August 25, 2020

Ms. Christy Woodward
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Denver, CO 80202

Via Email: christy.woodward@coga.org

RE: Engine Rulemaking Rebuttal and Technical Analysis

Dear Christy,

Spirit Environmental, LLC ("Spirit") was engaged to carefully review and respond to the expert testimony and alternate proposal presented by the National Parks Conservation Association ("NPCA") in their prehearing statement. The data and technical analyses that follow are being provided to the Colorado Oil & Gas Association ("COGA") and outside counsel representing numerous oil and natural gas operators in Colorado.

Summary of NPCA alternate proposal

NPCA submitted an alternate proposal that requests that the Air Quality Control Commission ("AQCC") adopt stricter standards for all engines by requiring that units be electrified where feasible, and that the horsepower ("hp") applicability threshold for four-stroke rich-burn engines ("4SRB") be lowered to 100 hp and greater. Spirit understands that the AQCC has directed that engines below 1000 HP are out of scope for the current rulemaking. As such, Spirit attempts, where possible, to address only those portions of NPCA's proposal related to engines equal to or greater than 1000 HP. In some instances, Spirit's responses implicate engines below 1000 HP because NPCA integrated its analysis of engines both above and below 1000 HP.

NPCA proposed the following language revisions to Regulation 7:

"I.D.5.b.(iii)(a). The owner or operator of any stationary natural gas fired reciprocating internal combustion engine shall electrify the engine unless the owner or operator shows that electrification is infeasible. The Division shall determine whether an owner or operator has demonstrated that electrification is infeasible based on information and data provided by the owner or operator, and any other information reasonably available to the Division (as applicable). In making the determination, the Division shall consider whether there is no reasonable access or opportunity to create access to the power grid, or whether the cost per ton of NOx reduction

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IPANM EXHIBIT 13

would be substantially more than alternative pollution control measures that achieve the same or greater pollution control identified in Table 2. The burden shall be on the owner or operator to demonstrate that electrification of an engine is infeasible based on this standard. (b) If an owner or operator shows, to the Division's satisfaction, that electrification is infeasible, the following emission standards shall apply:

- All 4SRB engine between 100 hp - 500 hp
  - Comply with a 0.25 g/hp-hr NOx limit, OR
  - Install and operate NSCR and AFRC on units.
- All 4SRB engines >500 hp
  - Establish a 0.2 g/hp-hr NOx limit for all units."

The intent of this document is to carefully review NPCA's proposal, and the technical and economic feasibility issues created by such a proposal for engines that would be subject to the Division's draft rule as modified by NPCA's alternate proposal.

Our approach in reviewing NPCA's alternate proposal has been to determine whether the assumptions and claims in its supporting economic impact analysis ("EIA") are accurate, and whether an objective third-party review of control costs and feasibility would yield the same results.

Spirit reached out to several Colorado based control system vendors, engine manufacturers, oil and natural gas operators, and other industry experts to gather costs and other data that are relevant to this discussion. What follows is a summary of our findings and conclusions for the electrification of all subject engines, and the feasibility of lowering the 4SRB emission limit to 0.2 g/hp-hr for engines >1,000hp (as noted in NPCA's proposal).

Electrification

NPCA has requested that the Division alter the proposal to "require owners and operators of engines subject to Regulation Number 7, Part E, Section I.D.5 to electrify their engines unless an operator demonstrates that electrification is infeasible," (NPCA Final Economic Impact Analysis). The cost and challenges presented in electrifying all engines for not only the operator, but the public, are high. The NPCA proposal also inappropriately places the responsibility of determining infeasibility on the operators as opposed to determining this at the time of rulemaking. The Division does not have the capacity or resources to review and address all these individual infeasibility claims on an engine by engine basis. The Division should deem the NPCA alternative proposal technically and economically infeasible as the costs and challenges outweigh any potential benefit electrification of natural gas fired engines equal to or greater than 1,000 hp could provide.

A. Cost Effectiveness and Feasibility

The NPCA claims to adopt the Division's estimates for cost of electrification of engines. NPCA included a Division document as Exhibit 2 – *NOx Emission 4-Factor Analysis for Reasonable Progress*. This document cites a cost of $103 to $4,743 per ton of NOx reduced. Spirit finds this estimate to be far too low and as acknowledged by the Division in the document itself, does not account for a significant number of considerations and costs associated with electrification – particularly for larger engines. Upon review, this estimate was taken from a 2007 document prepared by the Western Regional Air Partnership ('WRAP") titled *Area Source Emissions Inventory Protection and Control Strategy Evaluation – Phase II.* Spirit reviewed the basis for this cost analysis and found that the WRAP did not include many of the significant costs that would be associated with replacing a large natural gas fired engine with an electric motor. Their analysis appears to only include a small cost estimate for the electric motor itself, but no other capital expenditures or ongoing operating and maintenance costs. And notably, the CARB materials do not even address engines above 1000 HP. See Table CE-8-1 below[1].

Table CE-8-1. Capital, O&M and annualized costs by engine horsepower. (CARB, 2001b)

Horse Power Range	Capital Cost	O&M	Annualized Cost
50 - 150	14,000	unknown	$4,492
151 - 300	24,000	unknown	$8,023
301 - 500	40,000	unknown	$12,839
501 - 1000	90,000	unknown	$28,855

Cost Effectiveness: $103/ton-NOx – $4,743/ton-NOx

For example, the WRAP has a stated $90,000 for the cost to purchase an electric motor for a stated horsepower range of 501 to 1,000. Cost estimates from oil and gas operators indicate a cost for the electric motor, labor, and equipment modifications to be at least $500,000, not including other significant capital expenditures or ongoing operation and maintenance expenses. The disparity in costs between these figures is startling. Because the numbers provided by NPCA are not representative of the actual costs, it is inappropriate for NPCA to use this limited information to broadly claim that electrification is cost effective for the oil and natural gas industry.

NPCA also cites a recent study by SW Energy Efficiency Project ("SWEEP") in its Final Economic Impact Analysis. In this study, the author claims that if electricity is available at the site that the replacement of natural gas fired engines with electric motors will result in reduced annual

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[1] Bar-Ilan, Amnon, Ron Friesen, Alison Pollack, and Abigail Hoats (2007), *WRAP Area Source Emissions Inventory Protection and Control Strategy Evaluation – Phase II*, Western Governors Association, Denver, CO. Chapter 4

operating costs and improved energy efficiency. They also claim that this change would significantly reduce methane and CO2 emissions compared with natural gas fired engines. In our opinion these claims are not accurate and sufficient data was not included in the SWEEP document to support these claims. While utility provided electricity may be available at many sites, this does not mean the power is sufficient enough to run large electric compressors at the location. Many of the sites would still need to make significant power upgrades and pay high costs to support such a change. As we will discuss in greater detail below, there are many factors that impact the costs of upgrading electric power at facilities, all of which can have a significant impact on cost.

The SWEEP study also claims that replacement of natural gas fired engines with electric motors is cost-effective and that the reduced maintenance costs associated with electric motors will more than offset the slight increase in annual electricity costs. SWEEP does not provide any actual cost data to support this claim, instead they cite a personal communication email with an engine vendor, who may not have experience with electricity costs for large electric motors. If this statement were correct then clearly oil and natural gas operators would already be electrifying their engines. In fact, data collected from oil and natural gas operators shows that the electricity costs alone are substantially more than routine natural gas fired engine maintenance. One operator shared their electricity costs from their fully electrified facility and noted electricity costs of $800,000 per month to run their station.. Similar to the WRAP study above, this cost analysis appears to leave out key cost parameters that significantly affect the overall cost-effectiveness of electrification of large natural gas fired engines.

Additionally, NPCA cites a California Air Resources Board ("CARB") document as Exhibit-8, which they claim supports their position that electrification of large engines, >1,000 hp, is feasible and cost-effective. We have reviewed this document and find that this is untrue, and that CARB also agrees that this is not the case for larger natural gas fired engines. "*The cost estimates shown in Table V-1 are a mixture of quotes and extrapolations of cost from information provided by industry sources, associations, local governments, and the U. S. EPA. It also includes an estimated cost for replacing engines in various horsepower ranges with an electric motor. Electrification may be a consideration as an alternative for internal combustion engines from 50 to 500 horsepower. Beyond that range, modification and installation costs may become so extensive that this approach may not be cost effective. The costs for electrification assume the units will be located relatively close to a power grid.*"[2]

It is unclear to Spirit why NPCA did not acknowledge or address CARB's statement that electrification may not be cost effective for larger engines. And nowhere does NPCA acknowledge that CARB provided no estimates for engines greater than 1000 HP. In general, we

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[2] California Air Resources Board – *Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for Stationary Spark-ignited Internal Combustion Engines.* https://ww3.arb.ca.gov/ractbarc/rb-icemain.pdf

find that NPCA did not actually conduct a cost analysis of any engines >1,000 hp and is simply extrapolating data for much smaller 50 hp to 500 hp engines using incomplete data to support their claims.

There are several aspects of NPCA's cost-analysis that need to be addressed. First, for electrification of engines to occur, the natural gas fired engine must be replaced with a new electric motor. It is highly unlikely that the horsepower of the compressor and electric motor will match, therefore leading to the need for additional equipment, and potentially a new compressor. Our review found that while it may be possible to couple the existing compressor to the new electric motors, a significant overhaul would also be required and the equipment and labor costs may be so extensive that it could be more cost effective to purchase a new electric motor and compressor as a packaged set. These determinations would need to be made on a case by case basis. Estimates from engine vendors and oil and natural gas operators range from $500,000 to $980,000 per unit to replace a natural gas fired engine greater than 1,000 hp with an electric powered natural gas compressor package depending on size and needs. This cost alone is significant, and not addressed in NPCA's cost analysis. This cost also assumes that sufficient electric power already exists at the site and does not account for any other capital costs or other significant operation and maintenance expenditures related to converting the site.

NPCA's alternate proposal also contains no evaluation of cumulative costs as they relate to this proposal. It relies on the Division's economic impact analysis ("EIA") and concludes "the proposed electrification requirement will not cost owners and operators substantially more than the cumulative costs associated with the NOx pollution limits for engines," (Ex. 2 NPCA EIA at 3). We find this statement to be wholly unsupported.

Spirit received cost analyses from several oil and natural gas operators, and the data indicate a very substantially higher cost in dollars per ton-removed ("$/ton removed") from replacing existing RICE equal to or greater than 1,000 hp with electrically driven motors. Spirit and the oil and natural gas operators used concepts from EPA's BACT/RACT based approach to evaluate the economic impact of replacing natural gas fired engines greater than or equal to 1,000 hp with electric motors. We used a conservative interest rate of 5.5% (which does not include typical opportunity cost) and equipment life of 20 years. The cost that we reviewed, (excluding lost value of existing assets) results in a range of up-front capital costs from about $50,000,000 to upwards of $260,000,000. The company-wide increase in operation and maintenance cost resulting from natural gas to electric conversion ranged from $15,000,000 a year for a small operator, to upwards of $70,000,000 a year for a larger operator. Using assumptions specific to their own fleets, the operators reported a cost-effectiveness range of $40,000 to $350,000 per ton of NOx removed over the life of a replacement electric motor, far in excess of the $103 to $4,743 per ton cost-effectiveness that NPCA cites.

As mentioned above, NPCA's review did not evaluate the numerous costs and factors that impact an operator's ability to electrify a facility. We find that a true cost-effectiveness exercise for the replacement of natural gas fired engines equal to or greater than 1,000 hp with electric motors should carefully review the following:

- Electric motor costs
- Compressor retrofit or new compressor package if not possible
- Potential expansion of facility to accommodate new equipment
- Intra-facility electrical upgrades (e.g. MCC, transformers, facility substation, wiring, buildings)
- Transmission line expansion to facility
- Electrical substation (utility company)
- Right-of-Way ("ROW") costs and acquisition
- Permitting timeframes and lost revenue from long-lead items
- Construction, engineering, and labor costs
- Electric motor maintenance costs
- Electric power costs ($/kWh)
- The NOx emissions from the power plant supplying power to the facility
- The fuel savings and additional natural gas sales resulting from electrification
- The cost from lost production during equipment replacement and downtime

B. Power Availability and Access

Another component to installing electric engines to replace existing natural gas fired engines is the increased electric power requirements for the facility. For sites where connecting to electric power is possible, the additional costs of infrastructure needed to connect to the utility grid falls on the operator. Both transmission lines that carry power at high voltages for long distances, as well as distribution lines that carry power shorter distances to the source, would need to be constructed and run to the facility. A conservative estimate from a utility provider reveals an upfront cost of roughly $2 million for the first mile of transmission line, and an additional $1 million for each mile thereafter. It is also around $3 million per additional substation, plus the cost of additional feeder lines at $40,000 per mile and $38,000 per facility for transformers. In addition to these utility infrastructure costs, data from oil and natural gas operators indicates that the cost of acquiring right-of-way ("ROW") to run the utility lines to the facilities would likely cost an additional $26,000 to $72,000 per mile.

One of the most significant ongoing costs, which was not evaluated in NPCA's proposal, is the annual electricity costs that oil and natural gas operators would incur from the local utility provider. Based on the data we have reviewed, the monthly utility bill to the operators could increase by as much as $30,000 to 60,000 per electric driven compressor per month, based on a 1,380 hp equivalent electric motor[3]. Spirit received information from one operator that noted their fully electric-driven natural gas processing plant costs around $800,000 per month in electricity costs from the utility provider. Annualized, this is $9,600,000 per year in electricity costs.

The Division itself also cites that if all statewide RICE engines above 500 hp were converted to electric, "a minimum of 600 MW of extra generating capacity would be required."[4] Currently, the CDPHE engine inventory indicates that about 1.6 million horsepower of natural gas fired engines greater than 1,000 hp exist in Colorado. The equivalent power from these engines alone is equal to about 1,240 MW of power[5]. Assuming they all operate 8,760 hours per year means they consume up to 11.4 terawatt-hours ("tWh") of power. Within Colorado alone, only about 50 tWh of electric power is generated, meaning an additional 20% of power would need to be produced to meet this demand[6]. In discussions with one of the major electric utility providers, we do not believe it is possible to meet this demand in the next 5-10 years to support this proposal.

NPCA also suggests that the increased electric power demands could be offset by clean renewable energy sources (e.g. solar). Assuming half of the 20% increased power demand statewide could be supplied by solar energy, or about 5.0 tWh, about 15,500 acres of solar panels would need to be installed[7]. Solar power also has the disadvantage that it only produces peak power in full sun exposure, meaning no power is produced at night, and less power is produced during the winter months, making solar infeasible for power production to support this proposal. This renders clean energy that is currently available insufficient for this replacement, and instead points to the expansion of existing coal and natural gas fired power plants across the state in order to reach the increased energy demand from electric engines. Given the rural location of many facilities, coal fired power plants in the area are more common, thus meaning potential benefit from running an electric compressor may be offset in part due to increased NOx emissions from the coal fired electric power source.

Electric power delivery and efficiency is also an issue that is not addressed through NPCA's proposal. Converting a natural gas fired engine to electric motor may seem to provide immediate emission reduction benefits, however, burning one BTU of gas on site to operate a compressor versus burning a BTU of gas at a power plant hundreds of miles away is ultimately less efficient and could result in additional emissions just to supply electricity to the electric compressor due to losses down the electric transmission lines.

C. Timing

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[3] Assumes $0.03-$0.08 cents per kWh
[4] CDPHE – RICE Four-factor Analysis
[5] Standard conversion of 1hp = 0.746kw. [1,661,806 hp X 0.746 kw/1hp = 1,239.23 MW]
[6] https://www.energy.gov/sites/prod/files/2016/09/f33/CO_Energy%20Sector%20Risk%20Profile.pdf (US Dept of Energy – State of Colorado Energy Sector Risk Profile)
[7] NREL - *Land Use Requirements for Solar Power Plants in the United States.* Table ES-1. 3.1 acres of solar for 1 gWh of power. https://www.nrel.gov/docs/fy13osti/56290.pdf

Time constraints to provide electric power to oil and natural gas facilities prove to be another challenge that is not properly addressed by NPCA's proposal. The additional substations, transmission lines, and equipment that would need to be built to provide the increased power needed for electrification could take as much as 3 years. To request additional distribution (< 10 MW) can take at least a year from start to finish, while requesting additional transmission (> 10 MW) would take in excess of three years from start to finish. In addition, residential applications take precedence over industrial projects when it comes to utility companies providing service. This means that a natural gas site awaiting additional transmission would be surpassed by a newly built residence in the area, potentially pushing these timelines further out into the future. Such uncertainty is incompatible with regulations mandating compliance deadlines.

NPCA has oversimplified this process and does not address the significant time constraints and permitting process that supplying electrical power to oil and natural gas facilities creates. While we have not quantified the potential lost revenue from these delays, there would inevitably be business delays and potential lost revenue by delaying projects by 1 to 3 years while waiting for electric power connectivity to the sites.

D. Risk and Reliability

There are also reliability concerns surrounding use of the public power grid. Should a storm or equipment failure take out power in the area, unforeseen additional emissions at upstream facilities or compressor stations due to flaring, blow downs, and other shut down and startup operations would occur. These conditions are not unlikely. According to data gathered from Xcel Energy on an example set of 15 randomly selected oil and natural gas sites, an estimated 158 outages occurred between 2018 to 2020. Even a short outage likely requires the entire facility to restart, which may result in the flaring of natural gas onsite and the associated unaccounted-for emissions. Eastern Colorado also sees frequent afternoon thunderstorms due to prevailing wind patterns over the Rockies and the existence of the Denver Convergence Vorticity Zone. These storms are capable of damaging winds, lightning, and hail, that can take out power lines. Colorado ranks 19th in the nation for number of cloud-to-ground lightning flashes and the Colorado National Weather Service offices collectively issued over 220 high wind warnings across the state from 2010 to 2019 alone (weather.gov). This doesn't include the 530 winter storm warnings that also contain damaging winds and ice that impede reliable electric power delivery to customers.

Lost power due to natural phenomena or utility failures means the electric compressors depending on said power could not operate. Operators could be forced to flare extra gas, resulting in unintended additional emissions.

Overall Spirit finds the broad electrification of natural gas fired engines requirement infeasible. The increased strain on the public power grid burdens the public, while the cost per ton of NOx removed to oil and natural gas operators resulting from additional equipment, power costs, and utility bills is well above what is considered cost-effective.

4SRB Alternative Proposal

NPCA's alternate proposal requests a significant change to the rule applicability by lowering the horsepower threshold from 1,000 hp and greater, to 100 hp and greater for 4SRB engines. However, as noted above, the AQCC rejected engines below 1000 HP as outside of the scope of the rulemaking. In addition, the NPCA's alternate proposal mandates NOx emission limits of 0.2 g/hp-hr for engines greater than 500 hp (or as authorized for consideration by the AQCC, equal to or greater than 1000 HP), much lower than the Division's proposal of 0.8 g/hp-hr for existing 4SRB engines equal to or greater than 1,000 hp and 0.5 g/hp-hr for new 4SRB engines equal to or greater than 1,000.

Throughout its EIA and supporting exhibits, NPCA assumes that the only controls needed to achieve a 0.2 g/hp-hr NOx emission rate are the addition of an air-fuel ratio controller ("AFRC") and non-selective catalytic reduction ("NSCR"). This is also what NPCA's cost estimates are exclusively based on.

Table 1 presents controlled and uncontrolled NOx emission factor values for a range of control device efficiencies representative of 4SRB engines commonly found at oil and gas facilities. Table 1 demonstrates that the NOx emission limits proposed by NPCA are only achievable with control devices providing greater than 98% control of NOx.

Table 1 – Controlled and uncontrolled 4SRB engines NOx emission factors for a range of NSCR/AFRC control efficiencies.

NOx Unc. EF (g/hp-hr) / Control Device Efficiency	12.00	13.00	14.00	15.00	16.00
90.0%	1.20	1.30	1.40	1.50	1.60
90.3%	1.16	1.26	1.35	1.45	1.55
90.7%	1.12	1.21	1.31	1.40	1.49
91.0%	1.08	1.17	1.26	1.35	1.44
91.3%	1.04	1.13	1.21	1.30	1.39
91.7%	1.00	1.08	1.17	1.25	1.33
92.0%	0.96	1.04	1.12	1.20	1.28
92.3%	0.92	1.00	1.07	1.15	1.23
92.7%	0.88	0.95	1.03	1.10	1.17
93.0%	0.84	0.91	0.98	1.05	1.12
93.3%	0.80	0.87	0.93	1.00	1.07
93.7%	0.76	0.82	0.89	0.95	1.01
94.0%	0.72	0.78	0.84	0.90	0.96
94.3%	0.68	0.74	0.79	0.85	0.91
94.7%	0.64	0.69	0.75	0.80	0.85
95.0%	0.60	0.65	0.70	0.75	0.80
95.3%	0.56	0.61	0.65	0.70	0.75
95.7%	0.52	0.56	0.61	0.65	0.69
96.0%	0.48	0.52	0.56	0.60	0.64
96.3%	0.44	0.48	0.51	0.55	0.59
96.7%	0.40	0.43	0.47	0.50	0.53
97.0%	0.36	0.39	0.42	0.45	0.48
97.3%	0.32	0.35	0.37	0.40	0.43
97.7%	0.28	0.30	0.33	0.35	0.37
98.0%	0.24	0.26	0.28	0.30	0.32
98.3%	0.20	0.22	0.23	0.25	0.27
98.7%	0.16	0.17	0.19	0.20	0.21
99.0%	0.12	0.13	0.14	0.15	0.16

	Meets Division's proposed 0.8 g/hp-hr NOx emission limit (>1,000 hp existing engines)
	Meets Division's proposed 0.5 g/hp-hr NOx emission limit (>1,000 hp new engines)
	Meets NPCA's proposed 0.25 g/hp-hr NOx emission limit (all 100-500 hp engines)
	Meets NPCA's proposed 0.2 g/hp-hr NOx emission limit (all >500 hp engines)

While the addition of NSCR in conjunction with AFRC controls to an existing engine may provide >98% control with brand new catalyst elements and under ideal conditions, that level of control cannot be reliably maintained as catalytic elements age, and engine settings drift (within acceptable levels). This was confirmed by Innio – Waukesha, a rich-burn engine vendor familiar with Colorado oil and gas operations. Innio – Waukesha agreed that while a 4SRB engine equipped with NSCR and AFRC may be able to temporarily meet a 0.2 g/hp-hr NOx emission rate, maintaining it at those levels for ongoing compliance would be near impossible[8]. In fact, catalyst manufacturers and vendors contacted by Spirit (Miratech, Johnson Matthey, and RJ Mann) confirmed that they would only guarantee catalyst performance for at most 1 to 3 years because the catalyst elements and engine management systems must be in almost new condition to attempt to meet such a low standard and high control efficiency.

NPCA included data that supports the inability to meet these 98% reductions on an ongoing basis in Exhibit 1 – *Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories*. Within Exhibit 1 NPCA's experts note the following: "For example, retrofit installations of NSCR on five Caterpillar rich burn engines in Texas achieved a NOx reduction of 96% or greater on all of the engines. On two of those engines, testing conducted after more than 4,000 hours of operation with NSCR indicated the NSCR controls were still achieving a 95% NOx reduction." However, as shown by Table 1 and based on NPCA's own assumptions regarding the g/hp-hr for uncontrolled engines, 95 to 96 percent will not achieve the necessary limits. In NPCA's Exhibit 3 - *Initial Economic Impact Analysis (EIA) for A Proposal To Regulate NOx Emissions from Natural Gas Fired Rich-Burn Natural Gas Reciprocating Internal Combustion Engines (RICE) Greater Than 100 Horsepower*, Dr. Sahu recognizes that 4SRB engines pre-control emissions generally range from 15 to 16 g/hp-hr and claims that the proposed 0.2 g/hp-hr NOx emission limits are achievable for all 4SRB engines. Yet the references cited by Dr. Sahu to support this claim indicate that a 90% reduction of nitrogen oxides is state of the art emission performance level for existing RICE fueled by natural gas[9] and that 95% control of NOx may be assumed when evaluating the cost-effectiveness of NSCR/AFRC controls[10], yielding a 0.75 g/hp-hr NOx emission level at best.

A more realistically achievable level of control using NSCR in conjunction with AFRC lies in the range of 90%-95%[11]. Table 1 above demonstrates that, unlike NPCA's proposed limit, the

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[8] Verbal conversation with Innio/Waukesha dated 08/11/2020.
[9] NJ DEP State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines (2003), at 4-5.
[10] Commonwealth of Pennsylvania, Final Technical Support Document (June 2018) for the General Plan Approval and/or General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (BAQ-GPA/GP-5A, 2700-PM-BAQ0268); and the Revisions to the General Plan Approval and/or General Operating Permit for Natural Gas Compressor Stations, Processing Plants, and Transmission Stations (BAQ-GPA/GP-5, 2700- PM-BAQ0267), at 34.
[11] Stationary Reciprocating Internal Combustion Engines - Updated Information on NOx Emissions and Control Techniques, EPA-457/R-00-001, September 2000.

Division's proposed 0.8 g/hp-hr NOx limit for existing engines equal to or greater than 1,000 hp can be achieved using NSCR and AFRC. Spirit also agrees that these two controls are readily available and reasonable to install on new and existing 4SRB engines to reduce NOx emissions. For new 4SRB engines >1,000 hp, the Division's proposed 0.5 g/hp-hr NOx limit is achievable through the use of NSCR/AFRC in conjunction with engine combustion improvements that have become common as part of the design of a new engine from the outset.

For existing 4SRB engines to consistently meet a NOx emission level of 0.2 g/hp-hr, other significant equipment upgrades, in addition to an AFRC and/or NSCR installation, would need to be made. These engine upgrades were not accounted for in the NPCA's EIA. Engine upgrade kits may be used to replace several major components on the existing engine (e.g. pistons, heads, turbocharger, emission management system, flywheel etc.), and work in conjunction with a traditional NSCR/AFRC system to further bolster the ability to achieve a 0.2 g/hp-hr NOx emission rate. However, even those NPCA's proposal does not even consider these costs, or attempt to determine the range of such costs. Such costs could be in the hundreds of thousands of dollars for engines that are low emitting – representing an extensive and expensive total cost to operators and potentially high cost-per-ton reduced. This is a significant cost to the oil and natural gas industry where operators are largely already controlling engines and is a significant additional cost to achieve the minimal additional reductions that would result.

Additionally, the cost analyses prepared by NPCA's experts or cited throughout their exhibits were overwhelmingly based on an annualized NSCR/AFRC cost estimate from a memo by E^C/R Incorporated. For this memo, E^C/R Incorporated collected capital cost data for retrofitting NSCR/AFRC on existing 4SRB engines from industry groups, vendors, and manufacturers of RICE control technology for engines in the 50 to 3,000 horsepower range. However, in actuality, the direct and indirect annual cost data in this memo was obtained from an INGAA/API Technical Report[12] based on a dataset which was limited to engines less than 500 hp. These direct and indirect annual costs for engines in the 300-500 hp range from the INGAA/API Technical Report were applied by E^C/R Incorporated to any engine above 300 hp, including up to 3,000 hp. This is inappropriate, because direct and indirect annual costs increase with the engine horsepower, and the use of this data results in a gross underestimation of direct and indirect annual costs for engines equal to or greater than 1,000 hp, which are the main focus of our review.

Finally, NPCA's calculated cost is based on an underestimate of the total number of engines that will require retrofit in order to meet their alternate proposal. First, NPCA excluded from their cost estimate engines that, based on Division's APEN data, appeared to not be operating. Such engines are usually present at existing facilities to provide redundancy or backup capacity. Though they may not operate in certain given years, such engines would still need to be available

[12] Emission Control Cost Analysis Background for "Above the Floor" Emission Controls for Natural Gas-Fired RICE, Attachment D. Available at: https://downloads.regulations.gov/EPA-HQ-OAR-2008-0708-0279/attachment_1.pdf.

for use on an as-needed basis, and under NPCA's proposal would need to be retrofitted to meet proposed emission standards. The cost of these retrofits needs to be included in NPCA's analysis, regardless of the fact that associated actual emission reductions may be minimal. Second, NPCA also excluded from their cost estimate engines that, based on Division's APEN data, appeared to already meet NPCA's proposed standard. However, the Division's data was based on reported actual NOx emissions from APEN forms. The annual NOx actual emissions were then divided by an *assumed 8,760 hours of operation* and the engine horsepower rating to calculate the resulting NOx emission factor, in g/hp-hr. This leads to an underestimate of the actual NOx emission factor for engines that do not operate all year (not uncommon in oil and gas operations) and therefore an underestimate of the number of engines requiring retrofit. Based on NPCA's data presented in Table 1 of their EIA, this adds up to excluding 47 engines from their cost calculation, or up to 22% of the 4SRB engines that would potentially be subject to their alternate proposal. This is particularly misleading as retrofits on such engines would be just as costly as for any other engine but would lead to minimal emission reductions.

After careful review of all NPCA's documents, Spirit asserts that the 0.2 g/hp-hr NOx emission limit proposed by NPCA for 4SRB engines greater than or equal to 1000 HP is not appropriately supported. We disagree with NPCA, and their experts, and do not believe that this alternate proposal is feasible. Many of their data sources and assessments make broad leaps and assumptions by underestimating costs, overestimating potential NOx emission reductions, underestimating the number of engines affected, and underestimating the overall economic impact on the oil and natural gas industry.

Closing

Spirit appreciates the opportunity to support COGA and the oil and gas operators with this technical rebuttal support. If you have any questions, please do not hesitate to contact us.

Spirit Environmental, LLC