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Via email
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Re: Comments on the Proposed COMAR 26.11.41, Control of Methane Emissions from the Natural Gas Industry

Dear Mr. Mosier:

The Environmental Integrity Project, the Chesapeake Climate Action Network Action Fund, Clean Air Task Force, and Sierra Club (collectively, "Commenters"), submit the following comments on the Maryland Department of the Environment's ("MDE's") proposed regulation limiting methane emissions from certain natural gas facilities in Maryland, which were published in the Maryland Register on July 31, 2020. Specifically, these comments address the Proposed COMAR 26.11.41, Control of Methane Emissions from the Natural Gas Industry ("Draft Rule").

Commenters thank MDE for its work on this important new rule and for considering the comments that follow. While Commenters have identified some concerns with the Draft Rule, we also recognize its strengths, which are also discussed below in the context of specific issues. As MDE has recognized, state regulations like this are especially important given the EPA's recent rollback of the methane standards that apply to oil and natural gas industry facilities.

As discussed in detail below, our greatest concerns relate to the high volume of gas required to trigger the blowdown notification requirement and the exclusion of intermittent-bleed pneumatic devices from the transition to low- and no-bleed devices. Commenters also address the Draft Rule's incorporation of the Cove Point Liquefied Natural Gas facility's leak detection and repair plans by reference. Finally, Commenters discuss the need for regulatory action to address the environmental justice concerns that surround the siting of natural gas infrastructure.

I. Comments on Proposed § .07B – Blowdown Events and Reports

By adopting this rule, Maryland will become the second state in the nation to promulgate a regulation that requires the natural gas industry to report planned and unplanned blowdowns from compressor stations. It will be the first to require industry operators to directly notify communities of large blowdown events in their area.

That being said, the volume of gas that triggers the blowdown notification requirements is too high. The threshold of 1 million standard cubic feet ("scf") represents a very large amount of vented, uncontrolled emissions, and will result in high-emitting blowdowns that do not trigger notification requirements. Assuming a natural gas density of 0.042 pounds ("lbs") per scf,[1] a blowdown can emit approximately 42,000 lbs (21 short tons) of natural gas before triggering notification requirements. In addition to methane, vented gas contains volatile organic compounds and hazardous air pollutants (such as benzene, toluene, ethylbenzene, xylene, and hexane), so it is appropriate that neighboring communities be informed when a blowdown that is considerably smaller than the proposed threshold is planned or anticipated. Since blowdowns can be such a significant source of vented emissions to the atmosphere, the public notification requirement should be tightened to provide fenceline communities with adequate notice and information about these releases.

MDE appears to be seeking a blowdown threshold that is above a de minimis level that would be triggered too frequently—potentially affecting the practicality and effectiveness of the notification system—yet below a level that would exclude significant emission events from notification requirements. While facilities subject to the EPA's Greenhouse Gas Reporting Program ("GHGRP")[2] typically report that they perform a few dozen blowdowns each year,[3] this same data suggests that very few of these blowdowns will trigger the current threshold of 1 million scf—about two per year, total, for the two Maryland facilities that experience blowdown events and report data to the GHGRP, based on the most recent data from each facility (see Table 1 of Attachment A).[4]

The data from Maryland facilities is consistent with nationwide patterns. National GHGRP data for 2018 shows that blowdowns for liquefied natural gas ("LNG") stations and transmission compressor stations emit an average of 0.78 metric tons of methane, or approximately 43,300 scf, per blowdown, as seen in Table 2 of Attachment A.[5] This average incorporates emergency

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[1] EPA, AP-42 5th Edition, Volume 1: 1.4 Natural Gas Combustion, Supp. D, Table 1.4-2 (July 1998), *available at* https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

[2] Only facilities emitting over 25,000 metric tons of greenhouse gases (measured as carbon dioxide equivalent) are required to report emissions to GHGRP. *See* 40 C.F.R. § 98.231. In recent years, only the Cove Point Liquefied Natural Gas Facility ("Cove Point") and the Ellicott City Natural Gas Compressor Station ("Transco Station 190") reported to the program. However, Transco did not report after 2016, presumably because annual emissions dropped below the reporting threshold.

[3] For the years reported (2015-2018 for Cove Point and 2015-2016 for Transco Station 190), the facilities reported varying numbers of blowdowns, from a low of ten for Transco 190 in 2015 to a high of 52 for Cove Point in 2018. The average number per year, per facility, is 29.5. Note that reporting facilities are required to report all blowdowns for which the physical volume of the vented equipment is 50 scf or greater. *See* 40 CFR § 98.233(i). For moderate pressure equipment (~500 p.s.i.), blowdowns as small as ~1,500 scf must therefore be reported to GHGRP. Indeed, GHGRP data shows that operators do report emissions to EPA from blowdowns as small as 500 scf.

[4] GHGRP reports do not include the volume of each blowdown event, but operators must report, for each type of equipment vented, total emissions and the number of blowdown events. This allows calculation of the average blowdown volume for each type of equipment, for each facility. For Cove Point in 2018, the largest volume per blowdown was about 18,500 scf, for pig launchers, so it is clear that Cove Point had no blowdowns over 1 million scf. For Transco Station 190 in 2016, one equipment type (pipelines) had two blowdowns with an average blowdown volume over 1 million scf. This is consistent with data from prior years.

[5] For the national average GHGRP data, the only category of blowdowns within the sector category of "onshore natural gas transmission compression" with average releases greater than the proposed 1 million scf threshold were emergency shutdowns, which averaged 1.3 million scf per event. Notification is generally infeasible for emergency events.

blowdowns, for which advance notice is generally impossible. The national average for LNG and transmission compressor stations excluding emergency blowdowns is 0.71 metric tons of methane, or 39,800 scf, per blowdown (again, see Table 2 of Attachment A)—more than a factor of twenty below the threshold in the Draft Rule.

Clearly, if MDE maintains the extremely high threshold in the Draft Rule, the vast majority of blowdowns—including large events releasing tens of tons of natural gas—will occur without operators notifying neighbors. MDE must set a lower threshold.

Commenters urge MDE to set a blowdown notification threshold of 10,000 scf. In August of last year, the Massachusetts Department of Environmental Protection ("MassDEP") issued Algonquin Gas Transmission, LLC, ("Algonquin") an air quality permit for a new compressor station.[6] This permit requires Algonquin to notify the governments of the four proximate municipalities of planned and unplanned blowdowns with a volume greater than 10,000 scf (relevant excerpts of the permit are included as Attachment B). Applying a threshold of 10,000 scf to GHGRP data that is specific to Maryland facilities, Commenters estimate that this level would be exceeded approximately seven times a year by the Cove Point LNG Facility ("Cove Point") (over a four-year period, 29 blowdowns exceeded 10,000 scf out of 132 blowdowns reported to GHGRP), and approximately 23 times annually by the Ellicott City Natural Gas Compressor Station ("Transco Station 190") (45 blowdowns surpassed 10,000 scf over a two-year period).[7]

If MDE does not adopt the Algonquin precedent of providing notification at the 10,000 scf threshold, we suggest a threshold of 20,000 scf based on Maryland regulations. COMAR 26.11.06.06B requires Maryland installations to control their VOC emissions, with the collateral effect of controlling methane emissions. Transco Station 190's Title V operating permit already incorporates this regulation by reference. Per the regulation, VOC emissions above a specific numerical threshold requires the installations to flare to control the emissions. For facilities constructed before May 12, 1972, this threshold is 200 lbs/day. A threshold of 20 lbs/day applies to facilities constructed on or after this date.

As the threshold in the Draft Rule will only trigger public reporting, as opposed to the control requirements triggered by the VOC thresholds, it is reasonable to use COMAR 26.11.06.06B's lower threshold of 20 lbs of VOC to set a blowdown threshold that represents a significant event above a de minimis level. This 20 lbs of VOC threshold can be converted to a volume of gas using standard assumptions regarding VOC content in transmission natural gas.

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[6] Commenters want to alert MDE to the fact that the First Circuit vacated the permit on June 3, 2020, after residents near the proposed site appealed. The Court vacated the permit based on its determination that MassDEP's best available control technology ("BACT") analysis was insufficient. *See Town of Weymouth, Massachusetts v. Massachusetts Department of Environmental Protection*, 961 F.3d 34, 44-47 (1st. Cir. 2020). The blowdown notification threshold was not at issue. Since the flaw was narrow, the court gave MassDEP 75 days (until August 17, 2020) to remedy the deficiency and issue a new permit. *Id*. at 58-59. MassDEP had the option to request more time. *Id*. It appears that MassDEP availed itself of this option, because DEP is accepting public comments on the BACT issue until September 8th. There is no indication that MassDEP will revisit its decision to set the 10,000 scf blowdown threshold, or that it will issue a permit with a different threshold.

[7] Commenters analyzed available GHGRP blowdown data for Cove Point and Transco Station 190 by calculating an average volume per blowdown of each reporting category (e.g. facility piping, pipeline venting, compressors) annually from 2015 onward. This allows an approximation of how many events in each given year would exceed a chosen reporting threshold, as seen in Table 3 of Attachment A.

Assuming a VOC weight percentage of 2.3% and a weight of 0.042 lbs/scf of gas for transmission gas,[8] the corresponding volume of gas for a 20 lbs/day venting event would be 20,700 scf of gas. We suggest rounding to 20,000 scf as a threshold for the public notice requirement. Cove Point would trigger this threshold an estimated six times per year, while Transco Station 190 would also be required to notify the public of six events a year.[9]

Finally, as stated above, the national average for LNG and transmission compressor stations, excluding emergency blowdowns, in the GHGRP data is 0.71 metric tons of methane, or 39,800 scf, per blowdown, which is more than a factor of twenty below the threshold in the Draft Rule. Although, as discussed above, we strongly advocate a lower reporting threshold, MDE must at least require public notification for blowdowns with emissions that are equal to or greater than this national average, rounded to 40,000 scf. Based on the GHGRP data, Commenters estimate that blowdowns at Cove Point would exceed this threshold an average of 4.5 times per year, while blowdowns from Transco Station 190 would trigger the notification requirement once a year.[10]

Commenters propose that MDE adopt an alternative threshold for the blowdown notification requirements that provides the public with adequate notice of large blowdowns at compressor stations and other affected facilities. MDE should select a 10,000 scf threshold based on the MassDEP compressor station air permit. If MDE does not adopt this threshold, it should require notice for blowdowns over 20,000 scf based on the Maryland regulation that requires installations to control VOC emissions that exceed 20 lbs/day. Finally, MDE also has the option of setting a threshold of 40,000 scf based on GHGRP data. MDE could either insert the alternate threshold in the final rule or address the issue with subsequent amendments.

II. Comments on Proposed § .04 – Natural Gas-Powered Pneumatic Devices Methane Emission Control Requirements

Commenters generally support the approach MDE has taken in the Draft Rule of requiring operators to transition away from high-bleed pneumatic devices—first to low-bleed devices, and then to no-bleed devices (e.g., compressed air, electric valve controllers, mechanical control systems). However, as Commenters noted at the December 16, 2019 Air Quality Control Advisory Council meeting, the Draft Rule only requires this transition for continuous-bleed pneumatic controllers, and does not adequately address intermittent-bleed pneumatic controllers. "Intermittent bleed" is defined in the Draft Rule as a pneumatic controller that is designed to vent noncontinuously.[11] Under the Draft Rule, intermittent-bleed pneumatic devices must comply with leak detection and repair requirements through § .04A, yet are exempt from the low-bleed and no-bleed transition required for continuous-bleed devices under § .04B and C. This distinction is vitally important, as all or nearly all of the pneumatic devices in Maryland appear to be intermittent-bleed pneumatic devices.[12] MDE's draft of the rule from June 28, 2019, did require that all pneumatic devices in the state comply with the low-bleed and no-bleed transition

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[8] EPA, AP-42 5th Edition, Volume 1: 1.4 Natural Gas Combustion. Supplement D, Table 1.4-2 (July 1998), *available at* https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

[9] *See* Table 4 of Attachment A.

[10] *See* Table 5 of Attachment A.

[11] Draft Rule at § .01B(11).

[12] Based on the facilities that report to EPA's GHGRP, as discussed further below.

provisions (see Attachment C). MDE should return to this approach. It is arbitrary and capricious to finalize a rule that does not apply to all or the vast majority of the devices that are used in Maryland.

Of the five existing facilities affected by the Draft Rule, three report emissions and activity data to EPA's GHGRP: Cove Point, Transco Station 190, and Accident Natural Gas Compressor Station and Storage ("Accident Station"). While Cove Point does not include any emissions from pneumatic devices in its GHGRP facility report (so it presumably has no gas-driven controllers), both Accident Station and Transco Station 190 provide data on the number of high-bleed, intermittent-bleed, and low-bleed devices at each facility. Using the most recent reporting year data,[13] these two facilities report 116 pneumatic devices, every single one of which is an intermittent-bleed device. Though Commenters have not found a full inventory of the pneumatic devices at affected compressor stations that do not report to GHGRP,[14] the available GHGRP data suggests that it is likely that a large proportion, if not all, of the pneumatic devices at affected facilities are intermittent-bleed controllers.

The GHGRP data also reveals the magnitude of emissions from intermittent-bleed pneumatic devices in Maryland. In 2018, Accident Station reported emitting 589 metric tons of carbon dioxide equivalent ("CO2e") from its 61 intermittent-bleed pneumatic devices.[15] Transco Station 190 last reported 55 intermittent-bleed pneumatic devices, with estimated emissions of 518 metric tons of CO2e.[16] The GHGRP data uses a 100-year global warming potential from the Intergovernmental Panel on Climate Change's Fourth Assessment Report. Using the higher 20-year global warming potential for methane that MDE has adopted increases this CO2e estimate by a factor of about 3.4.[17] For these two facilities, replacement of these intermittent-bleed devices with no-bleed devices could result in an annual emissions reduction of 3,808 metric tons of CO2e.[18] These emission reductions are foregone by not including these devices in the transition to low-bleed and zero-bleed devices in the Draft Rule.

There is also precedent for transitioning intermittent-bleed devices to no-bleed or low-bleed pneumatics. British Columbia's Board of the Oil and Gas Commission finalized Drilling and Production Regulation 282/2010 in 2018, which became effective on January 1, 2020 (Attachment

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[13] As noted above, Transco Station 190 last reported data to the GHGRP in 2016, with reporting years after stating "Facility discontinued reporting for a valid reason." *See* EPA GHGRP, Transco Station 190 (2016), *available at* https://ghgdata.epa.gov/ghgp/service/facilityDetail/2017?id=1006953&ds=E&et=&popup=true.

[14] The GHGRP data is the best data available to Commenters; it does not appear that MDE conducted a survey of the pneumatic devices in the state as part of its review.

[15] EPA GHGRP, Accident Station (2018), *available at* https://ghgdata.epa.gov/ghgp/service/facilityDetail/2018?id=1008234&ds=E&et=&popup=true.

[16] EPA GHGRP, Transco Station 190 (2016), *available at* https://ghgdata.epa.gov/ghgp/service/facilityDetail/2017?id=1006953&ds=E&et=&popup=true.

[17] The United Nations' Intergovernmental Panel on Climate Change's ("IPCC's") *Fourth Assessment Report* defines a global warming potential ("GWP") of 25 for methane over a 100-year time-frame. MDE correctly used the updated 20-year GWP for methane of 86 from the IPCC's *Fifth Assessment Report* when developing the Draft Rule, which increases CO2e by a factor of approximately 3.4 (86/25), with the assumption that pneumatic emissions are methane.

[18] (518 metric tons + 589 metric tons CO2e)*86/25 = 3,808 metric tons CO2e.

D).[19] These regulations prohibit all existing large compressor stations[20] from using a pneumatic device that emits natural gas after December 31, 2021.[21] In addition, any new facility, of any size, that began operations on or after January 1, 2021, cannot use any pneumatic device that emits natural gas.[22] For facilities that are not gas processing plants or large compressor stations, natural gas emissions are only allowed from pneumatic devices if: (1) The pneumatic device (including intermittent-bleed devices) is low-bleed (lower than 0.17 cubic meters per hour); or (2) the device cannot be operated to meet low- or no-bleed requirements without compromising the safe operation of the facility, is marked, and emissions are minimized.[23]

Since 2010, Wyoming has required that controllers, including intermittent-bleed controllers, at new and modified facilities bleed less than six scf. Otherwise, operators must route the emissions from the controller to a process.[24] A more recent regulation required operators of existing pneumatic controllers in the Upper Green River Basin to replace any pneumatic controllers, again including intermittent-bleed controllers, emitting over 6 scf or to route emissions from those controllers to a process by January 1, 2017.[25]

To ensure that the regulations result in meaningful reductions in methane emissions, and to further Maryland's climate goals, MDE should amend § .04 of the regulation to phase out intermittent-bleed pneumatic controllers. MDE should either revise the Draft Rule now or amend the regulations through subsequent rulemaking. It is arbitrary and capricious for Maryland to finalize a rule that does not meaningfully address the types of pneumatic devices that are most prevalent in Maryland.

III. Comments on Proposed § .03C – Cove Point's Leak Detection and Repair Plans

To control natural gas leaks at Cove Point, the Draft Rule incorporates two site-specific leak detection and repair ("LDAR") plans that apply to Cove Point by reference. The Draft Rule does not comply with the statutory requirements that govern incorporation by reference in a regulation. Most notably, the Draft Rule does not fix the relevant version of either of the two plans

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[19] Province of British Columbia, Board of the Oil and Gas Commission, Drilling and Production Regulation 282/2010 (Dec. 17, 2018), as amended.

[20] "Large compressor station" is defined in the British Columbia regulation as a compressor station where the total power of all the compressors is 3 MW or greater. *Id*. at § 52.05(1).

[21] *Id*. at § 52.05(3).

[22] *Id*. at § 52.05(2).

[23] *Id*. at § 52.05(4)(b).

[24] Wyoming Department of Environmental Quality, *Oil and Gas Production Facilities: Permitting Guidance*, at Ch. 6, § 2 (2010) (excerpts at Attachment E) (stating that gas-operated "pneumatic controllers shall be low [under 6 scf/hour] or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system."). Wyoming applies these provisions to both continuous-bleed and intermittent-bleed pneumatic controllers. *See* Email from Mark Smith, Wyoming Department of Environmental Quality, to David McCabe, CATF (Sept. 22, 2014) (Attachment F).

[25] Wyoming Air Quality Standards and Regulations, at Ch. 8 § 6(f); *see also* Wyoming Department of Environmental Quality, *Comment Response Concerning the Proposed Wyoming Air Quality Standards and Regulations, Chapter 8, Section 6, Nonattainment Area Regulations*, at 10 (Feb. 27, 2015) (relevant pages at Attachment G) ("The regulation does not limit operators from using intermittent or continuous bleed controllers as long as the bleed rate is below the 6 standard cubic feet per hour (scfh) threshold.").

by "edition number, year, or other specific indication of the version being adopted," as required by § 7-207 of the State Government article of the Maryland Code.

A. Statutory Requirements for Incorporation by Reference

Agencies that wish to incorporate a document into a regulation by reference must comply with § 7-207. The statute allows agencies to incorporate non-governmental publications into their regulations only if certain requirements are met.[26] Pursuant to these requirements, regulations must incorporate a specific version of the document, identifying it by "an edition number, year, or other specific indication of the version being adopted."[27] Further, "prospective incorporation" is not allowed for materials in this category.[28] Prospective incorporation means that the regulation incorporates future versions of the referenced document, so that the regulation itself does not need to be revised when a new version of the document issues.

B. Incorporation by Reference in the Draft Rule

The Draft Rule does not subject Cove Point to the general LDAR requirements that apply to compressor stations. Instead, Cove Point must comply with two LDAR plans that are specific to its operations. These are the only LDAR requirements that the Draft Rule imposes on Cove Point. The Draft Rule incorporates both LDAR plans by reference, without explicitly setting out the requirements they impose on Cove Point. Specifically, § .03C of the Draft Rule states:

> C. Cove Point Liquefied Natural Gas facility shall comply with:
>
> > (1) The leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06B – E; and
> >
> > (2) The leak detection and repair plan defined and approved under the Certificate of Public Convenience and Necessity, issued by the Maryland Public Service Commission on May 30, 2014, Order No. 86372, Case No. 9318, as amended on February 6, 2018, with Order No. 88565, and Errata on February 23, 2018, Order No. 88565, as amended.[29]

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[26] Other materials concerned with incorporation by reference support this interpretation of § 7-207's two-part structure. *The Research Guide for Maryland Regulations*, promulgated by the Division of State Documents in 1992, describes § 7-207: "Not only is there [a] statutory provision permitting incorporation by reference of documents, but in some cases incorporation is actually required." *See* Maryland Office of the Secretary of State, Division of State Documents, *Research Guide for Maryland Regulations*, at 8 (1992) ("Research Guide"); *see also* Maryland Office of the Secretary of State, Division of State Documents, *Incorporation by Reference (IBR) Manual*, at 6-19 (July 2009) ("IBR Manual").
[27] Maryland Code, State Government, § 7-207(a)(4)(iii).
[28] Maryland Code, State Government, § 7-207(a)(4)(iv). The Research Guide affirms that documents in this category must be fixed by edition, publisher, or year. Prospective incorporation is not allowed, so "[c]hanges [to the incorporated document] must be proposed in the form of an amendment to the regulation that originally incorporated the document." Research Guide at 9.
[29] 47 Md. Reg. 729, 761 (July 31, 2020).

Under the Climate Action Plan ("CAP"),[30] Cove Point's import facility needs to meet the LDAR requirements in its Greenhouse Gas Monitoring and Repair Plan ("Import LDAR Plan"). The second LDAR plan Cove Point must follow derives from the Certificate of Public Convenience and Necessity ("CPCN")[31] issued by the Maryland Public Service Commission ("PSC") for Cove Point's export facility ("Export LDAR Plan").[32] As both of these plans are separate from the CAP and CPCN, which are themselves separate from the Draft Rule, the Draft Rule effectively employs two layers of incorporation by reference to impose LDAR requirements on Cove Point.

The Draft Rule does specify the relevant version of the CPCN by date and arguably fixes the CAP. However, the Draft Rule does not fix the version of either the Import or the Export LDAR Plan by year, edition, or otherwise, contrary to the statutory requirements. This is exemplified by the fact that the Export and Import LDAR Plans underwent revision while MDE was developing the Draft Rule, yet the language incorporating each plan by reference did not change during the drafting process. To clarify, MDE released its second "discussion draft" of the regulation on October 11, 2019. At the time, the original Import LDAR Plan, dated February 2018, was in place. The Export LDAR Plan was in either its second or third iteration at the time of the October 11, 2019 discussion draft.[33] The discussion draft incorporated both plans by reference using the same language as the Draft Rule—the language quoted above—other than a revision related to the date of the CPCN that is not relevant to this discussion. In December 2019, both the Import and the Export LDAR Plans were revised.[34] Yet the incorporation by reference language in the Draft Rule has not changed, other than the irrelevant revision to the CPCN's date noted above. In other words, MDE incorporated both the 2018 and 2020 versions of the Import and Export LDAR Plans into the regulation using the same language, demonstrating that the language in the Draft Rule itself does not fix a specific version of either plan and has already allowed prospective incorporation. There is nothing in this provision of the Draft Rule to prevent the improper incorporation of a 2021 or 2022 version of either plan.

In addition, the subsection that incorporates the Export LDAR Plan states that the CPCN was "issued by the Maryland Public Service Commission on May 30, 2014, Order No. 86372, Case No. 9318, as amended on February 6, 2018, with Order No. 88565, and Errata on February 23, 2018, Order No. 88565, *as amended*." (Emphasis added.) The provision's second use of the term "as amended" can be read to signal that the Draft Rule prospectively incorporates amendments to the Export LDAR Plan. Alternatively, it can be read to prospectively incorporate future versions of the CPCN. Either way, this is impermissible. Under § 7-207, only future versions of federal laws can be prospectively incorporated through use of the phrase "as amended."[35] Other,

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[30] Dominion Energy, *Greenhouse Gas Monitoring and Repair Plan*, at § 1.1 (Dec. 2019). Cove Point developed the Climate Action Plan pursuant to its obligations under the CO_2 Budget Trading Program.
[31] PSC, Certificate of Public Convenience and Necessity, Order No. 86372, Case No. 9318 (May 30, 2014), amended by Order No. 88565 (Feb. 6, 2018), and Errata for Order No. 88565 (Feb. 23, 2018).
[32] Dominion Energy, *LDAR Monitoring Plan, Cove Point Liquefaction Export Facility*, at § 1.1 (Dec. 2019).
[33] Commenters are in possession of the second version of the Export LDAR Plan, dated September 2018.
[34] MDE, *Technical Support Document for New COMAR 26.11.41*, App. D (July 2020).
[35] Maryland Code, State Government, § 7-207(a)(3)(iii)(2); *see also* IBR Manual at 5 ("First, if the agency wants to incorporate future changes to a [federal] law being incorporated by reference, it may do so by using the phrase "as amended." This phrase will automatically incorporate into COMAR future amendments to the federal law. Second, if the agency does not want to prospectively incorporate, "as amended" should not be used and, to clarify the agency's

non-governmental documents must be fixed to a specific version.[36] MDE should revise this use of the term out of the Draft Rule.

At best, the Draft Rule is ambiguous regarding whether it is incorporating specific versions of the plans. At worst, it actively invites prospective incorporation. This approach gives rise to one primary concern that § 7-207 is meant to address.[37] If Cove Point's operator alters the plans, say by weakening the applicable LDAR requirements, then the Draft Rule itself is effectively updated without any of the due process and procedural protections that normally govern changes to regulations.[38] Under the terms of the Export LDAR Plan, Cove Point's operator has the power to unilaterally update the plan as long as it notes the updates in an annual report to MDE.[39] This process does not implicate rulemaking procedures. The Import LDAR Plan does not contain any provisions relevant to plan changes. It has, however, undergone revision in the past.[40] The CAP and CPCN do not discuss or set forth any requirements related to plan changes.

The concerns identified here can be easily remedied by specifying the versions of the two LDAR plans incorporated by the Draft Rule. The Import LDAR Plan was issued in December 2019 under the November 17, 2017 CAP. The Export LDAR Plan was also issued in December 2019 under the CPCN.

In sum, § 7-207 defines the requirements that relate to incorporation by reference. To bring the Draft Rule into compliance with the statute, MDE should fix the Import and Export LDAR Plans to their present versions to prevent the prospective incorporation of any future changes to the plans. The term "as amended" should be removed from the provision.

IV. Addressing Environmental Justice Concerns with the Draft Rule

Given that natural gas infrastructure is increasing in Maryland, Commenters also urge MDE to add a provision to the Draft Rule to ensure that environmental justice concerns are addressed in the siting of any new facilities under this chapter. All too often, the public health and environmental burdens of natural gas infrastructure fall on the low-income communities and communities of color that are most vulnerable to their impacts. Communities of color that are also low-income bear a particularly disproportionate share of these burdens. Siting decisions are a

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intention, the year, or other specific identification, of the version being incorporated should appear in parenthesis following the citation of the law incorporated.").

[36] Maryland Code, State Government, § 7-207(a)(4)(iii).

[37] A second concern is that the plans are not generally available. Documents incorporated by reference must be made publicly accessible through methods defined by statute. Maryland Code, State Government, § 7-207(a)(4)(i)(1) (referencing Maryland Code, Education, § 23-303); *see also* Research Guide at 8; IBR Manual at 7. In its October 11, 2019 presentation, MDE stated: "Cove Point to follow Certificate of Public Convenience and Necessity (CPCN) and Climate Action Plan – which will be made public." It is not clear whether MDE was referring to the LDAR plans produced pursuant to those documents, but this would make sense contextually.

[38] The standards in the current LDAR plans are adequate. It is important that the Draft Rule ensures that these standards are not diluted over time.

[39] Dominion Energy, *LDAR Monitoring Plan, Cove Point Liquefaction Export Facility*, at §§ 6.7, 6.8.

[40] Commenters are in possession of an Export LDAR Plan from September 2018 and an Import LDAR Plan from February 2018. Appendix D of MDE's *Technical Support Document for New COMAR 26.11.41* contains revised versions of the plans, both from December 2019.

major part of this problem. There are not currently protections in place that ensure the problem is fully addressed at the siting stage.

An example of a provision that has been used to help address environmental justice concerns in natural gas compressor siting is § 10.1-1307(E) of the Virginia Code, which governs, among other things, permit approvals issued by the Virginia Air Pollution Control Board ("Board"). Specifically, paragraph E states:

> The Board in making regulations and in approving variances, control programs, or permits, and the courts in granting injunctive relief under the provisions of this chapter, shall consider facts and circumstances relevant to the reasonableness of the activity involved and the regulations proposed to control it, including:
>
> > 1. The character and degree of injury to, or interference with, safety, health, or the reasonable use of property which is caused or threatened to be caused;
> > 2. The social and economic value of the activity involved;
> > 3. The suitability of the activity to the area in which it is located; and
> > 4. The scientific and economic practicality of reducing or eliminating the discharge resulting from such activity.

This provision was instrumental in ensuring that Virginia regulators conducted a comprehensive review of a compressor station proposed for the historic community of Union Hill in Buckingham County, Virginia. The first permit the Board issued for the compressor station was vacated by the U.S. Court of Appeals for the Fourth Circuit on two grounds, one of which was a failure to properly consider environmental justice. "[E]nvironmental justice is not merely a box to be checked,"[41] the court concluded. In vacating the permit for the compressor station, the Fourth Circuit relied on the Virginia statutory provision cited above. "Indeed," wrote the Fourth Circuit, "under Virginia law, the Board is required to consider 'character and degree of injury to . . . health,' and 'suitability of the activity to the area.'"[42] The court faulted Virginia's initial environmental justice review for (a) failing to make "any findings regarding the character of the local population at Union Hill"; (b) failing to consider the potential degree of injury from air pollution to the specific local population; and (c) relying on evidence that was either incomplete or had been discounted by subsequent evidence.[43]

The vacatur of the permit by the Fourth Circuit caused the Board and the Virginia Department of Environmental Quality ("DEQ") to thoroughly and seriously consider the environmental justice implications of the proposal when the company re-applied for the permit. In discussing the compressor station at an Air Board meeting on June 18, 2020, DEQ Director David Paylor stated that his agency had received a new application from Dominion Energy ("Dominion") for the compressor station but had not yet made a determination as to its completeness. He stated:

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[41] *Friends of Buckingham v. State Air Pollution Control Board*, 947 F.3d 68, 92 (4th Cir. 2020) (citing Va. Code Ann. § 10.1–1307(E)).
[42] *Id*. at 87.
[43] *Id*. at 86.

> [DEQ] ha[s] made it clear to Dominion that we will be reviewing the revised application in the context of the findings of the Fourth Circuit. And any recommendation that we would make to the Air Board with regards to that application is going to be informed by the adequacy of the responses that [Dominion] may give to the findings of the Fourth Circuit.[44]

Furthermore, Director Paylor stated that he and his agency intended to ask the Virginia Department of Health, which had conducted a health assessment of the proposed compressor station, to respond to detailed questions about this assessment.

MDE's own grant of authority to regulate air pollutants is substantially similar to that granted to the Virginia Air Pollution Control Board under § 10.1-1307(E) of the Virginia Code. Section 2-301(a)(1) of the Environmental Article of the Code of Maryland specifically grants MDE the broad authority to "adopt rules and regulations for the control of air pollution in this State, including testing, monitoring, record keeping, and reporting requirements." Section 2-301(b) goes on to require that "[i]n adopting any rule of regulation under this title, the Department shall consider, among other things:

> (1) The residential, commercial, or industrial nature of the area affected;
> (2) Zoning;
> (3) The nature and source of various kinds of air pollution;
> (4) The problems of any commercial or industrial establishment that may be affected by the rule or regulation; and
> (5) The environmental conditions, population density, and topography of any area that may be affected by the rule or regulation."[45]

Commenters believe this broad statutory mandate authorizes MDE to issue a regulatory provision that requires analysis of the impacts of natural gas infrastructure on vulnerable communities in siting decisions.

In addition, the Code of Maryland clearly contemplates that State agencies will consider such factors in their decision-making. The Code explicitly requires consideration of socioeconomic factors for siting decisions in other regulatory contexts – such as for electric power plants. Section 3-303 of the Natural Resources Article of the Annotated Code of Maryland requires multiple State agencies—including MDE and the Maryland Department of Natural Resources ("DNR")—to coordinate in implementing "a continuing research program for electric power plant site evaluation and related environmental and land use considerations."[46] Section 3-303 states that the components of this program must include, among numerous other factors, both "(5) [a]n environmental evaluation of electric power plant sites proposed for future development and

[44] Recording of *State Air Pollution Control Board Meeting* (June 18, 2020), *available at* https://register.gotowebinar.com/recording/1575409255257375503 (relevant discussion begins at timestamp 1:00:17).
[45] Maryland Code, Environment, § 2-301(b).
[46] Maryland Code, Natural Resources, § 3-303(a)(1).

expansion and their relationship to the waters and air of the State," and an "(8) [a]nalysis of the socioeconomic impact of electric power generation facilities on the land uses of the State."[47]

Furthermore, in an acknowledgement of the risks that new gas infrastructure poses to environmental justice communities in Maryland, the PSC recently issued a draft rule that would require applicants wishing to construct new fossil fuel generating stations to "[u]se [an environmental justice screening and mapping tool] to identify areas within affected communities that may be subject to additional impacts as a result of permitting and operating the proposed [fossil fuel generating station]."[48] This rulemaking was the result of a complaint brought by groups in Brandywine, Maryland, against the PSC, MDE, and DNR under Title VI of the Civil Rights Act of 1964,[49] which prohibits discrimination on the basis of race, color, or national origin in any programs or activities receiving federal financial assistance. Local groups brought the complaint after the PSC approved yet another gas-fired facility in Brandywine, a predominantly Black community already "overburdened by local sources of pollution."[50] In lieu of further federal investigation, the Maryland agencies agreed to enter into an Informal Resolution Agreement that resulted in the PSC's proposed rule. The Agreement also formally recognized that "MDE has an affirmative obligation to not only eliminate discrimination in their organizational processes but to also *proactively prevent discrimination*."[51]

To proactively prevent discrimination in the siting of the facilities addressed in the Draft Rule, Commenters respectfully urge MDE to revise the Draft Rule to include a provision analogous to § 10.1-1307(E) of the Virginia Code or Environment § 2-301(a)(1) of the Code of Maryland. Ideally, such a provision would explicitly (rather than implicitly, as Paragraph E and § 2-301(a)(1) do) require that future siting decisions for new facilities take into consideration potential impacts on vulnerable populations, including low-income communities and communities of color. For the reasons above, Commenters believe such a provision would not only be squarely within MDE's statutory authority, but would also substantially comport with the Maryland Legislature's clear intention that State regulators take such factors into consideration as a matter of course when making regulatory decisions.

Some of the Commenters raised these concerns in the public stakeholder process that preceded the formal comment period on the Draft Rule, and we are raising them again here because of the critical importance of ensuring that energy infrastructure does not disproportionately harm

[47] Maryland Code, Natural Resources, § 3-303(b).

[48] 47 Md. Reg. 729, 749-54 (July 31, 2020).

[49] 42 U.S.C. §§ 200d–2000d-7.

[50] Complaint under Title VI of the Civil Rights Act of 1964, 42 U.S.C. § 2000d, filed by Earthjustice (May 11, 2016), *available at* https://earthjustice.org/sites/default/files/files/TitleVI-PG-Complaint.pdf. Once all the approved fossil fuel-fired power plants are constructed, there will be a total of three large gas-fired power plants in the immediate vicinity of Brandywine, all within three miles of one another. There will be a total of five large fossil fuel-fired power plants within 13 miles of Brandywine. *Id.*

[51] Letter from Rosanne Goodwill, Director, Office of Civil Rights, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, and Lilian S. Dorka, External Civil Rights Compliance Office, Office of General Counsel, EPA, to Jason Stanek, Chairman, PSC, Ben Grumbles, Secretary, MDE, and Mark J. Belton, Secretary, Maryland Department of Natural Resources, sent on January 30, 2019, to notify the agencies of the resolution of Complaint No. DOT #2016-0361 and EPA Complaint Nos. 28R-16-R3, 29R-16-R3, and 30R-16-R3 filed on June 14, 2016, at Subpart B: Informal Resolution Agreement between MDE and EPA, EPA Complaint Number 29R-16-R3 (emphasis added).

low-income communities and communities of color. Even if MDE does not add the requested provision to the Draft Rule at this time, Commenters strongly urge MDE to issue a regulation in the near future that addresses these issues.

Thank you for considering our comments.

Sincerely,

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Attachment A

Table 1. Expected blowdown frequency estimation using Maryland GHGRP data: 1.0 million scf threshold

		2015				2016				2017				2018			
		N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*
Cove Point LNG	Facility Piping	5	1.1	12,282	0	2	165	4,605,623	2	4	6.1	85,134	0	7	0.08	638	0
	Pipeline Venting	5	0.3	3,350	0	3	177	3,293,718	3	3	7.4	137,703	0	2	0.34	9,490	0
	Compressors	20	0.6	1,675	0	10	0.4	2,233	0	7	0	-	0	34	0.73	1,199	0
	Scrubbers/Strainers	0	0		0	0	0		0	0			0	2	0.05	1,396	0
	Pig Launchers	2	13.5	376,824	0	4	3.6	50,243	0	4	1.5	20,935	0	2	0.74	20,656	0
	ESD	0	0		0	0	0		0	0			0	0			0
	Other > 50cf	0	0		0	7	0.23	1,834	0	4	0.04	558	0	5	0.11	1,228	0
	TOTAL	32			0	26			5	22			0	52			0

32 Blowdowns
0 Blowdowns > 1MMCF

26 Blowdowns
5 Blowdowns > 1MMCF

22 Blowdowns
0 Blowdowns > 1MMCF

52 Blowdowns
0 Blowdowns > 1MMCF

Total for 4 years
132 Blowdowns
5 Blowdowns > 1MMCF

		2015				2016			
		N	tons	CF/event	N*	N	tons	CF/event	N*
Transco Station 190	Compressors	10	5.5	30,704	0	33	9.1	15,394	0
	Pipeline Venting					2	147	4,103,191	2
	TOTAL	10			0	35			2

10 Blowdowns
0 Blowdowns > 1MMCF

35 Blowdowns
2 Blowdowns > 1MMCF

Total for 2 years
45 Blowdowns
2 Blowdowns > 1MMCF

Calculations throughout Attachment A assume a methane percentage of 94% by weight for transmission and distribution. *See* EPA, *Lessons Learned from Natural Gas STAR Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, at 7 (Oct. 2006), *available at* https://www.epa.gov/sites/production/files/2016-06/documents/ll_pneumatics.pdf. They also assume a natural gas density of 0.042 lbs/scf. *See* EPA, AP-42 5th Edition, Volume 1: 1.4 Natural Gas Combustion. Supplement D, Table 1.4-2 (July 1998), *available at* https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

Table 2. EPA GHGRP national blowdown average by sector and equipment type (2018)

	Total blowdowns	Total methane emissions (metric tons)	Methane emissions per blowdown (metric tons)	Approximate average blowdown volume (cubic feet)
LNG import and export equipment	**5,769**	**28.66**	**0.005**	**277**
All other equipment volume ≥ 50 cf	17	0.3	0.020	1,107
Compressors	360	1.3	0.004	201
Facility piping	5,377	18.8	0.003	195
Pig launchers and receivers	6	7.8	1.295	72,275
Pipeline venting	2	0.3	0.170	9,470
Scrubbers/strainers	7	0.1	0.017	944
Onshore natural gas transmission compression	**63,172**	**53,422.68**	**0.846**	**47,210**
All other equipment volume ≥ 50 cf	783	3,711.1	4.740	264,593
Compressors	49,097	25,417.7	0.518	28,901
Emergency shutdowns	170	4,411.1	25.948	1,448,541
Facility piping	9,546	8,939.5	0.936	52,279
Pig launchers and receivers	564	548.4	0.972	54,279
Pipeline venting	706	9,936.1	14.074	785,679
Scrubbers/strainers	2,306	458.9	0.199	11,109
Sector total	**68,941**	**53,451.3**	**0.78**	**43,283**
Excluding emergency shutdowns	**68,771**	**49,040.3**	**0.71**	**39,809**

Table 3. Expected blowdown frequency estimation using Maryland GHGRP data: 10,000 scf threshold

		2015				2016				2017				2018			
		N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*
Cove Point LNG	Facility Piping	5	1.1	12,282	5	2	165	4,605,623	2	4	6.1	85,134	4	7	0.08	638	0
	Pipeline Venting	5	0.3	3,350	0	3	177	3,293,718	3	3	7.4	137,703	3	2	0.34	9,490	0
	Compressors	20	0.6	1,675	0	10	0.4	2,233	0	7	0	-	0	34	0.73	1,199	0
	Scrubbers/Strainers	0	0		0	0	0		0	0			0	2	0.05	1,396	0
	Pig Launchers	2	13.5	376,824	2	4	3.6	50,243	4	4	1.5	20,935	4	2	0.74	20,656	2
	ESD	0	0		0	0	0		0	0			0	0			0
	Other > 50cf	0	0		0	7	0.23	1,834	0	4	0.04	558	0	5	0.11	1,228	0
	TOTAL	32			7	26			9	22			11	52			2

2015	2016	2017	2018	**Total for 4 years**
32 Blowdowns	26 Blowdowns	22 Blowdowns	52 Blowdowns	**132** Blowdowns
7 Blowdowns > 10MCF	9 Blowdowns > 10MCF	11 Blowdowns > 10MCF	2 Blowdowns > 10MCF	**29 Blowdowns > 10MCF**
0 Blowdowns > 1MMCF	5 Blowdowns > 1MMCF	0 Blowdowns > 1MMCF	0 Blowdowns > 1MMCF	**5** Blowdowns > 1MMCF

		2015				2016			
		N	tons	CF/event	N*	N	tons	CF/event	N*
Transco Station 190	Compressors	10	5.5	30,704	10	33	9.1	15,394	33
	Pipeline Venting					2	147	4,103,191	2
	TOTAL	10			10	35			35

2015	2016	**Total for 2 years**
10 Blowdowns	35 Blowdowns	**45** Blowdowns
10 Blowdowns > 10MCF	35 Blowdowns > 10MCF	**45 Blowdowns > 10MCF**
0 Blowdowns > 1MMCF	2 Blowdowns > 1MMCF	**2** Blowdowns > 1MMCF

Table 4. Expected blowdown frequency estimation using Maryland GHGRP data: 20,000 scf threshold

		2015				2016				2017				2018			
		N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*
Cove Point LNG	Facility Piping	5	1.1	12,282	0	2	165	4,605,623	2	4	6.1	85,134	4	7	0.08	638	0
	Pipeline Venting	5	0.3	3,350	0	3	177	3,293,718	3	3	7.4	137,703	3	2	0.34	9,490	0
	Compressors	20	0.6	1,675	0	10	0.4	2,233	0	7	0	-	0	34	0.73	1,199	0
	Scrubbers/Strainers	0	0		0	0	0		0	0			0	2	0.05	1,396	0
	Pig Launchers	2	13.5	376,824	2	4	3.6	50,243	4	4	1.5	20,935	4	2	0.74	20,656	2
	ESD	0	0		0	0	0		0	0			0	0			0
	Other > 50cf	0	0		0	7	0.23	1,834	0	4	0.04	558	0	5	0.11	1,228	0
	TOTAL	32			2	26			9	22			11	52			2

2015	2016	2017	2018	**Total for 4 years**
32 Blowdowns	26 Blowdowns	22 Blowdowns	52 Blowdowns	**132** Blowdowns
2 Blowdowns > 20MCF	9 Blowdowns > 20MCF	11 Blowdowns > 20MCF	2 Blowdowns > 20MCF	**24 Blowdowns > 20MCF**
0 Blowdowns > 1MMCF	5 Blowdowns > 1MMCF	0 Blowdowns > 1MMCF	0 Blowdowns > 1MMCF	**5** Blowdowns > 1MMCF

		2015				2016			
		N	tons	CF/event	N*	N	tons	CF/event	N*
Transco Station 190	Compressors	10	5.5	30,704	10	33	9.1	15,394	0
	Pipeline Venting					2	147	4,103,191	2
	TOTAL	10			10	35			2

2015	2016	**Total for 2 years**
10 Blowdowns	35 Blowdowns	**45** Blowdowns
10 Blowdowns > 20MCF	2 Blowdowns > 20MCF	**12 Blowdowns > 20MCF**
0 Blowdowns > 1MMCF	2 Blowdowns > 1MMCF	**2** Blowdowns > 1MMCF

Table 5. Expected blowdown frequency estimation using Maryland GHGRP data: 40,000 scf threshold

		2015				2016				2017				2018			
		N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*	N	tons	CF/event	N*
Cove Point LNG	Facility Piping	5	1.1	12,282	0	2	165	4,605,623	2	4	6.1	85,134	4	7	0.08	638	0
	Pipeline Venting	5	0.3	3,350	0	3	177	3,293,718	3	3	7.4	137,703	3	2	0.34	9,490	0
	Compressors	20	0.6	1,675	0	10	0.4	2,233	0	7	0	-	0	34	0.73	1,199	0
	Scrubbers/Strainers	0	0		0	0	0		0	0			0	2	0.05	1,396	0
	Pig Launchers	2	13.5	376,824	2	4	3.6	50,243	4	4	1.5	20,935	0	2	0.74	20,656	0
	ESD	0	0		0	0	0		0	0			0	0			0
	Other > 50cf	0	0		0	7	0.23	1,834	0	4	0.04	558	0	5	0.11	1,228	0
	TOTAL	32			2	26			9	22			7	52			0

2015	2016	2017	2018	Total for 4 years
32 Blowdowns	26 Blowdowns	22 Blowdowns	52 Blowdowns	**132** Blowdowns
2 Blowdowns > 40MCF	9 Blowdowns > 20MCF	7 Blowdowns > 40MCF	0 Blowdowns > 40MCF	**18 Blowdowns > 40MCF**
0 Blowdowns > 1MMCF	5 Blowdowns > 1MMCF	0 Blowdowns > 1MMCF	0 Blowdowns > 1MMCF	**5** Blowdowns > 1MMCF

		2015				2016			
		N	tons	CF/event	N*	N	tons	CF/event	N*
Transco Station 190	Compressors	10	5.5	30,704	0	33	9.1	15,394	0
	Pipeline Venting					2	147	4,103,191	2
	TOTAL	10			0	35			2

2015	2016	Total for 2 years
10 Blowdowns	35 Blowdowns	**45** Blowdowns
0 Blowdowns > 40MCF	2 Blowdowns > 40MCF	**2 Blowdowns > 40MCF**
0 Blowdowns > 1MMCF	2 Blowdowns > 1MMCF	**2** Blowdowns > 1MMCF

Attachment B

MassDEP
Commonwealth of Massachusetts
Executive Office of Energy & Environmental Affairs

Department of Environmental Protection

Southeast Regional Office • 20 Riverside Drive, Lakeville MA 02347 • 508-946-2700

August 26, 2019

Mr. Thomas Wooden Jr.
Vice President, Field Operations
Algonquin Gas Transmission, LLC
P.O. Box 1642
Houston, TX 77251-1642

RE: Weymouth
Transmittal No.: X266786
Application No.: SE-15-027
Class: SM-25
FMF No.: 571926
AIR QUALITY PLAN APPROVAL

Dear Mr. Wooden:

The Massachusetts Department of Environmental Protection ("MassDEP"), Bureau of Air and Waste, has reviewed your Non-Major Comprehensive Plan Application ("Application") dated October 2015 with revisions dated May 25, 2018 and a revised Sound Impact Assessment Report dated October 15, 2018. Additionally, this Final Approval incorporates the changes required by the Final Decision dated July 12, 2019 and the Final Decision on Reconsideration dated August 7, 2019 "In Matter of Algonquin Gas Transmission, LLC", Docket Nos. 2019-008, 009, 010, 011, 012, and 013. This Application concerns the proposed construction of a new natural gas compressor station ("Project") located at 50 Bridge Street in Weymouth, Massachusetts. The revised Application bears the seal and signature of Lynne Santos, Massachusetts Registered Professional Engineer Number 47225. Department Form BWP AQ Sound bears the seal and signature of Dale Raczynski, Massachusetts Registered Professional Engineer Number 36207.

This Application was submitted in accordance with 310 CMR 7.02 Plan Approval and Emission Limitations as contained in 310 CMR 7.00 "Air Pollution Control" regulations adopted by MassDEP pursuant to the authority granted by Massachusetts General Laws, Chapter 111, Sections 142A-142N, Chapter 21C, Sections 4 and 6, and Chapter 21E, Section 6. MassDEP's review of your Application has been limited to air pollution control regulation compliance and does not relieve you of the obligation to comply with any other regulatory and statutory requirements.

In response to a public petition, accompanied by over one hundred (100) signatures, the Proposed Plan Approval was subject to a 30-day public comment period. A significant number of comments were received and are addressed in the accompanying Response to Comments ("RTC") document.[1] As a result of the comments received, this Plan Approval has been modified from the initial Proposed Plan Approval, as discussed in the RTC.

[1] https://www.mass.gov/service-details/algonquin-natural-gas-compressor-station-weymouth

MassDEP received an updated Application on May 25, 2018. The Application revisions are reflected in this Plan Approval and include: 1) revised turbine startup, shutdown, and transient event emissions, which are based on updated guidance from the turbine manufacturer; 2) revised emissions modeling, which is based on updated background monitor data and meteorological data; 3) updated gas quality data, based on the Facility owner/operator, Algonquin Gas Transmission, LLC's ("Permittee" or "Algonquin") review of gas analyses system-wide; and 4) updated venting emissions, which are based on engineering design of the Weymouth Compressor Station and electively implementing best management practices, including pressurized holds, to reduce gas releases from operation and maintenance activities.

A supplemental Sound Impact Assessment Report, with a cover letter dated October 16, 2018, presented revised sound impacts and proposed additional sound mitigation measures, which have been incorporated into this Plan Approval.

Additionally, at the direction of Governor Charles Baker, the Massachusetts Department of Public Health ("DPH") hired a contractor to conduct a Health Impact Assessment ("HIA"), which was finalized on January 4, 2019.[2] The HIA analyzed: 1) the current health status of the local community; 2) current background air quality near the proposed project site; 3) the potential health effects of the proposed compressor station on residents of surrounding neighborhoods and municipalities and; 4) possible actions to protect and promote community health in the area. In issuing this Plan Approval, MassDEP has considered the results of the HIA and recommendations contained therein. The changes made as a result of the HIA include: 1) restrictions designed to mitigate noise and dust associated with construction of the Project; 2) enhanced blowdown notification; 3) enhanced leak detection requirements; and 4) requirement for submitting a decommissioning plan.

MassDEP has determined that the Application is administratively and technically complete and that the Application is in conformance with the Air Pollution Control regulations and current air pollution control engineering practice, and hereby grants this Plan Approval for said Application, as submitted, subject to the conditions listed below.

Please review the entire Plan Approval, as it stipulates the conditions with which the Permittee must comply in order for the Facility to be operated in compliance with this Plan Approval.

1. DESCRIPTION OF FACILITY AND APPLICATION

A. PROJECT DESCRIPTION

Algonquin has proposed the installation and operation of a new natural gas compressor station ("Project"). This Project will support the capacity upgrades and expansion of Algonquin's natural gas transmission pipeline system, which runs from Mahwah, New Jersey to Beverly, Massachusetts for further transportation and deliveries on the Maritimes & Northeast Pipeline, LLC system. Collectively, this is referred to as the Atlantic Bridge Project. On January 25, 2017, the Federal Energy Regulatory Commission ("FERC") approved the Atlantic Bridge Project, which includes siting of this Compressor Station.[3]

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[2] http://foreriverhia.com/documents/

[3] "Order Issuing Certificate and Authorizing Abandonment," FERC docket No. CP16-9-000

MassDEP = Massachusetts Department of Environmental Protection.

EPA = United States Environmental Protection Agency

Table 11	
EU	**Reporting Requirements**
Facility-wide	1. The Permittee shall notify MassDEP upon commencement of construction, upon initial startup, and upon commencement of commercial operation of the equipment approved herein. Each notification shall be made within 30 days of the respective milestone.
Facility-wide	2. The Permittee shall notify MassDEP prior to any scheduled maintenance events expected to result in a blowdown with volume expected to be greater than 10,000 scf. The notification shall include the date(s), anticipated time(s), and expected duration of the blowdown(s). The notification shall identify the estimated quantity of emissions from the blowdown, steps taken to minimize emissions, and steps taken to minimize any potential nuisance impacts. This notification shall be provided to MassDEP no later than 72 hours prior to the event. The Permittee shall provide the Town of Weymouth, City of Quincy, Town of Braintree, and Town of Hingham a copy of this notification simultaneously with the notification to MassDEP.
	3. The Permittee shall simultaneously notify MassDEP, the Town of Weymouth, the Town of Braintree, the Town of Hingham, and the City of Quincy of any unplanned releases with a volume greater than 10,000 scf within 2 hours of said event.
	4. The Permittee shall submit to MassDEP all information required by this Plan Approval over the signature of a "Responsible Official" as defined in 310 CMR 7.00 and shall include the Certification statement as provided in 310 CMR 7.01(2)(c).
	5. The Permittee shall notify the Southeast Regional Office of MassDEP, BAW Air Permit Chief by telephone: 508-946-2824, email: Sero.Air@mass.gov, or fax : (508) 946-2865, as soon as possible, but no later than three (3) business day after discovery of any exceedance of Table 8A, 8B, 8C, or 8D requirements. A written report shall be submitted to the Air Permit Chief at MassDEP within ten (10) business days of the notification and shall include: identification of exceedance, duration of exceedance, reason for the exceedance, corrective actions taken, and action plan to prevent future exceedance.
	6. The Permittee shall report to MassDEP, in accordance with 310 CMR 7.12, all information as required by the Source Registration/Emission Statement Form. The Permittee shall note therein any minor changes (under 310 CMR 7.02(2)(e), 7.03, 7.26, etc.), which did not require Plan Approval.
	7. The Permittee shall submit to MassDEP for approval, a pretest protocol at least 30 days prior to testing for any sound impact or emissions testing required in this Plan Approval.
	8. The Permittee shall submit to MassDEP, a final test results report, within 45 days after testing, for all sound impact or emissions testing required in this Plan Approval.

Table 11 Key:

EU = Emission Unit

MassDEP = Massachusetts Department of Environmental Protection.

I. This Plan Approval may be modified or amended when in the opinion of MassDEP such is necessary or appropriate to clarify the Plan Approval conditions or after consideration of a written request by the Permittee to amend the Plan Approval conditions.

J. Pursuant to 310 CMR 7.01(3) and 7.02(3)(f), the Permittee shall comply with all conditions contained in this Plan Approval. Should there be any differences between provisions contained in the General Conditions and provisions contained elsewhere in the Plan Approval, the latter shall govern.

6. MASSACHUSETTS ENVIRONMENTAL POLICY ACT

In a letter dated March 15, 2016 and in a follow-up letter dated May 31, 2016 to the Secretariat of the Executive Office of Energy and Environmental Affairs ("EOEEA"), the Town of Weymouth requested an advisory opinion on the applicability of this proposed Project to review under the Massachusetts Environmental Policy Act ("MEPA"). The request for Advisory Opinion requested MEPA invoke the Fail-Safe provisions, requiring the proposed project go through the MEPA review process. Secondly, the request for Advisory Opinion indicated that the Project may have been improperly segmented from the proposed Access Northeast Project[11]. The request for Advisory Opinion was published in the June 8, 2016 Environmental Monitor for public review and comment, subject to a 20-day comment period.

In a letter dated July 11, 2016 to the Mayor of the Town of Weymouth, the Secretariat of the EOEEA concluded "that the project is not subject to MEPA review and the project does not meet the criteria for invoking Fail-Safe Review." Additionally, a determination was made that the Atlantic Bridge Project and the Access Northeast Project "are sufficiently distinct in purpose, design, and scope that they have independent utility and can be reviewed separately."

Alan S. Pickering
Deputy Regional Director
Bureau of Air and Waste

Enclosure

cc: Mayor Hedlund, Weymouth
rhedlund@weymouth.ma.us
Ted Langill
TLangill@weymouth.ma.us

Mayor Thomas Koch, Quincy
mayorkoch@quincyma.gov

Mayor Joseph Sullivan, Braintree
mayorsoffice@braintreema.gov

Hingham Town Administrator, Thomas Mayo
townadministrator@hingham-ma.gov

[11] On June 29, 2017 Algonquin withdrew the application for the Access Northeast Project from FERC.

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dmccormack@weymouth.ma.us

Weymouth Fire Department
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Algonquin Gas, Gus McLachlan
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MassDEP: Gary Moran
Millie Garcia-Serrano
Kathleen Kerigan

Attachment C

Title 26

DEPARTMENT OF THE ENVIRONMENT

Subtitle 11 AIR QUALITY

Chapter 28 Control of Methane Emissions from the Natural Gas Industry

For Discussion Only

Authority: Environment Article, §§ 1-404, 2-103, 2-1202 and 2-1205, Annotated Code of Maryland

.01 Definitions.

A. In this chapter, the following terms have the meanings indicated.

B. Terms Defined.

(1) “Affected facilities” means any one of the following facilities:

(a) Cove Point Liquefied Natural Gas Station;

(b) Myersville Natural Gas Compressor Station;

(c) Accident Natural Gas Compressor Station and Storage;

(d) Rutledge Natural Gas Compressor Station;

(e) Ellicott City Natural Gas Compressor Station; and

(f) Any new, modified, or reconstructed natural gas compressor station, natural gas underground storage facility, or liquefied natural gas station.

(2) “Audio, visual, olfactory inspection” means sensory monitoring to detect natural gas leaks utilizing a human ear, eyes, and nose.

(3) “Blowdown” means the release of pressurized natural gas from stations, equipment, or pipelines into the atmosphere for maintenance, testing, repair, and replacement activities.

(4) “Component” means a valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, reciprocating compressor rod packing/seal, metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(5) "Continuous bleed" means the continuous venting of natural gas from a gas powered pneumatic device to the atmosphere.

(6) “Difficult-to-monitor” means components that cannot be monitored for natural gas leakage without elevating the monitoring personnel more than two (2) meters above the grade.

(7) “Direct measurement” means use of high volume sampling, calibrated bagging, calibrated flow measuring instrument, or a temporary meter.

(8) “Fuel gas system” means components and equipment that collect and transfer natural gas to be used as a fuel source to on-site natural gas powered equipment other than a vapor control device.

(9) Fugitive Emissions Component.

(a) “Fugitive emission component” means any component that has the potential to emit fugitive emissions of natural gas, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers, vapor collection systems, thief hatches or other openings on a storage vessel, compressors, instruments, natural-gas powered pneumatic devices, and meters.

(b) “Fugitive emission component” does not include devices that vent as a part of normal operations, such as natural gas-driven pneumatic device, insofar as the natural gas discharged from the device’s vent is not considered a fugitive emission.

(10) “Leak or fugitive leak” means any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using U.S. EPA Method 21 (40 CFR 60, Appendix A-7) or any emissions discovered from a fugitive emissions component observed using an auditory, visual or olfactory inspection.

(11) “Leak detection and repair or LDAR” means the inspection of components to detect leaks of total hydrocarbons and the repair of components with leaks above the standards specified in this chapter and within the timeframes specified in this chapter.

(12) “Liquefied natural gas or LNG” means natural gas or synthetic gas having methane (CH4) as its major constituent which has been changed to a liquid.

(13) “LNG station” means a pipeline transmission facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas, and includes all components and stationary equipment within the fence-line.

(14) “Natural gas” means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases, which has methane (CH_4) as its major constituent.

(15) "Natural gas compressor station" means all equipment and components located within a facility fence-line associated with moving natural gas from production fields or natural gas processing plants through natural gas transmission pipelines, or within natural gas storage fields.

(16) "Natural gas underground storage" means all equipment and components associated with the temporary subsurface storage of natural gas in depleted crude oil or natural gas reservoirs or salt dome caverns, not including gas disposal wells.

(17) "Optical gas imaging or OGI" means an instrument that makes emissions visible that may otherwise be invisible to the naked eye.

(18) "Pneumatic device" means an automation device that uses natural gas, compressed air, or electricity to control a process.

(19) "Reciprocating natural gas compressor" means equipment that increases the pressure of natural gas by positive displacement of a piston in a compression cylinder and is powered by an internal combustion engine or electric motor with a horsepower rating supplied by the manufacturer.

(20) "Reciprocating natural gas compressor rod packing" means a seal comprising of a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that leaks into the atmosphere.

(21) "Reciprocating natural gas compressor seal" means any device or mechanism used to limit the amount of natural gas that leaks from a compression cylinder into the atmosphere.

(22) "Sales gas system" means components and equipment that collect and transfer natural gas to be used as a fuel source for natural gas powered equipment off-site..

(23) "Successful repair" means tightening, adjusting, or replacing equipment or a component for the purpose of stopping or reducing fugitive leaks below the minimum leak threshold or emission flow rate standard specified in this chapter.

(24) "Unsafe-to-monitor" means components that cannot be monitored for natural gas leakage because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey.

(25) "Vapor collection system" means equipment and components installed on pressure vessels, separators, tanks, or sumps including piping, connections, reciprocating compressors, natural gas-powered pneumatic devices, and flow-inducing devices used to collect and route emission vapors to a processing, sales gas, or fuel gas system; or to a vapor control device.

(26) "Vapor control device" means destructive or non-destructive equipment used to control otherwise vented emissions.

.02 Applicability.

The provisions of this chapter apply to an affected facility as that term is defined in Regulation .01B of this chapter.

.03 Leak Detection and Repair Requirements

A. Affected facilities that are natural gas compressor stations and natural gas underground storage facilities and use natural gas-powered equipment to compress natural gas shall comply with the following leak detection and repair requirements.

(1) Owners and operators of affected facilities subject to this section shall develop and submit to the Department an initial methane emissions monitoring plan that includes the following items:

(a) A list of all fugitive emissions components, difficult-to-monitor, and unsafe-to-monitor components at an affected facility.

(b) Procedures and timeframes to identify fugitive emissions detection and needed repair.

(c) A defined observation path throughout the site to confirm all components can be viewed and recorded.

(d) Manufacturer and model number of fugitive emissions detection equipment to be used.

(i) If an affected facility uses optical gas imaging to meet the requirements of §A(5) of this regulation, the monitoring plan must include elements specified in 40 CFR §60.5397a (c)(7).

(ii) If an affected facility uses EPA Method 21 (40 CFR 60, Appendix A-7) to meet the requirements of §A(5) of this regulation, the monitoring plan must include elements specified in 40 CFR §60.5397a (c)(8).

(2) Owners and operators of the affected facilities subject to this section shall submit the initial methane emissions monitoring plan required in §A(1) to the Department within 60 days of the adoption of this regulation.

(3) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility shall submit an initial monitoring plan with the elements in §A(1) of this regulation within 60 days of the facility startup operation for each new collection of fugitive emissions components at the new, modified, or reconstructed compressor station.

(4) Except for unsafe-to-monitor components, owners or operators of affected facilities subject to this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar week.

(5) Leak Monitoring Survey.

(a) Owners and operators of affected facilities subject to this section shall inspect all fugitive emission components for leaks using an OGI or EPA Method 21 within 150 days of the adoption of this regulation and quarterly thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses natural gas-powered equipment to compress natural gas shall meet the requirements of §A(5)(a) within 150 days of the startup of the facility's operations.

(c) At least annually, all difficult-to-monitor components shall be inspected for leaks using an optical gas imaging (OGI) camera.

(6) Repair Requirements.

(a) Any leaking fugitive emissions component shall be successfully repaired, replaced, or removed from service as soon as practicable, but no later than 30 calendar days of initial leak detection.

(b) Each repaired or replaced fugitive emissions component must be resurveyed within 30 days after being repaired or replaced using either OGI or EPA Method 21 (40 CFR 60, Appendix A-7).

(i) Owners and operators of facilities subject to this section that use EPA Method 21 (40 CFR 60, Appendix A-7) to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the EPA Method 21 (40 CFR 60, Appendix A-7) instrument indicates a concentration of less than 500 ppm or when no soap bubbles are observed when using a bubble test.

(ii) Owners and operators of affected facilities subject to this section that use optical gas imagining to resurvey the repaired or replaced fugitive emissions component shall consider the fugitive emissions component repaired when the optical gas imaging instrument shows no indication of visible emissions.

(c) A delay of repair may be granted by the Department, if the owner or operator can provide documentation that:

(i) It will take longer than 30 days to have the parts or equipment required to make necessary repairs ordered and delivered;

(ii) Repairing a leaking component is technically infeasible;

(iii) The repair requires a vent or compressor station blowdown; or

(iv) The repair is unsafe to repair during the operation of the unit.

(d) Leaking components under the delay of repair shall be clearly marked and the repair or replacement of the leaking component or equipment must be completed during the next planned compressor station shutdown, vent blowdown, or within 7 days after the owner or operator receives parts or equipment needed to fix the leaking component or equipment.

B. Affected facilities that are natural gas compressor stations and natural gas underground storage facilities and use electric-powered equipment to compress natural gas shall comply with the following leak detection and repair requirements.

(1) Owners and operators of facilities in this section shall meet the requirements of §A(1)—(3) and (6) of this regulation.

(2) Except for unsafe-to-monitor components, owners or operators of facilities in this section shall conduct an audio, visual, and olfactory inspection of all fugitive emission components for leaks or indications of leaks at least once per calendar month.

(3) Leak Monitoring Survey

(a) Owners and operators of affected facilities subject to this section shall inspect all fugitive emission components, including difficult-to-monitor components, for leaks using an optical gas imaging (OGI) or US EPA Reference 21 within 150 days of the adoption of this regulation and annually thereafter.

(b) Owners and operators of affected facilities that install any new, modified, or reconstructed natural gas compressor station or underground storage facility that uses natural gas-powered equipment to compress natural gas shall meet the requirements of §B(3)(a) within 150 days of the startup of the facility's operations.

C. Cove Point Liquefied Natural Gas station shall comply with the leak detection and repair requirements as specified by the Climate Action Plan, which is defined, prepared, and approved under COMAR 26.09.02.06.B – E.

D. Any new, modified, or reconstructed liquefied natural gas station, that begins operations after the effective date of this Chapter, shall comply with §A of this regulation.

E. The Department may approve a new technology or alternative practice to identify leaking fugitive emissions components as an equivalent substitution for the requirements in §A or §B of this regulation, if an owner requests approval from the Department.

.04 Natural Gas-Powered Pneumatic Devices Methane Emission Control Requirements.

A. All affected facilities listed under Regulation .01 of this chapter must follow these requirements and §B of this regulation.

(1) Beginning January 1, 2021, each natural gas-powered pneumatic device shall comply with the leak detection and repair requirements specified in Regulation .03 of this chapter when the device is idle and not controlling.

(2) Beginning January 1, 2021, no natural gas-powered pneumatic device shall vent natural gas at a rate greater than six (6) standard cubic feet per hour.

(3) Each natural gas-powered pneumatic device must be tagged with the month and year of installation, reconstruction, or modification, and identification information including a permanent tag that identifies the natural gas flow rate as less than or equal to six (6) standard cubic feet per hour.

(4) Continuous bleed pneumatic devices in operation may be used provided that the devices meet the following requirements:

(a) The device shall be tested annually using a direct measurement method (high volume sampling, bagging, calibrated flow measuring instrument); and

(b) Any device with a measured emissions flow rate that exceeds six (6) standard cubic feet per hour shall be successfully repaired within 14 calendar days from the date of the exceedance.

B. Beginning January 1, 2022, each natural gas-powered pneumatic device shall:

(1) Collect all vented natural gas with the use of a vapor collection system; or

(2) Use compressed air or electricity to operate.

.05 Reciprocating Natural Gas Compressor Methane Emission Control Requirements.

A. All reciprocating natural gas compressor components at an affected facility shall comply with the leak detection and repair requirements specified in §A(5) and (6) of Regulation .03 of this chapter.

B. Control Measures.

(1) Beginning January 1, 2021, compressor vent stacks used to vent rod packing/seal emissions shall be controlled with the use of a vapor collection system as specified in Regulation .06 of this chapter; or

(2) A reciprocating natural gas compressor with a rod packing/seal with a measured emission flow rate that exceeds 0.5 standard cubic feet per minute, or a combined rod packing or seal emission flow rate that exceeds the number of compression cylinders multiplied by 0.5 standard cubic feet per minute shall be successfully repaired or replaced within 30 calendar days from the date of the exceedance.

C. The reciprocating natural gas compressor rod packing/seal emission flow rate through the rod packing/seal vent stack shall be measured annually by April 1st of each year beginning in 2021 through direct measurement (high volume sampling, bagging, calibrated flow measuring instrument) while the compressor is operating at normal operating temperature.

(1) Direct measurements shall use one of the following methods:

(a) Vent stacks shall be equipped with a meter or instrumentation to measure the rod packing or seal emissions flow rate; or

(b) Vent stacks shall be equipped with a clearly identified access port installed at a height of no more than six feet above grade or a permanent support surface to measure individual or combined rod packing or seal emission flow rates..

(2) If the measurement is not obtained because the compressor is not operating for the scheduled test date then testing shall be conducted within seven calendar days of resumed operation.

D. Delay of Repair

(1) A delay of repair may be granted by the Department if the owner or operator provides documentation that the delivery of parts or equipment required to make necessary repairs will take more than 30 days from the last emission flow rate measurement and have been ordered.

(2) A delay of repair to obtain parts or equipment shall not exceed 60 days from the date of last emission flow rate measurement unless the owner or operator notifies the Department, in writing, of the extended delay and provides an estimated time by which the repairs will be completed.

(3) A reciprocating natural gas compressor with a rod packing/seal emission flow rate measured above the standard specified in §B(2) of this regulation, and which has leaking parts that has been approved by the Department as technically infeasible, unsafe to monitor or requires a facility shutdown shall be successfully repaired by the end of the next planned process shutdown or within 12 months from the date of the flow rate measurement, whichever is sooner.

.06 Vapor Collection System and Vapor Control Devices

A. The vapor collection system shall route all gases, vapors, and fumes to one of the following:

(1) Sales gas system;

(2) Fuel gas system; or

(3) Beginning January 1, 2021, all vapor control devices shall be one of the following:

(a) A non-destructive vapor control device manufacturer-certified to achieve at least 95 percent vapor control efficiency of total emissions and shall not result in emissions of nitrogen oxides (NOx); or,

(b) A destructive vapor control device manufacturer-certified to achieve at least 95 percent vapor control efficiency of total emissions and not more than 15 parts per million volume (ppmv) NOx when measured at 3 percent oxygen; and does not require the use of supplemental fuel gas, other than gas required for a pilot burner, to operate.

B. The vapor collection system shall have no detectable emissions, as determined using auditory, visual, and olfactory inspections as specified in §A(4) of Regulation .03 of this chapter.

C. The vapor collection system shall comply with the leak detection and repair requirements specified in §A(5) and (6) of Regulation .03 of this chapter.

.07 Record Keeping and Reporting Requirements

A. Owners or operators of affected facilities shall maintain, and make available upon request by the Department, a copy of records necessary to verify compliance with the provisions of this chapter.

(1) For each leak monitoring survey conducted according to Regulation .03 of this chapter, owners and operators shall:

(a) Submit a report to the Department within 60 days of each leak monitoring survey with the following information:

(i) Location of each fugitive emission and repair;

(ii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan;

(iii) Number and type of components for which fugitive emissions were detected;

(iv) Number and type of difficult-to-monitor fugitive emission components monitored;

(v) Instrument reading of each fugitive emissions component that requires repair when. EPA Method 21 (40 CFR 60, Appendix A-7) is used for monitoring;

(vi) Number and type of fugitive emissions components that were not repaired;

(vii) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found;

(viii) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found;

(ix) Repair methods applied in each attempt to repair the fugitive emissions components;

(x) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair;

(xi) The date of successful repair of the fugitive emissions component; and

(xii) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(b) Maintain, for at least five years, record of each leak detection and repair inspection, along with the following information:

(i) Date of the survey;

(ii) Beginning and end time of the survey;

(iii) Name of operator(s) performing survey;

(iv) Monitoring instrument used including the manufacturer, model number, serial number, and calibration documentation;

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed;

(vi) Fugitive emissions component identification when EPA Method 21 (40 CFR 60, Appendix A-7) is used to perform the monitoring survey;

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey;

(viii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan; and

(ix) Proof that parts or equipment required to make necessary repairs have been ordered.

(2) For each natural gas-powered pneumatic device, owners and operators shall:

(a) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of the emission flow rate measurement and report annually beginning April 1, 2021;

(b) Maintain records of the date, location and manufacturer specifications for each pneumatic device constructed, modified or reconstructed and report annually beginning April 1, 2021;

(c) Maintain records of the manufacturer's specifications indicating that the device is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour;

(d) Maintain records of the demonstration that the use of pneumatic device with a natural gas bleed rate greater than the applicable standard is required and the reasons why and report annually beginning April 1, 2021;

(e) Maintain records of deviations in cases where the pneumatic device was not operated in compliance with the requirements specified in Regulation .04 of this chapter and report annually beginning April 1, 2021; and

(f) Maintain, for at least five years, purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility.

(3) For each reciprocating natural gas compressor, owners and operators shall:

(a) Maintain, for at least five years from the date of each leak concentration measurement, a record of each rod packing leak concentration measurement found above the minimum leak threshold and report annually beginning April 1, 2021;

(b) Maintain, for at least five years from the date of each emissions flow rate measurement, a record of each rod packing or seal emission flow rate measurement and report annually beginning April 1, 2021;

(c) Maintain, for at least one calendar year, a record that documents the date(s) and hours of operation a compressor is operated in order to demonstrate compliance with the rod packing leak concentration or emission flow rate measurement in the event that the compressor is not operating during a scheduled inspection;

(d) Maintain records that provide proof that parts or equipment required to make necessary repairs have been ordered;

(e) Report annually the cumulative number of hours of operation or the number of months since initial startup or since the previous reciprocating compressor rod packing replacement, whichever is later, and beginning April 1, 2021;

(f) Submit a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure, if applicable;

(g) Report records of deviations that occurred during the reporting period annually beginning April 1, 2021; and

(h) Maintain, for at least five years, a record of purchase orders, work orders, or any in-house or third-party reports produced or provided to the affected facility.

B. Blowdown Events and Reports

(1). Affected facilities shall notify the Department and post notifications on a publicly accessible website at least seven days prior to any planned blowdown event.

(2) Affected facilities shall notify the Department and post notifications on a publicly accessible website within one hour of any emergency blowdown event.

(a) When safety concerns preclude a facility from providing prior notification of an emergency blowdown the requirements of regulation B(2) shall not apply.

(b) In the event a facility is unable to notify the Department or public prior to an emergency blowdown event, the facility shall send notice to the Department within 24 hours indicating the reasoning why prior notice was not possible.

(3) Affected facilities shall report the following information on blowdown emissions within 15 miles of the facility's fence-line to the Department annually by April 1 of each year:

(a) Date and type (i.e. planned or emergency) of each blowdown event;

(b) Methane emissions in metric tons released from each blowdown event; and

(c) Annual methane emissions in metric tons from all blowdown events.

(4) Methane emissions shall be calculated according to procedures in 40 CFR Part 98 Subpart W §98.233(i).

C. Greenhouse Gas Emissions Reporting.

(1) Owners and operators of affected facilities shall report methane, carbon dioxide, and nitrous oxide mass emissions to the Department annually by April 1st.

(2) Owners and operators of affected facilities shall follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in 40 CFR Part 98 Subpart C and 40 CFR Part 98 Subpart W.

(3) The reporting threshold in 40 CFR §98.30 and 40 CFR §98.231 does not exempt an affected facility from following the requirements in §B(1) and (2) of this regulation.

D. All required reports shall be submitted to:

The Maryland Department of the Environment
Air and Radiation Compliance Division
1800 Washington Boulevard, 7th floor
Baltimore MD 21230
Attention Compliance Engineer

Attachment D

PROVINCE OF BRITISH COLUMBIA

REGULATION OF THE BOARD OF THE OIL AND GAS COMMISSION

Oil and Gas Activities Act

The Board of the Oil and Gas Commission orders that, effective January 1, 2020, the Drilling and Production Regulation, B.C. Reg. 282/2010, is amended as set out in the attached Schedule.

DEPOSITED

December 17, 2018

B.C. REG. 286/2018

Date Dec 17/2018

Chair, BOARD OF DIRECTORS

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Oil and Gas Activities Act*, S.B.C. 2008, c. 36, ss. 106, 111 and 112

Other:

R10240117

(c) for each calendar year, the volume of natural gas emitted from the compressor during a period of 15 minutes that is representative of the normal operating conditions of the compressor.

Pneumatic devices

52.05 (1) In this section:

"large compressor station" means a compressor station at which the total power of all compressors is 3 MW or greater;

"pneumatic device" does not include a pneumatic pump or a pneumatic compressor starter.

(2) A facility permit holder who operates a facility that began operations on or after January 1, 2021 must not use at the facility a pneumatic device that emits natural gas.

(3) Beginning on January 1, 2022, a facility permit holder who operates a gas processing plant, or a large compressor station, that began operations before January 1, 2021 must not use at the facility a pneumatic device that emits natural gas.

(4) Beginning on January 1, 2022, a facility permit holder who operates a facility that began operations before January 1, 2021, other than a gas processing plant or a large compressor station, must not use at the facility a pneumatic device that emits natural gas unless

(a) the emissions of natural gas from the device do not exceed 0.17 m^3 per hour, or

(b) all of the following requirements are met:

(i) the facility permit holder has a signed statement, from a professional engineer licensed or registered under the *Engineers and Geoscientists Act*, that

(A) the device cannot be operated so as to meet the requirement in paragraph (a) without compromising the safe operation of the facility, and

(B) it is not practical to replace the device with a device that can be operated so as to meet those requirements;

(ii) the emissions of natural gas from the device are minimized to the extent consistent with efficient operation of the device and safe operation of the facility, and

(iii) the device is marked with a weatherproof and readily visible tag.

(5) Subject to subsection (6), a facility permit holder who operates a facility that uses a pneumatic device that emits natural gas must maintain a record of the following:

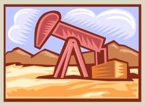
(a) a description of the device;

(b) the purposes and operational settings of the device;

(c) whether the device is being used under subsection (4) (b);

(d) the volume of natural gas emitted from the device in each calendar month.

Attachment E



Oil and Gas Production Facilities
Chapter 6, Section 2 Permitting Guidance

June 1997
Revised November 1998
Revised January 2000
Revised August 2001
Revised July 28, 2004 (specific guidance for Jonah/Pinedale Anticline Area)
Revised August 2007
Revised March 2010

This Guidance applies to surface oil and gas production facilities where hydrocarbon fluids are produced, processed and/or treated prior to custody transfer from the facility.

This Guidance does not apply to natural gas-fired engines unless the engine is used to power a pumping unit.

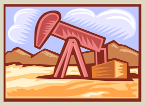
The Presumptive BACT permitting requirements under this Guidance apply to facilities with associated wells spud on/after August 1, 2010 and to facilities with a modification occurring on/after August 1, 2010.

Start up or modification of a facility may occur prior to obtaining an Air Quality Permit or Waiver only when the Presumptive BACT permitting requirements under this Guidance are met. Otherwise, an Air Quality Permit or Waiver shall be obtained prior to start up or modification of a facility.

For the purposes of this Guidance CDA refers to facilities located in Concentrated Development Areas.

JPAD refers to facilities located in the Jonah and Pinedale Anticline Development Area.

STATEWIDE refers to all facilities not located in the CDA or JPAD areas.



Presumptive BACT Requirements for STATEWIDE Facilities cont'd

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low* or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60-days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or no-bleed controllers or the discharge streams of the existing natural gas-operated controllers shall be routed into a closed loop system.

*low bleed devices vent less than 6 cfh

Blow down/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blow down/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blow down/venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 8 TPY VOC or greater than or equal to 5 TPY total HAPs that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

Presumptive BACT Requirements for CDA Facilities cont'd

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low* or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60-days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or no-bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into closed loop system.

*low bleed devices vent less than 6 cfh

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the Concentrated Development Areas. The permits will be modeled after those issued to companies completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or "Green Completions" permit is available on the AQD website, http://deq.state.wy.us/aqd or a copy may be obtained by contacting the Wyoming Air Quality Division at **(307) 777-7391 or (307) 473-3475.**

Green Completion permit applications shall be filed with the Division by November 1, 2010.

Presumptive BACT Requirements for JPAD Facilities cont'd

Pneumatic Heat Trace Pumps & Other Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

For pneumatic pump emissions controlled by a combustion unit used to control flash or dehydration unit emissions which may be removed, the control method for pump emissions will be evaluated upon request for approval to remove the combustion unit. (see Flashing, Page 18)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low* or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60-days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or no-bleed controllers or the controller discharge streams shall be routed into a closed loop system.

*low bleed devices vent less than 6 cfh

Attachment F

Subject: RE: Intermittent-bleed pneumatic controllers
Date: Monday, September 22, 2014 at 8:39:34 AM Eastern Daylight Time
From: Mark D. Smith
To: David McCabe

Yes David. That is correct. We require all controllers to emit less than 6 scf/hr whether the controllers are continuous or intermittent bleed devices.

Mark D. Smith
Air Quality Engineer
Department of Environmental Quality
Air Quality Division
State of Wyoming
122 W. 25th Steet, 2nd Floor East Wing
Cheyenne, WY 82002
(307) 777-8663
(307) 777-5616 (fax)
mark.smith1@wyo.gov

From: David McCabe [mailto:dmccabe@catf.us]
Sent: Friday, September 19, 2014 1:19 PM
To: mark.smith1@wyo.gov
Subject: Intermittent-bleed pneumatic controllers

Hi Mark,

Thanks for discussing how the Wyoming Oil and Gas Production Air Permitting Guidance works with me yesterday.

As I understand it, Wyoming's P-BACT permitting requirements do not allow pneumatic controllers at new or modified facilities to emit more than 6 scfh, <u>whether the controllers are continuous-bleed or intermittent bleed.</u> Is that correct?

Best,

David

David McCabe, PhD
Atmospheric Scientist
Clean Air Task Force
http://www.catf.us
dmccabe@catf.us
mobile +1 626 710 6542

CATF is a nonprofit organization dedicated
to reducing atmospheric pollution through

research, advocacy, and private sector collaboration.

E-Mail to and from me, in connection with the transaction
of public business, is subject to the Wyoming Public Records
Act and may be disclosed to third parties.

Attachment G

February 27, 2015

COMMENT RESPONSE CONCERNING THE PROPOSED WYOMING AIR QUALITY STANDARDS AND REGULATIONS, CHAPTER 8, SECTION 6, NONATTAINMENT AREA REGULATIONS

The Air Quality Division is taking this opportunity to respond to all comments officially submitted prior to the close of the Air Quality Advisory Board meeting on December 10, 2014.

INTRODUCTION

On December 10, 2014 the Air Quality Advisory Board (Board) met in Pinedale, Wyoming. The Air Quality Division (Division) requested the Board's consideration on proposed changes to Wyoming Air Quality Standards and Regulations (WAQSR), Chapter 8, Nonattainment Area Regulations. Chapter 8, Section 6, Upper Green River Basin existing source regulations, was proposed to establish requirements for existing oil and gas production facilities, and compressor stations, located in the Upper Green River Basin (UGRB) ozone nonattainment area (NAA). As indicated in the October 31, 2014 Public Notice, the public was given 30 days (October 31, 2014 – December 1, 2014) to comment on the proposed WAQSR, Nonattainment Area Regulations. Additionally, verbal and/or signed comments presented to the Division at the December 10, 2014 Board meeting were also included as part of the official public record.

The Division appreciates all the input received from interested parties and stakeholders regarding the proposed regulation. The support, additional information and individual concerns provided within the comments were taken into consideration by the Division and are addressed in this document.

The Division has embarked upon this rulemaking to reduce ozone precursor emissions in the UGRB using strategies well known for resulting in the reduction of pollutants for improved air quality. Holding operators of existing facilities to the same standards as operators of new and modified facilities not only levels the playing field among companies but also helps Wyoming stay at the forefront of sensible oil and gas air regulations.

OVERVIEW OF COMMENTS RECEIVED

During the public comment period, including the Board meeting, the Division received twelve (12) individual comment letters. Comments were received from concerned citizens, industrial proponents, a governmental agency, and environmental advocacy groups.

PROCESS FOR TRACKING PUBLIC COMMENTS

Official comments on the existing source regulation were divided into groups by commenter type; citizens, industrial proponents, governmental agencies, and environmental advocacy groups. The Division analyzed each letter and verbal comment to identify potentially substantive comments. Within each commenter group the letters and verbal comments containing substantive comments requiring a response from the Division were given a unique identifying number (e.g. citizen letter 1 is coded C-1, industrial proponent letter 1 is coded P-1, governmental agency verbal comment is codes V-GA-1, Air Quality Advisory Board verbal comment is V-AB-1, and environmental group 2 verbal comment number 2 is V-EG-2).

CONTENT ANALYSIS ANNOTATION

The Content Analysis process was used to identify substantial comments that may require a response from the Division. Substantial comments are identified electronically on the original correspondence or written transcript from the Board meeting, along with their unique identifier by highlighting individual comments. The letter/written transcript identifier and comment number are annotated in the left or right hand margins of the correspondence. Official comment letters, annotated by the Division, are located in Attachment A of this document.

All official comments received are included under specific headings such as: General Comments or Sections of the proposed regulation. Where possible, comments consisting of similar content have been grouped together by topic with the Division's overarching response following.

OFFICIAL COMMENT LOG

Unique Identifying Number	Date Received	Organization or Individual
C-1	11/21/14	Written Comment - Meredith Taylor
C-2	11/24/14	Written Comment - Dave Hohl
C-3	11/28/14	Written Comment - John Otis Carney, Jr.
C-4	11/28/14	Written Comment - Todd J. Herreid
C-5	11/28/14	Written Comment - Jim Roscoe

exceeds the requirements of the proposed regulation, not the Guidance. The determination of affected source applicability will rely on a proponent-initiated permit comparison between the requirements of the proposed regulation and existing permit conditions. An affected owner or operator would determine equipment applicability using the same operating conditions as approved in their federally enforceable Chapter 6, Section 2 permit.

PROPOSED REGULATION - EXISTING PNEUMATIC CONTROLLERS– SECTION 6 (f):

Comment Number(s): P-1-12

RESPONSE:
The use of the term "no-bleed" was already addressed in previous comments on the proposed regulation and the language was revised. "No-bleed" is not used in the proposed regulation.

Comment Number(s): P-1-13, V-P-3-3

RESPONSE:
The intent and purpose of the proposed regulation is that emissions from pneumatic controllers be controlled by utilizing low or zero-bleed rate controllers. The regulation does not limit operators from using intermittent or continuous bleed controllers as long as the bleed rate is below the 6 standard cubic feet per hour (scfh) threshold. The decision to retain the language proposed by the Division is to ensure that controllers used in the ozone nonattainment area are not emitting more than 6 scfh.

PROPOSED REGULATION - FUGITIVES – SECTION 6 (g):

Comment Number(s): V-P-3-5

RESPONSE:
The Division's intent is that the control system inspection is included in an LDAR protocol, which is consistent with Chapter 6, Section 2 permitting actions for new and modified sources. In the case where an operator is not required to implement an LDAR protocol, the operator would be subject to provision (h)(i)(C), the requirements for inspection of the "control systems."

Comment Number(s): EG-1-5, V-AB-1-2, V-P-3-6

RESPONSE:
Due to requests for clarity concerning Subsection (g)(i)(C), the Division revised the language to clarify the requirements of the LDAR quarterly inspections. The Division's intent is to mirror what is required for