentration of pneumatic devices, full-time operator presence, and are on a power grid. In an instrument pressurized air system, atmospheric air is compressed, stored in a volume tank, filtered, and dried. The advantage of a pressurized air system for operating pneumatic devices is that operation is the same whether they air or natural gas is used. Existing pneumatic gas supply piping, control instruments, and valve actuators can be reused when converting from natural gas to compressed air.

The U.S. EPA runs a voluntary program, EPA Natural Gas STAR, for companies adopting strategies to reduce their methane emissions. Experience from companies participating in the program indicates that strategies to reduce emissions from pneumatic devices are highly cost effective, and many even pay for themselves in a matter of months.<sup>(46)</sup> EPA reports that one company replaced 70 high-bleed pneumatic devices with low-bleed devices and retrofitted 330 high-bleed devices, which resulted in an emission reduction of 1,405 thousand cubic meters per year. At \$105/m<sup>3</sup>, this resulted in a savings of \$148,800 per year. The cost, including materials and labor for the retrofit and replacement, was \$118,500, and therefore, the payback period was less than one year. Early replacement (replacing prior to projected end-of-service-life) of a high-bleed valve with a low-bleed valve is estimated to cost \$1,350. Based on \$3/m<sup>3</sup> gas, the payback was estimated to take 21 months. For new installations or end of service life replacement, the incremental cost difference of high-bleed devices versus low-bleed devices was \$150 to \$250. Based on \$3 per Mcf gas, the payback was estimated to take 5 to 12 months.<sup>(46)</sup>

Overall, cost-effective strategies are available for reducing emissions and enhance gas collection from pneumatic devices in Barnett Shale area operations. These strategies include:

- Installing low- or no-bleed pneumatic devices at all new facilities and along all new transmission lines;
- Retrofitting or replacing existing high-bleed pneumatic devices with low- or no-bleed pneumatic devices;
- Ensuring that all natural gas actuated devices discharge into sales lines or closed loops, instead of venting to the atmosphere;
- Using pressurized instrument air as the pneumatic fluid instead of natural gas.

## 6.0 CONCLUSIONS

Oil and gas production in the Barnett Shale region of Texas has increased rapidly over the last 10 years. The great financial benefits and natural resource production that comes from the Barnett Shale brings with it a responsibility to minimize local, regional, and global air quality impacts. This report examined emissions of smog forming compounds, air toxic compounds, and greenhouse gases from oil and gas activity in the Barnett Shale area, and identified methods for reducing emissions.

Emissions of ozone and fine particle smog forming compounds (NO<sub>x</sub> and VOC) will be approximately 191 tons per day on an annual average basis in 2009. During the summer, VOC emissions will increase, raising the NO<sub>x</sub> + VOC total to 307 tpd, greater than the combined emissions from the major airports and on-road motor vehicles in the D-FW metropolitan area.

Emissions in 2009 of air toxic compounds from Barnett Shale activities will be approximately 6 tpd on an annual average, with peak summer emissions of 17 tpd.

Emissions of greenhouse gases like carbon dioxide and methane will be approximately 33,000 CO<sub>2</sub> equivalent tons per day. This is roughly comparable to the greenhouse gas emissions expected from two 750 MW coal-fired power plants.

Cost effective emission control methods are available with the potential to significantly reduce emissions from many of the sources in the Barnett Shale area, including

- the use of "green completions" to capture methane and VOC compounds during well completions,
- phasing in of electric motors as an alternative to internal-combustion engines to drive gas compressors,
- the control of VOC emissions from condensate tanks with vapor recovery units, and
- replacement of high-bleed pneumatic valves and fittings on the pipeline networks with no-bleed alternatives.

Large reductions in greenhouse gas emissions could be achieved through the use of green completion methods on all well completions, with the potential to eliminate almost 200 tpd of methane emissions while increasing revenue for producers by recovering saleable gas. In addition, the replacement of internal combustion engines with electric motors for compression power could reduce smog-forming emissions in the D-FW metropolitan area by 65 tpd. Significant emission reductions could also be achieved with the use of vapor recovery units on oil and condensate tanks, which could eliminate large amounts of VOC emissions. Vapor recovery units on condensate tanks would pay for themselves in a matter of months by generating additional revenue to producers from the gas and condensate that would be captured instead of released to the atmosphere. Fugitive emissions of methane, VOC, and HAPs could be reduced with a program to replace natural gas actuated pneumatic valves with units actuated with compressed air. For those devices in locations where compressed air is impractical to implement, connection of the bleed vents of the devices to sales lines also could greatly reduce emissions.

There are significant opportunities available to improve local and regional air quality and reduce greenhouse gas emissions by applying readily available methods to oil and gas production activities in the Barnett Shale.

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45. ENVIRON International Corporation, "Development of Baseline 2006 Emissions from Oil and Gas Activity in the Denver-Julesburg Basin." a report prepared for the Colorado Department of Public Health and Environment. April 30, 2008.

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on-line document:

<http://www.cdphe.state.co.us/ap/ozone/RegDevelop/IssuePapers/April4-08/APCDOZISSUEPAPERpneumaticdevicesRev1.pdf>

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on-line document:

[http://www.wrapair.org/forums/ssjf/documents/eiccts/OilGas/2007-10\\_Phase\\_II\\_O&G\\_Final\)Report\(v10-07%20rev.s\).pdf](http://www.wrapair.org/forums/ssjf/documents/eiccts/OilGas/2007-10_Phase_II_O&G_Final)Report(v10-07%20rev.s).pdf)

*Author's Notes:*

*A draft version of this report was prepared in September 2008 and distributed for review and comment to oil and gas producers, state and federal regulators, authors of some of the references used in this report, and others. The author appreciates the comments received by those reviewers and the time they took to provide feedback. For the purpose of full disclosure, the author notes that he was an employee with Radian International LLC working on projects for several gas industry clients, including the Gas Research Institute and gas pipeline companies, during the time that "Methane Emissions from the Natural Gas Industry" (Reference 15) was published. The authors of Reference 15 were also employees of Radian International LLC, working as contractors for the Gas Research Institute and the Environmental Protection Agency. The author of this study notes that he did not work on or participate in the GRI/EPA project performed by the other Radian International personnel.*

*Images on the cover page from the Texas Railroad Commission and the U.S. Department of Energy.*

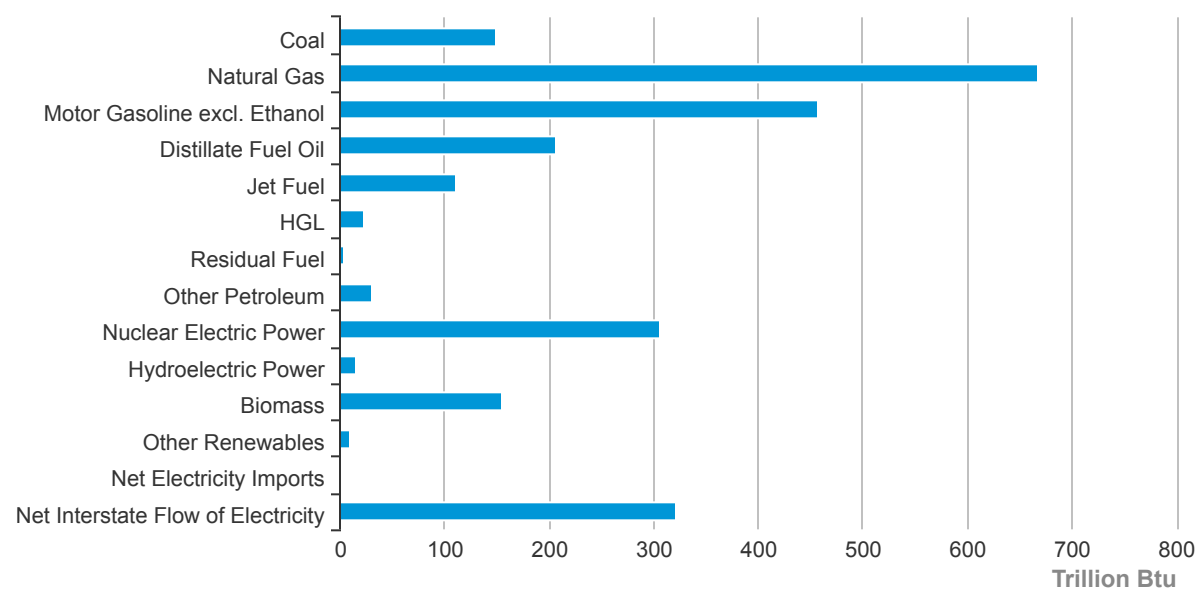
*Some typos and spreadsheet errors fixed on 2/8/2009.*

*Finally, the statements and recommendations in this study are those of the author, and do not represent the official positions of Southern Methodist University.*



# Exhibit 16

## Virginia Energy Consumption Estimates, 2018



Source: Energy Information Administration, State Energy Data System

# Exhibit 17



**Dominion  
Energy<sup>®</sup>**

**Virginia Electric and Power  
Company's Report of Its  
Integrated Resource Plan**

**Before the Virginia State  
Corporation Commission and  
North Carolina Utilities  
Commission**

**Case No. PUR-2020-00035  
Docket No. E-100, Sub 165**

**Filed: May 1, 2020**



## **Chapter 5: Generation – Supply-Side Resources**

This chapter provides an overview of the Company's existing supply-side generation, the generation resources under construction or development, and the Company's analysis of future supply-side generation. This chapter also provides a discussion of challenges related to the development of significant volumes of solar resources.

### **5.1 Existing Supply-Side Generation**

#### ***5.1.1 System Fleet***

Figure 5.1.1.1 shows the Company's 2019 capacity resource mix by unit type.

Figure 5.1.1.1 - 2019 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity (MW)	Percentage (%)
Coal	3,684	17.7%
Nuclear	3,348	16.1%
Natural Gas	8,413	40.3%
Pumped Storage	1,808	8.7%
Oil	2,143	10.3%
Renewable	667	3.2%
NUG-Coal	0	0.0%
NUG- Natural Gas Turbine	0	0.0%
NUG- Solar	592	2.8%
NUG- Contracted	198	0.9%
Company Owned	20,063	96.2%
Company Owned and NUG Contracted	20,853	100.0%
Purchases	0	0.0%
Total	20,853	100.0%

Due to differences in operating and fuel costs of various types of units and in PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is dispatched by PJM within PJM's larger footprint, ensuring that customers in the Company's service territory receive the economic benefit of all resources in the PJM power pool regardless of the source. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 5.1.1.2 and 5.1.1.3 provide the Company's 2019 actual capacity and energy mix.

Figure 5.1.1.2 - 2019 Actual Capacity Mix

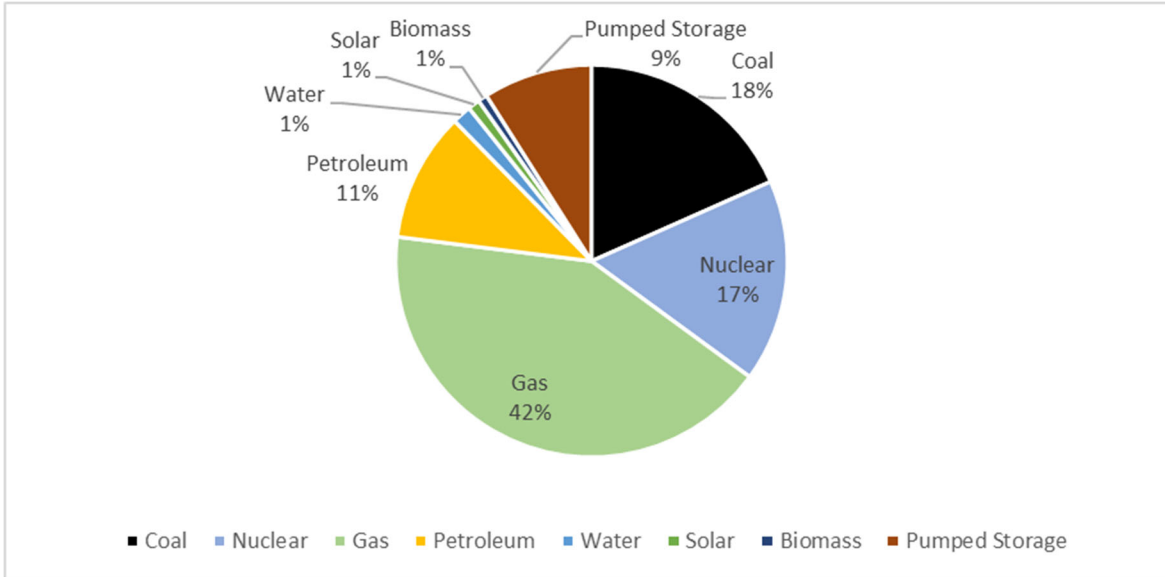
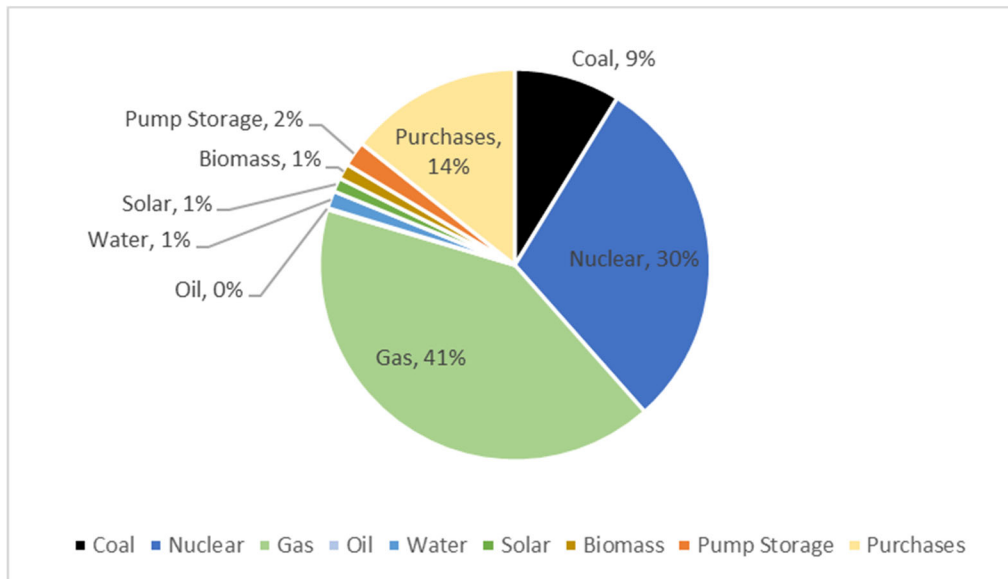


Figure 5.1.1.3 - 2019 Actual Energy Mix



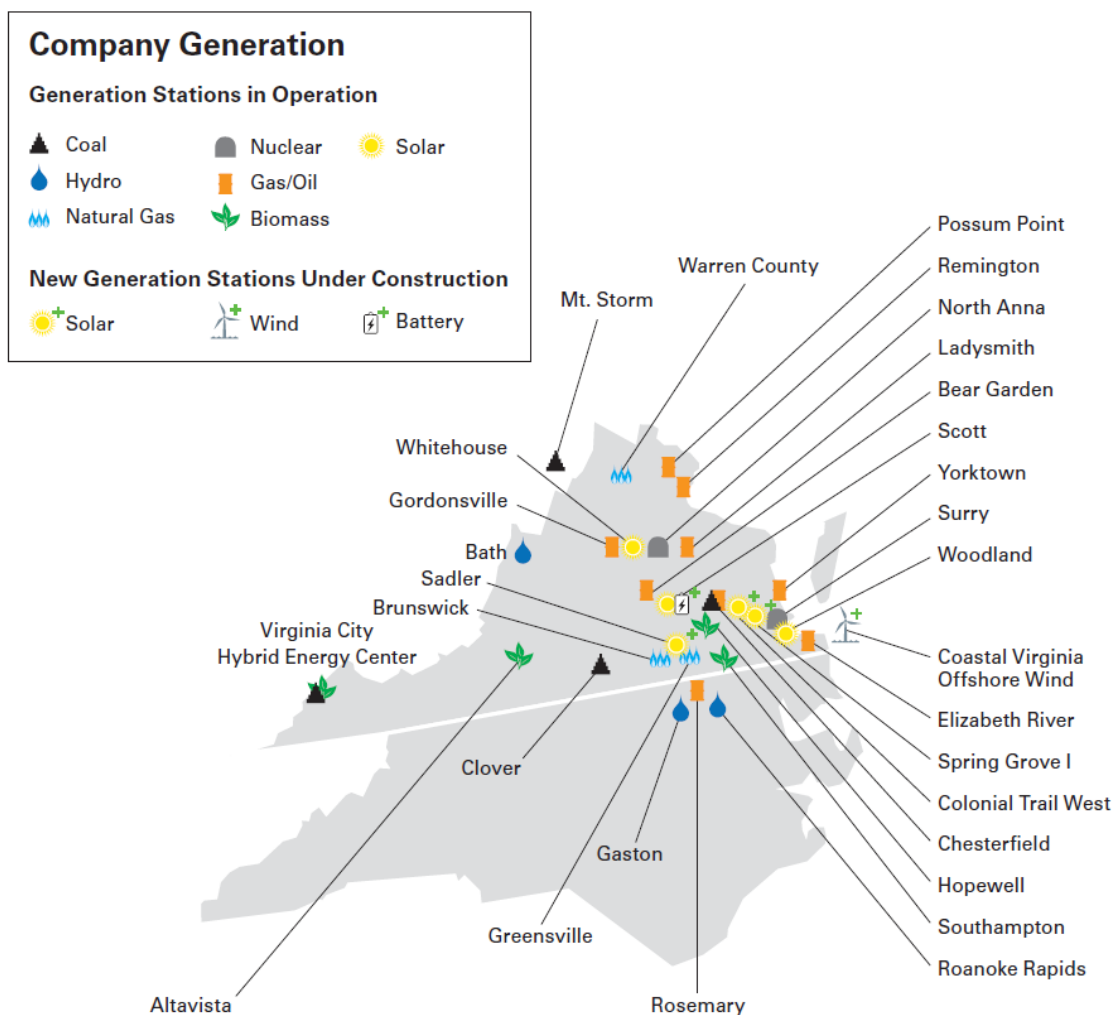
Appendices 5A through 5E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Appendix 5F provides a summary of the existing capacity by fuel class. Appendices 5G and 5H provide energy generation by type and by the system output mix. Appendix 5I provides a list of all Company-build or third-party PPA solar and wind generating facilities placed in service, under construction, or under development since July 1, 2018. Appendix 5O provides a list of renewable resources, and Appendix 5P provides a list of potential supply-side resources. Appendices 5Q and 5R present the Company's summer capacity position and seasonal

capability, respectively. Appendix 5S provides the construction cost forecast for Alternative Plan B.

### 5.1.2 Company-Owned System Generation

The Company's existing system generating resources are located at multiple sites distributed throughout its service territory, as shown in Figure 5.1.2.1. This diverse fleet of 90 generation units includes 4 nuclear, 8 coal, 9 CCs, 40 CTs, 3 biomass, 2 heavy oil, 6 pumped storage, 14 hydro, and 4 solar with a total summer capacity of approximately 20,063 MW.

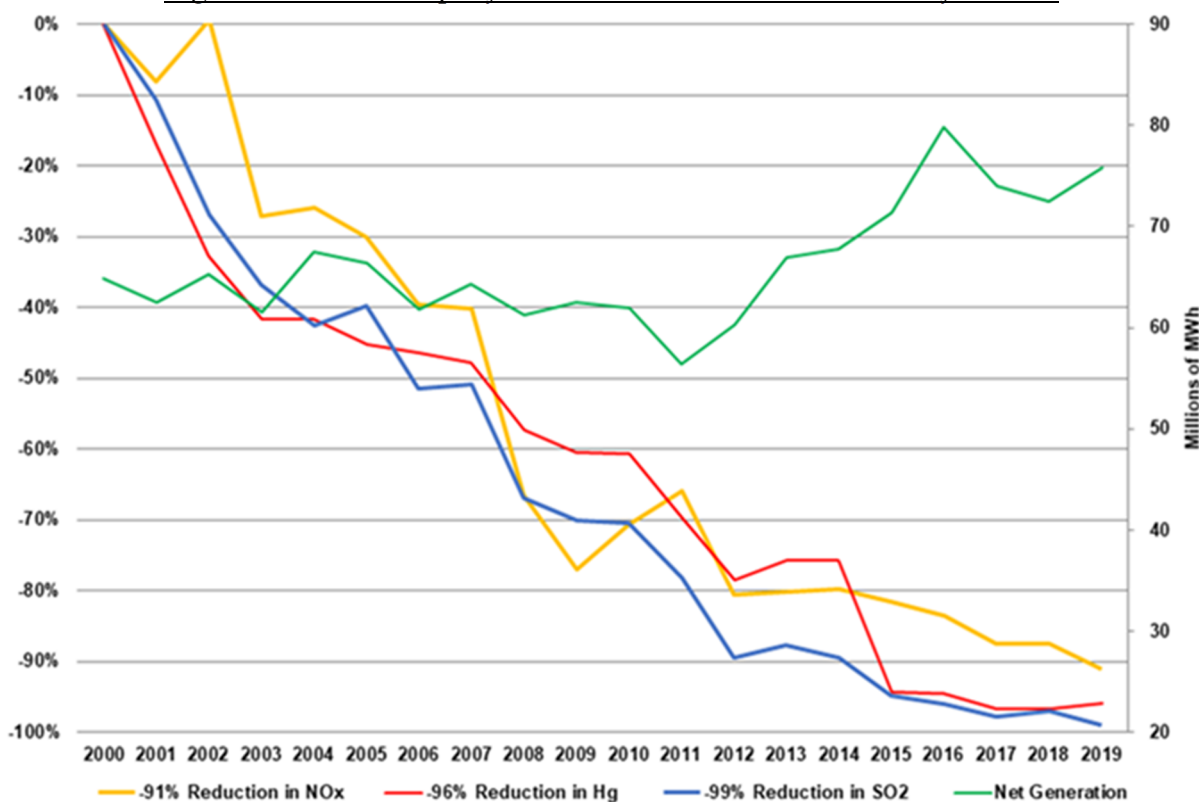
Figure 5.1.2.1 – Company Generation Resources



The Company currently owns and operates 667 MW of renewable resources, including solar, hydro, and biomass, with an additional 210 MW (nameplate) under construction. The Company also owns and operates four nuclear facilities (3,348 MW), providing significant zero-carbon generation for its customers.

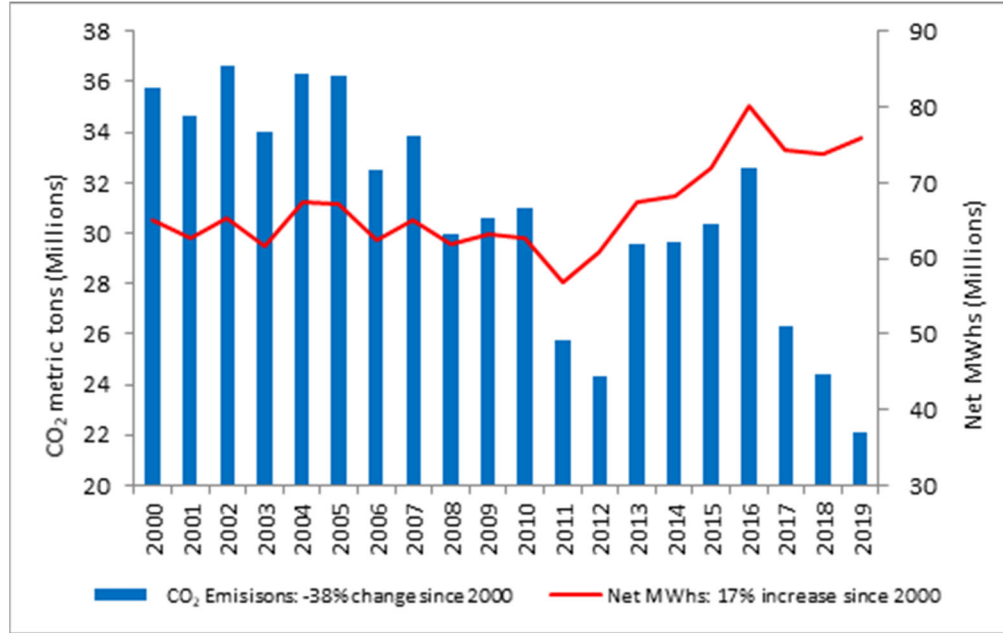
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, the conversion to dry ash handling, and the addition of air pollution controls. This strategy has resulted in significant reductions of air pollutants such as NO<sub>x</sub>, SO<sub>2</sub>, and mercury, as shown in Figure 5.1.2.2, and has also reduced the amount of coal ash generated and the amount of water used.

Figure 5.1.2.2 – Company Annual Reduction in Emissions by Percent



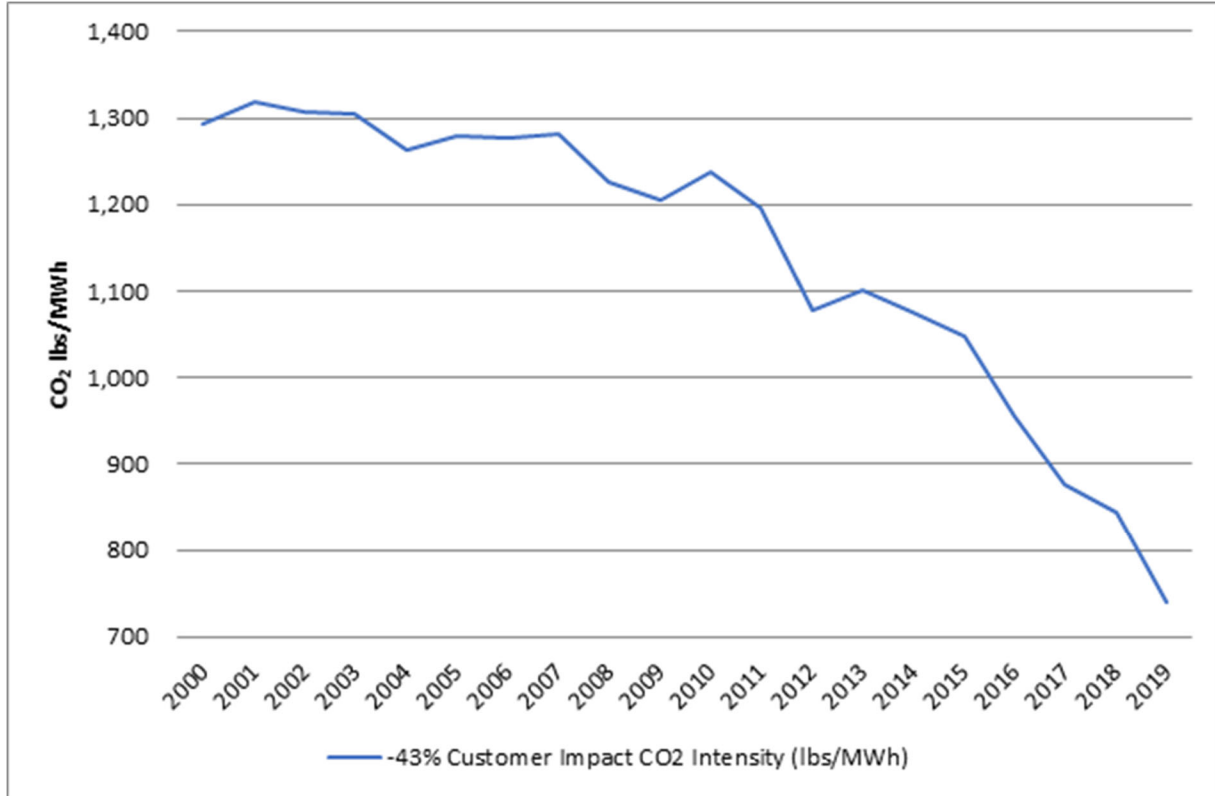
The Company develops a comprehensive GHG inventory annually. The Company's direct CO<sub>2</sub> equivalent emissions (based on ownership percentage) were 22.1 million metric tons in 2019 compared to 24.6 million metric tons in 2018. The Company has been a leader in reducing CO<sub>2</sub> emissions through retiring certain units; building additional efficient and lower-emitting natural gas-fired power generating sources and carbon-free renewable energy sources, such as solar; and maintaining its existing fleet of non-emitting nuclear generation. As shown in Figure 5.1.2.3, from 2000 through 2019, the Company has reduced the CO<sub>2</sub> emissions in tons from its power generation fleet serving Virginia jurisdictional customers by 38%, while power production has increased by 17%.

Figure 5.1.2.3 – Company CO<sub>2</sub> Mass Reductions versus Net Generation



The Company's integrated business strategy has also resulted in significant reduction in CO<sub>2</sub> emission intensity. CO<sub>2</sub> intensity is the amount of emissions per MWh delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, NUGs, and net purchased power. As shown in Figure 5.1.2.4, customer impact CO<sub>2</sub> intensity has decreased by 43% since 2000.

Figure 5.1.2.4 – Customer Impact CO<sub>2</sub> Intensity



### 5.1.3 Non-Utility Generation

A portion of the Company's load and energy requirement is supplemented with contracted NUGs. The Company has existing contracts with fossil-burning and renewable behind-the-meter NUGs for capacity of approximately 812 MW (nameplate).

For modeling purposes, the Company assumed that its NUG capacity would be available as a firm generating capacity resource in accordance with current contractual terms. These NUG units also provide energy to the Company according to their contractual arrangements. At the expiration of these NUG contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that NUGs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned, sponsored supply, or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter into future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

## 5.2 Evaluation of Existing Generation

The Company continuously evaluates various options with respect to its existing fleet, cognizant of environmental regulations and other policy considerations.

### 5.2.1 Retirements

As discussed in Section 1.2, the VCEA mandates the retirement of carbon-emitting generation on a specific schedule unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric services:

- Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024;
- Altavista, Hopewell, and Southampton (biomass) by 2028; and
- All remaining generation units that emit CO<sub>2</sub> as a byproduct of combustion by 2045.

Separate from these mandates, and consistent with prior Plans, the Company completed a unit evaluation economic analysis focused on coal-fired, heavy-oil fired, and large combined cycle Company generation facilities under market conditions.

Global assumptions included potential carbon regulations as well as market forecasts consistent with four ICF commodity forecast scenarios: No CO<sub>2</sub> Tax, Mid-Case Federal CO<sub>2</sub> with Virginia in RGGI, Virginia in RGGI and High-Case Federal CO<sub>2</sub>.

A combination of PLEXOS production-cost modeling software and Excel models were used to calculate a unit NPV to customers over the next ten years. Unit NPVs were derived by comparing the total unit costs, including O&M and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues. Negative NPV results indicated an economic benefit of unit retirement to customers compared to continued operations of the unit in the PJM market.

The results of the analysis are included in Figure 5.2.1.1. In general, it can be concluded that the Company's coal-fired power plants located in Virginia continue to face pressure due to unfavorable market conditions and carbon regulations. Coal-fired generating facilities Chesterfield Units 5 and 6 and Clover Units 1 and 2 had negative NPVs under all four scenarios, including No CO<sub>2</sub> Tax. Mount Storm's coal-fired Units 1 through 3 showed positive NPVs in all four cases with a higher upside potential under Virginia in RGGI and the No CO<sub>2</sub> Tax scenarios. Heavy oil-fired power station Yorktown Unit 3 had negative NPVs in all four scenarios.

Figure 5.2.1.1 – Retirement Analysis Results

Units	No CO <sub>2</sub> Tax	Virginia in RGGI	Mid-Case Federal CO <sub>2</sub> with Virginia in RGGI	High-Case Federal CO <sub>2</sub>
Chesterfield 5 - 6	-	-	-	-
Clover 1 - 2	-	-	-	-
Mt. Storm 1 - 3	+	+	+	+
Yorktown 3	-	-	-	-

Based on the above results and other factors, including but not limited to power prices and the retirement-related mandates in the VCEA, the Company anticipates retiring Yorktown Unit 3 and Chesterfield Units 5 and 6 in 2023. Other than these units, inclusion of a unit retirement in this 2020 Plan should be considered as tentative only. The Company has not made any decision

regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units for potential retirement.

### ***5.2.2 Uprates and Derates***

Efficiency, generation output, and environmental characteristics of units are reviewed as part of the Company's normal course of business. Many of the uprates and derates occur during routine maintenance cycles or are associated with standard refurbishment. However, several unit ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations. Appendix 5K provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

### ***5.2.3 Environmental Regulations***

There are a number of final, proposed, and anticipated EPA regulations that will affect certain units in the Company's current fleet of generation resources. Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife. For further discussion on significant developments to environmental regulation, see Sections 1.3 and 1.11.

## **5.3 Generation Under Construction**

The Company currently has four generation projects under construction for which the SCC has issued a certificate of public convenience and necessity: (i) the CVOW demonstration project; (ii) Spring Grove 1 Solar Project; (iii) Sadler Solar Project; and (iv) the Battery Energy Storage System at Scott Solar Facility. Appendix 3A provides details on each project.

## **5.4 Generation Under Development**

The Company currently has solar, offshore wind, pumped storage, and CT generation projects under development. The Company is also pursuing subsequent license extensions for its nuclear facilities. The following sections provide details on these projects, as does Appendix 3B.

The Company has paused material development activities for North Anna 3 following receipt of the combined operating license ("COL") in 2017. The Company is currently incurring minimal capital costs associated with North Anna 3 specific to the administrative functions of maintaining the COL.

### ***5.4.1 Solar***

The Company issued a request for proposal ("RFP") for new solar and wind resources in August 2019. The Company is currently evaluating the results of that RFP and intends to bring new Company-build and PPA resources before the SCC for approval as part of its annual plan regarding the development of solar, onshore wind, and energy storage required by the VCEA.



### **5.4.2 Offshore Wind**

The Company is actively participating in offshore wind policy and innovative technology development to identify ways to advance offshore wind generation responsibly and cost-effectively.

The CVOW demonstration project—the Mid-Atlantic’s first offshore wind project in a federal lease area—is under construction with a targeted in-service date by the end of 2020. This demonstration project is an important first step toward offshore wind development for Virginia and the United States. Along with clean energy, it is providing the Company valuable experience in permitting, constructing, and operating offshore wind resources, which will help inform utility-scale development of the adjacent 112,800 acre wind lease area.

As discussed in Section 1.2, the VCEA specifies that the construction or purchase of up to 5,200 MW of offshore wind capacity is in the public interest. In September 2019, the Company filed with PJM to interconnect more than 2,600 MW of offshore wind capacity by 2026 (“CVOW commercial project”), enough to power more than 650,000 homes during peak winds.

On January 7, 2020, the Company selected Siemens Gamesa Renewable Energy as the preferred turbine supplier for the CVOW commercial project with the intent to provide their latest state-of-the-art wind turbine, based on its proven Offshore Direct Drive platform. Ongoing efforts of this project include ocean survey work that will be performed in 2020 to support the development of the Construction and Operations Plan, which is expected to be submitted to the Bureau of Ocean Energy Management in late 2020. Pending regulatory approval, the CVOW commercial project is expected to be in-service by the end of 2026.

### **5.4.3 Pumped Storage**

Pumped storage hydroelectric power is a mature proven storage technology. It can also serve as a system-stabilizing asset to accommodate the intermittent and variable output of renewable energy sources such as solar and wind. Virginia Senate Bill No. 1418 became law effective on July 1, 2017, and supported construction of “one or more pumped hydroelectric generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source . . . located in the coalfield region of the Commonwealth.” On September 6, 2017, the Company filed a preliminary permit application with FERC for a location in Tazewell County, Virginia. This application was approved on December 11, 2017, and the Company is continuing to conduct feasibility studies for a potential pumped storage facility at the Tazewell County site.

### **5.4.4 Extension of Nuclear Licensing**

An application for a subsequent license renewal is allowed during a nuclear plant’s first period of extended operation—that is, in the 40 to 60 years range of its service life. Surry Units 1 and 2 entered into that initial license renewal period in 2012 and 2013, respectively. North Anna Units 1 and 2 entered or will enter into that period in 2018 and 2020, respectively. The Company has

continued to track the preliminary cost estimates for the extension of the nuclear licenses at its Surry and North Anna Units.

In November 2015, the Company notified the NRC of its intent to file for subsequent license renewal for its two nuclear units (1,676 MW total) at Surry in order to operate an additional 20 years, increasing their operating life from 60 to 80 years. As with other nuclear units, Surry was originally licensed to operate for 40 years and then renewed for an additional 20 years. Absent subsequent license renewal approval, the existing licenses for Surry Units 1 and 2 will expire in 2032 and 2033, respectively. In support of the application development, the NRC finalized guidance documents in early July 2017, related to developing and reviewing subsequent license renewal applications. The Surry subsequent license renewal application was submitted to the NRC on October 15, 2018, in accordance with Title 10 of the Code of Federal Regulations (“CFR”) Part 54.

The Surry subsequent license renewal application was subsequently declared “technically sufficient and available for docketing” by the NRC on December 10, 2018, which began the safety and environmental reviews required for the renewed licenses. Several NRC audits and public meetings have been conducted during both the safety and environmental reviews in late 2018 and 2019 related to this licensing action. The NRC staff has asked requests for additional information (“RAIs”) during this review period seeking clarification or additional action to be taken by the Company prior to entering the subsequent period of operation. These environmental and safety RAIs have been addressed to the satisfaction of the NRC staff.

As a result, the NRC issued the Final Safety Evaluation Report (“SER”) for Surry Power Station on March 9, 2020. On the basis of its review of the Surry subsequent license renewal application, the NRC staff determined that the requirements of 10 CFR 54.29(a) have been met for the subsequent license renewal of Surry Units 1 and 2. The NRC also issued the Final Supplemental Environmental Impact Statement (“FSEIS”) on April 6, 2020. The NRC staff’s conclusion was “that the adverse environmental impacts of license renewal for Surry are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable.”

The Advisory Committee on Reactor Safeguards (“ACRS”) Full-Committee meeting was conducted on April 8, 2020, with unanimous approval by the committee to approve the renewal of the operating licenses for Surry Units 1 and 2.

The NRC Director of Nuclear Reactor Regulation will make a decision for renewed licenses for Surry Units 1 and 2 based on the issuance of the FSEIS, Final SER and the ACRS letter of recommendation in June 2020. This will preserve the option to continue operation of Surry Units 1 and 2 until 2052 and 2053, respectively.

The Company notified the NRC in November 2017 of its plans to file an subsequent license renewal application for its two nuclear units (1,672 MW total) at North Anna in accordance with 10 CFR Part 54 in late 2020. Absent subsequent license renewal approval, the existing licenses for the two units will expire in 2038 and 2040, respectively. The review process for North Anna will remain unchanged, so the expected outcome would be similar to Surry. The renewed

licenses for North Anna would be expected 18 months following the NRC declaring the subsequent license renewal application as technically sufficient and available for docketing, which is expected within 45 to 60 days following the Company's submittal. Currently, the forecast receipt of the renewed licenses for North Anna Units 1 and 2 is June 2022, based on a targeted submittal date in October 2020.

#### **5.4.5 Combustion Turbines**

In order to preserve the option to address probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities in the near term, the Company is evaluating sites and equipment for the construction of gas-fired CT units.

### **5.5 Future Supply-Side Generation Resources**

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of the alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or PJM. The technology's ability to be dispatched is based on whether the resource is able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand and supply conditions. Further, analysis of the alternative resources requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks.

The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel and O&M. Figure 5.5.1 summarizes the resource types that the Company reviewed as part of the generation planning process. Those resources considered for further analysis in the busbar (*i.e.*, LCOE) screening model are identified in the final column.

Further analysis was conducted in PLEXOS to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matched the resources found to be cost-effective in this screening process. This PLEXOS simulation analysis further refines the Company's analysis and assists in selecting the type and timing of additional resources that economically fit the customers' current and future needs.

**Figure 5.5.1 - Alternative Supply-Side Resources**

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource	PLEXOS Resource
Combined Cycle - 3X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 2X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 1X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Aero-derivative Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Large Nuclear	Baseload	Yes	Uranium	Yes	No
Nuclear Small Modular Reactor	Baseload	Yes	Uranium	Yes	Yes
Biomass	Baseload	Yes	Renewable	Yes	No
Fuel Cell	Baseload	Yes	Natural Gas	Yes	No
Supercritical Pulverized Coal with CCS	Intermediate	Yes	Coal	Yes	No
Solar & Aero-derivative CT	Peak	Yes	Renewable	Yes	No
Solar	Intermittent	No	Renewable	Yes	Yes
Wind - Onshore	Intermittent	No	Renewable	Yes	Yes
Wind - Offshore	Intermittent	No	Renewable	Yes	Yes
Battery Generic (30 MW)	Peak	Yes	Varies	Yes	Yes
Pumped Storage (300 MW)	Peak	Yes	Renewable	Yes	Yes
Combined Heat and Power	Peak	Yes	Varies	Yes	Yes

### ***5.5.1 Supply-Side Resource Options***

The following sections provide details on certain newer supply-side resource options the Company has considered. Previous Plans provide additional details on the more proven technologies, including biomass, CCs, CTs, nuclear, and solar. In addition, Section 5.4 provides additional details on generation currently under development, including offshore wind and pumped storage.

#### **Aero-derivative Combustion Turbine**

Aero-derivative CT technology consists of a gas generator that has been derived from an existing aircraft engine and used in an industrial application. Designed for a small footprint and low weight using modular construction, aero-derivative CTs utilize advanced materials for high efficiency and fast start-up times with little or no cyclic life penalty. Aero-derivative CTs have been designed for quick removal and replacement, allowing for fast maintenance and greatly reduced downtimes, and resulting in high unit availability and flexibility. This is a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatchable renewable resources, such as solar and wind.

#### **Combined Heat and Power / Waste Heat to Power**

Combined heat and power (“CHP”) is the use of a power station to generate electricity and useful thermal energy from a single fuel source. CHP plants capture the heat that would otherwise be wasted to provide useful thermal energy, usually in the form of steam or hot water. The recovery of otherwise wasted thermal energy in the CHP process allows for more efficient fuel usage.

CHP's reduction in primary energy use through fuel efficiency leads to lower greenhouse gas emissions.

Waste heat to power ("WHP") is a type of combined heat and power that generates electricity through the recovery of qualified waste heat resources. WHP captures heat byproduct discarded by existing industrial processes and uses that heat to generate power. Industrial processes that involve transforming raw materials into useful products all release hot exhaust gases and waste streams that can be captured to generate electricity. WHP is another form of clean energy production.

The Company will continue to track this technology and its associated economics based on site and fuel resource availability.

### **Energy Storage**

There are five main types of energy storage technologies: electromechanical, electrochemical, thermal, chemical, and electrical.

Electromechanical storage involves creating potential energy, which can be converted to kinetic energy. Pumped storage hydro, the most commonly used electromechanical storage technology, requires pumping large quantities of water to a reservoir at a higher elevation than the source, which creates potential energy that can be converted to kinetic energy that then spins a water turbine. Pumped storage hydro is a mature technology compared to other types of energy storage, and it represents the largest amount of installed storage capacity in the United States. See Section 5.4.3 for a discussion of the pumped storage hydroelectric facility under development. Other examples of electromechanical storage include flywheels and compressed air energy storage.

Electrochemical (or battery) storage involves storing electricity in chemical form. One advantage of electrochemical storage is the fact that electrical and chemical energy share the same carrier—the electron—which limits efficiency losses due to converting one form of energy to another. Lithium ion is now the most commonly used type of battery in utility-scale projects because lithium ion costs have been falling rapidly for nearly a decade. This decrease in cost is attributable to advancements in battery design, efficiency gains in manufacturing, and increased supply. Other examples of electrochemical storage include lead acid batteries, sodium sulfur batteries, and flow batteries.

Batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications. Batteries can be used to provide energy for a power station black start, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. They vary in size, differ in performance characteristics, and are usable in different locations. Batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. Battery storage technology approximates dispatchability for these variable energy resources. The primary challenge facing battery systems is the cost. Other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for

utility-scale battery systems. The SCC recently approved the Company’s application to pilot three lithium ion battery energy storage systems for different use cases. The results of these pilots will inform future deployment of batteries.

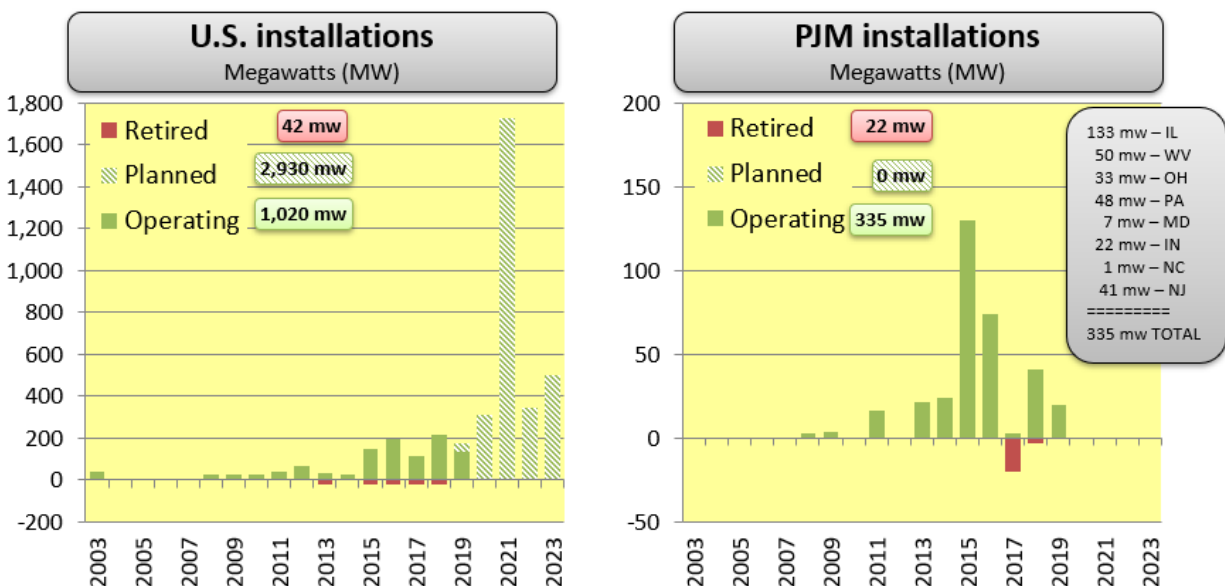
Thermal storage involves converting stored heat into energy, or supplying cool air to reduce air conditioning load. Water heaters, ice storage, and chilled water storage are all examples of thermal storage.

Chemical storage involves altering the molecular structure of compounds (such as water) by splitting or combining molecules. For example, hydrogen gas can be created by splitting H<sub>2</sub>O molecules into H<sub>2</sub> and O<sub>2</sub>. The H<sub>2</sub> (hydrogen gas) can be stored and later burned to produce steam to power a turbine. Another example of chemical storage is power-to-gas conversion, which converts electrical power into gaseous fuel.

Electrical storage primarily refers to super capacitors and magnetic energy storage, which can provide short, powerful bursts of energy to jumpstart other technologies.

Cost considerations and technology maturity have restricted widespread deployment of most of these technologies, with the exception of pumped storage hydroelectric power and batteries. At present, lithium-ion batteries and pumped storage are the most commercially viable energy storage technologies for utility-scale projects. Based on the most current information sourced from the U.S. Energy Information Administration, the amount of utility-scale battery storage installed in the entire United States is just over 1,000 MW, as shown in Figure 5.5.1.1. Of those 1,000 MW, only 335 MW are located within the PJM region.

Figure 5.5.1.1 – Utility-Scale Battery Storage Installations



As discussed in Section 1.2, the VCEA requires the Company to build 2,700 MW of energy storage by 2035. The Company will continue to study energy storage to determine the feasibility of constructing this quantity of energy storage capacity.

### **Fuel Cell**

Fuel cells convert chemical energy from hydrogen-rich fuels into electricity and heat, there is no burning of the fuel. Fuel cells emit water and CO<sub>2</sub>, resulting in power production that is almost entirely absent of NO<sub>x</sub>, SO<sub>x</sub>, or particulate matter. Similar to a battery, a fuel cell is comprised of many individual cells that are grouped together to form a fuel cell stack. Each individual cell contains an anode, a cathode, and an electrolyte layer. When a hydrogen-rich fuel, such as clean natural gas or renewable biogas, enters the fuel cell stack, it reacts electrochemically with oxygen (*i.e.*, ambient air) to produce electric current, heat, and water. While a typical battery has a fixed supply of energy, fuel cells continuously generate electricity as long as fuel is supplied. Fuel cells were invented in 1932 and put to commercial use by NASA in the 1950s. They are now most common as a power source for buildings and remote areas, but continual improvements in technology are quickly bringing them into wider use.

### **Integrated-Gasification Combined Cycle with Carbon Capture Sequestration**

Integrated-gasification CC plants use a gasification system to produce synthetic natural gas from coal that is then used to fuel a CC. The gasification process produces a pressurized stream of CO<sub>2</sub> before combustion, which, as research suggests, provides some advantages in preparing the CO<sub>2</sub> for CCS systems. Integrated-gasification CC systems remove a greater proportion of other air effluents in comparison to traditional coal units.

### **Reciprocating Internal Combustion Engine**

Reciprocating internal combustion engines use reciprocating motion to convert heat energy into mechanical work. Stationary reciprocating engines differ from mobile reciprocating engines in that they are not used in road vehicles or non-road equipment.

There are two basic types of stationary reciprocating engines, spark ignition and compression ignition. Spark ignition engines use a spark (across a spark plug) to ignite a compressed fuel-air mixture. Typical fuels for such engines are gasoline and natural gas. Compression ignition engines compress air to a high pressure, heating the air to the ignition temperature of the fuel, which then is injected. The high compression ratio used for compression ignition engines results in a higher efficiency than is possible with spark ignition engines. Diesel fuel oil is normally used in compression ignition engines, although some are dual-fueled (*i.e.*, natural gas is compressed with the combustion air and diesel oil is injected at the top of the compression stroke to initiate combustion).

### **Small Modular Reactors**

Small modular reactors (“SMRs”) are utility-scale nuclear units with electrical output of 300 MW or less. SMRs are manufactured largely off-site in factories, and then delivered and

installed on-site in modules. The smaller power output of SMRs when compared to conventional baseload nuclear units currently in operation offers a number of advantages, including reduced land surface area, potential for reduced security and emergency planning zone requirements, lower initial capital and operating costs, and flexibility in meeting specific power needs by staging multiple units in the same or multiple locations. A typical SMR design entails underground placement of reactors and spent-fuel storage pools and a natural cooling feature that can continue to function in the absence of external power. SMR design development and permitting have advanced with some designs currently under review by the NRC. The Company will continue to monitor the industry's ongoing research and development regarding this technology. The federal government recently approved partial co-funding for up to two demonstration projects. The Company is reviewing and evaluating the potential for participation in this funding opportunity in support of its emission reduction targets.

### ***5.5.2 Levelized Busbar Costs / Levelized Cost of Energy***

The Company's busbar model was designed to estimate the levelized cost of energy of various generating resources on an equivalent basis. The busbar results show the LCOE of various generating resource technologies at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include fuel, heat rate, emissions, variable and fixed O&M costs, expected service life, and overnight construction costs.

Figures 5.5.2.1 and 5.5.2.2 display summary results of the busbar model comparing the economics of the different technologies. The results are separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources for the energy and capacity value they provide to customers. For example, dispatchable resources are able to generate when power prices are the highest, while non-dispatchable resources may not have the ability to do so. Furthermore, non-dispatchable resources typically receive less capacity value for meeting the Company's reserve margin requirements and may require additional technologies in order to assure grid stability.



Figure 5.5.2.1 - Dispatchable LCOE (2023 COD)

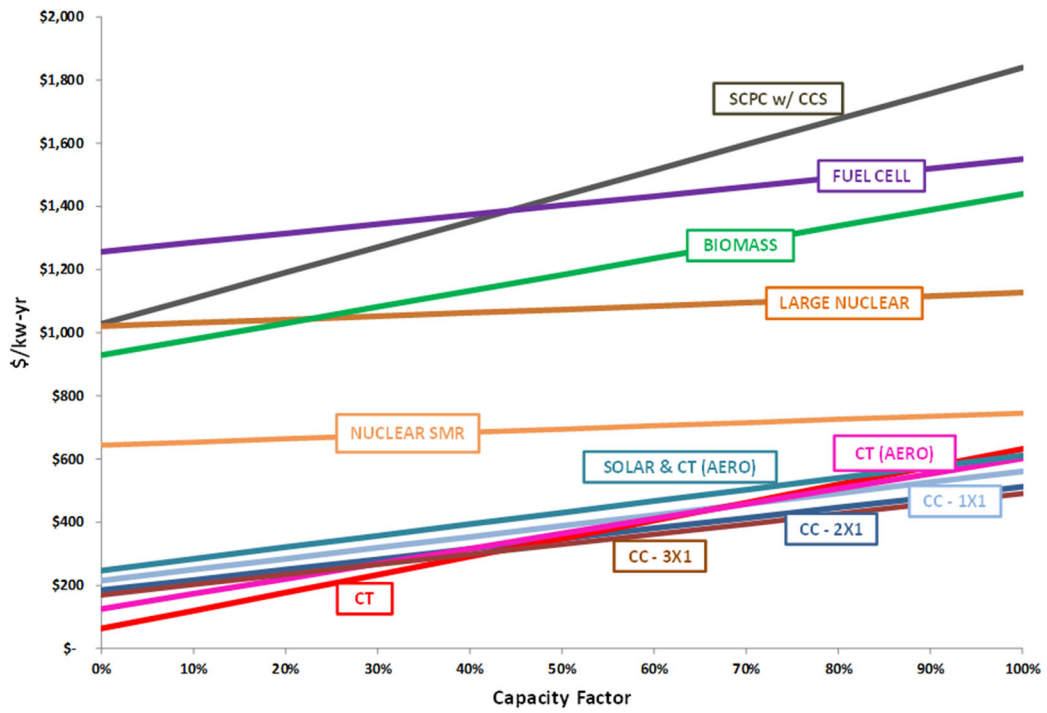
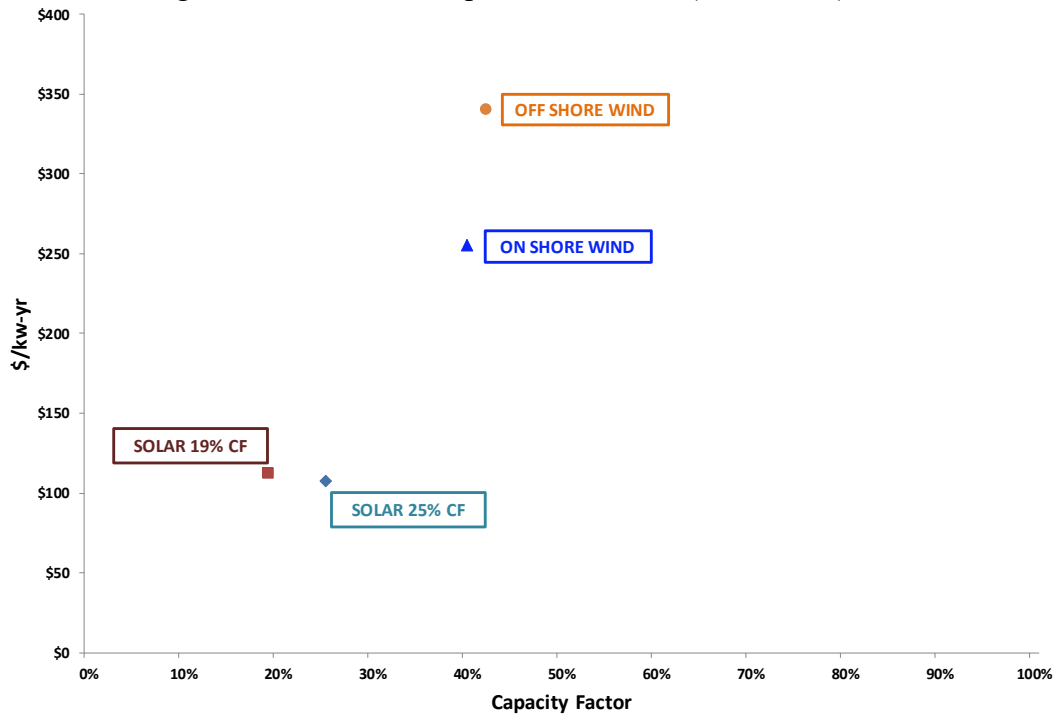


Figure 5.5.2.2 - Non-Dispatchable LCOE (2023 COD)



Appendix 5M contains the tabular results of the screening level analysis. Appendix 5N displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated construction costs.

In Figure 5.5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with LCOE above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher LCOE resources, however, may be necessary to achieve other constraints like those required by carbon regulations. Figures 5.5.2.1 and 5.5.2.2 allow comparative evaluation of resource types.

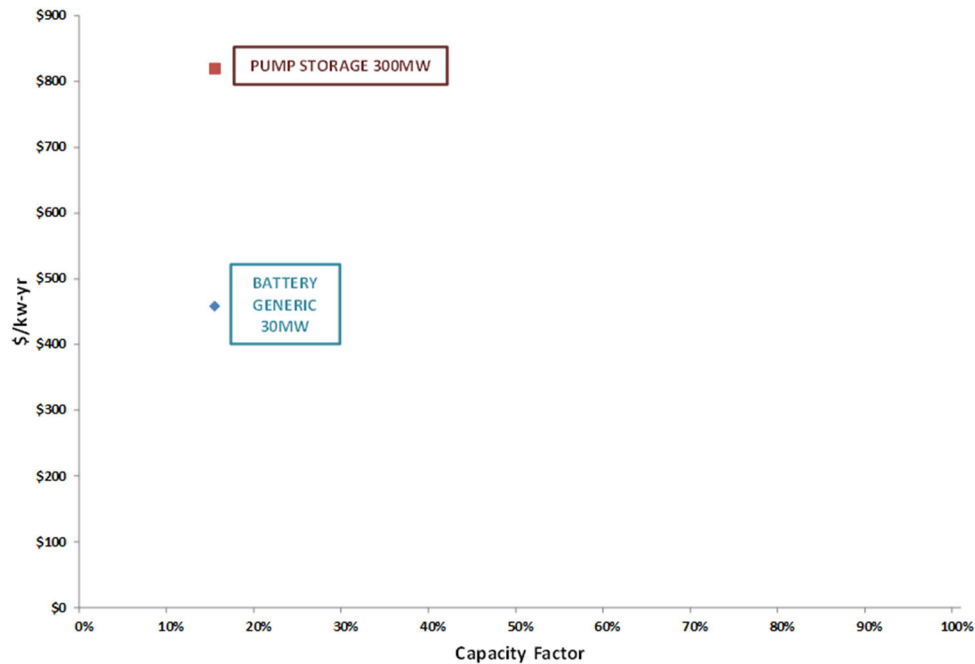
In Figure 5.5.2.1, the value of each cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of operating the unit, including fuel, emissions, and any REC or production tax credit ("PTC") value a given unit may receive.

Figure 5.5.2.2 displays the non-dispatchable resources that the Company considered in its busbar analysis. Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods than dispatchable resources, requiring more capacity to maintain the same level of system reliability. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability.

As shown in Figure 5.5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 25% for meeting the Company's peaking requirements. The CC 3x1 technology is the most economical option for capacity factors greater than approximately 25%. As depicted in Figure 5.5.2.2, solar is a competitive choice at capacity factors of approximately 25%.

Figure 5.5.2.3 shows the estimated LCOE for a 300 MW pumped storage facility and generic 30 MW 4-hour battery. All LCOE are based on a 15% capacity factor, which was derived from the historical performance of the Company's pumped storage facilities, and projected performance of future energy storage technologies, as calculated by the PLEXOS model.

Figure 5.5.2.3 - Energy Storage LCOE (2023 COD)



The assessment of alternative resource types and the busbar screening process provides a simplified foundation in selecting resources for further analysis. However, the busbar curve is static in nature because it relies on an average of all of the cost data of a resource over its lifetime.

### 5.5.3 Third-Party Market Alternatives

During the last several years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territories.

In Virginia, the Company has issued an annual RFP for utility-scale solar and wind generating facilities since 2015. These RFPs have resulted in both Company-owned solar facilities and solar PPAs. Outside of the utility-scale solar and wind RFPs, the Company entered into PPA agreements for several solar facilities totaling 67 MW. The Company has also issued RFPs for small-scale solar resources. The Company will continue to issue annual RFPs for solar and wind resources, consistent with the competitive procurement requirements of the VCEA.

In North Carolina, the Company has signed 91 PPAs totaling approximately 686 MW (nameplate) of new solar NUGs. Of these, 572 MW (nameplate) are from 80 solar projects that were in operation as of March 2020. The majority of these projects are qualifying facilities contracting to sell capacity and energy at the Company's published North Carolina Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act.

## **5.6 Challenges Related to Significant Volumes of Solar Generation**

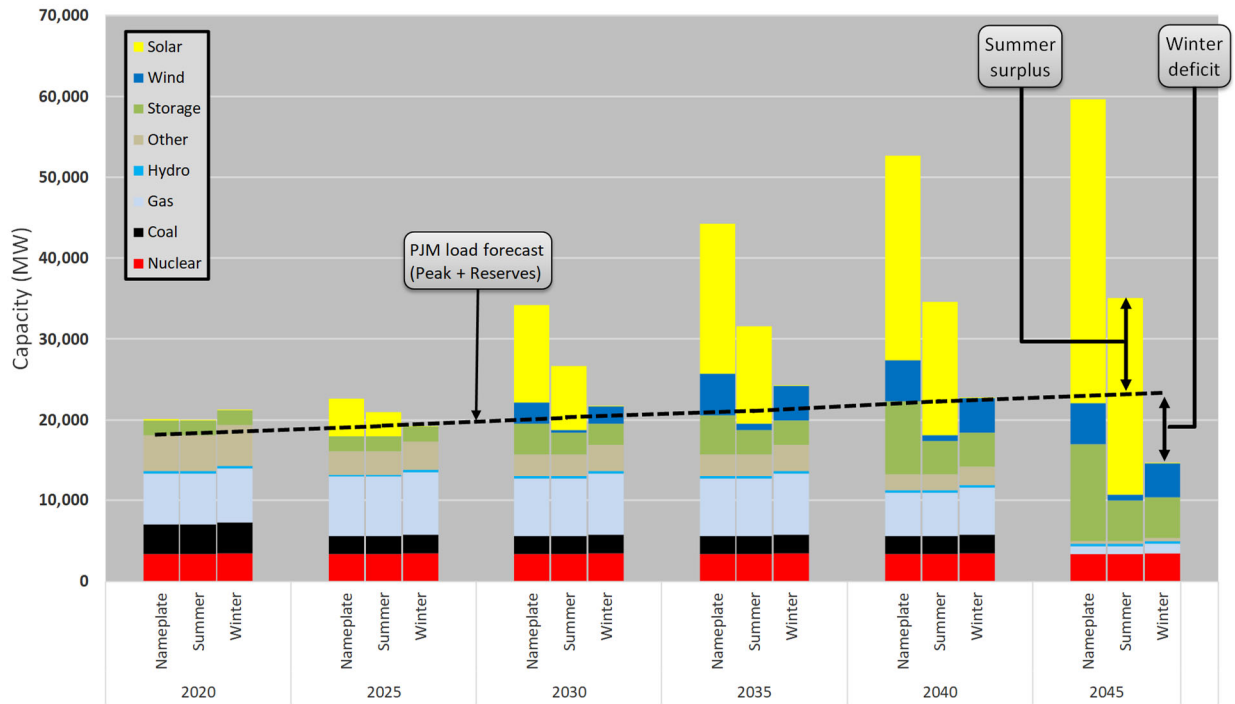
All Alternative Plans in this 2020 Plan include significant development of solar resources, as shown in Section 2.2. Based on current technology, challenges will arise as increasing amounts of these non-dispatchable, intermittent resources are added to the system. This section seeks to identify these challenges, which include intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load, as well challenges related to system restoration. This section also discusses challenges related to constructing the level of solar generation in Alternative Plans B through D. In this 2020 Plan, Alternative Plan B best addresses these challenges based on current technology. But the Company stands ready to meet these challenges with continued study, technological advancement, and innovation, and will provide the results of these advancements in future Plans and update filings.

### ***5.6.1 Challenges Related to Capacity***

Solar generation significantly contributes to meeting peak demand in the summer, but barely contributes to meeting winter peak demand. This is because summer peak demand occurs during late afternoon hours when the sun is typically shining and, consequently, when the solar facilities are producing energy. In contrast, winter peak demand typically occurs in the early morning hours when the sun is beginning to rise, and when solar facilities are just starting to ramp up production.

As the Company adds increasing amounts of solar resources to the system, this will result in the system having excess capacity in the summer, but not having enough capacity in the winter. For example, Figure 5.6.1.1 shows the nameplate capacity, summer capacity, and winter capacity of existing and new resources in Alternative Plan D compared to the 2020 PJM Load Forecast. As can be seen, the Company has approximately 11,500 MW more capacity than needed in the summer in Alternative Plan D, but then has a deficit of approximately 8,800 MW in the winter.

Figure 5.6.1.1 – Alternative Plan D Capacity in Summer and Winter



Notes: “Other” = biomass, small combustion turbines, NUGs, demand response, purchases, & heavy oil units

Adding energy storage resources is one way the Company could meet this winter capacity deficit. The capacity value of energy storage resources is limited, however, by the size of the resource and by the time it takes to recharge. Significantly more energy storage capacity would be needed, both in magnitude and duration, as the peak gets steeper and as the period that those resources are expected to support the system becomes longer. The combination of these factors would likely lead to an overbuilt system (*i.e.*, a system with higher resource nameplate capacity compared to peak load). In addition, many forms of utility-scale energy storage are still in the early stages of development, as discussed further in Section 5.5.1, with higher costs relative to other current technologies. Technological advancements may provide other options to meet this challenge in the long term without necessitating an overbuild of the system.

The Company could also meet this challenge related to winter capacity in the future by buying capacity to fill the deficit to the extent required by PJM market rules. In this 2020 Plan, the Company assumed it would meet any winter deficit with capacity from the market. Historically, the Company was able to self-supply to meet the vast majority of all its capacity needs; Alternative Plans C and D rely heavily on the market to maintain the reliability of the system.

## 5.6.2 Challenges Related to Energy

In addition to challenges related to winter capacity, development of significant volumes of solar generation also present challenges related to energy. Specifically, the Company would likely need to import a significant amount of energy during the winter, but would need to export

significant amounts of energy during the spring and fall. Figure 5.6.2.1 shows the level of imports for each Alternative Plan. Figure 5.6.2.2 shows what percentage of time in the year 2045 the Company must use imports to meet load. In addition, Figure 5.6.2.2 shows the percentage of time in year 2045 that imports are constrained by system limitations—5,200 MW for Plans A and B, and 10,400 MW for Plans C and D.

Figure 5.6.2.1 – Annual Imports for Each Alternative Plan

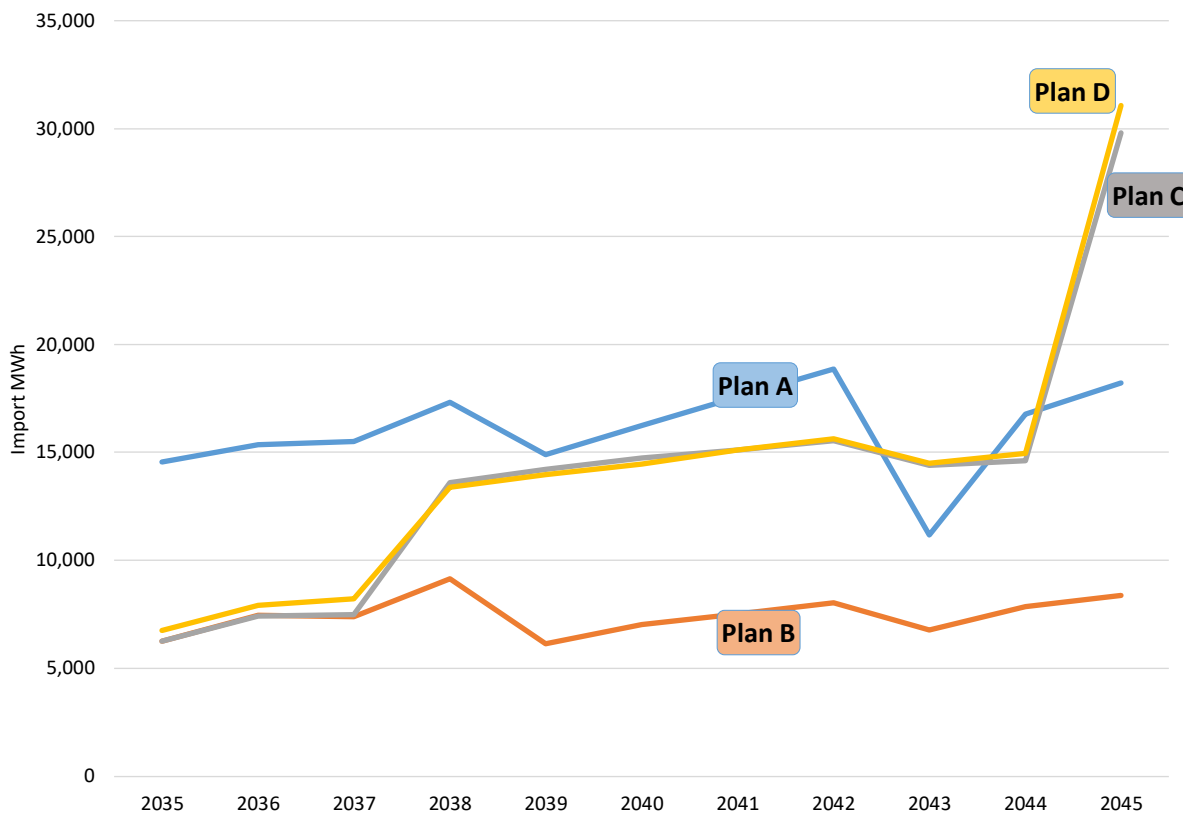
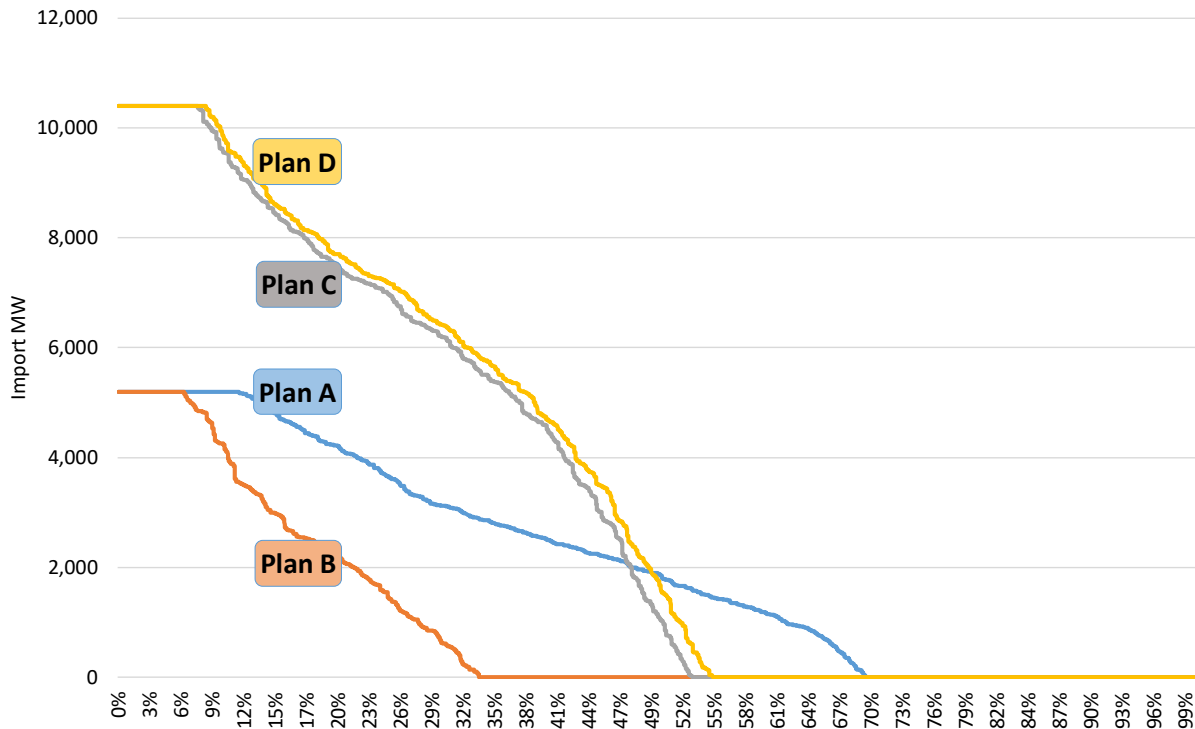


Figure 5.6.2.2 – Year 2045 Import Duration Curve



Importing significant energy presents its own challenges. Section 7.5 includes a discussion of the upgrades that would be needed to the Company’s transmission system to physically import these increased levels of energy, as well as an estimate of those costs. Notably, relying on increased imports could also contribute to regional CO<sub>2</sub> emission because the imported power from PJM would come in part from carbon-emitting generation in the PJM region. Figure 2.2.6 shows regional carbon emissions for each Alternative Plan.

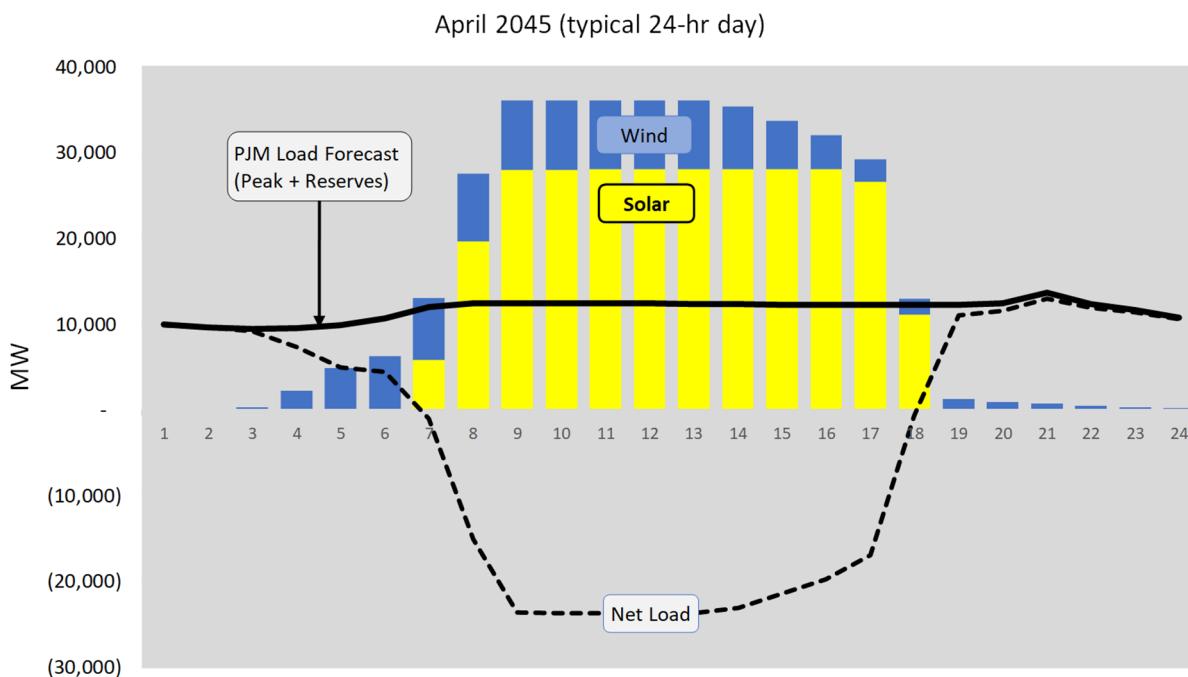
### 5.6.3 Challenges Related to the Solar Production Profile

Output from solar facilities generally tracks the sun, ramping up in the morning as the sun rises, producing consistently throughout the day subject to cloud cover, and then ramping down as the sun sets. This production profile generally (although not perfectly) fits well with customer demand in the summertime because customer demand is higher during the afternoon hours when solar production is high. In the spring and fall, however, as increasing amounts of solar generation is added to the system, solar can produce more energy than is needed to meet customer demand during the daytime.

Figure 5.6.3.1 shows the capacity of the solar and wind resources in Alternative Plan D during a typical day in April compared to the PJM Load Forecast. As can be seen, the inclusion of large amounts of solar and wind generation significantly alters the shape of the net load profile (*i.e.*, forecasted load less the non-dispatchable solar and wind energy) causing a dip in the middle of the day. This profile is commonly referred to as a “duck curve” because it produces a profile

that resembles the silhouette of a duck. As Figure 5.6.3.1 shows, the Company would need additional energy at dawn and dusk, but would have excess energy during the daytime.

Figure 5.6.3.1 – Solar and Wind Capacity Compared to Load Forecast



The Company could address this challenge with additional energy storage resources, though some energy would be lost when storage resources are used. The Company could also increase the amount of energy it exports subject to system need, though this would be limited by transmission export capacity. The Company may also be limited in its ability to export excess energy in the spring and fall to the extent neighboring states elect to develop significant volumes of solar resources similar to Virginia and also have excess energy.

In some instances, it would become more economic to “dump” this excess energy when compared to the costs of building additional energy storage resources, increasing transmission export capacity, or facing negative market energy prices. From an operational perspective, energy is “dumped” by lowering the output levels of certain solar facilities during periods of low demand. One possible clean energy solution to this challenge, however, would be to utilize long-term storage solutions for this dump energy. For example, the Company could utilize this excess energy to create carbon-free hydrogen fuel that could subsequently be used in natural gas-fired generators. When hydrogen fuel is used in gas-fired generators, the byproduct is water rather than CO<sub>2</sub>. The Company will continue to study these types of innovative alternatives to address challenges caused by increasing levels of solar generation on the system. Based on the advancements and innovations in the industry in the next 25 years, Virginia may need to adjust its RPS to accommodate other potential technologies that would provide clean energy while maintaining system reliability.

Another potential issue caused by the solar production profile shown in Figure 5.6.3.1 is the steep generation changes in the dawn and dusk periods. In a three-hour period, the system would



have to ramp over 30,000 MW of supply—an extremely large magnitude, especially over that short of a duration. Essentially, the Company would be ramping up and down its entire fleet of dispatchable resources twice a day. Backup generation resources along with energy storage resources may be required to manage these large transitions.

#### ***5.6.4 Challenges Related to Black Start and System Restoration***

“Black start” refers to the critical process of restoring the system without relying on the external transmission network to recover from a total or partial shutdown. Development of significant volumes of solar generation also present challenges in a black start event. The system has traditionally been set up to rely on dispatchable, quick-start units for black start, such as combustion turbines. Initial power from these units are used to start larger dispatchable generators, allowing even larger units (*e.g.*, nuclear) and customers to reconnect to the grid in a very logical and coordinated process. This process is largely a manual process for grid operators as they must maintain a fine balance between energy supply and demand; black start units thus have strict operational requirements to be available around-the-clock and be able to produce steady and predictable output. Such requirements impose difficulties for non-dispatchable, intermittent solar resources to be included in the system restoration plan.

In this 2020 Plan, Alternative Plan B preserves approximately 9,700 MW of natural gas-fired generation to address future system reliability, stability and energy independence, including challenges related to black start. The Company will continue to study how to address these black start-related challenges as the Company transition to a cleaner future, as discussed further in Section 7.5.5.

#### ***5.6.5 Challenges Related to Constructability***

Beyond the system challenges that arise from adding increasing amounts of intermittent generation to the system, solar developers—including the Company—will face increasing challenges in permitting and constructing the amount of solar generation envisioned by the VCEA, as modeled in Alternative Plans B through D.

Utility-scale solar generating facilities require a significant amount of land. Based on current technology, every one megawatt of solar capacity requires approximately 10 acres of land. The VCEA requires this new solar capacity to be located in Virginia. Acquiring this amount of land—and receiving the required permits for that land—could prove increasingly difficult as development continues.

This difficulty in acquiring land and permitting projects will be exacerbated if localities and members of the public continue to raise objections to siting solar facilities in their communities. For example, in October 2019, the Culpepper County Board of Supervisors adopted new provisions to its Utility Scale Solar Development Policy intended “to limit ‘utility scale solar sprawl.’” These new provisions would limit total solar development in the county to 2,400 acres—1% of the total land mass in Culpeper—and would limit the size of individual projects to 300 acres (the equivalent of approximately 30 MW). As another example, in Spotsylvania County, Virginia, neighboring property owners and community members have filed complaints

with the county's board of zoning appeals related to the development of a 6,300 acres utility-scale solar facility.

Aside from the land, the supply chain organization for the solar industry will be challenged to meet the level of solar generation in Alternative Plans B through D. This includes both equipment suppliers and construction contractors. Specifically, world-wide panel manufacturers will need to ramp up production as the demand for solar generation increases both inside the Company's service territory and across the United States. Additionally, qualified construction contractors for building utility-scale solar facilities will need to expand and train a large a labor force. Utilizing a skilled vendor to construct the solar facilities will be an important factor going forward, as the land available for future solar development is expected to be less optimal, requiring more design and engineering work to meet output targets.

# Exhibit 18

COAL | ELECTRIC POWER — 13 Apr 2020 | 20:03 UTC — New York

# Bulk of Virginia's coal plants must shut down before 2025 under new state law

Author [Darren Sweeney](#) 

Editor [Rocco Canonica](#) 

Commodity [Coal](#), [Electric Power](#)

Topic [Energy Transition](#), [Environment and Sustainability](#)

## HIGHLIGHTS

**State also will join Regional Greenhouse Gas Initiative**

**Sets mandatory benchmarks to reach 100% renewable power**

Dominion Energy Virginia must shut down its 1,032-MW Chesterfield coal plant within the next five years under a new Virginia law that essentially phases out the state's coal-fired generation.

The Virginia Clean Economy Act, signed into law on April 12 by Governor Ralph Northam, requires "all coal-fired electric generating units operating in the Commonwealth" to be retired by the end of 2024 with limited exceptions. The governor also signed legislation that will lay the groundwork for the state to join the Regional Greenhouse Gas Initiative.

"These new clean energy laws propel Virginia to leadership among the states in fighting climate change," Northam said in an April 12 news release. "They advance environmental justice and help create clean energy jobs. In Virginia, we are proving that a clean environment and a strong economy go hand-in-hand."

The Virginia Clean Economy Act requires Dominion Energy Virginia, known legally as Virginia Electric and Power Co., and American Electric Power Co. Inc. utility Appalachian Power Co. to "retire all other electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity" by Dec. 31, 2045.

The act replaces the state's voluntary renewable portfolio standard with mandatory annual benchmarks that would eventually require electricity suppliers to produce 100% of their electricity from renewable sources.

Appalachian Power must procure 100% of its electricity from renewable resources by 2050, while Dominion Energy Inc. subsidiary Dominion Energy Virginia must hit that benchmark by 2045.

Dominion Energy Virginia and Appalachian Power must "retire all generating units principally fueled by oil with a rated capacity in excess of 500 [MW] and all coal-fired electric generating units operating in the Commonwealth"

by Dec. 31, 2024. The bill provides an exception for coal plants co-owned with a cooperative utility and for Dominion Energy Virginia's 624-MW Virginia City Hybrid Energy Center.

## SIX COAL PLANTS

An S&P Global Market Intelligence analysis showed there are six coal-fired power plants operating in Virginia, with a total combined output of 2,927 MW. Dominion owns two and co-owns a third, the 881-MW Clover plant, with Old Dominion Electric Cooperative.

The remaining three coal plants are small with the 105-MW Spruance Genco unit owned by asset manager Ares Owners Holdings LP set to be retired later this year.

Appalachian Power retired the 335-MW Glen Lyn coal plant and the last coal unit at its 705-MW Clinch River plant in Virginia in May 2015.

"The Virginia Clean Economy Act sends a clear message to polluters in Virginia and possibly beyond: investments in fossil fuels are not only immoral, they are uneconomical," Harrison Wallace, Virginia Director of the Chesapeake Climate Action Network's Action Fund, said in a written statement. "Now, with the passage of this historic legislation, we have the opportunity to bring thousands of Virginians to work in a new energy economy that will clean up our air and improve public health."

Northam signed an executive order in September 2019 calling for 30% of the state's electricity to be generated from renewable resources by 2030 and 100% of Virginia's electricity to be produced by carbon-free resources by 2050.

In February, Dominion Energy said it would shut down coal plants and ramp up renewable investments to achieve net-zero carbon dioxide and methane emissions by 2050 for both its power generation and natural gas operations.

In a recent filing with the Virginia State Corporation Commission, Dominion

said that "significant build-out of natural gas generation facilities is not currently viable" under the Virginia Clean Economy Act.

Dominion did not indicate whether it would abandon any gas-fired generation plans in its 2020 integrated resource plan.

The company laid out plans to add at least eight new natural gas-fired plants, totaling nearly 3,700 MW, by 2033 in its 2018 integrated resource plan.

"Natural gas remains an important part of the around the clock reliability our customers rely on," Dominion Energy spokesman Jeremy Slayton said in a written statement.

In addition to phasing out fossil fuels, the Virginia Clean Economy Act adopts a target for energy storage deployment of 3,100 MW by the end of 2035. A new energy efficiency standard also would apply to both utilities with a 5% energy savings target for Dominion and a 2% target for Appalachian Power by 2025, both from 2019 levels.

The legislation establishes that 16,100 MW of solar and onshore wind, including 100 MW of rooftop solar, is in the public interest.

"The construction or purchase" of offshore wind facilities up to 5,200 MW off the Virginia shoreline by Dec. 31, 2024, also is in the public interest.

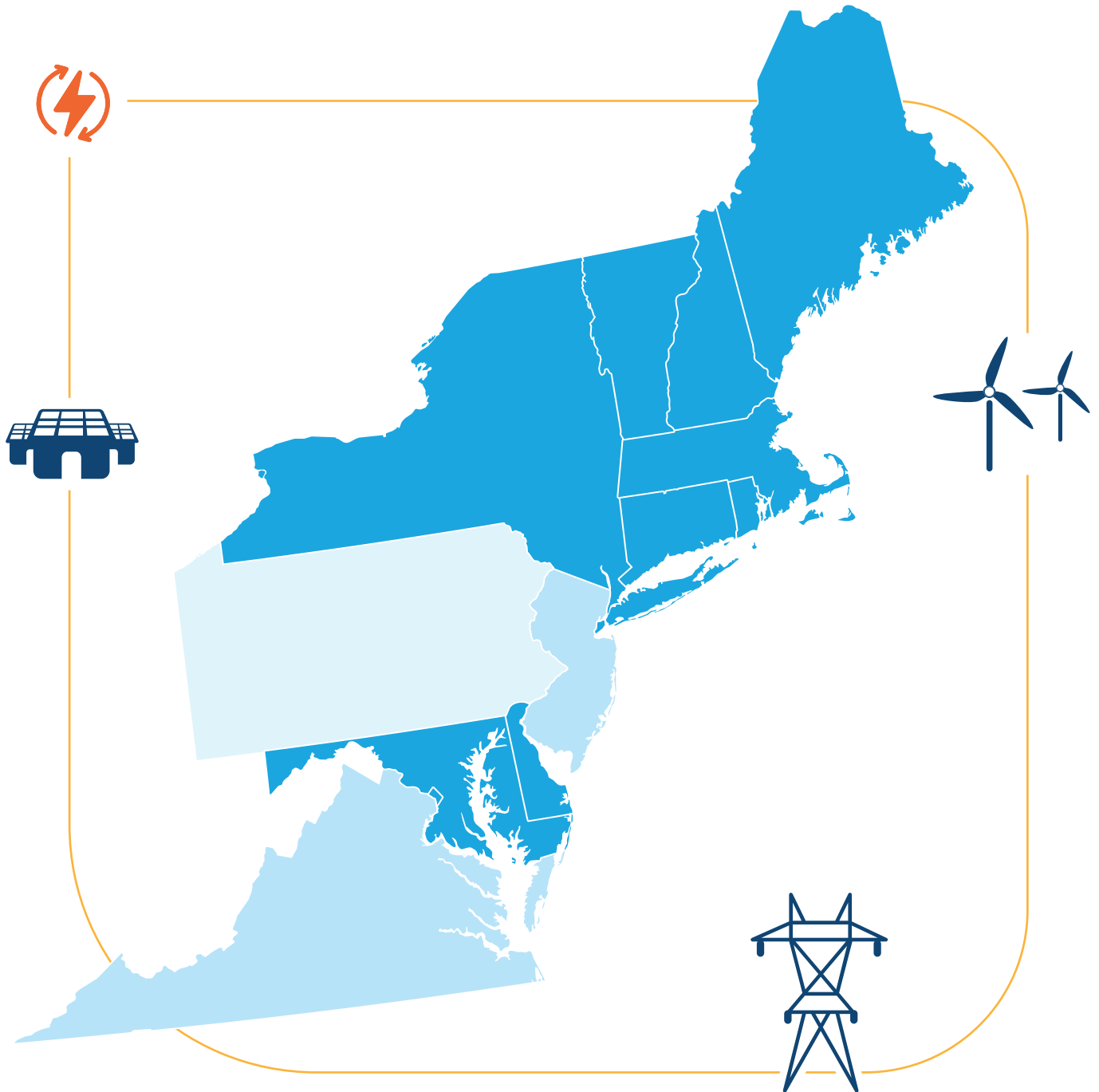
Dominion Energy Virginia in September 2019 announced plans to build the "largest offshore wind project" in the U.S. off the coast of Virginia Beach in three phases of 880 MW each. If approved, the first phase of the \$8 billion project would be completed in 2024, with the final phases expected to come online in 2025 and 2026.

# Exhibit 19



# The Regional Greenhouse Gas Initiative

## 10 Years in Review



2019

## Executive Summary

Through ten years of operation, the Regional Greenhouse Gas Initiative (RGGI) has helped Northeast and Mid-Atlantic states<sup>1</sup> achieve significant reductions in emissions of carbon dioxide (CO<sub>2</sub>) and other pollutants from the electric power sector. The country's first program designed to reduce climate change-causing pollution from power plants has provided a wealth of lessons to be incorporated into the next generation of climate policies, from successes to build on to opportunities for improvement.

The participating states have experienced substantial benefits from RGGI since 2008, the year before the program launched. Concerns that climate policy would make states less competitive have been directly refuted by RGGI's experience: the RGGI program is helping participating states outperform the rest of the country. Since 2008:

- **CO<sub>2</sub> emissions from RGGI power plants have fallen by 47%**, outpacing the rest of the country by 90%;
- **Electricity prices in RGGI states have fallen by 5.7%**, while prices have *increased* in the rest of the country by 8.6%;
- **GDP of the RGGI states has grown by 47%**, outpacing growth in rest of the country by 31%;
- **RGGI states have generated \$3.2 billion in allowance auction proceeds**,<sup>i</sup> the majority of which have been invested in energy efficiency and renewable energy programs; and
- **RGGI-driven reductions in co-pollutant emissions have resulted in over \$5.7 billion in health and productivity benefits.**<sup>ii</sup>

Much has changed since RGGI was launched, beyond the climate, economic and health improvements described above. Most notably, climate policy has advanced by leaps and bounds. When RGGI was implemented, it was just the second program in the world to regulate carbon emissions, and the first to require polluters to pay for emissions allowances (permits to emit pollution). Now, there are 57 national or subnational carbon pricing programs in place,<sup>iii</sup> many of them drawing on lessons learned from RGGI.

At the same time, findings from the scientific community have made the urgency of climate action increasingly hard to ignore. If the planet is to avoid crossing the 1.5 degree warming threshold, global annual GHG emissions need to be reduced by 45% from 2010 levels by 2030.<sup>iv</sup> To make a meaningful difference in reducing the catastrophic costs of climate change, we need urgent action.

Finally, sound climate policy needs to be oriented around climate justice. Programs designed to reduce GHG emissions must be good for the planet and for communities. In the RGGI context, that means improving air quality in environmental justice communities, ensuring that underserved populations have access to RGGI-funded energy efficiency and clean energy programs, and importantly, that those communities have a say in shaping the policy.<sup>v</sup> While there is much more to do to protect vulnerable communities from power plant pollution, states must also act with urgency to reduce locally-harmful pollution from other sources, most notably transportation.

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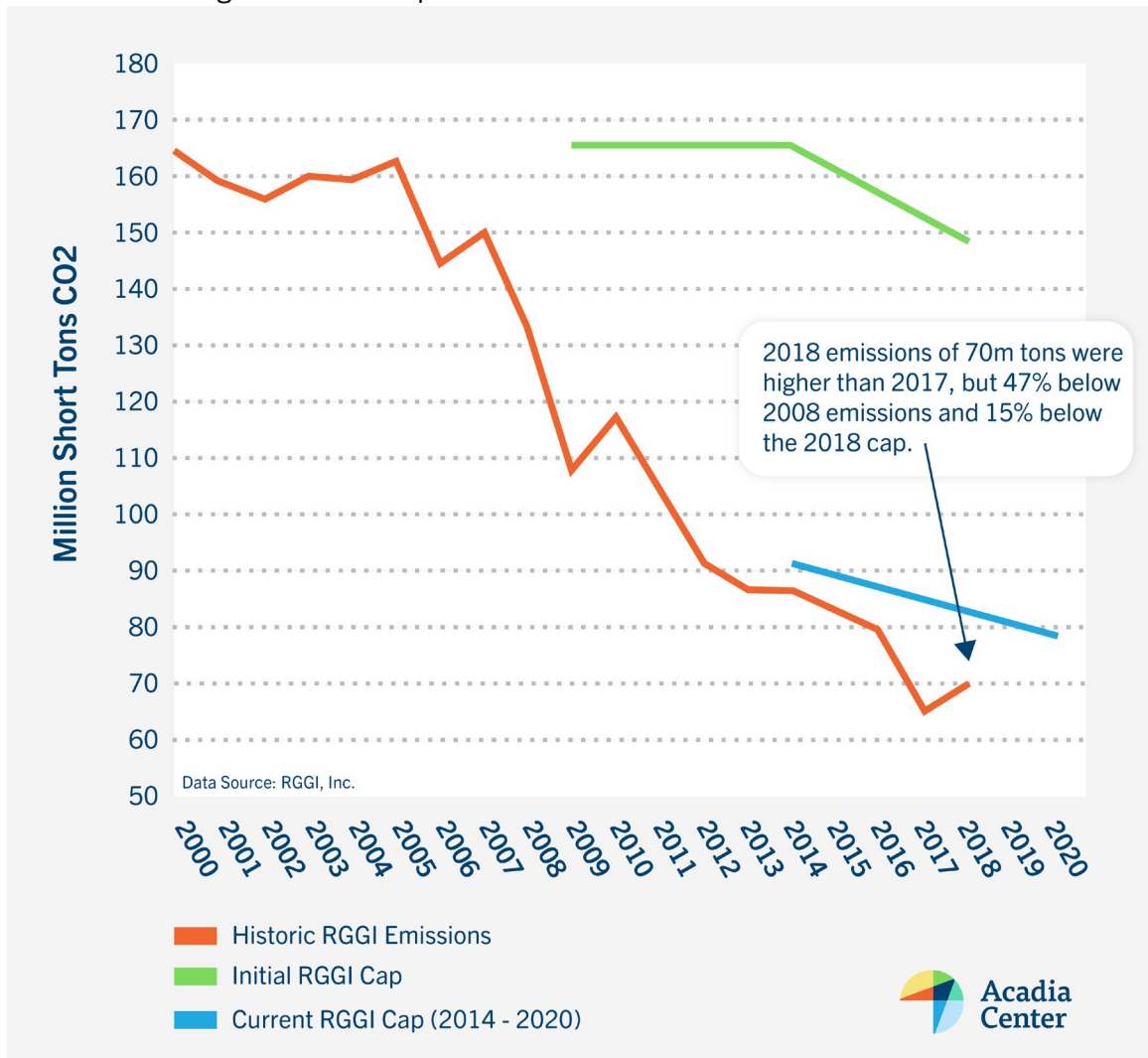
<sup>1</sup> Analysis in this report covers the currently participating RGGI states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. [Footnotes elaborate on points within this report, whereas endnotes cite references and provide detailed analytic methodologies where relevant.]

## Emissions Trends and RGGI Cap Dynamics

### Rapid CO<sub>2</sub> Reductions Outpace the Rest of the Country

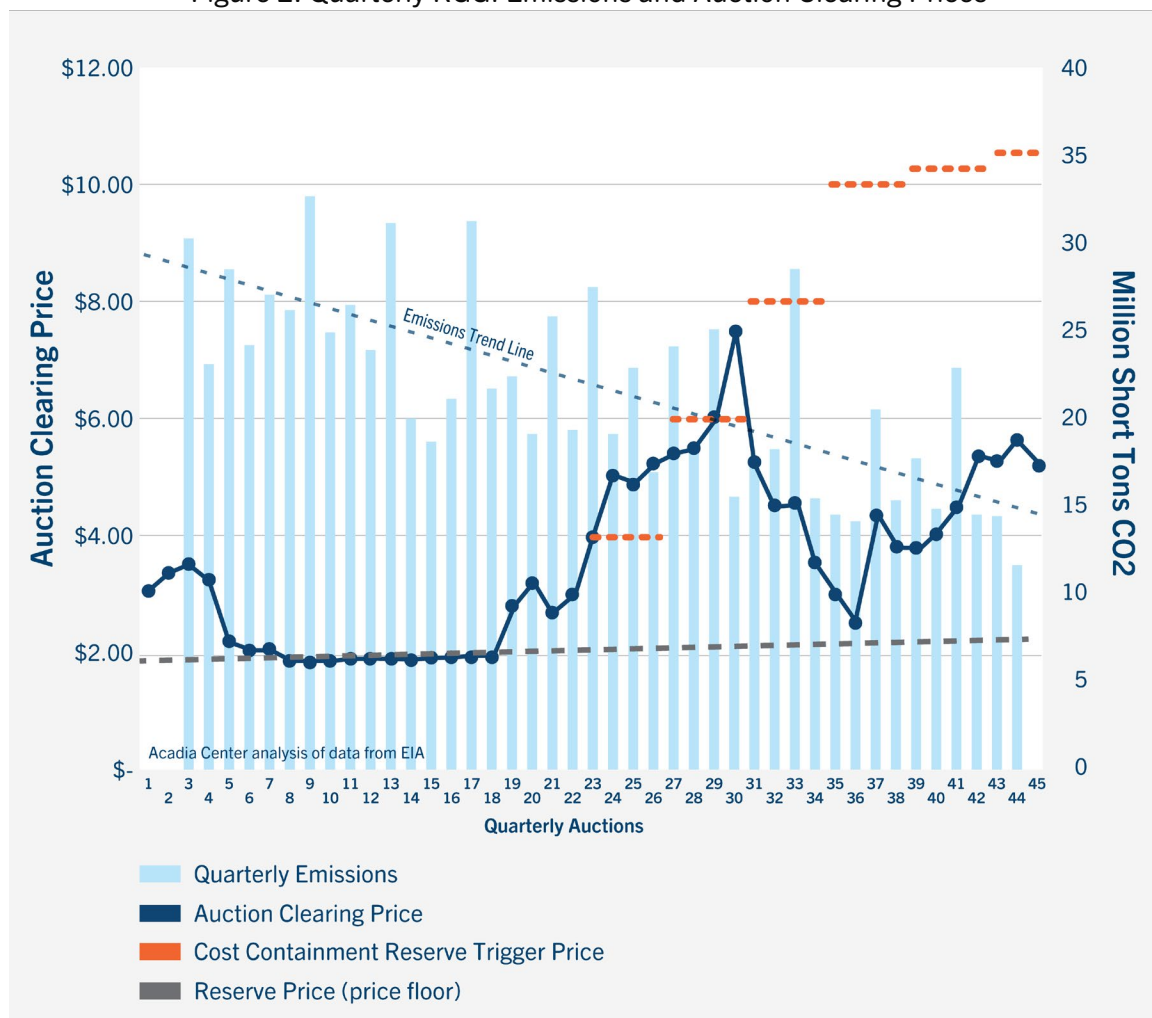
States participating in RGGI have seen a steep decline in CO<sub>2</sub> emissions from power plants over the last 10 years. Since 2008, the year before the program launched, RGGI emissions have fallen from 133 million short tons of CO<sub>2</sub> to 70 million tons in 2018, shown in Figure 1. The impressive electric sector emission reductions achieved in RGGI states over that time period have outpaced reductions in the rest of the country by a staggering 90%. While the RGGI program has not been the sole factor behind the region's rapid electric sector decarbonization, earlier analysis shows that it has been a key driver—and accelerator—of emission reductions from power plants.<sup>vi</sup>

Figure 1: RGGI Cap and Historic Emissions – Nine RGGI States



As Figure 2 shows, rapidly declining RGGI emissions and an oversupply of allowances have kept RGGI allowance prices relatively low. From Auctions 8 to 18, RGGI allowances sold at the reserve price—the lowest price at which allowances can be sold through auction—and the highest RGGI auction clearing price since the program launched was \$7.50 per allowance. For comparison, the 2019 auction reserve price in California and Quebec’s cap-and-invest program is \$15.62 per allowance.<sup>vii</sup> This higher reserve price provides a greater incentive to pursue additional CO<sub>2</sub> abatement measures.

Figure 2: Quarterly RGGI Emissions and Auction Clearing Prices



## Aligning the RGGI Cap with Current Emissions and the Climate Crisis

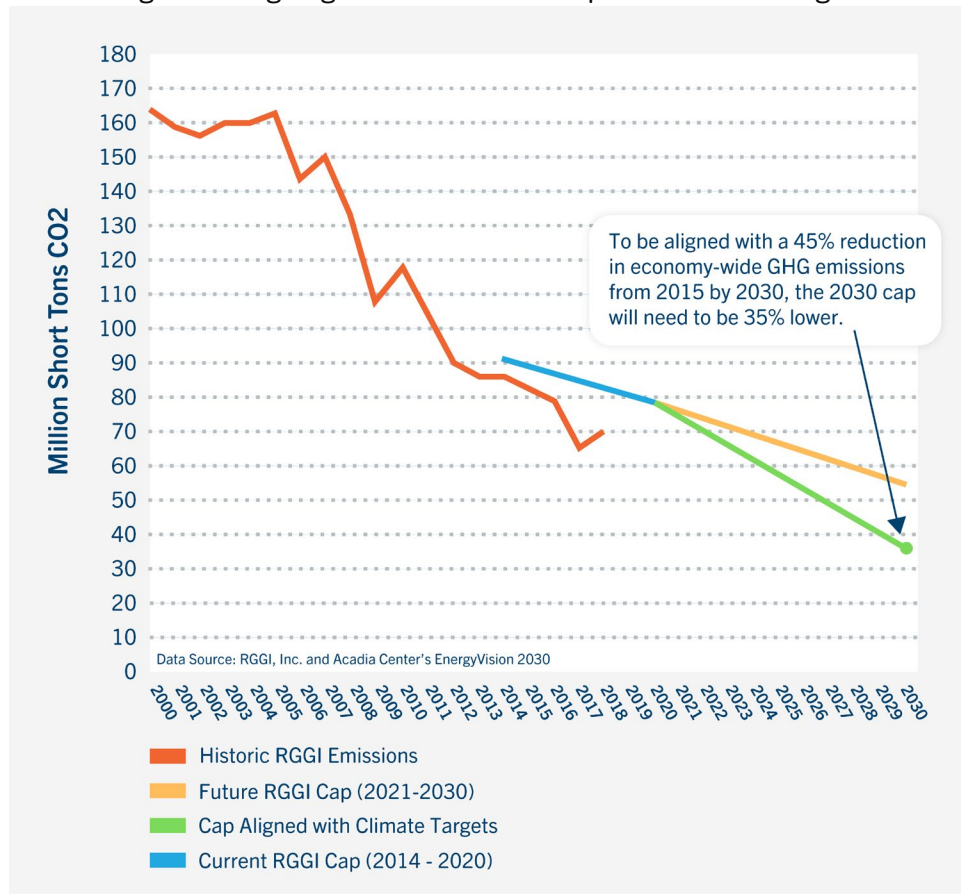
Through the first half of 2019 it appears the trend of declining RGGI emissions will continue, with RGGI COATS<sup>viii</sup> data showing the lowest first-half emissions in the program’s history (see Figure 2).<sup>ix</sup> The fact that RGGI emissions have been well below the RGGI cap in every year of the program’s history, as shown in Figure 1, is good for the climate and encouraging for future decarbonization efforts, but it also highlights the need for certain program reforms.

Chief among these reforms is a more stringent cap on emissions. In 2017, at the conclusion of the latest RGGI Program Review, the RGGI states committed to a new cap from 2021-2030 with a slightly faster emission reduction trajectory than the cap in place from 2014-2020. The extension of the cap and the increased ambition are positive steps, and the 2030 cap level of 54.7 million short tons commits the region to a 30% reduction in electric sector CO<sub>2</sub> emissions beyond the 2020 requirement. In addition to the lower cap, the Program Review resulted in measures that will strengthen the program by constraining RGGI allowance supply and limiting future emissions.<sup>x</sup> A third adjustment for banked allowances will eliminate the allowance surplus accrued through 2020, higher Cost Containment Reserve (CCR) price triggers will help avoid unnecessary increases in allowance supply, and the innovative Emissions Containment Reserve (ECR) will help the RGGI states secure additional, low-cost emission reductions.<sup>xi</sup>

Despite these measures to strengthen the program, a more ambitious RGGI cap is necessary. 2018 emissions are already well below the new, more ambitious cap set for 2021. In fact, 2018 emissions are already below the cap level set for 2023. To be most effective, the RGGI cap needs to more closely reflect the new, lower-carbon reality of the region's electric sector and the science-based GHG reduction targets adopted by the RGGI states.

The region's electric sector CO<sub>2</sub> emissions will need to be far below the 2030 cap if the region is to achieve its economy-wide GHG reduction goals. Acadia Center's EnergyVision 2030<sup>xii</sup> finds that for the Northeast states to achieve a 45% reduction in economy-wide GHG emissions by 2030 (from 2015 levels), the region would need to achieve a 57% reduction in electric sector GHG emissions by 2030 (compared to a 20% reduction from transportation and 30% reduction from buildings). As shown in Figure 3, if that 57% reduction from 2015 were applied to the RGGI cap, it would yield a 2030 cap of 35.8 million short tons: a 35% lower RGGI cap than what the states have agreed to. This more ambitious electric sector decarbonization will make it possible for the region to achieve greater emission reductions through the electrification of other sectors.

Figure 3: Aligning the Future RGGI Cap with Climate Targets



Of course, achieving economy-wide climate targets will require significant action to reduce GHG emissions from all sectors. There are critical carbon pricing policies currently in development or under consideration that, if implemented, will steer the region in the right direction. At the state level, momentum is building around carbon pricing bills that would establish a price on CO<sub>2</sub> emissions from sectors not covered by RGGI. Across the region, the 12 states of the Transportation & Climate Initiative (TCI) are developing a multi-state cap-and-invest program to reduce CO<sub>2</sub> emissions from the transportation sector.<sup>xiii</sup> Both of those policies can build on the best of the RGGI model, but in order to be most effective, they will depend on a decarbonized electric sector.

## Economic Trends and Electricity Prices

### RGGI's Economic Impacts

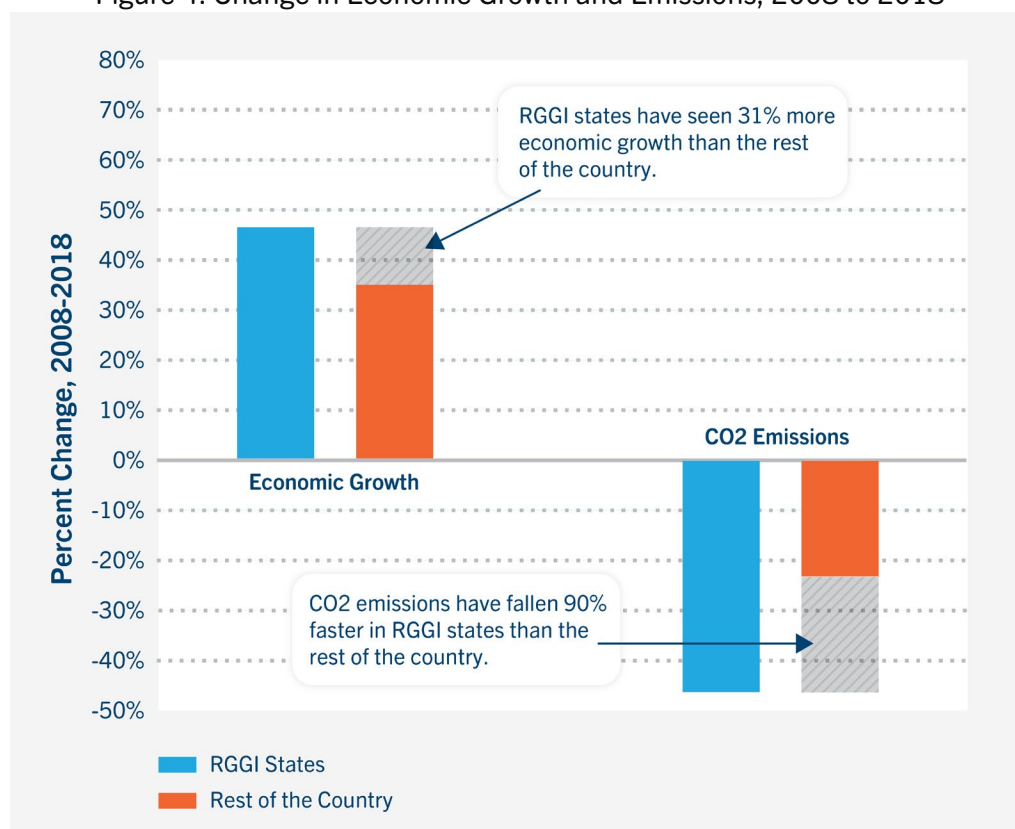
RGGI has generated significant economic benefits for states participating in the program. By selling allowances, RGGI states raise revenue to reinvest in energy efficiency, renewable energy, and other consumer programs that increase economic activity in participating states. The majority of program revenue (58% through 2016<sup>xiv</sup>) has been invested in energy efficiency programs that reduce consumers' bills and reduce demand for power. Lower power demand resulting from energy efficiency means fewer emissions from power plants, and less money leaving the region to pay for imported fossil fuels. Energy bill savings increase consumer spending, benefiting businesses that offer goods and services in the region. According to independent macroeconomic analysis of

RGGI through 2017, the program has created over \$4 billion in net economic gains and over 44,000 job-years of employment.<sup>xv</sup>

## Economic Growth and Emissions

The RGGI states have managed to rapidly reduce CO<sub>2</sub> emissions without impeding economic growth. In fact, the region has proven that decarbonization and economic growth can go hand in hand. While the country as a whole has been experiencing declining CO<sub>2</sub> emissions and economic growth, the RGGI states have seen faster economic growth and steeper CO<sub>2</sub> reductions. As shown in Figure 4, from 2008 (before RGGI's launch) to 2018, **RGGI states' economies grew by 46.9% versus 35.8% in states that do not regulate or put a price on carbon emissions** (this group of 40 states, referred to below as the "rest of the country", does not include California, which has similarly outpaced national growth since capping carbon emissions<sup>xvi</sup>). Over the same 2008 to 2018 period, **emissions in the RGGI region dropped by 46% versus 24% in the rest of the country.**<sup>xvii</sup>

Figure 4: Change in Economic Growth and Emissions, 2008 to 2018

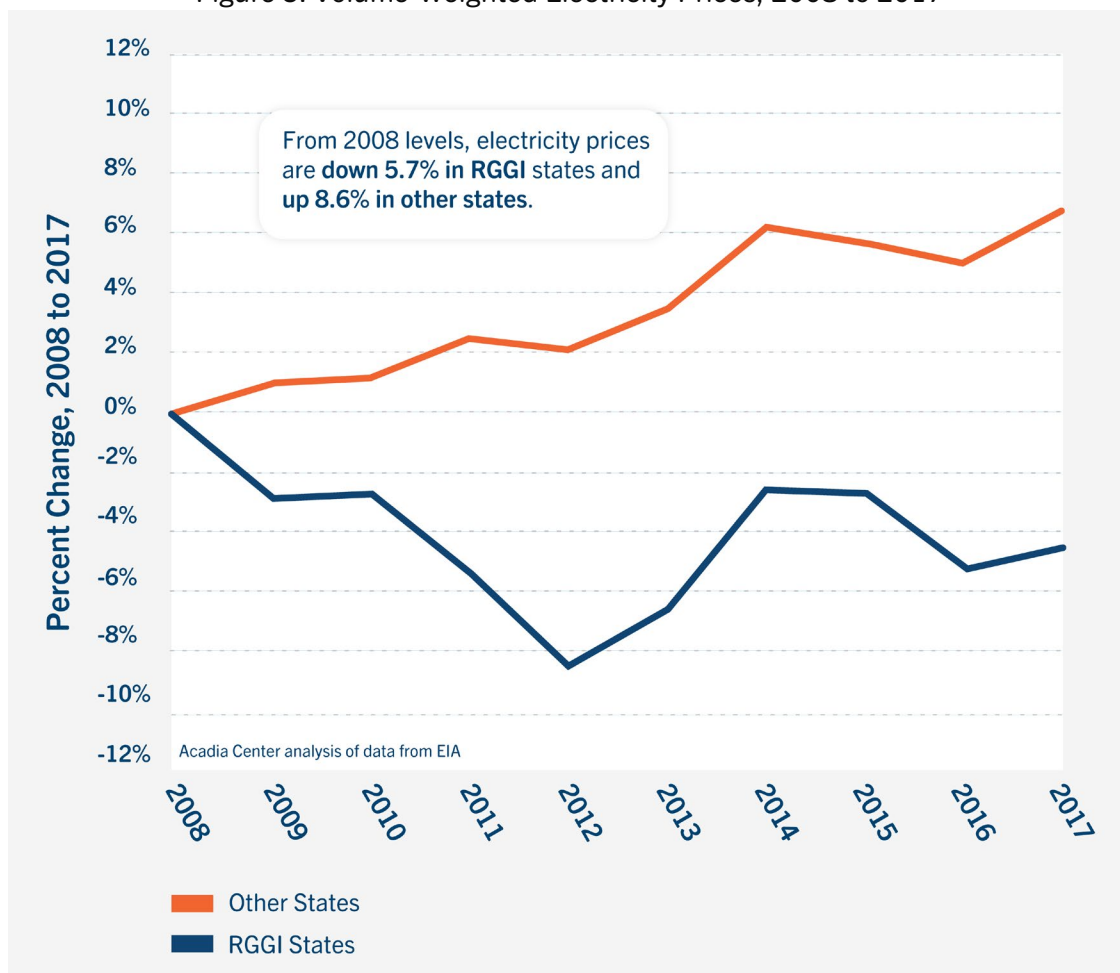


Electricity demand has historically been tied to economic growth, with electricity consumption and related emissions increasing during periods of economic expansion and decreasing in economic downturns. This correlation has been broken in the RGGI region, a new reality that appears to be mirrored—though slightly less dramatically—at the national level. A decade of RGGI and decarbonization of the electric power sector demonstrates that emissions reductions can be achieved as the economy grows.

## Electricity Prices

Average retail electricity prices in the region have decreased since RGGI took effect. Comparing retail electricity prices from 2008 to 2017 shows that prices have dropped by 5.7% across the region.<sup>xviii</sup> While RGGI's direct impact on electricity prices is difficult to isolate from other factors, it is evident that the program has not caused electricity prices to rise from 2008 levels, in part due to RGGI-funded investments in energy efficiency. Concerns that climate policy will make states less competitive are directly refuted by RGGI's experience: RGGI states are faring much better than the rest of the country on electricity price trends. As shown in Figure 5, while RGGI's electricity prices have fallen from where they were in 2008, the rest of the country<sup>2</sup> has experienced an 8.6% increase in retail electricity prices over the same period.

Figure 5: Volume-Weighted Electricity Prices, 2008 to 2017



<sup>2</sup> The “rest of the country” excludes California, which, like the RGGI states, has implemented a cap-and-invest program to reduce CO<sub>2</sub> emissions.

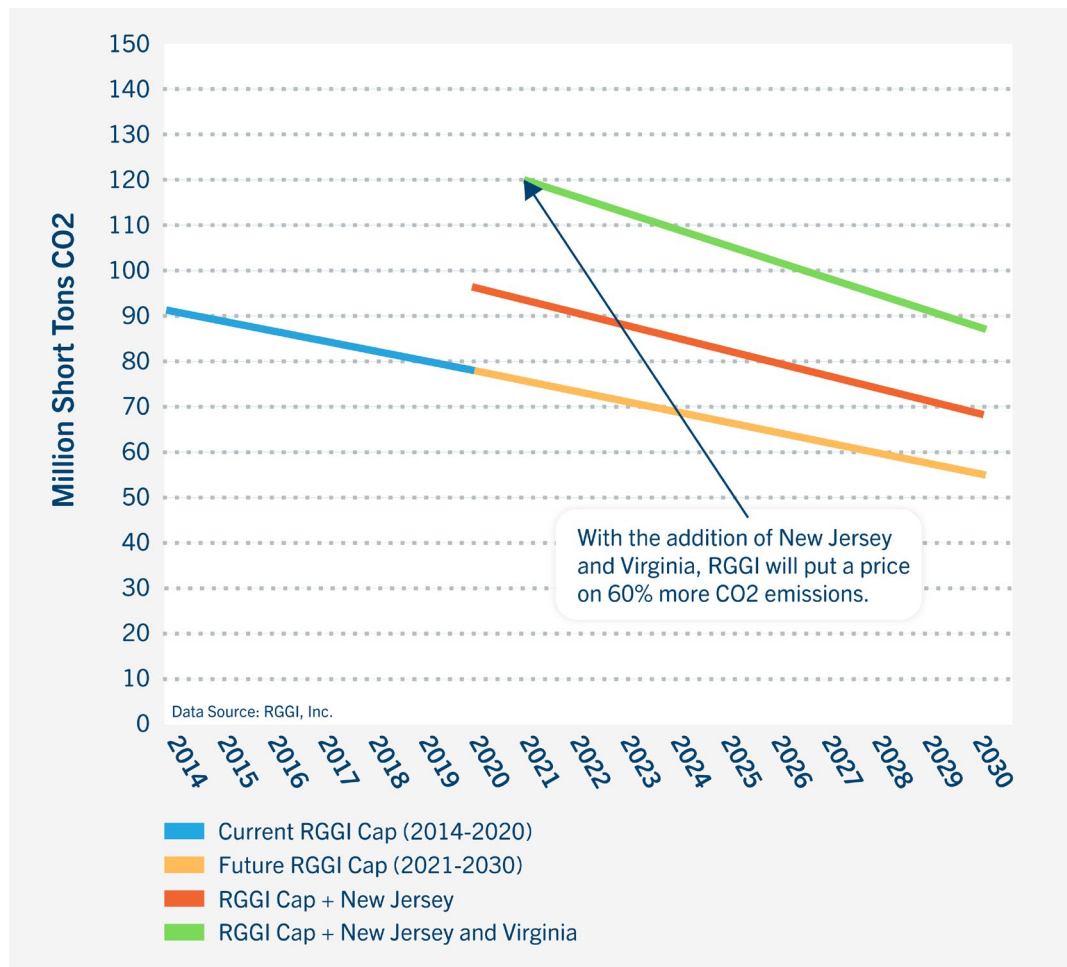


## Welcoming Additional States

There are currently nine states participating in the RGGI market, but that number is poised to grow to 11 by 2021. New Jersey is set to be the first addition, with the New Jersey Department of Environmental Protection adopting regulations in the summer of 2019 to rejoin the RGGI program on January 1<sup>st</sup>, 2020.<sup>xix</sup> This will mark New Jersey's return to the program, as the state participated in RGGI as a founding member until then-Governor Christie removed the state from the program in 2011. It appears likely that Virginia will follow New Jersey, with regulations approved to participate in a carbon trading program linked with the RGGI market.<sup>xx</sup> Virginia's participation in the RGGI market is expected to begin on January 1<sup>st</sup>, 2021.

Regulations in both New Jersey and Virginia would implement state CO<sub>2</sub> emission budgets aligned with the 2020-2030 RGGI cap, requiring a 30% reduction in region-wide emissions over that time period. The addition of these two states to the program will represent a substantial expansion, both in terms of CO<sub>2</sub> emissions and economic weight. By adding New Jersey and Virginia to the program, the combined GDP of the RGGI states would rise from \$3.3 trillion to \$4.5 trillion, a 35% increase, the equivalent of the world's 4<sup>th</sup> largest economy. As shown in Figure 6, expanding the RGGI cap to include these states would increase the amount of CO<sub>2</sub> emissions that face a carbon price by 60%.

Figure 6: RGGI Cap with New Jersey and Virginia



## Conclusion

RGGI has successfully demonstrated the viability of a market-based program to reduce CO<sub>2</sub> emissions from the power sector while generating benefits for participating states. RGGI's experience has disproven the concerns most frequently associated with capping emissions from the power sector. Emissions have declined rapidly, far more dramatically than projected, without stifling economic growth. RGGI's reinvestment model has benefited the regional economy and increased employment while accelerating deployment of renewable energy and funding energy efficiency programs. The region's residents now pay lower electricity prices than before the program began and breathe cleaner air.

The RGGI states have committed to build on this success by extending the program through 2030. In the coming years the RGGI states will need to conduct another Program Review to reevaluate how the program aligns with the achievement of state climate targets.

A cleaner electric grid will prove vital to delivering significant CO<sub>2</sub> reductions from the electrification of transportation and buildings – the two other key sectors that must be decarbonized to avert climate disaster. By strengthening RGGI and applying lessons learned from the program to the transportation sector, the region can take meaningful action to address vehicle pollution—the largest source of CO<sub>2</sub> emissions in the country. Many of the RGGI states are currently building on their track record of bipartisan collaboration to develop a regional cap-and-invest program for the transportation sector through the Transportation and Climate Initiative (TCI). If this program applies the best of the RGGI model while delivering an even bolder, more equitable framework, the region will be well on its way to a low-carbon future that works for all.

## For More Information:

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## Endnotes

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- <sup>i</sup> RGGI, Inc., *Auction Results*, 2019. Available at: <https://www.rggi.org/auctions/auction-results>
- <sup>ii</sup> Michelle Manion, et al., *Analysis of the Public Health Impacts of the Regional Greenhouse Gas Initiative*, Abt Associates, January 2017. Available at: <https://www.abtassociates.com/insights/publications/report/analysis-of-the-public-health-impacts-of-the-regional-greenhouse-gas>
- <sup>iii</sup> World Bank, *States and Trends of Carbon Pricing 2019*, Available at: <https://openknowledge.worldbank.org/handle/10986/31755>
- <sup>iv</sup> Joeri Rogelj, Drew Shindell, and Kejun Jiang, *Global Warming of 1.5°C, Chapter 2: Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development*, IPCC, October 2018. Available at: [https://www.ipcc.ch/site/assets/uploads/sites/2/2019/02/SR15\\_Chapter2\\_Low\\_Res.pdf](https://www.ipcc.ch/site/assets/uploads/sites/2/2019/02/SR15_Chapter2_Low_Res.pdf)
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- <sup>vi</sup> Brian Murray and Peter Maniloff, *Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors*, Duke Nicholas Institute, August 2015. Available at: <https://nicholasinstitute.duke.edu/environment/publications/why-have-greenhouse-emissions-rggi-states-declined-econometric-attribution-economic>
- <sup>vii</sup> California Cap-and-Trade Program and Québec Cap-and-Trade System, *Joint Auction #20 Summary Results Report*, August 2019. Available at: [https://ww3.arb.ca.gov/cc/capandtrade/auction/aug-2019/summary\\_results\\_report.pdf](https://ww3.arb.ca.gov/cc/capandtrade/auction/aug-2019/summary_results_report.pdf)
- <sup>viii</sup> RGGI CO<sub>2</sub> Allowance Tracking System: <https://www.rggi.org/allowance-tracking/rggi-coats>
- <sup>ix</sup> RGGI cap levels and emissions data from RGGI, Inc., at: <http://rggi.org/>
- <sup>x</sup> RGGI, Inc., *Summary of RGGI Model Rule Updates*, December 2017. Available at: [https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Summary\\_Model\\_Rule\\_Updates.pdf](https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Summary_Model_Rule_Updates.pdf)
- <sup>xi</sup> RGGI, Inc., *Elements of RGGI*, 2019. Available at: <https://www.rggi.org/program-overview-and-design/elements>
- <sup>xii</sup> EnergyVision 2030, Acadia Center, 2017. Available at: <https://2030.acadiacenter.org/>
- <sup>xiii</sup> The Transportation & Climate Initiative: <https://www.transportationandclimate.org/content/about-us>
- <sup>xiv</sup> RGGI, Inc., *The Investment of RGGI Proceeds in 2016*, September 2018. Available at: [https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI\\_Proceeds\\_Report\\_2016.pdf](https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2016.pdf)
- <sup>xv</sup> Paul Hibbard, et al., *The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States*, Analysis Group, April 2018. Available at: [https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis\\_group\\_rggi\\_report\\_april\\_2018.pdf](https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_april_2018.pdf)
- <sup>xvi</sup> As detailed in the Environmental Defense Fund's recent report, *Carbon Market California: A Comprehensive Analysis of the Golden State's Cap-and-Trade Program*, California has experienced significant economic benefits resulting from AB 32, and GDP growth in the state outpaced the national average in 2011, 2012, and 2013: [http://www.edf.org/sites/default/files/content/carbon-market-california-year\\_two.pdf](http://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdf)
- <sup>xvii</sup> In order to compare emissions in the RGGI states to emissions in the rest of the country, the emissions measured in this section are from EIA Form 923. This represents a broader range of emissions sources than those covered by RGGI, which explains the difference in reported RGGI emissions here versus elsewhere in this report.
- <sup>xviii</sup> Energy Information Administration (EIA), Form 826, <http://www.eia.gov/electricity/data/eia826/>. The volume-weighted average shown in Figure 5 is a product of each state's electricity price multiplied by electric load in the given year.
- <sup>xix</sup> *Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative*, Office of the Governor of New Jersey, June 2019. Available at: <https://www.state.nj.us/governor/news/news/562019/approved/20190617a.shtml>
- <sup>xx</sup> *Virginia Adopts Regulation to Limit Carbon Pollution, Fight Climate Change*, Virginia Department of Environmental Quality, April 2019. Available at: <https://www.deq.virginia.gov/ConnectWithDEQ/NewsReleases/CarbonRule.aspx>

# Exhibit 20

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## Combined cycle gas turbines

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**Topic last reviewed:** 10 April 2013

**Sectors:** Upstream

**Category:** Power and heat generation

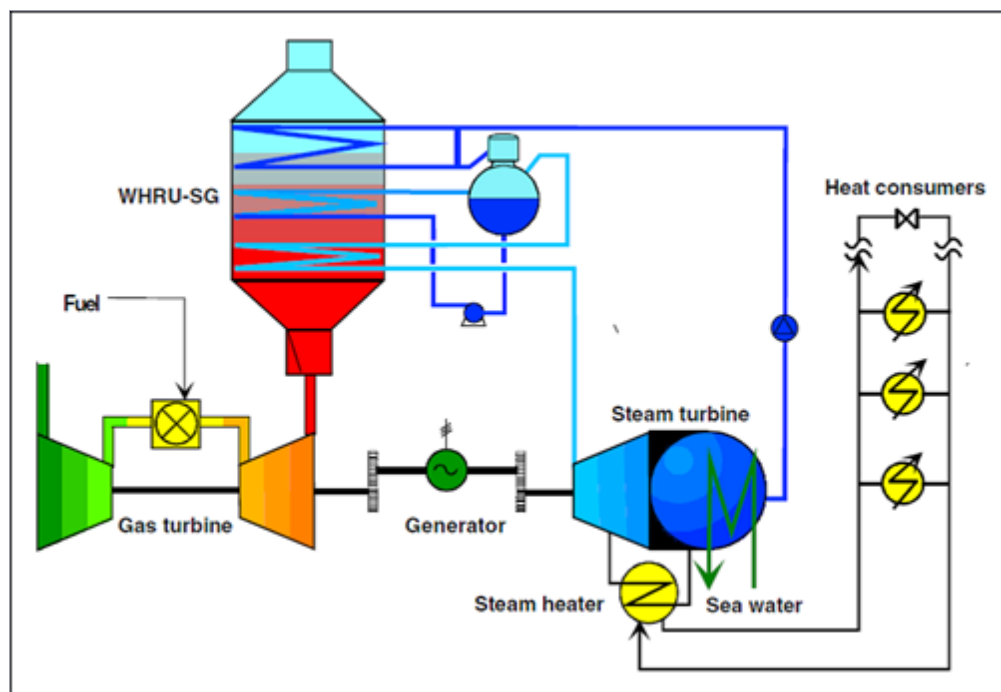
A combined-cycle power system typically uses a gas turbine to drive an electrical generator, and recovers waste heat from the turbine exhaust to generate steam. The steam from waste heat is run through a steam turbine to provide supplemental electricity. The overall electrical efficiency of a combined-cycle power system is typically in the range of 50–60% — a substantial improvement over the efficiency of a simple, open-cycle application of around 33%.

A combined-cycle power system is the traditional technology of choice for most large onshore power generation plants, and is therefore well established. The technology have also been used on a few offshore installations for over 10 years. Most offshore installations are designed to generate power from open-cycle gas turbines which offer reduced capital costs, size and weight (per MW installed), but with compromised energy efficiency and fuel costs per unit output. Combined-cycle system operation is suitable for stable load applications, but less suitable for offshore applications with variable or declining load profiles. In a new 'greenfield' development incorporating a combined-cycle system design, the size of the gas turbine can be optimized and is likely to be smaller than an equivalent open-cycle configuration. Additionally, the waste heat recovery unit (WHRU) can replace the gas turbine silencer, thereby mitigating some of the space and

Retrofitting gas turbine generator technology to convert from simple, open-cycle systems to combined-cycle operation is complex and costly; hence this is not common in offshore installations. The additional topside weight and space necessary to incorporate a steam turbine, as well as the need for additional personnel on the platform to manage the steam system operations, makes a combined-cycle retrofit a challenging project.

A combined-cycle power system typically consists of the following equipment: gas turbines (GTs); waste heat recovery units for steam generation (WHRU-SG); steam turbines (STs); condensers; and other auxiliary equipment. The figure below illustrates a combined-cycle power system using a gas turbine generator with waste heat recovery and steam turbine generator.

**Figure 1: Combined cycle power system using a gas turbine generator with waste heat recovery and steam turbine generator**



For a more detailed description of this technology in typical onshore applications, please refer to:

BREF on Large Combustion Plants (see Reference 3)

BREF on Energy Efficiency (general info under the chapter for cogeneration, see Reference 4)

Offshore Gas Turbines (and Major Driven Equipment) Integrity and Inspection Guidance Notes (see Reference 6)

## Technology maturity

<b>Commercially available?:</b>	Yes
<b>Offshore viability:</b>	Yes
<b>Brownfield retrofit?:</b>	Yes
<b>Years experience in the industry:</b>	5-10

## Key metrics

<b>Range of application:</b>	10 ~ 20 MW (not including the gas turbine) power units already installed in the industry; potentially up to 50 MW (Wall, et al.)
<b>Efficiency:</b>	50–60% (overall power generation efficiency), a significant improvement over simple cycle efficiencies of around 33%
<b>Guideline capital costs:</b>	Offshore brownfield: No known cases
<b>Guideline operational costs:</b>	Less fuel and energy is used, saving operational costs

**Typical scope of work  
description:**

For new offshore installations, it is important to analyse the need for power and heat, the available space, and weight restrictions to design an optimal solution to balance capital costs, logistical constraints and energy costs.

For existing offshore platforms with open-cycle gas turbine generators, the space and weight constraints to install a waste heat recovery unit and steam turbine generator must be considered. Such modifications may be costly or technically infeasible for some offshore installations, and the capital cost for modification, operational cost savings from using less energy / fuel, and reduced greenhouse gas (GHG) emissions must then be evaluated before the decision to retrofit the power system can be taken.

**Decision drivers****Technical:**

Footprint: size, weight, plot area required. Current design places WHRU-SG on top of the GT, alleviating plot area issues. Weight is an issue and needs to be optimized. Could potentially lead to higher overpressures due to more equipment congestion. Load profile of installation needs to be relatively stable. Brownfield integration —waste heat capture and transport, tie-ins.

**Operational:**

Operators need to be trained in steam systems;  
Operational complexity



<b>Commercial:</b>	Driven by fuel gas price and potential gas savings and/or value of CO <sub>2</sub> reduction versus incremental capital costs
<b>Environmental:</b>	Improved energy efficiency over simple cycle. Combined cycle's improved efficiencies lead to reductions in GHG, nitrogen oxides (NO <sub>x</sub> ), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM).

## Alternative technologies

The following are technologies that provide similar benefits (high efficiency power generation) and may be considered as alternatives to a combined-cycle system:

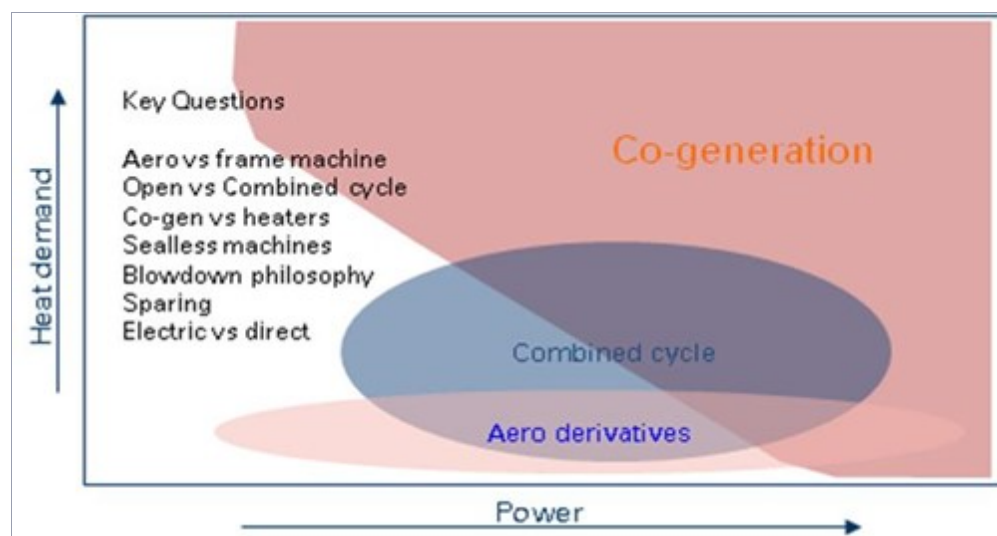
Organic Rankine Cycle (refer to Reference 5)

Aeroderivative Gas Turbines (see Reference 6)

Offshore electrification (bringing power from shore)

**Figure 2** illustrates high-level applicability of technologies based on the demand for power and heat. For low to moderate heat demand applications, combined-cycle technology may be appropriate for stable load applications; however, the trade-off between capital costs and fuel / emissions savings must be evaluated.

**Figure 2: The applicability of technologies based on the demand for power and heat**



## Operational issues/risks

Issues and risks are few and known. Combined-cycle technology has been used for many years for onshore applications. The technology has also been used for more than 10 years for offshore applications, including both floating (Snorre B) and fixed (Oseberg D) installations.

## Opportunities/business case

Steam turbine power potentially replaces an additional GT generator

Design may be optimized, especially for greenfield applications

Design allows for heat extraction, eliminating the need for fired heaters

Peak saving duties (under additional firing)

Integration with nearby platforms, central power generation unit.

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## References:

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2. Kloster, P. (ABB Miljø AS, Norway, 1999). 'Energy Optimization on Offshore Installations with Emphasis on Offshore Combined Cycle Plants'. SPE Paper 56964.
3. European Commission (2006). 'Large Combustion Plants'. Best Available Techniques Reference Document (BREF). ([http://eippcb.jrc.es/reference/BREF/lcp\\_bref\\_0706.pdf](http://eippcb.jrc.es/reference/BREF/lcp_bref_0706.pdf))
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[production-platforms.html](#))



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# Exhibit 21



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** MI-0435**Corporate/Company:** DTE ELECTRIC COMPANY**Facility Name:** BELLE RIVER COMBINED CYCLE POWER PLANT**Process:** FGCTGHRSG (EUCTGHRSG1 & EUCTGHRSG2)**Pollutant:** Carbon Dioxide Equivalent  
(CO<sub>2</sub>e)**CAS Number:** CO<sub>2</sub>e**Pollutant Group(s):** Greenhouse Gasses (GHG),**Substance Registry System:** Carbon Dioxide Equivalent (CO<sub>2</sub>e)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** P**P2/Add-on Description:** Energy efficiency measures**Test Method:**

Unspecified

[EPA/DAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

No

**EMISSION LIMITS:****Case-by-Case Basis:**

BACT-PSD

**Other Applicable Requirements:**

NSPS

**Other Factors Influence Decision:**

No

**Emission Limit 1:**

2042773.0000 T/YR 12-MO ROLLING TIME PERIOD; EACH UNIT

**Emission Limit 2:**

794.0000 LB/MW-H 12-OPER MO ROLL AVG; EACH UNIT

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

The estimated cost of CCS is over \$70,000,000 per year. This does not take into account the large parasitic load caused by a CCS system. For emission limit 2 above (794 LB/MW-H), compliance is determined monthly at the end of the initial and each subsequent 12-operating month period. The first month of the initial compliance period is defined in 40 CFR 60.5525(c)(1)(i).

# Exhibit 22



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## Pollutant Information

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Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** VA-0325**Corporate/Company:** VIRGINIA ELECTRIC AND POWER COMPANY**Facility Name:** GREENSVILLE POWER STATION**Process:** COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)**Pollutant:** Nitrogen Oxides (NOx)**CAS Number:** 10102**Pollutant Group(s):** InOrganic Compounds, Oxides  
of Nitrogen (NOx),  
Particulate Matter (PM),**Substance Registry System:** Nitrogen Oxides (NOx)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** SCR**Test Method:**

EPA/OAR Mthd 20

[EPA/OAR Methods](#)[All Other Methods](#)**Percent Efficiency:** 0**Compliance Verified:** Unknown**EMISSION LIMITS:****Case-by-Case Basis:** N/A**Other Applicable Requirements:****Other Factors Influence Decision:** Unknown**Emission Limit 1:** 2.0000 PPMVD 1 HR AVG**Emission Limit 2:** 0**Standard Emission Limit:** 0**COST DATA:****Cost Verified?** No**Dollar Year Used in Cost Estimates:****Cost Effectiveness:** 0 \$/ton**Incremental Cost Effectiveness:** 0 \$/ton**Pollutant Notes:** Turbine: 2.0 ppmvd @ 15% O2 (1-hour average)





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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** VA-0325**Corporate/Company:** VIRGINIA ELECTRIC AND POWER COMPANY**Facility Name:** GREENSVILLE POWER STATION**Process:** COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)**Pollutant:** Carbon Monoxide**CAS Number:** 630-08-0**Pollutant Group(s):** InOrganic Compounds,**Substance Registry System:** Carbon Monoxide**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** Oxidation Catalyst**Test Method:**

EPA/OAR Mthd 10B

[EPA/OAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

Unknown

**EMISSION LIMITS:****Case-by-Case Basis:**

N/A

**Other Applicable Requirements:****Other Factors Influence Decision:**

Unknown

**Emission Limit 1:**

1.6000 PPMVD 3 HR AVG

**Emission Limit 2:**

286.0000 TONS/YR 12 MO ROLLING AVG

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

Emission Limit 1 turbine without DB: 1.0 ppmvd 3 hr avg  
Alternative Operation: 436 lb/turbine/calendar year; Cold start: 6,944 lb/turbine; Warm start: 3,316 lb/turbine; Hot start: 1,771 lb/turbine



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** VA-0325**Corporate/Company:** VIRGINIA ELECTRIC AND POWER COMPANY**Facility Name:** GREENSVILLE POWER STATION**Process:** COMBUSTION TURBINE GENERATOR WITH DUCT-FIRED HEAT RECOVERY STEAM GENERATORS (3)**Pollutant:** Volatile Organic Compounds  
(VOC)**CAS Number:** VOC**Pollutant Group(s):** Volatile Organic Compounds  
(VOC),**Substance Registry System:** Volatile Organic Compounds (VOC)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** Oxidation Catalyst and good combustion practices**Test Method:**

EPA/OAR Mthd 320

[EPA/OAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

Unknown

**EMISSION LIMITS:****Case-by-Case Basis:**

N/A

**Other Applicable Requirements:****Other Factors Influence Decision:**

Unknown

**Emission Limit 1:**

1.4000 PPMVD

**Emission Limit 2:**

214.8000 T/YR PER TURBINE-12 MO ROLLING TOTAL

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

Emission Limit 1: Turbine: 0.7 ppmvd without DB



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** CT-0161**Corporate/Company:** NTE CONNECTICUT, LLC**Facility Name:** KILLINGLY ENERGY CENTER**Process:** Natural Gas w/Duct Firing**Pollutant:** Nitrogen Oxides (NOx)**CAS Number:** 10102**Pollutant Group(s):** InOrganic Compounds, Oxides  
of Nitrogen (NOx),  
Particulate Matter (PM),**Substance Registry System:** Nitrogen Oxides (NOx)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** SCR**Test Method:**

Unspecified

[EPA/DAR Methods](#)[All Other Methods](#)**Percent Efficiency:** 0**Compliance Verified:** Unknown**EMISSION LIMITS:****Case-by-Case Basis:** LAER**Other Applicable Requirements:** NSPS , SIP , OPERATING PERMIT**Other Factors Influence Decision:** Unknown**Emission Limit 1:** 2.0000 PPMVD @15% O2 1 HOUR BLOCK**Emission Limit 2:** 0**Standard Emission Limit:** 0**COST DATA:****Cost Verified?** No**Dollar Year Used in Cost Estimates:****Cost Effectiveness:** 0 \$/ton**Incremental Cost Effectiveness:** 0 \$/ton**Pollutant Notes:**



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** CT-0161**Corporate/Company:** NTE CONNECTICUT, LLC**Facility Name:** KILLINGLY ENERGY CENTER**Process:** Natural Gas w/Duct Firing**Pollutant:** Carbon Monoxide**CAS Number:** 630-08-0**Pollutant Group(s):** InOrganic Compounds,**Substance Registry System:** Carbon Monoxide**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** Oxidation Catalyst**Test Method:**

Unspecified

[EPA/QAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

Unknown

**EMISSION LIMITS:****Case-by-Case Basis:**

BACT-PSD

**Other Applicable Requirements:**

OPERATING PERMIT

**Other Factors Influence Decision:**

Unknown

**Emission Limit 1:**

1.7000 LB/MMBTU 1 HOUR BLOCK

**Emission Limit 2:**

0

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** CT-0161**Corporate/Company:** NTE CONNECTICUT, LLC**Facility Name:** KILLINGLY ENERGY CENTER**Process:** Natural Gas w/Duct Firing**Pollutant:** Volatile Organic Compounds  
(VOC)**CAS Number:** VOC**Pollutant Group(s):** Volatile Organic Compounds  
(VOC),**Substance Registry System:** Volatile Organic Compounds (VOC)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** Oxidation Catalyst**Test Method:**

Unspecified

[EPA/DAR Methods](#)[All Other Methods](#)**Percent Efficiency:** 0**Compliance Verified:** Unknown**EMISSION LIMITS:****Case-by-Case Basis:** BACT-PSD**Other Applicable Requirements:** OPERATING PERMIT**Other Factors Influence Decision:** Unknown**Emission Limit 1:** 1.6000 PPMVD @15% O2**Emission Limit 2:** 0**Standard Emission Limit:** 0**COST DATA:****Cost Verified?** No**Dollar Year Used in Cost Estimates:****Cost Effectiveness:** 0 \$/ton**Incremental Cost Effectiveness:** 0 \$/ton**Pollutant Notes:**



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#) [New Search](#) [Search Results](#) [Facility Information](#) [Process List](#) [Process Information](#)

[Pollutant Information](#)

[Help](#)

**DRAFT**

**RBLC ID:** VA-0332

**Corporate/Company:** CHICKAHOMINY POWER LLC

**Facility Name:** CHICKAHOMINY POWER LLC

**Process:** Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators

**Pollutant:** Nitrogen Oxides (NOx)

**CAS Number:** 10102

**Pollutant Group(s):** InOrganic Compounds, Oxides  
of Nitrogen (NOx),  
Particulate Matter (PM),

**Substance Registry System:** Nitrogen Oxides (NOx)

**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A

**P2/Add-on Description:** Controlled by dry, low NOx burners and selective catalytic reduction (SCR).

**Test Method:**

[EPA/DAR Methods](#)

[All Other Methods](#)

**Percent Efficiency:** 0

**Compliance Verified:** No

**EMISSION LIMITS:**

**Case-by-Case Basis:** BACT-PSD

**Other Applicable Requirements:** NSPS , SIP

**Other Factors Influence Decision:** No

**Emission Limit 1:** 2.0000 PPMVD 15% O2 1 HR AVG

**Emission Limit 2:** 128.4000 TONS/YR 12-MO ROLLING AVG

**Standard Emission Limit:** 0

**COST DATA:**

**Cost Verified?** No

**Dollar Year Used in Cost Estimates:**

**Cost Effectiveness:** 0 \$/ton

**Incremental Cost Effectiveness:** 0 \$/ton

**Pollutant Notes:** Alternative short-term emission limits apply during  
tuning, startup and shutdown. CEMS required.



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**DRAFT****RBLC ID:** VA-0332**Corporate/Company:** CHICKAHOMINY POWER LLC**Facility Name:** CHICKAHOMINY POWER LLC**Process:** Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators**Pollutant:** Carbon Monoxide**CAS Number:** 630-08-0**Pollutant Group(s):** InOrganic Compounds,**Substance Registry System:** Carbon Monoxide**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** B**P2/Add-on Description:** Controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time).**Test Method:**

Unspecified

[EPA/DAR Methods](#)[All Other Methods](#)**Percent Efficiency:** 0**Compliance Verified:** No**EMISSION LIMITS:****Case-by-Case Basis:** BACT-PSD**Other Applicable Requirements:** NSPS , SIP**Other Factors Influence Decision:** No**Emission Limit 1:** 1.0000 PPMVD @ 15% O2 3 HR AVG**Emission Limit 2:** 94.3000 TONS/YR 12 MO ROLLING AVG**Standard Emission Limit:** 0**COST DATA:****Cost Verified?** No**Dollar Year Used in Cost Estimates:****Cost Effectiveness:** 0 \$/ton**Incremental Cost Effectiveness:** 0 \$/ton**Pollutant Notes:** Alternative emission limits apply during startup, shutdown, and tuning. CEMS required.



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**DRAFT****RBLC ID:** VA-0332**Corporate/Company:** CHICKAHOMINY POWER LLC**Facility Name:** CHICKAHOMINY POWER LLC**Process:** Three (3) Mitsubishi Hitachi Power Systems combustion turbine generators**Pollutant:** Volatile Organic Compounds  
(VOC)**CAS Number:** VOC**Pollutant Group(s):** Volatile Organic Compounds  
(VOC),**Substance Registry System:** Volatile Organic Compounds (VOC)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** B**P2/Add-on Description:** Controlled by an oxidation catalyst and good combustion practices (e.g. controlled fuel/air mixing, adequate temperature, and gas residence time)**Test Method:**

Unspecified

[EPA/OAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

No

**EMISSION LIMITS:****Case-by-Case Basis:**

BACT-PSD

**Other Applicable Requirements:**

NSPS , SIP

**Other Factors Influence Decision:**

No

**Emission Limit 1:**

0.7000 PPMVD @ 15% O2 3 HR AVG

**Emission Limit 2:**

68.1000 T/YR 12 MO ROLLING AVG

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

Alternative emission limits apply during startup and shutdown. Compliance is based on compliance with CO limits, determined by CEMS. VOC emissions during tuning are limited by the duration of the tuning event.





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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** VA-0328**Corporate/Company:** NOVI ENERGY**Facility Name:** C4GT, LLC**Process:** GE Combustion Turbine - Option 1 - Normal Operation**Pollutant:** Nitrogen Oxides (NOx)**CAS Number:** 10102**Pollutant Group(s):** InOrganic Compounds, Oxides  
of Nitrogen (NOx),  
Particulate Matter (PM),**Substance Registry System:** Nitrogen Oxides (NOx)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** A**P2/Add-on Description:** dry, low NOx burners and selective catalytic reduction**Test Method:**[EPA/DAR Methods](#)[All Other Methods](#)**Percent Efficiency:** 0**Compliance Verified:** No**EMISSION LIMITS:****Case-by-Case Basis:** BACT-PSD**Other Applicable Requirements:** NSPS , SIP**Other Factors Influence Decision:** No**Emission Limit 1:** 2.0000 PPMVD @ 15% O2 1 H AV**Emission Limit 2:** 141.3000 T/YR 12 MO ROLLING TOTAL**Standard Emission Limit:** 0**COST DATA:****Cost Verified?** No**Dollar Year Used in Cost Estimates:****Cost Effectiveness:** 0 \$/ton**Incremental Cost Effectiveness:** 0 \$/ton**Pollutant Notes:** Alternative emission limits apply during tuning, water washing, startup and shutdown. CEMS required.



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** VA-0328**Corporate/Company:** NOVI ENERGY**Facility Name:** C4GT, LLC**Process:** GE Combustion Turbine - Option 1 - Normal Operation**Pollutant:** Carbon Monoxide**CAS Number:** 630-08-0**Pollutant Group(s):** InOrganic Compounds,**Substance Registry System:** Carbon Monoxide**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** B**P2/Add-on Description:** Oxidation catalyst and good combustion practices**Test Method:**

Unspecified

[EPA/QAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

No

**EMISSION LIMITS:****Case-by-Case Basis:**

BACT-PSD

**Other Applicable Requirements:**

NSPS , SIP

**Other Factors Influence Decision:**

Unknown

**Emission Limit 1:**

1.0000 PPMVD@ 15% O2 3 HR AV/WITHOUT DB

**Emission Limit 2:**

1.6000 PPMVD@ 15% O2 3 HR AV/WITH DB

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

Alternative emission limits apply during startup and shutdown. CEMS required.



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## Pollutant Information

Click on the **Process Information** button to see more information about the process associated with this pollutant.

Or click on the **Process List** button to return to the list of processes.

[RBLC Home](#)[New Search](#)[Search Results](#)[Facility Information](#)[Process List](#)[Process Information](#)[Pollutant Information](#)[Help](#)**FINAL****RBLC ID:** VA-0328**Corporate/Company:** NOVI ENERGY**Facility Name:** C4GT, LLC**Process:** GE Combustion Turbine - Option 1 - Normal Operation**Pollutant:** Volatile Organic Compounds  
(VOC)**CAS Number:** VOC**Pollutant Group(s):** Volatile Organic Compounds  
(VOC),**Substance Registry System:** Volatile Organic Compounds (VOC)**Pollution Prevention/Add-on Control Equipment/Both/No Controls Feasible:** B**P2/Add-on Description:** Oxidation catalyst and good combustion practices**Test Method:**

Unspecified

[EPA/DAR Methods](#)[All Other Methods](#)**Percent Efficiency:**

0

**Compliance Verified:**

No

**EMISSION LIMITS:****Case-by-Case Basis:**

BACT-PSD

**Other Applicable Requirements:**

SIP , NSPS

**Other Factors Influence Decision:**

Unknown

**Emission Limit 1:**

0.7000 PPMVD @ 15% O2 3 HR AV/WITHOUT DB

**Emission Limit 2:**

1.4000 PPMVD @ 15% O2 3 HR AV/WITH DB

**Standard Emission Limit:**

0

**COST DATA:****Cost Verified?**

No

**Dollar Year Used in Cost Estimates:****Cost Effectiveness:**

0 \$/ton

**Incremental Cost Effectiveness:**

0 \$/ton

**Pollutant Notes:**

Alternative emission limits apply during startup and shutdown. Compliance is based on compliance with CO limits, determined by CEMS.

# Exhibit 23



Prepared for:  
Chickahominy Power, LLC  
Herndon, Virginia

Prepared by:  
AECOM  
Chelmsford, Massachusetts  
60522108-1  
November 2018

# Air Permit Application

Chickahominy Combined-Cycle Power Plant Project  
Charles City County, Virginia





Prepared for:  
Chickahominy Power, LLC  
Herndon, Virginia

Prepared by:  
AECOM  
Chelmsford, Massachusetts  
60522108-1  
November 2018

# Air Permit Application

Chickahominy Combined-Cycle Power Plant Project  
Charles City County, Virginia

Prepared by:

Robert Hall

Stephanie Carcieri

Reviewed by:

Sim Deshpande

Jeff Connors

## 3.0 Project Emission Summary

This section presents a summary of the Project emissions and a discussion of the methodology used to calculate emissions. The section is organized by emission sources. Within each emission source subsection, the methods used to calculate emissions are discussed followed by a summary of the emission estimates for the specific source as well as, in the case of the CTGs, mode of operation.

The Project consists of the following sources of air emissions:

- Three GE 7HA.02 or three MHPS M501JAC natural gas-fired CTGs;
- Two 52 MMBtu/hr natural gas-fired auxiliary boilers for the GE 7HA.02 option;
- Two 84 MMBtu/hr natural gas-fired auxiliary boilers for the MHPS M501J option;
- Three 12 MMBtu/hr natural gas-fired fuel gas heater;
- One 3,000 kW emergency diesel generator operating on ULSD fuel;
- One 376 bhp emergency fire-water pump operating on ULSD fuel;
- One 572 gallon diesel tank and one 2,500 gallon diesel tank; and
- Circuit breakers (containing SF<sub>6</sub>).

The emissions calculation procedures used in determining the potential emissions from the Project are based on CTG information provided by the manufacturer, other equipment vendor data, emission limitations specified by the applicable New Source Performance Standards, emission factors documented in USEPA's "Compilation of Air Pollution Emission Factors, AP-42" and proposed BACT and LAER emission limits. Operational limitations have been accounted for while estimating potential annual emissions.

Detailed emission calculations for each emission source are presented in Appendix B.

### 3.1 Combustion Turbine Generators

The main sources of emissions at the site are the three CTGs. The following subsections present the maximum hourly emissions per CTG during normal operations and start-up/shutdown events, as well as the total annual emissions for both CTGs including start-up/shutdown emissions. Additional details such as emission and flow calculations at various loads, ambient temperature, with and without inlet air cooling, are provided in Appendix B.

#### 3.1.1 General Electric 7HA.02 Combustion Turbines

##### 3.1.1.1 Continuous Operating Scenario

Normal operation of a combustion turbine generator is characterized as continuous operation at operating loads in the 30% to 45%, depending upon the ambient air temperature, up to 100% while firing natural gas. Each of the three CTGs is proposed to be operated up to 8,760 hr/yr with no annual operational restrictions. Table 3-1 presents the maximum hourly emissions (lb/hr) and the annual emissions (tons per year) for criteria pollutants for normal operations.

**Table 3-1 GE 7HA.02 - Hourly and Annual Emissions during Normal Operations <sup>(a)</sup>**

Pollutant	Maximum Hourly Emissions Per CTG during Normal Operations (lb/hr/CTG)	Potential Annual Emission Rates Per Turbine during Normal Operations (tons/year/CTG) <sup>(b)</sup>
NO <sub>x</sub>	26.5	116.1
CO	8.1	35.5
VOC	3.24	14.2
PM <sub>10</sub> /PM <sub>2.5</sub>	12.4	54.3
SO <sub>2</sub>	4.15	18.2
H <sub>2</sub> SO <sub>4</sub>	2.77	12.1
NH <sub>3</sub>	24.5	107.3
Lead	0.0018	0.0078
GHGs CO <sub>2</sub> e	434,064	1,901,202
(a) Emission rates are for one combustion turbine. See Tables B-1.2 to B-1.4 in Appendix B for detailed calculations.		
(b) Annual emissions during normal operation (tons per year) are based on 8,760 hours per year at the maximum hourly emission rate for each pollutant.		

**3.1.1.2 Start-up/Shutdown Operations Scenario**

The Project plans to start up the each CTGs in independently. Table 3-2 summarizes the duration of start-up and shutdown events.

Emissions (per CTG) of NO<sub>x</sub>, CO, and VOC during each event of start-up and shutdown operations are summarized in Table 3-3. Detailed emissions calculations can be found in Appendix B.

**Table 3-2 GE 7HA.02 - Start-up and Shutdown Duration (CTGs Only)**

GE 7HA.02				
Type of Start	Duration of Start-up/Shutdown Events (minutes per event per CTG)			
	CTG 1	CTG 2	CTG 3	Average <sup>(a)</sup>
Cold Start	66	66	66	66
Warm Start	48	48	48	48
Hot Start	24	24	24	24
Shutdown	15	15	15	15
(a) Total time from first firing to emission compliance.				



**Table 3-3 GE 7HA.02 - Average Emissions per CTG during Start-up/Shutdown**

<b>Parameter</b>	<b>CTG 1, 2 or 3 Emissions during Start-up/Shutdown (lb/event)</b>
<b>NO<sub>x</sub></b>	
Cold start	312
Warm start	175
Hot start	84
Shutdown	16.3
<b>CO</b>	
Cold start	924
Warm start	470
Hot start	449
Shutdown	190
<b>VOC</b>	
Cold start	66.0
Warm start	48.0
Hot start	45.6
Shutdown	32.5
<b>Fuel, MMBtu/event</b>	
Cold start	1,464
Warm start	1,116
Hot start	384
Shutdown	175

Table 3-4 presents a summary of the emissions with start-up and shutdown events including the offline times associated with these events. Annual emissions resulting from start-up/shutdown operations for the proposed CTGs are based on 18 cold starts/year, 52 warm starts/year, and 208 hot starts/year. For each cold start, the CTGs are conservatively assumed to be offline for 48 hours as a minimum for cold starts, for each warm start the CTGs are conservatively assumed to be offline for 8 hours as minimum and for each hot start, the CTGs are conservatively assumed to be offline for 0 hours as a minimum. Under this operating scenario, it is estimated that the CTGs would be offline for 1,280 hours/year. Additional details are provided in Appendix B, Tables B-1.3 and B-1.4.

**Table 3-4 GE 7HA.02 - Annual Emissions Including Start-up/Shutdown (Average per CTG)<sup>(a)</sup>**

Operating Mode	hr/yr	NO <sub>x</sub>		CO		VOC	
		lb/hr <sup>(a)</sup>	tpy	lb/hr <sup>(a)</sup>	tpy	lb/hr <sup>(a)</sup>	tpy
Offline <sup>(b)</sup>	1,280	0	0	0	0	0	0
Normal operation, without duct burning	7,266	26.5	96.3	8.1	29.4	3.2	11.8
Cold start	19.8	283.6	2.81	840.0	8.32	60.0	0.59
Warm start	41.6	219.0	4.56	588.0	12.23	60.0	1.25
Hot start	83.2	210.0	8.74	1,122	46.68	114.0	4.74
Shutdown	69.5	65.0	2.26	760.0	26.41	130.0	4.52
<b>TOTALS</b>	<b>8,760</b>		<b>114.6</b>		<b>123.1</b>		<b>22.9</b>
(a) The lb/hr emissions represent the average lb/hr for the duration of the event, not the maximum hourly emission rate during the event							
(b) The offline hours based on 18 cold starts, 52 warm starts and 208 hot starts per year.							

### 3.1.1.3 GE 7HA.02 - Combustion Turbine Generator Emissions: Maximum Annual

Annual emissions for the three CTGs were calculated based on the maximum of either 8,760 hr/year of continuous operation or emissions which include the maximum number of startup/shutdown events. The annual emissions during startup/shutdown include the appropriate downtime based on the assumed number of cold, hot and warm starts and shutdowns. Tables 3-5 and Table 3-6 present the annual emissions (tons/year) of criteria pollutants and HAPs, respectively, for the three CTGs arranged in a 1 on 1 configuration for two cases:

- (1) Continuous operations for all turbines 8,760 hours per year (see Table 3-1).
- (2) Continuous operations for all turbines 7,266 hours per year, 1,280 hours per year downtime, and 214 hours per year in startup/shutdown operations (see Table 3-4).

Note that the maximum emissions for all pollutants except for CO and VOCs occur during 8,760 hours of continuous operation.

**Table 3-5: GE 7HA.02- Combustion Turbine Generators: Annual Criteria Pollutant Emissions**

Pollutant	Potential Annual Emission Rates (Per Turbine)			Three 1x1 GE 7HA.02 Configuration
	Annual Emissions for Continuous Operation (tpy) <sup>a</sup>	Annual Emissions with Startup and Shutdown (tpy) <sup>b</sup>	Worst-Case Annual Emissions (tpy) <sup>c</sup>	Worst-Case Annual Emissions (Total) (tpy)
NO <sub>x</sub>	116.1	114.6	116.1	348.2
CO	35.5	123.1	123.1	369.2
VOC	14.2	22.9	22.9	68.7
PM <sub>10</sub> / PM <sub>2.5</sub>	54.3	<54.3	54.3	162.9
SO <sub>2</sub>	18.2	<18.2	18.2	54.6
H <sub>2</sub> SO <sub>4</sub>	12.1	<12.1	12.1	36.4
NH <sub>3</sub>	107.3	<107.3	107.3	321.9
Lead	0.0078	<0.0078	0.0078	0.023
GHG CO <sub>2</sub> e	1,901,202	<1,901,202	1,901,202	5,703,605

(a) Detailed information for emissions during continuous operation is in Table 3-1.  
(b) Detailed information for emissions including startup and shutdown are in Tables 3-3 and 3-4.  
(c) Worst-case emissions are the maximum for each pollutant of either continuous operation or with startup and shutdown.

**Table 3-6: GE 7HA.02 - Combustion Turbine Generators: Annual Hazardous Air Pollutant (HAP) Emissions**

CTGs: Annual HAP Emissions <sup>(a)</sup> (Total Three 1x1 Configuration; ton/year)	
Pollutant <sup>(b)</sup>	GE 7HA.02
Formaldehyde	8.77E+00
Toluene	4.05E+00
Xylene	1.99E-00
Acetaldehyde	1.24E-00
Ethylbenzene	9.96E-01
Propylene Oxide	9.03E-01
Benzene	3.73E-01
Acrolein	1.99E-01
Nickel	9.86E-02
Chromium	6.57E-02
Other HAPs	2.42E-01
<b>TOTAL</b>	<b>18.93</b>

(a) See Table B-1.5 for detailed calculations.  
(b) The highest ten HAPs in terms of annual emissions are presented in this table. The remaining HAP emissions are presented under the group "Other HAPs".

### 3.1.2 MHPS M501JAC Combustion Turbines

#### 3.1.2.1 Continuous Operations Scenario

Normal operation of a combustion turbine generator is characterized as continuous operation at operating loads in the 50% to 100% range while firing natural gas. Each of the three CTGs is proposed to be operated up to 8,760 hr/yr. Table 3-7 presents the maximum hourly emissions (lb/hr) and the annual emissions (tons per year).

**Table 3-7 MHPS M 501JAC - Hourly and Annual Emissions during Normal Operations <sup>(a)</sup>**

Pollutant	MHPS M501JAC	
	Maximum Hourly Emissions Per CTG during Normal Operations (lb/hr/CTG)	Potential Annual Emission Rates Per Turbine during Normal Operations (tons/year/CTG) <sup>(b)</sup>
NO <sub>x</sub>	29.3	128.3
CO	8.90	39.0
VOC	3.60	15.8
PM <sub>10</sub> /PM <sub>2.5</sub>	12.3	53.9
SO <sub>2</sub>	4.64	20.3
H <sub>2</sub> SO <sub>4</sub>	4.88	21.4
NH <sub>3</sub>	27.1	118.7
Lead	0.00199	0.0087
GHGs CO <sub>2</sub> e	484,822	2,123,519
(a) See Tables B-2.2 to B-2.4 in Appendix B for detailed calculations.		
(b) Annual emissions (tons per year) are based on 8,760 hours per year firing natural gas.		

#### 3.1.2.2 Start-up/Shutdown Operations Scenario

The Project has the capability to start up each CTG independently of the other CTGs. Therefore, the startup time for each CTG will be identical. Table 3-8 summarizes the duration of start-up and shutdown events for each CTG.

Emissions (per CTG) of NO<sub>x</sub>, CO, and VOCs during each event of start-up and shutdown operations are summarized in Table 3-9. Detailed emissions calculations can be found in Tables B-2.3 and B-2.4 in Appendix B.

**Table 3-8 MHPS M501JAC - Start-up and Shutdown Duration (CTGs Only)**

<b>MHPS M501JAC</b>	
<b>Type of Start</b>	<b>Average Duration of Start-up/Shutdown Events (minutes per CTG)</b>
Cold Start	42
Warm Start	42
Hot Start	42
Shutdown	15

**Table 3-9 MHPS M501JAC - Average Emissions per CTG during Start-up/Shutdown**

<b>MHPS M501JAC</b>	
<b>Parameter</b>	<b>Emissions Per CTG during Start-up/Shutdown (lb/turbine/event) <sup>(a)</sup></b>
<b>NO<sub>x</sub></b>	
Cold start	60.0
Warm start	54.0
Hot start	42.0
Shutdown	19.2
<b>CO</b>	
Cold start	444
Warm start	396
Hot start	252
Shutdown	156
<b>VOC</b>	
Cold start	216
Warm start	216
Hot start	168
Shutdown	216
<b>Fuel, MMBtu/event</b>	
Cold start	1,008
Warm start	1,008
Hot start	1,392
Shutdown	348

Table 3-10 presents a summary of the emissions with start-up and shutdown events including the offline times associated with these events. Annual emissions resulting from start-up/shutdown operations for the proposed CTGs are based on 18 cold starts/year, 52 warm starts/year, and 208 hot starts/year. For each cold start, the CTGs are conservatively assumed to be offline for 48 hours as a minimum, for each warm start the CTGs are conservatively assumed to be offline for 8 hours as a minimum and for each hot start, the CTGs are conservatively assumed to be offline for 0 hours as a minimum. Under this operating scenario, it is estimated that the each CTGs would be offline for at least 1,280 hours/year. Additional details are provided in Appendix B, Tables B 2.1-3 and B 2.1-4.

**Table 3-10 MHPS M501JAC - Annual Emissions Including Start-up/Shutdown (Average per CTG) <sup>(a)</sup>**

Operating Mode	Duration	NO <sub>x</sub>		CO		VOC	
	hr/yr	lb/hr <sup>(a)</sup>	tpy	lb/hr <sup>(a)</sup>	tpy	lb/hr <sup>(a)</sup>	tpy
Offline <sup>(b)</sup>	1,280	0	0	0	0	0	0
Normal, without duct burning	7,216	29.3	105.71	8.90	32.11	3.60	12.99
Cold start	12.6	85.7	0.54	634	4.00	309	1.94
Warm start	36.4	77.1	1.40	566	10.30	309	5.62
Hot start	145.6	60.0	4.37	360	26.21	240	17.47
Shutdown	69.5	76.8	2.67	624	21.68	864	30.02
Totals	8,760		114.7		94.3		68.0
(a) The lb/hr emissions represent the average lb/hr for the duration of the event, not the maximum hourly emission rate during the event.							
(b) The offline hours are based on 18 cold starts, 52 warm starts and 208 hot starts per year.							

### 3.1.2.3 MHPS M501JAC - Combustion Turbine Generator Emissions: Total Annual

Annual emissions for the three CTGs were calculated based on the maximum of either 8,760 hr/year of continuous operation or emissions which include the maximum number of startup/shutdown events. The annual emissions during startup/shutdown include the appropriate downtime based on the assumed number of cold, hot, and warm starts and shutdowns. Tables 3-11 and Table 3-12 present the annual emissions (tons/year) of criteria pollutants and HAPs, respectively, for the two CTGs arranged in a 2 on 1 configuration for two cases:

- (1) Continuous operations for all turbines 8,760 hours per year (see Table 3-7).
- (2) Continuous operations for all turbines 7,216 hours per year, 1,280 hours per year downtime, and 264 hours per year in startup/shutdown operations (see Table 3-10).

Note that the maximum emissions for all pollutants except for CO and VOC occur during 8,760 hours of normal continuous operation.

**Table 3-11: MHPS 501JAC - Combustion Turbine Generators: Annual Criteria Pollutant Emissions**

Pollutant	Potential Annual Emission Rates (Per Turbine)			Three 1x1 Configuration
	Annual Emissions for Continuous Operation (tpy) <sup>a</sup>	Annual Emissions with Startup and Shutdown (tpy) <sup>b</sup>	Worst-Case Annual Emissions (tpy) <sup>c</sup>	Worst-Case Annual Emissions (Total) (tpy)
NO <sub>x</sub>	128.3	114.7	128.3	385.0
CO	39.0	94.3	94.3	282.9
VOC	15.8	68.0	68.0	204.1
PM <sub>10</sub> / PM <sub>2.5</sub>	53.9	<53.9	53.9	161.6
SO <sub>2</sub>	20.3	<20.3	20.3	61.0
H <sub>2</sub> SO <sub>4</sub>	21.4	<21.4	21.4	64.2
NH <sub>3</sub>	118.7	<118.7	118.7	356.1
Lead	0.0087	<0.0087	0.0087	0.026
GHG CO <sub>2</sub> e	2,123,519	<2,123,519	2,123,519	6,370,557

(d) Detailed information for emissions during continuous operation is in Table 3-7.  
(e) Detailed information for emissions including startup and shutdown are in Tables 3-9 and 3-10.  
(f) Worst-case emissions are the maximum for each pollutant of either continuous operation or with startup and shutdown.

**Table 3-12: MHPS 501JAC - Combustion Turbine Generators: Annual Hazardous Air Pollutant (HAP) Emissions**

CTGs: Annual HAP Emissions <sup>(a)</sup> (Total Three 1x1 Configuration; ton/year)	
Pollutant <sup>(b)</sup>	MHPS M501JAC
Formaldehyde	9.79E+00
Toluene	4.52E+00
Xylene	2.22E+00
Acetaldehyde	1.39E+00
Ethylbenzene	1.11E+00
Propylene Oxide	1.01E-00
Benzene	4.17E-01
Acrolein	2.22E-01
Nickel	1.10E-01
Chromium	7.34E-02
Other HAPs	2.71E-01
<b>TOTAL</b>	<b>21.14</b>

(a) See Table B-2.5 for detailed calculations.  
(b) The highest ten HAPs in terms of annual emissions are presented in this table. The remaining HAP emissions are presented under the group "Other HAPs".

## **3.2 Ancillary Equipment**

The facility will include two auxiliary boilers, three fuel gas heaters, and circuit breakers to support CTG operations. A firewater pump and a standby generator will also be installed along with distillate fuel oil tanks on-site to meet the power and electricity demands of the facility during power outages and other emergencies. Emissions of criteria pollutants from the ancillary equipment are presented in Table 3-13 and detailed emissions calculations are provided in Appendix B (Tables B-3 to B-7).

### **3.2.1 Auxiliary Boilers**

For the GE 7HA.02 option, the facility will include two natural gas-fired auxiliary boilers each with a rated heat input rate of 52 MMBtu/hr. The boilers are being permitted with an annual capacity factor limitation of 100% each. Emissions of criteria pollutants and HAPs from the auxiliary boiler are presented in Table 3-13 and detailed emission calculations are presented in Table B-1.5 and B-1.7.

For the MHPS M501JAC option, the facility will include two natural gas-fired auxiliary boilers each with a rated heat input rate of 84 MMBtu/hr. The boilers are being permitted with an annual capacity factor limitation of 100% each. Emissions of criteria pollutants and HAPs from the auxiliary boiler are presented in Table 3-13 and detailed emission calculations are presented in Table B-2.5 and B-2.7.

### **3.2.2 Fuel Gas Heaters**

The facility will also include three natural gas fired fuel gas heaters with heat input ratings of 12 MMBtu/hr each. The fuel gas heaters are also being permitted without any annual operating restrictions. Therefore, annual emissions are based on 8,760 hours/year. Emissions of criteria pollutants from the fuel gas heater are presented in Table 3-13 and detailed emission calculations of criteria pollutants and HAPs are presented in Tables B-1.5, B-2.5 and B-3.

### **3.2.3 Emergency Engines**

The facility will have a 3.0 MW emergency generator and a 376 bhp emergency firewater pump. The diesel fired emergency generator and firewater pump will meet the emission requirements in USEPA's Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, July 11, 2006 (40 CFR Part 60, Subpart IIII). They will also meet the requirements of 40 CFR 63, Subpart ZZZZ, however for these engines the only requirement under Subpart ZZZZ is to be in compliance with 40 CFR Part 60 Subpart IIII. Both the firewater pump and the emergency generator are expected to operate for no more than 100 hours/year for routine testing and maintenance, and 500 hours/year total for each unit (including emergency use). Emissions of criteria pollutants and HAPs from the emergency engines are presented in Tables 3-13 and detailed emissions calculations can be found in Appendix B (Table B-1.5, B-2.5, B-4, and B-5).

### **3.2.4 Circuit Breakers**

The proposed project will include circuit breakers which hold 22,800 pounds Sulfur hexafluoride (SF<sub>6</sub>). There will be a maximum leak rate of less than 0.5% annually. The expected emissions from this source are presented in Table B-6 in Appendix B.

### **3.2.5 Distillate Fuel Oil Storage Tanks**

The facility will have one 572 gallon storage tank for the diesel-fired fire water pump and one 2,500 gallon storage tank for the diesel-fired emergency generator. NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, regulates storage vessels with a capacity



greater than 75 cubic meters (m<sup>3</sup>) (19,813 gallons). The proposed tanks fall well under this capacity trigger; thus, Subpart Kb does not apply. VOC emissions from the distillate tanks are presented in Table 3-13 and detailed emissions calculations from the TANKs run can be found in Appendix B (Table B-7, and at the end of Appendix B).

### 3.2.6 Natural Gas Equipment Leaks

Fugitive GHG emissions from equipment leaks are estimated to be less than 250 tons CO<sub>2</sub>e/yr, the same as the Greenville Power Station.<sup>2</sup>

**Table 3-13 Annual Criteria Pollutant and HAP Emissions from Ancillary Equipment (tons/year)**

Compound	GE 7HA.02 Auxiliary Boilers	MHPS M501JAC Auxiliary Boilers	Fuel Gas Heaters	Emergency Generator	Emergency Fire Water Pump	Circuit Breakers	Storage Tanks	Natural Gas Equipment Leaks
<b>Criteria Pollutants</b>								
Nitrogen Oxides	5.01	8.09	1.73	11.6	0.62	-	-	-
Carbon Monoxide	16.85	27.23	5.83	6.36	0.54	-	-	-
VOCs	2.28	3.68	0.79	2.36	0.023	-	2.11E-03	-
Sulfur Oxides	0.521	0.842	0.180	0.011	0.001	-	-	-
PM <sub>10</sub> /PM <sub>2.5</sub>	3.19	5.15	1.10	0.36	0.03	-	-	-
Lead	2.23E-04	3.61E-04	7.73E-05	6.51E-05	5.71E-06	-	-	-
H <sub>2</sub> SO <sub>4</sub>	3.99E-02	6.45E-02	1.38E-02	8.52E-04	7.47E-05	-	-	-
<b>GHG CO<sub>2</sub>e</b>	54,262	87,654	18,783	1,203	106	1,140	-	250
<b>HAPs</b>	4.01E-02	6.48E-02	1.39E-02	1.14E-02	2.46E-03	-	-	-

### 3.3 Total Annual Project Emissions

Tables 3-14 and 3-16 show the annual potential-to-emit of the Project for the GE 7HA.02 and MHPS 501JAC, respectively, along with the ancillary equipment. Total HAP emissions from the Project will not exceed 25 tons/year and individual HAP emissions will not exceed 10 tons per year as shown in Tables 3-15 and 3-17 (see Appendix B, Table B-1.5 and B-2.5 for details).

<sup>2</sup> [Virginia DEQ - Dominion - Greenville](#), Dominion Response to Comments, April 22, 2016.

**Table 3-14: Total Annual Project Emissions, Option 1 (GE 7HA.02 CTGs)**

Emission Source Description	NO <sub>x</sub> (ton/yr)	SO <sub>2</sub> (ton/yr)	PM <sub>10</sub> (ton/yr)	PM <sub>2.5</sub> (ton/yr)	CO (ton/yr)	VOC (ton/yr)	H <sub>2</sub> SO <sub>4</sub> (ton/yr)	Lead (ton/yr)	GHG CO <sub>2</sub> e (ton/yr)
Combustion Turbine #1	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Combustion Turbine #2	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Combustion Turbine #3	116.07	18.19	54.31	54.31	123.06	22.89	12.14	7.82E-03	1,901,202
Auxiliary Boilers	5.01	5.21E-01	3.19	3.19	16.85	2.28E+00	3.99E-02	2.23E-04	54,262
Fuel Gas Heaters	1.73	1.80E-01	1.10E+00	1.10E+00	5.83	7.88E-01	1.38E-02	7.73E-05	18,783
Diesel-Fired Emergency Generator	11.63	1.11E-02	3.64E-01	3.64E-01	6.36	2.36E+00	8.52E-04	6.51E-05	1,203
Diesel-Fired Fire Water Pump	0.62	9.76E-04	3.11E-02	3.11E-02	0.54	2.32E-02	7.47E-05	5.71E-06	106
Emergency Generator Fuel Oil Tank						1.83E-03			
Fire Water Pump Fuel Oil Tank						2.85E-04			
Circuit Breakers									1,140
Natural Gas Equipment Leaks									250
<b>Total Project Emissions:</b>	<b>367.2</b>	<b>55.30</b>	<b>167.6</b>	<b>167.6</b>	<b>398.8</b>	<b>74.1</b>	<b>36.5</b>	<b>0.024</b>	<b>5,779,348</b>
<b>PSD Major Source Threshold</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100,000</b>
<b>PSD Major Source</b>	<b>Yes</b>	<b>No</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>No</b>	<b>No</b>	<b>No</b>	<b>Yes</b>
<b>PSD Significant Emission Rate</b>	<b>40</b>	<b>40</b>	<b>15</b>	<b>10</b>	<b>100</b>	<b>40</b>	<b>7</b>	<b>0.6</b>	<b>75,000</b>
<b>Proposed Project Subject to PSD</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>No</b>	<b>Yes</b>

**Table 3-15: Facility Wide HAP Emissions, Option 1 (GE 7HA.02 CTGs)**

Emission Source Description	HAP Estimates <sup>(a)</sup>	HAP Major Source Determination	Proposed Project Major Source?
CTGs	18.93	-	-
Ancillary Equipment	0.068	-	-
<b>Facility Wide Total</b>	<b>18.99</b>	<b>25</b>	<b>No</b>
<b>Facility Wide Single Maximum HAP</b>	<b>8.81</b>	<b>10</b>	<b>No</b>
(a) See Tables B-1.5 for detailed calculations.			

**Table 3-16: Total Annual Project Emissions, Option 2 (MHPS M501JAC CTGs)**

Emission Source Description	NO <sub>x</sub> (ton/yr)	SO <sub>2</sub> (ton/yr)	PM <sub>10</sub> (ton/yr)	PM <sub>2.5</sub> (ton/yr)	CO (ton/yr)	VOC (ton/yr)	H <sub>2</sub> SO <sub>4</sub> (ton/yr)	Lead (ton/yr)	GHG CO <sub>2</sub> e (ton/yr)
Combustion Turbine #1	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Combustion Turbine #2	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Combustion Turbine #3	128.33	20.32	53.87	53.87	94.29	68.04	21.39	8.74E-03	2,123,519
Auxiliary Boilers	8.09	8.42E-01	5.15	5.15	27.23	3.68E+00	6.45E-02	3.61E-04	87,654
Fuel Gas Heaters	1.73	1.80E-01	1.10E+00	1.10E+00	5.83	7.88E-01	1.38E-02	7.73E-05	18,783
Diesel-Fired Emergency Generator	11.63	1.11E-02	3.64E-01	3.64E-01	6.36	2.36E+00	8.52E-04	6.51E-05	1,203
Diesel-Fired Fire Water Pump	0.62	9.76E-04	3.11E-02	3.11E-02	0.54	2.32E-02	7.47E-05	5.71E-06	106
Emergency Generator Fuel Oil Tank						1.83E-03			
Fire Water Pump Fuel Oil Tank						2.85E-04			
Circuit Breakers									1,140
Natural Gas Equipment Leaks									250
<b>Total Project Emissions:</b>	<b>407.1</b>	<b>62.00</b>	<b>168.3</b>	<b>168.3</b>	<b>322.8</b>	<b>211.0</b>	<b>64.3</b>	<b>0.027</b>	<b>6,479,692</b>
<b>PSD Major Source Threshold</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100</b>	<b>100,000</b>
<b>PSD Major Source</b>	<b>Yes</b>	<b>No</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>No</b>	<b>No</b>	<b>Yes</b>
<b>PSD Significant Emission Rate</b>	<b>40</b>	<b>40</b>	<b>15</b>	<b>10</b>	<b>100</b>	<b>40</b>	<b>7</b>	<b>0.6</b>	<b>75,000</b>
<b>Proposed Project Subject to PSD</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>Yes</b>	<b>No</b>	<b>Yes</b>

**Table 3-17: Facility Wide HAP Emissions, Option 2 (MHPS M501JAC CTGs)**

Emission Source Description	HAP Estimates <sup>(a)</sup>	HAP Major Source Determination	Proposed Project Major Source?
CTGs	21.14	-	-
Ancillary Equipment	0.092	-	-
<b>Facility Wide Total</b>	<b>21.23</b>	<b>25</b>	<b>No</b>
<b>Facility Wide Single Maximum HAP</b>	<b>9.86</b>	<b>10</b>	<b>No</b>
(a) See Tables B-2.5 for detailed calculations.			

# Exhibit 24

# Selected Interest Rates (Daily) - H.15

## H.15 Selected Interest Rates [RSS](#) [Data Download](#)

The release is posted daily Monday through Friday at 4:15pm. The release is not posted on holidays or in the event that the Board is closed.

**Release date: April 2, 2021**

### Selected Interest Rates

Yields in percent per annum

Instruments	2021 Mar 26	2021 Mar 29	2021 Mar 30	2021 Mar 31	2021 Apr 1
Federal funds (effective) <a href="#">1</a> <a href="#">2</a> <a href="#">3</a>	0.07	0.07	0.07	0.06	0.07
Commercial Paper <a href="#">3</a> <a href="#">4</a> <a href="#">5</a> <a href="#">6</a>					
Nonfinancial					
1-month	0.07	0.07	0.06	0.04	0.06
2-month	n.a.	0.06	0.06	0.06	0.08
3-month	n.a.	0.07	0.07	0.06	0.10
Financial					
1-month	n.a.	n.a.	n.a.	0.11	0.07
2-month	n.a.	n.a.	n.a.	0.14	0.09
3-month	0.07	0.05	0.07	0.15	0.11
Bank prime loan <a href="#">2</a> <a href="#">3</a> <a href="#">7</a>	3.25	3.25	3.25	3.25	3.25
Discount window primary credit <a href="#">2</a> <a href="#">8</a>	0.25	0.25	0.25	0.25	0.25
U.S. government securities					
Treasury bills (secondary market) <a href="#">3</a> <a href="#">4</a>					
4-week	0.02	0.02	0.01	0.01	0.02
3-month	0.02	0.03	0.02	0.03	0.02
6-month	0.04	0.04	0.04	0.05	0.04
1-year	0.06	0.06	0.06	0.07	0.06
Treasury constant maturities					
Nominal <a href="#">9</a>					
1-month	0.02	0.02	0.01	0.01	0.02
3-month	0.02	0.03	0.02	0.03	0.02
6-month	0.04	0.04	0.04	0.05	0.04
1-year	0.06	0.06	0.06	0.07	0.06
2-year	0.14	0.14	0.16	0.16	0.17
3-year	0.31	0.32	0.33	0.35	0.35
5-year	0.85	0.89	0.90	0.92	0.90
7-year	1.32	1.37	1.39	1.40	1.37
10-year	1.67	1.73	1.73	1.74	1.69
20-year	2.27	2.32	2.29	2.31	2.24
30-year	2.37	2.43	2.38	2.41	2.34
Inflation indexed <a href="#">10</a>					

Instruments	2021 Mar 26	2021 Mar 29	2021 Mar 30	2021 Mar 31	2021 Apr 1
5-year	-1.72	-1.67	-1.62	-1.62	-1.65
7-year	-1.15	-1.11	-1.07	-1.08	-1.11
10-year	-0.67	-0.63	-0.62	-0.63	-0.66
20-year	-0.17	-0.13	-0.14	-0.13	-0.16
30-year	0.06	0.10	0.09	0.11	0.07
Inflation-indexed long-term average <sup>11</sup>	-0.06	-0.02	-0.03	-0.01	-0.04

n.a. Not available.

## Footnotes

1. As of March 1, 2016, the daily effective federal funds rate (EFFR) is a volume-weighted median of transaction-level data collected from depository institutions in the Report of Selected Money Market Rates (FR 2420). Prior to March 1, 2016, the EFFR was a volume-weighted mean of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page ([www.federalreserve.gov/releases/cp/](http://www.federalreserve.gov/releases/cp/)).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

8. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see [www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm](http://www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm). The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at [www.federalreserve.gov/releases/h15/data.htm](http://www.federalreserve.gov/releases/h15/data.htm).

9. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at [www.treasury.gov/resource-center/data-chart-center/interest-rates/](http://www.treasury.gov/resource-center/data-chart-center/interest-rates/). Source: U.S. Treasury.

10. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at [www.treasury.gov/resource-center/data-chart-center/interest-rates/](http://www.treasury.gov/resource-center/data-chart-center/interest-rates/).

11. Based on the unweighted average bid yields for all TIPS with remaining terms to maturity of more than 10 years.

Note: Current and historical H.15 data, along with weekly, monthly, and annual averages, are available on the Board's Data Download Program (DDP) at [www.federalreserve.gov/datadownload/Choose.aspx?rel=H15](http://www.federalreserve.gov/datadownload/Choose.aspx?rel=H15)). Weekly, monthly and annual rates are averages of business days unless

otherwise noted.

## Description of the Treasury Nominal and Inflation-Indexed Constant Maturity Series

Yields on Treasury nominal securities at “constant maturity” are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3, and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. Similarly, yields on inflation-indexed securities at “constant maturity” are interpolated from the daily yield curve for Treasury inflation protected securities in the over-the-counter market. The inflation-indexed constant maturity yields are read from this yield curve at fixed maturities, currently 5, 7, 10, 20, and 30 years.

Last Update: April 02, 2021

# Exhibit 25



# Selected Interest Rates (Daily) - H.15

## H.15 Selected Interest Rates [RSS](#) [Data Download](#)

The release is posted daily Monday through Friday at 4:15pm. The release is not posted on holidays or in the event that the Board is closed.

**Release date: April 2, 2021**

### Selected Interest Rates

Yields in percent per annum

Instruments	2021 Mar 26	2021 Mar 29	2021 Mar 30	2021 Mar 31	2021 Apr 1
Federal funds (effective) <a href="#">1</a> <a href="#">2</a> <a href="#">3</a>	0.07	0.07	0.07	0.06	0.07
Commercial Paper <a href="#">3</a> <a href="#">4</a> <a href="#">5</a> <a href="#">6</a>					
Nonfinancial					
1-month	0.07	0.07	0.06	0.04	0.06
2-month	n.a.	0.06	0.06	0.06	0.08
3-month	n.a.	0.07	0.07	0.06	0.10
Financial					
1-month	n.a.	n.a.	n.a.	0.11	0.07
2-month	n.a.	n.a.	n.a.	0.14	0.09
3-month	0.07	0.05	0.07	0.15	0.11
Bank prime loan <a href="#">2</a> <a href="#">3</a> <a href="#">7</a>	3.25	3.25	3.25	3.25	3.25
Discount window primary credit <a href="#">2</a> <a href="#">8</a>	0.25	0.25	0.25	0.25	0.25
U.S. government securities					
Treasury bills (secondary market) <a href="#">3</a> <a href="#">4</a>					
4-week	0.02	0.02	0.01	0.01	0.02
3-month	0.02	0.03	0.02	0.03	0.02
6-month	0.04	0.04	0.04	0.05	0.04
1-year	0.06	0.06	0.06	0.07	0.06
Treasury constant maturities					
Nominal <a href="#">9</a>					
1-month	0.02	0.02	0.01	0.01	0.02
3-month	0.02	0.03	0.02	0.03	0.02
6-month	0.04	0.04	0.04	0.05	0.04
1-year	0.06	0.06	0.06	0.07	0.06
2-year	0.14	0.14	0.16	0.16	0.17
3-year	0.31	0.32	0.33	0.35	0.35
5-year	0.85	0.89	0.90	0.92	0.90
7-year	1.32	1.37	1.39	1.40	1.37
10-year	1.67	1.73	1.73	1.74	1.69
20-year	2.27	2.32	2.29	2.31	2.24
30-year	2.37	2.43	2.38	2.41	2.34
Inflation indexed <a href="#">10</a>					

Instruments	2021 Mar 26	2021 Mar 29	2021 Mar 30	2021 Mar 31	2021 Apr 1
5-year	-1.72	-1.67	-1.62	-1.62	-1.65
7-year	-1.15	-1.11	-1.07	-1.08	-1.11
10-year	-0.67	-0.63	-0.62	-0.63	-0.66
20-year	-0.17	-0.13	-0.14	-0.13	-0.16
30-year	0.06	0.10	0.09	0.11	0.07
Inflation-indexed long-term average <sup>11</sup>	-0.06	-0.02	-0.03	-0.01	-0.04

n.a. Not available.

## Footnotes

1. As of March 1, 2016, the daily effective federal funds rate (EFFR) is a volume-weighted median of transaction-level data collected from depository institutions in the Report of Selected Money Market Rates (FR 2420). Prior to March 1, 2016, the EFFR was a volume-weighted mean of rates on brokered trades.

2. Weekly figures are averages of 7 calendar days ending on Wednesday of the current week; monthly figures include each calendar day in the month.

3. Annualized using a 360-day year or bank interest.

4. On a discount basis.

5. Interest rates interpolated from data on certain commercial paper trades settled by The Depository Trust Company. The trades represent sales of commercial paper by dealers or direct issuers to investors (that is, the offer side). The 1-, 2-, and 3-month rates are equivalent to the 30-, 60-, and 90-day dates reported on the Board's Commercial Paper Web page ([www.federalreserve.gov/releases/cp/](http://www.federalreserve.gov/releases/cp/)).

6. Financial paper that is insured by the FDIC's Temporary Liquidity Guarantee Program is not excluded from relevant indexes, nor is any financial or nonfinancial commercial paper that may be directly or indirectly affected by one or more of the Federal Reserve's liquidity facilities. Thus the rates published after September 19, 2008, likely reflect the direct or indirect effects of the new temporary programs and, accordingly, likely are not comparable for some purposes to rates published prior to that period.

7. Rate posted by a majority of top 25 (by assets in domestic offices) insured U.S.-chartered commercial banks. Prime is one of several base rates used by banks to price short-term business loans.

8. The rate charged for discounts made and advances extended under the Federal Reserve's primary credit discount window program, which became effective January 9, 2003. This rate replaces that for adjustment credit, which was discontinued after January 8, 2003. For further information, see [www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm](http://www.federalreserve.gov/boarddocs/press/bcreg/2002/200210312/default.htm). The rate reported is that for the Federal Reserve Bank of New York. Historical series for the rate on adjustment credit as well as the rate on primary credit are available at [www.federalreserve.gov/releases/h15/data.htm](http://www.federalreserve.gov/releases/h15/data.htm).

9. Yields on actively traded non-inflation-indexed issues adjusted to constant maturities. The 30-year Treasury constant maturity series was discontinued on February 18, 2002, and reintroduced on February 9, 2006. From February 18, 2002, to February 9, 2006, the U.S. Treasury published a factor for adjusting the daily nominal 20-year constant maturity in order to estimate a 30-year nominal rate. The historical adjustment factor can be found at [www.treasury.gov/resource-center/data-chart-center/interest-rates/](http://www.treasury.gov/resource-center/data-chart-center/interest-rates/). Source: U.S. Treasury.

10. Yields on Treasury inflation protected securities (TIPS) adjusted to constant maturities. Source: U.S. Treasury. Additional information on both nominal and inflation-indexed yields may be found at [www.treasury.gov/resource-center/data-chart-center/interest-rates/](http://www.treasury.gov/resource-center/data-chart-center/interest-rates/).

11. Based on the unweighted average bid yields for all TIPS with remaining terms to maturity of more than 10 years.

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Last Update: April 02, 2021

# Exhibit 26

[\(/global/en.html\)](#)

## Products

# NOxCat™ ETZ™ catalysts

The NOxCat ETZ catalyst is one of a family of products for use in selective catalytic reduction (SCR) systems, which cut emissions of nitrogen oxides (NOx) from power-generating and industrial facilities.

## Contacts

Global

## Dispersions & Pigments

✉ [Send email \(mailto:sandra.king@basf.com\)](mailto:sandra.king@basf.com)

## NOxCat™ETZ™ catalysts remove NOx emissions

The NOxCat ETZ catalyst is one of a family of products for use in selective catalytic reduction (SCR) systems, which cut emissions of nitrogen oxides (NOx) from power-generating and industrial facilities.

## How does NOxCat™ ETZ™ catalysts work?

Each of BASF's SCR catalysts "selectively" converts NO<sub>x</sub> into nitrogen and water. NOxCat ETZ is specifically designed for use in simple cycle power generating turbines and other high temperature turbine applications. The NOxCat ETZ catalyst can reduce these ozone-forming emissions by up to 97%.

## **NOxCat™ ETZ™ use a highly active zeolite catalyst**

This highly active zeolite catalyst is most effective at temperatures of 675°F (357°C) to 1075°F (580°C). It is supplied on ceramic structures in composite honeycomb configurations. ETZ catalysts do not contain heavy metals, reducing disposal concerns.

## **NOxCat™ ETZ™ catalysts work well in simple cycle power-generating turbines**

NOxCat™ ETZ™ catalyst is similar to other BASF zeolite SCR products that have been in commercial operation for over a decade, but it includes several advancements that make this catalyst excellent for use in simple cycle power-generating turbines.

Further information on our Website

- ETZ catalysts, stationary ([http://www.catalysts.basf.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nOx-Cat-\\_ETZ](http://www.catalysts.basf.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nOx-Cat-_ETZ))


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# Exhibit 27

[\(/global/en.html\)](/global/en.html)

## Products

# NOxCat™ VNX™ catalysts

BASF Catalysts NOxCat™ VNX™ catalysts are designed for use in selective catalytic reduction (SCR) systems, which reduce emissions of NOx from power generation and industrial facilities.

## Contacts

Global

## Dispersions & Pigments

✉ [Send email \(mailto:sandra.king@basf.com\)](mailto:sandra.king@basf.com)

## **NOxCat™ VNX™ catalysts remove NOx from power generation and industrial facilities**

From BASF's NOxCat™ family, VNX and ZNX catalysts are designed for use in selective catalytic reduction (SCR) systems, which reduce emissions of NOx (nitrogen oxides) from power generation and industrial facilities.

## **How do NOxCat™ VNX™ catalysts work?**

Each of BASF's SCR catalysts "selectively" converts NO<sub>x</sub> into nitrogen and water. Both VNX and ZNX catalysts can reduce these ozone-forming emissions by up to 99%.

## **NOxCat™ VNX™ catalysts are well suited for reciprocating engines, gas turbines, utility/industrial boilers, and chemical process applications**

- Reduces NO<sub>x</sub> by up to 99%
- Well suited for reciprocating engines, gas turbines, utility/industrial boilers, and chemical process applications
- Most effective at 550°F to 800°F (288°C to 427°C)
- Highly active vanadia/titania catalytic coatings

A related product, NOxCat VNX-HT catalyst is designed for use in aeroderivative simple-cycle turbines.

### Further information on our Website

- Catalysts reducing NO<sub>x</sub>, stationary (http://www.catalysts.basf.com/p02/USWeb-Internet/catalysts/en/content/microsites/catalysts/prods-inds/stationary-emissions/nox-cat-VNX-ZNX-pow-gen)

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# Exhibit 28



## **Preliminary Determination of Compliance**

### **Mariposa Energy Project**

Unincorporated Alameda County between Livermore and Byron

Address: 4887 Bruns Road, Livermore, California 94550

Bay Area Air Quality Management District  
Application 20737

August 2010

Brenda Cabral, Supervising Air Quality Engineer  
Madhav Patil, Air Quality Engineer



## 5 Best Available Control Technology (BACT)

The District's New Source Review regulations require the proposed Mariposa Energy Project to utilize the "Best Available Control Technology" ("BACT") to minimize air emissions, as discussed in more detail below. This section describes how the BACT requirements will apply to the facility.

### 5.1 Introduction

District Regulation 2-2-301 requires that the Mariposa Energy Project use the Best Available Control Technology to control NO<sub>x</sub>, CO, POC, PM<sub>10</sub>, and SO<sub>x</sub> emissions from sources that will have the potential to emit over 10 pounds per highest day of each of those pollutants. Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

- (a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or
- (b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or
- (c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO, or
- (d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and it must be commercially available, demonstrated to be effective and reliable on a full-scale unit, and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The simple-cycle turbines are subject to BACT under the District's New Source Review regulations (Regulation 2, Rule 2, Section 301) for NO<sub>x</sub>, CO, POC, PM<sub>10</sub>, and SO<sub>x</sub> because each unit will have the potential to emit more than 10 pounds per highest day of those pollutants.

The fire pump engine, S5, is subject to BACT under the District's New Source Review regulations (Regulation 2, Rule 2, Section 301) for NO<sub>x</sub> and CO because the engine will have the potential to emit more than 10 pounds per highest day of those pollutants.

The following sections provide the basis for the District BACT analyses for this equipment.

## 5.2 Best Available Control Technology for Oxides of Nitrogen (NO<sub>x</sub>) for Turbines

Oxides of Nitrogen (NO<sub>x</sub>) are a byproduct of the combustion of an air-and-fuel mixture in a high-temperature environment. NO<sub>x</sub> is formed when the heat of combustion causes the nitrogen molecules in the combustion air to dissociate into individual nitrogen atoms, which then combine with oxygen atoms to form nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>). This reaction primarily forms NO (95% to 98%) and only a small amount of NO<sub>2</sub> (2% to 5%), but the NO eventually oxidizes and converts to NO<sub>2</sub> in the atmosphere. NO<sub>2</sub> is a reddish-brown gas with a detectable odor at very low concentrations. NO and NO<sub>2</sub> are generally referred to collectively as "NO<sub>x</sub>".<sup>8</sup> NO<sub>x</sub> is a precursor to the formation of ground-level ozone, the principal ingredient in smog.

The District has examined technologies that may be effective to control NO<sub>x</sub> emissions in two general areas: combustion controls that will minimize the amount of NO<sub>x</sub> created during combustion; and post-combustion controls that can remove NO<sub>x</sub> from the exhaust stream after combustion has occurred.

### *Combustion Controls*

The formation of NO<sub>x</sub> during combustion is highly dependent on the primary combustion zone temperature, as the formation of NO<sub>x</sub> increases exponentially with temperature. There are therefore three basic strategies to reduce thermal NO<sub>x</sub> in the combustion process:

- Reduce the peak combustion temperature
- Reduce the amount of time the air/fuel mixture spends exposed to the high combustion temperature
- Reduce the oxygen level in the primary combustion zone

It should be noted, however, that techniques that control NO<sub>x</sub> by reducing combustion temperatures might involve a trade-off with the formation of other pollutants. Reducing combustion temperatures to limit NO<sub>x</sub> formation can decrease combustion efficiency, resulting in increased byproducts of incomplete combustion such as carbon monoxide and unburned

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<sup>8</sup> NO<sub>x</sub> can also be formed when a nitrogen-bound hydrocarbon fuel is combusted, resulting in the release of nitrogen atoms from the fuel (fuel NO<sub>x</sub>) and NO<sub>x</sub> can be formed by organic free radicals and nitrogen in the earliest stages of combustion (prompt NO<sub>x</sub>). Natural gas does not contain significant amounts of fuel-bound nitrogen, therefore thermal NO<sub>x</sub> is the primary formation mechanism for natural gas fired gas turbines. References to NO<sub>x</sub> formation during combustion in this analysis refer to "thermal NO<sub>x</sub>", NO<sub>x</sub> formed from nitrogen in the combustion air.

hydrocarbons. (Unburned hydrocarbons from natural gas combustion consist of methane, ethane and precursor organic compounds.)

The District prioritizes NO<sub>x</sub> reductions over carbon monoxide, however, because the Bay Area is not in compliance with applicable ozone standards, but does comply with carbon monoxide standards. The District therefore requires applicants to minimize NO<sub>x</sub> emissions to the greatest extent feasible, and then to optimize CO and POC emissions for that level of NO<sub>x</sub> control. This is a trade-off that must be kept in mind when selecting appropriate emissions control technologies for these pollutants.

The District has identified the following available combustion control technologies for reducing NO<sub>x</sub> emissions from the combustion turbines.

**Steam/Water Injection:** Steam or water injection was one of the first NO<sub>x</sub> control techniques utilized on gas turbines. Water or steam is injected into the combustion zone to act as a heat sink, lowering the peak flame temperature and thus lowering the quantity of thermal NO<sub>x</sub> formed. The injected water or steam exits the turbine as part of the exhaust. The lower peak flame temperature can also reduce combustion efficiency and prevent complete combustion, however, and so carbon monoxide and POC emissions can increase as water/steam-to-fuel ratios increase. In addition, the injected steam or water may cause flame instability and can cause the flame to quench (go out). Water/steam injection in the combustion turbines can achieve NO<sub>x</sub> emissions as low as 25 ppm @ 15% O<sub>2</sub>.

**Dry Low-NO<sub>x</sub> Combustors:** Another technology that can control NO<sub>x</sub> without water/steam injection is Dry Low-NO<sub>x</sub> combustion technology. Dry Low-NO<sub>x</sub> Combustors reduce the formation of thermal NO<sub>x</sub> through (1) “lean combustion” that uses excess air to reduce the primary combustion temperature; (2) reduced combustor residence time to limit exposure in a high temperature environment; (3) “lean premixed combustion” that reduces the peak flame temperature by mixing fuel and air in an initial stage to produce a lean and uniform fuel/air mixture that is delivered to a secondary stage where combustion takes place; and/or (4) two-stage rich/lean combustion using a primary fuel-rich combustion stage to limit the amount of oxygen available to combine with nitrogen and then a secondary lean burn-stage to complete combustion in a cooler environment. Dry Low-NO<sub>x</sub> combustors can achieve NO<sub>x</sub> emissions as low as 9 ppm.

**Catalytic Combustors:** Catalytic combustors, marketed under trade names such as XONON™, use a catalyst to allow the combustion reaction to take place with a lower peak flame temperature in order to reduce thermal NO<sub>x</sub> formation. XONON™ uses a flameless catalytic combustion module followed by completion of combustion (at lower temperatures) downstream of the catalyst. Catalytic combustors such as XONON™ have not been demonstrated on Aero-derivative simple-cycle gas turbines such as the GE LM 6000 PC Sprint or Siemens F Class. The technology has been successfully demonstrated in a 1.5-megawatt simple-cycle pilot facility, and it is commercially available for turbines rated up to 10 megawatts, but it is not currently available for turbines of the size proposed for the Mariposa Energy Project.

### ***Post-Combustion Controls***

The District has identified the following post-combustion controls that can remove NO<sub>x</sub> from the emissions stream after it has been formed.

**Selective Catalytic Reduction (SCR):** Selective catalytic reduction injects ammonia into the exhaust stream, which reacts with the NO<sub>x</sub> and oxygen in the presence of a catalyst to form nitrogen and water. NO<sub>x</sub> conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask or poison the catalyst. A small amount of ammonia is not consumed in the reaction and is emitted in the exhaust stream as what is commonly called “ammonia slip”. The SCR catalyst requires replacement periodically. SCR is a widely used post-combustion NO<sub>x</sub> control technique on gas turbines, usually in conjunction with combustion controls.

**Selective non-catalytic reduction (SNCR):** Selective non-catalytic reduction involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1400° to 2100° F<sup>9</sup> and is most commonly used in boilers because combustion turbines do not have exhaust temperatures in that range. Selective non-catalytic reduction (SNCR) requires a temperature window that is higher than the exhaust temperatures from utility combustion turbine installations.

**EMx™:** EMx™ (formerly SCONOX™) is a catalytic oxidation and absorption technology that uses a two-stage catalyst/absorber system for the control of NO<sub>x</sub>, CO, VOC and optionally SO<sub>x</sub> emissions for gas turbine applications. A coated catalyst oxidizes NO to NO<sub>2</sub>, CO to CO<sub>2</sub>, and VOCs to CO<sub>2</sub> and water, and the NO<sub>2</sub> is then absorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. A proprietary regenerative gas is periodically passed through the catalyst to desorb the NO<sub>2</sub> from the catalyst and reduce it to elemental nitrogen (N<sub>2</sub>). The EMx™ process uses no ammonia. The EMx™ catalyst requires replacement periodically. EMx™ has been successfully demonstrated on several small combined-cycle combustion turbine projects up to 45 megawatts. The District is not aware of any EMx™ installations for simple-cycle gas turbines or peaking units.

### **Proposed BACT for NO<sub>x</sub> for Simple-Cycle Gas Turbines**

#### **Combustion Controls**

Based on the preceding discussion, water-injection and dry low-NO<sub>x</sub> combustion are both technically feasible simple-cycle combustion turbine control technologies that are available to control NO<sub>x</sub> emissions. As part of the turbine selection process, the turbine vendor provided performance data for water-injected LM 6000 PC Sprint, dry-low NO<sub>x</sub> LM 6000 PD Sprint gas turbines and dry-low NO<sub>x</sub> LM 6000PF Sprint gas turbines (See Table 1). Although the LM 6000 PD turbine would have a similar NO<sub>x</sub> emission rate and the PF turbine would have a lower NO<sub>x</sub> emission rate than the PC turbine, the DLE models would have higher hydrocarbon and CO emission rates generally (except at the 17°F temperature case) when compared to the water-

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<sup>9</sup> NSCR discussion is from Institute of Clean Air Companies website:  
[www.icac.com/i4a/pages/index.cfm?pageID=3399](http://www.icac.com/i4a/pages/index.cfm?pageID=3399)

injected PC turbine. The applicant considered this tradeoff in the selection of the PC turbine, taking into account that any turbine selected would have to meet a 2.5-ppm NO<sub>x</sub> BACT limit utilizing post combustion technology.

The applicant has proposed the use of water-injection as BACT for the simple-cycle gas turbines. Water-injection is technologically feasible and commonly used at facilities of this type. This emissions control technology therefore satisfies the District's BACT requirement for combustion controls.

### **Post-Combustion Controls**

The applicant has proposed the use of Selective Catalytic Reduction (SCR) as BACT for the simple-cycle gas turbines.

Selective Catalytic Reduction (SCR) and EM<sub>x</sub> can achieve NO<sub>x</sub> emissions of 2.5 ppm for simple-cycle turbines. These are the most effective level of controls that can be achieved by post combustion controls. EM<sub>x</sub><sup>TM</sup> technology was first installed at the Redding Power Plant Unit #5, a 45-MW combined-cycle facility in Shasta County, California. The Shasta County Air Quality Management District evaluated EM<sub>x</sub><sup>TM</sup> at that facility under a demonstration NO<sub>x</sub> limit of 2.0 ppm (equivalent to what SCR can achieve for a combined-cycle unit).

After three years of operation, the Shasta County AQMD evaluated whether the facility was meeting this demonstration limit with EM<sub>x</sub><sup>TM</sup>, and concluded that "Redding Power is not able to reliably and continuously operate while maintaining the NO<sub>x</sub> demonstration limit of 2.0 ppmvd @ 15% O<sub>2</sub>." Based on Shasta County's negative experience with Redding Power, the District decided to accept SCR as a NO<sub>x</sub> control technology.

In addition to NO<sub>x</sub>, the District also compared the potential ancillary environmental impacts inherent in SCR and EM<sub>x</sub><sup>TM</sup> to determine whether EM<sub>x</sub><sup>TM</sup> should be considered more "effective" for purposes of the BACT analysis. In particular, the District evaluated the potential impacts from ammonia emissions that would occur from using SCR. The use of SCR will result in ammonia emissions because some of the ammonia used in the reaction to convert NO<sub>x</sub> to nitrogen and water does not get reacted and remains in the exhaust stream. The excess or unreacted ammonia emissions are known as "ammonia slip". Ammonia is a toxic chemical that can irritate or burn the skin, eyes, nose, and throat, and it also has the potential for reacting with nitric acid under certain atmospheric conditions to form particulate matter (Secondary PM).

With respect to the potential toxic impacts from ammonia slip emissions, the District has conducted a health risk assessment using air dispersion modeling to evaluate the potential health impacts of all toxics emissions from the facility, including ammonia slip. This assessment showed an acute hazard index of 0.026 and a chronic hazard index of 0.015. (See Health Risk Assessment in the Appendices.) A hazard index under 1.0 is considered less than significant. This minimal additional toxic impact of the ammonia slip resulting from the use of SCR is not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The District also considered the potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous

ammonia in a 19% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored on-site in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. These risks will be addressed in a number of ways under safety regulations and sound industry safety codes and standards. These safety measures include the Risk Management Plan requirement pursuant to the California Accidental Release Prevention Program, which must include an off-site consequences analysis and appropriate mitigation measures; a requirement to implement a Safety Management Plan (SMP) for delivery of ammonia and other liquid hazardous materials; a requirement to instruct vendors delivering hazardous chemicals, including aqueous ammonia, to travel certain routes; a requirement to install ammonia sensors to detect the occurrence of any potential migration of ammonia vapors offsite; a requirement to use an ammonia tank that meets specific standards to reduce the potential for a release event; and a requirement to conduct a “Vulnerability Assessment” to address the potential security risk associated with storage and use of aqueous ammonia onsite. With these safeguards in place, the risks from catastrophic ammonia releases from SCR systems can be mitigated to a less than significant level. The Energy Commission will also be evaluating these risks further through its CEQA-equivalent environmental review process and will impose mitigating conditions as necessary to ensure that the risks are less than significant. For all of these reasons, the potential environmental impact from aqueous ammonia transportation and storage does not justify the elimination of SCR as a control alternative.

Finally, the District also evaluated the potential for ammonia slip to have ancillary impacts on secondary particulate matter. Secondary particulate matter in the Bay Area is mostly ammonium nitrate.<sup>10</sup> The District has historically believed that ammonia was not a significant contributor to secondary particulate matter because the Bay Area is “nitric-acid limited”. This means that the formation of ammonium nitrate is constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere. Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with.

The District has recently started reconsidering the extent to which this situation is correct, however. This further evaluation has generally confirmed (preliminarily at least) that the Bay Area is in fact nitric acid limited, although it has shown that secondary particulate formation mechanisms are highly complex and that the District’s historical assumptions that ammonia emissions play no role whatsoever in secondary PM formation may, in hindsight, have been overly simplistic. The focus of the District further evaluation has been a computer modeling exercise designed to predict what PM<sub>2.5</sub> levels will be around the Bay Area, given certain assumptions about emissions of PM<sub>2.5</sub> and its precursors, about regional atmospheric chemistry, and about prevailing meteorological conditions. This information was used to create a computer model of regional PM<sub>2.5</sub> formation in the Bay Area from which predictions can be drawn about how emissions of PM<sub>2.5</sub> precursors will impact regional ambient PM<sub>2.5</sub> concentrations. The District’s report on its computer modeling exercise has not been finalized, but the draft report

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<sup>10</sup> See BAAQMD, Draft Report, *Fine Particulate Matter Data Analysis and Modeling in the Bay Area* (Draft, Oct. 1, 2009), at p. 8 (Draft PM<sub>2.5</sub> Modeling Report). The Air District anticipates issuing a final report in the near future.

concludes that regional ammonium nitrate buildup is limited by nitric acid, not by ammonia.<sup>11</sup> The draft report does find that the amount of available nitric acid is not uniform but varies in different locations around the Bay Area, and consequently the potential for ammonia emissions to impact PM<sub>2.5</sub> formation varies around the Bay Area. Specifically, according to the draft report, the model predicts that a reduction of 20% in total ammonia emissions throughout the Bay Area would result in changes in ambient PM<sub>2.5</sub> levels of between 0% and 4%, depending on the availability of nitric acid, leaving open the potential that ammonia restrictions could form a useful part of a regional strategy to reduce PM<sub>2.5</sub>.<sup>12</sup> The draft report therefore restates the general conclusion that the Bay Area is nitric acid limited, although it finds that reductions in the region's ammonia inventory could potentially achieve reductions in PM<sub>2.5</sub> concentrations in areas that may have sufficient available nitric acid.<sup>13</sup> (The draft report cautions that its assumptions regarding the availability of nitric acid may be misleading, however, because of the preliminary nature of the ammonia emissions inventory used for modeling.) Notably, the model also predicts that the Byron area where the facility would be located has low levels of available nitric acid, in the vicinity of 0.30 ppb.<sup>14</sup>

The District does not believe that these indications from its draft PM<sub>2.5</sub> data and modeling analysis provide a sufficient basis to disqualify SCR as a BACT technology at Mariposa based on its potential for ammonia slip emissions. As the report itself notes, the District's work in this area is still at a preliminary stage and it is difficult to draw any firm conclusion about secondary PM formation from it at this time. Moreover, secondary particulate formation is a highly complex atmospheric process, making it especially difficult to estimate how a specific facility's ammonia slip emissions might impact ambient PM levels. The District therefore notes the results of its recent work on secondary particulate matter and will be conducting additional work in this area going forward, but has concluded that there is not enough conclusive evidence at this stage that this facility could have a significant particulate matter impacts because of ammonia slip emissions from the SCR system.

In addition, the District notes that secondary PM formation from ammonia slip is a cold weather phenomenon that occurs only in the winter. This is because ammonium nitrate volatilizes at higher temperatures and only exists in a particulate phase in cold weather<sup>15</sup>. Moreover, the times when the Bay Area experiences problems with high ambient PM levels in the air are during the winter months (primarily November through February). The Mariposa Energy Project will be a peaker plant, however, which operates during periods of peak demand, which normally occur during the hot summer months, when air conditioning use is heavy.

The District therefore concludes that potential secondary PM formation from ammonia slip would not be a significant concern at Mariposa Energy Project because the facility will operate

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<sup>11</sup> Draft PM<sub>2.5</sub> Modeling Report at p. E-3 & p. 30

<sup>12</sup> Draft PM<sub>2.5</sub> Modeling Report at pp. E-3 – E-4

<sup>13</sup> Draft PM<sub>2.5</sub> Modeling Report at p. 30

<sup>14</sup> Draft PM<sub>2.5</sub> Modeling Report, Figure 17, p. 31

<sup>15</sup> Draft PM<sub>2.5</sub> Modeling Report at p. 10 (For all of the above notes, please check following link.)

[http://www.baaqmd.gov/~media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/PM-data-analysis-and-modeling-report\\_DRAFT.ashx](http://www.baaqmd.gov/~media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/PM-data-analysis-and-modeling-report_DRAFT.ashx)

primarily in weather conditions where ammonium nitrate secondary PM cannot form, and at times of the year when PM pollution is less of a concern.

Finally, the District also notes that although the manufacturer claims that EMx™ can be effectively scaled up from the smaller turbines on which it has demonstrated to the larger turbines at the proposed Mariposa Energy Project, earlier attempts to demonstrate the technology in practice have not been without problems. For example, the first attempt to scale the technology up from very small turbines (~5 MW) to the 50-MW range was at the Redding Power Plant Unit #5, a 45-MW combined-cycle facility in Shasta County, CA. The Shasta County Air Quality Management District evaluated EMx™ at that facility under a demonstration NO<sub>x</sub> limit of 2.0 ppm (equivalent to what SCR can achieve for a combined-cycle unit).

After three years of operation, the Shasta County AQMD evaluated whether the facility was meeting this demonstration limit with EMx™, and concluded that “Redding Power is not able to reliably and continuously operate while maintaining the NO<sub>x</sub> demonstration limit of 2.0 ppmvd @ 15% O<sub>2</sub>.”<sup>16</sup>

These concerns would be further compounded by the fact that Mariposa Energy Project will be a simple-cycle peaker plant, not a combined-cycle or cogeneration facility like other facilities where EMx™ has been installed. The EMx™ requires steam as part of the catalyst regeneration process. Unlike combined-cycle and cogeneration facilities, simple-cycle facilities like Mariposa Energy Project do not have any steam production. And there is an additional concern involving the damper systems that would be required with EMx™ to ensure proper regeneration gas distribution. Peaker plants require more rapid startups and more frequent load changes than combined-cycle and cogeneration plants, and to the District’s knowledge the effectiveness and longevity of these damper systems has not been demonstrated under these conditions.

Given the uncertainties that still remain in understanding how secondary PM formation is impacted by ammonia slip, the significant additional cost that would be necessary to implement EMx™, and the concern that scaling EMx™ up to fit this facility could involve significant implementation problems, the District has concluded that EMx™ should not be required here as a BACT technology.

Based on this review, the District has concluded that SCR meets the District’s BACT requirement. The proposed project would therefore comply with BACT for NO<sub>x</sub>.

#### ***Determination of BACT emissions limit for NO<sub>x</sub> for Simple-Cycle Gas Turbines***

The District is also proposing to establish a BACT emissions limit in the permit of 2.5 ppm (averaged over one hour), which is the most stringent limit that has been achieved in practice at any other similar facility and is the most stringent limit that would be technologically feasible.

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<sup>16</sup> Letter from R. Bell, Air Quality District Manager, Shasta County Air Quality Management District, to R. Bennett, Safety & Environmental Coordinator, Redding Electric Utility, June 23, 2005



To determine the most stringent emissions limit that has been achieved in practice, the District evaluated other similar simple-cycle natural gas fired turbines. Common simple-cycle gas turbine units proposed for use for intermediate peaking and peaking power in California are General Electric LMS-100 gas turbines (100 MW), and LM6000 (48.5 MW) gas turbines. LMS-100 gas turbines operate in a similar fashion and are appropriate for comparison with this facility. Numerous projects have been permitted with the LMS-100 gas turbines. The LM6000 gas turbines have also been installed at numerous sites across the state to provide peaking power.

The District reviewed the NO<sub>x</sub> emission limits of power plants using large turbines in a simple-cycle mode abated by SCR systems. The District also reviewed BACT determinations at the EPA RACT/BACT/LAER Clearinghouse, ARB BACT Clearinghouse and recent projects undergoing CEC licensing. Some of the LMS100 simple-cycle gas turbine permits and LM6000 simple-cycle gas turbine permits with NO<sub>x</sub> limits are shown in the Table 18 below.

<b>TABLE 19. NO<sub>x</sub> EMISSION LIMITS FOR LARGE SIMPLE-CYCLE POWER PLANTS USING SCR</b>	
<b>Facility</b>	<b>NO<sub>x</sub> (ppmvd @ 15% O<sub>2</sub>)</b>
Los Esteros Critical Energy Center, BAAQMD GE LM6000 Gas Turbines, 48.5 MW each	5.0 (3-hr)
Panoche Energy Center, SJVAPCD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
Walnut Creek Energy Park, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
Sun Valley Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
CPV Sentinel Energy Project, SCAQMD GE LMS100 Gas Turbines, 100 MW each	2.5 (1-hr)
Lambie Energy Center, BAAQMD GE LM6000 Gas Turbines, 48.5 MW each	2.5 (1-hr)
Riverview Energy Center, BAAQMD GE LM6000 Gas Turbines, 48.5 MW each	2.5 (1-hr)
Wolfskill Energy Center, BAAQMD GE LM6000 Gas Turbines, 48.5 MW each	2.5 (1-hr)
Goosehaven Energy Center, BAAQMD GE LM6000 Gas Turbines, 48.5 MW each	2.5 (1-hr)

As the Table 19 shows, emissions of 2.5 ppm NO<sub>x</sub> averaged over 1-hour is the most stringent emission limitation that has been determined to be achievable at any similar facility using SCR for NO<sub>x</sub> control.

The District examined only simple-cycle turbines in this review because simple-cycle turbines operate differently than combined-cycle turbines and cannot achieve the same NO<sub>x</sub> emissions performance as combined-cycle turbines, which are typically capable of meeting a 2.0-ppm limit. Simple-cycle turbines have higher exhaust gas temperatures than combined-cycle turbines because they do not use a heat recovery steam boiler, which removes some of the heat from the

exhaust and reduces the exhaust gas temperature. For this facility, the turbine exhaust temperatures from the simple-cycle turbines will exceed 863 degrees F, according to the permit application. These high exhaust temperatures can damage a standard SCR catalyst. As a result, simple-cycle turbines must use less-efficient high-temperature SCR catalysts, or must introduce a large amount of dilution air to cool the exhaust if they use a standard SCR catalyst. Both of these approaches lead to less efficient SCR performance as compared to a combined-cycle operation. High-temperature catalysts typically have a lower NO<sub>x</sub> conversion efficiency as compared to conventional SCR catalysts operating at a lower operating temperature. These catalysts have NO<sub>x</sub> conversion efficiency below 90% at elevated temperatures above 800°F,<sup>17</sup> whereas standard catalysts have NO<sub>x</sub> conversion efficiencies of greater than 90% at 600 to 700°F.<sup>18</sup> Dilution air fans can be used to cool the exhaust prior to entering the SCR system, but this approach has its own drawbacks. The introduction of dilution air may cool the exhaust into the appropriate temperature window, but there may be exhaust hot spots that lower catalyst NO<sub>x</sub> conversion rates. Optimum SCR performance requires uniform temperature profile, flow profile, and NO<sub>x</sub> concentration profile across the SCR catalyst face, and introducing large amounts of dilution air disrupts this uniformity. Changing turbine loads also tends to disrupt this uniformity, which makes controlling NO<sub>x</sub> more difficult with the simple-cycle peaking turbines proposed for the Mariposa Energy Project. The facility will operate in a load-following mode some of the time and this would mean non-steady-state operation where the exhaust temperature, flowrate, and NO<sub>x</sub> concentration all vary as the turbine load is changing. For all of these reasons, the District has concluded that the NO<sub>x</sub> emissions performance that can be achieved with combined-cycle turbines would not be achievable for simple-cycle turbines. The District has therefore reviewed only simple-cycle turbines in evaluating what emissions limits have been achieved in practice by other facilities. As shown in Table 18, 2.5 ppm is the most stringent emissions limitation that has been achieved by such facilities.

The District has therefore determined that 2.5 ppm, averaged over 1-hour, is the BACT emission limit for NO<sub>x</sub> for the simple-cycle gas turbines. The District is also proposing corresponding hourly, daily and annual mass emissions limits. Compliance with the NO<sub>x</sub> permit limits will be demonstrated on a continuous basis using a Continuous Emissions Monitor (CEM).

This proposed BACT emissions limit is consistent with the District's BACT Guidelines for this type of equipment. District BACT Guideline 89.1.3 does not specify BACT 1 (technologically feasible and cost-effective) for NO<sub>x</sub> for a simple-cycle gas turbine with a rated output > 40 MW. District BACT Guideline 89.1.3 does specify BACT 2 (achieved in practice) as 2.5 ppmvd @ 15% O<sub>2</sub> averaged over one hour, typically achieved through the use of High Temperature Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with steam or water injection.

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<sup>17</sup> BASF, High Temperature SCR for simple-cycle gas turbine applications, 2007

<sup>18</sup> BASF, NO<sub>x</sub> Cat™ VNX SCR Catalyst for natural gas turbines and stationary engines, 2009

**Archived:** Monday, April 12, 2021 8:01:17 AM

**From:** [abc123ko@everyactioncustom.com](mailto:abc123ko@everyactioncustom.com)

**Sent:** Friday, April 9, 2021 1:07:35 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)

**Subject:** Support the Pittsylvania County NAACP and Their Fight for Clean Air

**Importance:** Normal

---

Dear Anita Walthall,

I am writing to urge you to fully support the request of the Pittsylvania County NAACP branch for the Mountain Valley Pipeline Minor New Source Review Permit be denied and referred to the Air Pollution Control Board.

The current permitting process did not: (1) consider toxic cumulative direct and indirect impacts, (2) conduct a robust and inclusive community engagement program, or (3) perform an accurate air quality modeling analysis. Furthermore, the Air Quality Control Board should also request that the applicant provide information about any alternate sites that were considered and why they were removed from further evaluation.

A 27,756-horsepower compressor station, Lambert Compressor Station, is being proposed in Pittsylvania, VA. This compressor station will be located adjacent to two existing compressor stations and would increase air pollutant and particulate matter levels such as nitrogen oxides, formaldehyde, and carbon monoxide (to name a few), into the air. The new compressor station would add to the cumulative harm done to people in the minority-majority Banister voting district and the Chatham-Blairs Voting District, who have been burdened by pollution from two other Transco compressor facilities for sixty years.

Virginian residents deserve to know that the air they breathe in is safe and clean. Please do the right thing for PEOPLE, not corporations. Thank you for considering my views.

Sincerely,

Mrs. Kristin Hoffman

1201 N George Mason Dr Arlington, VA 22205-2539

[abc123ko@gmail.com](mailto:abc123ko@gmail.com)

**Archived:** Monday, April 12, 2021 8:01:17 AM

**From:** [abrooke.mason@everyactioncustom.com](mailto:abrooke.mason@everyactioncustom.com)

**Sent:** Friday, April 9, 2021 1:19:48 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)

**Subject:** Support the Pittsylvania County NAACP and Their Fight for Clean Air

**Importance:** Normal

---

Dear Anita Walthall,

I am writing to urge you to fully support the request of the Pittsylvania County NAACP branch for the Mountain Valley Pipeline Minor New Source Review Permit be denied and referred to the Air Pollution Control Board.

The current permitting process did not: (1) consider toxic cumulative direct and indirect impacts, (2) conduct a robust and inclusive community engagement program, or (3) perform an accurate air quality modeling analysis. Furthermore, the Air Quality Control Board should also request that the applicant provide information about any alternate sites that were considered and why they were removed from further evaluation.

A 27,756-horsepower compressor station, Lambert Compressor Station, is being proposed in Pittsylvania, VA. This compressor station will be located adjacent to two existing compressor stations and would increase air pollutant and particulate matter levels such as nitrogen oxides, formaldehyde, and carbon monoxide (to name a few), into the air. The new compressor station would add to the cumulative harm done to people in the minority-majority Banister voting district and the Chatham-Blairs Voting District, who have been burdened by pollution from two other Transco compressor facilities for sixty years.

Virginian residents deserve to know that the air they breathe in is safe and clean. Take action and support the Pittsylvania County NAACP! Thank you for considering my views.

Sincerely,

Mrs. Brooke Mason

2228 Banbury St Charlottesville, VA 22901-2956

[abrooke.mason@gmail.com](mailto:abrooke.mason@gmail.com)

**Archived:** Monday, April 12, 2021 8:01:18 AM  
**From:** [Kristin Hoffman](#)  
**Sent:** Friday, April 9, 2021 1:28:02 PM  
**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)  
**Cc:** [elle@chesapeakeclimate.org](mailto:elle@chesapeakeclimate.org)  
**Subject:** Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit  
**Importance:** Normal

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I respectfully request that the MVP Lambert Compressor Station Permit be reviewed with a full hearing in front of the Virginia Air Pollution Control Board.

Members of Our Revolution chapters across Virginia are impacted and concerned about the creation of another compressor station in Pittsylvania County. The air quality of the community is already being impacted negatively by Transco stations, and the addition of the MVP Lambert Compressor station will further risk their air quality and health. We request that the full impacts of the various chemicals and particulates being released into the community are investigated and accounted for cumulatively. Further, with many delays in the MVP mainline construction, there should be no rush to permit this compressor station. Our government should do the utmost to protect its citizens and the environment from harm. And this community deserves environmental justice considerations.

Thank you,

**Kristin Hoffman**

[Our Revolution State Organizer, Virginia](#)

1201 N George Mason Dr, Arlington, VA 22205

[kristin@ourrevolution.us](mailto:kristin@ourrevolution.us)

cell - 571-224-3580

Become a Movement Builder Member -> <https://ourrev.us/VAMEM>

**Archived:** Monday, April 12, 2021 8:01:18 AM  
**From:** [Cynthia Munley](#)  
**Sent:** Friday, April 9, 2021 1:49:02 PM  
**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)  
**Subject:** Lambert Compressor Station comments from Cynthia Munley  
**Importance:** Normal

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1. A full hearing in front of the Virginia Air Pollution Control Board is needed because of the severe consequences of adding another compressor station in this location.
2. This matters to me because everything is wrong concerning any permitting for the MVP's proposed compressor station in Pittsylvania County. The project makes no sense on every level. It is even a loss for the companies funding it and it is likely to be uncompleted and unsuccessful. I wish that no additional environmental damage be incurred for this failure of a project. Permitting a compressor station when MVP is likely to be a failed project and pipeline-to-nowhere would further expose the irresponsibility of the state of Virginia for wrongly permitting MVP at every juncture. MVP is being challenged with seven legal suits and recently failed to get a needed variance from FERC, which with a new FERK Chairman who sees MVP as an overbuilt, unnecessary pipeline, will likely further delay and impede this project. MVP does not have a viable way to cross water bodies. Using individual permits, it is likely to be challenged at every turn because the 42-inch mammoth pipeline has no way to cross water bodies without violating the Clean Water Act.

#### Comments:

Cumulative impacts make the suitability of the proposed location for the Lambert Compressor Station. If built next to the two existing Transco compressor stations, the combined emissions would be equivalent to a Clean Air Act Title V air polluting facility for carbon monoxide, nitrogen oxides, volatile organic compounds and hazardous air pollutants.

#### Health concerns:

- Formaldehyde in the air can lead to nasal and skin irritation as well as breathing problems. Formaldehyde can also increase complications of existing COPD and asthma. Higher concentrations of it can lead to tumor formation and pulmonary edema.
- MVP predicts that the Lambert Compressor Station will emit almost 9 pounds of formaldehyde an hour, on top of the background rate of 19 tons/year emitted by the Transco compressor stations 165 and 166.
- The proposed Lambert station would increase the emissions of particulate matter in the area by almost 30%.
- The percentage of people over the age of 64 in the nearby community is significantly higher than the state and national average. Older people are more vulnerable to particulate matter pollution, especially with increased rates of cardiorespiratory mortality and hospitalization.
- Chronic levels of air pollution also can increase the rates of respiratory tract infections such as pneumonia.
- In the Environmental Impact Statement, MVP projected that the Lambert compressor station would emit over 69 pounds of benzene annually. Acute chronic exposure (0.1 to 0.5 ppm) to benzene can reduce white blood cell counts, which is the most common indicator for leukemia risk.

#### Noise:

- The noise pollution resulting from 208 weekly startups and shutdowns for both the station's turbines would create unacceptable levels of air pollution emissions and significant noise impacts.

#### Environmental Justice concerns:

Genuine and accurate information discrepancies exist between the information provided by MVP and the EJ Analysis Report and what was communicated in MVP's final permit application. If this is the end of the review process, it is altogether likely that the EJ issues will be challenged in court. Although four EJ communities were identified within a 3-5 mile radius of the proposed compressor station site, MVP's September 2020 revised permit application to DEQ used data from a 1-mile radius.

MVP's information was cherry-picked and will be challenged. Best to stop this permit here.

**Procedural concerns:**

Although DEQ's notification processes rely on electronic outreach, the impacted localities do not have consistent internet access. The outreach timeline should have been earlier and conformed to Virginia's 2020 Environmental Justice Act.

During the public information session on Jan 7, 2021 regarding the timeline for approval, it was noted that a Clean Water Act 401 water certification from North Carolina is missing and DEQ staff acknowledged that they possibly should *NOT* be moving forward.

The completion rates for construction of the mainline MVP project that the developer included in the draft permit are significantly overstated, and could unfairly influence decision makers reviewing the permit. The most difficult and contested portions of the MVP have yet to be constructed making MVP's claim of 92% completion highly questionable. MVP does not use "full to restoration" percentage complete, instead relying on any preconstruction or ground-disturbing activity to inflate numbers. With the Mainline nowhere near completed, there is no need to permit or create infrastructure for a project with such uncertainty.

Wait for new census data with the most up to date information. It is not necessary to permit the MVP Lambert Compressor Station at this time.

**Archived:** Monday, April 12, 2021 8:01:18 AM

**From:** [Jolene Mafnas](#)

**Sent:** Friday, April 9, 2021 2:00:23 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)

**Subject:** Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit No. 21652 Public Comment

**Importance:** Normal

**Attachments:**

[04-09-21 Petition Regarding Permit No. 21652 for the Lambert Compressor Station.pdf](#);

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To Anita Hall:

Food & Water Watch is a national climate organization that fights for a livable climate, clean air and water. On behalf of Food & Water Watch, I urge the Department of Environmental Quality to deny the Lambert Compressor Station's air permit no. 21652, especially because this permit has not been heard in front of the full State Air Pollution Control Board nor has there been any meaningful engagement with the community. I have also attached a petition of 218 signatures urging DEQ to deny the Lambert Compressor Station's air permit no. 21652. Approving this permit would allow Mountain Valley Pipeline LLC—a company who has been found guilty for violating [over 300 environmental regulations](#)—to emit dangerous pollutants to nearby communities with those closest identified as environmental justice (EJ) communities. Already these EJ communities are experiencing the detrimental impacts from the existing Transco Compressor Station. If Lambert is built, there will be a significant compounded effect that will ultimately affect human health because [facilities like these are notorious for emitting](#) particulate matter, benzene, formaldehyde and nitrous oxide which can result in negative health effects like asthma, heart attacks, and cancer.

The Lambert Compressor Station would increase particulate matter pollution by almost 30% and the VA DEQ notes in its own draft review that Lambert's emission of fine particulate matter exceeds the respective permitting thresholds. This finding highlights how the Lambert Station will only bring negative health impacts to surrounding families who are most likely already coping with Transco's pollution affecting their health.

Another thing to consider is that according to a 2017 health equity report from the [Health Collaborative](#), an organization dedicated to improving the health of the Dan River area, the Danville Health District has an increased incidence of asthma compared to the rest of the state. This district also has an increased incidence of asthma related hospitalizations compared to the rest of the state and Pittsylvania county at large, demonstrating Danville area residents also experience asthma incidents more severely. These numbers demonstrate that these environmental justice communities may already be struggling with diseases related to compressor station pollutants at a higher rate than other areas in the state and even in its own county.

Additionally, this compressor station will put the community at an increased risk of a dangerous explosion. Considering that the mainline MVP's construction has been delayed for more than three years and is billions over budget, MVP may soon be a stranded asset. Therefore approving this permit before the mainline is even complete will only put a community in harm's way for a project that has a high chance of failing. In fact, a March study published by the [Institute for Energy Economics and Financial Analysis](#) found that MVP is struggling financially and if built would be severely underutilized due to a declining need for fracked gas. These factors highlight how the Lambert Compressor station is a useless venture that could ruin local indigenous communities' land which are relevant to cultural practices as mentioned in the Land and Heritage Consulting LLC's assessment of the project.

On top of that MVP has already violated water, erosion, and other environmental standards and as a result has been fined millions of dollars and should therefore not be allowed to wreak havoc in another community with its potential malpractice.

On top of that, compressor stations and other fracked gas infrastructure contribute to the climate crisis and building new fossil-fuel infrastructure will only undermine Virginia's commitments for renewable energy as well as any efforts to combat climate change. Although Virginia has declined in sourcing energy from coal, a primary driver for CO2 emissions, an [Environment and Energy Publishing article reported in May 2020](#) that Virginia had higher CO2 emissions in 2019 than in 2009 according to EPA. Despite coal fuel being used in about 43% of the state's power generation in 2008 to less than 10% in 2019, Virginia's CO2 emissions have risen between 2009-2019 because the buildout of fracked gas infrastructure is negating any reductions in CO2 from coal plant closures. Therefore any claims that fracked gas infrastructure can act as a transitory energy source for clean renewables is moot especially considering that solar and wind are just as competitive in price and safer for human health and the environment.

For these reasons and more, FWW strongly opposes this permit and urges you to deny it.

Sincerely,

**Jolene Mafnas**  
**(She/Her)**

Virginia Organizer

[Food & Water Action](#) and [Food & Water Watch](#)



O (703) 731-4907  
[jmafnas@fwwatch.org](mailto:jmafnas@fwwatch.org)

Fight like you live here.

04-09-21 Petition Regarding Permit No. 21652 for the Lambert Compressor Station.pdf

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**Virginia Department of Environmental Quality Deny Air Permit No. 21652 for the  
Lambert Compressor Station**

*The 218 Virginians, urge the Virginia Department of Environmental Quality to deny Mountain  
Valley Pipeline LLC's Air Permit No. 21652 for the Lambert Compressor Station .*

Friday, April 9, 2021

To Anita Hall:

As a resident of Virginia, I urge you to deny the proposed Lambert Compressor Station an air permit which would allow the facility to emit dangerous pollution, impacting nearby communities.

The communities closest to the compressor station have been identified as environmental justice communities, meaning that the Department of Environmental Quality must take extra precautions to protect this area's right to clean air and water -- including having a public hearing in front of the full Air Pollution Control Board. Already these families are experiencing the detrimental impacts from the existing Transco Compressor Station. Burdening them with pollution from yet another facility would be unconscionable.

Compressor stations like these can emit particulate matter, benzene, formaldehyde and nitrous oxide, which are associated with negative health effects like asthma, heart attacks, and cancer. In the DEQ's own draft review, it notes that Lambert's emission of fine particulate matter, which would increase particulate matter pollution in the area by 30%, exceeds the respective permitting threshold. This compressor station would also put the community at an increased risk of dangerous explosions and gas leaks.

Further, it makes no sense to approve the Lambert Compressor Station permit while the Mountain Valley Pipeline's main line construction has been delayed for more than three years and is billions over budget, signaling that MVP could soon be a stranded asset. On top of that, compressor stations like Lambert contribute to the climate crisis by emitting greenhouse gases and locking our state into decades more of fossil fuel infrastructure.

For these reasons and to protect our environment and local communities' right to clean air and water, I urge DEQ to deny this permit -- or at the very least, have a permit hearing in front of the full Air Pollution Control Board.

Signed,

First Name	Last Name	City	State	Zip Code
Amanda	Pagay	Alexandria	Virginia	22314
Helene	Shore	Vienna	Virginia	22182
Marilyn	Clark	Williamsburg	Virginia	23188
JeVerna	Haynes	Fredericksburg	Virginia	22405

Patricia	Williams	Afton	Virginia	22920
Barbara	Seaman	Alexandria	Virginia	22304
David	Newlin	Hillsboro	Virginia	20132
Anne	Larsen	Arlington	Virginia	22207
Ron	Rizzi	Marshall	Virginia	20115
Alex	Niconovich	Vienna	Virginia	22180
Karen	Holliday	Richmond	Virginia	23225
Frederick	Worth	Ashland	Virginia	23005
Fred	Reid	Louisa	Virginia	23093
Robert	O'Brien	Richmond	Virginia	23229
Michele	Shave	Williamsburg	Virginia	23188
Anne	Carson	Reston	Virginia	20191
Lynn	Gravelle	Chester	Virginia	23836
Robert	Wallace	Amelia Court House	Virginia	23002
Arthur	Leibowitz	Nyack	Virginia	23235
Lawrence	Jacksina	Charlottesville	Virginia	22902
Karen	Spurr	Virginia Beach	Virginia	23453
THOMAS E	TURNER	Manassas	Virginia	20112
Leslie	Calambro	Henrico	Virginia	23229
Shannon	Roth	Harrisonburg	Virginia	22802
Andrew	Trowbridge	Forest	Virginia	24551
James	Hartley	Arlington	Virginia	22207
Sandra	Uribe	Palmyra	Virginia	22963
Gina	Macias	Henrico	Virginia	23294
Jennifer	Keys	Ashburn	Virginia	20147
Margaret	Dyson-Cobb	Lexington	Virginia	24450
Debbie	Clark	Reston	Virginia	20190
Alison	Laurio	Front Royal	Virginia	22630
Gene	Cochran	Abingdon	Virginia	24211
Mary	Keller	Highland Springs	Virginia	23075
Mary	Armstrong	Midlothian	Virginia	22312
Raymond	Nuesch	Free Union	Virginia	22940
Lisa	Kingsley	Norfolk	Virginia	23507
Carol	Pruner	Roanoke	Virginia	24015
Tracy	Weldon	Midlothian	Virginia	23113
David	Scherer	Williamsburg	Virginia	23185
William	Staley	Sterling	Virginia	20164
Mark	Nuckols	Exmore	Virginia	23350
Patricia	Daniels	Manassas	Virginia	20109

Janice	Porter	Reston	Virginia	20191
Brian	Dunn	Henrico	Virginia	23233
Brad	Yoho	Ashburn	Virginia	20148
Pat	Mace	Spotsylvania	Virginia	22553
Norma	Riley	Stephens City	Virginia	22655
Blaine	Converse	Goochland	Virginia	23063
Elizabeth	Spiher	Culpeper	Virginia	22701
William	Welkowitz	Arlington	Virginia	22202
Sally	Mckee	Ashland	Virginia	23005
Brit	Horne	Charlottesville	Virginia	22901
Sarah	Vickers	Alexandria	Virginia	22305
Stacy	Sallerson	Chesterfield	Virginia	23838
Kristen	Mattioni	Boones Mill	Virginia	24065
Constance	O'Hearn	Arlington	Virginia	22204
Crystal	Hart	Leesburg	Virginia	20176
Caitlin	Archambault	Richmond	Virginia	23220
Richard	Rutherford	Staunton	Virginia	24401
Cynthia	Howell	Sterling	Virginia	20165
Carol	Miller	Hamilton	Virginia	20158
Mary	Barhydt	Norfolk	Virginia	23509
Amy	Cleveland	Prince George	Virginia	23875
Eileen	Embid	Alexandria	Virginia	22314
Joel	Serin	Alexandria	Virginia	22315
Ron	Mallard	Reston	Virginia	20191
Christopher	Dunn	Woodbridge	Virginia	22192
David	White	Charlottesville	Virginia	22902
Ellen	Atkinson	Lynchburg	Virginia	24502
Brooke	Kane	McLean	Virginia	22101
William	Huddle	Wytheville	Virginia	24382
Joel	Drebus	Reston	Virginia	20191
Sheila	Sylvester	Forest	Virginia	24551
Mary	Miller	Richmond	Virginia	23226
Christie	Lum	Lorton	Virginia	22079
Adam	DOnofrio	North Dinwiddie	Virginia	23803
Linda	Hertz	reston	Virginia	20190
Judith	Zwelling	Williamsburg	Virginia	23185
Kristine	Powers	Bedford	Virginia	24523
Kristine	Powers	Bedford	Virginia	24523
Patricia	Holbrook	Clintwood	Virginia	24228
Donna	Pitt	Newport	Virginia	24128

Cristeena	Naser	Alexandria	Virginia	22304
DeeDee	Tostanoski	Alexandria	Virginia	22314
Sara	Mauri	Arlington	Virginia	22205
Ellen	Kabat	Herndon	Virginia	20170
Susan	Kalan	Orange	Virginia	22960
Susan	Heytler	Marshall	Virginia	20115
Cynthia	Lonas	Glen Allen	Virginia	23060
Elliot	Daniels	Arlington	Virginia	22206
Jeffrey	Schnebelen	Stafford	Virginia	22554
Tyler	Arrowsmith	Alexandria	Virginia	22315
Fred	Krimgold	Mc Lean	Virginia	22101
Daniel	Giesy	Newport News	Virginia	23606
Carrie	Chilson	Williamsburg	Virginia	23185
Carol	Metzger	Kents Store	Virginia	23084
A Dean	Caulfield	Charlottesville	Virginia	22903
Joshua	Capps	Lorton	Virginia	22079
Elizabeth Struthers	Malbon	Blacksburg	Virginia	24060
Nancy	Schwall	Stafford	Virginia	22554
Peter	Sayre	Falls Church	Virginia	22044
Elizabeth	Ketz-Robinson	Alexandria	Virginia	22308
Krista	Powell	Harrisonburg	Virginia	22802
K.L.	Eckhardt	Winchester	Virginia	22601
Donald	Walsh	Alexandria	Virginia	22314
Jennifer	Tulo	Alexandria	Virginia	22306
Lois	Lommel	Richmond	Virginia	23235
Bruce	Supporter	Richmond	Virginia	23230
Andrew	Kalukin	Arlington	Virginia	22201
Morgan	Lazenby	Salem	Virginia	24153
Andrew	Schuler	Leesburg	Virginia	20175
Yvonne	Bounds	Reston	Virginia	20191
Margaret	Verry Fuller	Fairfax	Virginia	85741
John	Hitchins	Not Hispanic or Latino	Virginia	24014
Linda	Centorrinio	Fairfax	Virginia	22031
Cheryl	Arthur	Charlottesville	Virginia	22901
Jim	Lindsay	Arlington	Virginia	22201
Charlotte	Shnaider	Staunton	Virginia	24401
Bruce	Rauscher	Alexandria	Virginia	22312
Jason	Klinkel	Alexandria	Virginia	22301
William	Dent	Rockingham	Virginia	22801

Paul	Macomber	Herndon	Virginia	20171
Christiane	Riederer	Ashland	Virginia	23005
Virginia	Abraham	Springfield	Virginia	22152
Allen	Muchnick	Manassas	Virginia	20110
Laurel	Mancini	Virginia Beach	Virginia	23452
Quentin	Fischer	Roanoke	Virginia	24018
Greg	Singleton	Springfield	Virginia	22153
Nancy	Glynn	Alexandria	Virginia	22309
Linda	McDougal	BARHAMSVILLE	Virginia	23011
doug	meikle	Centreville	Virginia	20120
Susan	Dax	Fairfax	Virginia	22032
Sarah	Lanzman	Dyke	Virginia	22935
Tim	Schmitt	Arlington	Virginia	22205
Jessica	Cassidy	Herndon	Virginia	20170
Vicki	Nelson	Oakton	Virginia	22124
Charity	Moschopoulos	Annandale	Virginia	22003
Kathy	Zentz	Middlebrook	Virginia	24459
Pamela	Jiranek	Earlysville	Virginia	22936
Marie	Michl	Chesapeake	Virginia	23320
Susan	Weltz	Vienna	Virginia	22181
Kathy	Strozak	Smithfield	Virginia	23430
Claire	Jacobsen	Arlington	Virginia	22201
Claire	Jacobsen	Arlington	Virginia	22201
Claire	Jacobsen	Arlington	Virginia	22201
Zachary	Millimet	Alexandria	Virginia	22308
Marilyn	Anderson	Faber	Virginia	22938
Darek	Powell	Lynchburg	Virginia	24503
Ruth	Steenwyk	Amherst	Virginia	24521
Lindsay	Pugh	Disputanta	Virginia	23842
James	Jeffrey	Virginia Beach	Virginia	23456
Cindy	Speas	Falls Church	Virginia	22043
Valerie	Joseph	Fairfax	Virginia	22030
Peggy	Gilges	Charlottesville	Virginia	22901
Allen	Witherington	Palmyra	Virginia	22963
Laurie	Lagoe	Alexandria	Virginia	22309
Barbara	McCane	Chesapeake	Virginia	23325
David	Addison	Staunton	Virginia	24401
Agnes	Hetzel	Williamsburg	Virginia	23185
Edward	Savage	Catawba	Virginia	24070
Ron	Edwards	Center Cross	Virginia	22437

Pamela	Mullins	Gloucester	Virginia	23061
Jessica	Henao	Midlothian	Virginia	23083
Irwin	Flashman	Reston	Virginia	20190
Gail	White	Haymarket	Virginia	20169
Annie	Parr	Wingina	Virginia	24599
Debra	Shah	Vienna	Virginia	22180
josh	pucci	Mechanicsville	Virginia	23116
Julia	Lawrence	Henrico	Virginia	23233
Natalie	DeBoer	Richmond	Virginia	23229
Jean	Washburn	Glen Allen	Virginia	23060
Steve	TINGEN	Chantilly	Virginia	20151
Nancy	TINGEN	Chantilly	Virginia	20151
David	Guillaudeu	Ashburn	Virginia	20147
Diane	Berlin	Charlottesville	Virginia	22911
Kathy	Stark	Norfolk	Virginia	23508
Nora	Pfeiffer	Henrico	Virginia	23228
Diane	Berlin	Charlottesville	Virginia	22911
Walter	Moore	Moseley	Virginia	23120
Joseph	Rindler	Fredericksburg	Virginia	22401
Rhonda	Johnson	Aylett	Virginia	23009
Janet	Rountree	Suffolk	Virginia	23434
Teresa	McCartney	Glen Allen	Virginia	23060
C.	Kasey	Mechanicsville	Virginia	23116
Sandy	Scholar	Falls Church	Virginia	22043
Uwe	Dotzauer	Alexandria	Virginia	22304
Susan	Boyd	Alexandria	Virginia	22305
Mary	Baumeister	Alexandria	Virginia	22315
anhthu	lu	Falls Church	Virginia	22042
Roderick	Harrison	Reston	Virginia	20194
Abinaya	Venkatesan	Aldie	Virginia	20105
Ben	Rhoades	Fairfax	Virginia	22030
Aerin	Cuff	Drexel Hill	Pennsylvania	19026
Karen	Bryant	Fairfax	Virginia	22030
Josie	Taylor-soltys	Williamsburg	Virginia	23188
Lynne	Oglesby	Newport News	Virginia	23606
Polly	Cassady	Lynchburg	Virginia	24503
Derek	Meyer	Alexandria	Virginia	22305
Christine	Ilich	Flint Hill	Virginia	22627
Debbie	Freeman	Roanoke	Virginia	24018
Sapna	Batish	Reston	Virginia	20194



Lynda	West	Falls Church	Virginia	22044
Ann	Marckesano	Reston	Virginia	20194
Thomas	Smith	Roanoke	Virginia	24014
Shae	Savoy	Baltimore	Maryland	21212
Judith	Freeman	Charlottesville	Virginia	22901
Mollee	Sullivan	Midlothian	Virginia	23112
Wanda	ROBERTS	Charles City	Virginia	23030
Sarah	Jordan	Warrenton	Virginia	20187
Janice	Brown	Manassas	Virginia	20110
Suzanne	Hurley	Fairfax	Virginia	22033
Julianna	Luecke	Virginia Beach	Virginia	23454
Kelsey	Romano	Lovettsville	Virginia	20180
Stephanie	Clark	N. Chesterfield	Virginia	23236
Bobak	Zamanpour	Fairfax	Virginia	22030
Jose	Cruz	Herndon	Virginia	20170
Deborah	Roney	Vienna	Virginia	22180

**Archived:** Monday, April 12, 2021 8:01:18 AM

**From:** Doug Wellman

**Sent:** Friday, April 9, 2021 2:49:31 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)

**Subject:** Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit

**Importance:** Normal

---

**RE: Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit**

Dear Ms. Walthall:

I write to request that the Virginia Air Pollution Control Board (herein after, the Board) conduct a full hearing on Mountain Valley Pipeline's draft air permit for the Lambert Compressor Station. Concerns about air pollution and environmental justice need to be fully aired before the air permit is granted.

My interest stems from my awareness of the potential problems associated with compressor stations gained during the five years I spent challenging the Atlantic Coast Pipeline. That experience called attention to the importance of a full and open permit review process.

#### **Air Pollution**

The Board must consider that the Lambert station would join two existing Transco compressor stations in the same area, both of which emit large amounts of NO<sub>x</sub>, CO, VOCs, SO<sub>x</sub> and dangerous particulates. Current levels of dangerous air pollution must be considered before authorizing a permit for Lambert, so at a minimum the Board should withhold issuing a permit until a Transco study of ambient air pollution has been completed and considered.

More information is needed on Hazardous Air Pollutants (HAPs). In addition to formaldehyde,, which is listed in the draft permit, other HAPs like benzene, toluene and xylene should be included in the permit.

I am particularly concerned about releases of greenhouse gases. We have learned a great deal about the threats posed by climate change in recent years, and it is now recognized as one of the most important threats facing the country and the world. Leaks and intentional releases (during routine maintenance) of GHG's from pipelines and compressor stations can contribute significantly to climate change.

#### **Environmental Justice**

As we learned in the case of the Atlantic Coast Pipeline's Buckingham compressor station, relying on census tract data for demographic information may severely undercount existing environmental justice communities. Pollution hotspots and small population clusters can be missed without more careful study. As the Fourth Circuit Court of Appeals noted, seeking environmental justice involves more than checking a box.

In addition, full consideration must be given to the possibility of using electric turbines instead of gas-fired turbines, which are increasingly coming into favor around the country.

Thank you for the opportunity to register concerns about the Lambert air compressor permit.

Sincerely,

Douglas Wellman  
776 Laurel Lane  
Lovingston, VA 22949  
(434) 964-8307

**Archived:** Monday, April 12, 2021 8:01:18 AM  
**From:** [Finley-Brook, Mary](#)  
**Sent:** Friday, April 9, 2021 11:53:56 PM  
**To:** [Walthall, Anita](#)  
**Cc:** [qshabazz@vaejc.org](mailto:qshabazz@vaejc.org)  
**Subject:** public comment for Lambert Compressor Station  
**Importance:** Normal  
**Attachments:**  
[DEQ Lambert Compressor Station.pdf](#);

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Ms. Anita Walthall, DEQ Blue Ridge Regional Office,

Please find attached my public comment for Lambert Compressor Station.  
Applicant name and registration number: Mountain Valley Pipeline, LLC, 21652  
Facility name and address: 987 Transco Rd., Chatham, Va. 24531

Mary Finley-Brook, PhD  
Associate Professor of Geography, Environmental Studies & Global Studies  
University of Richmond  
#211 Richmond Way  
Richmond VA, 23173  
<http://geography.richmond.edu/faculty/mbrook/>

I support the mission & vision of the [Virginia Environmental Justice Collaborative](#).  
***A Clean, Healthy, Just & Equitable Environment for all.***



I stand in solidarity with the UR  
Black Student Coalition. Visit  
<https://linktr.ee/protectourweb/>  
for more information.

image001.jpg

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**PROTECT  
OUR  
WEB**

I stand in solidarity with the UR  
Black Student Coalition. Visit  
<https://linktr.ee/protectourweb/>  
for more information.



April 9, 2021

To: Ms. Anita Walthall, DEQ Blue Ridge Regional Office

RE: Lambert Compressor Station

Applicant name and registration number: Mountain Valley Pipeline, LLC, 21652

Facility name and address: 987 Transco Rd., Chatham, Va. 24531

I am a faculty member and researcher at the University of Richmond with focus on the energy sector. I serve on the board of the Virginia Environmental Justice Collaborative (VEJC). I am completing this technical review as part of my service to VEJC and to Virginia's frontline communities. As a resident of central Virginia, I am concerned about pollution and carbon footprints of all surrounding infrastructure as well as our energy rates.

This application is incomplete; thus, I recommend you reject it. There are a number of gaping holes in the evidence and fatal flaws with materials submitted. In particular, I address how independent consultant reports like Dr. Green's public health report would not stand up to peer review and how Dr. Lawrence's report on environmental justice admits important ground-truthing is weak or absent. Appendix 1 contains a list of questions that DEQ needs to address. These answers must be verified by the Air Pollution Control Board. **I recommend elevating this case to the Air Board**, any other course of action would be irresponsible. Yet I argue that DEQ expected elevation and tweaked their standard practices slightly to imply increased rigor - although I expose how what they state is 1) misleading because it much more limited than what they claim, and 2) procedures were less independent than they acknowledge.

Steps taken in this case to pay outside consultants are routinely only done in situations with concerning or extraneous circumstances. I was informed by DEQ Dir. Paylor on March 11, 2021 that DEQ picks and chooses which permit processes to provide extra resources. While I agree with DEQ that this case deserves attention, enhanced outreach and review still fell short of even the bare minimum required for fair environmental review, given the risks and vulnerabilities outlined below.

There are fatal flaws in the current environmental justice review and public health report. Both must be re-done to assure independence and accuracy. I have peer-reviewed both documents and the claims each author made. I am qualified to do this work as I have previously reviewed environmental and energy research on panels for the US Department of Energy (DOE), the Environmental Protection Agency (EPA) and the National Science Foundation (NSF). I have also reviewed dozens of peer-reviewed scholarly articles. These studies contain significant gaps and their findings must not be exaggerated.

In order to assure adequate oversight, I recommend:

1. Find additional modes to communicate with the impacted local community since distrust is high per Dr. Lawrence and some voices were not heard (i.e., the unincorporated

community of Sheva); this EJ consultancy process lacks meaningful involvement of environmental justice populations, as Dr. Lawrence explains in her text.

2. Complete quantitative cumulative impact assessment using baseline emission from both compressor stations; this did not occur and needs to, or there cannot be a convincing claim of overall emissions reductions.
3. Do a comprehensive public health study; the one from Dr. Green from Green Toxicology, LLC was an elaborate repackaging of massaged data from the permit application that was based way too heavily on the National Ambient Air Quality Standards (NAAQS) and lacked a comprehensive assessment of the actual conditions, meaning the methods are fundamentally flawed.
4. Lastly, if DEQ does not outright reject this permit extension and seeks to move forward, **there must be a public hearing before the Air Board.**

This current proposal contains inadequate information - I have included many crucial questions found in Appendix I of this report. My numerous queries in the appendix also demonstrate insufficient public health and safety protections.

Thank you for your attention to these concerns.



Mary Finley-Brook, PhD  
#211 Richmond Way #310  
Richmond, VA 23173



## **Lambert Compressor Station in Pittsylvania County**

Mary Finley-Brook, PhD  
Department of Geography and the Environment  
University of Richmond  
April 2021

### **Table of Contents**

Transco and Unsubstantiated Cumulative Impact  
Environmental Justice  
Comprehensive Risk Assessment  
Historic and Cultural Resources  
Public Health  
Alternative Sites and Best Available Control Technology  
Incompatibility with the Virginia Clean Economy Act

### **Appendices**

Appendix I: Remaining Questions  
Appendix II: Comments from Curt Nordgaard, MD, MSc

### **TRANSCO AND UNSUBSTANTIATED CUMULATIVE IMPACT**

When a compressor station was proposed in Buckingham - just north of Pittsylvania on the same Transco pipeline - it was very clear in project documents that Transco was defining access to gas for the ACP, and not vice versa. With Transco also being the larger entity in Pittsylvania, it seems illogical for DEQ to assume that Transco will fit their operations (and thus their emissions) around a smaller newcomer, the Mountain Valley Pipeline (MVP) or its Southgate Extension. This is the crux for the lower cumulative impact argument put forth in the permit application. DEQ needs to complete quantifiable baseline and cumulative emission data from the two facilities to assess properly. There also needs to be a commitment from both companies to work together. The Mountain Valley Pipeline placement and easement is incompatible with Transco, according to Williams' Transco.<sup>1</sup> Recent news articles relating this tension do not suggest a collaborative attitude and yet the entire outcome of what is suggested to be a cumulative impact analysis relies on actions on the Transco line and in the Transco station. Without this commitment in writing, anyone familiar with Transco's operations knows this is unlikely. Transco defines the situation as the bigger actor and as the gas supplier from long distances.

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1

[https://roanoke.com/news/local/mountain-valley-pipelines-extension-opposed-by-existing-transco-pipeline/article\\_a450c4ae-8697-11eb-b3d4-43e6c258f581.html](https://roanoke.com/news/local/mountain-valley-pipelines-extension-opposed-by-existing-transco-pipeline/article_a450c4ae-8697-11eb-b3d4-43e6c258f581.html);  
<https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/031721-transco-asks-court-to-deny-mountain-valley-pipe-expansion-easement-request>

Cumulative impact assessments of pollutants are unverifiable without quantitative analysis. On March 11, I asked Dr. Paylor in a zoom meeting with the VEJC if DEQ air permitting staff could talk the VEJC through how this cumulative impact analysis was done. I did not hear back, so I am assuming that for lack of time this was not possible. Verification of the claims in the cumulative impact assessment must be done before this permit moves forward, meaning the onus is on the Air Pollution Control Board to verify this process with quantitative proof, since I have not been shown any numbers or an exact methodology, and I have come to doubt that one exists. The foundation for this application is false if these emissions reductions are not verifiable. There is a large overall increase in horsepower as result of the new compressor station. So in spite of efficiency increases, the overall emissions will still be greater than the existing situation. I have verified that these concerns are valid with a number of national experts on compressor stations and one has entered a statement for the record (see Appendix II) also citing concerns with the claims of cumulative assessment without verification. The applicant and DEQ need to prove their as yet unsubstantiated claim. Until DEQ shows quantitative methods taking into account full data from both independent projects, DEQ seems to be asking us to accept wishful thinking as scientific proof.

Permit segmentation by this same Air Board and DEQ just months ago - with the case of the Newport News Shipyard (NNSY) - caused a new problem by not conducting cumulative impact analysis. The waste-to-energy plant Wheelabrator is now saying what many of us said at the time - that the overall environmental impact is negative due to the lack of communication and planning between these two interdependent systems.<sup>2</sup> One can't make a decision about a new energy source within a combined system without making sure that as a result the old energy source is forced to increase or change emissions due to the new plant. Many public commenters to DEQ said the application was incomplete because there was not enough information. DEQ and many state agencies have a piecemeal permitting approach; yet in writing up benefits from projects they allow applicants to overstep to make statements about the efficiencies in new technologies canceling out harm from projects outside the scope of the permit - without any evidence that the outside elements will cooperate with the idealized and often unrealistic scenario put forth by the applicant. The case of NNSY required collaboration from Wheelabrator to pick the best option. The case of Lambert requires involvement of Transco, since these two compressor stations and the pipelines that connect them are really the same system and emissions are interdependent.

The Air Pollution Control Board needs to be able to verify independently and to ask for additional evidence beyond the incomplete file information provided here. When the Air Board goes to verify cumulative impact assessment in this case, they need to be able to receive additional data, including from Transco. Based on my review of dozens of cases, I conclude that as long as DEQ staff can check the boxes on the minimal required information for approving permits, they generally do not go beyond to assure that they have the necessary information to actually make an informed decision about tradeoffs or overall real impacts of a project. Nonetheless, the mandate of the Air Board is broader; this mandate includes assessing local

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<https://www.pilotonline.com/news/environment/vp-nw-wheelabrator-norfolk-naval-shipyard-20210401-6sxx34uvenfi3ivbhc6tgoaal4-story.html>

economic implications and considering site suitability. When DEQ is the primary source feeding data, information and witnesses to the Air Board, this forces board members to make decisions without complete and impartial information. The Air Board should select their own expert witnesses and limit the ability of DEQ to filter and narrow the information they receive, so that independence is restored to air pollution oversight.

## ENVIRONMENTAL JUSTICE

Virginia's General Assembly passed House Bill 704 and Senate Bill 406 during the 2020 session. In recognition of the importance of environmental justice stated from Virginia DEQ, projects undergoing permitting the Commonwealth of Virginia should screen for vulnerable populations. **Figure 1** shows demographic analysis at the census tract level in the vicinity of the compressor station site. This data was taken from EJSCREEN and shows EJ populations exist in the vicinity as percentages above state averages. These thresholds trigger enhanced review.

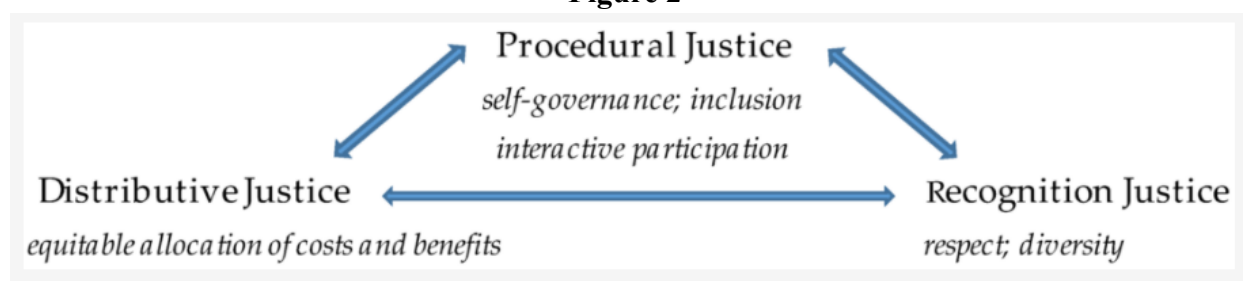
**Figure 1: Census Tracts Triggering Enhanced Review**

Census Tract ID #	People of Color	Poverty (per EPA criteria)
510030114003	52%	35%
510030114001	41%	44%

The enhanced review that MVP offered was a report by Dr. Lawrence of Land and Heritage Consulting, LLC from Chapel Hill, North Carolina. Before I address the findings of the report, it may be helpful to provide other limiting factors. Due to continued complete lack of DEQ staff training in EJ, regulators do not have a basic understanding that **environmental justice** requires **procedural justice** alongside **distributional justice**. Process matters!

**Figure 2** below is a standard conceptual frame from environmental justice frameworks and has been for years. The point of the diagram I published in 2016 in a special issue on public health and environmental justice is that one cannot just look at distribution to achieve justice. Factors such as participation and decision-making power are imperative. A consultant cannot just look at data and numbers transactionally or in terms of allocation (i.e., How many pounds of particulate matter? How much money in 'charitable contributions' to the local community (i.e., the local African American history museum?)) Without acknowledging or examining the broader pattern of silencing voices and erasing Black populations and histories across time, it may be counterproductive to bring up mitigation payments. Adequate financial resources for historical sites, preservation, and heritage are deserved without having to swap token support for local institutions, such as a donation for an African American museum as a tradeoff for increased public health risk and community harm, as Dr. Lawrence proposes in her environmental justice report.

Figure 2<sup>3</sup>



In addition to distributive and procedural justice, the third form of justice required for environmental justice is **recognition justice**: this means valuing diversity and cultural difference and treating others with respect. Dr. Lawrence does a good job in some places and with some groups, but she does an incomplete job in other places pointing out the injustices blocking recognition of minority ethnic and racial populations. Dr. Lawrence tends to reinforce a bias toward a framework of economic compensation, without addressing ways to stop other physical, psychological, race-based, income-based, or institutional harms.

DEQ has yet to even understand the concept of procedural justice but is not alone among Virginian agencies in this regard. Two decades ago the Department of Transportation (V-DOT) detailed environmental justice guidelines that described and spelled out how to involve impacted populations from the earliest planning stages through all steps of decision making in a process of meaningful interaction. The Commonwealth of Virginia has never used EJ guidelines in any permitting decision I have observed, including in the V-DOT, or in any process anyone has been able to tell me.<sup>4</sup> When you understand that they see environmental justice as something that can be bought and sold - as Dr. Lawrence's study also suggests - you realize that they continue to miss the whole point and that the bastardized process causes more harm than good because it lacks a sincere, open, and independent attempt to gather important social and ecological context.

The demographic and spatial analysis by Dr. Lawrence is relatively similar to EJSCREEN since it relies largely on the same census data, but she adds new information, such as the existence of a longstanding Freeman community in the vicinity of the compressor stations. However, there are many clues in the report and in the process that show that it cannot be considered independent. Thus the findings should be treated with cautious evaluation to avoid overreaching assertions about what was actually done. Much more must happen to assure the applicant and regulator will meet basic legal requirements and avoid civil rights violations. DEQ has a patchy track record and has been known to violate civil rights, as shown in the 2019 4th Circuit Court finding of

<sup>3</sup> Taken from Finley-Brook, M., & Holloman, E. L. (2016). Empowering energy justice. *International Journal of Environmental Research and Public Health*, 13(9), 926.

<sup>4</sup> Yet many staff of state agencies pat V-DOT on the back for this enlightened set of guidelines - the one that across decades has still never been used and is not enforced (these are just 'guidelines'). I have witnessed this congratulatory positioning multiple times while listening to proceedings of the Interagency Environmental Justice Working Group, a process that I describe as 'the blind leading the blind' because from poor process this past year (ask anyone in the Environmental Justice Collaborative - we observed every meeting) it was readily apparent that staff with DEQ and the Secretary of Natural Resources, who are at the front of the process, have no more knowledge, training, or understanding of environmental justice than when I worked with them in 2018-19 on the Governor's Advisory Council on Environmental Justice.

environmental racism and disproportionate impact in Buckingham, another rural African American community also located on the Transco pipeline. DEQ used the exact same flawed methods from Buckingham in yet another permitting case - the Chickahominy Gas Plant, a case that is coming in front of the Air Board again because of these concerns. We are directed by new law to break this cycle of abuse.

We need to define basic processes because there seems to be confusion between very different processes involved in public notification and participatory interaction.

**-Notification** is a one way street (information flows in one direction) and is never enough to satisfy an EJ mandate for community participation (although developers frequently try to limit this).

**-Participation** is a two way street (information flows in two directions) and involves free, informed dialogue where community input is recorded on the formal record and then to achieve EJ must be acted upon in a fair and just process with oversight and verification.

**-Meaningful interaction** (also sometimes called meaningful engagement) occurs over time and involves direct robust participation in decision-making from the earliest planning stages - so this must happen well before a draft permit application - until the last step of decommissioning and waste removal.

Writing the EJ consultant report was likely challenging with COVID and an initially distrustful population (as described in the report), but it is my professional opinion that actions by MVP could have made the situation worse. Dr. Lawrence had a very low response rate in her first recruitment. In September of 2020, MVP got involved and sought to set up additional appointments for her. This might have confused local populations: in the outreach email (**Figure 2 on the next page**) the option to talk to Dr. Lawrence is sandwiched between options to give comments to MVP. This could give people the impression that Dr. Lawrence was not fully independent in her process.

**Figure 2: September 2020 Outreach Email from MVP Southgate**

**Comments Form**

Please select the option below that best applies to your interest and return this form in the enclosed self-stamped envelope.

My name is \_\_\_\_\_ and I can be reached at \_\_\_\_\_.

☐ 1. I would like to be contacted by MVP Southgate team to discuss general questions related to the MVP compressor station project.

☐ 2. I would like to be contacted by Professor Lawrence's team to participate in the Community Impact Assessment.  
\*\*Please send this response back before September 30, 2020 for this option\*\*

☐ 3. I am including written comments about the project.

Please note that an independent consultant will be handling the responses, so if you select Option 2, your information will be only provided to Dr. Lawrence. If you select options 1 or 3, your information and comments will be provided to the MVP Southgate team.

You might ask how this work is supposed to occur with independence, since of course Dr. Lawrence was also paid by MVP. The answer is that these 3rd party 'independent' contractors reports are a construct created to intentionally muddy the water in controversial cases. This is the type of insight from interviewing people who have worked in the industry for a long time, as I do since I am writing a book on regulatory tricks in the energy sector.

There should be no need for either consultant report added to this file if DEQ knew how to conduct EJ assessment or if the state did its own verifiable public health research. These outside consultants are a trend commonly used in cases that are not 'shut and dry.' With their use in Virginia, I have seen considerable abuse with the use of 'experts' that cannot be clearly identified or are not qualified.<sup>5</sup>

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<sup>5</sup> I can give some examples, such as from the Atlantic Coast Pipeline and DEQ's use of two different sources from the Wilder School at VCU. One citation I traced back (with help of DEQ staff and Dominion Energy staff) to a footnote from a report by Dominion Energy that was taken out of context. The second source was to a researcher at VCU, who refused to speak to me when I contacted him. However, based on my review of his credentials, I suspect he did not have the expertise to 'verify' the information that DEQ said he had. I suspect what he verified was ESRI software and methods, which was different from what DEQ tried to imply in citing his work to try to shed doubt on the Union Hill household survey and Dr. Fjord's independent research - this independent research was later verified by the 4th Circuit Court and stood up to extensive peer review. This type of slipperiness from DEQ I am describing regarding the use of 'expert' witnesses is not acceptable. I spent months trying to get clear answers about the above ACP example because on multiple occasions Mike Dowd repeated the information from these supposed experts (i.e., in his powerpoint presentations to the Air Board). I am revisiting the specific of this case, that many will remember, so that we don't lose sight of the tricks utilized, or of common forms of regulatory trickery.

Dr. Lawrence violated norms for **procedural justice** - a core requirement for environmental justice (as outlined in **Figure 1** above on page 6) in how these meetings were set up. The process shows she is too tied to MVP to assure a trusted space for community members. All review of the materials should treat her report with this qualification: 1) there was no ‘independent’ EJ review (she worked for the company), and 2) she highlights ground truthing as imperative to verifying her research methods, and then admits that she was able to go very little of this necessary step in her implementation.

**Why did the EJ consultant choose to not speak to a representative of the Pittsylvania NAACP?** Perhaps she did not know about the Pittsylvania NAACP? If so, this would expose a high degree of ineptitude on the part of an environmental justice researcher. It is more likely that she was aware of the long- standing, well-established institution, with a history of involvement in natural resource management decisions in the county. Nevertheless, Lawrence selected to conduct an EJ assessment and chose to submit a report that left out this important stakeholder. This is a grave violation of **recognition justice**. Where there is an active local chapter, as there is in Pittsylvania, I would argue talking to the local NAACP chapter is essential for any quality EJ report (independent or not; this exclusion is unacceptable). I have had the opportunity to engage with and/or hear testimony from Anita Royston (Pittsylvania NAACP President) and Elizabeth Jones (Pittsylvania NAACP Environmental Justice Committee Chair), among others, on four occasions so far in 2021. The fact that I could do this easily from Richmond and that Dr. Lawrence never made this zoom call or phone call is worrisome. There is no justification for excluding this important African American institution<sup>6</sup> from an environmental justice assessment of their own community. Without addressing the broader pattern of silencing voices and erasing Black populations and histories across time, is it dangerous to suggest that a small one-time donation to a historical society, while it might get positive publicity for MVP, could balance out a relatively long-term (decades) increase in public health risk and harm. To make the suggestion without input from the directly impacted African American populations is an even graver violation of procedural environmental justice.

Dr. Lawrence’s original assessment identified 3 miles in distance as a frontline and 5 miles was defined as a buffer zone. MVP’s recap of the EJ consultancy report relied mainly on a 1 mile delineation and used it to disregard the EJ communities located just beyond this. Dr. Lawrence added 1 mile radius for unknown reasons in the second iteration of her report. The exact impact area should of course depend on the size of the facility and the amount of emissions, but in reality the idea of a concentric circle around air emissions from a smokestack does not equate to reality as concentrations and movements are likely to be irregular patterns than perfect spheres. I do know that local people expressed extreme frustration to me that they could not seem to get a clear answer from anyone about the actual impact area and why certain measures like 1, 3, or 5 miles would be selected over another measurement.

I strongly encourage Virginia DEQ and the Air Board to examine and remediate the following key weaknesses moving forward as likelihood of disproportionate impact and harm to vulnerable populations are both likely.

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<sup>6</sup> <http://naacppittsyco.org/home/about-us/>



Energy companies like Equitrans, Dominion Energy repeat the same tricks and DEQ mirrors their omissions and biases. These assertions are grounded by the following evidence.<sup>7</sup> As only one example, but one that should matter to this Air Board in particular, on June 21, 2019 at approximately 9:30am in the hearing room of the Virginia Crossing Hotel and Conference Center, Mike Dowd coached the permit applicant building a gas plant in Charles City on how best to present their testimony to the citizen Air Board for approval. Dowd was overheard providing specific detail to Jef Freeman of Balico, LLC about the specific language and other tactics they should employ together in their testimony (DEQ and Balico) so that the Air Board would treat the case favorably. DEQ, who is supposed to be the regulator in this case, was intentionally and explicitly assisting industry to get past the regulators, regardless of the fact that DEQ and the Air Board should have had more of a shared agenda in this instance than DEQ and a developer. Instances such as this explain the community's distrust in DEQ and these processes. Until this unethical behavior changes, I will be a watchdog for DEQ's permits.

Air Board processes occur with DEQ and state attorney's framing all terms and conditions seemingly with the goal to avoid litigation or to survive litigation. This high pressure and extremely controlled context eliminates the independence of the Air Board and becomes a show to more rigor in the permitting process, despite an outcome that is almost predetermined because of the approval bias of our state agencies. This Lambert Compressor Station review is an elaborately staged show with a predictable outcome, unless the Air Board regains independence and starts doing real verification, as is the intent and mandate of this citizen review board. The current practices are insufficient to attain functional regulatory oversight. Regulatory processes tend to be a showcase of DEQ culture and technical bias more than science or sustainability; the considerable time, effort, and resources used could be put to better use advancing clean energy and environmental justice. I spend many hours on public comments that I would rather spend challenging polluters, instead of challenging public servants. Yet unless there is accountability and transparency, I feel obligated to point out the continued use of smoke and mirrors.

It is necessary to review these past details if this controversial case in front of the same Air Board because, like Charles City, this Lambert case is also missing important information and there should not be a rush to permit, especially since the pipeline is facing so many other delays that this permitting process has absolutely no reason to rush. Please do not rush this permit.

Rushed permits mean cutting corners.

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<sup>7</sup> On June 21, another injustice that unfolded when Balico forced a decision in a one day hearing. They were asked by an Air Board member for another two weeks for review, but Balico was unwilling to grant more time for Air Board members who did not have adequate information to make an informed decision. As Air Board members know, this Chickahominy gas plant permit has come back to the Air Board with a request to reopen. But what is also notable is that the developer was not willing to allow two weeks for the Air Board to do an adequate job, and now more than a year later that has not even begun construction and still does not have necessary financial support. Based on my discussions with witnesses of the June 21 hearing, they felt the regulatory agency had rushed the process without allowing the Air Board members access to complete enough information for them to fulfill their mandate, which is more integral than the narrow scope of the DEQ permit. The Air Board cannot make informed decisions based on information spoon fed from DEQ and from DEQ's hand selected witnesses for the bulk of the hearing, with public comment crammed in after most of discussion has already occurred.



Rushed permits mean denying civil rights.  
Rushed permits means violating environmental justice protocols.  
Rushed permits lead to future delays when permits have to be redone.  
Rushed permits lead to court cases.  
Rushed permits cause social and ecological harm.

DEQ currently has a commitment to making every permit successful, so they see approval as a mere formality. I have now heard multiple staff explain they virtually never reject a permit application, but will spend a year or more working with the applicant to make sure it will succeed. The main way they do this is very narrow and technical - they just rework the models and emissions controls technology switching out equipment and models until they can get to where annual emissions are enough lower than the NAAQS so the applicant will likely avoid future violations. This is not the same as not causing harm. In fact, most emissions control equipment has tradeoffs: equipment may reduce emissions of some particular toxins, while increasing releases of other pollutants. DEQ gives a seal of approval while stating there will be no harm, although ignoring most toxins (and these are some of the most toxic) that are not NAAQS, such as volatile organic compounds (VOC) and Hazardous Air Pollutants (HAPs) (see for example Appendix II).

When DEQ is forced to admit there is harm, then they create a mitigation plan of some form of donation or offset, and state that this eliminates or balances out any harm, so DEQ can make a final assessment of no harm. Mitigation projects and pollution offsets have their own chapter in my book on fossil fuel industry manipulation of public opinion and trickery.

Knowledge that DEQ does not have the tools or willingness to properly screen for or protect EJ populations motivates me to do this work - without any financial compensation. Since I do not have overly close ties to industry or state regulatory agencies, I fit the bill of independent researcher, and I have for decades, so this is an issue I am qualified to speak to. Out of professional courtesy I don't like to criticize Dr. Green and, to a lesser degree, Dr. Lawrence, as I feel required to do here. In my courses and scholarship on energy and the environment, I commonly point out examples of unethical trends in development consulting, so I am attuned to these types of practices. Knowing the serious flaws in the methods and claims of the researchers used in this case, I argue accepting these studies from 'industry-tied' researchers and presenting their assessments as 'independent' is inaccurate, irresponsible and could cause undue harm to our rural areas and to low income populations.

## **COMPREHENSIVE RISK ASSESSMENT**

This permit application has not addressed important safety standards, like evacuation routes, given the highly pressurized and explosive nature of gas lines and compressor stations, especially given the proximity of the Mountain Valley Pipeline to the Transco, which Transco itself argues is so unsafe that they are unwilling to share an easement.<sup>8</sup> As I have stated in prior compressor

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<https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/031721-transco-asks-court-to-deny-mountain-valley-pipe-expansion-easement-request>

station assessments, there needs to be greater attention to medical and rescue services in this under-resourced part of the state, if there is going to be dangerous industrial infrastructure put in locations with emergency services and medical access on par with agricultural areas (which is largely what they are). **Where is the comprehensive risk assessment for this compressor station identifying emergency resources? Is there a safe evaluation route?**

## **HISTORIC AND CULTURAL RESOURCES**

Based on testimony of local residents (for example Elizabeth and Anderson Jones, DEQ hearing) there are long standing cultural practices of Native Virginians and African Americans that were not part of this review. I have heard local resident Anderson Jones speak about the cemetery that he takes care of near to the site and all the arrowheads he has from his 98-year old farm, which is adjacent to the compressor station property. I did not see any of these types of discussions in the report. Dr. Lawrence has extensive knowledge of Native populations and documents this portion of her student in great detail. She states that Native populations had good ideas for mitigation. Some indigenous people that I have worked with do think in terms of mitigation and will work with these projects, however, just as often (over the past decade) I have documented that many indigenous people strongly disapprove of offsets and mitigation measures that attempt to put a monetary value on their resources and culture. Throughout her work, Dr. Lawrence brought her worldview - a consultant's capitalist worldview - to her discussion of payments in exchange for harm. I would like to hear from impacted populations in their own words if they sought to sell their air, water, rights, cultural resources, etc. before I accept this as a local desire or conceptualization. Dr. Lawrence admits this is her frame from the start, but since she reports her findings in aggregation (which she has to do to protect identities) we really don't know what local people think from what she states. The comments I read showed great distrust of MVP's plan to pay to pollute (that is what these "donations" are equivalent to, if they convince people to approve the station in exchange for contributions).

Dr. Lawrence's study can serve as Step 1 - now there needs to be an independent environmental justice review with field methods to hear from the marginalized groups that were overlooked and assure not perspectives were diluted. Dr. Lawrence had a very small response rate, as she noted could be expected, but of the small numbers of respondents that she spoke to were mainly recruited with methods that require computer access and use, like email and facebook. So, given the digital divide in Pittsylvania (digital divides refer to gaps between people who are able to easily and frequently use the internet, and people who rarely use it or do not have access to it) it is unlikely that she got a representative sample of the local population. It is quite likely that the people who were left out had fewer economic resources. Rates of poverty within a 5-10 mile radius of the project are significant.

Outreach was too heavily reliant on e-mail and computer access for a population where the digital divide is prominent and some households do not have reliable and affordable broadband access. Even during times of COVID, developers and consultants need to find better and more appropriate ways to notify with local venues like churches, schools, businesses and civic organizations. Mailings tend to be mailed to adjacent property owners, but at DEQ's hearing

about this permit on February 8, 2021, people adjacent and near to the property line stated that they did not receive this notification.

It is clear historical resource studies at this site are incomplete. The consultants report might have addressed more of the details of responses - the questions would lead you to believe there was rich data but most of the report is computer maps that do not require local input.

There is at least one Freedman community identified in Dr. Laurence's report. She eventually talked to a member of the Blairs community,<sup>9</sup> but we have limited additional information. Dr. Lawrence's stress on the importance of techniques to groundtruth seem overlooked during implementation without field visits, observations, oral histories, etc. to provide missing context. I am highly concerned about the lack of input from or information about the unincorporated community of Sheva, as this is about 3 miles north - so is a fenceline community based on Dr. Lawrence's definitions. The air emissions from the compressor station are highest in the area and the internet coverage is lowest. This seems to have the potential to be a very vulnerable population and it is one that was essentially overlooked or erased if there is no additional assessment.

## **PUBLIC HEALTH**

To be frank, Dr. Green's research methods and her conclusions do not mesh. Her reports are built on circular arguments that use compliance with NAAQS as proof of the lack of harm, rather than actual on the ground or place-based evidence. She takes massaged numbers that were modeled to fit within annual NAAQS limits as her main evidence while overlooking other essential factors and the need for ground-truthing and to take into account variances based on proximity, cumulative exposures, preexisting health conditions, and other factors. Dr. Green's reports are low on actual evidence about the specifics of the case, but draw conclusive statements all the same. Dr. Green and her co-author Dr. Couch describe how the current air quality as good, but they do not take into consideration the annual tons of extremely toxic air pollution experienced in this area until about 2017 due to the Transco Compressor Station. These emissions have since decreased substantially, but the health impacts for the residents caused by the exposure can still show up in disease rates as illnesses present and progress. Any population that has lived by a compressor as dirty as the Transco station does not deserve to be burdened with any new infrastructure. Even if the efficiency levels of the new system are improved, the overall horsepower and the total emissions will increase upon the addition of the Lambert station.

Many professionals are calling for more stringent standards for various NAAQS. For example, the Independent Particulate Matter Review Panel published a 2020 paper on "The Need for a Tighter Particulate-Matter Air-Quality Standard" in *The New England Journal of Medicine* (Issue 383, no. 7, pages 680-683). This is a source I trust. To be honest, Dr. Green has a reputation nationally of being a "shill for the chemical industry": these are direct quotes from colleagues in New England, who I asked as they have a longer time frame to assess her work and greater experience with her modus operandi. The core of her argument is, and seemingly always will be,

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<sup>9</sup> Also mentioned here <https://pittsylvaniacountyva.gov/627/Black-History-Month>.

that infrastructure poses no real health risk. In the gas sector, there is a large and growing literature that contradicts Dr. Green (one contrarian scientist). Data and evidence that disputes Dr. Green's claims are coming from hundreds of qualified practitioners and professionals, like this 7th Edition Compendium of peer reviewed and medical assessment from all portions of the oil and gas supply chain (including compressor stations).<sup>10</sup> Instead of bringing in a public health expert to point out methods to improve the protection of public health around compressors, DEQ picked to spotlight a known 'gaslighter,' who alleges there is no harm. This doesn't surprise me, but it still disappoints me. A regulatory agency that routinely claims to have insufficient resources should be more interested in innovative problem-solving, particularly when solutions can bring greater environmental protections for Virginians, improve our collective knowledge and our use of science and technology to advance our common good.

DEQ relies on a dangerous circular argument: 'there are no disproportionate impacts for African American communities from compressor stations because there are no negative impacts from compressor stations.' This argumentation failed in front of the 4th Circuit Court, but we keep hearing the same argument (i.e., in Charles City, in Pittsylvania) from DEQ..

Once DEQ sought the input of Dr. Green, I suspect after the NNSY hearing, and her public health report was added to the Lambert record, the majority of the Lambert Compressor Station public comment period had already passed. We were only days from closure of the public comment period. It was not possible for people to review Dr. Green's materials (and a new report from Dr. Lawrence was also slipped in at the end of the original comment period). So DEQ extended the public comment period by one month after a complaint from Jess Simms of Appalachian Voices about the lack of time for review. This shift was done - in my perception - to assure Dr. Green's comment would receive full weight in front of the Air Board. I expect, based on observing dozens of hearings, that DEQ is planning for Dr. Green to be the star witness, as she was in the Navy's Newport News Shipyard gas plant in front of this same Air Board just months ago.

My concerns are the following:

- 1) Dr. Green's assessment contradicts other experts who say we need more stringent PM standards. Dr. Green argues that fine particulates group (or clump) together and thus are not fine enough to travel into the body as others have suggested. Yet other scientists and health experts show fine PM will enter the body and cause respiratory system damage and other damage.
- 2) With multiple exposures and vulnerabilities near compressor stations like Lambert, it is unlikely that harmful impacts can be entirely erased for all populations, as suggested by Dr. Green with her opinion of 'no harm.' This ignores the evidence that the proximity to emissions determines the impact even in the presence of compliance with the NAAQS.
- 3) Dr. Green as a star expert witness make a convenient argument for DEQ and the Air Board to disregard evidence from other experts - who are given only a few minutes in comparison to Dr Green's invitation to talk for multiple extended periods - like during the

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<sup>10</sup> <https://www.psr.org/blog/resource/fracking-compendium/>

recent NNSY hearing - so she can present her contrarian science in great detail that allows DEQ and anyone listening in the audience to entertain the false impression that compressor stations do not create public health risks or concerns for diseases like asthma or COPD.

I am concerned about the blatant disregard for local concerns, pre-existing diseases, and other risks because one professional says there is no harm using methods that would fail peer review. Not only is there lack of rigor to the study, Dr. Green claims results that cannot follow from the methods employed (i.e., a clear mismatch between the large confident claims made and the incomplete and narrow evidence presented). It appears like that DEQ intends to utilize Dr. Green in the same capacity as the NNSY hearing. In stating why they approved a new gas plant in a predominately low-income area where there are 80-90% people of color, various Air Board members acknowledged being influenced by this witness. Yet I have heard other expert witnesses and board members acknowledge in various hearings that existing NAAQS are not always protective of human health. I listened to Mike Dowd speak in contradictory terms on multiple occasions (i.e., Buckingham Compressor Station, Chickahominy Gas Plant) as to whether NAAQS are fully protective of health or not. Mr. Dowd has acknowledged in testimony that due to a number of conditions there is uncertainty about the protection of ALL people. Blanket statements like Dr. Green's 'no harm' mantra should only be proposed after extensive research considering proximity of exposure, duration of frequent exposures, age, preexisting health conditions, poverty, race, cumulative exposures, etc. Dr. Green has skipped the verification stage and jumped to repackage numbers intentionally modeled to fall below the NAAQS. She then reported that they were within safe limits and leaped to an unverifiable and undemonstrated conclusion that there would be no harm. This irresponsible conclusion could place public health at grave risk if these assumptions are incorrect. **The Air Board should request an independent, comprehensive health study.** If it does not, this process will likely allow for the intentional feeding of partial information (and even misinform) to board members.

## **ALTERNATIVE SITES AND BEST AVAILABLE CONTROL TECHNOLOGY**

The assessment of Best Available Control Technology (BACT) was incomplete and unconvincing. In light of the increasing use of electric motors and their growing affordability, particularly in relation to emissions pollution controls and contamination impacts, it is not sufficient to disqualify this option on a cost basis. The 4th Circuit Court, Buckingham County's case, required electric compressors to be considered with greater attention as an alternative. **If electric compressors are the BACT and are increasingly utilized, why were they not given full consideration in this case? Additionally, was there full consideration of alternative sites?** Documentation of these considerations also appears inadequate.

## **INCOMPATIBILITY WITH THE VIRGINIA CLEAN ECONOMY ACT**

This new fossil fuel project will be in the permitting process for at least a year more due to stream crossing review of the mainland Mountain Valley Pipeline system. With a necessary period of months for construction, an optimistic start date for the MVP is still more than a year away. Thus the lifetime of this gas pipeline - important for its overall cost-benefit analysis -

would extend well past the date that Virginia has committed to 100% renewables in the Virginia Clean Economy Act (VCEA).

In reading this case file, I was struck by how much more informed on issues of methane and climate and prepared to ask necessary questions that the State Corporation Commission (SCC) has been in recent cases when compared to DEQ. During recent SCC cases I have reviewed, SCC commissioners and staff asked applicants hard questions about the obvious incompatibility with VCEA. When assets become stranded within their useful lifetime, the expense will rest on ratepayers and potentially the state. We need any available investments to pay for transition to renewable energy or sources cleaner than fossil fuels. With the Header Improvement Project, SCC commissioners got Virginia Natural Gas to admit they had not done any assessment of REGGI, and then sent them back to do this. **Where is the complete assessment of the Regional Greenhouse Gas Initiative (RGGI)? Has there been any discussion of stranded assets?** Those who read current global and national news on the energy industry, know there are major discussions now of leaks from abandoned pipelines and midstream distribution lines and stations as well as drilling wells and pads because these kept from polluting once developers abandoned them and are very expensive remedy, especially when those from outside the area who receive the vast majority of the profit leave us to clean up their mess and no funds to do so. **Who will be responsible for this infrastructure if it is left in place and Equitrans Midstream has moved on to more profitable ventures or different technologies? Does the permit address decommissioning? What happens if this facility gets constructed and the rest of the MVP or the Southgate Extension remains unfinished?**

Our state's recent experiences show pipelines do not bring energy security. They are overpriced compared to renewable energy. Evidence of the social and ecological harms grow by the day. Don't we ever learn? Virginia does not need or want another compressor station or more pipelines. DEQ and the Air Board should listen to public commenters for once. I have seen many valid and detailed comments enter the record on this case and they deserve complete consideration and review, which I am going to be brutally frank and say does not happen. If you doubt this assessment, read the comments! I am not alone in this concern - others also say you need to work on your listening skills (that was the most polite way I could phrase it).

## CONCLUSION

The process must involve **a hearing and additional community listening sessions. The DEQ must hear directly from impacted populations.** Written comments cannot effectively record the feedback of those residents who remain without notification due to poor infrastructure, like internet and news coverage, or are uncertain how to meet written requirements, yet have every right to weigh in, given the breadth and depth of repercussions from compressor stations.

This permit process appears rushed. The documents on-file are incomplete and **too many questions remain unanswered** - as demonstrated throughout this report.

## APPENDIX 1

**Questions for the applicant and/or DEQ to answer before regulatory review could be considered complete.**

- Where is the comprehensive risk assessment? Is there a safe evaluation route?
- Were alternative sites adequately considered?
- If electric compressors are the Best Available Technology, are increasingly utilized, and are affordable in relation to emissions pollution controls and contamination impacts, why were they not given full consideration in this case?
- How was the Virginia Clean Economy Act taken into consideration?
- What is the likelihood that this facility will become a stranded asset?
- Can we be assured that the mainline MVP will be completed? Why rush an extension when the mainline is so vulnerable based on shifting markets and the multiple steps before regulatory processes and legal challenges can be completed?
- Where is the assessment of the Regional Greenhouse Gas Initiative (RGGI)?
- SCC commissioners know to ask for assessment of the impacts of VCEA and RGGI (see case file of Virginia Natural Gas Header Improvement Project - Docket #PUR-2019-00207), why doesn't DEQ also consider these policies and their clear implications for the MVP?
- Why did the EJ consultant choose to not speak with a representative of the Pittsylvania NAACP?
- If a local person were to inquire (as has occurred to me to inquire), what is the exact emissions impact area used for this permit (i.e., 1 mile , 1.5 miles, 3 miles, 5 miles)?
- Why hasn't the Air Board requested an independent, comprehensive health study?
- Appendix II points to inaccuracies in the reporting of contaminants in the gas: how can DEQ be sure to get accurate numbers from this and other applicants?
- Who will be responsible for this infrastructure if it is abandoned in place and Equitrans Midstream has moved on to more profitable ventures, or different technologies, or goes bankrupt?
- Why doesn't the permit address decommissioning?
- What happens if this facility gets constructed and the rest of the MVP or the Southgate Extension is not finished?

## APPENDIX II

Comments from Curt Nordgaard, MD, MSc; these were emailed to me on February 21, 2021

1 The hexane content of natural gas reported for the Mountain Valley Pipeline and the Southgate expansion is substantially different. This difference either needs to be rectified in the application or an appropriate justification for the difference provided.

The hexane content of natural gas in the Mountain Valley Pipeline is listed as 0.222% by weight, according to their FERC filing. On the other hand, the hexane content of natural gas in the Southgate expansion is listed as 0.04% by weight.

Mountain Valley Pipeline, FERC Docket 16-10:

Company Name: Mountain Valley Pipeline, LLC  
 Facility Name: Bradshaw Compressor Station  
 Project Description: Operational Emissions

**TABLE 12. Site-Specific Gas Analysis**

Sample Location: Multiple Locations  
 HHV (Btu/scf): 1,083

Constituent	Natural Gas Stream Speciation (Vol. %)	Natural Gas Stream Speciation (Wt. %)
N2	0.4949	0.788
METHANE	90.4241	82.411
CO2	0.2608	0.652
ETHANE	7.6812	13.124
PROPANE	0.6778	1.698
I-BUTANE	0.0754	0.249
N-BUTANE	0.1355	0.447
I-PENTANE	0.054	0.223
N-PENTANE	0.045	0.186
I-H EXAN ES	0.000	0.000
N-HEXANE	0.045	0.222
BENZENE	0.000	0.000
CYCLOHEXANE	0.000	0.000
HEPTANES	0.000	0.000
TOLUENE	0.000	0.000
2,2,4 Trimethylpentane	0.000	0.000
N-OCTANE	0.000	0.000
*E-BENZENE	0.000	0.000
*m,o,&p-XYLENE	0.000	0.000
I-NONANES	0.000	0.000
N-NONANE	0.000	0.000
I-DECANES	0.000	0.000
N-DECANE	0.000	0.000
I-UNDECANES +	0.000	0.000
Totals	99.895	100
*Gas Analysis showed no detectable compounds above hexane +, conservatively assumed all hexane + was n-he		
TOC (Total)	99.14	98.56
VOC (Total)	1.03	3.03
HAP (Total)	0.05	0.22



Southgate Expansion, FERC Docket CP19-14:

**MVP Southgate Project  
Lambert Compressor Station**

**Table B-8. Fugitive Blowdowns Potential Emissions Summary**

Natural Gas Specifications

Constituent	Mol Percent	Molecular Weight	Lb/Lb-Mol NG	Mass Percent	VOC
CO <sub>2</sub>	0.165	44.01	0.073	0.41%	No
Nitrogen	0.396	28.01	0.111	0.62%	No
Methane	87.823	16.04	14.089	79.08%	No
Ethane	11.303	30.07	3.399	19.08%	No
Propane	0.28	44.10	0.123	0.69%	Yes
i-Butane	0.009	58.12	0.005	0.03%	Yes
i-Pentane	0.003	72.15	0.002	0.01%	Yes
N-Pentane	0.003	72.15	0.002	0.01%	Yes
N-Hexane	0.008	86.18	0.007	0.04%	Yes
N-Butane	0.01	58.12	0.006	0.03%	Yes

Notes: Based upon representative gas analyses for Project.

Natural Gas Properties	
Molecular Weight	17.817
Specific Gravity	0.615
lb/Scf	0.047
Scf/lb	21.26

The hexane content of natural gas will likely influence hexane emissions from the Lambert compressor station when it is released as products of incomplete combustion, pipeline fugitives, flashing emissions, and storage tank working and breathing losses. Therefore, the hexane content of natural gas potentially impacts its air quality impacts and health risk.

MVP needs to explain why they used such a lower hexane content for an expansion of the same pipeline, with full details to account for any difference. Otherwise they must use the most accurate hexane content for typical and maximum emissions calculations, based upon an adequately representative sampling of natural gas entering the pipeline from the Equitrans gathering system that would supply it.

**2. Natural gas from other relevant pipelines includes BTEX along with hexane. If MVP is to claim that the gas in their pipeline will not contain BTEX, then they must provide adequate data to support that claim.**

EQM Midstream Partners, the largest owner of MVP and also its operator , will supply MVP with gas from its Weston facility. This is the same Equitrans facility that supplies natural gas to the Texas Eastern transmission pipeline.

EQMWESTON	73867	RAWHIDE	TEXAS EASTERN TRANSMISSION	Delivery	245000	229000	16000
EQMWESTON	73869	TOMBSTONE	TEXAS EASTERN TRANSMISSION	Delivery	1240800	659618	581182
EQMWESTON	73915	BAMBINO	TEXAS EASTERN TRANSMISSION	Delivery	643800	456000	187800
EQMWESTON	75111	BONNETHEAD NOMINATION POINT	TEXAS EASTERN TRANSMISSION	Delivery	915937	70000	845937
EQMWESTON	COLE_DEHY	Cole Farm Dehy	EQM GATHERING OPCO LLC	Delivery	200000	200000	0
EQMWESTON	A129103541	MAVERICK	DTE APPALACHIA GATHERING	Delivery	170000	0	170000
EQMWESTON	M5306625NP	GREAT HAMMERHEAD	MOUNTAIN VALLEY PIPELINE LLC	Delivery	0	0	0

Natural gas from the Texas Eastern pipeline contains the hazardous pollutants hexane, BTEX (benzene, toluene, ethylbenzene, and xylenes), and iso-octane. It consequently emits these compounds from flashing emissions, pipe fugitive emissions, and condensate tank emissions as part of its operations.

One example is shown here for Texas Eastern Transmission Co., FERC Docket CP19-512. However, in our experience Texas Eastern reports similar data for their other pipeline filings.

TABLE B-1 Piping Components Hourly and Annual Emission Estimates						
Source			MO-PC-NG			
Service			Gas			
			Natural Gas			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	236 components			
		Emission Factor	4.50E-03 kg/hr/component			
	Connectors	Count	194 components			
		Emission Factor	2.00E-04 kg/hr/component			
	Flanges	Count	170 components			
		Emission Factor	3.90E-04 kg/hr/component			
	Open-Ended Lines	Count	58 components			
		Emission Factor	2.00E-03 kg/hr/component			
	Pump Seals	Count	0 components			
		Emission Factor	2.40E-03 kg/hr/component			
Other	Count	30 components				
	Emission Factor	8.80E-03 kg/hr/component				
			Emissions			
			Avg. Hourly	Max. Annual	Max. Hourly	
Speciation	CO <sub>2,g</sub>	2384.96% by weight	81.3440 lb/hr	356.2867 tpy	82.5712 lb/hr	
	CO <sub>2</sub>	3.41% by weight	0.1162 lb/hr	0.5089 tpy	0.1622 lb/hr	
	TOC (Total)	100.00% by weight	3.4107 lb/hr	14.9389 tpy	3.4107 lb/hr	
	Methane	95.262% by weight	3.2491 lb/hr	14.2311 tpy	3.2964 lb/hr	
	Ethane	12.751% by weight	0.4349 lb/hr	1.9049 tpy	0.6672 lb/hr	
	VOC (Total)	2.198% by weight	0.0750 lb/hr	0.3284 tpy	0.3239 lb/hr	
	VOC (non-HAP)	2.131% by weight	0.0727 lb/hr	0.3183 tpy	0.3163 lb/hr	
	HAP (Total)	0.067% by weight	0.0023 lb/hr	0.0100 tpy	0.0076 lb/hr	
	Benzene	0.018% by weight	6.26E-04 lb/hr	2.74E-03 tpy	2.72E-03 lb/hr	
	Ethylbenzene	0.008% by weight	2.81E-04 lb/hr	1.23E-03 tpy	4.19E-04 lb/hr	
	Hexane (n-)	0.039% by weight	1.33E-03 lb/hr	5.83E-03 tpy	7.61E-03 lb/hr	
	Methanol					
	Naphthalene					
	Toluene	0.021% by weight	7.05E-04 lb/hr	3.09E-03 tpy	2.36E-03 lb/hr	
	Trimethylpentane (2,2,4-)	0.007% by weight	2.35E-04 lb/hr	1.03E-03 tpy	2.36E-04 lb/hr	
	Xylenes	0.025% by weight	8.55E-04 lb/hr	3.74E-03 tpy	3.56E-03 lb/hr	
NOTES						
1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017). The average SOCM1 w/o ethylene emission factor is used for pumps in heavy oil service (Table 2-1) since an emission factor isn't provided in Table 2-4.						
2. Piping component counts based on design drawings for the site.						
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.						
4. Weight percents based on gas analysis used to estimate gas release annual emissions (TABLE C-1). Maximum hourly emissions are based on the worst-case short-term weight percents even though the values are NOT presented.						

Since MVP will receive its gas from the same Equitrans Weston facility, it seems most likely that both pipelines will receive gas of the same composition. MVP needs to report a representative sampling of gas composition from the existing Equitrans Weston facility that will supply it, with a clear description of the sampling procedure. Since Equitrans is both the operator of the Weston facility and the MVP, there are no technical barriers for them to provide these data.

As noted above for hexane, understanding the composition of natural gas is critical for understanding its air quality impacts when the gas is emitted (piping fugitives, blowdowns) or processed (flashing emissions, pipeline liquids storage tank fugitives). The natural gas composition data are therefore necessary to adequately evaluate the pipeline's air quality impacts for the affected communities.

### **3. The air emissions modeling and EJ report omit substantial hazardous pollutant emissions from the Transco facility that currently overburden the affected communities.**

Section VI.3 (cumulative exposures) of the MVP EJ report asserts that “The environmental justice communities are also not overburdened by other sources of pollution.” MVP asserts this is true in part because the criteria pollutant modeling incorporated cumulative emissions from Transco Station 165. However, for hazardous air pollutants (HAPs), MVP only states that most of the emissions at that facility will decrease substantially after the Station 165 compressor engines are replaced under the Transco Southeast Trail project.

This is a qualitative statement that does not evaluate cumulative impact. MVP has not demonstrated that there is no cumulative impact of the HAP emissions from either the existing Transco compressor engines, Transco or MVP construction emissions, nor the new compressor engines at Transco Station 165 in addition to the MVP Lambert facility. Demonstrating no cumulative impact would require modeling of background + cumulative emissions, as was done for the criteria pollutants.

### **4. The omission of important hazardous pollutant emissions sources in the EJ report constitutes an ongoing and systematic injustice perpetrated against EJ communities.**

Section VI of the EJ report reads “...no community will face any appreciable health risk as a result of the facility's emissions...” and that “...the Station will cause no cumulative overburdening effect in combination with other sources of pollution.”

The US EPA defines environmental justice as “the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. ” (emphasis added).

The MVP Sept 2020 Supplemental Environmental Justice report admits that the community in the study area of its EJ analysis qualifies as an EJ community. Conforming with the principles of environmental justice, as summarized by the US EPA definition, would require the fair treatment of the EJ community that will be affected by the MVP facility.

Contrary to EJ principles, MVP is not providing fair treatment of the EJ community affected by its proposed facility. As noted above, MVP appears to have omitted important emissions sources (namely, hazardous air pollutant fugitives). Additionally, the air pollution impact analysis includes the cumulative impact of criterion pollutants but disregards the cumulative impact of hazardous air pollutants (HAPs).

The air pollution report and modeling, and EJ report, therefore fall far short of demonstrating no significant impact nor do they demonstrate no impact upon the EJ community that would be subject to the facility's emissions. On the contrary, emissions from the MVP Lambert facility

have been evaluated with a partiality that undermines fair treatment of the affected EJ community.

**Archived:** Monday, April 12, 2021 8:01:18 AM

**From:** [LYNDA MAJORS](#)

**Sent:** Friday, April 9, 2021 11:45:07 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)

**Subject:** Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit

**Importance:** Normal

---

Ms Walthall,

I am writing to request a hearing before the full Air Pollution Control Board as this is the minimum respect that should be given to Virginia citizens when the health impacts are so grave. The national standards for pollutants are sadly outdated as well as radioactivity not even considered as an impact on the community.

We have been fighting to stop the construction of the Mountain Valley Pipeline for over 6 years. At this point the mainline cannot cross the Jefferson National Forest, streams and wetlands and legal challenges remain a serious detriment to the completion of the pipeline. The Lambert compressor station will only exist if the mainline is completed and Southgate extension is built. No one should be subjected to this construction damage and taking of land if the project is as tenuous as this one is.

A full hearing before the Air Pollution Control Board will allow many more people to be engaged and participate is a decision that will have such an impact on their future.

Thank you for your consideration.

Lynda Majors  
2620 Mt Tabor Road  
Blacksburg, VA 24060  
540-552-8914

**Archived:** Monday, April 12, 2021 8:01:18 AM

**From:** [tlsmusz@gmail.com](mailto:tlsmusz@gmail.com)

**Sent:** Friday, April 9, 2021 11:37:03 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)

**Subject:** Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit

**Importance:** Normal

**Attachments:**

[Critique of Draft Permit for Lambert Compressor Station Proposed for Chatham Virginia .pdf](#);

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Dear Ms. Walthall,

I submitted my detailed written comments to you yesterday which includes my critique of the Lambert compressor station plans wherein I emphasized the very real health threats posed to both workers at the facility and Chatham residents. I neglected to state the following which support my reasons for engaging in this process:

- I am requesting that this proposal for Lambert Compressor Station **be elevated to a public hearing before the full Air Pollution Control Board** because of critical factors ignored or absent in this Draft proposal (such as radioactive emissions and debris, and cumulative air contaminants from 2 compressor stations operating in close proximity).
- As a long term resident of Virginia serving primarily rural populations during my career as an emergency medicine and later Palliative Care and Hospice physician, I am protective of the underserved populace in our rural areas – hardworking individuals who tend to suffer higher rates of chronic heart and lung disease than more urban populations. Adding another compressor station to further pollute Chatham’s air, water and soil is an unjust blow to the wellbeing, safety and health of the community.
- My document submitted to you yesterday addresses specific details of the permit which are lacking or unrealistic for achieving both a safe working environment and protection for the surrounding populace.

Based on the above concerns, I request a full hearing in front of the Virginia Air Pollution Control Board due to the deficiencies I noted in the draft permit.

Thank you for accepting my additional statements and request for a formal hearing before the Board.

I am again attaching my full written comments to accompany this supplemental email.

Tina L. Smusz, MD, MSPH

5555 Mt Tabor Rd <<...>>

Catawba, Virginia 24070

540-552-8763





## Critique of Draft Permit for Lambert Compressor Station Proposed for Chatham Virginia

Applicant name and registration number: Mountain Valley Pipeline, LLC, 21652

Facility name and address: 987 Transco Rd., Chatham, Va. 24531

DEQ contact: [Anita Walthall](#), 540-562-6769, [DEQ Blue Ridge Regional Office](#)

Comments by Tina Smusz, MD, MSPH

April 8, 2021

This critique of the Stationary Source Permit Draft for the Lambert Compressor Station in Chatham Virginia focuses on permit deficiencies which have grave implications for the health and wellbeing of both citizens living and working in the surrounding area as well as compressor station workers. This project would severely impact the quality of their environment in multiple ways.

Current statistics on population health for Pittsylvania County residents already portray a picture of a populace suffering numerous health problems with comparatively higher rates of chronic illness than the majority of Virginia counties [Pittsylvania County, Virginia | County Health Rankings & Roadmaps](#). These illnesses include heart and lung disease, both of which are exacerbated by air pollutants which will certainly be increased by the addition of another compressor station – with existing Transco compressor stations – in this relatively small geographic area.

### **Was the combined impact on air quality of multiple compressor stations even considered by DEQ when crafting this draft permit?**

Increased particulate matter in the air (PM<sub>10</sub> & PM<sub>2.5</sub>) which occurs with compressor station activity both causes and exacerbates heart and lung disease. Pregnant women and their fetuses are particularly vulnerable to this contaminant, which will be multiplied with the addition of another compressor station in the area. <https://www.psr.org/wp-content/uploads/2018/05/airborne-particulate-matter.pdf>

Along with customary impacts on air quality, compressor stations generate significant amounts of radioactive deposits known as TENORM<sup>1</sup> – both via their emissions (especially blowdown events) and from contamination of the pigging equipment which is sent through the gas pipeline between compressor stations to inspect and/or clean the pipe [PowerPoint Presentation \(iaea.org\)](#). Radioactive Lead<sub>210</sub> and Polonium<sub>210</sub> which travel in the methane stream of “fracked

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<sup>1</sup> Technologically Enhanced Normally Occurring Radioactive Material

gas” extracted from deep within the earth are deposited in the sludge that accumulates in the pipe lining <https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes>. Therefore, the “smart pig” devices also acquire a measure of radioactivity after transiting many miles of pipe between compressor stations.

The Lambert Compressor Station permit also does not address the issue of radioactivity in the gas plume expelled during “blowdown” operations nor the safe handling and disposal of the radioactive debris associated with the smart pig devices. It is sobering to see no mention of this potential health threat to workers, not to mention innocent citizens living downwind of any of area’s compressor stations. It is likely that the described “inlet air filters” designed to control particulate emissions from the combustion turbines will also collect radioactive debris and pose a hazard to compressor station workers who must perform maintenance associated with them.

The question should be formally addressed in the Compressor Station permit regarding safe and appropriate disposal of the radiation-contaminated debris generated at the station.

**Egregiously, the permit draft does not address this dangerous issue of radioactive contamination of air, soil and nearby water.**

Blowdowns also release hazardous air pollutants such as formaldehyde and BTEX compounds into the surrounding air <https://www.ingaa.org/File.aspx?id=31571>. All of the BTEX compounds (benzene, toluene, ethylbenzene and xylene) are known carcinogens.

The permit does not address the multitude of negative health impacts for people living near compressor stations. Item #4 states expectations for “good” air pollution control practices – but “good” is a far cry from what is needed for people living in the impacted community.

An important document was published in October 2017 - **Health Effects Associated with Stack Chemical Emissions from NYS Natural Gas Compressor Stations: 2008-2014** – A Technical Report Prepared for the Southwest Pennsylvania Environmental Health Project underwritten by the Park Foundation, authors P.N. Russo & D.O. Carpenter. This document looked at the health impacts of chemical and particulate emissions of 18 compressor stations in New York State. The document verifies that compliance with all air quality requirements is not assurance that compressor stations pose no significant threat to public health. Respiratory, cardiovascular and neurological health effects predominated among residents living near compressor stations.

The following is my commentary and critique of **Process Requirements** for the compressor station as they relate to potential human health impacts.

Section 4e. Emission Controls addresses minimizing emissions during start-up or shutdown using either the manufacturer’s written protocol or undefined “best engineering practices,” and

it is left to the operator to document and explain “the sufficiency of these practices.” This critical piece for protecting the surrounding community’s health via reduction of emissions should have well-defined protocols, parameters, and oversight by appropriate government agencies.

Section 6c. under **Emission Controls** suggests that pig launching and recovery are procedures resulting in significant emissions. I base this supposition on the limit of 2 events per 12 month period (a limit whose reason is not explained in the draft permit). Again, it is concerning that there is no mention of potential radioactivity associated with use of these devices.

Section 6f. states that “the permittee shall vent gas no more than twelve (12) times per year.” Also, “The permittee shall minimize the amount of time for each combustion turbine start-up purge.” There is no mention of DEQ monitoring these events or establishing a maximum duration for each of these highly polluting, noisy and distressing events for people living within close proximity to the compressor station.

Adequate forewarning of the inhabitants living nearest to the compressor station, would allow medically vulnerable people, and those with infants and children to either close up their dwellings or plan to be away from the area to avoid the airborne respiratory toxins emitted during that time period.

Section 7. Emission Controls addresses work practices to reduce emissions from leaks of gas from the facility. There are multiple inadequacies in this section which is a critical piece in protecting the health of the surrounding populace.

Section 7a. puts the onus on the permittee to “develop, maintain, and implement a fugitive emission component monitoring and repair plan.” This implies that there are not established standards and “best practice” requirements for this vital part of compressor station operation.

It specifies that “this plan shall consist of a daily auditory/visual/olfactory inspection program for all fugitive emissions components” which should be “conducted at least five days per week.” A more extensive leak detection survey is only scheduled quarterly. Also concerning is the 60 days grace period allowed for the initial extensive survey – a time during which the surrounding area and compressor station employees could be exposed to harmful emissions.

The rudimentary daily AVO (auditory/visual/olfactory) inspection program has serious built-in weaknesses, in that it relies on an intact olfactory system in the employee doing this cursory monitoring. Up to 19% of the general population (80% over 75 years old) have diminished sense

of smell. It is well known that loss (or reduction) of the ability to smell is also common among the populace who have or had COVID 19 infection [Anosmia and loss of smell in the era of covid-19 | The BMJ](#).

Notably, the methane intended for the Mountain Valley pipeline contains **no added odorant** and has minimal to no hydrogen sulfide content (a naturally occurring odorant in some gas) with resultant odorless, colorless gas. The daily AVO inspection program will therefore be effectively reduced to “A” for auditory, i.e., listening for leaks. Finally, it is concerning that 2 days out of 7, there is no mandatory monitoring per this permit.

Because the COVID pandemic is currently showing no significant sign of abating in the face of new variants, it must be a consideration in the timing of major construction projects such as a new compressor station. Active construction puts local residents at risk of contagion. Moreover, construction workers have one of the lowest rates of COVID vaccination in the nation, [United Contractors Launches "Roll Up Your Sleeves" Vaccination Information Campaign Across Construction Industry | Construction Dive](#).

The dearth of vaccinations in construction workers contributes to the well documented COVID clusters associated with construction sites. [A roundup of coronavirus outbreaks on construction sites | Construction Dive](#). This propensity for COVID spread associated with construction projects should put an indefinite HOLD on Lambert Compressor Station construction even if the permit is granted.

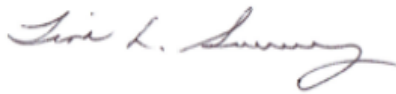
Section 7b. this section begins with allowing up to 3 days after discovery of a leak for the “**first attempt**” (highlighting is mine) *to repair any fugitive emissions component found to be leaking.*” 15 days total is allowed for repair of a discovered leak. Certain leaks warrant delayed repair “*If a leak is found that will emit less natural gas than a facility shutdown, repair may be delayed until the next facility shutdown.....*”). There appears to be no set maximum deadline for repairing the “*long-term leaking fugitive emissions components.*” This section can be interpreted as a license to pollute in small amounts over an extended time.

Compressor Station Emission Limits are established as if each compressor station operates in a void with no consideration of combined emissions from other industry or compressor stations in the nearby area. There is no explicit consideration or adjustment of operations based on their proximity to people’s homes, schools and other occupied buildings. Furthermore, as stated in this permit, “*Limits are a 3-hour average and do not apply during periods of start-up, shutdown, or when ambient temperatures are below 0 degree F.*” If emission limits do not apply during certain periods, it suggests that emissions could attain hazardous levels in the vicinity of the compressor station which should trigger an alert for people living or working nearby.

In conclusion, it can be assumed that all standard language and requirements are elucidated in this draft *Stationary Source Permit to Construct and Operate* a natural gas compressor station.

**What cannot be assumed is that the performance standards listed are adequately protective of the health of the environment – including the human beings residing and working nearby.**

Methane is rapidly becoming the dinosaur of modern fuel based on evidence of its impact on global warming, and air pollution. There is zero reason to build a soon-to-be defunct piece of fossil fuel infrastructure that will certainly diminish the health of compressor station workers as well as citizens in the surrounding area.

A handwritten signature in cursive script, appearing to read "Tina L. Smusz".

Tina L. Smusz, MD, MSPH

5555 Mt Tabor Rd

Catawba, Virginia 24070

540-552-8763 and 540-320-1567

**Archived:** Monday, April 12, 2021 8:01:18 AM  
**From:** Ginny Pannabecker  
**Sent:** Friday, April 9, 2021 10:39:58 PM  
**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov)  
**Subject:** Comment -- Mountain Valley Pipeline Lambert Compressor Station Draft Air Permit  
**Importance:** Normal

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Dear Anita Walthall,

My name is Virginia (Ginny) Pannabecker. I live at 705 S. Main St., Apt A-3, Blacksburg, VA, 24060, and my phone number is: (480) 862-9353.

While I'm not in Pittsylvania County, the Lambert Compressor Station would extend the Mountain Valley Pipeline which we are fighting in Montgomery County due to numerous documented air, water, and land issues that we have seen, and because the MVP is a costly fossil fuel project going the wrong direction from the green infrastructure we need for long term sustainability in Virginia. I support comments shared in the February 8 2021 Public Hearing on the MVP Lambert Compressor station from representatives from the local NAACP (also published in a [letter in the Star Tribune on March 8, 2021](#)), Food and Water Watch, African-American and Indigenous community members, and other community members from the Chatham community and beyond who shared grave concerns of air and water pollution. I join them in emphasizing that DEQ's focus must be on evaluating impact on air quality and on protecting and ensuring the health and well being of our environment and our communities.

I urge you to require review by the Citizen Air Pollution Control Board of the air permit and especially the environmental justice concerns and grave cumulative polluting impact from this station and ultimately, I urge you to deny the air permit. As we heard from many commenters at the February 8, 2021 Public Hearing, and again at the March 10, 2021 Air Board Committee on Public Engagement meeting, many community stakeholders have been left out of this process, which is against the requirements of the Virginia Environmental Justice Act's requirement of meaningful involvement of directly affected community members. For this reason alone, the permit should be denied, given the insufficient attempts and lack of success in reaching and providing accessible, feasible methods for directly affected community members from environmental justice communities to take part in this permit consideration process. There has been no opportunity for exchange of questions and responses, and meaningful dialogue with the community.

Additionally, the cumulative impact that this compressor station would result in for Chatham, Pittsylvania County, is of grave concern. With the two existing Transco compressor stations, the combined emissions with the new Lambert Compressor Station would be equivalent to a Clean Air Act Title 5 air polluting facility for carbon monoxide, nitrogen oxides, and other air pollutants.

As someone with asthma, I empathize with others who have asthma and I'm particularly concerned about air pollution in Virginia like in the Pittsylvania County area where the Lambert Compressor Station is proposed, that already has existing compressor stations. Right now with Covid-19, we should all be more aware of the importance of respiratory health. Air pollution at any level harms our respiratory health, making us more susceptible to respiratory diseases and other health complications. MVP predicts that the Lambert Compressor Station will emit almost nine pounds of formaldehyde an hour on top of the background rate of nineteen tons per year emitted by the Transco compressor stations. These emissions can cause breathing problems and increase complications of existing COPD and asthma. Particulate matter emission will increase by almost thirty percent. Particulate pollution that you breathe in can get stuck in your body, causing short term irritation and inflammation particularly harmful to those with asthma and other lung conditions, and long term exposure can lead to additional health conditions. The only hazardous air pollutant that is subject to hourly and yearly emission limits in the draft permit is formaldehyde. There are several other hazardous air pollutants listed including benzene, toluene, xylenes that can cause adverse health effects but are not in the air permit.

I urge you to implement processes for all reviews along the lines of the suggestions shared at the March 10th meeting:

- Methods for direct and broad, extensive communication and outreach, and opportunities to address the board, and eliminating presence of armed law enforcement at hearings.
- Sharing meeting material details, such as the survey you discussed at the Air Board Committee on Public Engagement March 10th hearing
- Recording public input
- Providing timelines and highlighting input options
- Attend community meetings not just scheduling your own meetings
- Valuing public opinion

Given the issues with the proposed Lambert Station, especially the lack of meaningful involvement of directly affected community members and the combined cumulative impacts of the existing compressor stations and the proposed Lambert station, **I urge you to require a review of this permit by the Citizen Air Pollution Control Board and further engage with broader representation of directly affected community members to fully understand the dire air quality and critical health concerns. Finally, I urge you to deny the permit and support community health.**

Thank you very much for your time.

Sincerely,

Virginia (Ginny) Pannabecker  
705 S. Main St., Apt A-3, Blacksburg, VA, 24060  
Phone number: (480) 862-9353.

**Archived:** Monday, April 12, 2021 8:01:20 AM

**From:** [Evan Johns](#)

**Sent:** Friday, April 9, 2021 10:05:07 PM

**To:** [anita.walthall@deq.virginia.gov](mailto:anita.walthall@deq.virginia.gov); [TLilley@cbf.org](mailto:TLilley@cbf.org); [asolaski@cbf.org](mailto:asolaski@cbf.org)

**Subject:** Evan Johns shared the folder "Exhibits" with you.

**Importance:** Normal



## Evan Johns shared a folder with you

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BEFORE THE ADMINISTRATOR  
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

\_\_\_\_\_  
IN THE MATTER OF )  
)  
)

CASH CREEK GENERATION, LLC )  
)

PETITION NOS. IV-2008-1 & IV-2008-2

HENDERSON, KENTUCKY )  
)  
TITLE V/PSD AIR QUALITY PERMIT )  
# V-07-017 )  
)

ISSUED BY THE KENTUCKY )  
DIVISION FOR AIR QUALITY )  
DIVISION )  
\_\_\_\_\_ )

**ORDER RESPONDING TO ISSUES RAISED IN JANUARY 31, 2008 AND FEBRUARY  
13, 2008 PETITIONS, AND DENYING IN PART AND GRANTING IN PART  
REQUESTS FOR OBJECTION TO PERMIT**

The United States Environmental Protection Agency (EPA) received timely petitions from Sierra Club and Valley Watch (Petitioners) dated January 31, 2008, and February 13, 2008, respectively, pursuant to Section 505(b)(2) of the Clean Air Act ("CAA" or "Act"), 42 United States Code (U.S.C.) § 7661d(b)(2) (the January 31, 2008, petition is referred to as "Petition 1" and the February 13, 2008, petition is referred to as "Petition 2"). Both Petitions request that EPA object to Permit #V-07-017 issued by the Kentucky Division for Air Quality ("KDAQ") on January 17, 2008, to Cash Creek Generation, LLC (Cash Creek). Permit #V-07-017 is a merged CAA prevention of significant deterioration (PSD) construction permit and CAA title V operating permit issued pursuant to Kentucky's Administrative Regulations (KAR) at 401 KAR 52:020 (title V regulations) and 51:017 (PSD regulations). The permit is for a new nominal 770 megawatt (MW) electric generating facility using Integrated Gasification Combined Cycle (IGCC) technology at the Cash Creek Generating Station located southwest of Owensboro (Henderson County), Kentucky.

This Order contains EPA's response to Petitioners' request that EPA object to the permit on the basis that: 1) the best available control technology (BACT) analyses did not include natural gas as a clean fuel; 2) the permit lacks the appropriate new source performance standards (NSPS) for the combustion turbines planned for the facility; 3) the permit lacks a PM<sub>2.5</sub> limit; 4) the permit lacks a BACT limit for CO<sub>2</sub>; 5) KDAQ did not consider, and was unresponsive to,



public input regarding an alternatives analysis for the proposed permit; 6) Elm Road sulfuric acid mist (SAM) limits were not considered in the BACT analysis; 7) KDAQ did not respond to comments regarding material handling and storage emissions; and 8) KDAQ did not respond to Valley Watch comments on increased ozone formation due to the emissions from the proposed source.

Based on a review of Petitions 1 and 2 and other relevant materials, including the Cash Creek permit and permit record, and relevant statutory and regulatory authorities, and, as discussed in this Order, I grant in part and deny in part the Petitions requesting that EPA object to the Cash Creek permit. I grant on issues 1, 2, 3, 5, 6 and 8 above.

## **I. STATUTORY AND REGULATORY FRAMEWORK**

Section 502(d)(1) of the CAA calls upon each State to develop and submit to EPA an operating permit program intended to meet the requirements of title V of the CAA. The Commonwealth of Kentucky<sup>1</sup> originally submitted its title V program governing the issuance of operating permits in 1993, and EPA granted full approval on October 31, 2001. 66 *Fed. Reg.* 54953 (October 31, 2001). The program is now incorporated into Kentucky's Administrative Regulations at 401 KAR 52:020. All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable State Implementation Plan (SIP). CAA §§ 502(a) and 504(a), 42 U.S.C. §§ 7661a(a) and 7661c(a).

The title V operating permit program does not generally impose new substantive air quality control requirements (referred to as "applicable requirements"), but does require permits to contain monitoring, recordkeeping, reporting and other conditions to assure sources' compliance with applicable requirements. 57 *Fed. Reg.* 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and for assuring compliance with such requirements.

Applicable requirements for a new major stationary source<sup>2</sup> include the requirement to obtain a preconstruction permit that complies with applicable New Source Review (NSR) requirements (e.g., PSD). Part C of Title I of the CAA establishes the PSD program, the

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<sup>1</sup> The Commonwealth of Kentucky Environmental and Public Protection Cabinet (Kentucky Cabinet), which submitted the title V program, oversees the Kentucky Division for Air Quality (KDAQ) which is the permitting authority for title V and PSD permits in Kentucky.

<sup>2</sup> The proposed Cash Creek facility is a "major stationary source" consistent with the definition of that term in 401 KAR 51:001 § 1(118).

preconstruction review program that applies to areas of the country, such as Henderson County, that are designated as attainment or unclassifiable for National Ambient Air Quality Standards (NAAQS). CAA §§ 160-169, 42 U.S.C. §§ 7470-7479. NSR is the term used to describe both the PSD program as well as the nonattainment NSR program (applicable to areas that are designated as nonattainment with the NAAQS). In attainment areas (such as Henderson County), a major stationary source may not begin construction without first obtaining a PSD permit. CAA § 165(a)(1), 42 U.S.C. § 7475(a)(1). The PSD program analysis must address two primary and fundamental elements (among other requirements) before the permitting authority may issue a permit: (1) an evaluation of the impact of the proposed new or modified major stationary source on ambient air quality in the area, and (2) an analysis ensuring that the proposed facility is subject to BACT for each pollutant subject to regulation under the PSD program. CAA § 165(a)(3), (4), 42 U.S.C. § 7475(a)(3), (4); *see also* 401 KAR 51:017 (Kentucky's PSD program).

EPA has promulgated two largely identical sets of regulations to implement the PSD program. One set, found at 40 Code of Federal Regulations (CFR) § 52.21, contains EPA's own federal PSD program, which applies in areas without a SIP-approved PSD program. The other set of regulations, found at 40 CFR § 51.166, contains requirements that state PSD programs must meet to be approved as part of a SIP. In 1989, EPA approved Kentucky's PSD rules into the SIP as meeting these requirements. 54 *Fed. Reg.* 36307 (September 1, 1989); *see also* 40 CFR § 52.931.<sup>3</sup> Thus, the applicable requirements of the Act for new major sources, such as Cash Creek, include the requirement to comply with PSD requirements under the Kentucky SIP. *See, e.g.*, 40 CFR § 70.2.<sup>4</sup> Kentucky's permit program provides for PSD permitting to occur concurrently with the title V permitting process. 401 KAR 51:017 § 1(3).

Under CAA section 505(a), 42 U.S.C. § 7661d(a), and the implementing regulations at 40 CFR § 70.8(a), states are required to submit each proposed title V permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if it is determined not to be in compliance with applicable requirements or the requirements of part

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<sup>3</sup> On February 10, 2006, EPA proposed to approve changes made to Kentucky's NSR program consistent with EPA's 2002 NSR Reform Rules. 71 *Fed. Reg.* 6988 (February 10, 2006). On July 11, 2006, EPA took final action approving Kentucky's NSR program incorporating changes made pursuant to EPA's 2002 NSR Reform Rules. 71 *Fed. Reg.* 38990 (July 11, 2006). Kentucky's revisions to its NSR program, consistent with NSR reform, became effective under Kentucky law on July 14, 2004, and were submitted to EPA as a SIP revision for approval in September 2004. For further information about rules incorporated into the Kentucky SIP, see <http://www.epa.gov/region4/air/sips/ky/kytoc.htm>.

<sup>4</sup> Kentucky defines "federally applicable requirement" in relevant part to include a "federally enforceable requirement or standard that applies to a source." 401 KAR 52:001 § 1(15). Kentucky further defines "federally enforceable requirement," as "[s]tandards or requirements in the state implementation plan (SIP) that implement the relevant requirements of the Act, including revisions to that plan promulgated at 40 CFR Part 52." 401 KAR 52:001 § 1(34).

70. 40 CFR § 70.8(c). If EPA does not object to a permit on its own initiative, section 505(b)(2) of the Act and 40 CFR § 70.8(d) provide that any person may petition the Administrator, within 60 days of the expiration of EPA's 45-day review period, to object to the permit. In response to such a petition, the Act requires the Administrator to issue an objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act. 42 U.S.C. § 7661d(b)(2); *see also* 40 CFR § 70.8(c)(1); *New York Public Interest Research Group, Inc. (NYPIRG) v. Whitman*, 321 F.3d 316, 333 n.11 (2d Cir. 2003). Under section 505(b)(2) of the Act, the burden is on the petitioner to make the required demonstration to EPA. *Sierra Club v. Johnson*, 541 F.3d 1257, 1266-1267 (11<sup>th</sup> Cir. 2008); *Citizens Against Ruining the Environment v. EPA*, 535 F.3d 670, 677-678 (7<sup>th</sup> Cir. 2008); *Sierra Club v. EPA*, 557 F.3d 401, 406 (6<sup>th</sup> Cir. 2009) (discussing the burden of proof in title V petitions); *see also NYPIRG*, 321 F.3d at 333 n.11. If, in responding to a petition, EPA objects to a permit that has already been issued, EPA or the permitting authority will modify, terminate, or revoke and reissue the permit consistent with the procedures set forth in 40 CFR §§ 70.7(g)(4) and (5)(i) - (ii), and 40 CFR § 70.8(d).

Where a petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on a permitting authority's alleged failure to comply with the requirements of its approved PSD program (as with other allegations of inconsistency with the Act), the burden is on the petitioner to demonstrate that the permitting decision was not in compliance with the requirements of the Act, including the requirements of the SIP.<sup>5</sup> Such requirements, as EPA has explained in describing its authority to oversee the implementation of the PSD program in states with approved programs, include the requirements that the permitting authority (1) follow the required procedures in the SIP; (2) make PSD determinations on reasonable grounds properly supported on the record; and (3) describe the determinations in enforceable terms. *See, e.g.*, 68 *Fed. Reg.* 9892, 9894-9895 (March 3, 2003); 63 *Fed. Reg.* 13795, 13796-13797 (March 23, 1998). EPA has approved the PSD programs into the SIPs of most states, including the Commonwealth of Kentucky, and as the permitting authority, Kentucky has substantial discretion in issuing PSD permits. Given this, in reviewing a PSD permitting decision, EPA will not substitute its own judgment for that of Kentucky. Rather, consistent with the decision in *Alaska Dep't of Env't'l Conservation v. EPA*, 540 U.S. 461 (2004), in reviewing a petition to object to a title V permit raising concerns regarding a state's PSD permitting decision, EPA generally will look to see whether the petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary.<sup>6</sup> *See, e.g., In*

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<sup>5</sup> The appeal of federal PSD permits issued pursuant to the federal regulations at 40 CFR § 52.21 is governed by the regulations at 40 CFR § 124.19, and authority to review such permits rests exclusively with the Environmental Appeals Board (EAB). Because of the exclusive authority of the EAB in this area, the Administrator has declined to review the merits of a federal PSD permit in the context of a petition to review a title V permit. *See, e.g., In re Kawaihae Cogeneration Project*, Petition No. 0001-01-C (Order on Petition) (March 10, 1997).

<sup>6</sup> As EPA has previously explained, in reviewing PSD permit determinations in the context of a

*re Louisville Gas and Electric Company*, Petition No. IV-2008-3 (Order on Petition) (August 12, 2009); *In re East Kentucky Power Cooperative, Inc.* (Hugh L. Spurlock Generating Station), Petition No. IV-2006-4 (Order on Petition) (August 30, 2007); *In re Pacific Coast Building Products, Inc.* (Order on Petition) (December 10, 1999); *In re Roosevelt Regional Landfill Regional Disposal Company* (Order on Petition) (May 4, 1999).

## II. BACKGROUND

### Facility

The Cash Creek facility is located southwest of Owensboro on Kentucky State Highway 1078 in Henderson County, Kentucky. The proposed facility would be a new nominal 770 MW electric generating facility using IGCC technology. As proposed, the IGCC process uses coal to produce synthesis gas (syngas) as the primary fuel to fire two combustion turbines in combination with heat recovery steam generating units and a steam turbine to produce electricity. The syngas mainly consists of hydrogen gas and carbon monoxide. The turbines will operate such that heat from the combustion turbines will be recovered in heat recovery steam generators and a steam turbine unit. The proposed permit also authorizes the construction of two gasifiers which convert coal slurry to syngas.

### Permit History

On May 4, 2006, KDAQ received a PSD/title V permit application from Cash Creek to construct a nominal 770 MW electric generating facility using IGCC technology. KDAQ issued a notice of deficiency on June 19, 2006. Cash Creek filed a response on August 9, 2006. A second notice of deficiency was issued by KDAQ on September 20, 2006. Cash Creek responded on October 12 and November 11, 2006. KDAQ determined that the application was administratively complete on March 29, 2007. *See* Cash Creek Permit Revised Statement of Basis (SOB) (November 14, 2007). On May 20, 2007, KDAQ published the first public notice

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petition to object to a title V permit, the standard of review applied by the EAB in reviewing the appeals of federal PSD permits provides a useful analogy. *In re Louisville Gas and Electric Company*, Petition No. IV-2008-3 (Order on Petition) (August 12, 2009) at 5 n.6; *see also In re East Kentucky Power Cooperative, Inc.* (Hugh L. Spurlock Generating Station), Petition No. IV-2006-4 (Order on Petition) (August 30, 2007) at 5. The standard of review applied by the EAB in its review of federal PSD permits is discussed in numerous EAB orders as the "clearly erroneous" standard. *See, e.g., In re Prairie State Generation Company*, 13 E.A.D. \_\_\_, PSD Appeal No. 05-05, slip op. at 13 (EAB, August 24, 2006); *In re Kawaihae Cogeneration*, 7 E.A.D. 107, 114 (EAB, April 28, 1997). In short, in such appeals, the EAB explained that the burden is on a petitioner to demonstrate that review is warranted. Ordinarily, a PSD permit will not be reviewed by the EAB unless the decision of the permitting authority was based on either a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that warrants review.

providing for a 30-day public comment period and announcing a public hearing on the draft Cash Creek Permit to be held on June 29, 2007. Petitioners submitted comments to KDAQ on June 29, 2007, including one set of comments submitted by Valley Watch, one set of comments submitted by the Cumberland Chapter of the Sierra Club, and a third set of comments submitted jointly by Sierra Club, Valley Watch, and the Environmental Law and Policy Center. KDAQ issued a revised SOB on November 14, 2007, and a Response to Comments (RTC) document on November 28, 2007. EPA did not object to the proposed permit within its 45-day review period which ended on January 14, 2008. KDAQ issued the final permit to Cash Creek on January 17, 2008.

### **Background on PSD and BACT**

The CAA and corresponding PSD regulations require that new major stationary sources employ BACT to minimize emissions of regulated pollutants emitted from the facility in significant amounts. CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 CFR § 52.21(j)(2); 401 KAR 51:017 § 8(2), (3). BACT is defined to mean:

an emission limitation based on the maximum degree of reduction [of pollutants emitted from the facility] which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3); 401 KAR 51:001§ 1(25).

EPA has developed a "top-down" process that permitting authorities can use to ensure that a BACT analysis satisfies the applicable legal criteria. The top-down BACT analysis consists of a five-step process which provides that all available control technologies be ranked in descending order of control effectiveness, beginning with the most stringent. *See In re Prairie State Generation Company*, 13 E.A.D. \_\_\_, PSD Appeal No. 05-05, slip op. at 17-18 (EAB, August 24, 2006). The most stringent control technology is deemed the control necessary to achieve BACT-level emission limits unless the applicant demonstrates, and the permitting authority determines, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not achievable in that case. An incomplete BACT analysis, including failure to consider all potentially applicable control alternatives, constitutes clear error. *See, e.g., Prairie State*, slip op. at 19; *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 142 (EAB, February 4, 1999); *In re Masonite Corp.* 5 E.A.D. 551, 568-569 (EAB, November 1, 1994). Cash Creek followed this top-down BACT methodology when it submitted its application for the Cash Creek facility, which KDAQ applied in issuing its permitting decision. SOB at 27-28.

### **III. EPA DETERMINATIONS ON PETITIONS 1 AND 2**

#### **A. Failure to Establish BACT Limits Based on Clean Fuels** (Section I of Petition 1 and Section II of Petition 2)

*Petitioners' Claims.* The permit does not establish BACT limits based on natural gas but instead includes two BACT limits depending on which fuel is used, one for natural gas and one for syngas. Despite the proposed facility being able to burn natural gas and thereby to achieve lower emission rates, KDAQ failed to establish the BACT limits based on the clean fuel - natural gas. Petitioners claim that the use of natural gas would not require a redesign of the facility since the permit record indicates that the facility is capable of burning either syngas or natural gas and that the facility will burn only natural gas for a startup period of six months to one year. Petitioners claim that the burden is on Cash Creek to demonstrate why the use of natural gas is not cost effective.

*EPA's Response.* For the reasons discussed below, EPA is granting the Petitions with respect to this issue on the basis that the record is inadequate. Petitioners have demonstrated that neither KDAQ nor the Applicant considered the possibility of natural gas as an alternative primary fuel source or provided an adequate explanation, considering the record in this case, of why such an analysis is unnecessary. *See* SOB at 14-28 (BACT analysis).

In its RTC on this issue, KDAQ explained that the IGCC process will use coal to produce syngas as the primary fuel and that natural gas is a secondary fuel. RTC at 24. KDAQ also stated the "facility is specifically designed for synthesis gas as the primary fuel alone and not in combination with natural gas." *Id.* The BACT analysis for this permit considers different technologies and fuels at different times in the plant's operation, but the analysis does not specifically include any consideration of using natural gas instead of syngas as the primary fuel.

To meet the applicable legal criteria under the Kentucky SIP, a BACT analysis for each pollutant must consider "application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of that pollutant." 401 KAR 51:001 § 1(25). The Clean Air Act also includes the term "clean fuels" in this part of the definition of BACT after the term "fuel cleaning." 42 U.S.C. § 7479(1). Thus, when a potential pollution control strategy is not evaluated in detail in a BACT analysis, the record should provide a reasoned basis to show why that option is not "available" in a particular instance. EPA has recognized that "available" options for a particular facility do not necessarily have to include options that would fundamentally "redefine" the source proposed by the permit applicant. *See, e.g., In re: Desert Rock Energy Company, LLC*, PSD Appeal No. 08-03 et al, slip op. at 59-65 (EAB, September 24, 2009). However, EPA interprets the Act to require a reasoned justification, based on an analysis of the underlying administrative record for each permit, to support a conclusion that an option is not "available" in a given case on the

grounds that it would fundamentally "redefine the source." *Desert Rock*, slip op. at 63-72, 76.

Based on the record here, KDAQ has not provided a reasoned explanation that demonstrates why the option of using exclusively natural gas is not "available" for this facility. The permit record makes clear that Cash Creek proposes to burn natural gas in its turbines for a startup period of six months to a year and to maintain the option of burning natural gas as a secondary fuel thereafter. KDAQ only made the statement that syngas is the primary fuel and natural gas is the secondary fuel, with a general reference to the specific design of the facility. Since the record here shows that the site has access to a natural gas supply and the applicant actually intends to use that supply for some period of time, KDAQ's cursory response is insufficient to demonstrate that the option of using only natural gas is not available at this facility. If KDAQ believes the option of using natural gas alone is not available because it constitutes "redefining the source" under the circumstances present here, KDAQ must clearly state and provide a rationale for that determination. Alternatively, if KDAQ believes that there are economic, environmental, or energy impacts from the use of only natural gas that weigh against its selection as BACT, KDAQ should include natural gas in the BACT analysis and provide a rationale for its elimination based on those criteria. KDAQ is also not precluded from determining that natural gas should be used more frequently as the fuel source for this facility, so long as KDAQ provides a reasonable basis for this determination in its BACT analysis.

States with SIP-approved PSD programs have independent discretion and are not necessarily required to follow all EPA policies or interpretations. *See, e.g., 57 Fed. Reg.* 28093, 28095 (June 24, 1992). However, states that issue PSD permits under SIP-approved regulations are required to conduct a BACT analysis that is reasoned and faithful to the statutory framework. *See Alaska Dep't of Env't'l Conservation v. EPA*, 540 U.S. 461, 484-91 (2004). When EPA is called on to assess whether a state action is supported by a reasoned basis, it is appropriate for EPA to consider prior decisions of the EAB and the Administrator that reach conclusions regarding the adequacy of particular reasoning. *See In re East Kentucky Power Cooperative, Inc.* (Hugh L. Spurlock Generating Station) Petition No. IV-2006-4 (Order on Petition) (August 30, 2007) at 5; *see also* n.6, *supra*. Even if not controlling precedent in a given state, such decisions provide useful guidelines on how to conduct a reasoned BACT analysis.

In *In re Northern Michigan*, PSD Appeal No. 08-02, slip op. at 17-28 (EAB, February 18, 2009), the EAB considered the BACT analysis for a facility that proposed to use both coal and wood fuel. The EAB remanded the permit because the record failed to provide a justification for why BACT limits for SO<sub>2</sub> in the permit were based predominantly on the combustion of coal and not weighted in favor of greater combustion of the cleaner wood fuel. The EAB also noted the lack of a complete BACT analysis based on the permitting authority's failure to include natural gas as a fuel option, where, similar to the circumstances here, the permit application identified natural gas as a fuel to be used for boiler startup and as a backup fuel source. *Id.* at 20 n.17. Although this decision of the EAB is not necessarily a controlling precedent under the Kentucky SIP, we believe the rationale applied there is equally applicable here and helps illustrate why KDAQ's response to comments lacked sufficient reasoning to demonstrate why greater utilization of natural gas fuel was not considered in the BACT analysis for this facility.

On the question of whether an option may be excluded because it redefines the proposed source, the EAB has developed an analytical framework that EPA uses to assess this issue in its own permitting decisions. *See, e.g., Prairie State*, slip op. at 26-37; *Desert Rock*, slip op. at 59-65. The framework calls for the permitting authority to first determine from the particular record how the permit applicant "defines the proposed facility's end, object, aim, or purpose" (the "basic" or "fundamental" design of the facility). The relevant definition of the facility should reflect "reasons independent of air quality permitting." The next step is for the permitting authority to then take a "hard look" at the applicant's determination in order to "discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility." As part of the latter step, the permitting authority should keep in mind that "BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility." *Desert Rock*, slip op. at 64. The initial opinion of the EAB that adopted this analytical framework was upheld on appeal by the Seventh Circuit Court of Appeals. *See Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

As explained above, KDAQ is not necessarily required to follow the analytical framework used by EPA to assess whether an option may be excluded from a BACT analysis on "redefining the source" grounds. However, if KDAQ intends to employ a different approach to determine whether an option is not "available" because it would "redefine the source," the State must articulate its intent to do so and provide a statutory foundation for any alternative approach. Since the EAB has articulated such a foundation for its approach that has been upheld by one U.S. Court of Appeals, we strongly recommend that SIP-approved states follow the framework articulated by the EAB for the same reason that we recommend states employ the complete top-down BACT methodology developed by EPA – to ensure states complete a BACT analysis that is faithful to the statutory guides.

Accordingly, the Petitions are granted with respect to this issue. KDAQ and Cash Creek should provide further explanation of and/or analysis regarding the choice of a primary fuel for this facility, and, if necessary, adjust the resulting BACT limits after such analysis. In so doing, EPA is not concluding that the present permit limits do not represent BACT – only that the present permit record does not provide a sufficient rationale to demonstrate the adequacy of the BACT determinations for this facility.

EPA's conclusion here, that KDAQ failed to provide a reasoned explanation for excluding the option of using only natural gas fuel on the record for this permit, should in no way be interpreted as EPA expressing a policy preference for construction of natural-gas fired facilities over IGCC facilities to generate electricity. EPA supports the development and use of a broad range of technologies across the energy sector including those that will enable the sustainable use of coal. The deployment of IGCC technology is one of the important technologies and a positive strategy to reduce emissions from coal-fired electricity generation. Technology that enables the United States to use its appreciable reserves of coal in an environmentally sustainable manner is



critical to achieving the goals of the PSD program and maintaining compliance with the NAAQS by reducing conventional air pollutants. EPA's sole concern in this Order is the adequacy of KDAQ's rationale for excluding the option of using exclusively natural gas fuel. This Order should not be interpreted to establish or imply an EPA position that PSD permitting authorities should conclude, under all circumstances, that BACT for a proposed electricity generating unit is firing such a unit with natural gas.

This Order does not conclude that it is not possible or permissible for the permit applicant or KDAQ to develop a rationale which shows that firing exclusively with natural gas would "redefine the source" or is otherwise not an "available option." This Order finds only that the Cash Creek permit record fails to include such a justification, and that a justification of this nature is needed under the particular circumstances to insure that KDAQ has provided a reasoned analysis that comports with the applicable legal criteria. Furthermore, EPA does not intend to discourage applicants that propose to construct an IGCC facility from seeking to hedge the risk of investing in the successful deployment of IGCC technology by proposing or retaining the option of utilizing natural gas fuel for some period during the construction or operation of an IGCC facility. Again, EPA's concern in this instance is solely the paucity of KDAQ's rationale for failing to consider the option of using exclusively natural gas as an "available" option in the BACT analysis at this proposed source, under the particular circumstances described in the record.

**B. Failure to Apply Subpart KKKK NSPS to Combustion Turbines**  
(Section II of Petition 1 and Section III of Petition 2)

*Petitioners' Claims.* Petitioners claim that the permit fails to include applicable requirements for the combustion turbines based on 40 CFR Part 60, Subpart KKKK. Since Cash Creek intends to run the turbines only on natural gas for the first six months to a year, Petitioners argue that the NSPS requirements for Stationary Combustion Turbines in Subpart KKKK should apply.

*EPA's Response.* As a threshold procedural matter, these issues were not raised during the public comment process for this permit. Petitioners assert that Cash Creek's intention to run the turbines on natural gas for the first six to twelve months only became apparent in Cash Creek's comments on the draft permit. Petition 1 at 9; Petition 2 at 12; RTC at 3. Since a review of the record shows no mention, prior to the issuance of the RTC, of Cash Creek's intention to run the turbines on natural gas for a startup period of six to twelve months, it was impracticable for Petitioners to raise such claims during the public comment period. Thus, Petitioners meet threshold requirements in Section 505(b)(2) of the CAA for issues raised for the first time in a Petition to the Administrator. With respect to the substantive issue raised by Petitioners, EPA grants the Petitions for the following reason.

The NSPS rules in place at the time KDAQ issued this permit specified that Subpart Da applies to "combined cycle gas turbines designed and intended to burn fuels containing 50

percent or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling basis."<sup>7</sup> 40 CFR § 60.40Da(b)(2); 72 *Fed. Reg.* 32723 (June 13, 2007). In issuing the final permit, KDAQ explained that it was revising the final permit to include the revised Subpart Da standard. RTC at 4. The final permit included a permit limitation stating that in accordance with Subpart Da, "the combined cycle gas turbine shall be designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis." Permit at 3. However, in the final permit record, Cash Creek stated its intent to burn "natural gas fuel approximately six (6) to twelve (12) months prior to the introduction of synthesis gas from the gasifiers." RTC at 3. Petitioners submit that KDAQ's application of Subpart Da in the permit is incorrect given that the turbines will be firing only natural gas for the first six to twelve months. Petition 1 at 9; Petition 2 at 12. A combustion turbine firing natural gas would ordinarily be subject to the requirements at Subpart KKKK – Standards of Performance for Stationary Combustion Turbines. 40 CFR § 60.4300, *et seq.* In issuing the final permit, KDAQ did not explain why Subpart KKKK would not apply during those times when the turbines would be fueled by natural gas.

Accordingly, the permit record fails to demonstrate that the appropriate NSPS was applied after it became clear that the turbines would be fueled exclusively by natural gas – which contains no synthetic-coal gas – for six to twelve months, and the Petitions are granted with respect to this issue. In responding to this issue, KDAQ could look to the relevant regulatory provisions, *see* 40 CFR §§ 60.40Da(b)(2) and 60.4310(c), guidance provided in the preamble to the proposed NSPS rules, *see* 72 *Fed. Reg.* 6323 (February 9, 2007), or other factors deemed appropriate, to provide a reasoned basis for its approach to addressing NSPS applicability for this source.<sup>8</sup>

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<sup>7</sup> Under the NSPS regulations in place at the time KDAQ issued the draft permit, Subpart Da applied to combined cycle gas turbines burning fuels containing 75 percent or more solid-derived fuel. *See* 71 *Fed. Reg.* 9867 (February 27, 2006). Subpart Da was revised prior to the issuance of the final permit to reduce the percentage of solid-derived fuel required for applicability to 50 percent. 72 *Fed. Reg.* 32722 (June 13, 2007). Subpart Da was revised again in 2009 to "clarify the implementation of the Subpart Da provisions to integrated coal gasification combined cycle electric utility power plants." 74 *Fed. Reg.* 5073 (January 28, 2009). In the 2009 revision, the 50 percent solid-derived fuel requirement was removed from the applicability provisions of Subpart Da and was instead incorporated into the IGCC definition in that Subpart. *See* 40 CFR § 40.61Da (Defining an IGCC electric utility steam generating unit as "an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. No solid fuel is directly burned in the unit during operation.").

<sup>8</sup> Should KDAQ determine, in the course of addressing Section III.A of this Order, that natural gas should be the primary fuel at this source, KDAQ's review of NSPS applicability would need to consider this change.

**C. Failure to Include a PM<sub>2.5</sub> BACT Limit**  
(Section III of Petition 1 and Section IV of Petition 2)

*Petitioners' Claims.* Petitioners claim that KDAQ may no longer use PM<sub>10</sub> standards as surrogates for PM<sub>2.5</sub> standards and that the Cash Creek permit failed to contain a BACT limit for PM<sub>2.5</sub>. Petitioners disagree with the use of the surrogate policy as a general matter and state that the surrogate policy was only intended for use until technical difficulties associated with analysis of PM<sub>2.5</sub> have been resolved.

*EPA's Response.* EPA recently addressed similar issues in *In re Louisville Gas and Electric Co.* (Order on Petition) (August 12, 2009) at 42-46. EPA grants the Petitions on this issue to require further consideration of PM<sub>2.5</sub>. As discussed below, the permit record does not provide an adequate rationale to support the use of the PM<sub>10</sub> surrogate approach for this permit.

*Background on PM<sub>2.5</sub> NAAQS and CAA*

EPA establishes NAAQS for certain pollutants, pursuant to section 109 of the CAA, 42 U.S.C. § 7409. Once a NAAQS is established, the CAA sets forth a process for designating areas in the nation as attainment, nonattainment, or unclassifiable, thus triggering additional requirements consistent with the CAA and its implementing regulations. Following establishment of a NAAQS, EPA also promulgates implementation rules that provide specific details of how states must comply with the NAAQS based on the corresponding designations for areas within the state. Generally, the SIP is the primary means by which states comply with CAA requirements to attain the NAAQS. See CAA §§ 110(a) and 171-193, 42 U.S.C. §§ 7410(a) and 7501-7515.

On July 28, 1997, EPA revised the NAAQS for PM to add new standards for "fine" particulates, using PM<sub>2.5</sub> as the indicator. 62 *Fed. Reg.* 39852 (July 28, 1997). On October 17, 2006, EPA revised the NAAQS for both PM<sub>2.5</sub> and PM<sub>10</sub>. 71 *Fed. Reg.* 61236 (October 17, 2006). On October 23, 1997, EPA issued a memorandum from John S. Seitz regarding implementation of the 1997 standards entitled, "*Interim Implementation for the New Source Review Requirements for PM<sub>2.5</sub>*" (Seitz Memorandum). The Seitz Memorandum explained that sources would be allowed to use implementation of a PM<sub>10</sub> program as a surrogate for meeting PM<sub>2.5</sub> NSR requirements until certain technical difficulties were resolved. Seitz Memorandum at 1. On April 5, 2005, EPA issued a second guidance memorandum from Stephen D. Page entitled, "*Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas*" (Page Memorandum), which re-affirmed the October 23, 1997, Seitz Memorandum. Page Memorandum at 1. On May 16, 2008, EPA promulgated the final rule entitled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers (PM<sub>2.5</sub>)" (May 2008 PM<sub>2.5</sub> NSR Implementation Rule). 96 *Fed. Reg.* 28321 (May 16, 2008). In the preamble to that rule, EPA explained the transition to the PM<sub>2.5</sub> NSR requirements beginning on page 28340. Specifically, EPA concluded that, if a SIP-approved state is unable to implement a PSD program for the PM<sub>2.5</sub> NAAQS based on that rule, the state may continue to implement a

PM<sub>10</sub> program as a surrogate to meet the PSD program requirements for PM<sub>2.5</sub> under the PM<sub>10</sub> Surrogate Policy in the Seitz Memorandum.<sup>9</sup> 96 *Fed. Reg.* at 28340-28341.

#### *Use of PM<sub>10</sub> as a Surrogate for PM<sub>2.5</sub>*

When EPA issued the PM<sub>10</sub> Surrogate Policy in 1997, the Agency did not identify criteria to be applied before the policy could be used for satisfying the PM<sub>2.5</sub> requirements. However, courts have issued a number of opinions that are properly read as limiting the use of PM<sub>10</sub> as a surrogate for meeting the PSD requirements for PM<sub>2.5</sub>. Applicants and state permitting authorities seeking to rely on the PM<sub>10</sub> Surrogate Policy should consider these opinions in determining whether PM<sub>10</sub> serves as an adequate surrogate for meeting the PM<sub>2.5</sub> requirements in the case of the specific permit application at issue.

Courts have held that a surrogate may be used only after it has been shown to be reasonable to do so. *See, e.g., Sierra Club v. EPA*, 353 F.3d 976, 982-984 (D.C. Cir. 2004) (stating general principle that EPA may use a surrogate if it is "reasonable" to do so and applying analysis from *National Lime Assoc. v. EPA*, 233 F.3d 625, 637 (D.C. Cir. 2000) that is applicable to determining whether use of a surrogate is reasonable in setting emissions limitations for hazardous air pollutants under Section 112 of the Act); *Mossville Env't'l Action Now v. EPA*, 370 F.3d 1232, 1242-43 (D.C. Cir. 2004) (EPA must explain the correlation between the surrogate and the represented pollutant that provides the basis for the surrogacy); *Bluewater Network v. EPA*, 370 F.3d 1, 18 (D.C. Cir. 2004) ("The Agency reasonably determined that regulating [hydrocarbons] would control PM pollution both because HC itself contributes to such pollution, and because HC provides a good proxy for regulating fine PM emissions"). Though these court decisions do not speak directly to the use of PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub>, EPA believes that the overarching legal principle from these decisions is that a surrogate may be used only after it has been shown to be reasonable (such as where the surrogate is a reasonable proxy for the pollutant or has a predictable correlation to the pollutant). Further, we believe that this case law governs the use of EPA's PM<sub>10</sub> Surrogate Policy, and thus that the legal principle from the case law applies where a permit applicant or state permitting authority seeks to rely upon the PM<sub>10</sub> surrogate policy in lieu of a PM<sub>2.5</sub> analysis to obtain a PSD permit.

With respect to PM surrogacy in particular, there are specific issues raised in the case law that bear on whether PM<sub>10</sub> can be considered a reasonable surrogate for PM<sub>2.5</sub>. The D.C. Circuit has concluded that PM<sub>10</sub> was an arbitrary surrogate for a PM pollutant that is one fraction of PM<sub>10</sub> where the use of PM<sub>10</sub> as a surrogate for that fraction is "inherently confounded" by the presence of the other fraction of PM<sub>10</sub>. *ATA v. EPA*, 175 F.3d 1027, 1054 (D.C. Cir. 1999) (PM<sub>10</sub> is an arbitrary indicator for coarse PM (PM<sub>10-2.5</sub>) because the amount of coarse PM within PM<sub>10</sub> will depend arbitrarily on the amount of fine PM (PM<sub>2.5</sub>)). In another case, however, the D.C. Circuit held that the facts and circumstances in that instance provided a reasonable rationale for using PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub>. *American Farm Bureau v. EPA*, 559 F.3d 512, 534-35

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<sup>9</sup> The Seitz Memorandum is commonly referred to as EPA's 1997 Surrogate Policy.

(D.C. Cir. 2009) (where record demonstrated that (1) PM<sub>2.5</sub> tends to be higher in urban areas than in rural areas, and (2) evidence of health effects from coarse PM in urban areas is stronger, EPA reasoned that setting a single PM<sub>10</sub> standard for both urban and rural areas would tend to require lower coarse PM concentrations in urban areas. The court considered the reasoning from the *ATA* case and accepted that the presence of PM<sub>2.5</sub> in PM<sub>10</sub> will cause the amount of coarse PM in PM<sub>10</sub> to vary, but on the specific facts before it held that such variation was not arbitrary). EPA believes that these cases demonstrate the need for permit applicants and permitting authorities to determine whether PM<sub>10</sub> is a reasonable surrogate for PM<sub>2.5</sub> under the facts and circumstances of the specific permit at issue, and not proceed on a general presumption that PM<sub>10</sub> is always a reasonable surrogate for PM<sub>2.5</sub>.

This case law suggests that any person attempting to show that PM<sub>10</sub> is a reasonable surrogate for PM<sub>2.5</sub> would need to address the differences between PM<sub>10</sub> and PM<sub>2.5</sub>. For example, emission controls used to capture coarse particles in some cases may be less effective in controlling for PM<sub>2.5</sub>. 72 *Fed. Reg.* 20586, 20617 (April 25, 2007). As a further example, the particles that make up PM<sub>2.5</sub> may be transported over long distances while coarse particles normally travel only short distances. 70 *Fed. Reg.* 65984, 65997-98 (November 1, 2005). Under the principles in the case law, any person seeking to use the PM<sub>10</sub> Surrogate Policy properly would need to consider these differences between PM<sub>10</sub> and PM<sub>2.5</sub> and demonstrate that PM<sub>10</sub> is nonetheless an adequate surrogate for PM<sub>2.5</sub>.

Finally, the PM<sub>10</sub> Surrogate Policy contains limits. In view of significant technical difficulties that existed in 1997, EPA believed that PM<sub>10</sub> could properly be used as a surrogate for PM<sub>2.5</sub> in meeting NSR requirements "until these difficulties are resolved." Seitz Memorandum at 1. Petitioners point out that the bases for the PM<sub>10</sub> Surrogate Policy no longer exist. Petition 1 at 12; Petition 2 at 15. Petitioners note that EPA stated in the May 2008 PM<sub>2.5</sub> NSR Implementation Rule that difficulties in testing, emission estimating and modeling "have largely been resolved." 73 *Fed. Reg.* 28321, 28340 (May 16, 2008).

In this case, the record for the Cash Creek permit does not provide an adequate rationale to support the use of PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub> under the circumstances for this specific permit. Overall, the record does not show how the use of the PM<sub>10</sub> Surrogate Policy is consistent with the case law discussed above in light of the differences between PM<sub>10</sub> and PM<sub>2.5</sub>, and does not demonstrate that the use of the Policy here falls within the limits of the Policy. For these reasons and based on the record now before EPA, the Petitions are granted on the claim that the permit record does not support the use of PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub>.<sup>10</sup>

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<sup>10</sup> In 2007, EPA denied a petition requesting that EPA object to the title V permit for Spurlock for failure to include a BACT limit for PM<sub>2.5</sub> emissions. *In re East Kentucky Power Cooperative*, Petition No. IV-2006-4 at 41-42 (Order on Petition) (August 30, 2007). EPA found that, under the circumstances presented in that matter, KDAQ's use of PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub> was appropriate. *Id.* EPA's decision in the present Order reflects the circumstances presented in this Cash Creek matter, including a more comprehensive petition, and an evolving understanding of

#### **D. Failure to Include a CO<sub>2</sub> BACT Limit**

(Section IV of Petition 1 and Section V of Petition 2)

*Petitioners' Claims.* Petitioners claim that EPA must object to the permit because the permit fails to include a BACT analysis for CO<sub>2</sub>. Petitioners maintain that CO<sub>2</sub> is subject to regulation under CAA § 821 and 40 CFR Part 75 and that KDAQ improperly limited BACT to pollutants subject to NAAQS, NSPS or CAA § 602.

*EPA's Response.* In its RTC on this issue, KDAQ explained that the Kentucky PSD regulations did not require a BACT analysis for CO<sub>2</sub> emissions. RTC at 41. KDAQ identified the provision of the Kentucky SIP that requires it to implement the state PSD program in a manner that is no more stringent than the federal PSD program. *Id.* (citing Kentucky Revised Statutes (KRS) 224.10-100(26)). KDAQ then found that there were no federal PSD requirements to control CO<sub>2</sub> at stationary sources.<sup>11</sup> Implicit in KDAQ's conclusion that the permit would not include a CO<sub>2</sub> BACT limit was an understanding that the federal PSD program did not apply to CO<sub>2</sub> emissions at the time the permit was issued. *Id.* As discussed below, Petitioners have failed to demonstrate that KDAQ's reliance on the SIP and its assumptions regarding the federal PSD program requirements led to a permit that is deficient under the CAA.

When KDAQ issued the permit in January 2008, at least one EPA Region and the EPA program office that oversees implementation of the federal PSD permitting program had taken the position that CO<sub>2</sub> emissions were not subject to federal PSD requirements because they believed there was a binding, historic interpretation of the phrase "subject to regulation" in the federal PSD regulations that required PSD regulations to apply only to those pollutants already subject to actual control of emissions under other provisions of the CAA.<sup>12</sup> See EPA Region 8's Response to Petition for Review, *In re: Deseret Power Electric Cooperative*, PSD Appeal No. 07-03 (filed November 2, 2007); Brief of the EPA Office of Air and Radiation, *In re: Christian*

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the technical and legal issues associated with the use of the PM<sub>10</sub> Surrogate Policy.

<sup>11</sup> As Petitioners note, KDAQ did incorrectly state that "there are no federal regulations establishing requirements for CO<sub>2</sub> at stationary sources." RTC at 41. However, given that this sentence directly follows KDAQ's discussion of the SIP requirement to implement their PSD program no more stringently than the federal PSD program, we think this sentence is more appropriately read to say that Kentucky found "there are no federal regulations establishing [PSD] requirements for CO<sub>2</sub> at stationary sources."

<sup>12</sup> Under the federal PSD permitting regulations, only newly constructed or modified major sources that emit one or more "regulated NSR pollutants" are subject to the requirements of the PSD program, including the requirement to install BACT for those regulated NSR pollutants that the facility emits in significant amounts. "Regulated NSR pollutants" include "any pollutant that otherwise is subject to regulation under the Act." 40 CFR § 52.21(b)(50)(vi); see also 401 KAR 51:001 § 1(207).

*County Generation, LLC*, PSD Appeal No. 07-01 (filed September 24, 2007). Accordingly, these EPA offices argued that the regulations in the CAA Acid Rain program that require monitoring of CO<sub>2</sub> at some sources (and which are cited by Petitioners in this matter) did not make CO<sub>2</sub> subject to PSD regulation. *Id.* Thus, it was not implausible for KDAQ to assume that the federal PSD program did not require permits to include limits for CO<sub>2</sub> emission because, at the time KDAQ issued the permit, two EPA offices that implement and interpret the requirements of the federal PSD program had taken that position. Moreover, at that time, no federal permitting authorities had actually imposed PSD requirements for CO<sub>2</sub>; in fact, no federal PSD permit has since issued with CO<sub>2</sub> limits.

A decision of EPA's Environmental Appeals Board ("EAB") subsequently addressed the position that CO<sub>2</sub> emissions were not subject to PSD regulation. *See In re: Deseret Power Electric Cooperative*, 14 E.A.D. \_\_\_, PSD Appeal No. 07-03 (EAB, November 13, 2008). The EAB determined that prior EPA actions were insufficient to establish a historic, binding interpretation that "subject to regulation" for PSD purposes included only those pollutants subject to regulations that require actual control of emissions. However, the EAB did not conclude that such an interpretation was impermissible under the CAA and found "no evidence of a Congressional intent to compel EPA to apply BACT to pollutants that are subject only to monitoring and reporting requirements." *Id.* at 63. Shortly thereafter, in order to address the ambiguity that existed in the federal PSD regulations following the EAB decision, then Administrator Stephen Johnson issued a memorandum setting forth the official EPA interpretation regarding which pollutants were "subject to regulation" for the purposes of the federal PSD permitting program. Memorandum from Stephen Johnson, EPA Administrator, to EPA Regional Administrators entitled, "*EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program*" (December 18, 2008) (Johnson Memo); *see also* 73 *Fed. Reg.* 80300 (December 31, 2008) (public notice of December 18, 2008 memo). The Johnson Memo established an interpretation of "subject to regulation" within the federal PSD regulations that "exclude[d] pollutants for which EPA regulations only require monitoring or reporting but [] include[d] each pollutant subject to either a provision in the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1; 73 *Fed. Reg.* at 80301. EPA received a petition for reconsideration of the position taken in the Johnson Memo, and on February 17, 2009, the new Administrator granted that petition. Letter from Lisa P. Jackson, EPA Administrator, to David Bookbinder, Chief Climate Counsel at Sierra Club (February 17, 2009). In granting reconsideration, Administrator Jackson announced the intent to conduct a rulemaking to take public comment on the issues raised in the memo, but she did not stay the effectiveness of the Johnson memo pending reconsideration.<sup>13</sup> EPA initiated the public

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<sup>13</sup> The grant of reconsideration also reiterated that states must issue PSD permits "under their own State Implementation Plans." February 17, 2009, letter granting reconsideration at 1; *see also* Johnson Memo at 3 n.1 ("To the extent approved State Implementation Plans contain the same language as used in [the relevant federal PSD regulations], States *may* interpret that language in state regulations in the same manner reflected in this memorandum.") (emphasis

comment process in a notice published in the Federal Register on October 7, 2009. 74 *Fed. Reg.* 51535. This notice summarizes the reasoning of Administrator Johnson's memo and several alternative interpretations that are advocated by citizens in the Petition for Reconsideration of the Johnson Memo and public comments on other EPA actions. While this reconsideration process is ongoing, EPA continues to adhere to the interpretation reflected in Administrator Johnson's memorandum of December 18, 2009. 74 *Fed. Reg.* at 51539.

While KDAQ's implicit assumption at the time the permit was issued – that there was an established federal standard that did not require PSD permits to include limits for CO<sub>2</sub> emissions – was later overturned by the EAB, it does not mean that Petitioners have demonstrated that KDAQ's reliance on this assumption led to a permit that is deficient under the CAA. Petitioners assert that the permit was issued in error because CO<sub>2</sub> "is clearly 'subject to regulation' under the [CAA] and Kentucky law," based on CAA regulations requiring their monitoring and reporting. Petition 1 at 14-17; Petition 2 at 17-20. Petitioners are essentially arguing that, at the time KDAQ issued the permit, the federal PSD program required application of BACT requirements to CO<sub>2</sub> emissions and KDAQ erred by not including such limits. However, this argument fails because the EAB specifically found that there was no established standard regarding whether CO<sub>2</sub> was "subject to regulation" under the federal PSD program and that the position urged by Petitioners – PSD regulation of CO<sub>2</sub> was required given existing monitoring and reporting requirements – is clearly dictated by the language of the CAA or EPA regulations. *Deseret Power*, slip op. at 63. Accordingly, Petitioners have not established that KDAQ's failure to require CO<sub>2</sub> emissions limits in this permit was incorrect because they did not show that KDAQ implemented the Kentucky PSD program in a manner less stringent than the existing federal PSD program.<sup>14</sup> Because Petitioners have not demonstrated that the permit is inconsistent with the requirements of the Act, the Petitions are denied with respect to this issue.<sup>15</sup>

**E. KDAQ Did Not Properly Consider and Did Not Respond to Comments on Alternatives Analysis Submitted by Petitioners.**  
(Section V of Petition 1 and Section VI of Petition 2)

*Petitioners' Claims.* Petitioners claim that KDAQ ignored their comments on alternatives

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added).

<sup>14</sup> The position taken in KDAQ's permitting decision rests on the interplay of its SIP and the federal PSD program, and that decision is consistent with the EPA's present position regarding which pollutants are subject to federal PSD permitting requirements. *See generally* February 17, 2009, letter granting reconsideration; Johnson Memo; Notice of Reconsideration (74 *Fed. Reg.* 51535, October 7, 2009).

<sup>15</sup> Actions are underway at EPA that could, when finalized, result in the promulgation of final standards controlling the emission of greenhouse gases. In particular, EPA has proposed a rule to regulate greenhouse gases from mobile sources under title II of the CAA. 74 *Fed. Reg.* 49454 (September 28, 2009).



to the proposed facility designed to reduce CO<sub>2</sub> impacts and in doing so inappropriately relied on a state law prohibition on implementing the Kyoto Protocol. Petitioners claim that KDAQ's refusal to consider the comments as part of an alternatives analysis pursuant to section 165(a)(2) of the Act is unlawful as section 165 is an applicable requirement for new major source construction under the Act and Kentucky SIP.

*EPA's Response.* As a procedural issue, KDAQ's conclusory response to Petitioners' comments on alternatives to the proposed facility was inadequate. The Cumberland Chapter of the Sierra Club submitted brief comments on alternatives to the proposed facility, including mitigation of CO<sub>2</sub> emissions through carbon capture and sequestration, closure of existing sources of CO<sub>2</sub>, and improved efficiency through co-location with an industry that could utilize the waste heat/steam, which Sierra Club asserted KDAQ was required to consider under CAA Section 165. RTC at 29-30. The Sierra Club also proposed "closing old, inefficient boilers, and investing energy efficiency and clean renewable energy (sic)" to curb CO<sub>2</sub> emissions. RTC at 32. KDAQ's response to the portion of comments on these alternatives referenced section 165(a)(2) of the CAA and stated that "no viable alternatives were presented during the public comment period for consideration by the Cabinet." RTC at 30.

Section 165(a)(2) of the CAA requires a PSD permit to be issued only after "a public hearing with the opportunity for interested persons...to submit written or oral presentations on the air quality impact of such source, alternatives thereto...and other appropriate considerations." 42 U.S.C. § 7475(a)(2). EPA's implementing regulations at 40 CFR 51.166(q)(2)(v) in turn require SIPs to "provide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations." Kentucky's PSD SIP expressly adopts this EPA PSD regulation. 401 KAR 51:017 § 15. KDAQ is thus obligated by its SIP to implement 40 CFR 51.166(q)(2)(v) which itself implements section 165(a)(2) of the CAA. Accordingly, in determining whether Petitioners have demonstrated that this permit has not been issued in accordance with applicable requirements of the Act, *see* 42 U.S.C. § 7661d(b)(2), it is appropriate for EPA to consider whether KDAQ's response was reasonable in light of CAA section 165(a)(2).

EPA has interpreted the requirements of Section 165(a)(2) to include an obligation by the permitting authority to consider and respond to such comments. *See Prairie State*, slip op. at 40 (stating, with regard to comments submitted under section 165(a)(2), that "the response to comments document must demonstrate that all significant comments were considered"). While the permitting authority is not required to "conduct an independent analysis of available alternatives," *Prairie State*, slip op. at 39, the permitting authority is required to provide a reasoned basis for rejection of the proposed alternatives. *See Prairie State*, slip op. at 40. In *Prairie State*, the EAB pointed to the level of detail provided by the Illinois Environmental Protection Agency (IEPA) in its response to the alternatives suggestions as sufficient given the nature and extent of comments submitted. *Id.* at 40, *citing In Re NE Hub Partners*, 7 E.A.D. 561, 583 (EAB 1998). For example, the IEPA considered each of the alternatives suggested by

commenters in turn in its response to comments and explained why each alternative was not viable. The EAB found that "all of these are sufficient responses to the comments calling for consideration of alternatives." *Id.* at 41. The summary response provided by KDAQ in this instance – simply stating that the alternatives are not "viable" without any explanation for that conclusion – is not sufficient. Accordingly, the Petitions are granted with respect to this issue.

We note that it appears KDAQ may have considered some of the alternatives raised in comments by Petitioners in the context of the BACT analysis. If so, KDAQ's obligations under section 165(a)(2) may be fulfilled by explaining that KDAQ does not consider the options viable for the same reasons they were eliminated from the BACT analysis. However, KDAQ's response does not in fact provide that explanation. Going forward, KDAQ should consider each alternative presented in the comments and provide a reasoned explanation for rejecting (or accepting) each of the alternatives proposed instead of relying on a conclusory statement that no viable alternatives were presented.

**F. Sulfuric Acid Mist (SAM) Limits at Elm Road Facility were not Considered in BACT Analysis**  
(Section VI of Petition 1 and Section VII of Petition 2)

*Petitioners' Claims.* Petitioners claim that the BACT analysis for SAM emission limits was flawed because it did not include the SAM limit permitted at the Elm Road facility in Wisconsin. The Elm Road IGCC unit has a SAM BACT limit of 0.0005 lb/MMBtu. The Cash Creek units have a proposed SAM BACT limit of 0.0035 lb/MMBtu. Petitioners state that neither Cash Creek nor KDAQ have offered evidence refuting that the Cash Creek units can achieve the lower BACT limit for SAM.

*EPA's Response.* As discussed *supra*, a BACT analysis culminates in an emission limit for each regulated pollutant that a facility has the potential to emit in significant amounts. In selecting the emission limits, the permitting authority is not required to use the lowest emissions limit found at a similar facility. *In re Cardinal FG Company*, 12 E.A.D. 153 at 170 (EAB, March 22, 2005). However, the BACT analysis should include a comparison of limits identified at similar facilities and provide an explanation for any differences between those limits and the ultimate BACT limit selected for the facility at issue. *Knauf Fiber Glass* at 143.

KDAQ in its RTC states that the "Elm Road facility is a circulating fluidized bed (CFB), not a gasifier, and is not an appropriate 'like facility' for consideration of appropriate emissions from Cash Creek." RTC at 54. However, KDAQ failed to recognize that, while the Elm Road facility may primarily utilize CFB technology, it does have one IGCC unit, a fact noted in the Cash Creek Statement of Basis. SOB at 18. Accordingly, KDAQ's PSD analysis was unreasonable because it failed to consider similar SAM limits identified for such units in determining BACT. Cash Creek and KDAQ have not provided an explanation for the exclusion of the Elm Road IGCC unit's SAM emission limit as BACT, and, therefore, the Petitions are granted with respect to this issue.

### **G. KDAQ Did Not Respond to Comments Regarding Material Handling and Storage Emissions**

(Section VII of Petition 1 and Section VIII of Petition 2)

*Petitioners' Claims.* Petitioners maintain that KDAQ failed to use the maximum theoretical throughput for coal handling and maximum emissions for coal pile wind erosion in its modeling for compliance with the 24 hour PM standards. Petitioners also contend that KDAQ failed to respond to the comment on this point.

*EPA's Response.* As discussed below, these objections to the permit were not raised with reasonable specificity during the comment period. Therefore, the Petitions are denied with respect to this issue.

Pursuant to section 505(b)(2) of the Act, a petition "shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." 42 U.S.C. § 7661d(b)(2).

Petitioners note in their comments that they did not have time during the comment period to review the emissions modeling but stated, "[i]f the modeling did not use the maximum theoretical emission rate for each source, the agency must reject the modeling demonstration and require the applicant to resubmit proper modeling." Comments of Sierra Club, Valley Watch, and Environmental Law and Policy Center at 13, RTC at 49 (emphasis added). Notably, the comment never refers to any applicable requirement that was lacking, only the *possible* failure to use "the maximum theoretical emission rate" in modeling. The comments cite to the Draft NSR Manual, but the citation refers to emissions from point source emission units, not fugitive emission sources of the type addressed in the comments. The comments do not mention any particular emission source of the nine emission sources in the permit or any particular emission rate or pollutant. Moreover, these general unsupported statements in the comments do not allege any particular error on KDAQ's part. *See In re Sutter Power Plant*, 8 E.A.D. 680, 691 (EAB, December 2, 1999). In lieu of identifying specific flaws in the permit, the comments included what amounts to a placeholder for a possible objection in a later petition. No other commenter mentioned this issue. Accordingly, given the nature of the underlying comments, the Petitions are denied on this issue because the Petitions do not satisfy the requirement in CAA section 505(b)(2) that a petition be based on objections raised with reasonable specificity during the comment period.<sup>16</sup>

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<sup>16</sup> EPA notes that, in the spirit of transparency, KDAQ could have included in its RTC an acknowledgment of the comment.

## **H. KDAQ Failed to Consider Valley Watch Comments Related to Increased Ozone Formation**

(Section I of Petition 2)

*Petitioner's Claims.* KDAQ failed to consider and respond to Valley Watch's comments related to increased ozone formation due to NO<sub>x</sub> and VOC emissions from the proposed source. Petitioners assert that KDAQ should require Cash Creek to undertake an air quality analysis for ozone.

*EPA's Response.* Petitioner raised comments about increased ozone formation in a letter dated June 29, 2007, from John Blair, President of Valley Watch, Inc. (Valley Watch letter). Valley Watch also joined comments submitted in a June 29, 2007, letter signed by Meleah A. Geertsma (Geertsma letter), on behalf of Sierra Club, Valley Watch, and the Environmental Law and Policy Center. While many of the comments submitted in the Valley Watch letter and the Geertsma letter are similar or the same, the issue of increased ozone formation only appears in the Valley Watch letter. KDAQ responded to the comments raised in the Geertsma letter in Attachment H of the RTC and also responded to a separate submittal by the Cumberland Chapter of the Sierra Club in Attachment C of the RTC. However, in its RTC, KDAQ does not include a response to the comments in the Valley Watch letter and, therefore, does not appear to have considered them. While KDAQ did address a general comment from a public hearing regarding the lack of an ozone analysis, *see* RTC at 173, KDAQ's RTC does not appear to give any consideration to the more detailed comments from the Valley Watch letter, including the request to conduct an air quality analysis addressing NO<sub>x</sub> emissions and accumulated emissions from nearby facilities.

40 CFR Part 70.7(h) provides for public notice and comment for all title V permit proceedings. It is clear that "an inherent component of any meaningful notice and opportunity for public comment is a response by the regulatory authority to significant comments." *In re Consolidated Edison Co., Hudson Ave. Generating Station*, Petition No. II-2002-10 at 8 (September 30, 2003); *see also Home Box Office v. FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977). KDAQ is required to respond to significant public comments and failed to do so with regard to the ozone air quality analysis comments raised in the Valley Watch letter. Accordingly, the Petition is granted with respect to this issue.<sup>17</sup>


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<sup>17</sup> In granting the petition in this regard, we are not reaching the substantive issues raised in the comment regarding increased ozone formation as a result of NO<sub>x</sub> and VOCs from the project or Petitioner's assertion that an air quality analysis for ozone should be completed. We note that KDAQ has not yet revised its SIP to reflect the current federal requirement to address NO<sub>x</sub> as a precursor to ozone. To rectify this situation, KDAQ has issued emergency regulations requiring major sources emitting more than 100 tons per year of NO<sub>x</sub> to conduct an ambient air quality analysis for ozone and has submitted a SIP revision to the same effect for EPA review.

#### IV. CONCLUSION

For the reasons set forth above and pursuant to section 505(b)(2) of the CAA and 40 CFR § 70.8(d), I hereby grant in part and deny in part the issues in the Petitions dated January 31, 2008, and February 13, 2008.

12/15/09  
Date:

  
\_\_\_\_\_  
Lisa P. Jackson  
Administrator

## IN RE NORTHERN MICHIGAN UNIVERSITY RIPLEY HEATING PLANT

PSD Appeal No. 08-02

### *ORDER DENYING REVIEW IN PART AND REMANDING IN PART*

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Decided February 18, 2009

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#### Syllabus

On May 12, 2008, the Michigan Department of Environmental Quality ("MDEQ" or "Department") issued a federal prevention of significant deterioration ("PSD") permit to Northern Michigan University ("NMU"), pursuant to Clean Air Act § 165, 42 U.S.C. § 7475. The permit authorizes NMU to construct a new circulating fluidized bed ("CFB") boiler at the Ripley Heating Plant on its campus in Marquette, Michigan. As permitted, the CFB boiler will function as a cogeneration unit that provides both electrical power and heat to NMU's facilities through the burning of wood, coal, and natural gas.

On June 13, 2008, Sierra Club filed a petition for review of this PSD permit pursuant to 40 C.F.R. part 124. In so doing, Sierra Club challenged a number of MDEQ's decisions and responses to comments pertaining to Best Available Control Technology ("BACT") requirements for the boiler's emissions of sulfur dioxide ("SO<sub>2</sub>"), fine particulate matter ("PM<sub>2.5</sub>"), carbon dioxide ("CO<sub>2</sub>"), and nitrous oxide ("N<sub>2</sub>O"). Sierra Club also challenged several aspects of the air quality analysis for the boiler, including the Department's calculation of PSD increment consumed by other emissions sources, its alleged failure to account in the air quality modeling for the CFB boiler's worst-case emissions, its refusal to require site-specific preconstruction monitoring, and its use of certain criteria to excuse analysis of impacts to "Class I" wilderness and wildlife areas.

Held: The Environmental Appeals Board ("Board") remands certain issues raised in Sierra Club's petition for review and denies review as to the remaining issues.

**SO<sub>2</sub> BACT.** The Board holds that MDEQ clearly erred in selecting BACT limits for the proposed boiler's emissions of SO<sub>2</sub>. The Board finds that in analyzing this issue, MDEQ failed to follow the U.S. Environmental Protection Agency's ("Agency") New Source Review Manual or any other method faithful to statutory and regulatory guidelines. The Board finds that, instead, the Department prematurely narrowed the focus of its BACT analysis to a combination of minimal wood burning and predominant use of coal from two local power plants. In so doing, MDEQ failed to provide in the record the necessary threads of logic or data to sustain these fuel choices as requiring NMU to achieve emissions limitations clean enough to be BACT. The Board also rejects MDEQ's contention that requiring NMU to burn coal from sources other than the two identified local power plants would "redefine the source," holding that the record fails to sustain such a claim.

Accordingly, the Board remands the permit to MDEQ to reconsider the BACT limitations chosen for SO<sub>2</sub> emissions from the CFB boiler.

BACT for PM<sub>2.5</sub>. The Board finds no clear error, abuse of discretion, or other basis for granting review of MDEQ's decision to substitute an alternative particulate matter BACT analysis for the requisite PM<sub>2.5</sub> BACT analysis, pursuant to the Agency's so-called "surrogate policy."

BACT for Greenhouse Gases CO<sub>2</sub> and N<sub>2</sub>O. The Board remands the permit for MDEQ to analyze whether CO<sub>2</sub> and N<sub>2</sub>O emissions from the CFB boiler should be limited pursuant to BACT. The Board directs MDEQ to be guided by its recent decision in *In re Deseret Power Electric Cooperative*, 14 E.A.D. 212 (EAB 2008).

PSD Increments. The Board remands the permit for MDEQ to reevaluate and clarify its analysis of PSD increment consumption/expansion in the area affected by proposed CFB boiler emissions. In so doing, the Board rejects Sierra Club's argument that the "plain language" of the statute and regulations require that *all* the emissions from a source that undergoes a major modification after an applicable "baseline" date must be treated as increment consuming. Rather, the Board holds that, under the statute, regulations, and long-standing Agency interpretation, pre-baseline emissions of a source modified after the baseline date remain as part of the baseline concentration, and only the post-baseline change in emissions from the modified source, whether upward or downward, is factored into the PSD increment consumption/expansion calculus.

Modeling of Worst-Case Emissions. The Board remands the permit so that MDEQ can ensure that the source impact modeling analyses for SO<sub>2</sub>, particulate matter, nitrogen oxide, and carbon monoxide are conducted on the basis of the maximum, "worst-case" emissions rates of those pollutants. The Board finds that the Department failed to adequately document this analytical step in the record or meaningfully respond to significant comments questioning the modeling inputs.

Preconstruction Monitoring. The Board remands the permit for MDEQ to reevaluate the issue of preconstruction monitoring and explain, in the record, how its ultimate decisions on this topic comply with the applicable provisions of the statute and regulations and reflect Agency guidance. In so holding, the Board rejects Sierra Club's argument that the "plain language" of the statute and regulations mandate the use of site-specific, sole-purpose preconstruction ambient air quality data. The Board holds that such an argument overlooks explicit statements of congressional intent allowing the use of alternative data, and long-established Agency guidelines implementing that intent.

Class I Increment Analysis. Finally, the Board holds that MDEQ adequately addressed concerns about protecting air quality at national parks and wilderness areas that might be affected by emissions from NMU's new boiler. The Board denies review on this ground.

***Before Environmental Appeals Judges Edward E. Reich, Charles J. Sheehan, and Anna L. Wolgast.***

***Opinion of the Board by Judge Sheehan:***

On May 12, 2008, the Michigan Department of Environmental Quality ("MDEQ" or "Department") issued a federal prevention of significant deterioration

(“PSD”) permit to Northern Michigan University (“NMU” or “University”), pursuant to Clean Air Act § 165, 42 U.S.C. § 7475. The permit authorizes NMU to construct a new circulating fluidized bed (“CFB”) boiler at the Ripley Heating Plant on the University’s campus in Marquette, Michigan. As permitted, the CFB boiler will function as a cogeneration unit that provides both electrical power and heat to NMU’s facilities through the burning of wood, coal, and natural gas. On June 13, 2008, Sierra Club filed a petition for review of this PSD permit pursuant to 40 C.F.R. part 124, requesting on a number of grounds that the permit be remanded to MDEQ for further consideration. For the reasons set forth below, the Environmental Appeals Board (“Board”) remands certain issues raised in Sierra Club’s petition for review and denies review as to the remaining issues.<sup>1</sup>

## I. BACKGROUND

### A. Statutory and Regulatory Background

In 1977, Congress enacted the PSD provisions of the Clean Air Act (“CAA” or “Act”) with a number of specific goals in mind. Among other things, Congress intended “to insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources.” CAA § 160(3), 42 U.S.C. § 7470(3). Congress also intended “to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.” CAA § 160(5), 42 U.S.C. § 7470(5).

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<sup>1</sup> MDEQ is authorized to administer the PSD permitting program within the State of Michigan pursuant to a delegation agreement with Region 5 of the U.S. Environmental Protection Agency. See 40 C.F.R. § 52.21(u); 45 Fed. Reg. 8348 (Feb. 7, 1980). In accordance with the delegation agreement and applicable regulations, MDEQ-issued PSD permit decisions are considered for procedural purposes to be federally issued PSD permit decisions. See 40 C.F.R. § 124.41 (the terms “EPA” and “Regional Administrator” mean the delegate agency and its head, respectively, when a state exercises delegated authority to administer the PSD permit program); 45 Fed. Reg. 33,290, 33,413 (May 19, 1980) (“For the purposes of Part 124, a delegate [s]tate stands in the shoes of the Regional Administrator. Like the Regional Administrator, the delegate must follow the procedural requirements of part 124. \* \* \* A permit issued by a delegate is still an ‘EPA-issued permit.’”). Consequently, appeals of MDEQ’s PSD permit decisions are required to be brought pursuant to 40 C.F.R. § 124.19 and heard by EPA’s Environmental Appeals Board. See, e.g., *In re Hillman Power Co.*, 10 E.A.D. 673, 675 (EAB 2002); *In re Gen. Motors, Inc.*, 10 E.A.D. 360, 362 & n.2 (EAB 2002); *In re Tondy Energy Co.*, 9 E.A.D. 710, 711-12 n.1 (EAB 2001); *In re Indeck-Niles Energy Ctr.*, PSD Appeal No. 04-01, at 1 (EAB Sept. 30, 2004) (Order Denying Review); *In re S. Shore Power LLC*, PSD Appeal No. 03-02 (EAB June 4, 2003) (Order Denying Review); *In re Tallmadge Generating Station*, PSD Appeal No. 02-12, at 1 (EAB May 21, 2003) (Order Denying Review in Part and Remanding in Part); *In re Select Steel Corp. of Am.*, PSD Appeal No. 98-21, at 1 n.1 (EAB Sept. 11, 1998) (Order Denying Review).



Toward these ends, Congress established a PSD permitting program that is applicable in areas of the country deemed to be in "attainment" or "unclassifiable" with respect to federal air quality standards called "national ambient air quality standards," or "NAAQS." See CAA §§ 161, 165, 42 U.S.C. §§ 7471, 7475. Congress charged the U.S. Environmental Protection Agency ("EPA" or "Agency") with developing NAAQS for air pollutants whose presence in the atmosphere above certain concentration levels could "reasonably be anticipated to endanger public health and welfare." CAA § 108(a)(1)(A), 42 U.S.C. § 7408(a)(1)(A); see CAA § 109, 42 U.S.C. § 7409. To date, EPA has promulgated NAAQS for six air contaminants: (1) sulfur oxides (measured as sulfur dioxide ("SO<sub>2</sub>")); (2) particulate matter (measured as "PM<sub>10</sub>," denoting particulates 10 micrometers or less in diameter, or as "PM<sub>2.5</sub>," denoting particulates 2.5 micrometers or less in diameter);<sup>2</sup>(3) carbon monoxide ("CO"); (4) ozone (measured as volatile organic compounds ("VOCs") or as nitrogen oxides ("NO<sub>x</sub>")); (5) nitrogen dioxide ("NO<sub>2</sub>"); and (6) lead. 40 C.F.R. §§ 50.4-.12.

In geographical areas deemed to be in "attainment" for any of these pollutants, the ambient air quality meets the NAAQS for that pollutant. CAA § 107(d)(1)(A)(ii), 42 U.S.C. § 7407(d)(1)(A)(ii). In areas designated "unclassifiable," air quality cannot be classified on the basis of available information as meeting or not meeting the NAAQS. CAA § 107(d)(1)(A)(iii), 42 U.S.C. § 7407(d)(1)(A)(iii). Areas may also be designated as "nonattainment," meaning that the concentration of a pollutant in the ambient air does not meet the NAAQS for that pollutant. CAA § 107(d)(1)(A)(i), 42 U.S.C. § 7407(d)(1)(A)(i). The PSD program is not applicable, however, in nonattainment areas. See CAA § 161, 42 U.S.C. § 7471.

Parties that wish to construct "major emitting facilities"<sup>3</sup> in attainment or unclassifiable areas must obtain preconstruction approval, in the form of PSD permits, to build such facilities. CAA § 165, 42 U.S.C. § 7475. Applicants for these

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<sup>2</sup> "Particulate matter" is "the generic term for a broad class of chemically and physically diverse substances that exist as discrete particles (liquid droplets or solids) over a wide range of sizes." National Ambient Air Quality Standards for Particulate Matter, 62 Fed. Reg. 38,652, 38,653 (July 18, 1997). As noted above, particulate matter with an aerodynamic diameter of 10 micrometers or less is referred to as "PM<sub>10</sub>." *Id.* at 38,653 n.1; see 40 C.F.R. § 50.6(c). PM<sub>10</sub> is comprised of two principal fractions, referred to as "fine" and "coarse" particulate matter. 62 Fed. Reg. at 38,654. Fine particulate matter, labeled "PM<sub>2.5</sub>," has an aerodynamic diameter of 2.5 micrometers or less, while coarse particulate matter has an aerodynamic diameter greater than 2.5 but less than or equal to 10 micrometers. *Id.* nn.5-6; see 40 C.F.R. § 50.7(a). EPA has promulgated separate NAAQS for PM<sub>10</sub> and PM<sub>2.5</sub>. See 40 C.F.R. §§ 50.6-.7.

<sup>3</sup> A "major emitting facility" is a stationary source in any of certain listed stationary source categories that, in new or modified form, emits or has the potential to emit 100 tons per year ("tpy") or more of any air pollutant, or any other new or modified stationary source that has the potential to emit 250 tpy or more of any air pollutant. See CAA § 169(1), (2)(C), 42 U.S.C. § 7479(1), (2)(C).

permits must achieve emissions limits established by the “best available control technology,” or “BACT,” for pollutants emitted from their facilities in amounts greater than applicable levels of significance.<sup>4</sup> CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(b)(23), (j)(2)-(3). Applicants also must demonstrate, through analyses of the anticipated air quality impacts associated with their proposed facilities, that their facilities’ emissions will not cause or contribute to an exceedance of any applicable air quality standard or related criterion. *See* CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3) (listing three categories of compliance standards); 40 C.F.R. § 52.21(k)-(m).

### B. *Factual and Procedural Background*

On February 5, 2007, NMU filed an application with MDEQ for permission to construct a new CFB boiler on its campus near Lake Superior in Michigan’s Upper Peninsula. *See* Petition for Review Ex. 4 (NTH Consultants, Ltd., *Permit to Install Application for a Circulating Fluidized Bed (CFB) Boiler at Northern Michigan University* (Feb. 5, 2007)) (“Permit Appl.”). The boiler, which will include a steam turbine, generator, and associated equipment, is designed to serve as a cogeneration unit that provides 120,000 pounds of steam per hour and ten megawatts of electrical power to NMU’s facilities. Permit Appl. § 2.0, at 3; Petition for Review Ex. 5 (MDEQ, *Public Participation Documents for Northern Michigan University Ripley Heating Plant: Fact Sheet 1* (Oct. 19, 2007)) (“Fact Sheet”). By proposing this project, NMU hopes to expand the reliability and efficiency of its existing powerhouse operations, which are conducted out of the Ripley Heating Plant on the north end of campus.<sup>5</sup> Fact Sheet at 1.

At present, the Ripley Heating Plant is comprised of three natural gas- and No. 2 fuel oil-fired boilers, the oldest of which has been in operation since 1967, along with emissions control equipment and associated infrastructure. *See id.*; Permit Appl. § 6.2, at 57 & app. A (site drawings). NMU plans to construct the CFB boiler in a new building immediately adjacent to the building housing the three existing boilers. Permit Appl. §§ 2.0, 6.2, at 3, 57; Fact Sheet at 1. The new boiler, unlike the older ones, will be designed to burn solid fuels, including bituminous and subbituminous coals and wood. Permit Appl. § 2.1, at 3; *see* Fact Sheet at 1. The boiler will also be designed to combust natural gas, which NMU

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<sup>4</sup> The level of significance is, for example, 100 tpy for CO, 40 tpy for NO<sub>x</sub>, 40 tpy for SO<sub>2</sub>, 25 tpy for total particulate matter, and 15 tpy for PM<sub>10</sub>. 40 C.F.R. § 52.21(b)(23)(i) (listing various air pollutants and levels of emissions deemed “significant”). The level of significance for any other pollutant “regulated under the Act” but not listed in 40 C.F.R. § 52.21(b)(23)(i) is “any emissions rate.” *Id.* § 52.21(b)(23)(ii).

<sup>5</sup> While not discussed in the administrative record, NMU indicates that there is another motive driving its new boiler proposal: namely, avoidance of \$1 million or more annually in heating and electricity costs. Intervenor Northern Michigan University’s Brief in Response to Petition [Corrected] 3 (Sept. 23, 2008).

proposes to use during boiler startup operations and as a backup fuel when neither coal nor wood is available. Permit Appl. § 2.1, at 3.

NMU plans to obtain coal exclusively from two “nearby” utilities: (1) the Marquette Board of Light and Power (“Marquette”); and (2) We Energies’ Presque Isle Power Plant (“Presque Isle”). *Id.*; Fact Sheet at 2. The University also plans to obtain wood from independent suppliers and pipeline-quality natural gas from its campus natural gas supplier. Permit Appl. § 2.1, at 3; Fact Sheet at 2. NMU has arranged for shipments of the solid fuels to arrive by truck every day on average, except weekends, with a typical shipment consisting of forty tons of coal “and/or” forty tons of wood. Permit Appl. §§ 2.2, 2.2.1, at 4. The University plans to construct silos to hold a three-day supply of the coal and/or wood fuels, which will allow boiler operation through weekends and holidays.<sup>6</sup> *Id.* § 2.2, at 4. NMU projects that the annual maximum deliveries of solid fuels for the boiler will be in the range of “68,669 tons of bituminous coal, 95,329 tons of [Powder River Basin] coal, and 199,533 tons of wood.” *Id.* § 2.2.1, at 4.

NMU’s proposed installation of a new CFB boiler at the Ripley Heating Plant is considered a “major modification” that will result in a significant net increase in emissions of SO<sub>2</sub>, PM<sub>10</sub>, CO, and NO<sub>x</sub> from the facility. *See* Permit Appl. §§ 4.1 tbl. 4-1, 5.0, 6.0, at 24, 33, 51-52 (three existing boilers’ potential to emit SO<sub>2</sub>, PM<sub>10</sub>, CO, and NO<sub>x</sub> is limited by permit to 99.9 tpy for each pollutant, while projected emissions from the new CFB boiler are 388.9 tpy of SO<sub>2</sub>, 26.9 tpy of PM<sub>10</sub>, 152.6 tpy of CO, and 89.8 tpy of NO<sub>x</sub>); 40 C.F.R. § 52.21(b)(23)(i) (net emissions increase levels deemed “significant” are 40 tpy for SO<sub>2</sub>, 15 tpy for PM<sub>10</sub>, 100 tpy for CO, and 40 tpy for NO<sub>x</sub>). Moreover, the University is located within Marquette County, Michigan, an area designated as attainment or unclassifiable for SO<sub>2</sub>, CO, ozone, PM<sub>10</sub>, and NO<sub>2</sub>. *See* 40 C.F.R. § 81.323 (Michigan air quality status). Accordingly, PSD compliance is required under federal law.

MDEQ reviewed NMU’s application for a PSD permit, which included BACT and air quality analyses for the CFB boiler. *See, e.g.,* Response of MDEQ Ex. 7 (MDEQ, *Permit Evaluation Form: Northern Michigan University* (2007)) (“Permit Eval. Form”); *id.* Ex. 9 (MDEQ, *Air Dispersion Analysis Summary, NMU – Ripley Heating Plant* (May 8, 2007)). Upon examination of a proposed SO<sub>2</sub> emissions limit of 0.2 pounds per million British Thermal Units (“lb/MMBtu”) of heat input, MDEQ determined that a lower BACT limit might be within reach of the boiler, so the Department requested an additional BACT analysis from NMU. Permit Eval. Form at 3. NMU complied with the Department’s request by submitting a permit application addendum on September 18, 2007. *See* Letter from Jeffrey P. Jaros, Project Manager, NTH Consultants, Inc., to David Riddle, Senior

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<sup>6</sup> As discussed *infra* note 22 and accompanying text, MDEQ’s representation at oral argument was at variance from this record, asserting that there will be three days’ storage space for each fuel.

Environmental Engineer, MDEQ, *Addendum to Application No. 60-07 to Update SO<sub>2</sub> Emission Limit, Northern Michigan University – Ripley Heating Plant* (Sept. 18, 2007) (“Permit Appl. Add.”).

On October 19, 2007, MDEQ issued a draft PSD permit containing proposed terms and conditions to regulate the CFB boiler. That same day, the Department published a notice inviting public comment on the draft permit and establishing a comment period, which ran through December 27, 2007. On November 27, 2007, MDEQ held a public hearing on the draft permit at the Marquette City Hall. The Department accepted numerous oral and written comments on the draft permit from interested individuals and organizations, including Sierra Club. *See, e.g.*, Petition for Review Ex. 2 (Letter from David C. Bender & Bruce E. Nilles, Sierra Club, to William Presson, MDEQ (Dec. 24, 2007)) (“SC Cmts.”). On May 12, 2008, after reviewing the public comments on the draft permit, MDEQ issued a document responding to the comments, along with a final PSD permit authorizing NMU’s construction of the CFB boiler. *See id.* Ex. 6 (MDEQ, *Response to Comments Document for PSD Permit No. 60-07, Northern Michigan University, Ripley Heating Plant* (May 12, 2008)) (“RTC Doc.”); *id.* Ex. 1 (MDEQ, Permit to Install No. 60-07 (May 12, 2008)) (“Permit”).

On June 13, 2008, Sierra Club filed PSD Appeal No. 08-02 with this Board. *See* Petition for Review and Request for Oral Argument (June 13, 2008) (“Pet’n”). At the request of the Board, and after a granted motion for an extension, MDEQ submitted a response to the merits of the petition for review on August 5, 2008. *See* Response of the Michigan Department of Environmental Quality (Aug. 5, 2008) (“MDEQ Resp.”). On August 21, 2008, by leave of the Board, Sierra Club filed a reply to MDEQ’s response. *See* Petitioner’s Reply Brief (Aug. 21, 2008) (“Reply to MDEQ”). On September 5, 2008, NMU filed a motion to intervene as a party, which the Board granted, and, on September 23, 2008, the University filed a corrected response to Sierra Club’s petition. *See* Intervenor Northern Michigan University’s Brief in Response to Petition [Corrected] (Sept. 23, 2008) (“NMU Resp.”). Sierra Club then sought and received permission to file a reply to NMU’s response, which the Board accepted as filed on October 3, 2008, after Sierra Club sought leniency for an out-of-time filing. *See* Sierra Club’s Reply to Intervenor Northern Michigan University’s Brief in Response to Petition (Oct. 3, 2008) (“Reply to NMU”). On October 22, 2008, the Board heard oral argument in this dispute. *See* Oral Argument Transcript (Oct. 22, 2008) (“OA Tr.”). The case now stands ready for decision by the Board.

## II. DISCUSSION

Under the rules governing this proceeding, a PSD permit ordinarily will not be reviewed unless it is based on a clearly erroneous finding of fact or conclusion of law, or involves an important matter of policy or exercise of discretion that

warrants review. *See* 40 C.F.R. § 124.19(a); 45 Fed. Reg. 33,290, 33,412 (May 19, 1980). The Board's analysis of PSD permits is guided by the preamble to section 124.19, which states that the Board's power of review "should be only sparingly exercised" and that "most permit conditions should be finally determined at the [permit issuer's] level." 45 Fed. Reg. at 33,412; *accord In re Cardinal FG Co.*, 12 E.A.D. 153, 160 (EAB 2005). The burden of demonstrating that review is warranted rests with the petitioner, who must raise objections to the permit and explain why the permit issuer's previous response to those objections is clearly erroneous or otherwise warrants review. *In re BP Cherry Point*, 12 E.A.D. 209, 217 (EAB 2005); *In re Steel Dynamics, Inc.*, 9 E.A.D. 740, 744 (EAB 2001).

The question presently before the Board is whether Sierra Club has made a sufficient showing that any condition of the PSD permit is clearly erroneous or involves an important matter of policy or exercise of discretion warranting review. In its petition, Sierra Club begins by challenging MDEQ's decisions regarding BACT requirements for SO<sub>2</sub>, PM<sub>2.5</sub>, carbon dioxide, and nitrous oxide emissions from the CFB boiler. We address each of these matters in Parts II.A.1-4 below. Sierra Club then raises a series of challenges to MDEQ's air quality analysis for this permit.<sup>7</sup> We address these matters in Parts II.B.1-4 below.

## A. BACT Issues

### 1. Introduction

As noted above, NMU proposes a new solid fuel-fired CFB boiler near its Ripley Heating Plant. "In support of the Governor's 21st Century Energy Plan," the boiler is "designed to allow operation on Renewable Resources (specifically wood chips) up to 100% of the total heat input." Letter from Michael G. Hellman, Facilities Specialist/Planner, NMU, to Mary Ann Dolehanty, MDEQ 1 (Feb. 5, 2007) (permit application cover letter). This "preference" for renewable resources, however, yields to coal and natural gas if renewable resources are unavailable or not economically feasible. *Id.* The result, notwithstanding NMU's stated intention as late as its permit application addendum that wood be the "primary fuel," Permit Appl. Add. at 1, is a permit allowing coal burning over twenty-two days per month. Fact Sheet at 4.

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<sup>7</sup> Sierra Club also argued that MDEQ erred in its treatment of several matters pertaining to boiler startup, shutdown, and malfunction ("SSM"). *See* Pet'n at 38-39 (alleging failure to ensure SSM plan received appropriate public notice and comment), 42-43 (alleging failure to model potential uncontrolled emissions during SSM periods). Sierra Club withdrew these elements of its appeal after receiving clarification of SSM matters in MDEQ's response to the petition. Reply to MDEQ at 20-21, 22 & n.10; *see* MDEQ Resp. at 17-18. For this reason, we do not address SSM issues further.

## 2. Overview of Legal Requirements

As mentioned in Part I.A above, the Act and Agency PSD regulations make major new stationary sources and major modifications, such as the NMU facility, subject to BACT for emissions of certain pollutants. CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)(2). The BACT requirement is defined as follows:

[BACT] means an emissions limitation based on the maximum degree of reduction of each pollutant subject to regulation under [the Act] emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition of BACT).

This high threshold demands corresponding exertions from permitting authorities. Proceeding “on a case-by-case basis,” CAA § 169(3), 42 U.S.C. § 7479(3), taking a “careful and detailed” look, *In re Cardinal FG Co.*, 12 E.A.D. 153, 162 (EAB 2005), attentive to the “technology or methods appropriate for the particular facility,” *In re Prairie State Generating Co.*, 13 E.A.D. 1, 121 (EAB 2006), *aff’d sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007), they are to seek the result “tailor-made” for that facility and that pollutant. *In re CertainTeed Corp.*, 1 E.A.D. 743, 747 (Adm’r 1982), *cited in, e.g., In re Christian County Generation, LLC*, 13 E.A.D. 449, 454 (EAB 2008); *In re Three Mountain Power, LLC*, 10 E.A.D. 39, 47 (EAB 2001).

The analytical rigor demanded by Congress has found widely adopted expression in a guidance manual issued by EPA’s Office of Air Quality Planning and Standards in 1990. *See generally* Office of Air Quality Planning & Standards, U.S. EPA, *New Source Review Workshop Manual* (draft Oct. 1990) (“NSR Manual”). While not binding Agency regulation or the required vehicle for making a BACT determination, *Prairie State*, 13 E.A.D. at 13, the NSR Manual offers the “careful and detailed analysis of [BACT] criteria” required by the CAA and regulations. *Cardinal*, 12 E.A.D. at 162. For this reason, it has guided state and federal

permitting authorities on PSD requirements and policy for many years.<sup>8</sup> *E.g.*, *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 183 (EAB 2000) (“[t]his top-down analysis is not a mandatory methodology, but it is frequently used by permitting authorities to ensure that a defensible BACT determination, involving consideration of all requisite statutory and regulatory criteria, is reached”); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n.14, 134 n.25 (EAB 1999) (same). The Board has commonly used it as a touchstone for Agency thinking on PSD issues. *E.g.*, *In re Deseret Power Elec. Coop.*, 14 E.A.D. 212,220 n.7 (EAB 2008); *In re Indeck-Elwood, LLC*, 13 E.A.D. 126, 133 n.13, 158-59 & n.65 (EAB 2006).

The NSR Manual’s “top-down” method is simply stated: assemble all available control technologies, rank them in order of control effectiveness, and select the best. So fixed is the focus on identifying the “top,” or most stringent alternative, that the analysis presumptively ends there and the top option selected – “unless” technical considerations lead to the conclusion that the top option is not “achievable” in that specific case, or energy, environmental, or economic impacts justify a conclusion that use of the top option is inappropriate. NSR Manual at B.2, .7-.8, .24, .26. In those events, remaining options are then reranked, the several factors applied, and so on until a “best” technology emerges out of this winnowing process.<sup>9</sup>

More specifically, the top-down method unfolds over five steps. *E.g.*, NSR Manual at B.5-.9; *see Prairie State*, 13 E.A.D. at 13-14 (summarizing steps). The first step requires the permitting authority to identify all “potentially” available control options. NSR Manual at B.5. Available control options are those technologies, including the application of production processes or innovative technologies, that have “a practical potential for application to the emissions unit and the regulated pollutant under evaluation,” *id.*, including technology required under the

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<sup>8</sup> In 2007, EPA reaffirmed the viability of the NSR Manual for guiding BACT analyses. 72 Fed. Reg. 31,372, 31,380 (June 6, 2007) (“it remains EPA’s policy to use the five-step, top-down process [set forth in the NSR Manual] to satisfy the [BACT] requirements when PSD permits are issued by EPA and delegated permitting authorities”).

<sup>9</sup> As a general matter, the Board will not fault a BACT analysis simply for deviating from the NSR Manual’s five-step structure. We will, however, carefully examine each analysis to ensure a defensible BACT determination that reflects consideration of all relevant statutory and regulatory criteria in the PSD permitting program. *See, e.g.*, *In re ConocoPhillips Co.*, 13 E.A.D. 768, 787-94 (EAB 2008) (remanding BACT determination for petroleum refinery flare CO emissions due to lack of adequate analysis establishing that permit issuer considered all relevant statutory and regulatory criteria); *Knauf*, 8 E.A.D. at 134-44 (remanding BACT analysis conducted for fiberglass plant’s emissions of PM<sub>10</sub> because explanations of competing control options and other technical matters were insufficiently detailed to demonstrate compliance with PSD program requirements).



lowest achievable emission rate (“LAER”).<sup>10</sup> *Id.* at B.10-.17; *see, e.g., Prairie State*, 13 E.A.D. at 14-28 (applying step one analysis); *Steel Dynamics*, 9 E.A.D. at 183-86 (evaluating challenge to permit issuer’s step one analysis).

The second step eliminates “technically infeasible” options from the potentially available options. NSR Manual at B.7. This involves first determining for each technology whether it is “demonstrated,” i.e., installed and operated successfully elsewhere on a similar facility, or, if not demonstrated, whether it is both “available” and “applicable.”<sup>11</sup> *Id.* at B.17-.22. Technologies identified in step one as “potentially” available, but neither demonstrated nor found to be both available and applicable, are eliminated under step two from further analysis. *Id.*; *see, e.g., Prairie State*, 13 E.A.D. at 34-38 (evaluating step two analysis); *Cardinal*, 12 E.A.D. at 163-68; *Steel Dynamics*, 9 E.A.D. at 199-202; *In re Maui Elec. Co.*, 8 E.A.D. 1, 13-16 (EAB 1998).

In step three, remaining control technologies are ranked and then listed in order of control effectiveness for the pollutant under review, with the most effective alternative at the top. NSR Manual at B.7. A step three analysis includes making determinations about comparative control efficiencies among control techniques employing different emission performance levels and different units of measure of their effectiveness. *Id.* at B.22-.26; *see, e.g., In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 459-64 (EAB 2005) (evaluating challenge to step three analysis).

In the fourth step, energy, environmental, and economic impacts are considered and the top alternative is either confirmed as appropriate or is determined to be inappropriate. NSR Manual at B.8-.9, .26-.53. The cost effectiveness of the alternative technologies is considered under this step. *Id.* at B.31-.46. Step four thus validates the suitability of the top control option identified or provides a clear justification as to why the top control option should not be selected as BACT. *Id.* at B.26; *see, e.g., Prairie State*, 13 E.A.D. at 46-51 (applying step four analysis; evaluating all three collateral impacts); *Three Mountain Power*, 10 E.A.D.

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<sup>10</sup> The LAER requirement provides that all affected sources must comply with either the most stringent limit contained in a state implementation plan or the most stringent emission limit achieved in practice, whichever is more stringent. In contrast, under BACT, consideration of energy, environmental, or economic impacts may justify a lesser degree of control. Compare 40 C.F.R. § 52.21(b)(12) (definition of BACT) with *id.* §§ 51.165(a)(1)(xiii), .166(b)(52) (definition of LAER). The NSR Manual suggests that LAER determinations “are available for BACT purposes and must also be included as control alternatives” during step one of the BACT analysis and “usually represent the top alternative.” NSR Manual at B.5.

<sup>11</sup> According to the NSR Manual, a technology is considered “available” if it “can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term.” NSR Manual at B.17. An “available” technology is considered “applicable” if it “can reasonably be installed and operated on the source type under consideration.” *Id.*



at 56-59 (evaluating environmental impacts); *Steel Dynamics*, 9 E.A.D. at 202-07, 212-13 (evaluating economic impacts).

Finally, under step five, the most effective control alternative not eliminated in step four is selected and the permit issuer sets as BACT an emissions limit for a specific pollutant that is appropriate for the selected control method. NSR Manual at B.53-.54; *see, e.g., Prairie State*, 13 E.A.D. at 51-85 (step five analysis).

The NSR Manual thus exacts thoughtful, substantial efforts by reviewing authorities. Not merely an option-gathering exercise with casually considered choices, the NSR Manual or any BACT analysis calls for a searching review of industry practices and control options, a careful ranking of alternatives, and a final choice able to stand as first and best. If reviewing authorities let slip their rigorous look at “all” appropriate technologies, if the target ever eases from the “maximum degree of reduction” available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.

### 3. MDEQ's BACT Analysis

The greater part of Sierra Club's challenge centers on particular BACT issues. We take up each in turn. But with conformity to federal standards the central question, and with NMU and MDEQ having chosen to rely on a state document purporting to guide them through their BACT responsibilities, *see* Permit Appl. § 5.1, at 33, we first briefly assess those state procedures.

#### a. *General Conformity with Clean Air Act and Federal Guidelines*

The alignment between the NSR Manual and NMU's BACT analysis, as approved by MDEQ, is, at best, imperfect. The permit application itself commences with inconsistent objectives, the first paragraph assuring that NMU performed the review “in accordance with the U.S. EPA's recommended top-down procedure outlined in the [NSR Manual],” Permit Appl. § 5.0, at 33, the second apparently quite the opposite – that the review follows a “more streamlined analysis by circumventing the rigorous approach set forth in the [NSR Manual].” *Id.* § 5.1, at 33.

The “more streamlined” procedure is MDEQ's “Operational Memorandum No. 20.” *See* Air Quality Division, MDEQ, *Operational Memorandum No. 20: Best Available Control Technology (BACT) Determinations* (Aug. 24, 2005) (“State Manual”). Even brief examination shows it to run largely against the current of EPA's NSR Manual. The latter's tenet of settling on the “top” technology – “unless” that technology's achievement is demonstrably not possible, in which case additional reviews run until an achievable “best” is identified, NSR Manual

at B.2 – appears in the State Manual to transform into a four-level series of generally downward slips, away from the “top” control.<sup>12</sup>

Alignment with the NSR Manual appears to occur in Level 4, which liberally paraphrases the Manual’s five steps in its opening words.<sup>13</sup> State Manual at 4. But the comparison fades with the State Manual’s suggestion that their “best interests” usually counsel both applicant and MDEQ to “avoid” the NSR Manual, since the NSR Manual is “[h]ighly complex and quantitative,” “[d]ifficult to agree upon,” and “[t]ime and resource intensive.” *Id.* at 5.

The adequacy of MDEQ’s BACT determinations turn on their individual merits. The foundation beneath them, however, the State Manual, stands apart from federal standards.

#### b. SO<sub>2</sub> BACT: Clean Fuels

In its brief list of BACT production processes, methods, systems, and techniques, Congress sounds one prominent note: fuels. CAA § 169(3), 42 U.S.C. § 7479(3). In addition to “fuel cleaning” and “treatment or innovative fuel combustion techniques,” the remaining listed control is “clean fuels.” *Id.* Congressional direction to permitting applicants and public officials is emphatic. In making BACT determinations, they are to give prominent consideration to fuels. Board cases frequently underscore this charge. *See, e.g., In re Prairie State Generating Co.*, 13 E.A.D. 1, 14-28 (EAB 2006), *aff’d sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007); *In re Hillman Power Co.*, 10 E.A.D. 673, 677-79, 688-92 (EAB 2002); *In re Maui Elec. Co.*, 8 E.A.D. 1, 7-16 (EAB 1998); *In re Inter-Power of N.Y., Inc.*, 5 E.A.D. 130, 134 (EAB 1994); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 793-94 (Adm’r 1992).

The cleanest fuel choice for the NMU facility, argues Sierra Club, is wood.<sup>14</sup> Its permit limits, however, allow NMU to burn coal “more than”

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<sup>12</sup> Level 1, for example, begins tracking NSR Manual language by requiring identification of the “top control,” i.e., LAER. State Manual at 2. It then departs from the NSR Manual’s “unless” clause by allowing non-selection of LAER for no stated reason, sending the applicant to Level 2. Levels 2 and 3 continue to point the permit applicant toward successively less stringent options. Neither Level 2’s identification of BACT for “the same or similar source types anywhere in the nation,” *id.*, nor Level 3’s for “different processes or industry types,” *id.* at 3, purport to seek out the “top” technology.

<sup>13</sup> Indeed, the permit applicant ventures the view that Level 4 “mirrors” the NSR Manual’s top-down approach. Permit Appl. § 5.1, at 35.

<sup>14</sup> The parties do not dispute that wood produces lower sulfur emissions when burned than coal. For information on contaminants emitted during the combustion of these fuels, see Office of Air Quality, Planning & Standards, U.S. EPA, *I Compilation of Air Pollutant Emission Factors AP-42: Stationary Point and Area Sources* chs. 1.1.3, 1.6.3, at 1.1-3 to -5, 1.6-2 to -3 (5th ed. 1995, rev’d Sept. 1998 & Sept. 2003).

twenty-two days per month and wood just over seven days per month. Fact Sheet at 4 (discussion of basis for SO<sub>2</sub> limits); Permit Eval. Form at 3 (comparing relative wood-to-coal fuel mix allowed by various SO<sub>2</sub> emission limits). Coal will be supplied from two, and only two, sources: Marquette and Presque Isle, both “nearby” electrical generating facilities. Fact Sheet at 2; RTC Doc. at 19-20. Each facility will supply coal that is restricted, by its own PSD permit, to a specified maximum sulfur content. BACT limits were “established based on the characteristics” of the coal with the higher allowable sulfur content of the two, 1.5%. RTC Doc. at 20; *see* Permit spec. cond. 1.3, at 7 (sulfur content of coal burned in CFB boiler “shall not exceed a maximum of 1.5 percent by weight, calculated on the basis of 12,000 Btu per pound of coal”).<sup>15</sup> Because these fuel choices – minimal use of wood and primary use of Marquette and Presque Isle coal – form the two pillars beneath the ultimate BACT limits, we carefully examine the basis for each.<sup>16</sup>

i. *Record for State Conclusions: Minimal Use of Wood and Exclusive Use of Marquette and Presque Isle Coal*

(a) *Minimal Use of Wood*

MDEQ's permit evaluation form presents three scenarios of days-of-wood-burning per month to days-of-coal-burning per month, ranging from a high of 500 hours (i.e., twenty days plus twenty hours) of wood burning to a low of 184 hours (i.e., seven days plus sixteen hours) of wood burning. *See* Permit Eval. Form at 3-4. The 500-hours scenario yields the lowest sulfur emission limit on a thirty-day average, 0.07 lb/MMBtu. *Id.* at 3. The 184-hours option produces the highest limit, 0.15 lb/MMBtu. *Id.* MDEQ selected the highest limit. *Id.*; Permit spec. cond. 1.1e, at 6 (thirty-day rolling average SO<sub>2</sub> limit).

Parsing the record for the reasoning behind MDEQ's choice yields little light. As between the availability of wood and coal, the documentation is neutral, their characteristics indistinguishable. Both the fact sheet and the permit evaluation form acknowledge storage limited to “three days['] fuel supply” but do not differentiate between wood and coal such that either would be in greater supply.

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<sup>15</sup> Inconsistent statements in the record hinder absolute certainty on the source of the higher sulfur coal. *Compare* Permit Eval. Form at 4 (stating that Marquette is limited by permit to 1.5% sulfur coal and Presque Isle to 1.0% sulfur coal), *and* Permit Appl. Add. at 2 (Marquette coal has 1.5% sulfur content at 12,500 Btu/lb), *with* RTC Doc. at 20 (Presque Isle coal “may, by permit, contain up to 1.5% sulfur”).

<sup>16</sup> MDEQ generally complimented NMU's BACT determination efforts. *See, e.g.*, RTC Doc. at 17 (“[t]he BACT limits are appropriate for this facility”); *id.* at 20 (MDEQ “completed a thorough BACT review”).

Fact Sheet at 2; Permit Eval. Form at 4. Likewise, both recognize inclement weather's possible disruption of "any" fuel deliveries, again without either fuel singled out as more likely to suffer the effects. Fact Sheet at 2; Permit Eval. Form at 4. Yet, at the critical point of allocating fuel proportions in the permit, wood's demonstrably lower sulfur emissions and apparent equal availability to coal seemingly have no persuasive weight and are dismissed without explanation. The result is MDEQ's decision: coal usage over wood, by a margin of nearly three to one.

(b) *Exclusive Use of Marquette and Presque Isle Coal*

Commitment to these two coal sources alone was early and, through to the latter stages of the process, unvarying. From the initial permit application to the much later permit evaluation, NMU and MDEQ settled on precisely the same expression of their wishes – that all coal "will" come from either Marquette or Presque Isle. Permit Appl. § 2.1, at 3; Permit Eval. Form at 4; *see also* Permit Appl. Add. at 2 ("it is expected that the coal will come from" Marquette with Presque Isle "as a backup supplier"). This unwavering preference echoes elsewhere in the record, for example, in the Department's claim of "no [storage] space" beyond that set aside for coal from these "local power plants." RTC Doc. at 20. Indeed, although the record reflects that other coal, relative to Marquette and Presque Isle coal, will produce the lowest sulfur emissions, MDEQ proceeds without explaining why these sources are unavailable or not technically feasible.<sup>17</sup>

In one striking instance, the Department notes that "[o]ne of the lowest [power plant] emission limits found" in its database review is 0.05 lb/MMBtu, using 0.9% sulfur coal. Permit Eval. Form at 3 (twenty-four hour average SO<sub>2</sub> limit for 270-megawatt power plant; permit issued in 2004). Although this limit is considerably less than NMU's final permitted limit, MDEQ nonetheless declined to consider it as BACT, offering not a word of explanation for not choosing it.

In another part of the record, drawing in on particular characteristics of the proposed NMU plant (i.e., CFB boiler without scrubbers), MDEQ assembles a list of five similar permitted coal burning facilities and their sulfur emission limits. *See* Permit Eval. Form at 3. The lowest limit of the five is 0.103 lb/MMBtu for a

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<sup>17</sup> MDEQ also neglects to fully analyze the possibility of natural gas as a fuel source. NMU identifies natural gas in its permit application as a fuel that "will be used primarily for boiler startup" and at "any other times when solid fuel firing may not be available" as a backup fuel source. Permit Appl. § 2.1, at 3. NMU explains further that its existing natural gas supplier will provide it with "pipeline quality gas," *id.*, and mentions in its own BACT analysis that "pipeline quality natural gas and wood are lower in sulfur content than coal fuels." *Id.* § 5.3, at 40. Despite these references (which imply that natural gas is an available and technically feasible fuel for the CFB boiler), MDEQ's BACT analysis contains no evaluation of this fuel as a technological option that could potentially allow NMU to achieve very low emissions of SO<sub>2</sub> or other pollutants.

44-megawatt facility – closest in power production by a wide margin to NMU's<sup>18</sup> – and, since permitted in 2006, the most currently reviewed facility of the group. *Id.* Again, the lower limit is not chosen and compelling BACT data are inexplicably passed over without the Department attempting even the barest justification.

ii. *Reasonableness of MDEQ's Conclusions*

(a) *Minimal Use of Wood*

(1) *Inclement Weather*

MDEQ roots its commitment to only some seven days of wood burning per month in its determination that winter snows impede wood delivery. RTC Doc. at 19. This finding does not withstand the implications of its own record.

First, if snow makes uncertain the availability of “any” fuel deliveries, the Department fails to clarify why the consequences fall only on wood, and not on Marquette or Presque Isle coal deliveries.<sup>19</sup> *See* RTC Doc. at 19, 24; Permit Eval. Form at 4; Fact Sheet at 2. Discrepancies in the record with such an overwhelming tilt in favor of coal erode confidence in MDEQ's conclusion. For example, many statements expressly connect winter weather to disruptions not just of coal, but of “any” fuel supplies. *E.g.*, RTC Doc. at 24; Permit Eval. Form. at 4.<sup>20</sup>

Second, even assuming, as did the permit, disproportionate weather impacts on the order of making coal three times as available as wood, *see* Permit Eval. Form at 3, the factual predicate does not sustain the conclusion. The furthest reach of inclement weather is “winter or \* \* \* spring,” RTC Doc. at 19, yet the permit sets a static, year-round assumption of twenty-two days of coal to seven days of wood availability per month.<sup>21</sup>

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<sup>18</sup> The four other facilities have one or two CFB boilers that range in size from 250 to 660 megawatts. Permit Eval. Form at 3.

<sup>19</sup> “If only coal can be obtained \* \* \* ” – so the Department paints the sole consequence of severe winter weather. RTC Doc. at 24. Absent without explanation is the no less plausible result of winter snows: that only wood can be obtained.

<sup>20</sup> A lone phrase in one of MDEQ's responses to comments, without explanation and implausibly, converts weather's undifferentiated effects to restricting only the “wood supply.” RTC Doc. at 19.

<sup>21</sup> MDEQ cites federal government reports to sustain its claim of severe weather in northern Michigan. MDEQ Resp. at 13 n.49 (citing National Climatic Data Center website for storm events). Without deciding whether this extra-record information is properly before us, we note that, in any event, even enhanced data about local weather conditions would not, without more, bear on the relative availability of particular fuels.

Third, the record tells merely of wood provided by unidentified “independent suppliers.” Permit Appl. § 2.1, at 3; Permit Eval. Form at 4. Whether these suppliers are nearer or more distant than Marquette or Presque Isle, and thus more or less likely to suffer delivery disruptions due to poor weather, the record does not say. In the absence of this information, the true effects of inclement weather on wood deliveries cannot be known.

## (2) *Storage Restrictions*

While MDEQ makes claims that storage room for combined wood and coal supplies is limited to three days,<sup>22</sup> substantiating documentation is missing. MDEQ identifies no particular physical, structural, or other impediment to back its assertions. The record’s single pointer allowing any independent judgment as to storage limitations is the site diagram showing a facility of apparently spacious storage capacity. *See* Permit Appl. app. A (detailed Ripley Heating Plant diagram). It outlines wood silos with no visible spacial restraints inhibiting larger or additional silos.<sup>23</sup> It demarcates a “wood handling building” and “wood hopper” of dimensions comparable to the wood silo, both clearly suggesting additional on-site capacity for greater supplies of wood. *See id.* Expanses of seemingly empty “lot” space (denominated as Lots #19 and #22) and an unlabeled area ringing much of the coal containment area – all many times the size of the outlined wood silo – also call into question why such large tracts are unavailable for wood storage. *See id.* Nor does the diagram account for the storage possibilities of substantial other areas of apparently empty space interspersed throughout the facility. Given that purported storage limitations are central to the BACT analysis in this case, one reasonably should expect a robust presentation of evidence in the record to establish limited space as a fact.<sup>24</sup>

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<sup>22</sup> We take MDEQ’s frequent finding of only three days’ storage, e.g., Fact Sheet at 2; RTC Doc. at 20, 24, at its logical word – storage of combined wood and coal supplies, not separate three-day supplies for each. At oral argument, however, MDEQ stated that NMU will have three days’ storage space for each fuel. OA Tr. at 44-45; *see also* MDEQ Resp. at 2 (“[w]ood and coal will be stored in silos that have the capacity to store up to a three-day supply of each fuel”). We defer to the record, not counsel’s representations. *E.g., In re Wash. Aqueduct Water Supply Sys.*, 11 E.A.D. 565, 589 (EAB 2004) (a permit issuer “cannot through its arguments on appeal augment the record upon which the permit decision was based”).

<sup>23</sup> We recognize that MDEQ, accommodating community concerns about possible odors from stored, wet wood, barred stockpiling wood outside fuel silos. Permit spec. cond. 3.2, at 11; *see* RTC Doc. at 4. To sensibly confine fuel storage to silos, however, does not address or explain MDEQ’s sanctioning of NMU’s failure to propose construction of additional storage silos on a site the University’s own diagram appears to show fully capable of handling more.

<sup>24</sup> At oral argument, MDEQ instead suggested that NMU intended its diagram to show only the details of the Ripley Heating Plant, and not what structures or uses might be present on or intended for the seemingly capacious empty spaces surrounding the plant. OA Tr. at 47.

(b) *Exclusive Use of Marquette and Presque Isle Coal*

Had it come after “careful and detailed” consideration, *In re Cardinal FG Co.*, 12 E.A.D. 153, 162 (EAB 2005), or been attentive to “[appropriate] technology or methods,” *In re Prairie State Generating Co.*, 13 E.A.D. 1, 12 (EAB 2006), *aff’d sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007), MDEQ’s unqualified declaration that “[c]oal will be obtained” from Marquette or Presque Isle might have withstood scrutiny.<sup>25</sup> See Permit Eval. Form at 4. But all indications are otherwise, suggesting a fixed, preselected outcome, or at least one never subjected to serious examination.<sup>26</sup>

First, the four corners of the record itself, including the facility diagram noted above, belie claims of no storage space for coal other than Marquette or Presque Isle coal. Second, even were storage space limited to three days’ supply, shutting out any coal but Marquette or Presque Isle coal raises an obvious question to which the record gives no answer: why even a storage-limited site is incapable of accommodating non-Marquette or non-Presque Isle coal. Third, taking MDEQ at its word of severe weather disruptions to “any” fuel supply, the argument that Marquette and Presque Isle coal deliveries will somehow – and unique among all other coals or wood – prevail over such weather, and resoundingly enough to write their use into the permit twenty-two days per month, year round, is unsustainable.

The record is silent as to why other coal sources, whether more distant or more proximate, were not considered. This gap is particularly troubling on a record that spotlights at least two coal-fired, lower sulfur-polluting facilities, both employing low sulfur coal or other low sulfur emission technological features apparently achievable but inexplicably rejected for the NMU facility.<sup>27</sup> See Permit

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<sup>25</sup> NMU itself acknowledged single-focus coal procurement: “MDEQ correctly [considered] \* \* \* the [Marquette and Presque Isle] coal \* \* \* that would be available to NMU when biomass is unavailable.” NMU Resp. at 23 (emphasis added).

<sup>26</sup> MDEQ provides some indication why it holds so persistently to these two coal sources alone. The Department claims the 1.5% sulfur content of the higher sulfur coal is “legally allowed,” as if to suggest that use of “legal” fuel ends the permit authority’s BACT obligations to seek the cleanest fuel available. See MDEQ Resp. at 16 (explaining that coal used at Presque Isle is allowed by permit to contain a maximum of 1.5% sulfur by weight) (citing RTC Doc. at 20).

<sup>27</sup> If MDEQ implicitly argues that severe weather disruptions to fuel deliveries necessitate exclusive use of Marquette or Presque Isle coal because both sources are nearby and presumably more likely to prevail during poor weather, see, e.g., RTC Doc. at 19, it does so unsuccessfully. Proximity alone is insufficient on a record devoid of attempts to identify other technically feasible sources as proximate as, or more proximate than, Marquette or Presque Isle. NMU offers Marquette and Presque Isle proximity as conferring a coal storage advantage (i.e., space limitations necessitate “just in time”  
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Eval. Form at 3 (considering 24-hour average SO<sub>2</sub> BACT limits of 0.05 lb/MMBtu for 270-megawatt plant and 0.103 lb/MMBtu for 44-megawatt plant).

One ambiguous sentence in the record, embellished slightly in MDEQ's brief, attempts a justification. "A different plan would redefine the source as proposed," says the Department. RTC Doc. at 19; *see* MDEQ Resp. at 15. Yet, at best, this "plan" is opaque. The preceding sentence speaks in one breath of a broad "choice" of fuels and in another of MDEQ's decision to choose only Marquette and Presque Isle coal. RTC Doc. at 19; *see* Fact Sheet at 2; Permit Eval. Form at 4. At worst, MDEQ's assertion that a different coal source constitutes impermissible "redefining" is unpersuasive and not supported by the record.

MDEQ's brief also notes the difficulty of arranging transport of non-local lower sulfur coal to the Ripley Heating Plant. MDEQ Resp. at 15. Such shipments, necessitating that NMU "receive," "stockpile," and "feed" the non-local coal into the boiler, would require "changes in design of the facility," thus "impermissibly redefining the source." *Id.* The brief is not part of the administrative record for this permit, and thus we give its factual representations no weight. *See* 40 C.F.R. § 124.18(c) (administrative record for EPA-issued permit is considered complete on date final permit is issued). We do, however, address the legal argument it raises.

### c. *Redefining the Source*

"Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives." NSR Manual at B.13. Board and Administrator decisions adhere firmly to this principle. *See, e.g., Prairie State*, 13 E.A.D. at 20-28; *In re Hillman Power Co.*, 10 E.A.D. 673, 691-92 (EAB 2002); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 135-44 (EAB 1999); *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 29-30 n.8 (EAB 1994); *In re Haw. Commercial & Sugar Co.*, 4 E.A.D. 95, 99-100 (EAB 1992); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 793 n.38 (Adm'r 1992); *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 843 & n.12 (Adm'r 1989).

As more finely rendered by the Board, "certain [design] aspects" of the proposed facility are beyond the reach of BACT; "other [design] aspects" are within it. *Prairie State*, 13 E.A.D. at 20. To guide it, the Board gives central importance to "how the permit applicant defines the proposed facility's purpose or basic de-

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(continued)

deliveries from nearby coal sources, NMU Resp. at 23), but again, no record support either for this statement or the basis behind it is offered.



sign,” *id.* at 28,<sup>28</sup> but puts the applicant’s case to a “hard look.” *Id.* at 34-35, 13 E.A.D. at 26; *e.g.*, *Knauf*, 8 E.A.D. at 135-44.

Accordingly, the Board takes care to identify “inherent” design elements, *Prairie State*, 13 E.A.D. at 22, part of the “fundamental purpose” of the proposed facility, *id.* 13 E.A.D. at 25 n.25, or a design such that change to it would “call into question [the facility’s] existence.” *See id.* 13 E.A.D. at 24. This test shields from BACT review fuel choices found “integral” to the basic design. Proposed coal-fired electrical generators need not consider a natural gas turbine, for example. *See id.* (citing *SEI Birchwood*, 5 E.A.D. at 29-30 n.8; *Haw. Commercial*, 4 E.A.D. at 99-100; *Old Dominion*, 3 E.A.D. at 793; NSR Manual at B.13).

On the other hand, the CAA promotes “clean fuels” with particular vigor. *See* CAA § 169(3), 42 U.S.C. § 7479(3). Merely equating use of lower polluting fuels to impermissible redesign in the hope of paving an automatic BACT off-ramp pointedly frustrates congressional will. The United States Court of Appeals for the Seventh Circuit is notably dismissive of such strategies. Clean fuels may not be “read out” of the Act merely because their use requires “some adjustment” to the proposed technology. *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007). If the only required adjustment were that a dirtier fuel be “switched” to a cleaner fuel, said the court in an illustration of near perfect aptness to NMU’s CFB boiler, then low sulfur coal should be the BACT choice over high sulfur coal. *Id.*

Too late and on too meager a record, MDEQ attempts to inject the specter of major redesign. Its brief pushes forward entirely new theories – “transport” difficulties, “stockpile \* \* \* and [boiler] feed” problems – that it claims amount to redesign or “redefining the source” were non-Marquette or -Presque Isle coal forced upon it.<sup>29</sup> MDEQ Resp. at 15. But the record before us does not sustain such claims. The documentary trail offers no basis to conclude that any fundamental design change, or any source or facility design change whatsoever, would result were NMU, like the facility posited in *Sierra*, to burn lower sulfur non-Marquette or -Presque Isle coal. No data show the CFB boiler incapable of burning coal from other sources. Indeed, that its design allows burning of “bituminous and subbituminous Powder River Basin \* \* \* coals,” Permit Appl. § 2.1, at 3, suggests so broad a coal range as to be nearly dispositive evidence to the

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<sup>28</sup> Deference to applicant characterization is not unbridled. A design motivated by cost savings, avoidance of risks inherent in new or innovative technologies, or other considerations unrelated to basic design elements will not escape BACT review. *E.g.*, *Prairie State*, 13 E.A.D. at 22 n.21.

<sup>29</sup> NMU adds parallel facility design concerns – *e.g.*, infeasibility, harm to the “business plan” – also without reference to any sustaining basis in the record. *See* NMU Resp. at 23-24.

contrary.<sup>30</sup> No facility diagram or other reason tells why storage space designated exclusively for Marquette and Presque Isle coal cannot make way for non-Marquette or -Presque Isle coal, or why storage areas for additional non-Marquette and -Presque Isle coal is not feasible. Nor does MDEQ put before us any documentation that delivery of non-Marquette or -Presque Isle coal would work some harm, or force some change, to the basic facility design.

#### d. Conclusion

If the NSR Manual is the broad, oft-traveled thoroughfare to determining BACT, MDEQ has almost categorically declined to follow it – or any method consistently faithful to statutory and regulatory guidelines. MDEQ's SO<sub>2</sub> BACT analysis locks onto a combination of minimal wood burning and predominant use of Marquette or Presque Isle coal, yet offers few connecting threads of logic or data to sustain these fuel choices, justify them as enabling NMU to achieve emissions limitations clean enough to be BACT, or support the redefining-the-source claim. The Department's decision lacks a coherent, "clearly ascertainable basis," *Knauf*, 8 E.A.D. at 134, or "careful and detailed" look, *In re Cardinal FG Co.*, 12 E.A.D. 153, 162 (EAB 2005), and we are unable to conclude that it "meets the requirement of rationality." *In re Gov't of D.C. Mun. Separate Storm Sewer Sys.*, 10 E.A.D. 323, 343 (2002). Therefore, under part 124, we remand the permit to MDEQ for reconsideration of the BACT limitations chosen for SO<sub>2</sub> emissions from the CFB boiler.

### 4. Pollutants with No BACT Controls

#### a. BACT Analysis for PM<sub>2.5</sub> Emissions from the CFB Boiler

In comments on the draft permit and in its opening brief, Sierra Club notes the PSD program's requirement of BACT limits for "each pollutant subject to regulation." SC Cmts. at 7 (citing CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)(2)); Pet'n at 8 (citing 40 C.F.R. § 52.21(j)(2)). Sierra Club observes that PM<sub>2.5</sub> is a "pollutant subject to regulation under the Act" because EPA established NAAQS for that specific air contaminant in July 1997. Pet'n at 8 (citing National Ambient Air Quality Standards for Particulate Matter, 62 Fed. Reg. 38,652 (July 18, 1997) (codified as amended at, *inter alia*, 40 C.F.R. § 50.7)). Sierra Club then contends that MDEQ erred in issuing NMU's permit because it substituted a PM<sub>10</sub> BACT analysis for the requisite PM<sub>2.5</sub> BACT analy-

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<sup>30</sup> "Bituminous" or "soft" coals are the largest group of coals and have lower fixed carbon and higher volatile matter than anthracite (i.e., hard coal). Office of Air Quality, Planning & Standards, U.S. EPA, *I Compilation of Air Pollutant Emission Factors AP-42: Stationary Point and Area Sources* ch. 1.1, at 1.1-1 (Sept. 1998). "Subbituminous" coals "have higher moisture and volatile matter and lower sulfur content than bituminous coals and may be used as an alternative fuel in some boilers originally designed to burn bituminous coals." *Id.*

sis, pursuant to the Agency's so-called "surrogate" policy.<sup>31</sup> SC Cmts. at 6-8; Pet'n at 8-11.

EPA released the surrogate policy in October 1997, just a few months after it promulgated the PM<sub>2.5</sub> NAAQS. *See* MDEQ Resp. Ex. 5 (Memorandum from John S. Seitz, Director, Office of Air Quality Planning & Standards, U.S. EPA, to Regional Air Directors, *Interim Implementation of New Source Review Requirements for PM<sub>2.5</sub>* (Oct. 23, 1997)) ("Seitz Policy"). In so doing, EPA noted "significant technical difficulties" attending full implementation of PSD requirements for PM<sub>2.5</sub>, largely resulting from a lack of adequate tools for calculating PM<sub>2.5</sub> emissions, and authorized interim use of PM<sub>10</sub> as a "surrogate" for PM<sub>2.5</sub> in meeting the PSD requirements. *Id.* at 1-2. EPA later reaffirmed the Seitz Policy in April 2005, noting that the Agency had not yet promulgated an implementation rule for PM<sub>2.5</sub> and thus administration of PSD requirements for PM<sub>2.5</sub> emissions remained "impractical." *Id.* Ex. 6, at 4 (Memorandum from Stephen D. Page, Director, Office of Air Quality Planning & Standards, U.S. EPA, to Regional Offices, *Implementation of New Source Review Requirements in PM-2.5 Nonattainment Areas 4* (Apr. 5, 2005)).

On May 12, 2008, the date MDEQ issued NMU's PSD permit, and all throughout the preceding development period for this permit, the PM<sub>10</sub>/PM<sub>2.5</sub> surrogate policy represented the Agency's recommended approach for regulating PM<sub>2.5</sub> emissions. MDEQ indisputably relied on that policy in developing NMU's BACT limits for PM<sub>2.5</sub>. Permit spec. conds. 1.1bb, 1.1cc & n.\*; *see* RTC Doc. at 18.

On appeal, Sierra Club attempts to establish clear error in MDEQ's reliance on this approach by asserting that "no provision nor legal basis in the regulations" allows for such an approach, Pet'n at 9, and by claiming that substitution of PM<sub>10</sub> limits for PM<sub>2.5</sub> limits is "arbitrary" in light of the differing health impacts of PM<sub>2.5</sub>/PM<sub>10</sub>.<sup>32</sup> *Id.* at 10-11. These arguments essentially repeat contentions Sierra Club made in comments on the draft permit. *See* SC Cmts. at 6-8. The Department responded to these arguments by referencing the "administrative impracticabilities" – i.e., lack of measurable standards and calculation tools – EPA cites

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<sup>31</sup> Notably, Sierra Club does not challenge the adequacy of the PM<sub>10</sub> analysis, only the use of PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub>.

<sup>32</sup> Sierra Club also makes arguments relating to a final PM<sub>2.5</sub> implementation rule EPA issued on May 16, 2008, just four days after MDEQ issued NMU's permit. Pet'n at 9-10; Reply to MDEQ at 2-3; Reply to NMU at 5; *see* Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM<sub>2.5</sub>), 73 Fed. Reg. 28,321 (May 16, 2008) (to be codified in scattered sections of 40 C.F.R. pts. 51-52). In light of Sierra Club's dismissal of these arguments as irrelevant to the permit at issue in this case, *see* Reply to MDEQ at 3 & n.1; OA Tr. at 22-23, we do not address them.

as justification for the surrogate policy, and also presented some comparative information on PM<sub>2.5</sub> limits at other facilities. RTC Doc. at 18.

We hold on this record that MDEQ properly relied on the surrogate policy to evaluate BACT requirements for the CFB boiler's emissions of PM<sub>2.5</sub>. Sierra Club failed to make any showing of clear error, abuse of discretion, or other grounds for a grant of review of the Department's permit decisions pertaining to PM<sub>2.5</sub>. See 40 C.F.R. § 124.19(a). Accordingly, we deny review on this basis.

b. *BACT Analyses for CO<sub>2</sub> and N<sub>2</sub>O Emissions from the CFB Boiler*

Lastly, Sierra Club argues that MDEQ erred by declining to conduct BACT analyses for carbon dioxide ("CO<sub>2</sub>") and nitrous oxide ("N<sub>2</sub>O") emissions from the CFB boiler. Pet'n at 11-18; Reply to MDEQ at 4-11; Reply to NMU at 6-20. In brief, Sierra Club claims that these two pollutants are "subject to regulation" under the CAA and thus BACT limits must be developed for them. In Sierra Club's view, CO<sub>2</sub> is regulated under the Act because section 821 of Public Law 101-549, enacted in 1990, provides for monitoring and reporting of CO<sub>2</sub> emissions from certain stationary sources. Sierra Club's arguments in this regard closely and substantially track those made in *In re Deseret Power Electric Cooperative*, a case recently the subject of detailed analysis and remand by this Board. See generally *In re Deseret Power Elec. Coop.*, 14 E.A.D. 212 (EAB 2008). For the reasons set forth in that decision, we similarly remand the CO<sub>2</sub> issue here, directing MDEQ, guided by our findings in *Deseret*, to undertake the same consideration whether the CAA's "pollutant subject to regulation" language requires application of a BACT limit to CO<sub>2</sub> emissions.

In addition, with respect to the questions whether approval by EPA of CO<sub>2</sub>- or N<sub>2</sub>O-related provisions in several state implementation plans ("SIPs") constitutes CO<sub>2</sub> or N<sub>2</sub>O regulation under the Act, we instruct the Department to fully consider these issues on remand, its response to comments having failed to do so. See RTC Doc. at 8, 18-19, 29-30. Lastly, Sierra Club contends for the first time that CO<sub>2</sub> is one of the constituents of municipal solid waste landfill emissions (subject to CAA § 111 and implementing regulations) and therefore is regulated under the Act. As this argument was not presented to MDEQ during the public comment period, it is not preserved for consideration in this appeal. *In re ConocoPhillips Co.*, 13 E.A.D. 768, 800-05 (EAB 2008); *In re Christian County Generation, LLC*, 13 E.A.D. 449, 457-63. However, since the remand requires a fresh analysis of whether CO<sub>2</sub> and N<sub>2</sub>O are "subject to regulation," the Department should consider in the remand proceeding this or any other issue pertaining to possible BACT limits for CO<sub>2</sub> and N<sub>2</sub>O emissions from NMU's boiler.

## B. Air Quality Issues

We turn our attention next to a second focal point of the PSD program: *air quality*. In section 165 of the Clean Air Act, Congress directs owners and operators of proposed major emitting facilities to demonstrate that emissions from the construction or operation of their facilities “will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region, or (C) any other applicable emission standard or standard of performance under this chapter.” CAA § 165(a)(3), 42 U.S.C. § 7475(a)(3). EPA’s regulations implement this provision by requiring, among other things, that each applicant for a PSD permit conduct a “source impact analysis,” as follows:

The owner or operator of the proposed source or modification shall demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of:

- (1) Any national ambient air quality standard in any air quality control region; or
- (2) Any applicable maximum allowable increase over the baseline concentration in any area.

40 C.F.R. § 52.21(k).

The national ambient air quality standards, or NAAQS, referenced in the first prong of the source impacts analysis are (as noted in Part I.A above) maximum ambient air concentrations for specific pollutants that EPA has determined are necessary to protect public health and welfare. *See* CAA §§ 108(a)(1)(A), 109, 42 U.S.C. §§ 7408(a)(1)(A), 7409; 40 C.F.R. §§ 50.4-.12. The maximum allowable increase over a baseline referenced in the second prong of the analysis is called a “PSD increment” or “air quality increment.” EPA designates increments as amounts of specific pollutants that can be added to the ambient air over certain baseline concentrations of those pollutants without causing significant deterioration of air quality from the baseline levels. *See* CAA § 165(a)(3)(A), 42 U.S.C. § 7475(a)(3)(A); 40 C.F.R. § 52.21(c). The smallest increments are available (thus allowing for the smallest degree of air quality deterioration) in “Class I” areas, which consist of national parks and wilderness areas. Larger increments are available in “Class II” areas, which are areas in which “normal well-managed industrial growth” is anticipated, and the largest increments are available in “Class III” areas,

which are designated for more intensive development.<sup>33</sup> See CAA §§ 162, 163(b)(1), 42 U.S.C. §§ 7472, 7473(b)(1); 40 C.F.R. § 52.21(c); NSR Manual at C.4-5.

A permit applicant establishes compliance with the NAAQS and PSD increment elements of the source impact analysis through the vehicle of an “ambient air quality analysis,” which applicants must prepare under the permitting rules for each regulated pollutant their proposed facilities will emit in “significant” amounts.<sup>34</sup> 40 C.F.R. § 52.21(b)(23)(i), (m)(1)(i). This analysis predicts a pollutant’s future concentration in the ambient air by modeling a proposed facility’s expected emissions of the pollutant against the backdrop of existing ambient conditions. To conduct an air quality analysis, a permit applicant compiles data on the proposed facility’s physical specifications and anticipated emission rates, local topography, existing ambient air quality, meteorology, and related factors. See, e.g., 40 C.F.R. § 52.21(l), (m); *id.* pt. 51 app. W (Guideline on Air Quality Models); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 145-48 (EAB 1999); NSR Manual at C.16-.23, .31-.50. These data are then processed using mathematical models that calculate the rates at which pollutants are likely to disperse into the atmosphere under various climatological conditions, with the goals of determining whether emissions from the proposed source will cause or contribute to a violation of either the NAAQS or the PSD increments. See 40 C.F.R. § 52.21(l); *id.* pt. 51 app. W; NSR Manual at C.24-.27, .51-.70.

As a general matter, an air quality analysis will unfold in two phases. First, the permit applicant will conduct a “preliminary analysis” using dispersion modeling to evaluate whether emissions of the pollutant from the proposed facility will – by themselves, without consideration of existing ambient air quality – exceed certain “significant ambient impact levels,” or “SILs.”<sup>35</sup> See NSR Manual at C.24

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<sup>33</sup> Congress expressly designated all international parks, national wilderness areas/memorial parks over 5,000 acres in size, and national parks over 6,000 acres in size as Class I areas. CAA § 162(a), 42 U.S.C. § 7472(a). Congress also initially designated all other areas falling within state-determined attainment and unclassifiable areas as Class II areas. CAA § 162(b), 42 U.S.C. § 7472(b). These latter areas may be redesignated as Class I or Class III upon state or tribal proposal and EPA approval as a revision to the applicable state implementation plan. 40 C.F.R. § 52.21(g).

<sup>34</sup> More precisely, each applicant for a proposed major stationary source that has the potential to emit any regulated pollutant in a “significant” amount, or for a proposed major modification that will result in a “significant net emissions increase” of any regulated pollutant, must include in the permit application an ambient air quality analysis for each such pollutant. 40 C.F.R. § 52.21(m)(1)(i). The emissions rates deemed “significant” for these purposes are rates equal to or in excess of the following: for CO, 100 tpy; for NO<sub>x</sub> or SO<sub>2</sub>, 40 tpy; and for PM<sub>10</sub>, 15 tpy. *Id.* § 52.21(b)(23)(i) (listing significant rates for these and other pollutants).

<sup>35</sup> As we observed in *Knauf*, the SILs are “just one set of several standards in the PSD program that make use of the word ‘significant.’ These levels are not to be confused with the significance levels  
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& tbl. C-4, at C.28 (listing SILs recommended for use in Class II areas). If the new emissions do not exceed these levels, the proposed facility will have successfully demonstrated compliance with the NAAQS and PSD increments. *See In re Prairie State Generating Co.*, 13 E.A.D. 1, 103-08 (EAB 2006) (citing Agency guidance on use of SILs), *aff'd sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007); *In re AES Puerto Rico, LP*, 8 E.A.D. 324, 331, 343-44 (EAB 1999), *aff'd sub nom. Sur Contra La Contaminacion v. EPA*, 202 F.3d 443 (1st Cir. 2000). If the new emissions do exceed these levels, then a second phase, called a "full impact analysis," will typically be conducted. In this second phase, the permit applicant will use dispersion models to estimate the ambient concentrations that will result from its proposed emissions in combination with emissions from existing sources. NSR Manual at C.24-.53; *see* Air Quality Division, MDEQ, *Air Dispersion Modeling Guidance Document* § 1.0, at 1 (June 2008). These figures will then be used to determine whether the proposed facility causes or contributes to a violation of the NAAQS and PSD increments. *See, e.g., AES Puerto Rico*, 8 E.A.D. at 345-47; *Knauf*, 8 E.A.D. at 148-54.

In the present case, NMU's proposed installation of a new CFB boiler at the Ripley Heating Plant is considered a "major modification" that will result in a significant net increase in emissions of SO<sub>2</sub>, PM<sub>10</sub>, CO, and NO<sub>x</sub> from the facility, as noted in Part I.B above. Accordingly, the ambient air quality analysis requirements apply with respect to each of these four pollutants. However, upon conducting preliminary air quality analyses, NMU determined that the proposed boiler will emit only one pollutant, SO<sub>2</sub>, at levels in excess of the SILs. Permit Appl. §§ 6.0, 6.5, at 51-52, 69-76. Thus, the University conducted a full impact air quality analysis solely for that pollutant. *See id.* §§ 6.5.2-.3, at 71-74. MDEQ reviewed and approved NMU's air quality modeling and conclusions regarding the boiler's impact on the NAAQS and PSD increments. *See* Fact Sheet at 2-3; MDEQ Resp. Ex. 9 (MDEQ, *Air Dispersion Analysis Summary, NMU – Ripley Heating Plant* (May 8, 2007)) ("Air Analysis Summary").

On appeal, Sierra Club challenges four aspects of the air quality analysis performed for the CFB boiler and approved by MDEQ, claiming as follows: (1) the Department's attempt to account for PSD increment-consuming emissions from the nearby Presque Isle Power Plant is erroneous as a matter of law; (2) the Department failed to account for worst-case emissions in the air quality modeling used to establish compliance with NAAQS and PSD increment standards; (3) the Department failed to require that NMU conduct site-specific preconstruction monitoring mandated by the CAA; and (4) the Department employed improper

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that govern PSD review generally." 8 E.A.D. at 149 n.40; *cf.* 40 C.F.R. § 52.21(b)(23)(i) (listing of the latter significance levels).



standards in excusing NMU from conducting PSD increment analyses for Class I-designated areas. We address each of these issues in turn below.

### 1. *Consumption/Expansion of PSD Increment*

#### a. *Legal Background*

As noted above, PSD increments are designed to “prevent significant deterioration” of air quality in locations that already have relatively clean air by ensuring that contaminants projected to be contributed by proposed new or modified sources, combined with levels of contamination already present in the ambient air as of a specific baseline date, will fall within bounds established by the Agency. To date, EPA has established PSD increments for just three pollutants – SO<sub>2</sub>, PM<sub>10</sub>, and NO<sub>2</sub>. The increments consist of numeric concentrations, measured in micrograms of pollutant per cubic meter of air, that vary according to averaging period (3-hour, 24-hour, or annual averages) and geographic location (Class I, II, or III). See 40 C.F.R. § 52.21(c) (table of increment levels).

As PSD permits are issued over the course of time, newly authorized emissions are said to “consume” a portion of the PSD increment available in a given area, thus “shrinking” or reducing the remaining amount of increment available for new development.<sup>36</sup> *In re W. Suburban Recycling & Energy Ctr., LP*, 8 E.A.D. 192, 195 (EAB 1999); see 72 Fed. Reg. 31,372, 31,376-77 (June 6, 2007); 45 Fed. Reg. 52,676, 52,717-20 (Aug. 7, 1980); 43 Fed. Reg. 26,388, 26,400-02 (June 19, 1978). Conversely, as sources reduce their emissions or close down completely, pollutant levels that previously existed are eliminated, thus “freeing up” portions of increment – i.e., “expanding” the increment – and making it available again for new development. 72 Fed. Reg. at 31,376-77; 45 Fed. Reg. at 52,717-20; 43 Fed. Reg. at 26,400-02; NSR Manual at C.10-11. In the State of Michigan, MDEQ policy specifies that no single facility may consume more than 80% of applicable Class II increment standards, in order to allow for future industrial growth. *E.g.*, Air Quality Division, MDEQ, *Air Dispersion Modeling Guidance Document* § 1.0, at 1 (June 2008); see Permit Appl. § 6.0, at 51.

#### b. *Procedural Background*

In its petition, Sierra Club argues that MDEQ’s attempt to account for increment-consuming emissions from the nearby Presque Isle Power Plant is erroneous as a matter of law. Pet’n at 39. By way of background, Sierra Club explains that in the original source impact analysis prepared by NMU for its permit application, the University had assumed emissions from all existing stationary sources in the

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<sup>36</sup> The *amount* of increment consumed by a source that has undergone a major modification is at issue in this appeal and is addressed in the following analysis.



vicinity of the new powerhouse – including Presque Isle – were included in the baseline concentration and thus did not consume any increment. *Id.* at 40 (citing Permit Appl. § 6.5.2, at 71). In preparing that analysis, NMU had actively sought MDEQ's input to ensure evaluation of a complete inventory of emissions sources, but neither the Department nor NMU identified Presque Isle as an increment-consuming source. *See* Permit Appl. §§ 6.4, 6.5.2, at 67, 71. In comments on the draft permit, however, Sierra Club pointed out that Presque Isle had undergone construction through one or more major modifications since the date designated as the "major source baseline" for SO<sub>2</sub> (i.e., January 6, 1975), and emissions attributable to those modifications could not, by virtue of their timing, possibly be reflected in the baseline concentration. It took the position that it was improper to exclude not only post-January 6, 1975 emissions, but that *all* of Presque Isle's emissions (whether pre- or post-January 6, 1975) should have been modeled as consuming some portion of the PSD increment available in the ambient area near NMU's campus. SC Cmts. at 44-54 (cited in Pet'n at 40).

In its response to comments, MDEQ did not acknowledge any error in its review and approval of NMU's original PSD increment analysis. Instead, the Department simply changed course, treating Presque Isle as an increment-consuming source for purposes of calculating that facility's effect on the air quality modeling. MDEQ explained its revised analysis as follows:

The SO<sub>2</sub> major source baseline date was set by the [CAA] to be January 6, 1975. Emissions associated with modification at a major stationary source consume increment after this date. A comparison was made between the reported SO<sub>2</sub> emissions from Presque Isle for 1973 and 2006 which were found to be 15,274 tpy and 16,609 tpy respectively. This increase of 1335 tpy should not be part of the baseline and should be considered in the PSD increment analysis. New modeling was conducted by [MDEQ] which added the 1335 tpy to the increment analysis and the results indicated that this change had no effect on either the 3-hr or 24-hr PSD maximum (100%) SO<sub>2</sub> PSD increment levels. However, the addition of the 1335 tpy did cause the annual PSD increment concentration to increase to approximately 10 percent which is still well below the State's 80% allowable Class II PSD increment criterion.

RTC Doc. at 14.

*c. Arguments on Appeal*

On appeal, Sierra Club asserts that “[t]here is no legal basis for the 1,355 tons used” by MDEQ in its revised analysis, Pet’n at 41, and continues to claim that the Department should have used all of Presque Isle’s “actual emissions” to calculate increment consumption. As authority for its proposition, Sierra Club points to the PSD regulations, which specify, in its view, that all “actual emissions” from new and modified major stationary sources constructed after the major source baseline date should be excluded from the baseline concentration and instead analyzed as consuming part of the PSD increment. *Id.* (citing 40 C.F.R. § 52.21(b)(13)(ii)(a)). Sierra Club notes that “actual emissions” are defined as “the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation.” *Id.* (quoting 40 C.F.R. § 52.21(b)(21)(ii)). Alternatively, a source’s “actual emissions” can be presumed to be its “allowable emissions.” *Id.* (referring to 40 C.F.R. § 52.21(b)(21)(iii)).

Employing these definitions, and drawing on Presque Isle emissions data taken from EPA’s Acid Rain Database, Sierra Club concludes that “[a]t a minimum, the ‘actual emissions’ from [Presque Isle] would be the average rate during the representative two years preceding the date of permit issuance for the NMU plant; while MDEQ did not calculate this amount, it is approximately between 14,235 and 16,690 tons of SO<sub>2</sub>.” Reply to MDEQ at 21 n.9 (citing Pet’n at 42 & n.6, which provides the Acid Rain Database reference as [www.epa.gov/airmarkets](http://www.epa.gov/airmarkets)). Sierra Club criticizes MDEQ for choosing Presque Isle emissions data from two “random” years, 1973 and 2006, calculating the difference between the two emissions rates, and thereby deriving a figure for use in the increment-consumption analysis that, in its view, is ten times lower than it should be. *Id.* at 22; Pet’n at 42; OA Tr. at 27-28.

*d. Analysis*

Upon review of the briefs, we find that the parties generally do not disagree on what law applies to this issue. Indeed, each side quotes portions from the same regulatory and statutory provisions, albeit for differing purposes. *Compare* Pet’n at 39-42, Reply to MDEQ at 21-22, *and* Reply to NMU at 26-30, *with* MDEQ Resp. at 19-20, *and* NMU Resp. at 24-25. Their disagreement lies in how these provisions should be interpreted, which leads to a dispute over the method that should be used to determine how much increment a modified source consumes (or relinquishes) as a result of the modification. MDEQ and NMU cite the statute, regulations, and long-standing Agency guidance to support their view that any post-baseline *change* in a facility’s emissions (be it upward or downward) resulting from a major modification must be factored into the increments analysis. *See* MDEQ Resp. at 19-20; NMU Resp. at 24-25. Thus, only the emissions impact of the change consumes (or relinquishes) increment. Sierra Club urges a contrary

interpretation based on the “plain language” of the relevant authorities, suggesting that *all* emissions from a source that has undergone a major modification since the baseline date must be treated as increment-consuming, not just the emissions associated with the change. *See* Reply to MDEQ at 21-22; Reply to NMU at 26-30; OA Tr. at 27, 109-10.

### i. *Congressional Intent*

To resolve these competing interpretations, we look first to the statute and legislative history to see what those sources might tell. We learn, at the outset, that Congress largely left to EPA the task of defining the methods by which PSD increments are deemed consumed or expanded. *See* CAA § 165(e)(1), (3), 42 U.S.C. § 7475(e)(1), (3) (directing EPA to promulgate regulations implementing PSD program); *see also* 72 Fed. Reg. at 31,379 (the CAA “provide[s] no guidance on increment consumption calculations”); 45 Fed. Reg. at 52,718 (same). Congress did, however, define several parameters for the “baseline concentration” of pollutants, which are relevant to the increments analysis. *See* 45 Fed. Reg. at 52,718 (“Increment consumption or expansion is directly related to baseline concentration. Any emissions not included in the baseline are counted against the increment.”).

Under Congress’ definition, the “baseline concentration” of a pollutant in a particular area is the concentration present in the ambient air at the time the first PSD permit application affecting that area is submitted. CAA § 169(4), 42 U.S.C. § 7479(4); *Ala. Power Co. v. Costle*, 636 F.2d 323, 374 (D.C. Cir. 1979). This concentration must *include* emissions from major emitting facilities upon which construction commenced prior to January 6, 1975 (even those not yet operational by the date of the first PSD application), and *exclude* emissions from major emitting facilities that commence construction after January 6, 1975. CAA § 169(4), 42 U.S.C. § 7479(4); S. Rep. No. 95-127, at 97-98 (1977), *reprinted in* 3 A Legislative History of the Clean Air Act Amendments of 1977, at 1471-72 (1978). Emissions from the latter (excluded) category of sources must, under Congress’ definition, instead “be counted against the maximum allowable increases in pollutant concentrations established under this part” – i.e., against the PSD increments. CAA § 169(4), 42 U.S.C. § 7479(4); *Ala. Power*, 636 F.2d at 376-77.

Industry expressed concern that the latter portion of Congress’ definition could adversely affect future development if it were interpreted to deny the idea of a “negative increment” (i.e., the increment expansion concept). Industry explained:

After defining the baseline to be the ambient concentrations of [pollutants] in existence at the time the first applicant for a nondeterioration permit is filed, this section goes on to state that \* \* \* [pollutants] emitted from any

major emitting facility on which construction is commenced after January 6, 1975, will not be included in the baseline, but must be subtracted from the available increment. Thus even when an existing unit is shut down, creating an emission reduction below baseline, its replacement unit is classed as a new source and therefore must be subtracted from the available increment as if it were above the baseline. Since the increment is a non-renewable value which, once exhausted, ends future growth, it is foreseeable that in the long run every existing major emitting facility in nondeterioration areas will be forced to cease operations. This could occur because worn-out boilers and other sources vital to operation would not be able to be replaced by new boilers once the increment has been used up – even though the ambient air quality may be better than it was during the baseline year, and even though the replacement boiler would probably emit less than the existing boiler.

Surely no one intended this absurd result – yet a careful reading of the language in either version of [the proposed legislation] inescapably leads to this anomalous result. It is clear that the language provides a disincentive to modernize older inefficient sources. Since owners would be given no credit for cleanup, they would be forced to go to boundless effort to keep such sources operational in order to avoid using up any of that precious allowance for expansion in the area.

*Clean Air Act Amendments of 1977: Hearing Before the Subcomm. on Environmental Pollution of the S. Comm. on Environment & Public Works, 95th Cong. 520 (1977), reprinted in 5 A Legislative History of the Clean Air Act Amendments of 1977, at 4170 (1978) (statement of Roger H. Watts, Assistant General Counsel, ITT Rayonier, Inc., for American Paper Institute and National Forest Products Association); accord Clean Air Act Amendments of 1977: Hearings Before the Subcomm. on Health & the Environment of the H. Comm. on Interstate & Foreign Commerce, 95th Cong. 1258 (1977) (similar statement of Roger H. Watts) (“We have raised this point with the Senate Committee on Environment and Public Works, where the provision originated, and have been informally advised that the staff will make the necessary adjustments. We call it to your attention in case the alteration is overlooked, because of the potentially serious impacts from this deceptively innocuous-sounding sentence.”).*

Congress did not alter the statutory language in response to industry’s pleas, but it also left unchanged the language that assigns to the baseline the pollutant

levels emitted by pre-January 6, 1975 facilities. *Compare* S. 3219, 94th Cong. § 160(c)(2)(D) (1976) with Clean Air Act Amendments of 1977, Pub. L. No. 95-95, tit. I, § 127(a), 91 Stat. 685, 741 (1977) (codified as amended at CAA § 169(4), 42 U.S.C. § 7479(4)). However, the legislative history does suggest that Congress intended its definition of “baseline concentration” to be interpreted in such a way that *changes* in emissions would be the focus of the increment calculus for replaced (and, by implication, modified) sources. In a report on the CAA Amendments of 1977, the Senate Committee on Environment and Public Works explained that emissions from sources that commence construction after January 6, 1975, are not in the baseline but are increment-consuming, and then clarified that “[t]his of cour[s]e does not include facilities built as replacements for sources in existence before January 6, 1975. Only the emissions from such replacement facilities *in excess of those* from the source replaced would be deducted from the increment.” S. Rep. No. 95-127, at 97 (1977), *reprinted in* 3 A Legislative History of the Clean Air Act Amendments of 1977, at 1471 (1978) (emphasis added).

## ii. Agency Implementation of Congressional Intent

Turning from congressional to administrative intent, we find compelling evidence that EPA has long held to the principles of consumption/expansion in its implementation of the PSD increment program. In iterations of the PSD regulations going back to the 1970s and continuing to the present day, the Agency has described the method of calculating how much increment remains available to prospective permittees as one involving evaluation of increases and decreases in emissions since the baseline date. *See, e.g.*, 72 Fed. Reg. 31,372, 31,376-77 (June 6, 2007); 45 Fed. Reg. 52,676, 52,717-20 (Aug. 7, 1980); 43 Fed. Reg. 26,388, 26,400-02 (June 19, 1978). For instance, in the preamble to the 1978 PSD regulations, the Agency explained:

[I]ncrement consumption can be best tracked by tallying changes in the emission levels of sources contributing to the baseline concentration and increases in emissions due to new sources. \* \* \* Thus, to implement the air quality increment approach set forth in the Act, the reviewing authority needs to verify that all changes from baseline emission rates (decreases or increases as appropriate) in conjunction with the increased emissions associated with approved new source construction will not violate an applicable increment or NAAQS.

\* \* \*

\* \* \* Increases in the baseline emissions of sources contributing to the baseline concentration will also consume

increment \* \* \* . Conversely, reductions in the baseline emissions of sources existing [at the time of baseline establishment] generally expand the available PSD increment(s).

43 Fed. Reg. at 26,400-01; *accord* NSR Manual at C.10 (“The amount of PSD increment that has been consumed in a PSD area is determined from the emissions increases and decreases [that] have occurred from sources since the applicable baseline date.”).

The Agency confirms this approach in its most current pronouncements on this topic, contained in the preamble to a rule proposing to clarify the PSD increment analysis. *See generally* 72 Fed. Reg. 31,372 (June 6, 2007). In a background section discussing existing practice, EPA identifies the compilation of “emissions inventories” as an important, long-established element of the increments analysis, as follows:

The inventory of emissions includes emissions from increment-affecting sources at two separate time periods – the baseline date and the current period of time. For each source that was in existence on the relevant baseline date \* \* \* , the inventory includes the source’s actual emissions on the baseline date and its current actual emissions. The change in emissions over these time periods represents the emissions that consume increment (or, if emissions have gone down, expand the available increment). For sources constructed since the relevant baseline date, all their current actual emissions consume increment and are included in the inventory.

*Id.* at 31,377; *accord* NSR Manual at C.31-.36 (discussing selection of sources for PSD emissions inventories).

In addition, the Agency explains that in the past, it “never adopted detailed regulations establishing a specific methodology that sources and reviewing authorities must use to calculate an increase in concentrations for purposes of determining compliance with PSD increments.” 72 Fed. Reg. at 31,378. Rather, it chose to describe its recommended approaches in guidance documents, leaving room for permitting authorities to exercise discretion in each unique circumstance.<sup>37</sup> *See id.* at 31,376. These representations tend to minimize the importance

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<sup>37</sup> Indeed, EPA historically has “given reviewing authorities substantial leeway within the PSD program to select data and emissions calculation methodologies that they believe are representative of  
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of the “plain language” upon which Sierra Club leans so heavily in this instance.

### iii. *Plausible Alternative Interpretation*

We are not convinced that the statutory, regulatory, and preamble language that Sierra Club highlights is so clear and unambiguous. As Sierra Club rightly points out, “[f]or purposes of PSD permitting, [the term] ‘construction’ includes modifications.” Reply to NMU at 29 n.13 (citing CAA §§ 169(2)(C), 111(a)(4), 42 U.S.C. §§ 7479(2)(C), 7411(a)(4); 40 C.F.R. § 52.21(b)(8)). Therefore, references in the statute, regulations, and preamble to sources upon which “construction” commenced or took place after a relevant baseline date, *see* CAA § 169(4), 42 U.S.C. § 7479(4) (last sentence); 40 C.F.R. § 52.21(b)(13)(ii)(a); 72 Fed. Reg. at 31,377 (last sentence of fragment quoted in Part II.B.1.d.ii above), may be reasonably interpreted to include not only newly built sources, but also modified sources. Assuming *arguendo* that this interpretation is appropriate for all three textual references (which we need not decide), such a reading would not necessarily dictate the result Sierra Club advocates.

Instead, one could reasonably construe the statutory, regulatory, and preamble language to mean that *all actual emissions from the modifications to a source* consume increment, not that *all actual emissions from the modifications to the source plus actual emissions from the portions of the source that were not modified* consume increment. In this way, the emissions in question could be specifically tied back to the modifications, and only those emissions would be considered increment-consuming. This reading strikes us as plausible. Sierra Club’s “plain” language reading, on the other hand, produces results that confound the very sense and policy undergirding a workable increment consumption scheme. Were Sierra Club’s views to prevail, no increment credit would be given for sources that shut down, and emissions already counted in the baseline concentration would be counted again against the PSD increment – in effect, double counting. *See* OA Tr. at 29-35. This seems a manifest unfairness and does violence to what we must assume to be a prudently conceived and administered system.

### iv. *Conclusion on “Plain Language”*

In light of all the foregoing factors, it seems apparent that the Agency, implementing Congress’ intent, designed the increment calculus to unfold in a very

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(continued)

actual emissions.” 72 Fed. Reg. at 31,386. In proposing new regulations to refine the PSD increment modeling procedures, the Agency has signaled an interest, going forward, in making more uniform the methods by which permitting authorities may conduct these analyses. *See id.* at 31,378. In so doing, however, the Agency has retained its basic approach to increments as one that takes into account emissions increases and decreases after applicable baseline dates. *E.g., id.* at 31,380, 31,384-85. At this writing, EPA has not finalized these proposed regulations.



different way than that urged by Sierra Club. We therefore find Sierra Club's "plain language" argument to be unpersuasive. *See, e.g., In re Rochester Pub. Utils.*, 11 E.A.D. 593, 603-08 (EAB 2004) (Board generally will give effect to unambiguous regulatory language, but where the meaning of a regulation is unclear, the Board must construe the regulation in light of its context and purpose), *appeal dismissed by stip. sub nom. Minn. Ctr. for Envtl. Advocacy v. EPA*, No. 05-1113 (8th Cir. Jan. 12, 2005).

#### v. *Remand for Record Clarification*

All this being said, we nonetheless find fault in the Department's rather cryptic explanation of the methodology for its increment calculus. MDEQ failed to provide even brief explanations of the reasons why it selected 1973 and 2006 as the relevant years from which to draw comparative emissions data, whether those data consisted of twelve-month averages or one-month or one-day snapshots, or why the Department did not average two years of pre- and post-modification emissions data to calculate "actual emissions," as indicated by the Agency's methods and guidelines for undertaking this calculus. *See* 40 C.F.R. § 52.21(b)(13)(ii), (21); *see also id.* pt. 51 app. W § 8.1.2.i & tbl. 8-2; 45 Fed. Reg. at 52,717-19; NSR Manual at C.10-.11, .35-.36, .44-.50.

The Board has long held that the administrative record for a final permit must reflect the permit issuer's "considered judgment," meaning the permit issuer has an obligation to articulate with reasonable clarity the reasons for its conclusions and the significance of the crucial facts it relied upon in reaching those conclusions. *See, e.g., In re Wash. Aqueduct Water Supply Sys.*, 11 E.A.D. 565, 586-90 (EAB 2004); *In re Ash Grove Cement Co.*, 7 E.A.D. 387, 417-18 (EAB 1997); *In re Austin Powder Co.*, 6 E.A.D. 713, 720 (EAB 1997); *In re GSX Servs. of S.C., Inc.*, 4 E.A.D. 451, 453-54 (EAB 1992); *see also In re Chem. Waste Mgmt., Inc.*, 2 E.A.D. 575, 579 (Adm'r 1988); *In re Carolina Power & Light Co.*, 1 E.A.D. 448, 451 (Acting Adm'r 1978). Moreover, it remains a perennial and important requirement that permit issuers "briefly describe and respond to all significant comments on the draft permit" in their response-to-comment documents. 40 C.F.R. § 124.17(a)(2). The Board has construed this provision as meaning that responses to comments must address the issues raised in a meaningful fashion and, though perhaps brief, must nonetheless be clear and thorough enough to adequately encompass the issues raised by commenters. *See, e.g., Wash. Aqueduct*, 11 E.A.D. at 586-90 (remanding for failure to respond to commenter's data sets showing differing metals levels in facility effluent); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 174-81 (EAB 2000) (remanding for failure to address commenter's alternative calculation of potential to emit lead); *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 555-58 (EAB 1999); *In re Tallmadge Generating Station*, PSD Appeal No. 02-12, at 8-12, 22-28 (EAB May 21, 2003) (Order Denying Review in Part and Remanding in Part).



In the present case, many of the facts and analyses underlying MDEQ's various conclusions about the PSD increment calculus are missing from the permit record, including the response-to-comments document. Their absence, particularly in the face of Sierra Club's significant comments, is clear error. Accordingly, we remand this issue to MDEQ for reevaluation and clarification. We expect that, on remand, the Department will analyze with as much precision as reasonably possible the consumption/expansion of PSD increments and explain its analysis in a clear and meaningful fashion, including references to relevant statutory and regulatory provisions and Agency guidance where appropriate.

## 2. *Modeling of Source Impacts Using "Maximum" or "Worst-Case" Emissions*

Next, Sierra Club argues that the source impact analysis conducted for the proposed CFB boiler fails to reflect "maximum" or "worst-case" emissions and, as such, is "contrary to law and established EPA policy." Pet'n at 42. As support for this position, Sierra Club cites the NSR Manual, which provides the following guidance in a section on "Source Data" inputs to the air quality analysis:

A source's ***emissions rate*** as used in a[n air quality] modeling analysis for any pollutant is determined from the following source parameters (where MMBtu means "million Btu's heat input"):

- ***emissions limit***(e.g., lb/MMBtu);
- ***operating level***(e.g., MMBtu/hour); and
- ***operating factor***(e.g., hours/day, hours/year).

\* \* \*

For both NAAQS and PSD increment compliance demonstrations, the ***emissions rate*** for the proposed new source or modification must reflect the maximum allowable operating conditions as expressed by the federally enforceable ***emissions limit***, ***operating level***, and ***operating factor*** for each applicable pollutant and averaging time. The applicant should base the emissions rates on the results of the BACT analysis \* \* \* .

NSR Manual at C.44-45 (quoted in Pet'n at 43). Sierra Club also cites an Agency rule revising the *Guideline on Air Quality Models*, which states the following with respect to "Source Data" inputs to air models: "For point source applications[,] the load or operating condition that causes maximum ground-level concentrations [of

air contaminants] should be established. As a minimum, the source should be modeled using the design capacity (100 percent load)."<sup>38</sup> 70 Fed. Reg. 68,218, 68,240 (Nov. 9, 2005) (codified at 40 C.F.R. pt. 51 app. W § 8.1.2.a) (quoted in part in Pet'n at 43).

The parties do not dispute that worst-case emissions should be employed in the modeling analyses conducted to demonstrate a facility's compliance with the NAAQS and PSD increments. See Pet'n at 42-45; MDEQ Resp. at 20-22; Reply to MDEQ at 22-24; NMU Resp. at 26; Reply to NMU at 30-33. They differ, however, on whether the emissions rates used in the air models in this particular case actually represented the proposed CFB boiler's maximum worst-case emissions rates or some lesser, non-worst-case rates.

Sierra Club takes the position that the modeling performed for the CFB boiler did not incorporate worst-case emissions because MDEQ used the BACT emissions limits set forth in NMU's permit, multiplied by the maximum heat input, to model the boiler's maximum emissions. Pet'n at 43-44. The permitted emissions limits, however, have relatively long averaging periods – twelve months, thirty days, and twenty-four hours for SO<sub>2</sub>, and twelve months or an unspecified "Test Protocol" interval<sup>39</sup> for PM, PM<sub>10</sub>/PM<sub>2.5</sub>, CO, and NO<sub>x</sub> – whereas the relevant NAAQS and PSD increments have averaging periods as short as one hour (for CO), three hours (for SO<sub>2</sub>), or eight hours (also for CO), in addition to longer twenty-four hour or annual averaging periods (for SO<sub>2</sub>, PM<sub>10</sub>, and NO<sub>2</sub>). Compare Permit spec. cond. 1.1a-1j, at 6 (BACT emissions limits for PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, and CO) with 40 C.F.R. §§ 50.4-.8, .11 (NAAQS for SO<sub>2</sub>, PM<sub>10</sub>, PM<sub>2.5</sub>, CO, and NO<sub>2</sub>) and 40 C.F.R. § 52.21(c) (increments for PM<sub>10</sub>, SO<sub>2</sub>, and NO<sub>2</sub>). Thus, in Sierra Club's view, the Department's approach does not align with, or satisfy, the appropriate modeling benchmark.

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<sup>38</sup> EPA originally published its *Guideline on Air Quality Models* in April 1978 and incorporated it by reference into the PSD regulations in June 1978. Revision to the Guideline on Air Quality Models, 70 Fed. Reg. 68,218, 68,218 (Nov. 9, 2005); see 40 C.F.R. § 52.21(l)(1) (specifying that all estimates of ambient concentrations must be based on applicable air quality models, data bases, and other requirements set forth in the Agency's *Guideline*, which is codified in 40 C.F.R. pt. 51 app. W); see also *In re Prairie State Generating Co.*, 13 E.A.D. 1, 132 (EAB 2006) (noting that although the *Guideline on Air Quality Models* has been promulgated as codified regulatory text in Appendix W, it "provides permit issuers broad latitude and considerable flexibility in application of air quality modeling"), *aff'd sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

<sup>39</sup> The PSD permit specifies that "[s]tack testing procedures and the location of stack testing ports shall be in accordance with the applicable federal Reference Methods." Permit spec. cond. 1.9, at 8. NMU relies on that permit condition, in conjunction with EPA's standard test methods, to argue that the length of the test protocol intervals are not, in fact, unspecified. For instance, NMU claims that the sampling time for PM emissions must be at least 120 minutes. NMU Resp. at 26 (citing 40 C.F.R. § 60.50Da(b)(2)(i)). Neither NMU nor MDEQ, however, provide any other specific information on the federally required length of the averaging periods for PM, PM<sub>10</sub>/PM<sub>2.5</sub>, CO, or NO<sub>x</sub>.

Sierra Club argues that modeled emissions limits can only represent “worst-case” emissions when they incorporate averaging times that are equal to or shorter than those of the compliance standards against which they are being measured (here, the NAAQS and PSD increments). Pet’n at 43-45; Reply to MDEQ at 23-24; Reply to NMU at 30-33; OA Tr. at 36-38. Sierra Club contends that longer averaging periods can mask shorter-term emissions spikes (e.g., an emissions limit averaged over a twelve or twenty-four hour period can be met even if emissions are extremely high for an hour or two, as long as emissions are sufficiently low for the remainder of the twelve or twenty-four hours in the averaging period). See Reply to MDEQ at 23; Reply to NMU at 30-33. It is the shorter-term spikes, however, that constitute the facility’s “maximum” or “worst-case” emissions, claims Sierra Club, and it is those shorter-term spikes that Sierra Club argues are not captured and appropriately modeled in the source impact analyses conducted for NMU’s proposed boiler. See Pet’n at 43-44; Reply to MDEQ at 23-24.

Sierra Club submitted comments along these lines during the public review period for NMU’s draft PSD permit and also included a suggestion that the maximum hourly heat input rate be incorporated into the permit as an enforceable limit. See SC Cmts. at 36-39. MDEQ’s total response to the group’s comments consisted of the following two sentences: “The maximum hourly heat input rate and the hourly emissions are limited by the size of the equipment. A permit limit is not required.” RTC Doc. at 15. In so responding, the Department chose not to directly engage Sierra Club’s contention that averaging periods exceeding an hour in length cannot provide a basis for calculating maximum emissions.

MDEQ takes a different tack now, in response to Sierra Club’s petition. The Department flatly contradicts the group’s assertion that the air quality analysis used NMU’s permitted emissions limits to model the boiler’s SO<sub>2</sub> impacts. MDEQ Resp. at 21. Instead, the Department states that the modeling incorporated the “maximum, worst-case, *hourly* emission rate of SO<sub>2</sub> emissions,” as documented in NMU’s permit application and the MDEQ Air Dispersion Analysis Summary. *Id.* (emphasis added). Those documents list the maximum hourly emission rate for SO<sub>2</sub> as 8.78E+01 pounds per hour (or 87.8 pounds per hour), which equates to a modeled emission rate of 11.06 grams per second.<sup>40</sup> Permit Appl. § 6.3 tbl. 6-4, at 64; Air Analysis Summary at 1-2. NMU’s permit application explains:

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<sup>40</sup> To convert an emissions rate measured in pounds per hour to the equivalent rate measured in grams per second, multiply x pounds per hour by 1 hour per 3,600 seconds by 453.59 grams per pound. Thus:

$$87.7 \text{ lb/hr} * 1 \text{ hr/3,600 sec} * 453.39 \text{ g/lb} = 11.06 \text{ g/sec}$$

Permit Appl. § 6.3, at 64.

The maximum emission rates have been determined on a worst case basis considering each type of fuel source (i.e., highest lb/hr rate from wood, coal, natural gas).

\* \* \*

\* \* \*

For each pollutant with standards that have an annual averaging period, it was conservatively assumed that the maximum hourly emission rate would occur continuously (i.e., 24 hours per day and 365 days per year).

Permit Appl. § 6.3, at 64. In its response brief, MDEQ explains further that the source impact modeling assumed continuous operation of the boiler (a conservative assumption, since the boiler is not authorized to operate continuously) along with the burning of 3.5% sulfur by weight coal (another conservative assumption, since the boiler will burn coal with no more than 1.5% sulfur by weight). MDEQ Resp. at 21-22. Taken together, these assumptions guarantee, in MDEQ's view, that the source impacts of the proposed boiler will fall well under the NAAQS and PSD increments. *Id.* at 22.

As a threshold matter, questions pertaining to the appropriate pollutant emissions rates and other inputs to air quality models raise scientific and technical concerns that generally are best left to the specialized expertise and reasoned judgment of the permitting authority. Indeed, the Board has a well-established body of case law articulating deference in such circumstances, absent some strong evidentiary showing or argument by the petitioner that the permit issuer clearly erred in its technical analysis. *E.g.*, *In re Carlota Copper Co.*, 11 E.A.D. 692, 720 (EAB 2004) (Board "traditionally defer[s] to the technical expertise of the permit issuer in the absence of compelling or persuasive evidence or argument to the contrary"), *appeal docketed*, No. 07-1524 (S. Ct. June 6, 2008); *In re Phelps Dodge Corp.*, 10 E.A.D. 460, 517-19 (EAB 2002) (same); *In re Town of Ashland Wastewater Treatment Facility*, 9 E.A.D. 661, 667 (EAB 2001) (Board assigns "heavy burden" to petitioners seeking review of technical issues; "clear error or a reviewable exercise of discretion is not established simply because the petitioner presents a difference of opinion or alternative theory regarding a technical matter"); *In re Envotech, LP*, 6 E.A.D. 260, 284 (EAB 1996) (in general, Board will defer to permit issuer in technical areas "absent compelling circumstances"). In the circumstances of this case, however, the sparseness of MDEQ's response to Sierra Club's detailed comments on this issue, along with the thinness of the permitting record and the shifting explanations by the Department, do not provide the necessary foundation for us to extend such deference.

Here, Sierra Club raised serious and substantial concerns touching on whether the modeled emissions (not just SO<sub>2</sub> emissions, but also PM<sub>10</sub>, NO<sub>x</sub>, and

CO emissions, which MDEQ failed altogether to address in its response to comments or this appeal) are truly “worst-case” emissions, as all parties agree they must be for the modeling to be valid. Neither the Department’s response to comments, nor the permitting documents the Department references in its response to the petition, provide a straightforward answer to Sierra Club’s concerns in this regard. For example, none of the record materials directly address the notion that long averaging periods may provide unsuitable bases for analyzing worst-case emissions impacts that occur over shorter time periods, particularly in the face of a host of NAAQS and increment compliance standards expressly setting short-duration averaging periods.

Moreover, MDEQ points out now (though it did not do so in its response to comments) that the record materials identify 87.8 pounds per hour as the proposed boiler’s maximum hourly SO<sub>2</sub> emissions rate. MDEQ Resp. at 21 n.74 (citing Air Analysis Summary at 2; Permit Appl. § 6.3 tbl. 6-4, at 64). The provenance of this figure is not immediately clear.<sup>41</sup> At oral argument, MDEQ stated that some of these assumptions indeed played a role in the derivation of the worst-case emissions rates, explaining specifically that the 92% control efficiency condition is drawn from the New Source Performance Standards (“NSPS”) applicable to NMU’s facility. OA Tr. at 87; *see* Permit Appl. tbl. 4-1 n.1, at 24 (“SO<sub>2</sub> emission rates are based on 3.5 percent (average max.) sulfur coal and 92 percent reduction requirement per NSPS. The limits are also based on a 30-day rolling average.”).<sup>42</sup> For its part, Sierra Club takes issue with the 92% reduction assumption and contends that a true “worst-case” emissions rate is an uncontrolled rate, which, by its calculations, would be 512.5 pounds of SO<sub>2</sub> per hour. Reply to MDEQ at 24 & n.12; Reply to NMU at 32 & n.18; OA Tr. at 113.

In our view, the record for this permit lacks a coherent, persuasive explanation of MDEQ’s decision to rely on particular emissions rates for each of the relevant pollutants (i.e., not just SO<sub>2</sub> but also PM<sub>10</sub>, NO<sub>x</sub>, and CO<sup>43</sup>) as “worst-case”

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<sup>41</sup> One can perhaps piece together from various sections of the permit application some of the operating conditions that seem to have been assumed in the derivation of this purported “worst-case” figure. These conditions include the burning of coal with a maximum sulfur content of 3.5% and the use of pollutant control equipment that would achieve 92% reduction of SO<sub>2</sub> emissions, with boiler emissions being averaged over a thirty-day rolling time period. *See* Permit Appl. §§ 4.1 tbl. 4-1 & n.1, 5.3.1, 6.3, at 24, 42, 64 (information gleaned from emissions estimates section, control technology review section, and ambient impact analysis section of application).

<sup>42</sup> At oral argument, MDEQ also denied that the 87.8 pounds/hour figure reflected in any way a thirty-day rolling average, insisting instead that it represents the proposed boiler’s maximum *hourly* emissions. OA Tr. at 88-89. We are unable to determine the truth of the matter from any of the materials in this record.

<sup>43</sup> As noted in our air quality introduction in Part II.B above, the proposed CFB boiler is considered a “major modification” that will result in a significant net increase in emissions of these four  
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values suitable for use in the source impact modeling analysis. Instead, the record contains significant comments from Sierra Club questioning these matters and a dismissive, erratic, and inadequate response to those comments from the Department. *See* SC Cmts. at 36-39; RTC Doc. at 15. The Department's late-proffered explanations in briefs and argument before this Board fail to adequately clarify matters and, in any event, are incapable of repairing the record deficiencies. *See, e.g., In re Wash. Aqueduct Water Supply Sys.*, 11 E.A.D. 565, 589 (EAB 2004) (a permit issuer "cannot through its arguments on appeal augment the record upon which the permit decision was based"). Accordingly, we have no sound basis upon which to defer to the Department's technical judgment on this foundational aspect of the air quality analysis. As noted in Part II.B.1 above, a permitting authority has a responsibility to explain its decisionmaking processes in ways that are meaningful, clear, and thorough enough to adequately address the issues raised by commenters. MDEQ failed to achieve this standard with respect to the question of worst-case emissions in the air models for NMU's boilers. We remand these issues to the Department for reevaluation and clarification as necessary.

### 3. *Preconstruction Monitoring*

We turn next to the issue of preconstruction monitoring. The CAA and implementing regulations establish a program for PSD permit applicant collection and submission of twelve months of ambient air quality monitoring data, for the year *preceding* the date of permit application, showing pollutant concentrations at the site of the proposed facility and in areas that may be affected by emissions from that facility. CAA § 165(a)(7), (e), 42 U.S.C. § 7475(a)(7), (e); 40 C.F.R. § 52.21(m). These data may then be used, in conjunction with other information, to demonstrate the facility's compliance with the NAAQS and PSD increments. *See* NSR Manual at C.16-.21.

A permitting authority has discretion to exempt a facility from the preconstruction monitoring requirements if either of the following two conditions is present: (1) the facility's modeled emissions predict air quality impacts that are lower than certain pollutant levels known as "significant monitoring concentrations" ("SMCs") or "monitoring *de minimis* levels"; or (2) the existing pollutant concentrations in the areas potentially affected by the facility are less than the SMCs.<sup>44</sup>

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pollutants. Consequently, the CAA's ambient air quality requirements apply with respect to each of these pollutants.

<sup>44</sup> As designed by EPA, the SMCs are a different animal, as it were, and enter the picture at a different point, than the "significant impact levels" or "SILs" mentioned above in the introduction to the air quality analysis discussion. *See supra* Part II.B; *see also* 40 C.F.R. § 52.21(i)(5)(i)-(ii) (SMCs); NSR Manual tbls. C-3 & C-4, at C.17, .28 (SMCs; SILs for Class II areas). SMCs are used for the specific purpose of evaluating whether a proposed facility should be required to conduct preconstruction

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40 C.F.R. § 52.21(i)(5)(i)-(ii); see *In re EcoEléctrica, LP*, 7 E.A.D. 56, 61-65 (EAB 1997); Office of Air Quality Planning & Standards, U.S. EPA, EPA-450/4-87-007, *Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD)* § 2.1.1, at 4 (May 1987) [hereinafter *Ambient Monitoring Guidelines*]; NSR Manual at C.16-.17 & tbl. C-3. As a general matter, the results of the preliminary air quality analysis (also discussed in Part II.B above) are used to determine whether an applicant may be exempted from preconstruction monitoring. *In re Prairie State Generating Co.*, 13 E.A.D. 1, 92 n.100 (EAB 2006), *aff'd sub nom. Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007); NSR Manual at C.18, .24.

In the instant case, the preliminary air quality analysis indicated that combined emissions from NMU's Ripley Heating Plant, including the existing boilers and the proposed CFB boiler, would result in ambient concentrations of CO, PM<sub>10</sub>, and NO<sub>x</sub> that are each less than their respective SMCs.<sup>45</sup> See Permit Appl. §§ 6.5.1, 6.5.4-.5, at 70-71, 74-76. The preliminary analysis also indicated that the proposed boiler alone, as well as in combination with the existing boilers, would generate SO<sub>2</sub> impacts greater than the SMC for that pollutant.<sup>46</sup> See *id.* § 6.5.2 & tbl. 6-10, at 71-72; MDEQ Resp. Ex. 9, at 2. Assuming these figures accurately portray the facts, it would appear that NMU had a legal obligation to conduct preconstruction monitoring for SO<sub>2</sub> but not for CO, PM<sub>10</sub>, or NO<sub>x</sub>.

In comments on the draft permit, Sierra Club submitted detailed observations about the preconstruction monitoring requirements and pointed out that the permitting record for NMU's proposed boiler lacked any explicit mention of, or demonstration of compliance with, those requirements. See SC Cmts. at 39-44. Sierra Club consequently argued that the air quality determination was "deficient" and that MDEQ therefore could not properly issue the permit to NMU. *Id.* at 42.

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(continued)

tion ambient monitoring, whereas SILs are consulted by permitting authorities at an earlier stage to determine whether a proposed facility should be required to perform a full impact analysis or just a preliminary impact analysis. See NSR Manual fig. C-3, at C.27 (flow chart showing that determination of whether modeled impacts exceed SILs precedes use of SMCs to determine need for preconstruction monitoring); see also *In re EcoEléctrica, LP*, 7 E.A.D. 56, 62-66 & nn.5, 10-11 (EAB 1997); 73 Fed. Reg. 28,321, 28,324 (May 16, 2008).

<sup>45</sup> Notably, the record materials do not explicitly mention the SMCs for these pollutants or where NMU's projected emissions fall with respect to the SMCs. Instead, they focus on the SILs and report that projected emissions are less than the relevant SILs. Upon further inquiry, we find that the SMCs for CO, PM<sub>10</sub>, and NO<sub>x</sub> are greater in magnitude than their comparable SILs, so emissions of these pollutants at levels below the SILs would necessarily also fall below the SMCs. Compare 40 C.F.R. § 52.21(i)(5)(i)-(ii) (SMCs) with NSR Manual tbl. C-4, at C.28 (SILs).

<sup>46</sup> Again, the record materials do not mention the SMC for SO<sub>2</sub> or where NMU's projected emissions fall with respect to that SMC. Upon investigation, we find that the SMC for SO<sub>2</sub> averaged over 24 hours is greater than the comparable SIL for that pollutant (13 g/m<sup>3</sup> versus 5 g/m<sup>3</sup>), but NMU's projected 24-hour-average emissions of SO<sub>2</sub> (61 g/m<sup>3</sup>) exceed both the SMC and the SIL.



MDEQ's full response to the Club's detailed comments stated that its own "experience with monitoring in the Upper Peninsula shows consistent background levels across a large geographical area including the location of this facility. Therefore, [the Department] did not require pre-construction monitoring. No written waiver was requested by the permit applicant, and none was issued by [MDEQ]." RTC Doc. at 15.

On appeal, Sierra Club essentially repeats its comments on the draft permit, choosing to continue to press its points in light of the Department's failure, in its view, to adequately respond to them. Accordingly, Sierra Club urges the Board to remand NMU's permit on several grounds. First, Sierra Club argues that the "plain language" of the CAA and implementing regulations directs PSD permit applicants to install a series of continuous ambient air quality monitors around the areas of their proposed facilities and gather twelve months of data therefrom for the sole purpose of determining whether the facilities will violate the NAAQS or PSD increments. Pet'n at 45-48; Reply to MDEQ at 25-26. In this line of argument, data gathered for other purposes (such as state air quality planning) or from monitors that are not in areas affected by the proposed facility (i.e., that are not "site-specific") would be unsuitable for use in fulfilling the preconstruction monitoring requirement. Pet'n at 46-48.

Second, Sierra Club acknowledges the existence of long-standing Agency guidance that suggests, contrary to Sierra Club's plain language argument, that the requirement to collect site-specific monitoring data can be waived in certain circumstances. Pet'n at 48-50; Reply to MDEQ at 26-28; OA Tr. at 16-21. Such waiver can occur in cases where existing ambient data are deemed sufficiently representative of air quality in the targeted area – in terms of the sufficiency of the monitoring locales selected and the quality and currentness of the monitoring data – to legitimately be substituted for site-specific data. *See* NSR Manual at C.18-.19; *Ambient Monitoring Guidelines* § 2.4, at 6-9; *see also, e.g., In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 145-48 (EAB 1999); *In re Haw. Elec. Light Co.*, 8 E.A.D. 66, 97-105 (EAB 1998); *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 850-51 (Adm'r 1989). Sierra Club refuses to concede that permit issuers have legal authority to issue such waivers, Pet'n at 49 n.7, but, in the event this argument does not prevail, Sierra Club contends in the alternative that MDEQ failed to fulfill the requirements of this Agency policy. According to Sierra Club, the Department erroneously failed to include any explicit findings in the permitting record on the validity, sufficiency, or representativeness of any substitute data that might have been used to justify NMU's *de facto* preconstruction monitoring waiver. *Id.* at 48-50; Reply to MDEQ at 26-28.

Third, Sierra Club argues that even if MDEQ had attempted to demonstrate fulfillment of the conditions of EPA's waiver policy in this case, the Department would have been constrained to conclude that the substitute data were, in fact, not representative. Pet'n at 50-54. Sierra Club begins with the issue of monitor loca-



tion, noting that the record contains no evidence of monitors used other than an oblique reference to “background concentrations” collected at Escanaba, Michigan (SO<sub>2</sub>); Two Rivers, Wisconsin (NO<sub>x</sub>); Green Bay, Wisconsin (PM<sub>10</sub>); and Milwaukee, Wisconsin (CO and lead). *Id.* at 51 (citing Permit Appl. app. C); Reply to MDEQ at 27-28. Sierra Club points out that Agency policy allows data from off-site monitors to be used if those data represent the locations of: (a) maximum concentration increase from the proposed facility; (b) maximum air pollutant concentration from existing sources; and (c) maximum combined impact area (existing sources plus proposed facility). Pet’n at 51 (citing *Ambient Monitoring Guidelines* § 2.4.1, at 6-8; *Hibbing Taconite*, 2 E.A.D. at 850-51). The record contains no evidence, claims Sierra Club, that these particular monitors, or any others for that matter, satisfy any of these requirements.<sup>47</sup> Pet’n at 51; *see* OA Tr. at 18-21, 114-15. Sierra Club similarly asserts that the record contains no evidence demonstrating fulfillment of Agency guidelines on the requisite *quality* (in terms of monitor calibration, data recovery, and other standards) or *currentness* (in terms of most recent three years) of the data collected from these or any other off-site monitors. Pet’n at 53-54.

In response, MDEQ dismisses all of Sierra Club’s arguments as baseless. First, the Department claims that nothing in the CAA requires that preconstruction monitoring data be collected by a permit applicant for the sole purpose of analyzing its proposed facility’s source impacts, as Sierra Club contends. MDEQ Resp. at 22. Where existing representative data collected by others exist, any requirement imposed on an applicant to collect additional monitoring data would, in MDEQ’s view, “needlessly” and “wasteful[ly]” require the applicant to “expend resources.” *See id.* at 23. The Department then asserts that existing data collected by others does exist in this case, from the years 2003 through 2005, and it sanctioned their use as sufficiently representative for NMU’s situation. *Id.* at 23-25; OA Tr. at 91-99.

MDEQ explains that on August 21, 2006, it sent a table of background pollutant concentrations to NMU for use in the source impact analysis. *Id.* at 23-24 (citing Permit Appl. at 69 & app. C). The table lists three monitoring samples from the years 2003 through 2005 for each of five pollutants and selects the highest sample value for each pollutant as the appropriate “background concentration” for NMU’s analysis. *See* Permit Appl. tbl. 6-8, at 69, & app. C. For example,

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<sup>47</sup> Sierra Club also observes that NMU’s boiler will be situated in a “multisource impact area,” meaning its impacts will be added to those of two already existing coal-fired plants (Marquette and Presque Isle) and two mining companies (Empire Iron and Tilden Mining). Pet’n at 51-52. EPA’s *Ambient Monitoring Guidelines*, claims Sierra Club, discourage substitution of off-site monitoring data in such circumstances, but MDEQ failed to acknowledge or abide by this policy. *Id.* The Department also purportedly ignored certain other Agency guidelines regarding monitor selection in areas that have multiple air pollution sources and flat terrain. *Id.* at 52 (citing *Ambient Monitoring Guidelines* § 2.4.1, at 6-8).

MDEQ chose readings collected in 2003-2004 from an SO<sub>2</sub> monitor in Escanaba, Michigan, 65.3 kilometers distant from NMU's campus, along with a reading collected in 2005 from an SO<sub>2</sub> monitor in Michigan's Seney National Wildlife Refuge, 158.5 kilometers distant, to represent the background SO<sub>2</sub> concentration in the ambient air around the proposed boiler in Marquette. *Id.* As the Department observes, it "determined that regional monitoring data from monitors located in Michigan and Wisconsin [were] appropriate for NMU's air quality analysis because [those data were] either representative of air quality near NMU or even more conservative because [they] reflected higher concentrations of criteria pollutants in the ambient air than those present in Marquette." MDEQ Resp. at 24; *accord* OA Tr. at 91-99.

MDEQ did not release this kind of information in its response to comments. There, the Department simply remarked on the existence of "consistent background levels" of pollutants across the Upper Peninsula, including the areas around NMU's campus. RTC Doc. at 15. In so doing, the Department may have intended to indicate that it had decided to grant NMU an *exemption* from the preconstruction monitoring requirement, pursuant to 40 C.F.R. § 52.21(i)(5)(ii), because the background pollutant concentrations were less than their respective SMCs. This interpretation of events is somewhat appealing in that it lends some consistency to MDEQ's other ambiguous statement that NMU did not request a written waiver from preconstruction monitoring and MDEQ did not issue one – instead, perhaps, the Department, *sua sponte*, simply granted an exemption and made a waiver unnecessary. *See* RTC Doc. at 15.

The situation is muddled, however. MDEQ's response on appeal seems to indicate that preconstruction monitoring was, in fact, conducted after all, for all pollutants, pursuant to a *de facto* waiver allowing the use of existing ambient data from air monitors in Escanaba, Two Rivers, Green Bay, Milwaukee, and elsewhere. *See* MDEQ Resp. at 23-25. Matters are further confused by NMU's contentions that its emissions will result in concentrations less than the SMCs for all pollutants except SO<sub>2</sub>, and thus MDEQ required preconstruction monitoring only for that pollutant, which the Department appropriately conducted using representative off-site data. *See* NMU Resp. at 27 (citing Permit Appl. at 69). Put another way, and attempting to harmonize a discordant presentation, NMU may be claiming that MDEQ granted it a preconstruction monitoring *exemption* for PM<sub>10</sub>, CO, and NO<sub>x</sub> emissions and a *waiver* for site-specific SO<sub>2</sub> emissions.

At the outset, we reject Sierra Club's contention that the plain language of the CAA and implementing regulations mandate the use of site-specific, sole-purpose preconstruction ambient air quality data. *See* Pet'n at 46-48 (quoting CAA § 165(a)(7), (e)(1)-(2), 42 U.S.C. § 7475(a)(7), (e)(1)-(2); 40 C.F.R. § 52.21(m)(1)(i), (iii)-(iv)); Reply to MDEQ at 25-26. In so arguing, Sierra Club overlooks statements of congressional intent to the contrary. H.R. Rep. No. 95-294, at 171 (1977) ("preconstruction, onsite air quality monitoring may be

for less than a year if the basic necessary information can be provided in less time, or it may be waived entirely if the necessary data [are] already available"); H.R. Rep. No. 95-564, at 152 (1977) (Conf. Rep.) (one-year monitoring requirement "may be waived by the [s]tate"). EPA has long implemented the PSD program pursuant to the understanding that representative data may be substituted where circumstances warrant, *see, e.g.*, NSR Manual at C.18-19; *Ambient Monitoring Guidelines* § 2.4, at 6-9, and the Board and its predecessors have long upheld the Agency's guidance to that effect. *E.g.*, *Knauf*, 8 E.A.D. at 145-48; *Haw. Elec.*, 8 E.A.D. at 97-105; *Hibbing*, 2 E.A.D. at 850-52. Sierra Club has failed to persuade us to deviate from these precedents here.

That being said, preconstruction monitoring is yet another element of the PSD permitting program that MDEQ failed to treat with due care in these proceedings. Sierra Club submitted detailed, significant comments on this topic during the public review period, *see* SC Cmts. at 39-44, but the Department abruptly dismissed them in its response-to-comments document with the vague three-sentence answer quoted above. *See* RTC Doc. at 15. This state of affairs does not comport with 40 C.F.R. § 124.17(a)(2) and concomitant well-settled Board case law, which place upon permit issuers an obligation to provide meaningful responses to significant comments that articulate with reasonable clarity the facts and circumstances supporting the permit issuers' decisions. *E.g.*, *In re Amerada Hess Corp.*, 12 E.A.D. 1, 14-20 (EAB 2005); *In re Wash. Aqueduct Water Supply Sys.*, 11 E.A.D. 565, 586-90 (EAB 2004); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 174-81 (EAB 2000); *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 555-58 (EAB 1999); *In re Ash Grove Cement Co.*, 7 E.A.D. 387, 417-18 (EAB 1997); *In re Austin Powder Co.*, 6 E.A.D. 713, 720 (EAB 1997); *In re Tallmadge Generating Station*, PSD Appeal No. 02-12, at 8-12, 22-28 (EAB May 21, 2003) (Order Denying Review in Part and Remanding in Part). The Department further clouds matters, rather than clarifies them, in its brief. Accordingly, remand is warranted on this ground. On remand, the Department must reevaluate the issue of preconstruction monitoring for NMU's proposed boiler and explain the ways in which its ultimate decisions on the topic comply with the applicable provisions of the statute and regulations and reflect Agency guidance on data representativeness and related matters.

#### 4. Class I Increment Analysis

Finally, Sierra Club challenges MDEQ's analysis of the proposed boiler's effects on PSD increment in several Class I areas. In brief, Sierra Club argues that the Department unlawfully used SILs and arbitrary distances to excuse NMU from preparing increment consumption analyses that otherwise would be mandated by the CAA and its implementing regulations. Pet'n at 54-58; Reply to MDEQ at 29-30.

Under the CAA and its implementing regulations, permit issuers are obliged to notify federal managers of any lands within Class I areas that “may be affected” by emissions from a proposed major emitting facility. CAA § 165(d)(2)(A), 42 U.S.C. § 7475(d)(2)(A); 40 C.F.R. § 52.21(p); *see* 40 C.F.R. § 124.42(a). EPA has interpreted the “may affect” clause as including all facilities proposing to locate within 100 kilometers (“km”) – or about 62 miles – of a Class I area, as well as certain large facilities proposing to locate more than 100 km from Class I areas. *See* NSR Manual at E.16. Moreover, as discussed above, permit applicants are legally obligated to demonstrate that their proposed facilities will not cause or contribute to air pollution in violation of any PSD increment, including the Class I increments. CAA § 165(a)(3)(A), 42 U.S.C. § 7475(a)(3)(A); 40 C.F.R. § 52.21(k)(2). This latter requirement applies irrespective of distance.

Of course, as implemented, the PSD program does not mandate that each permitting record contain an increment consumption analysis for every Class I area in the country, regardless of distance from the proposed major emitting facility. As the EPA Administrator stated in a prior case:

EPA has implicitly countenanced the view that, as a practical matter, pollution sources may be too distant from a specific area to have anything except an imperceptible or insignificant effect on the area in question. In other words, the mere possibility of pollution molecules being transported from a source to a [C]lass I area is not, by itself, sufficient reason to trigger the demonstration requirements of the [CAA].

*In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 781 (Adm’r 1992). Thus, where reasonable, EPA has historically attempted to streamline the PSD permitting process by promulgating specific thresholds, such as SILs, beneath which impacts are deemed to be insignificant and certain complex analyses not necessary.

To date, EPA has promulgated SILs only for Class II areas, which cover most of the country. *See* NSR Manual tbl. C-4, at C.28. For Class I areas, in lieu of actual SILs, but serving roughly the same function, the Agency has chosen instead to recommend that a full source impact analysis be conducted for any proposed facility that will increase pollutant concentrations in a Class I area by 1 g/m<sup>3</sup> (24-hour average) or more. *Id.* at E.16-17; *see In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 155-56 (EAB 1999). Importantly, however, EPA does not stop with this threshold. The Agency goes on to acknowledge that certain attributes of Class I areas may be sensitive to pollutant increases that are less than 1 g/m<sup>3</sup>. NSR Manual at E.17; *see id.* at E.10-12 (discussing special attributes of Class I areas). The Agency consequently suggests that permit issuers consult with federal land managers to decide what specific level of impact analysis is necessary in a given case. *Id.* at E.17-18.

In the case before us, the Class I areas nearest NMU's Ripley Heating Plant are the Seney National Wildlife Refuge in Seney, Michigan, approximately 55 miles (89 km) away;<sup>48</sup> Isle Royale National Park on Isle Royale in Lake Superior, an unspecified distance away (although farther than Seney); and the Forest County Potawatomi Community Reservation near Crandon, Wisconsin, at least 100 miles (160 km) away. *See* RTC Doc. at 13; *see also* MDEQ Resp. Ex. 10; 73 Fed. Reg. 23,086 (Apr. 29, 2008) (final Class I designation notice for Forest County).

The permitting record indicates that in May 2007 and/or April 2008, MDEQ contacted federal representatives regarding potential CFB boiler emissions impacts to Isle Royale National Park and Seney National Wildlife Refuge.<sup>49</sup> *See* RTC Doc. at 13; Air Analysis Summary at 1-2; MDEQ Resp. Ex. 10 (E-mails from/to Steve Kish, MDEQ, to/from Jill Webster, U.S. Fish & Wildlife Service (Apr. 10, 2008)). The record indicates further that these representatives reported that they did not expect any adverse impacts to visibility or air quality related values on the basis of the NMU boiler information sent them by MDEQ. RTC Doc. at 13; MDEQ Resp. Ex. 10. Moreover, MDEQ explains that the air quality modeling conducted for NMU's boiler revealed a maximum increase of 0.42 g/m<sup>3</sup> in the 24-hour average SO<sub>2</sub> concentration at Seney National Wildlife Refuge, the closest Class I area to Marquette. RTC Doc. at 13. This figure, at less than half the informal significance level recommended by EPA, appears to have provided the Department with its rationale for excusing NMU from conducting increment analyses for the Isle Royale, Seney, and Forest County Class I areas.<sup>50</sup> *See id.*

On appeal, Sierra Club argues that the 1 g/m<sup>3</sup> Class I threshold lacks a legal basis and thus MDEQ erred in relying on it. Pet'n at 55. To the extent this is an argument that 1 g/m<sup>3</sup> is not a regulatory requirement, we agree. *Knauf*, 8 E.A.D. at 156 n.49. However, this figure is a long-established EPA guideline. NSR Manual at E.16-.17. Importantly, the NSR Manual stresses the need for permit issuers to consult with federal land managers about air quality issues, and MDEQ appears to have adequately fulfilled that responsibility here, as documented in the response to comments and elsewhere in the record. Sierra Club has failed to show

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<sup>48</sup> The record actually contains several estimates of the distance between NMU's facility and Seney National Wildlife Refuge. *See* RTC. Doc. at 13 (refuge is approximately 55 miles (or about 89 km) to east-southeast of NMU facility); MDEQ Resp. Ex. 10 (northwest corner of refuge is approximately 93.5 km from NMU); Permit Appl. § 3.1, at 14 & app. C (refuge is about 60 miles away; SO<sub>2</sub> monitor in refuge is 158.5 km away).

<sup>49</sup> These representatives may or may not have been the federal land managers for the affected areas; the record does not make these points clear. Sierra Club, however, does not take issue with the identity of these parties, and thus we do not address the matter further.

<sup>50</sup> Sierra Club's contention that MDEQ employed an arbitrary distance threshold of 100 miles to excuse NMU from analyzing impacts to the Forest County Reservation is speculative.

clear error in the Department's handling of these issues or other grounds for a grant of review on this basis. *See* 40 C.F.R. § 124.19(a).

### III. CONCLUSION

For the foregoing reasons, we remand five components of NMU's PSD permit decision, as summarized below, for further proceedings consistent with this opinion.

First, we remand the permit for MDEQ to reconsider the BACT limitations chosen for SO<sub>2</sub> emissions from the proposed CFB boiler. On remand, MDEQ will be expected to ensure that a rational, defensible BACT determination is made for this pollutant, involving consideration of all requisite statutory and regulatory criteria and giving attention as appropriate to the clean fuels issue. MDEQ will also be expected to clearly document all facets of its BACT-related decisions in the administrative record. In particular, any contention that particular fuel choices or related factors would improperly "redefine the source" must be thoroughly explained and supported with references to suitable legal authority. *See supra* Part II.A.3.

Second, we remand the permit for MDEQ to analyze whether CO<sub>2</sub> and N<sub>2</sub>O emissions from the CFB boiler should be limited pursuant to BACT. MDEQ should be guided in these efforts by our recent decision in *In re Deseret Power Electric Cooperative*, 14 E.A.D. 212 (EAB 2008). Included in its evaluation should be MDEQ's assessment whether approval by EPA of CO<sub>2</sub>- and N<sub>2</sub>O-related provisions in certain existing SIPs constitutes regulation of those pollutants under the Act. MDEQ will be expected to clearly document its decisions in the administrative record. *See supra* Part II.A.4.b.

Third, we remand the permit for MDEQ to reevaluate and clarify its analysis of PSD increments consumed/relinquished by the CFB boiler, other boilers in the Ripley Heating Plant, and other sources in relevant affected areas. On remand, MDEQ will be expected to analyze with as much precision as reasonably possible the consumption/expansion of PSD increments and explain its analysis in the record in a clear and meaningful fashion, including references to relevant statutory and regulatory provisions and Agency guidance where appropriate. *See supra* Part II.B.1.

Fourth, we remand the permit so that MDEQ can ensure that the source impact modeling analyses for SO<sub>2</sub>, PM<sub>10</sub>, NO<sub>x</sub>, and CO are conducted on the basis of the maximum, "worst-case" emissions rates of those pollutants. MDEQ will be expected to document its decisions in this regard in a clear and meaningful fashion. *See supra* Part II.B.2.

Fifth, we remand the permit for MDEQ to reevaluate the issue of preconstruction monitoring and explain, in the record, the ways in which its ultimate decisions on this topic comply with the applicable provisions of the statute and regulations and reflect Agency guidance. *See supra* Part II.B.3.

Finally, on each of these five matters, MDEQ is directed to craft new or revised permit terms as necessary, submit any such permit terms and all other findings on remand to public review, and consider and respond to significant public comments in its documentation of the revised final permit decision. Pursuant to 40 C.F.R. § 124.19(f)(1)(iii), an appeal of the Department's decision after remand will be required to exhaust administrative remedies. Accordingly, any party who participates in the remand process and is not satisfied with MDEQ's decision on remand may file an appeal with the Board pursuant to 40 C.F.R. § 124.19. Any such appeal shall be limited to issues within the scope of the Board's remand. Review of all other issues is denied.

So ordered.

**Comments on the**  
**Draft Stationary Source Permit to Construct and Operate**  
**issued to Mountain Valley Pipeline, LLC**  
**for a**  
**Natural Gas Compressor Station (Lambert Compressor Station)**  
**located at**  
**987 Transco Road, Chatham, VA 24531 (Registration No. 21652)**  
**by**  
**Ranajit Sahu<sup>1</sup> on behalf of Appalachian Mountain Advocates**

The following significant comments are provided for the proposed draft permit:

1. Right below the table containing the equipment list (shown below), the draft permit (p. 2) states that “Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.” This is highly inappropriate. These specifications, which include the rated capacities of the various equipment are the basis for all the emissions calculations (and therefore the impact analyses, etc.) contained in the application and the permit. They are critical data that should be enforceable. Without this data, the source can make changes to equipment without an assessment of its impacts.

Also, as a practical matter, by not making this information enforceable via the permit, compliance inspections at the facility become largely meaningless. Most inspections include verification of equipment consistent with those listed in the permit. If no information about the equipment such as their rated capacities are included in the permit, the inspector simply cannot verify if the actual equipment at the site is the same as that which was permitted.

<b>Reference No.</b>	<b>Equipment Description</b>	<b>Rated Capacity</b>	<b>Delegated Federal Requirements</b>
CT-01	Solar Mars Combustion Turbine Model 100	16,610 hp*	40 CFR 60, Subpart KKKK
CT-02	Solar Taurus Combustion Turbine Model 70	11,146 hp*	40 CFR 60, Subpart KKKK
MT-01	Capstone Microturbine Model C200	200 kW	---
MT-02	Capstone Microturbine Model C200	200 kW	---
MT-03	Capstone Microturbine Model C200	200 kW	---
MT-04	Capstone Microturbine Model C200	200 kW	---
MT-05	Capstone Microturbine Model C200	200 kW	---
FUG	Fugitive natural gas leaks from fugitive emission components	---	---

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<sup>1</sup> Resume provided in Attachment A.



\*Based on ambient temperature of 0° and 100% operating load.

The majority of the comments that follow mainly reference the two Solar combustion turbines (CT-01 and CT-02), the two largest sources of air emissions from the proposed compressor station.

2. Condition 1 (and Conditions 4a/4b) state that startup and shutdown when using natural gas will include periods below 50% load. However, no technical basis is provided for this load level demarcating startup/shutdown from “normal” operation. Since emissions of NO<sub>x</sub> from the combustion turbines depends on the proper functioning of the SCR catalyst, startup/shutdown should be defined via the minimum operating temperature (MOT) of the SCR catalyst (with technical justification provided for the MOT selected, which should be as low as possible so as to minimize emissions during startup and shutdown). Since Condition 10 for the SCRs for each combustion turbine already requires the continuous measurements of gas temperatures at the inlet to the SCT catalyst, it is technically proper and more appropriate to use the MOT to define the end of startup and beginning of shutdown.

3. Condition 2 requires that carbon monoxide (CO) and volatile organic compounds (VOCs) from the combustion turbines be controlled by oxidation catalysts. The operating temperature of the oxidation catalyst is defined in Condition 4c which states that the oxidation catalyst “shall be considered in operation” when the inlet gas temperature to the catalyst is 600 F or the minimum “combustion chamber temperature” derived from the most recent performance test that demonstrates compliance with this permit. This condition is problematic for at least two reasons. It is not clear what is meant by the “combustion chamber temperature.” The only relevant temperature should be the inlet gas temperature to the oxidation catalyst, which is also the temperature required to be monitored by Condition 12. Second, the “above 600 F or minimum...derived from the most recent performance test” might result in a temperature that is substantially higher than 600 F for example, say 800 F. If that is the case, this condition allows the oxidation catalyst to not be in operation unless the temperature is 800 F in this example. That is inappropriate. As written, the condition incentivizes the test to be run at a high gas inlet temperature which would show compliance because higher temperatures should result in lower CO and VOC emissions. And, thereby establish that high temperature to be the minimum temperature below which the catalyst would be considered to be not “in operation.” The condition should be reworded to establish a minimum temperature such as 600 F which could be lowered based on a performance test but not made any higher.

~~4. The draft permit uses many non-defined terms such as:~~

- ~~(i) “good air pollution control practices” (Conditions 4, 4b);~~
- ~~(ii) “best engineering practices” (Conditions 1a, 4e), and~~
- ~~(iii) “proper operation” (Conditions 34, 46d)~~

~~None of these phrases are defined anywhere in the permit. Therefore, the permit conditions that use these phrases and terms are unenforceable and therefore meaningless. Each of these terms should be defined in such manner as to make them enforceable.~~

~~5. Multiple Conditions such as 1, 4h, 9, 40c and 40d reference “SoLoNOx.” While Condition 1 states that this is a “dry low NO<sub>x</sub> combustion control technology”, it is a proprietary technology specific to Solar Turbines.<sup>2</sup> Solar does not provide sufficient detail about how this technology works. It should be defined in the permit.~~

~~6. PM, PM<sub>10</sub> and PM<sub>2.5</sub> emissions to the atmosphere from the combustion turbines (and the micro turbines) reflect not only the PM that may enter the turbines via the inlet air but also the generation of these pollutants in the combustion process and the passage of the exhaust gases through the SCR and oxidation catalysts in the case of the combustion turbines. Therefore it is not clear why just having the filters for inlet air as required by Condition 3 would be sufficient to control the PM, PM<sub>10</sub>, and PM<sub>2.5</sub> in the exhaust of the combustion turbines. The DEQ should clarify.~~

~~7. Condition 6c states that pig launching and recovery shall be limited to two events each per 12-month period. However, the Engineering Analysis (p. 4) states that “[P]igging operations are expected to only occur once every five to seven years.” Why is the permit allowing for more frequent pigging (i.e., two events every 12 months) when the Engineering Analysis and the applicant’s permit application contemplate that this will happen far less frequently? The DEQ should explain this discrepancy.~~

~~8. Condition 6f. requires the combustion turbine not to vent gas unless the case pressure is 30 psig. What is the basis of this pressure and why could it not be lower than this value before venting is allowed?~~

~~9. Condition 7a provides a choice of using either Method 21 or optical gas imaging for the quarterly surveys of components that may be sources of fugitive emissions. Condition 34 requires the same for the VGRS. Instead, both of these conditions should require optical gas imaging, which can be used to quickly identify leakers (for Condition 7a) and any leaks of the pressurized hold (for Condition 34), supplemented by Method 21 if needed. And, it should require such surveys on a monthly basis instead of quarterly. Optical gas imaging can be conducted relatively quickly and a monthly frequency is more appropriate in order to quickly identify leaking components than would be the case if quarterly surveys are required as in the current draft permit.~~

~~10. Condition 7c requires that the monitoring plan be submitted to the Blue Ridge Regional Office for review and approval. However, it does not require public review. That is insufficient. This plan should be made available for public review on an appropriate public website.~~

~~Condition 13 requires that the permittee develop a monitoring plan for the monitoring devices listed in Conditions 8-12, and 16. Like the comment 9 above, this plan also should be made available for public review via a publicly available website.~~

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<sup>2</sup> See, for example, [https://www.solarturbines.com/en\\_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html](https://www.solarturbines.com/en_US/services/equipment-optimization/system-upgrades/safety-and-sustainability/solonox-upgrades.html)

11. The permit does not specify a test method to determine compliance with the sulfur content limit in the pipeline natural gas per Condition 15, should that be required per Condition 16. The test protocol and any test reports should be made available on a public website.

12. Conditions 18, 19, 20, 21, 22, 23, 24, 53, and 54 each contain the sentence “[T]hese emissions are derived from the estimated overall emission contribution from operating limits.” It is not clear what this sentence means. The DEQ should explain and clarify.

13. Condition 20 should also include a limit for ammonia, which will be emitted as a result of use of SCR for NO<sub>x</sub> control for the two combustion turbines.

14. The NO<sub>x</sub> limit for the combustion turbines is listed as 2.70 ppmv at 15% oxygen on a 3-hour average basis subject to the exclusions listed for each of the two combustion turbines in Conditions 20 and 21. Per the Engineering Analysis (p. 3), the SCR’s NO<sub>x</sub> reduction efficiency is 70%. While the SCR is listed as a voluntary control, combustion turbines similar to these in simple cycle operation have achieved lower levels of NO<sub>x</sub>, i.e., 2 ppmv at 15% oxygen because SCRs can be designed and operated to achieve far greater than 70% control – i.e., 90-95% NO<sub>x</sub> reduction is not uncommon. The DEQ should discuss why the SCRs chosen cannot achieve this level of NO<sub>x</sub> for each turbine or what the incremental cost would be to achieve this 2 ppmv level as compared to the stated 2.7 ppmv level. This is not discussed anywhere in the record. Based on such discussion, the DEQ should require the lower 2 ppmv limit as opposed to 2.7 ppmv for the two combustion turbines.

15. Conditions 25-28 require a “at least once a week” opacity reading using EPA Method 9 in order to assure that opacity does not exceed 5% from each combustion turbine or each microturbine. The duration of the Method 9 reading is noted as a 6-minute average in Condition 33. Conducting a 6-minute test “once a week” is inadequate, on its face, to assuring continuous compliance with the 5% opacity limit. The DEQ should explain how the random 6-minute observation once per week and during the initial and subsequent performance tests is adequate.

16. Conditions 30 and 31 require an initial stack test for CO, VOC, PM<sub>10</sub>, and PM<sub>2.5</sub>. The stack test should also include SO<sub>2</sub> and NO<sub>x</sub>, even though the latter will be measured using CEMS. The SO<sub>2</sub> results will confirm the sulfur content limit of the pipeline natural gas required in Condition 15. Additionally, the referenced test protocol and test report should be made publicly available via a website.

17. Condition 32 requires a repeat of the performance test “every two years” to demonstrate compliance with the emission limits in Condition 20 for the Solar Mars 100 combustion turbine but omits the same requirement (i.e., compliance with Condition 21) for the Solar Taurus 70 combustion turbine. DEQ should explain this omission.

Importantly, the “every two year” stack testing for continuous compliance demonstration for the two combustion turbines is insufficient. The condition should require Continuous Emission Monitoring Systems (CEMS) for CO, VOC, filterable PM<sub>10</sub>, and filterable PM<sub>2.5</sub>. These can be supplemented by annual stack tests for condensable PM for which no CEMS are currently available. Using stack tests every 2 years (i.e., for a few hours every 2 years) to demonstrate

“continuous” compliance with the short term limits proposed in the permit is antithetical to the concept of continuous compliance. CEMS for each of these pollutants is widely available.

18. Condition 38b notes the possibility of missing or invalid data for the NO<sub>x</sub> CEMS but does not require how these periods will be accounted for – i.e., it does not include any missing data substitution algorithms. DEQ should address this deficiency.

19. Conditions 52-56 address formaldehyde emissions from the combustion and microturbines. These include short term (i.e., pounds per hour) and annual (i.e., tons per year) limits in Condition 52, and startup and shutdown limits (on a per event basis) for each of the two combustion turbines in Conditions 53 and 54 respectively. However, Conditions 55 and 56 require only a one-time performance test for the combustion and microturbines, respectively. No periodic tests are required in the permit. First, the DEQ should explain how a one-time performance test for a few hours can assure continuous compliance with the limits in Condition 52. Second, the DEQ should explain how compliance with the startup/shutdown emissions limits in Conditions 53 and 54 are to be demonstrated, as is noted in Condition 58.

20. Condition 57 requires the specification of the maximum hexane content in the natural gas that will be used in the turbines. However, it is not at all clear how that will inform the emissions of hexane from the turbines. The DEQ should explain.

21. The Engineering Analysis (p. 5) states that the emissions rates for NO<sub>x</sub>, CO and unburned hydrocarbons (UHC) are “guaranteed” by the vendor. But no citation is provided. The DEQ should provide the support for this statement – i.e., the respective guarantees by Solar, the combustion turbines manufacturer.

22. The Engineering Analysis (p. 6) notes that emissions of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> and SO<sub>2</sub> are based on AP-42, Table 3.1-2a. A review of this table<sup>3</sup> shows that each of the PM emission factors is poorly rated as a “C”. The DEQ should explain why use of these C-rated emission factors is appropriate. **As the DEQ is likely aware the EPA has expressly cautioned against mis-using AP-42.** In light of EPA’s concerns, the DEQ should fully address the used of poorly rated emission factors from AP-42 in this permit.

23. The Engineering Analysis (p. 6) also notes that the emissions of fugitives was based on emission factors from a 1995 EPA document (EPA-453/R-95-017) and INGAA guidelines. It is not clear how the INGAA guidelines or which guidelines were used and in what manner. The DEQ should clarify. Additionally, the use of average emission factors from the 1995 EPA document to estimate the potential to emit emissions from fugitive components is inappropriate for the same reasons as EPA has stated in cautioning the use of AP-42 as noted in the previous comment. The DEQ should provide a technical justification for the use of average emission factors from the 1995 EPA document.

24. The Engineering Analysis (p. 7) states that “[B]ased on the applicant’s calculations, the facility will emit two State Air Toxic pollutants of concern for compressor stations, namely hexane and formaldehyde.” While these are certainly two of the toxic air pollutants that will be

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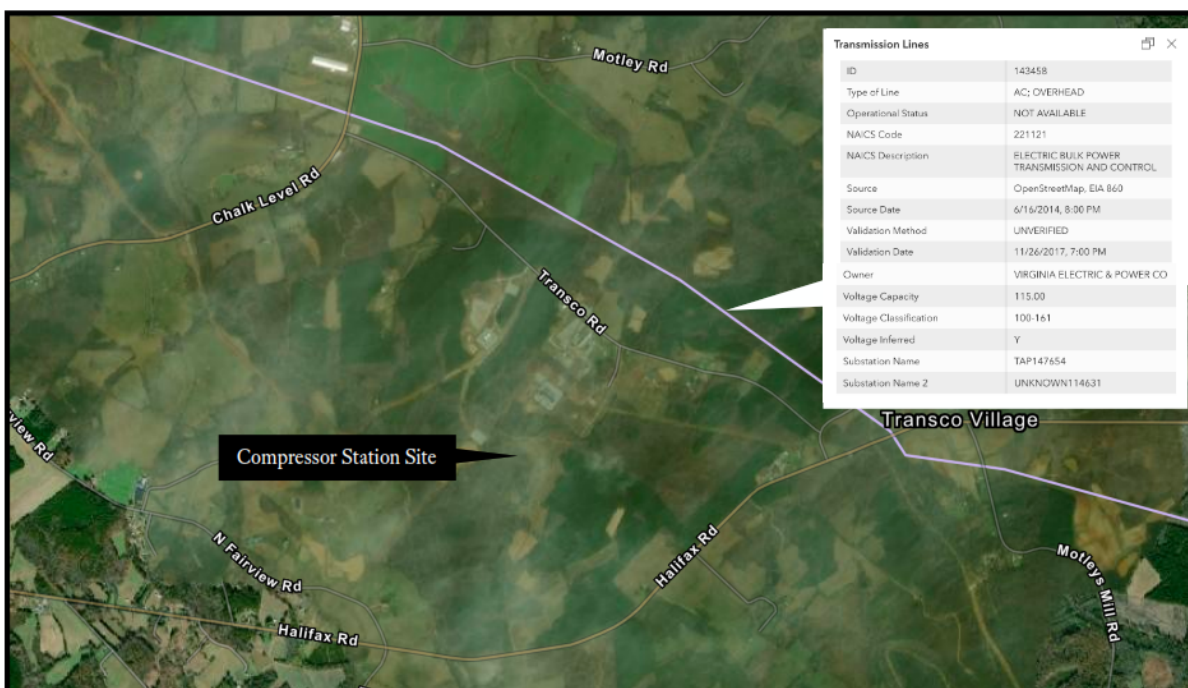
<sup>3</sup> <https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf>

emitted from the combustion turbines, there are others as well. In fact Section 3.1 from AP-42 (Table 3.1-3) notes that benzene will be emitted (with a A-rated factor) and there are others as well listed on the same table, with poorly rated factors. It is incorrect for DEQ to assume, simply based on the “applicant’s calculations” that only hexane and formaldehyde are the toxic pollutants of concern. DEQ’s analysis is incomplete.

25. Section V in the Engineering Analysis discusses BACT for the compressor station. In the following discussion (p. 10), the DEQ rejects the use of electrically-driven (as opposed to combustion turbine-driven) compressors as BACT, stating:

“The applicant provided supplemental information (dated June 30, 2020) that includes an evaluation of the feasibility of using electric compressor turbines (ECT) over natural gas-fired combustion turbines and a consideration of the pollution possibility for electric compression technology. This information demonstrates that the electrical transmission infrastructure required for the use of ECTs at the proposed Station does not exist. Therefore, if the substitution of ECTs for the proposed combustion turbines was considered as a control technique in the context of a BACT determination, the use of such ECTs at the proposed Station is not an available option for consideration.” (emphasis added)

The DEQ’s statement that the “...transmission infrastructure....does not exist” is an overstatement. While it may not exist at the exact site of the proposed Lambert station, there is electrical infrastructure fairly close by, as can be seen from the following map showing a transmission line very close to the proposed Lambert station location.



Source: UNITED STATES DEPARTMENT OF ENERGY, ENERGY INFORMATION ADMINISTRATION, *United States Energy Atlas: Electricity Energy Infrastructure & Resources* (accessed February 18, 2021), available at <https://atlas.eia.gov/app/895faaf79d744f2ab3b72f8bd5778e68>

Electric Substations

OBJECTID	32138
ID	147634
NAME	CHATHAM
CITY	CHATHAM
STATE	PA
ZIP	15131
TYPE	SUBSTATION
STATUS	IN SERVICE
COUNTRY	PITTSBURGH
COUNTYFIPS	51143
COUNTRY	USA
LATITUDE	34.894740470001
LONGITUDE	-79.387633293
NAICS CODE	22131
NAICS DESC	ELECTRIC BULK POWER TRANSMISSION AND CONTROL
SOURCE	BAGGBY: <a href="http://www.pge.com/systems/energy/infrastructure/">http://www.pge.com/systems/energy/infrastructure/</a>
SOURCE DATE	July 15, 2014
VAL_METHOD	BAGGBY
VAL_DATE	March 31, 2015
LINE1	1
MAX_VOLT	115
MIN_VOLT	115
MAX_INFER	N
MIN_INFER	N

Compressor Station Site

Citations for both of the maps are shown below each map.

Based on this, the DEQ should fully evaluate, as part of its BACT analysis, the use of electric motors to drive the compressors, thereby eliminating all of the combustion generated pollution from the station.

Pollutant (averaging period)	Total Modeled Concentration (µg/m³)	Ambient Background Concentration	Total Concentration (µg/m³)	NAAQS (µg/m³)
------------------------------------	-------------------------------------------	----------------------------------------	-----------------------------------	------------------

7

		( $\mu\text{g}/\text{m}^3$ )		
NO <sub>2</sub> (1-hr)	178.8	--- <sup>(1)</sup>	178.8	188
NO <sub>2</sub> (annual)	21.8	13.2	35.0	100
CO (1-hr)	2,151	1,955	4,106	40,000
CO (8-hr)	1,106	1,495	2,601	10,000
PM <sub>2.5</sub> (24-hr)	5.8	17	23.0 <sup>(2)</sup>	35
PM <sub>2.5</sub> (annual)	1.0	6.9	7.9 <sup>(2)</sup>	12
PM <sub>10</sub> (24-hr)	9.1	22	31.1	150

<sup>(1)</sup> Season and hour of day varying.

<sup>(2)</sup> Total concentration includes the contribution from secondary PM<sub>2.5</sub> formation.

I have highlighted the predicted total concentrations for a few of the NAAQS comparisons above, namely for NO<sub>x</sub> 1-hour (predicted total value of 178.8  $\mu\text{g}/\text{m}^3$  versus the NAAQS of 188  $\mu\text{g}/\text{m}^3$ ) and for PM<sub>2.5</sub> for two different averaging times (predicted 23  $\mu\text{g}/\text{m}^3$  versus NAAQS of 35  $\mu\text{g}/\text{m}^3$  for the 24-hour average and predicted 7.9  $\mu\text{g}/\text{m}^3$  versus NAAQS of 12  $\mu\text{g}/\text{m}^3$  for the annual average). Given the discussion below, I consider these comparisons to indicate that the model prediction are close to the respective NAAQS and should be reevaluated. This is in spite of irrelevant DEQ's contention (as noted in the Engineering Analysis's attached memorandum from the Office of Air Quality Assessments) that the Lambert station's contributions to the total for NO<sub>x</sub> is small as compared to that from the nearby Transco station.

As the DEQ is well aware, the results of any dispersion modeling are only reliable if representative and accurate inputs are used in the modeling. In addition to the selection of the model itself, critical inputs are the emissions rates of the various pollutants and the meteorological data that are used to drive the model.

As I have noted prior, emissions factors used for certain pollutants (such as PM, PM<sub>10</sub>, and PM<sub>2.5</sub>) are likely significantly inaccurate. Therefore, just for this reason alone and given the closeness of the predicted total concentrations and the respective NAAQS as noted above, the DEQ should reassess the dispersion modeling for PM<sub>2.5</sub>.

Equally concerning is the use of inappropriate meteorological data in the analysis. While the DEQ does not discuss this in its Engineering Analysis (including the attached memorandum

from the Office of Air Quality Assessments), the details are provided in the June 2020 dispersion modeling report<sup>5</sup> provided as part of the permit application for the Lambert station.

For the choice of meteorological data, the sum total of the discussion is contained in Section 3.3 of the modeling report as follows:

“Guidance for air quality modeling recommends the use of one year of onsite meteorological data or five years of representative off-site meteorological data. Since onsite data are not available for the Project, meteorological data available from the National Weather Service was used in this analysis. Surface meteorological data collected at the NWS station at the Lynchburg Regional Airport (LYH) and upper air data from the Piedmont Triad International Airport in Greensboro, NC (GSO) for the period 2012-2016; generated using the most recent version of AERMET (v19191) (US EPA 2019b) was acquired from VA DEQ and used in the modeling analyses.” (emphasis added)

The critical issue is the representativeness of the meteorological data that is used since, as the discussion above admits, onsite (i.e., on-property) meteorological data, which by definition would be representative, was not collected and therefore was “not available.” Instead surface meteorological data recorded at the LYH airport was used. But this location is at a significant distance from the Chatham site – Google Maps seems to indicate roughly 40 miles or so. Distance alone is not the only determinant of representativeness or lack thereof since topographical complexities and locations also play a role in this assessment. Here, it is clear that the topography is not flat between Lynchburg and the project site. In fact, the modeling report describes the terrain in the area (in Section 3.4.1) as follows:

“The Project is situated at approximately 670 feet elevation above mean sea level. Within about 20 km surrounding the Project, the terrain is characterized by rolling hills, with approximate elevations between 450 to 950 feet above mean sea level.”

I note that the terrain discussion (i.e., only focusing on “within 20 km” does not even extend to Lynchburg. In any case, it is clear that because the terrain is not simple or flat in combination with the considerable distance between the location of the airport where the meteorological data was collected, there is simply no basis (and the modeling report provides none) to assume that this data is representative of the project location.

The results of the modeling analysis, which critically depend on the use of representative meteorological data, are therefore not reliable.

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<sup>5</sup> AECOM, MVP Southgate Project: Lambert Compressor Station, Pittsylvania County, Virginia, Air Quality Dispersion Modeling Report, June 2020.



## ATTACHMENT A

**RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)**

**CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES**

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### EXPERIENCE SUMMARY

Dr. Sahu has over thirty one years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources including stationary and mobile sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

He has over twenty eight years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past twenty six years include various trade associations as well as individual companies such as steel mills, petroleum refineries, chemical plants, cement manufacturers, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, land development companies, and various entities in the public sector including EPA, the US Dept. of Justice, several states (including Oregon, New Mexico, Pennsylvania, and others), various agencies such as the California DTSC, and various municipalities. Dr. Sahu has performed projects in all 50 states, numerous local jurisdictions and internationally.

In addition to consulting, for approximately twenty years, Dr. Sahu taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management). He also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies (please see Annex A).

### EXPERIENCE RECORD

2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.), public sector (such as the US Department of Justice), and public interest group clients with project management, environmental consulting, project management, as well as regulatory and engineering support consulting services.

- 1995-2000 Parsons ES, **Associate, Senior Project Manager and Department Manager for Air Quality/Geosciences/Hazardous Waste Groups**, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing full-service consulting, project management, regulatory compliance and A/E design assistance in all areas.
- Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.
- 1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.
- 1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.
- 1989-1990 Kinetics Technology International, Corp. **Development Engineer**. Involved in thermal engineering R&D and project work related to low-NO<sub>x</sub> ceramic radiant burners, fired heater NO<sub>x</sub> reduction, SCR design, and fired heater retrofitting.
- 1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

## EDUCATION

- 1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.
- 1984 M. S., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.
- 1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

## TEACHING EXPERIENCE

### Caltech

- "Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.
- "Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.
- "Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.
- "Heat Transfer," - taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.
- "Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

### U.C. Riverside, Extension

- "Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.
- "Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.

"Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.

"Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.

"Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.

"Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.

"Advanced Hazard Analysis - A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.

"Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

#### Loyola Marymount University

"Fundamentals of Air Pollution - Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.

"Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.

"Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.

"Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

#### University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

#### University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

#### International Programs

"Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.

"Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

#### **PROFESSIONAL AFFILIATIONS AND HONORS**

President of India Gold Medal, IIT Kharagpur, India, 1983.

Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992.

American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-mid-1990s.

Air and Waste Management Association, West Coast Section, 1989-mid-2000s.

## **PROFESSIONAL CERTIFICATIONS**

EIT, California (#XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2021.

## **PUBLICATIONS (PARTIAL LIST)**

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," *J. Coal Quality*, **8**, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R. Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NO<sub>x</sub> Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Purchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

#### **PRESENTATIONS (PARTIAL LIST)**

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

## Annex A

### Expert Litigation Support

#### A. Occasions where Dr. Sahu has provided Written or Oral testimony before Congress:

1. In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled “Hitting the Ethanol Blend Wall – Examining the Science on E15.”

#### B. Matters for which Dr. Sahu has provided affidavits and expert reports include:

2. Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado – dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.
3. Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).
4. Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).
5. Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).
6. Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. *United States, et al. v. American Electric Power Service Corp., et al.*, C2-99-1182, C2-99-1250 (Southern District of Ohio).
7. Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility – submitted to the Minnesota Pollution Control Agency.
8. Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. *United States v. East Kentucky Power Cooperative, Inc.*, 5:04-cv-00034-KSF (Eastern District of Kentucky).
9. Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.
10. Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.
11. Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.
12. Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women’s Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.
13. Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo’s eight new proposed PRB-fired PC boilers located at seven TX sites.
14. Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of

- Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).
15. Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club – submitted to the Louisiana DEQ.
  16. Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.*, 2:05cv0885 (Western District of Pennsylvania).
  17. Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.
  18. Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with *General Power Products, LLC v MTD Products Inc.*, 1:06 CVA 0143 (Southern District of Ohio, Western Division).
  19. Expert Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.
  20. Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.
  21. Affidavits (May 2010/June 2010 in the Office of Administrative Hearings)/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).
  22. Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy in the matter of the air permit challenge for Duke Cliffside Unit 6. *Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC*, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).
  23. Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.us
  24. Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.
  25. Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone’s proposed Unit 3 in Texas.
  26. Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*
  27. Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper’s proposed Pee Dee plant in South Carolina).
  28. Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.
  29. Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
  30. Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

31. Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).
32. Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
33. Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions*, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.
34. Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.
35. Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). *United States of America v. DTE Energy Company and Detroit Edison Company*, Civil Action No. 2:10-cv-13101-BAF-RSW (Eastern District of Michigan).
36. Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.
37. Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)’s Cherokee power plant. No. 09-cv-1862 (District of Colorado).
38. Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).
39. Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
40. Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. Public Service Company of New Mexico* (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE) (District of New Mexico).
41. Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.
42. Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.
43. Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (Eastern District of Texas, Texarkana Division).
44. Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf



- Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).
45. Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.
  46. Expert Report (March 2011), Rebuttal Expert Report (June 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).
  47. Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority*, Civil Action No. 4:11-cv-00791 (Southern District of Texas, Houston Division).
  48. Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.
  49. Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).
  50. Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. *Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P.*, Civil Action No. A-08-CA-648-LY (Western District of Texas, Austin Division).
  51. Expert Report (October 2011) on behalf of the Defendants in the matter of *John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al.*, Case No. 3:10-cv-747 (TJM/DEP) (Northern District of New York).
  52. Declaration (October 2011) on behalf of the Plaintiffs in the matter of *American Nurses Association et. al. (Plaintiffs), v. US EPA (Defendant)*, Case No. 1:08-cv-02198-RMC (US District Court for the District of Columbia).
  53. Declaration (February 2012) and Second Declaration (February 2012) in the matter of *Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association*, Case No. 11-417-MJP (Western District of Washington).
  54. Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.*, Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).
  55. Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency*, Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).
  56. Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).
  57. Declaration (March 2012) in the matter of the Las Brisas Energy Center *Environmental Defense Fund et al., v. Texas Commission on Environmental Quality*, Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261<sup>st</sup> Judicial District).
  58. Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant *State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al.*, Civil Action No. 07-CV-5298 (JKG) (Eastern District of Pennsylvania).

59. Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project.
60. Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana) – Harm Phase.
61. Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator, Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.
62. Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.
63. Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.
64. Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.
65. Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.
66. Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.
67. Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).
68. Declaration (April 2013) on behalf of Petitioners in the matter of *Sierra Club, et al., (Petitioners) v Environmental Protection Agency et al. (Respondents)*, Case No., 13-1112, (Court of Appeals, District of Columbia Circuit).
69. Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).
70. Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of *A. J. Acosta Company, Inc., v. County of San Bernardino*, Case No. CIVSS803651.
71. Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.
72. Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.
73. Expert Report (December 2013) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).
74. Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.

75. Expert Report (January 2014) on behalf of Baja, Inc., in *Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al.*, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).
76. Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific Environment, and the Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States*, Civil Action No. 13-1820 RC (District Court for the District of Columbia).
77. Declaration (April 2014) on behalf of Respondent-Intervenors in the matter of *Mexichem Specialty Resins Inc., et al., (Petitioners) v Environmental Protection Agency et al.*, Case No., 12-1260 (and Consolidated Case Nos. 12-1263, 12-1265, 12-1266, and 12-1267), (Court of Appeals, District of Columbia Circuit).
78. Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).
79. Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).
80. Direct Prefiled Testimony (August 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of Consumers Energy Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17317 (Michigan Public Service Commission).
81. Declaration (July 2014) on behalf of Public Health Intervenors in the matter of *EME Homer City Generation v. US EPA* (Case No. 11-1302 and consolidated cases) relating to the lifting of the stay entered by the Court on December 30, 2011 (US Court of Appeals for the District of Columbia).
82. Expert Report (September 2014), Rebuttal Expert Report (December 2014) and Supplemental Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).
83. Expert Report (November 2014) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).
84. *Declaration (January 2015) relating to Startup/Shutdown in the MATS Rule (EPA Docket ID No. EPA-HQ-OAR-2009-0234) on behalf of the Environmental Integrity Project.*
85. Pre-filed Direct Testimony (March 2015), Supplemental Testimony (May 2015), and Surrebuttal Testimony (December 2015) on behalf of Friends of the Columbia Gorge in the matter of the Application for a Site Certificate for the Troutdale Energy Center before the Oregon Energy Facility Siting Council.
86. Brief of Amici Curiae Experts in Air Pollution Control and Air Quality Regulation in Support of the Respondents, On Writs of Certiorari to the US Court of Appeals for the District of Columbia, No. 14-46, 47, 48. *Michigan et. al., (Petitioners) v. EPA et. al., Utility Air Regulatory Group (Petitioners) v. EPA et. al., National Mining Association et. al., (Petitioner) v. EPA et. al.*, (Supreme Court of the United States).
87. Expert Report (March 2015) and Rebuttal Expert Report (January 2016) on behalf of Plaintiffs in the matter of *Conservation Law Foundation v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).
88. Declaration (April 2015) relating to various Technical Corrections for the MATS Rule (EPA Docket ID No. EPA-HQ-OAR-2009-0234) on behalf of the Environmental Integrity Project.
89. Direct Prefiled Testimony (May 2015) on behalf of the Michigan Environmental Council, the Natural Resources Defense Council, and the Sierra Club in the matter of the Application of DTE Electric Company

- for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy and for Miscellaneous Accounting Authority, Case No. U-17767 (Michigan Public Service Commission).
90. Expert Report (July 2015) and Rebuttal Expert Report (July 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).
  91. Declaration (August 2015, Docket No. 1570376) in support of “Opposition of Respondent-Intervenors American Lung Association, et. al., to Tri-State Generation’s Emergency Motion;” Declaration (September 2015, Docket No. 1574820) in support of “Joint Motion of the State, Local Government, and Public Health Respondent-Intervenors for Remand Without Vacatur;” Declaration (October 2015) in support of “Joint Motion of the State, Local Government, and Public Health Respondent-Intervenors to State and Certain Industry Petitioners’ Motion to Govern, *White Stallion Energy Center, LLC v. US EPA*, Case No. 12-1100 (US Court of Appeals for the District of Columbia).
  92. Declaration (September 2015) in support of the Draft Title V Permit for Dickerson Generating Station (Proposed Permit No 24-031-0019) on behalf of the Environmental Integrity Project.
  93. Expert Report (Liability Phase) (December 2015) and Rebuttal Expert Report (February 2016) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., Environmental Law and Policy Center, and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).
  94. Declaration (December 2015) in support of the Petition to Object to the Title V Permit for Morgantown Generating Station (Proposed Permit No 24-017-0014) on behalf of the Environmental Integrity Project.
  95. Expert Report (November 2015) on behalf of Appellants in the matter of *Sierra Club, et al. v. Craig W. Butler, Director of Ohio Environmental Protection Agency et al.*, ERAC Case No. 14-256814.
  96. Affidavit (January 2016) on behalf of Bridgewatch Detroit in the matter of *Bridgewatch Detroit v. Waterfront Petroleum Terminal Co., and Waterfront Terminal Holdings, LLC.*, in the Circuit Court for the County of Wayne, State of Michigan.
  97. Expert Report (February 2016) and Rebuttal Expert Report (July 2016) on behalf of the challengers in the matter of the Delaware Riverkeeper Network, Clean Air Council, et. al., vs. Commonwealth of Pennsylvania Department of Environmental Protection and R. E. Gas Development LLC regarding the Geyer well site before the Pennsylvania Environmental Hearing Board.
  98. Direct Testimony (May 2016) in the matter of Tesoro Savage LLC Vancouver Energy Distribution Terminal, Case No. 15-001 before the State of Washington Energy Facility Site Evaluation Council.
  99. Declaration (June 2016) relating to deficiencies in air quality analysis for the proposed Millenium Bulk Terminal, Port of Longview, Washington.
  100. Declaration (December 2016) relating to EPA’s refusal to set limits on PM emissions from coal-fired power plants that reflect pollution reductions achievable with fabric filters on behalf of Environmental Integrity Project, Clean Air Council, Chesapeake Climate Action Network, Downwinders at Risk represented by Earthjustice in the matter of *ARIPPA v EPA, Case No. 15-1180*. (D.C. Circuit Court of Appeals).
  101. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Huntley and Huntley Poseidon Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
  102. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Backus Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.

103. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Drakulic Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
104. Expert Report (January 2017) on the Environmental Impacts Analysis associated with the Apex Energy Deutsch Well Pad on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
105. Affidavit (February 2017) pertaining to deficiencies water discharge compliance issues at the Wood River Refinery in the matter of *People of the State of Illinois (Plaintiff) v. Phillips 66 Company, ConocoPhillips Company, WRB Refining LP (Defendants)*, Case No. 16-CH-656, (Circuit Court for the Third Judicial Circuit, Madison County, Illinois).
106. Expert Report (March 2017) on behalf of the Plaintiff pertaining to non-degradation analysis for waste water discharges from a power plant in the matter of *Sierra Club (Plaintiff) v. Pennsylvania Department of Environmental Protection (PADEP) and Lackawanna Energy Center*, Docket No. 2016-047-L (consolidated), (Pennsylvania Environmental Hearing Board).
107. Expert Report (March 2017) on behalf of the Plaintiff pertaining to air emissions from the Heritage incinerator in East Liverpool, Ohio in the matter of *Save our County (Plaintiff) v. Heritage Thermal Services, Inc. (Defendant)*, Case No. 4:16-CV-1544-BYP, (US District Court for the Northern District of Ohio, Eastern Division).
108. Rebuttal Expert Report (June 2017) on behalf of Plaintiffs in the matter of *Casey Voight and Julie Voight (Plaintiffs) v Coyote Creek Mining Company LLC (Defendant)*, Civil Action No. 1:15-CV-00109 (US District Court for the District of North Dakota, Western Division).
109. Expert Affidavit (August 2017) and Penalty/Remedy Expert Affidavit (October 2017) on behalf of Plaintiff in the matter of *Wildearth Guardians (Plaintiff) v Colorado Springs Utility Board (Defendant)*, Civil Action No. 1:15-cv-00357-CMA-CBS (US District Court for the District of Colorado).
110. Expert Report (August 2017) on behalf of Appellant in the matter of *Patricia Ann Troiano (Appellant) v. Upper Burrell Township Zoning Hearing Board (Appellee)*, Court of Common Pleas of Westmoreland County, Pennsylvania, Civil Division.
111. Expert Report (October 2017), Supplemental Expert Report (October 2017), and Rebuttal Expert Report (November 2017) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant)*, Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).
112. Declaration (December 2017) on behalf of the Environmental Integrity Project in the matter of permit issuance for ATI Flat Rolled Products Holdings, Breckenridge, PA to the Allegheny County Health Department.
113. Expert Report (Harm Phase) (January 2018), Rebuttal Expert Report (Harm Phase) (May 2018) and Supplemental Expert Report (Harm Phase) (April 2019) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).
114. Declaration (February 2018) on behalf of the Chesapeake Bay Foundation, et. al., in the matter of the Section 126 Petition filed by the state of Maryland in *State of Maryland v. Pruitt (Defendant)*, Civil Action No. JKB-17-2939 (Consolidated with No. JKB-17-2873) (US District Court for the District of Maryland).
115. Direct Pre-filed Testimony (March 2018) on behalf of the National Parks Conservation Association (NPCA) in the matter of *NPCA v State of Washington, Department of Ecology and BP West Coast Products, LLC*, PCHB No. 17-055 (Pollution Control Hearings Board for the State of Washington).
116. Expert Affidavit (April 2018) and Second Expert Affidavit (May 2018) on behalf of Petitioners in the matter of *Coosa River Basin Initiative and Sierra Club (Petitioners) v State of Georgia Environmental Protection Division, Georgia Department of Natural Resources (Respondent) and Georgia Power*

*Company (Intervenor/Respondent)*, Docket Nos: 1825406-BNR-WW-57-Howells and 1826761-BNR-WW-57-Howells, Office of State Administrative Hearings, State of Georgia.

117. Direct Pre-filed Testimony and Affidavit (December 2018) on behalf of Sierra Club and Texas Campaign for the Environment (Appellants) in the contested case hearing before the Texas State Office of Administrative Hearings in Docket Nos. 582-18-4846, 582-18-4847 (Application of GCGV Asset Holding, LLC for Air Quality Permit Nos. 146425/PSDTX1518 and 146459/PSDTX1520 in San Patricio County, Texas).
118. Expert Report (February 2019) on behalf of Sierra Club in the State of Florida, Division of Administrative Hearings, Case No. 18-2124EPP, Tampa Electric Company Big Bend Unit 1 Modernization Project Power Plant Siting Application No. PA79-12-A2.
119. Declaration (March 2019) on behalf of Earthjustice in the matter of comments on the renewal of the Title V Federal Operating Permit for Valero Houston refinery.
120. Expert Report (March 2019) on behalf of Plaintiffs for Class Certification in the matter of *Resendez et al v Precision Castparts Corporation* in the Circuit Court for the State of Oregon, County of Multnomah, Case No. 16cv16164.
121. Expert Report (June 2019), Affidavit (July 2019) and Rebuttal Expert Report (September 2019) on behalf of Appellants relating to the NPDES permit for the Cheswick power plant in the matter of *Three Rivers Waterkeeper and Sierra Club (Appellees) v. State of Pennsylvania Department of Environmental Protection (Appellee) and NRG Power Midwest (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-088-R.
122. Affidavit/Expert Report (August 2019) relating to the appeal of air permits issued to PTTGCA on behalf of Appellants in the matter of *Sierra Club (Appellants) v. Craig Butler, Director, et. al., Ohio EPA (Appellees)* before the State of Ohio Environmental Review Appeals Commission (ERAC), Case Nos. ERAC-19-6988 through -6991.
123. Expert Report (October 2019) relating to the appeal of air permit (Plan Approval) on behalf of Appellants in the matter of *Clean Air Council and Environmental Integrity Project (Appellants) v. Commonwealth of Pennsylvania Department of Environmental Protection and Sunoco Partners Marketing and Terminals L.P.*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-057-L.
124. Expert Report (December 2019), Affidavit (March 2020), and Supplemental Expert Report (July 2020) on behalf of Earthjustice in the matter of *Objection to the Issuance of PSD/NSR and Title V permits for Riverview Energy Corporation*, Dale, Indiana, before the Indiana Office of Environmental Adjudication, Cause No. 19-A-J-5073.
125. Affidavit (December 2019) on behalf of Plaintiff-Intervenor (Surfrider Foundation) in the matter of *United States and the State of Indiana (Plaintiffs), Surfrider Foundation (Plaintiff-Intervenor), and City of Chicago (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant)*, Civil Action No. 2:18-cv-00127 (US District Court for the Northern District of Indiana, Hammond Division).
126. Declarations (January 2020, February 2020, May 2020, July 2020, and August 2020) in support of Petitioner's Motion for Stay of PSCAA NOC Order of Approval No. 11386 in the matter of the *Puyallup Tribe of Indians v. Puget Sound Clean Air Agency (PSCAA) and Puget Sound Energy (PSE)*, before the State of Washington Pollution Control Hearings Board, PCHB No. P19-088.
127. Expert Report (April 2020) on behalf of the plaintiff in the matter of Orion Engineered Carbons, GmbH (Plaintiff) vs. Evonik Operations, GmbH (formerly Evonik Degussa GmbH) (Respondent), before the German Arbitration Institute, Case No. DIS-SV-2019-00216.
128. Expert Independent Evaluation Report (June 2020) for *PacifiCorp's Decommissioning Costs Study Reports dated January 15, 2020 and March 13, 2020 relating to the closures of the Hunter, Huntington, Dave Johnston, Jim Bridger, Naughton, Wyodak, Hayden, and Colstrip (Units 3&4) plants*, prepared for the Oregon Public Utility Commission (Oregon PUC).

129. Direct Pre-filed Testimony (July 2020) on behalf of the Sierra Club in the matter of *the Application of the Ohio State University for a certificate of Environmental Compatibility and Public Need to Construct a Combined Heat and Power Facility in Franklin County, Ohio*, before the Ohio Power Siting Board, Case No. 19-1641-EL-BGN.
130. Expert Report (August 2020) and Rebuttal Expert Report (September 2020) on behalf of WildEarth Guardians (petitioners) in the matter of *the Appeals of the Air Quality Permit No. 7482-M1 Issued to 3 Bear Delaware Operating – NM LLC (EIB No. 20-21(A) and Registrations Nos. 8729, 8730, and 8733 under General Construction Permit for Oil and Gas Facilities (EIB No. 20-33 (A)*, before the State of New Mexico, Environmental Improvement Board.
131. Expert Report (July 2020) on the *Initial Economic Impact Analysis (EIA) for A Proposal To Regulate NOx Emissions from Natural Gas Fired Rich-Burn Natural Gas Reciprocating Internal Combustion Engines (RICE) Greater Than 100 Horsepower* prepared on behalf of Earthjustice and the National Parks Conservation Association in the matter of Regulation Number 7, Alternate Rules before the Colorado Air Quality Control Commission.
132. Expert Report (August 2020) and Supplemental Expert Report (February 2021) on the Potential Remedies to Avoid Adverse Thermal Impacts from the Merrimack Station on behalf of Plaintiffs in the matter of *Sierra Club Inc. and the Conservation Law Foundation (Plaintiffs) v. Granite Shore Power, LLC et. al., (Defendants)*, Civil Action No. 19-cv-216-JL (US District Court for the District of New Hampshire.)
133. Expert Report (August 2020) and Supplemental Expert Report (December 2020) on behalf of Plaintiffs in the matter of *PennEnvironment Inc., and Clean Air Council (Plaintiffs) and Allegheny County Health Department (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant)*, Civil Action No. 2-19-cv-00484-MJH (US District Court for the Western District of Pennsylvania.)
134. Pre-filed Direct Testimony (October 2020) and Sur-rebuttal Testimony (November 2020) on behalf of petitioners (Ten Persons Group, including citizens, the Town of Braintree, the Town of Hingham, and the City of Quincy) in the matter of Algonquin Gas Transmission LLC, Weymouth MA, No. X266786 Air Quality Plan Approval, before the Commonwealth of Massachusetts, Department of Environmental Protection, the Office of Appeals and Dispute Resolution, OADR Docket Nos. 2019-008, 2019-009, 2019010, 2019-011, 2019-012 and 2019-013.
135. Expert Report (November 2020) on behalf of Protect PT in the matter of *Protect PT v. Commonwealth of Pennsylvania Department of Environmental Protection and Apex Energy (PA) LLC*, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2018-080-R (consolidated with 2019-101-R)(the “Drakulic Appeal”).
136. Expert Report (December 2020) on behalf of Plaintiffs in the matter of *Sierra Club Inc. (Plaintiff) v. GenOn Power Midwest LP (Defendants)*, Civil Action No. 2-19-cv-01284-WSS (US District Court for the Western District of Pennsylvania.)
137. Pre-filed Testimony (January 2021) on behalf of the Plaintiffs (Shrimpers and Fishermen of the Rio Grande Valley represented by Texas RioGrande Legal Aid, Inc.) in the matter of the Appeal of Texas Commission on Environmental Quality (TCEQ) Permit Nos. 147681, PSDTX1522, GHGPSDTX172 for the Jupiter Brownsville Heavy Condensate Upgrader Facility, Cameron County, before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-21-0111, TCEQ Docket No. 2020-1080-AIR.

**C. Occasions where Dr. Sahu has provided oral testimony in depositions, at trial or in similar proceedings include the following:**

138. Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado – dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.
139. Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.

140. Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, *United States, et al. v. Ohio Edison Co., et al.*, C2-99-1181 (Southern District of Ohio).
141. Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, *United States v. Illinois Power Co., et al.*, 99-833-MJR (Southern District of Illinois).
142. Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. *United States, et al. v. Cinergy Corp., et al.*, IP 99-1693-C-M/S (Southern District of Indiana).
143. Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia DEP.
144. Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.
145. Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.
146. Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.
147. Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.
148. Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
149. Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*
150. Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coletto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
151. Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
152. Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.
153. Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).
154. Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
155. Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
156. Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
157. Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. *United States v. Alabama Power Company*, CV-01-HS-152-S (Northern District of Alabama, Southern Division).
158. Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania – Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey



- (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.*, 2:05cv0885 (Western District of Pennsylvania).
159. Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).
  160. Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions*, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.
  161. Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
  162. Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.
  163. Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.
  164. Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).
  165. Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)’s Cherokee power plant. No. 09-cv-1862 (D. Colo.).
  166. Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).
  167. Deposition (August 2011) on behalf of the United States in *United States of America v. Cemex, Inc.*, Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).
  168. Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.
  169. Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC*, 09-CV100-RET-CN (Middle District of Louisiana).
  170. Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).
  171. Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.
  172. Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.
  173. Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).

174. Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).
175. Deposition (February 2014) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).
176. Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.*, Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).
177. Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).
178. Deposition (June 2014) and Trial (August 2014) on behalf of ECM Biofilms in the matter of the *US Federal Trade Commission (FTC) v. ECM Biofilms* (FTC Docket #9358).
179. Deposition (February 2015) on behalf of Plaintiffs in the matter of *Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp (Defendants)*, Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).
180. Oral Testimony at Hearing (April 2015) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).
181. Deposition (August 2015) on behalf of Plaintiff in the matter of *Conservation Law Foundation (Plaintiff) v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).
182. Testimony at Hearing (August 2015) on behalf of the Sierra Club in the matter of *Amendments to 35 Illinois Administrative Code Parts 214, 217, and 225* before the Illinois Pollution Control Board, R15-21.
183. Deposition (May 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).
184. Trial Testimony (October 2015) on behalf of Plaintiffs in the matter of *Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants)*, Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).
185. Deposition (April 2016) on behalf of the Plaintiffs in *UNatural Resources Defense Council, Respiratory Health Association, and Sierra Club (Plaintiffs) v. Illinois Power Resources LLC and Illinois Power Resources Generation LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (Central District of Illinois, Peoria Division).
186. Trial Testimony at Hearing (July 2016) in the matter of Tesoro Savage LLC Vancouver Energy Distribution Terminal, Case No. 15-001 before the State of Washington Energy Facility Site Evaluation Council.
187. Trial Testimony (December 2016) on behalf of the challengers in the matter of the Delaware Riverkeeper Network, Clean Air Council, et. al., vs. Commonwealth of Pennsylvania Department of Environmental Protection and R. E. Gas Development LLC regarding the Geyer well site before the Pennsylvania Environmental Hearing Board.
188. Trial Testimony (July-August 2016) on behalf of the United States in *United States of America v. Ameren Missouri*, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

189. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Huntley and Huntley Poseidon Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
190. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Backus Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
191. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Drakulic Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
192. Trial Testimony (January 2017) on the Environmental Impacts Analysis associated with the Apex energy Deutsch Well Pad Hearing on behalf citizens in the matter of the special exception use Zoning Hearing Board of Penn Township, Westmoreland County, Pennsylvania.
193. Deposition Testimony (July 2017) on behalf of Plaintiffs in the matter of *Casey Voight and Julie Voight v Coyote Creek Mining Company LLC (Defendant)* Civil Action No. 1:15-CV-00109 (US District Court for the District of North Dakota, Western Division).
194. Deposition Testimony (November 2017) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).
195. Deposition Testimony (December 2017) on behalf of Plaintiff in the matter of *Wildearth Guardians (Plaintiff) v Colorado Springs Utility Board (Defendant)* Civil Action No. 1:15-cv-00357-CMA-CBS (US District Court for the District of Colorado).
196. Deposition Testimony (January 2018) in the matter of National Parks Conservation Association (NPCA) v. State of Washington Department of Ecology and British Petroleum (BP) before the Washington Pollution Control Hearing Board, Case No. 17-055.
197. Trial Testimony (January 2018) on behalf of Defendant in the matter of *Oakland Bulk and Oversized Terminal (Plaintiff) v City of Oakland (Defendant,)* Civil Action No. 3:16-cv-07014-VC (US District Court for the Northern District of California, San Francisco Division).
198. Trial Testimony (April 2018) on behalf of the National Parks Conservation Association (NPCA) in the matter of NPCA v State of Washington, Department of Ecology and BP West Coast Products, LLC, PCHB No. 17-055 (Pollution Control Hearings Board for the State of Washington).
199. Deposition (June 2018) (harm Phase) on behalf of Plaintiffs in the matter of *Natural Resources Defense Council, Inc., Sierra Club, Inc., and Respiratory Health Association v. Illinois Power Resources LLC, and Illinois Power Resources Generating LLC (Defendants)*, Civil Action No. 1:13-cv-01181 (US District Court for the Central District of Illinois, Peoria Division).
200. Trial Testimony (July 2018) on behalf of Petitioners in the matter of *Coosa River Basin Initiative and Sierra Club (Petitioners) v State of Georgia Environmental Protection Division, Georgia Department of Natural Resources (Respondent) and Georgia Power Company (Intervenor/Respondent)*, Docket Nos: 1825406-BNR-WW-57-Howells and 1826761-BNR-WW-57-Howells, Office of State Administrative Hearings, State of Georgia.
201. Deposition (January 2019) and Trial Testimony (January 2019) on behalf of Sierra Club and Texas Campaign for the Environment (Appellants) in the contested case hearing before the Texas State Office of Administrative Hearings in Docket Nos. 582-18-4846, 582-18-4847 (Application of GCGV Asset Holding, LLC for Air Quality Permit Nos. 146425/PSDTX1518 and 146459/PSDTX1520 in San Patricio County, Texas).
202. Deposition (February 2019) and Trial Testimony (March 2019) on behalf of Sierra Club in the State of Florida, Division of Administrative Hearings, Case No. 18-2124EPP, Tampa Electric Company Big Bend Unit 1 Modernization Project Power Plant Siting Application No. PA79-12-A2.
203. Deposition (June 2019) relating to the appeal of air permits issued to PTTGCA on behalf of Appellants in the matter of *Sierra Club (Appellants) v. Craig Butler, Director, et. al., Ohio EPA (Appellees)* before the

- State of Ohio Environmental Review Appeals Commission (ERAC), Case Nos. ERAC-19-6988 through -6991.
204. Deposition (September 2019) on behalf of Appellants relating to the NPDES permit for the Cheswick power plant in the matter of *Three Rivers Waterkeeper and Sierra Club (Appellees) v. State of Pennsylvania Department of Environmental Protection (Appellee) and NRG Power Midwest (Permittee)*, before the Commonwealth of Pennsylvania Environmental Hearing Board, EHB Docket No. 2018-088-R.
  205. Deposition (December 2019) on behalf of the Plaintiffs in the matter of David Kovac, individually and on behalf of wrongful death class of Irene Kovac v. BP Corporation North America Inc., Circuit Court of Jackson County, Missouri (Independence), Case No. 1816-CV12417.
  206. Deposition (February 2020) and testimony at Hearing (August 2020, virtual) on behalf of Earthjustice in the matter of *Objection to the Issuance of PSD/NSR and Title V permits for Riverview Energy Corporation*, Dale, Indiana, before the Indiana Office of Environmental Adjudication, Cause No. 19-A-J-5073.
  207. Hearing (July 14-15, 2020, virtual) on behalf of the Sierra Club in the matter of *the Application of the Ohio State University for a certificate of Environmental Compatibility and Public Need to Construct a Combined Heat and Power Facility in Franklin County, Ohio*, before the Ohio Power Siting Board, Case No. 19-1641-EL-BGN.
  208. Hearing (September 2020, virtual) on behalf of WildEarth Guardians (petitioners) in the matter of *the Appeals of the Air Quality Permit No. 7482-M1 Issued to 3 Bear Delaware Operating – NM LLC (EIB No. 20-21(A) and Registrations Nos. 8729, 8730, and 8733 under General Construction Permit for Oil and Gas Facilities (EIB No. 20-33 (A))*, before the State of New Mexico, Environmental Improvement Board.
  209. Deposition (December 2020, virtual) in support of Petitioner’s Motion for Stay of PSCAA NOC Order of Approval No. 11386 in the matter of the *Puyallup Tribe of Indians v. Puget Sound Clean Air Agency (PSCAA) and Puget Sound Energy (PSE)*, before the State of Washington Pollution Control Hearings Board, PCHB No. P19-088.
  210. Hearing (September 2020, virtual) on the *Initial Economic Impact Analysis (EIA) for A Proposal To Regulate NOx Emissions from Natural Gas Fired Rich-Burn Natural Gas Reciprocating Internal Combustion Engines (RICE) Greater Than 100 Horsepower* prepared on behalf of Earthjustice and the National Parks Conservation Association in the matter of Regulation Number 7, Alternate Rules before the Colorado Air Quality Control Commission.
  211. Deposition (December 2020, virtual and Hearing February 2021, virtual) on behalf of the Plaintiffs (Shrimpers and Fishermen of the Rio Grande Valley represented by Texas RioGrande Legal Aid, Inc.) in the matter of the Appeal of Texas Commission on Environmental Quality (TCEQ) Permit Nos. 147681, PSDTX1522, GHGPSDTX172 for the Jupiter Brownsville Heavy Condensate Upgrader Facility, Cameron County, before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-21-0111, TCEQ Docket No. 2020-1080-AIR.
  212. Deposition (January 2021, virtual) on behalf of Plaintiffs in the matter of *PennEnvironment Inc., and Clean Air Council (Plaintiffs) and Allegheny County Health Department (Plaintiff-Intervenor) v. United States Steel Corporation (Defendant)*, Civil Action No. 2-19-cv-00484-MJH (US District Court for the Western District of Pennsylvania.)
  213. Deposition (February 2021) on behalf of Plaintiffs in the matter of *Sierra Club Inc. (Plaintiff) v. GenOn Power Midwest LP (Defendants)*, Civil Action No. 2-19-cv-01284-WSS (US District Court for the Western District of Pennsylvania.)



February, 2021

## Curriculum Vitae

### GEORGE D. THURSTON

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### Education

Degree	Field	Institution
Diploma	Academic	Barrington High School, RI
Sc.B. (Honors)	Environmental Engineering	Brown University
A.B.	Environmental Studies	Brown University
S.M.	Environmental Health Sciences	Harvard Univ. Schl. of Public Health
Sc.D.	Environmental Health Sciences	Harvard Univ. Schl. of Public Health

### Postdoctoral Training

<u>Specialty</u>	<u>Mentor</u>	<u>Place of Training</u>
Environ. Epidemiology	Dr. H. Ozkaynak	Harvard Univ., Kennedy Schl. of Gov., Camb., MA

### Internships and Residencies N/A

### Clinical and Research Fellowships N/A

**Licensure and Certification:** Environmental Benefits Mapping and Analysis Program - Community Edition (BenMAP-CE) Training Certification (August 2014).

### Academic Appointments

1987-1993	Assistant Professor, Dept. of Environmental Medicine, New York University School of Medicine, New York City, NY.
1993-2006	Associate Professor (Tenured), Dept. of Environmental Medicine, New York University School of Medicine, New York City, NY.
2007-present	Professor (Tenured), Dept. of Environmental Medicine, New York University School of Medicine, New York City, NY.
2007-present	Affiliated Faculty, Environmental Studies Program, College of Arts and Sciences, New York University, New York City, NY.
2012-present	Affiliated Faculty, Marron Institute on Cities and the Urban Environment, New York University, New York City, NY
2012-present	Faculty Mentoring Champion, Dept. of Environmental Medicine, New York University School of Medicine, New York City, NY.

### Hospital Appointments: N/A

### Other Professional Positions and Visiting Appointments:

Oak Ridge Institute for Science and Education (ORISE) Fellow (2008-2010)

## Major Administrative Responsibilities

<i>Year</i>	<i>Title, Place of Responsibility</i>
1995-2004	Director, Community Outreach and Environmental Education Program, NYU-NIEHS Center of Excellence, Nelson Inst. of Environ. Med., NYU School of Medicine, Tuxedo, NY
2002-2012	Deputy Director, NYU Particulate Matter Research Center, Nelson Inst. of Environmental Medicine, NYU School of Medicine, Tuxedo, NY
2007-2008	Director, Environmental Epidemiology Core, NYU-NIEHS Center of Excellence, Department of Environmental Medicine, Tuxedo, NY
2010-2015	Co-Leader, Metals Research Focus Group, NYU-NIEHS Center of Excellence, Department of Environmental Medicine, Tuxedo, NY.
2012-2016	Chair, Appointments and Promotions Committee, Department of Environmental Medicine, NYU School of Medicine.
2014-2016	Co-Chair, Environmental Health Research Affinity Group, NYU Global Institute of Public Health (GIPH), New York University, Washington Square.
2012-present	Director, Academic Program in Exposure Assessment and Health Effects, Department of Environmental Medicine, NYU School of Medicine.

## Teaching Experience

<i>Year</i>	<i>Name of course</i>		<i>Type of Teaching</i>
1984-1994	Air Poll. Transport Modeling	(G48.2048)	Course Director
2006-present	Climate, Air Pollution, & Health	(G48.1010)	Course Director
1986-present	Aerosol Science	(G48.2033)	Course Director
1984-2010	Environmental Contamination	(G48.2305)	Lecturer
1984-present	Environ. Hygiene Measurements	(G48.2035)	Lecturer/Lab
1990-1998	Environmental Toxicology	(G48.1006)	Lecturer
1993-1995	Environmental Epidemiology I	(G48.2039)	Lecturer
2001-2003	NYU Summer Institute, Wagner School		Lecturer
2006-present	Environmental Epidemiology I	(G48.2039)	Lecturer
2006-present	Science, Health & Envir. Journalism	(G54.1017.0)	Lecturer
2009-2011	Global Environmental Health	(U10.2153.1)	Course Director
2009-2012	Global Issues in Environ. Health	(G48.1011)	Course Director
2009-present	Earth Systems Science (undergrad)	(V36.0200)	Lecturer
2011-present	Principles of Environmental Health	(G48.1004)	Course Director
2013-present	Environ. Hygiene Measurements	(G48.2035)	Lecturer

## Awards and Honors

November 1999	Orange Environment Citizens Action Group, OE Award for Excellence in Translating Science to the Public
December 2000	NYU School of Medicine Dean's Research Incentive Award
October 2012	Recipient of the "Haagen Smit Prize" for Best Paper, <u>Atmospheric Environment</u> . <a href="http://geo.arc.nasa.gov/sgg/singh/winners12.html">http://geo.arc.nasa.gov/sgg/singh/winners12.html</a>
March 2013	Recipient of the "Best Paper of the Year – Science" Award from <u>ES&amp;T</u> <a href="http://pubs.acs.org/doi/full/10.1021/es400924t">http://pubs.acs.org/doi/full/10.1021/es400924t</a>
May 2018	Recipient of the "Public Service Award" from the American Thoracic Society <a href="https://conference.thoracic.org/about/conference-history/public-service.php">https://conference.thoracic.org/about/conference-history/public-service.php</a>

## Major Committee Assignments

### New York University Committees

2007-present:	University Sustainability Task Force
2010-2012:	University Faculty Senate Alternate

2012-2016: University Faculty Senator

NYU School of Medicine Departmental Committees

1992-1998: Sterling Forest Library Committee, Member, NYU SOM Dept of Environ. Medicine  
1991-1994 Health & Safety Committee, Member, NYU SOM Dept. of Environ.. Medicine  
1992-2004 Community Outreach and Education Comm., Chairman, NYSOM Dept. of Environ. Med.  
1999-2004 Dept. Chairman's Internal Advisory Comm., Member, NYUSOM Dept. of Environ. Med.  
2005-present Dept. Academic Steering Committee, Member, NYUSOM Dept. of Environ. Medicine  
2007-present Dept. Appointments & Promotions Comm., Member, NYUSOM, Dept. of Environ. Medicine  
2012-2016 Dept. Appointments & Promotions Comm., Chair, NYUSOM, Dept. of Environ. Medicine

Advisory Committees

Regional

1983-1984 Massachusetts Acid Rain Advisory Board, Member, Mass. Dept. of Env. Protection  
1984-1986 Committee on Environ. And Occup. Health. , NY State American Lung Association  
1991-1996 Air Management Advisory Comm., Member of Health Effects Subcom., NY State DEC  
1995-1999 Engineering Advisory Board, Member, Tuxedo, NY  
1997-1998 Advisory Committee to the Mayor on the Port of Newburgh, Member, Newburgh, NY  
1996-1999 CUES Asthma Working Group, Member, New York Academy of Medicine  
2008-2010 New York City Community Air Study (NYCCAS) Advisory Panel

National

1995-1999 Comm. on Health Effects of Waste Incineration, Member, National Academy of Sciences  
1995-1999 National Air Conservation Commission, Member, American Lung Association  
2000-2004 National Action Panel on Environment, Member, American Lung Association  
2005-present National Clean Air Committee, Member, American Lung Association  
2007-2010 U.S. EPA Clean Air Science Advisory Committee (CASAC) for SO<sub>x</sub> and NO<sub>x</sub>  
Mar. 2012 EPA Panelist for "Kickoff Workshop to Inform EPA's Review of the Primary NO<sub>2</sub> NAAQS"

International

1996-1997 Sulfur in Gasoline Health and Environment Panel, Chairperson, Health Canada  
Sept. 2007 Illness Cost of Air Pollution Expert Committee, Canadian Medical Association  
2008-2012 Global Burden of Disease (GBD), Committee on the Human Health Effects of Outdoor Air Pollution, World Health Organization (WHO)

Grant Review Committees (National)

March 1989 EPA Air Chemistry and Physics Extramural Grants Review Panel (*ad hoc member*)  
Oct. 1989 NIEHS P30 Center Special Review Panel (*ad hoc member*)  
July 1992 NIH R01 Epidemiology & Disease Control Study Section (*ad hoc member*)  
Nov. 1992 NIEHS P20 Center Development Grant Special Study Section, (*ad hoc member*)  
June 1996 EPA Special Review Panel of the Health Effects Institute (HEI) (*ad hoc member*)  
March 1997 EPA Office of Res. and Development External Grant Review Panel (*ad hoc member*)  
April 1997 NIEHS Community-Based Participatory Res. R01 Special Study Sect. (*ad hoc member*)  
July 1997 EPA National Environ. Research Lab Intramural Research Review Panel (*ad hoc member*)  
June 1998 EPA Office of Res. and Development External Grant Review Panel (*ad hoc member*)  
July 1998 EPA Climate Policy and Programs Division Grant Application Review (*ad hoc member*)  
Oct. 1998 Mickey Leland Center for Air Toxics Grant Review Panel (*ad hoc member*)  
April 2000 NIEHS P30 Center Special Review Panel (*ad hoc member*)  
July 2001 NIEHS Community-Based Participatory Res. R01 Special Study Sect. (*ad hoc member*)  
Dec. 2001 NIEHS Program Project P01 Site Visit Review Panel (*ad hoc member*)  
April 2003 NIH R21 Fogarty Health, Env. and Economic Development Study Sect. (*ad hoc member*)  
Nov. 2003 U.S. EPA STAR Grant Panel (Epidemiologic Research on Health Effects of Long-Term Exposure to Ambient Particulate Matter and Other Air Pollutants) (*member*)  
October 2004 NIEHS Program Project P01 Review Panel (*ad hoc member*)  
June 2005 NIH Special Emphasis Panel (ZRG1 HOP Q 90 S) (*ad hoc member*)



Nov. 2005	NIH Infectious Disease, Reproductive Health, Asthma/Allergy, and Pulmonary (IRAP) Conditions Study Section Review Panel ( <i>ad hoc member</i> )
Feb. 2006	NIH Infectious Disease, Reproductive Health, Asthma/Allergy, and Pulmonary (IRAP) Conditions Study Section Review Panel ( <i>ad hoc member</i> )
June 2006	NIH Infectious Disease, Reproductive Health, Asthma/Allergy, and Pulmonary (IRAP) Conditions Study Section Review Panel ( <i>ad hoc member</i> )
Dec. 2006	NIEHS Special Emphasis Panel on Genetics, Air Pollution, and Respiratory Effects (ZES1 TN-E FG P) ( <i>member</i> )
Nov. 2007	NIH Special Emphasis Panel on Community Participation in Research (ZRG1 HOP-S) ( <i>member</i> )
June 2009	NIH Study Section Review Panel on Challenge Grants in Health & Science Research
March 2011	U.S. EPA Science to Achieve Results (STAR) Graduate Fellowship Review Panel – Clean Air Panel ( <i>chair</i> )
Sept. 2011	NIH Special Epidemiology Study Section (ZRG1 PSE K 02 M) ( <i>member</i> )
Oct. 2012	NIH Cardiac and Sleep Epidemiology (CASE) Study Section ( <i>ad hoc member</i> )
June 2013	NIH Special NHLBI Dataset Study Section (ZRG1 PSEQ 56) ( <i>member</i> )
July 2013	NIH “Career Awards” Study Section (ZES1 LWJ-D, K9) ( <i>member</i> )
Sept. 2013-15	Permanent Member, NIH Cardiac and Sleep Epidemiology Study Section (CASE) Study Section
Sept. 2015-17	Permanent Member, NIH Cancer, Heart, and Sleep Epidemiology Study Section (CHSE) Study Section
Nov. 2016	NIEHS R13 Study Section ( <i>member</i> )
Mar. 2018	NIEHS K99 Study Section ( <i>member</i> )
Nov. 2018	NHLBI U01 New Epidemiology Cohort Studies in Heart, Lung, Blood and Sleep Diseases and Disorders Study Section ( <i>member</i> )
Aug. 2019	ZHL1 CSR-B Continuation of Existing Grant Based Epidemiology Cohort Studies in Heart Lung, Blood, and Sleep Diseases and Disorders ( <i>member</i> )
Oct. 2019	NIEHS K99 Study Section ( <i>member</i> )
June 2020	NIEHS K23 Study Section ( <i>member</i> )
Aug. 2020	NIEHS R21 Study Section ( <i>member</i> )
Dec. 2021	NIEHS R21 Study Section ( <i>Chair</i> )

#### Memberships, Offices, And Committee Assignments in Professional Societies

<i>Year</i>	<i>Society/Committees</i>
1980-1996	Air and Waste Management Association (Comm. on Health Effects and Exposure,)
1992-Present	American Thoracic Society (ATS): Environmental and Occup. Health (EOH) Assembly, 1995-1999, 2012-2013: ATS EOH Long Range Planning Committee; 1993-1994, 2002-2004: ATS Program Committee 2006-2007 Chairman of the ATS-EOH Nominating Committee 2010-2018: ATS Environmental Health Policy Committee, member 2012-2014: ATS Environmental Health Policy Committee, Vice-Chairman 2015-2018: ATS Environmental Health Policy Committee, Chairman
1990-present	International Society of Exposure Science
1992-present	International Society for Environmental Epidemiology Annual Meeting Program Committee: 1998, 2000, 2003, 2004, 2006, 2016 ISEE Conference Planning Committee: 2006-2019 ( <i>Chair 2012-2019</i> ) ISEE North American Chapter Policy Committee ( <i>Chair 2019-present</i> ) ISEE 2021 Annual Meeting Scientific Program and Local Planning Committees (member)
2007-2009	New York Academy of Sciences (membership given in appreciation for a 1/23/07 NYAS forum presentation)
2017-present	American Public Health Association (APHA)

## Editorial Positions

### Journal Board Membership

<i>Year</i>	<i>Name of Board</i>
1993-2008	International Society of Exposure Analysis (J. of Exp. Anal. and Environ. Epid.)
2017-present	Environmental Health Perspectives (EHP) Editorial Review Board

### Ad Hoc Manuscript Reviewer

<i>Years</i>	<i>Journal</i>
1996-1998	American Journal of Epidemiology
1994	Archives of Environmental Health
1995-present	Atmospheric Environment
1995-present	Environmental Health Perspectives
1994-present	Environmental Research
2004-present	Environmental Science and Technology
2011-present	Epidemiology
1993-present	Journal of Exposure Analysis and Environmental Epidemiology
1994-present	Journal of the Air and Waste Management Association
1996-present	Journal of the American Medical Association
1997-present	Journal of Occupational and Environmental Medicine
1997-present	Journal of Respiratory and Critical Care Medicine
2013-present	Nature: Climate Change
2006-present	Thorax

### Scientific Report Reviewer

August, 1986	Reviewer for the National Academy of Sciences, Board on Environmental Studies and Toxicology report “The Airliner Cabin Environment: Air Quality and Safety”
October, 2002	Reviewer for the NAS, Board on Environmental Studies and Toxicology report “Estimating the Public Health Benefits of Proposed Air Pollution Regulations”

## Mentoring of Graduate Students, Residents, Post-Doctoral Fellows in Research

Under direct supervision:

<i>Student Name</i>	<i>Type of Position</i>	<i>Time Period</i>	<i>Present Position</i>
Mark Ostapczuk	Masters	1984-1986	Industrial Hyg., Barr Labs, Pomona, NJ
Kazuhiko Ito	Masters/Doctoral	1984-1990	Scientist, NYC Dept. of Health, NYC, NY
Peter Jaques	Masters/Doctoral	1988-1998	Assoc. Prof., Clarkson Univ., Potsdam, NY
R. Charon Gwynn	Masters/Doctoral	1992-1999	Deputy Commissioner, NYC Dept. of Health
Ramona Lall	Masters/Doctoral	2000-2007	Research Sci. IV, NYC Dept. of Health, NY
Ariel Spira-Cohen	Masters/Doctoral	2003-2009	Research Sci. III, NYC Dept. of Health, NY
Kevin Cromar	Masters/Doctoral	2008-2012	Assistant Professor, NYU Marmor Inst.
Lital Yinon	Doctoral	2011-2015	Self-Employed
Chris Lim	Doctoral	2012-2018	Assistant Professor, Arizona State Univ.
Mostafijur Rahman	Doctoral	2016-2020	Post-Doc, Univ. of Southern California

In advisory function (thesis committee):

<i>Student Name</i>	<i>Advisory Role</i>	<i>Time Period</i>	<i>Student's Supervisor</i>
Shao-Keng Liang	Doctoral Committee member	1990-1994	Dr. J. Waldman, UMDNJ, Rutgers
Jerry Formisano	Doctoral Committee member	1997-2000	Dr. M. Lippmann, NYU SOM
Yair Hazi	Doctoral Committee member	1993-2001	Dr. B. Cohen, NYU SOM
Samantha Deleon	Doctoral Committee member	1997-2003	Dr. K Ito, NYU SOM

Chun Yi Wu	Doctoral Committee member 2000-2004	Dr. L.C. Chen, NYU SOM
Carlos Restrepo	Doctoral Committee member 2002-2004	Dr. R. Zimmerman, Wagner, NYU
Shaou-I Hsu	Doctoral Committee member 2000-2009	Dr. M. Lippmann, NYU-SOM
Steven Schauer	Doctoral Committee member 2007-2009	Dr. B. Cohen, NYU-SOM
Christine Ekenga	Doctoral Committee Chair 2009-2011	Dr. G. Friedman-Jimenez, NYU-SOM
Rebecca Gluskin	Doctoral Committee Chair 2009-2012	Dr. Kazuhiko Ito, NYU SOM
Jiang Zhou	Doctoral Committee Chair 2008-2012	Dr. Kazuhiko Ito, NYU SOM
Eric Saunders	Doctoral Committee Chair 2012-2016	Dr. Terry Gordon, NYU SOM
Ruzmyn Vilcassim	Doctoral Committee Chair 2012-2018	Dr. Terry Gordon, NYU SOM

### **Teaching Awards Received**

N/A

### **Major Research Interests**

- 1) Air Pollution Epidemiology: Real-world air pollution exposures and human health effects in the general population and study cohorts of suspected susceptible individuals (e.g., children).
- 2) Aerosol Science: Ambient particulate matter aerosol exposures, including designing and implementing air monitoring equipment to collect human exposures to air pollution.
- 3) Environmental Exposure Assessment: Methods to assess human exposures and health effects from air pollution, especially the development of source apportionment models to separate human effects on the basis of pollution source. Design of epidemiological models/methods that better incorporate potential air pollution confounders/effect modifiers (e.g. weather and genetic influences).

### **Patents**

None

### **Boards and Community Organizations**

1990-1995	St. Mary's Episcopal Church, Tuxedo, NY, Vestry member
1992-2008	Monroe-Woodbury Soccer Club, Coach (Board Member: 1999-2000)
1994-1999	Orange County Citizen's Foundation, Member
1999-2009	Y2CARE Monroe-Woodbury, NY School District Residents Action Group, Founder
2005-present	St. Mary's Episcopal Church, Tuxedo, NY, Community Outreach Committee, Member
2006-present	EPISCOBUILD-Newburgh, NY Habitat for Humanity Advisory Board, Member
2012-2018	St. Mary's Episcopal Church, Tuxedo, NY, Vestry member

### **Military Service**

None

### **International Scientific Meetings Organized**

May 28-30, 2003	"Workshop on the Source Apportionment of PM Health Effects." U.S. EPA PM Centers, Harriman, NY.
Aug. 1-4, 2004	"Sixteenth Conference of the International Society for Environmental Epidemiology," Kimmel Conference Center, Washington Square, New York University, New York City, NY.

### **Scientific Forums for the Public Organized**

June 2001	"Science and Community Interaction Forum on the Environment." Held at Hostos Community College, Bronx, , New York City, NY.
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- October 2001 “Forum on Environmental Health Issues Related to the World Trade Center Disaster.” Held at NYU Law School, Washington Square, New York City, NY.
- October 2002 “2<sup>nd</sup> Annual Forum on the Environmental Health Issues Related to the World Trade Center Disaster.” Held at Manhattan Borough Community College, New York City, NY.
- October 2003 “3<sup>rd</sup> Annual Forum on the Environmental Health Issues Related to the World Trade Center Disaster.” Held at NYU Lower Manhattan Campus, New York City, NY.
- Sept. 2006 “Let's Clear the Air”, South Bronx High School, New York City, NY

### **Invited U.S. House and Senate Congressional Testimony**

- Feb. 5, 1997 “Human Health Effects of Ambient Ozone Exposures” Statement before the Committee on Environment and Public Works, Subcommittee On Clean Air, Wetlands, Private Property, And Nuclear Safety, U.S. Senate, Washington, DC.  
<http://epw.senate.gov/105th/thurston.htm>
- April 16, 1997 “Human Health Effects of Ambient Ozone and Particulate Matter Exposures.” Statement before the Government Reform and Oversight Committee of the U.S. House of Representatives, Washington, D.C.
- May 8, 1997 “Human Health Effects of Ambient Ozone and Particulate Matter Exposures.” Statement before the Subcommittee on Health and Environment, Committee on Commerce of U.S. House of Representatives, Washington,. D.C.
- July 29, 1997, “The Human Health Effects of Ambient Ozone and Particulate Matter Air Pollution.” Statement before the Subcommittee on Commercial and Administrative Law of the Judiciary Committee of the U.S. House of Representatives, Washington,. D.C.  
<http://judiciary.house.gov/legacy/commercial.htm>
- October 22, 1997 “Ozone and Particulate Matter Air Pollution Health Effects.” Statement before the U.S. Senate Committee on Environment and Public Works Subcommittee on Clean Air, Wetlands, Private Property, and Nuclear Safety. Washington, DC.  
<http://epw.senate.gov/105th/thursto2.htm>
- July 15, 1999: “The Mandated Release of Government-Funded Research Data.” Statement before the Committee On Government Reform, Subcommittee on Government Management, Information And Technology, U.S. House of Representatives
- July 26, 2001 “The Human Health Effects Of Air Pollution From Utility Power Plants.” Statement before the Committee on Environment and Public Works, U.S. Senate, Washington, D.C.  
<http://www.c-spanvideo.org/program/PlantE>
- Feb 11, 2002: “The Air Pollution Effects of The World Trade Center Disaster.” Statement before the Committee on Environment And Public Works, Subcommittee On Clean Air, Wetlands, And Climate Change. United States Senate, New York, NY.  
<http://www.c-spanvideo.org/program/Qualitya>
- March 5, 2002 “The Use of the Nationwide Registries to Assess Environmental Health Effects.” Statement before the Committee On Health, Education, Labor, And Pensions, Subcommittee On Public Health, U.S. Senate, Washington, DC.
- Sept. 3, 2002 “The Clean Air Act and The Human Health Effects of Air Pollution from Utility Power Plants.” Statement before the U.S. Senate Committee on Health, Education, Labor, and Pensions, Subcommittee on Public Health, Washington, D.C. <http://www.c-spanvideo.org/program/AirStand>
- April 1, 2004 “The Human Health Benefits Of Meeting the Ambient Ozone And Particulate Matter Air Quality Standards.” Statement before the Committee on Environment

and Public Works, Subcommittee on Clean Air, Climate Change, and Nuclear Safety, U.S. Senate, Washington, D.C.

<http://epw.senate.gov/epwmultimedia/epw040104.ram>

July 19, 2006 “The Science And Risk Assessment Of Particulate Matter (PM) Air Pollution Health Effects.” Statement before the Committee on Environment and Public Works, U.S. Senate, Washington, D.C.

<http://epw.senate.gov/hearingstatements.cfm?id=258766>

May 7, 2008 “Science And Environmental Regulatory Decisions.” Statement before the Committee On Environment And Public Works of The U.S. Senate, Subcommittee on Public Sector Solutions to Global Warming, Oversight, and Children’s Health Protection, U.S. Senate, Washington, D.C.

<http://www.c-spanvideo.org/program/RegulatoryD>

<http://epw.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&HearingID=a1954f70-802a-23ad-4192-fc2995dda7f4>

October 4, 2011 “The Science of Air Pollution Health Effects and the Role of CASAC in EPA Standard Setting” Statement before the Subcommittee on Energy and the Environment, Committee on Science, Space and Technology, U.S. House Of Representatives, Washington, DC.

<http://science.house.gov/hearing/energy-and-environment-subcommittee---hearing-quality-science-quality-air>

## **Other Invited Presentations**

### Regional Presentations

April 21, 1993 “Summertime Smog and Hospital Admissions for Respiratory Illness”, Environmental and Occupational Health Sciences Institute Seminar Series Lecture, UMDNJ-Robert Wood Johnson Medical School, Piscataway, NJ.

Dec .14, 1995 “Health Effects of Acidic Aerosols”, NY State Dept. of Health, Wadsworth Center Seminar, Albany, NY

Jan. 18, 1996 “Outdoor Air Pollution and Asthma in Children “ American Lung Association Press Briefing, New York, NY.

June 1, 1996 “Asthma and Urban Air Pollution”, WHEACT, Harlem Hospital, New York, NY.

July17, 1996 “Asthma and Outdoor Air Pollution”, Making the Connection: Urban Air Toxics & Public Health. Northeast States for Coordinated Air Use Management (NESCAUM), Roxbury, MA

Feb. 11, 1997 “Outdoor Air Pollution and Asthma”, Bellevue Hospital Asthma Clinic *Grand Rounds*. New York City, NY.

Feb. 26, 1998 “Scientific Research for Ozone and Fine Particulate Standards “, Pace University School of Law, White Plains, NY

Nov. 30, 1998 “Outdoor Air Pollution and Asthma”, Center for Urban and Environmental Studies (CUES), NY Academy of Medicine,, New York, NY

Feb. 22, 1999 “Asthma and Air Pollution”, Cornell University, Ithaca, NY

April 28, 2001 “Asthma and Air Pollution in New York City”, NYC Council Environmental Candidate School, NY League of Conservation Voters, New York, NY.

Nov. 1, 2001 “Air Quality and Environmental Impacts Due to the World Trade Center Disaster”, Testimony before the Comm. on Environ. Protection, NYC Council, New York, NY.

Nov. 13, 2001 “WTC Pollution Impacts in Lower Manhattan”, Stuyvesant High School Parents Association General Meeting, Stuyvesant High School, New York, NY

Feb. 28, 2002 “Lung Cancer Effects of Long-Term Exposure to Ambient Fine Particulate Matter”, Mailman School of Public Health, Columbia University, New York, NY.

April 5, 2002 “Air Pollution Impacts of the WTC Disaster”, 23rd Annual Scientific Conference of the NY/NJ Education and Research Center: "Worker Health and Safety: Lessons Learned in the Aftermath of Sept. 11, 2001," Mt. Sinai School of Medicine, NYC, NY

April 21, 2002 “Adverse Health Effects of Power Plant Air Pollution on Children” Earth Day 2002, 14<sup>th</sup> Street Y, New York City, NY.

May 23, 2002 “Human Health Effects of Power Plant Pollution”, Rockland County Conservation Association, Suffern, NY

May 31, 2002 “Environmental Health Impacts of the World Trade Center Disaster”, University of Rochester Medical School, Rochester, NY.

Sept. 19, 2002 “Community Air Pollution Related to the World Trade Center Disaster”. NYC Council Forum: The Environmental Health Consequences of 9/11: Where Do We Stand One Year Later? Borough of Manhattan Community College, New York City, NY.

Oct. 3, 2002 “Community Exposures to Particulate Matter Air Pollution from the World Trade Center Disaster”, Mount Sinai School of Medicine *Grand Rounds*, New York City, NY.

April 11, 2003 “Environmental Impacts of the World Trade Center Disaster”, NIEHS Public Interest Liaison Group, New York City, NY.

April 21, 2003 “Asthma and Air Pollution”, Airborne Threats to Human Health, NIEHS Town Hall Meeting, Syracuse, NY.

May 7, 2003 “Asthma and Air Pollution in NY City” Environmental Candidate School for New York City Council Candidates, Wagner School, NYU, New York City, NY.

July 21, 2003 “Health Effects of Particulate Matter Air Pollution”, Ozone Transport Commission, Philadelphia, PA.

Nov. 18, 2004 “Ambient Air Pollution Particulate Matter (PM): Sources and Health Impacts”. U.S. Environmental Protection Agency, Region 2, New York City, NY.

Feb. 17, 2005 “Community Air Pollution Aspects Of The Demolition Of 9-11 Contaminated Buildings”. Testimony before the Committee on Lower Manhattan Redevelopment, New York City Council, New York City, NY.

Oct. 19, 2005 Air Pollution Health Effects: Consideration of Mixtures. Fall Meeting of the Mid-Atlantic Chapter of the Society of Toxicology (MASOT), East Brunswick, NJ.

Dec. 7, 2006 Asthma and Air Pollution Effects in the South Bronx. New York City Child Health Forum, The Children’s Health Fund, Harlem, NYC, NY.

Jan. 18, 2007 Air Pollution Effects in New York City. NYU Environmental Sciences Seminar Lecture, Washington Square, NYC, NY.

Jan. 23, 2007 The South Bronx Backpack Study: Asthma and Air Pollution in NYC. Presented at the forum "High Asthma Rates in the Bronx: What Science Now Knows and Needs to Learn." New York Academy of Sciences, 7 World Trade Center, NYC, NY.

Oct. 2, 2009 “Diesel Air Pollution and Asthma in New York City”. Brown Superfund Research Program, Brown University, Providence, RI.

June 19, 2012 “The Backpack Study of Asthma and Diesel Air Pollution in the South Bronx”. Region 1 U.S. EPA, Citizen Science Workshop, New York City, NY.

Sept. 23, 2019 “Childhood Health Benefits from Improving Air Quality “. The New York City Council Committee on Environmental Protection, New York City Hall, NY.

Oct. 13, 2020 “NYU Community Townhall-Flu and COVID-19” Speaker. Online Zoom to the Public.

### National Presentations

- Oct. 20, 1987. NIEHS Symposium on the Health Effects of Acid Aerosols: “Re-examination of London, England, Mortality in Relation to Exposure to Acidic Aerosols During 1963-1972 Winters” RTP, NC.
- Aug. 13, 1991 “Kuwait Mortality Risks from SO<sub>2</sub> and Particles: Insights from the London Fogs” The Kuwait Oil Fires Conf., American Academy of Arts and Sciences, Cambridge, MA.
- Jan. 24, 1994 “Air Pollution Epidemiology: Is the Model the Message?” The First Colloquium on Particulate Air Pollution and Human Morbidity and Mortality”. Beckman Center of the NAS, Irvine, CA.
- May 23, 1994 “Ozone Epidemiological and Field Studies”. American Thoracic Society Annual Meeting, Boston, MA.
- May 25, 1994 “Epidemiological Evidence Linking Outdoor Air Pollution and Increased Hospital Admissions for Respiratory Ailments” American Thoracic Society Annual Meeting, Boston, MA.
- May 6, 1996 “Associations Between PM<sub>10</sub> & Mortality in Multiple US Cities”. Second Colloquium on Particulate Air Pollution and Health. Park City, Utah.
- Sept. 5, 1996 “Particulate Matter Exposure Issues for Epidemiology” U.S. EPA Particulate Matter Workshop, RTP, NC
- April 3, 1997 “Health Effects of Ambient Ozone & Particulate Matter” Air and Waste Assoc. Regional Conference On Impacts of EPA’s Proposed Changes to Ozone and PM Standards, Oak Brook, IL
- April 22, 1998 “The New EPA Standards for Ambient PM and Ozone” American Lung Association Annual Meeting, Chicago, IL.
- Dec. 21, 1999 “Global Overview of Human Death and Illness due to Air Pollution”. California Air Resources, Sacramento, CA.
- March 24, 2000 “Estimating Ancillary Impacts, Benefits and Costs Of Proposed GHG Mitigation Policies For Public Health” Resources for the Future, Wash., DC.
- June 24, 2002 “Investigations Into the Environmental Health Impacts Related to the WTC Disaster” Air And Waste Management Annual Meeting, Baltimore, MD.
- July 15, 2002 “Air Pollution and Human Health” NIEHS Built Environment Conference, RTP, NC
- July 26, 2002 “The Human Health Effects of Power Plant Emissions and Associated Air Pollution”, The Environment & Health Forum, Physicians for Social Responsibility, Washington, DC.
- October 7, 2002 “Community Exposures to Particulate Matter Air Pollution from the World Trade Center Disaster” Plenary Speaker at the American Association for Aerosol Research, Charlottesville, North Carolina.
- Nov. 11, 2002 “Characterization of Community Exposures to World Trade Center Disaster Airborne and Settled Dust Particulate Matter Air Pollution”, American Public Health Association Annual Meeting, Philadelphia, PA.
- Dec. 5, 2002 “Susceptibility of Older Adults to Air Pollution”, EPA Workshop on Differential Susceptibility of Older People to Environmental Hazards. National Academy of Sciences, Washington, DC.
- Feb. 3, 2003 “Health Effects of Particulate Matter Air Pollution”, National Air Quality Conference, U.S. EPA, San Antonio, Texas
- May 17, 2003 “Assessing the Influence of Particle Sources and Characteristics on Adverse Health Effects of PM”, PG18 - New Tools to Evaluate the Health Effects of Air Pollution in Epidemiologic Studies. American Thoracic Society Annual Meeting, Seattle, WA.
- Sep. 10, 2003 “Nature and impact of World Trade Center Disaster fine particulate matter air pollution at a site in Lower Manhattan after September 11.” Annual Meeting of the American Chemical Society, New York, NY.

- October 20, 2003 “Translating Air Pollution Risks to the Community” Annual Meeting of the NIEHS Center Directors, Baltimore, MD.
- May 18, 2004 “The Health Imperative for Implementation of the Clean Air Act” State and Territorial Air Pollution Program Administrators/ Association of Local Air Pollution Control Officials (STAPPA/ALAPCO) National Conference, Point Clear, Alabama.
- Oct. 18, 2004 “NIEHS Centers’ Investigations of the World Trade Center Collapse Pollution Exposures and Effects: A Public Health Collaboration” National Institute of Environmental Health Sciences Center Directors’ Meeting, Research Triangle Park, NC.
- May 25, 2005 “Human Health Effects Associated with Sulfate Aerosols”, American Thoracic Society Annual Meeting, San Diego, CA
- Oct. 24, 2005 “The Science Behind the Particulate Matter (PM) Standards” State and Territorial Air Pollution Program Administrators/ Association of Local Air Pollution Control Officials (STAPPA/ALAPCO) National Conference, Alexandria, Virginia.
- Oct. 14, 2008 “Diesel Air Pollution and Asthma Exacerbations in a Group of Children with Asthma” Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Pasadena, California.
- Feb. 26, 2010 “What studies are appropriate to use to estimate health impacts from specific sources such as diesel PM?” CARB Symposium: *“Estimating Premature Deaths from Long-term Exposure to PM<sub>2.5</sub>”*. Sacramento, CA.
- May 6, 2011 “Lung Cancer Risks from Exposure to Fine Particle Air Pollution” NYU Cancer Institute Symposium: “Cancer and the Environment”, NYC, NY.
- May 16, 2012 “The Human Health Effects of Air Pollution” The Air We Breathe: Regional Summit on Asthma and Environment at Allegheny General Hospital, Pittsburgh, PA.
- June 20, 2013 “Particles in our Air: A Global Health Risk”, Northeastern University, Research Seminar. Boston, MA.
- Mar 5, 2015 “Air Pollution, Climate Change and Health”. Stegner Institute Air Quality Symposium, Salt Lake City, Utah.
- Apr 22, 2017 “The Clean Air Health Benefits of Climate Mitigation Action”, Yale University, Global Health & Innovation Conference, New Haven, CT.
- Feb. 8, 2021 “Clearing the Air: the case for lowering US PM<sub>2.5</sub> standards”. Session Discussant. Annual Meeting of the American Association for the Advancement of Science (AAAS). Virtual Online Meeting

#### International Presentations

- May 1, 1987 “Acid Aerosols: Their Origins, Occurrence, and Possible Health Effects”, Canadian Environmental Health Directorate Seminar, Health and Welfare Canada, Ottawa, Canada
- July 2, 1987 “Health Effects of Air Pollution in the US”, University of Sao Paulo, Sao Paulo, Brasil
- Feb. 5, 1991 “Results from the Analysis of Toronto Summer Sulfate and Aerosol and Acidity Data”, Workshop on Current Use and Future Directions of Hospital-Based Data in the Assessment of the Effects of Ambient Air Pollution on Human Health. Health and Welfare Canada, Ottawa, Canada.
- April 23, 1997 “An Evaluation of the Role of Acid Aerosols in Particulate Matter Health Effects”, Conference on the Health Effects of Particulate Matter in Ambient Air. Air & Waste Management Association, Prague, Czech Republic.
- May 12, 1998 “The Health Effects of PM and Ozone Air Pollution”, Air Pollution: Effects on Ontario’s Health and Environment. Ontario Medical Association, Toronto, Canada
- Nov. 1, 1999 “Climate Change and the Health Impacts of Air Pollution”. The Public Health Opportunities and Hazards of Global Warming Workshop at the U.N. Framework Convention on Climate Change, Conference of Parties (COP5), Bonn, Germany.



August 31, 2000 “Particulate Matter Air Pollution and Health in three Northeastern Cities”, World Congress on Lung Health, Florence, Italy

January 29, 2001 “PM Exposure Assessment and Epidemiology”, NERAM International Colloquia: Health and Air Quality: Interpreting Science for Decision Makers. Ottawa, Canada.

Feb. 4-5, 2002: “Air Pollution Exposure Assessment Approaches in U.S. Long-Term Health Studies”, Workshop on Exposure Assessment in Studies on the Chronic Effects of Long-term Exposure to Air Pollution, World Health Organization, Bonn, Germany

May 2, 2002 “Health Effects of Sulfate Air Pollution” Air Pollution as a Climate Forcing Workshop, East-West Center, Honolulu, Hawaii

Sept. 24, 2003 “Identification and Characterization of World Trade Center Disaster Fine Particulate Matter Air Pollution at a Site in Lower Manhattan Following September 11.” Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Perth, Australia.

Dec. 1, 2003 “Terrorism and the Pulmonary Effects of the World Trade Center Disaster Particulate Matter Air Pollution”, British Thoracic Society, London, England.

Aug. 3, 2004 “A Study of Traffic-Related Pm Exposures And Health Effects Among South Bronx Children With Asthma”. Annual Meeting of the International Society for Environmental Epidemiology (ISEE). New York, NY.

Sept 14, 2005 “Results And Implications of The Workshop on the Source Apportionment of PM Health Effects”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Johannesburg, South Africa.

Sept. 4, 2006 “A Source Apportionment of U.S. Fine Particulate Matter Pollution for Health Effects Analysis”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Paris, France.

Sept. 4, 2007 “Applying Attributable Risk Methods to Identify Susceptible Subpopulations”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Mexico City, Mexico.

Aug. 27, 2009 “Ischemic Heart Disease Mortality Associations with Long-Term Exposure to PM<sub>2.5</sub> Components”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Dublin, Ireland.

Dec. 1, 2010 “The Hidden Air Quality Health Benefits of Climate Change Mitigation”. The Energy and Resources Institute (TERI), Lodhi Road, New Delhi, India.

July 17, 2012 “Recent Findings on the Mechanisms and Health Risks of Particulate Matter Air Pollution”, European Centre for Environment & Human Health, Truro, England.

Aug. 29, 2012 “Health Effects of PM Components: NYU NPACT Epidemiology Results and their Integration with Toxicology Results”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Columbia, SC.

May 20, 2013 “Long-term PM<sub>2.5</sub> Exposure and Mortality in the NIH-AARP Cohort”, Annual Meeting of the American Thoracic Society (ATS). Philadelphia, PA.

Oct. 27, 2013 “Human Health Effects and Global Implications of Particle Air Pollution”, Center of Excellence in Exposure Science and Environ. Health, Technion University, Haifa, Israel.

May 17, 2015 “Human Health Co-Benefits of Climate Change Mitigation Measures” in the Environment, Global Climate Change And Cardiopulmonary Health session of the American Thoracic Society (ATS) Annual Meeting in Denver, CO, USA.

Jan. 21, 2016 “Particle Air Pollution: Its Adverse Human Health Effects and Potential Climate Mitigation Health Co-Benefits”. Imperial College. London, England.

Sep. 1, 2016 “Air Quality Health Co-benefits from Climate Change Mitigation Measures”. 2016 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Rome, Italy.

Feb. 12, 2017	“Human Health Effects and Global Implications of Particle Air Pollution”. MASDAR Institute. Abu Dhabi, United Arab Republic.
Apr. 22, 2017	“Clean Air Health Benefits from Climate Change Mitigation Action”. Global Health & Innovation Conference. Yale University, New Haven, CT.
May 22, 2017	“Air Pollution Health Effects of Energy Sources: Which Are the Most Toxic?” American Thoracic Society (ATS) Annual Meeting in Washington, DC. USA.
Oct 29, 2018`	“Health effects of dust, species and components of PM”, Workshop on Evaluating the short-term health effects of desert and anthropogenic dust. At the First WHO Global Conference on Air Pollution and Health / Improving Air Quality, Combatting Climate Change – Saving Lives. World Health Organization, Geneva, Switzerland.
March 8, 2019	“Human Health Effects of Particulate Matter in Bangladesh, and Implications Regarding Biomass Combustion” Kings College, London, England
May 21, 2019	“Policies That Protect Vulnerable Populations The Role of the EPA in the Current Climate” American Thoracic Society (ATS) Annual Meeting in Dallas, TX. USA.
Oct. 3, 2019	“Breaching Silos: Engendering Interdisciplinary Academic, Research, and Societal Connections”. The Air We Breathe: A Multidisciplinary Perspective School Of On Air Quality. University of Utah, Salt Lake City, UT.
Dec. 12, 2019	“Accelerating the Elimination of Coal Combustion by Focusing on the Health Benefits of Clean Air” 25th UN Conference on Climate (COP25), Madrid, Spain <a href="https://www.imperial.ac.uk/news/194386/align-health-climate-goals-motivate-action/">https://www.imperial.ac.uk/news/194386/align-health-climate-goals-motivate-action/</a>
Aug. 22, 2019	“Civic Engagement by Scientists: Why and How To Make a Difference”, 31 <sup>st</sup> Conference of the Internatioanal Society for Environmental Epidemiology, Utrecht, Netherlands.
Jan. 17, 2020	“The perils posed by the US Environmental Protection Agency's ‘Transparency’ Rule”. Webinar. UCSF Program on Reproductive Health and the Environment.

### Scientific Meeting Sessions Chaired

May 1, 1996	“ <u>Epidemiological Findings</u> ”, 2 <sup>nd</sup> Colloquium on Particulate Air Pollution & Health. Park City, UT.
May 14, 1996	“ <u>Particulate Toxicity</u> ”, American Thoracic Society Annual Meeting, New Orleans, LA.
Jan. 30, 1998	“ <u>Evaluation of PM Measurement Methods</u> ”. PM <sub>2.5</sub> : A Fine Particulate Standard Specialty Conference. Los Angeles, CA.
August 18, 1998	“ <u>Communities and Airports: How to Co-Exist?</u> ”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Boston, MA.
April 28, 1998	“ <u>Clean Air Act Update</u> ”, American Thoracic Society Annual Meeting, Chicago, IL.
Oct. 21, 1998	“ <u>Health Effects and Regulatory Issues in PM</u> ”, Particulate Methodology Workshop,. U.S. EPA Center, for Statistics and the Env., Univ. of Washington, Seattle, WA.
April 26, 1999	“ <u>Pulmonary Smoking and Air Pollution Epidemiology.</u> ” American Thoracic Society Annual Meeting, San Diego, CA
Sept. 6, 1999	“ <u>Personal exposures to Gases and Particles</u> ”, Annual Conference of the International Society for Environmental Epidemiology (ISEE), Athens, Greece.
Jan. 26, 2000	“ <u>Epidemiology of Particulate Matter Air Pollution</u> ”, PM2000 Specialty Conference, Air & Waste Management Assoc., Charleston, SC
March 31, 2000	“ <u>Epidemiology: Particles, Co-pollutants &amp; Morbidity and Mortality</u> ”, Workshop on Inhaled Environmental/Occupational Irritants and Allergens: Mechanisms of Cardiovascular Responses, American Thoracic Society, Scottsdale, AZ
May 8, 2000	“ <u>Outdoor Air Pollution: Epidemiologic Studies</u> ”, American Thoracic Society Annual Meeting, Toronto, Canada
Sept. 5, 2001	“ <u>Mortality Epidemiology Studies</u> ”, Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Garmisch, Germany.

- May 20, 2002 "After September 11: Bio-terrorism and The Environmental Health Aftermath of The World Trade Center Disaster", Plenary Session. American Thoracic Society Annual Meeting, Atlanta, GA.
- April 1, 2003 "Epidemiology: Short-Term and Long-Term Health Effects", Conference on Particulate Matter: Atmospheric Sciences, Exposure, and the Fourth Colloquium on PM and Human Health, Pittsburgh, PA
- May 19, 2003 "Particulate Air Pollution and Diseases in Adults", American Thoracic Society Annual Meeting, Seattle, WA.
- May 21, 2003 "Air Pollution as a Cause of Childhood Asthma and Chronic Airway Disease", American Thoracic Society Annual Meeting, Seattle, WA.
- Sept. 2003 "Unexplained Medical Symptoms", Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Perth, Australia.
- Sept. 25, 2005 "Technology and Health", Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Johannesburg, South Africa.
- June 22, 2006 "Characteristics of PM and Related Considerations", Annual Meeting of the Air and Waste Management Association, New Orleans, LA.
- Sept. 3, 2006 "Air Pollution Mechanisms", Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Paris, France.
- Sept. 20, 2006 "Linkage and Analysis of Air Quality and Health Data", EPA & CDC Symposium on Air Pollution Exposure and Health, RTP, NC
- Sept. 5, 2007 "Radiation Exposures and Health Risks", 2007 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Mexico City, Mexico
- Aug. 26, 2009 "Exploring the Range of Methodological Approaches Available for Environmental Epidemiology." 2009 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Dublin, Ireland
- March 23, 2010 "Exposure to and Health Effects of Traffic Pollution", 2010 American Association for Aerosol Research Conference on Air Pollution and Health, San Diego, CA.
- Sept. 16, 2011 "Susceptibility to Air Pollution", 2011 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Barcelona, Spain.
- Aug. 27, 2012 "Source Apportionment Of Outdoor Air Pollution: Searching For Culprits". 2012 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Columbia, SC.
- Aug. 21, 2013 "Source-specific health effects of air pollution". 2013 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Basel, Switzerland.
- May 19, 2015 "Indoor and outdoor pollution: epidemiology and mechanisms". 2015 Annual Meeting of the American Thoracic Society (ATS). Denver, CO, USA.
- Sept. 1, 2016 "Climate Change, Mitigation Measures and Co-Benefits". 2016 Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Rome, Italy.
- May 22, 2017 "Realizing the Paris Climate Agreement To Improve Cardio-Pulmonary Health: Where Science Meets Policy" American Thoracic Society (ATS) Annual Meeting in Washington, DC. USA.
- Aug. 24, 2020 "Variability of PM<sub>2.5</sub>, Health Effects as a Function of Particle Source and/or Composition. Annual Meeting of the International Society for Environmental Epidemiology (ISEE). Online.

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### *Invited Journal Editorials*

- Thurston GD and Bates DM. (2003). Air Pollution as an Underappreciated Cause of Asthma Symptoms, 2003. JAMA, 290:14, pp. 1915-1916.

- Thurston G.D. (2006). Hospital admissions and fine particulate air pollution. *JAMA*. Oct 25; 296(16):1966.
- Thurston G. (2007). Air pollution, human health, climate change and you. *Thorax*. 2007 Sep; 62 (9): 748-9.
- Thurston GD, Balmes JR. (2012 ). Particulate matter and the environmental protection agency: setting the right standard. *Environmental Health Policy Committee of the American Thoracic Society*. *Am J Respir Cell Mol Biol*. Dec;47(6):727-8. doi: 10.1165/rcmb.2012-0414ED.
- Thurston GD. (2013). Mitigation Policy: Health Co-Benefits. *Nature Climate Change*. Oct. (3) 863-864.
- Thurston GD, Balmes JR. (2017). We need to “Think Different” about PM. *Am. J Resp. & Crit. Care Med*. 2017 Jul 01; 196(1):6-7.
- Thurston GD, Newman J. (2017). “Walking to a Pathway for the Cardiovascular Effects of Air Pollution”. *Lancet*. 2017 Dec 5. pii: S0140-6736(17)33078-7.
- Thurston, GD. The perils posed by the US Environmental Protection Agency's transparency rule *The Lancet Respiratory Medicine*, Volume 6, Issue 8, Pe40-E41, August 01, 2018
- Thurston GD, Rice MB. Air Pollution Exposure and Asthma Incidence in Children: Demonstrating the Value of Air Quality Standards. *JAMA*. 2019 May 21;321(19):1875-1877.

#### Book Chapters

- Thurston, G.D. and Leber, M. The relationship between asthma and air pollution. In: *Emergency Asthma* (ed.: B. Brenner), pp. 127-144. Marcel-Dekker, New York, NY (1999).
- Thurston, G.D. and Ito, K. Epidemiological studies of ozone exposure effects. In: *Air Pollution and Health* (ed.: S. Holgate and H. Koren). Academic Press. London. pp. 485-510 (1999).
- Chen, LC, Thurston, G, and Schlesinger, RB. Acid Aerosols as a Health Hazard. In: *Air Pollution and Health* (ed.: J. Ayres, R. Maynard, and R. Richards). *Air Pollution reviews: Vol. 3*. Imperial College Press. London. pp. 111-161 (2006).
- Thurston, G.D. and Wallace, L. Air Pollution: Outdoor and Indoor Sources. In: *Environmental and Occupational Medicine*, 4<sup>th</sup> Edition (Eds.: W. Rom and S. Markowitz). Lippincott, Williams, and Wilkins, Philadelphia (2006).
- Thurston, G.D. Outdoor Air Pollution. In: *Encyclopedia of Public Health* (ed. K. Heggenhougen) Elsevier Press. (2008).
- Thurston, G.D and Bell, M. Aerosols, global climate, and the human health co-benefits of climate change mitigation. In *Aerosol Handbook* (2<sup>nd</sup> edition) (eds.: Lev S. Ruzer and Naomi H. Harley). CRC Press (2012).
- Thurston, G. and Bell, M. The Human Health Co-benefits of Air Quality Improvements Associated with Climate Change Mitigation. In. *Global Climate Change and Public Health* (eds. Kent E. Pinkerton and William N. Rom). Humana Press (2013).
- Thurston, GD. Outdoor Air Pollution: Sources, Atmospheric Transport, and Human Health Effects. *International Encyclopedia of Public Health*, 2nd Edition (Editor-in-Chief: S.R. Quah). Academic Press (2016).

#### National Academy Committee Books Co-Authored

- National Research Council (NRC), *Waste Incineration & Public Health*. Committee on Health Effects of Waste Incineration. Board on Environmental Studies and Toxicology. National Academy Press, Washington, DC (2000).

### International Reports Co-Authored

Health Canada, *Health and Environmental Impact Assessment Panel Report*, “Joint Industry/Government Study: Sulfur in Gasoline and Diesel Fuels”. Ottawa, Canada. (1997).

World Health Organization (WHO), *Exposure assessment in studies on the chronic effects of long-term exposure to air pollution*. Report EUR/03/5039759. Geneva, Switzerland (2003).

### Journal Commentaries Published

Thurston GD, De Matteis S, Murray K, Scheelbeek P, Scovronick N, Budolfson M, Spears D, Vineis P. Maximizing the Public Health Benefits from Climate Action. *Environ Sci Technol*. 2018 Apr 3;52(7):3852-3853.

### Peer Reviewed Journal Articles/Letters

Thurston, G.D. General Discussion: Atmospheric dispersion modeling - A critical review. *J. Air Pollut. Control Assoc.* 29: 939 (1979).

Thurston, G.D. Discussion of multivariate analysis of particulate sulfate and other air quality variables by principal components - part I. Annual data from Los Angeles and New York. *Atmos. Environ.* 15: 424-425 (1981).

Thurston, G.D., J.D. Spengler and P.J. Samson. An assessment of the relationship between regional pollution transport and trace elements using wind trajectory analysis. *Receptor Models Applied to Contemporary Pollution Problems*, Ed. E. Frederick, Air Pollution Control Association, Pittsburgh, PA (1982).

Spengler, J.D. and G.D. Thurston. Mass and elemental composition of fine and coarse particles in six U.S. cities. *J. Air Poll. Control Assoc.* 33: 1162-1171 (1983).

Currie, L., R. Gerlach, C. Lewis, W.D. Balfour, J. Cooper, S. Dattner, R. DeCesar, G. Gordon, S. Heisler, P. Hopke, J. Shah and G. Thurston. Inter-laboratory comparison of source apportionment procedures: Results for simulated data sets. *Atmos. Environ.* 18: 1517-1537 (1984).

Thurston, G.D. and J.D. Spengler. A quantitative assessment of source contributions to inhalable particulate matter in metropolitan Boston, Massachusetts. *Atmos. Environ.* 19: 9-25 (1985).

Thurston, G.D. and N.M. Laird. Letters: Tracing aerosol pollution. *Science* 227: 1406-1407 (1985).

Thurston, G.D. and J.D. Spengler. A multivariate assessment of meteorological influences on inhalable particle source impacts. *J. Clim. and Appl. Met.* 24: 1245-1256 (1985).

Ozkaynak, H., J.D. Spengler, A. Garsd and G.D. Thurston. Assessment of population health risks resulting from exposures to airborne particles. *Aerosols: Second U.S.-Dutch International Symposium*, Lewis Publishing Co., December 1985 (Peer Reviewed).

Ozkaynak, H., A.D. Schatz, G.D. Thurston, R.G. Isaacs and R.B. Husar. Relationships between aerosol extinction coefficients derived from airport visual range observations and alternative measures of airborne particle mass. *J. Air Pollut. Control Assoc.* 35: 1176-1185 (1985).

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Ozkaynak, H., and G.D. Thurston. Associations between 1980 U.S. mortality rates and alternative measures of airborne particle concentration. *Risk Analysis* 7: 449-460 (1987).

Liroy, P.J., D. Spektor, G. Thurston, N. Bock, F. Speizer, C. Hayes and M. Lippmann. The design considerations for ozone and acid aerosol exposure and health investigation: The Fairview Lake Summer Camp-Photochemical Smog Case Study. *Environ. Int'l.* 13: 27-83 (1987).

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Lippmann, M. and G.D. Thurston. Exposure Assessment - Input into risk assessment. *Arch. Environ. Health* 43: 113-123 (1988).

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