December 1, 2014

Via Email

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Re: State of Alaska's Comments in Response to the Environmental Protection Agency's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units
Docket # EPA–HQ–OAR–2013–0602

Dear Ms. McCarthy and Mr. McLerran:

On behalf of the State of Alaska, we submit the following comments on the proposed guidelines for carbon dioxide (CO_2) emissions from existing utility electric generating units (EGUs) ("Proposed Rule"). The Proposed Rule would require states to develop and implement federally enforceable plans designed to achieve mandated reductions in the average CO_2 emission rate of certain fossil-fuel fired generators – "affected EGUs." These mandated emission rates are based on the application of four Best System of Emission Reduction (BSER) building blocks that collectively assert significant authority over the generation, transmission, and consumption of electricity: (1) heat rate improvements at coal-fired generating units, (2) re-dispatch from coal EGUs to natural gas combined cycle EGUs, (3) new renewable energy generation, and (4) demand side energy efficiency measures. The Proposed Rule presumes that states can implement a combination of these BSER building blocks in order to achieve the target emission rate by 2030.[1] Contrary to this presumption, for the reasons outlined below, these measures cannot be implemented in Alaska to achieve the emission rate assigned by the Environmental Protection Agency (EPA).

EPA does not possess the authority to promulgate this Proposed Rule under the Clean Air Act (CAA). These far reaching BSER measures, together with the numerical CO_2 emission limits, would effectively establish a national energy policy.[2] For Alaska, implementing the rule is particularly problematic because EPA designed the rule for generating units that are interconnected through a robust transmission grid. A lack of interconnectivity is the very characteristic that most distinguishes Alaska's electric utility sector from the rest of the country. Because of this difference and others, Alaska should be exempted from any final rule limiting CO_2 emissions from existing EGUs. Alternatively, EPA must conduct the necessary analysis to determine an achievable and reasonable CO_2 emission rate for existing EGUs in Alaska based on an accurate factual record.

I. EPA lacks authority under the Clean Air Act to issue these regulations.[3]

The Proposed Rule exceeds EPA's authority under the Clean Air Act (CAA). First, application of §111(d) is limited to source categories that are not already regulated under §112; EPA has already elected to regulate coal-fired power plants under §112.[4] Second, regulations governing emissions from new sources under §111(b) are a necessary predicate for any §111(d) regulation of existing sources; here, EPA has only issued proposed §111(b) regulations. Third, the Proposed Rule impermissibly expands EPA's authority beyond air pollution control into the management of state energy generation and usage. Fourth, the Proposed Rule mandates firm, numerical emission targets rather than the guidelines and procedures contemplated by §111(d). This Proposed Rule would

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1 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units, Proposed Rule*, 79 Fed. Reg. 34,830, 34,836-34,837 (June 18, 2014) ("Proposed Rule").

2 *See* Proposed Rule, 79 Fed. Reg. at 34,924.

3 The legal defects summarized in this section are described more fully in the attached Legal Memorandum (Attachment A).

4 CAA §111(d)(1)(A)(i), 42 U.S.C. § 7411(d)(1)(A)(i).

effectively negate state authority to evaluate EPA's guidelines in the context of costs, technical and physical feasibility, energy needs, other environmental impacts, and the "remaining useful life of the existing source." Fifth, the BSER measures proposed by EPA improperly include measures beyond the physical or legal control of the regulated sources. Standards of performance established under §111(d) must be achievable through source-level, inside-the-fence line measures. Sixth, the Proposed Rule conflicts with the balance of federal and state authority with respect to energy policy established in the Federal Power Act.

Most frustrating for our state, EPA simply has not presented facts or reasoning to support the application of this rule in Alaska. EPA's foundational assumptions regarding the generation and transmission of electricity, particularly the premise of a robust interconnected grid, have little relevance to Alaska. The technical analyses – including the crucial Integrated Planning Model (IPM) and Regulatory Impact Analysis (RIA) – fail to evaluate the application of this rule in our state. EPA has no basis to conclude that the costs of implementing the proposed BSER measures in Alaska would be reasonable, that the rule will not impair the reliability of electric service in the state, or that the measures are even technically feasible.

II. Alaska should be exempted from the rule.

Alaska should be exempted from any §111(d) rule governing carbon emissions from EGUs because Alaska's electric utility sector differs in critical respects from the industry in the continental U.S. Perhaps most significantly, Alaska does not have a robust interconnected grid. Because of the lack of transmission interconnections and other unique circumstances, Alaska cannot reasonably implement the BSER measures. However, Alaska is already achieving carbon emission savings pursuant to our own policies without federal intervention.

It bears noting that even the primary policy motivation for this rule – the finding that fossil fuel-fired EGUs are the largest emitters of GHGs among stationary sources in the U.S. – does not apply to Alaska. Nationally, power plants account for roughly one-third of all domestic GHG emissions.[5] EPA reports that, in 2005, sources in the U.S. emitted 7,195.3 million metric tons (MMT) of CO_2e.[6] Of that, emissions from the electric

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[5] Executive Office of the President, The President's Climate Action Plan, at 6 (June 2013), available at http://www.whitehouse.gov/sites/default/files/image/president 27sclimateactionplan.pdf; *also see* Proposed Rule, 79 Fed. Reg. at 34,880; EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 Executive Summary, EPA-HQ-OAR-2013-0602-0557 at ES-21 (2013) ("EPA GHG Inventory").

[6] EPA GHG Inventory, at ES-7 (Table ES-2).

power industry accounted for 2,445.7 MMT – slightly more than one-third of U.S. CO_2e emissions.[7] By comparison, in 2005,[8] electric generation in Alaska produced 3.2 MMT CO_2e – only 6 percent of the state's total 52.1 MMT CO_2e emissions.[9] By our count, the five "likely affected fossil sources" in Alaska accounted for only 4.4% of statewide GHG emissions.[10] These emissions are *de minimus* in the context of the issue EPA seeks to address in this rulemaking. The policy rational behind the Clean Power Plan's focus on the electric utility sector does not apply to Alaska.

While the opportunity to reduce CO_2 emissions from Alaska's electric utility sector is negligible, attempts to comply with the Proposed Rule would result in extraordinary costs. Implementing the Proposed Rule may also raise issues regarding the reliability of electric service, and may result in irrational consequences – including greater impairment to air quality in Fairbanks. This rule should not be applied in Alaska.

A. Alaska's utility sector is fundamentally different from the electric utility industry in the continental U.S.

Alaska's electric utility sector differs in many ways from the industry in the rest of the United States. The utility power sector in the continental U.S., as described by EPA, is characterized by the interconnection of a variety generation resources by robust transmission grids extending over large regions.[11] The interconnected nature of the continental grid enables flexible dispatch of generation resources and renders electricity a generally fungible product.[12] The fungible nature of electricity and the flexibility in dispatch practices permitted by an interconnected transmission grid are "central" to EPA's evaluation of the "best system of emission reductions." [13] However, EPA's

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7 *Id.* at ES-21 (Table ES-7).

8 2005 is the most recent year for which statewide data is publically available.

9 Center for Climate Strategies, Alaska Greenhouse Gas Inventory and Reference Case Projections, 1990-2020, at v, Table ES-1 (July 2007), *available at* http://dec.alaska.gov/air/doc/AK-GHG-EI-2007.pdf.

10 *See id.*

11 Proposed Rule, 79 Fed. Reg. at 34,862/1-2.

12 Proposed Rule, 79 Fed. Reg. at 34,862/1-2.

13 EPA, Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units at 43 ("EPA Legal Memorandum"); *also see*, Proposed Rule, 79 Fed. Reg. at 34,862/1-2.

description of the utility power sector in the continental U.S., does not describe the electric utility sector in Alaska.

Alaska does not have a robust infrastructure of looped transmission facilities interconnected with generation facilities extending over large regions. Rather, as a state, Alaska is "islanded" – we have no interconnection with other states or regions.[14] Our relatively small population (0.3% of U.S. population) is dispersed over a substantial geographic area (16% of U.S. landmass or 570,641 square miles).[15] Transmission lines do link a few major population centers, but these systems have limits. Because the Proposed Rule relies on a factual premise that does not apply to Alaska, our state should be exempted from the rule.

1. Alaska's electric utility sector lacks interconnectivity.

Alaska's utilities face unique challenges in providing electric service – in fact, electric utility service is not universally available. 128 electric utilities serve our major population centers and rural communities.[16] The service areas for these utilities include over 150 remote, stand-alone electric distribution systems serving villages, most of which are inaccessible by road.[17] In these rural locations, service is provided by small

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[14] B.C. Hydro serves a small electric load in the remote coastal community of Hyder, Alaska. Otherwise, no Alaska load is served by electric generation resources located outside of the state.

[15] U.S. Census Bureau, State & County QuickFacts: Alaska, http://quickfacts.census.gov/qfd/states/02000.html. By comparison Wyoming, with the lowest population of any state, has a population density of 5.8 people per square mile, *Id.* at Wyoming, http://quickfacts.census.gov/qfd/states/56000.html, 483% greater than the 1.2 people per square mile in Alaska.

[16] Regulatory Commission of Alaska, Fiscal Year 2012 Annual Report 70-72 (Nov. 2012), *available at* http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=acc2839e-81bb-4f93-a2f1-0fb2698ffd2c ("RCA 2012 Annual Report").

[17] Alaska Energy Authority, Renewable Energy Atlas of Alaska at 2 (April 2013) *available at* www.akenergyauthority.org/PDF%20files/2013-RE-Atlas-of-Alaska-final.pdf ("Renewable Energy Atlas"); also s*ee id.* at 2-4 (illustrating Alaska's electric generation and transmission infrastructure).

generation units that either operate in isolation or are only weakly linked to other small electric generation units.[18]

In addition to lacking interconnection amongst our electric utility systems, we also lack an interconnected road or natural gas pipelines linking our cities, towns and villages. In this context, one utility, Alaska Village Electric Corporation, serves 54 villages, including Old Harbor and Savonga – communities 734 miles apart.[19] Another utility, Alaska Power Company, serves 26 communities, including Klawock and Tok – communities separated by 645 miles.[20] The absence of transmission lines to share power among communities and a road or pipeline system to transport fuel to remote areas, presents a huge challenge for providing affordable and reliable power to rural consumers.

With some notable exceptions, the power and heating needs for these remote areas are met by diesel barged up from lower-48 suppliers or transported from petroleum refineries in Nikiski or Valdez, Alaska.[21] After seasonal freeze-up, many remote communities must rely on fuel that is stored in local tank farms, or pay a premium for fuel flown in by air tankers.[22] When fuel reserves run short in these remote communities, truly extraordinary (and expensive) measures may be necessary to ensure the availability of fuel.[23] To help communities meet their energy needs the state supports programs to maintain fuel tanks, improve power generation and end use efficiency, and exploit local renewable energy sources such as wind, biomass, solar, geothermal, and hydroelectric.[24]

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18 EPA's exclusion of 472 Alaskan EGUs from the electric power sector modeling illustrates our reliance on small, isolated generating units. EPA, Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, EPA-HQ-OAR-2013-0602-0212, at 4-64, Table 4-35 (Nov. 2013), *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

19 RCA 2012 Annual Report 16.

20 *Id.* at 15.

21 Renewable Energy Atlas 2.

22 *Id.*

23 *See*, *e.g.*, William Yardley, Tanker with Crucial Fuel Delivery is Sighted Off Nome, N.Y. Times, Jan. 14, 2012, at A14, *available at* http://www.nytimes.com/2012/01/14/us/fuel-tanker-renda-and-icebreaker-healy-are-sighted-off-nome.html?_r=0.

24 Renewable Energy Atlas 2.

The provision of electric utility service in Alaska cannot be compared to the more densely populated areas of the country. Elsewhere in the U.S., most electric consumers are connected to an extensive electric grid. These interconnected states also have well-established interconnected energy markets that provide for the sale and transmission of power from where it can be most economically produced to where demand exists. Here, other than Anchorage and Matanuska load centers, no Alaskan load centers are interconnected by redundant transmission infrastructure. Alaskan loads are too small and too distant to support the type of electric transmission grid available in the continental U.S.

2. Even Alaska's major population and electric load centers have limited interconnectivity.

There are a few larger electric utility load centers in Southeast, Southcentral, and Interior Alaska. Four of these load centers have limited transmission interconnections: the Kenai Peninsula, Anchorage, Matanuska, and Fairbanks load centers. Because the transmission lines generally follow the 470-mile long Alaska Railroad corridor between Seward and Fairbanks, these loosely interconnected electric load centers are jointly referred to as the "Railbelt."[25]

The Municipality of Anchorage is Alaska's largest population center with 291,826 people (in 2010) and a land area of 1,705 square miles.[26] Our largest city is spread over seventy percent more land area than the State of Rhode Island which had a population more than three times that of Anchorage in 2010.[27] With a land area of 24,608 square miles and a population in 2010 of 88,995,[28] the Matanuska-Susitna Borough is larger than

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[25] In addition to the transmission lines generally following the railroad corridor, the Railbelt transmission system also includes: approximately 376 miles of transmission line south of the railroad corridor on the Kenai Peninsula, approximately 168 miles of transmission line west of the railroad corridor on the north side of Cook Inlet, and approximately 100 miles east of Fairbanks to Fort Greely where the railroad is currently being extended.

[26] U.S. Census Bureau, State & County QuickFacts: Anchorage Municipality, http://quickfacts.census.gov/qfd/states/02/02020.html.

[27] U.S. Census Bureau, State & County QuickFacts: Rhode Island, http://quickfacts.census.gov/qfd/states/44000.html.

[28] U.S. Census Bureau, State & County QuickFacts: Matanuska-Susitna Borough, http://quickfacts.census.gov/qfd/states/02/02170.html.

ten states, each of which has a population many times larger than the Matanuska-Susitna Borough.[29] Even in our "urban" areas, Alaskan utilities have a lot of ground to cover to deliver power from generating units to load.

a. Railbelt Utilities

The Railbelt load centers are served by six vertically integrated, cooperative or municipally owned utilities. The Kenai Peninsula is served by Homer Electric Association (Homer), the City of Seward, and Chugach Electric Association (Chugach). The Anchorage load center is served by Chugach, Anchorage Municipal Light and Power (ML&P), and Matanuska Electric Association (MEA). MEA also serves in the Matanuska load center. Golden Valley Electric Association (GVEA) serves the Fairbanks load center[30] Each of these independent utilities is governed by a locally elected board.

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[29] U.S. Census Bureau, State & County QuickFacts: Rhode Island, http://quickfacts.census.gov/qfd/states/44000.html (Rhode Island - population 1,052,567); U.S. Census Bureau, State & County QuickFacts: Deleware, http://quickfacts.census.gov/qfd/states/10000.html (Deleware - pop. 897,934); U.S. Census Bureau, State & County QuickFacts: Connecticut, http://quickfacts.census.gov/qfd/states/09000.html (Connecticut - pop. 3,574,097); U.S. Census Bureau, State & County QuickFacts: Hawaii, http://quickfacts.census.gov/qfd/states/15000.html (Hawaii - pop. 1,360,301); U.S. Census Bureau, State & County QuickFacts: New Jersey, http://quickfacts.census.gov/qfd/states/34000.html (New Jersey - pop. 8,791,894); U.S. Census Bureau, State & County QuickFacts: New Hampshire, http://quickfacts.census.gov/qfd/states/33000.html (New Hampshire - pop. 1,316,470); U.S. Census Bureau, State & County QuickFacts: Vermont, http://quickfacts.census.gov/qfd/states/50000.html (Vermont - pop. 625,741); U.S. Census Bureau, State & County QuickFacts: Massachusetts, http://quickfacts.census.gov/qfd/states/25000.html (Massachusetts - pop. 6,547,629); U.S. Census Bureau, State & County QuickFacts: Maryland, http://quickfacts.census.gov/qfd/states/24000.html (Maryland - pop. 5,773,552); U.S. Census Bureau, State & County QuickFacts: West Virginia, http://quickfacts.census.gov/qfd/states/54000.html (West Virginia - pop. 1,852,994).

[30] The Fairbanks load area includes the Denali Borough, the Fairbanks-North Star Borough (FNSB) and unincorporated regions surrounding the FNSB. Black & Veatch, Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study 1-1 (Feb. 2010) ("Alaska RIRP").

The Railbelt utilities serve a region of approximately 100,000 square miles, approximately half the size of the area served by the Electric Reliability Council of Texas (ERCOT). ERCOT provides independent system operator (ISO) service through a unified system controlling 43,000 miles of transmission infrastructure and 550 generation units.[31] By contrast, our Railbelt utilities independently provide service in their territories utilizing a total of 1,500 miles of transmission infrastructure and 39 utility or state owned generation units, plus purchases from a few small independent power producers. Even if an ISO were created in Railbelt Alaska, it would take a substantial investment in infrastructure to have the same system operational flexibility enjoyed by ERCOT.

The Railbelt utilities generate approximately 80% of the state's electricity and serve a peak load of around 870 MW.[32] All five of the "likely affected EGUs" identified by EPA – Nikiski Cogeneration, George M. Sullivan Plant 2, Beluga Power Plant, Southcentral Power Plant, and Healy Unit 1[33] -- provide electricity within the Railbelt. With the exception of transmission between the Anchorage and Matanuska load centers, the Railbelt load centers, and thus the affected EGUs, are connected by only single contingency outage transmission tie lines. Because loss of these single contingency lines means no energy can be transported amongst load centers, each utility must carry sufficient reserve locally to meet their loads.[34]

b. Railbelt Transmission Connections

The Kenai Peninsula load center is connected to the Anchorage load center by a 90-mile, single contingency 115kV transmission tie line owned by Chugach. The ability to move power on the Kenai to Anchorage transmission line is constrained by a stability limit of approximately 70 to 75MW, the need for approximately 10MW of reserve capacity, and increased line losses associated with increased energy transfer.

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31 Electric Reliability Council of Texas, Inc., About ERCOT, www.ercot.com/about (last visited Nov. 26, 2014).

32 Alaska RIRP 3-2. By comparison, many electric utilities in the continental U.S. have single coal or nuclear plants that exceed 900MW of capacity. *Id.*

33 EPA, Goal Computation TSD, Appendix 7: 2012 Plant-Level Data for Likely Covered Fossil Sources, EPA-HQ-OAR-2013-0602-0256. Although EPA listed Healy Unit 1 as "likely affected EGU," because of an ambiguity in the Proposed Rule, it is unclear whether unit meets the criteria. *See* discussion *infra* Part III.B.

34 Alaska RIRP § 3.1, 3-2.

The Matanuska and Anchorage load centers are connected by multiple transmission systems. The first is a 230 kV transmission system owned by Chugach. This system connects Chugach's and ML&P's generation plants to the Teeland Substation in the western portion of the Matanuska load center. The second system is a 115 kV transmission line jointly owned by ML&P, Chugach and MEA. This 115kV line connects the Eklutna Hydroelectric Project to the Anchorage load center and to the eastern portion of the Matanuska load center. Finally, MEA owns a 115 kV transmission system that connects the eastern and western portions of the Matanuska load center, creating a looped system with the Anchorage load center.

The Matanuska and Anchorage load centers are connected to the Fairbanks load center by a 200-mile, single contingency transmission system currently operated at 138kV running from Teeland Substation to Healy. This includes (1) a 6 mile 138kV line connecting the Teeland and Hollywood substations, which is currently owned by the State and due to transfer to MEA in 2018; (2) a 21 mile 115 kV line connecting Hollywood and Douglas that is owned by MEA; and (3) the 173-mile Alaska Intertie built to a 345 kV design connecting the Douglas and Healy substations and owned by the State. From Healy, two 138kV transmission lines carry power to Fairbanks – a 103 mile line running to the Goldhill substation and the 97 mile long Northern Intertie running into Wilson Substation. While conditions can vary, the Alaska Intertie is typically operated at or near its usual stability limit of approximately 70-80 MW throughout the year to deliver electricity generated at hydroelectric and natural gas facilities to Fairbanks. Energy purchases are generally scheduled to the maximum capacity of the line, depending on the availability of hydroelectric and gas generation capacity, and the availability of natural gas fuel.

These transmission lines follow routes that are often remote from all road access,[35] and are subject to outages during winter peak loads caused by avalanches and ice loading. In particular, the Alaska Intertie has two cables bundled together about 8 inches apart for each phase. The snow/ice loading on the Intertie can be particularly dramatic when the accumulated snow and ice bridges the gap between the two cables. Once such a bridge is formed, snow and ice accumulate across the entire platform, causing accumulations of more than one-foot diameter. There is a particular risk of ground fault when uneven snow loading causes the lines to sag to the ground.

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[35] An exception to this is the Alaska Intertie, which runs parallel to the Parks Highway as it crosses through Denali National Park.

3. Regulatory Environment

Alaska's regulatory environment differs from the framework presumed by EPA. In the continental U.S., FERC regulates interstate electric energy transmission and the wholesale energy market.[36] However, because Alaska has no interstate electric energy transmission, Alaskan utilities are largely unaffected by FERC transmission and wholesale market rules.[37] Instead, wholesale transactions between utilities are regulated by our public utility commission, the Regulatory Commission of Alaska (RCA).[38]

The RCA regulates electric utilities according to traditional economic ratemaking principles – requiring that reliable service is provided at just, reasonable, non-discriminatory rates.[39] Utilities, under RCA oversight, must apportion charges to their respective customer classes according to the "cost causer-cost payer" principle.[40] The RCA and the Alaska Energy Authority (AEA), through the Intertie Management Committee, may implement reliability standards.[41]

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36 Federal Power Act (FPA) § 201(a) & (b)(1), 16 U.S.C. § 824(a) and (b)(1); Congress directed FERC "to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy," and "to" promote and encourage such interconnection and coordination." FPA § 202(a), 16 U.S.C. § 824a(a). FERC also regulates the rates and charges for interconnection and transmission to ensure the rates are "just and reasonable," and that no person is subjected to "undue prejudice or disadvantage" or "any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service." FPA § 205(a)–(b), 16 U.S.C. § 824d(a)–(b). Congress empowered FERC to take action on its own motion in order to ensure these measures are implemented. FPA § 206(a), 16 U.S.C. § 824e(a).

37 FPA §201(b)(1), 16 U.S.C. § 824(b)(1).

38 AS 42.05.431(b).

39 AS 42.05.431.

40 3 AAC 48.510.

41 AS 42.05.291; s*ee* The Intertie Management Committee's Railbelt Operating and Reliability Standards (Oct. 1, 2013) *available at* http://www.akenergyauthority.org/PDF%20files/IMC%20Railbelt%20Operating%20&%20Reliability%20Standards.pdf.

There are limits to the RCA's statutory authority. Unlike public utility commissions in many other states,[42] the RCA does not have general facility siting authority. Also, while other states have enforceable resource plans, in Alaska, utilities submit 10-year capital improvement plans for informational purposes only.[43] Significantly, municipal and cooperative utilities, including all of the utilities affected by this rule, may choose to be altogether exempt from economic regulation by the RCA.[44]

Nor is the limited Alaska transmission system managed by a Regional Transmission Organization or ISO as is typical elsewhere in the country. Here, individual electric utilities or state agencies own discrete portions of the transmission infrastructure. Each utility operates the transmission infrastructure it owns and, in some cases, operates transmission infrastructure owned by the State under contract. Interconnection agreements exist, if at all, only when each of the participating utilities find the terms of the agreement to be in their individual members or customers best interests.

No organized wholesale power market exists in Alaska. Instead, wholesale power transactions between utilities are based upon bilateral agreements, and typically involve hour-ahead non-firm economy energy transactions. Existing transmission system limitations prevent most Alaska utilities from entering into firm wholesale power transactions. By contrast, within the interconnected continental grid, power can be bought on a firm or non-firm basis, and for varying blocks of time.

Although outlined in AS 44.99.115, Alaska's energy policy is not integrated in a single statute. Our policies are integrated through multiple statutes that establish and allocate duties and authority amongst numerous state departments and agencies, including AEA, DEC and the RCA.

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42 *See* EPA, State Plan Considerations TSD, EPA-HQ-OAR-2013-0602-0463, at 69 (June 2014).

43 3 AAC 50.790, 770(e)(1).

44 AS 42.05.711(b) and (h).

B. Alaska should be exempted from the rule because without an interconnected grid we cannot execute the "best system of emission reductions" as outlined by EPA.

1. EPA's evaluation of the statutory BSER criteria presumes, and relies on, the existence of an interconnected grid.

The existence of an interconnected and integrated electricity system is "central" to EPA's rationale for the Proposed Rule:

> Central to our BSER determination is the fact that the nation's electricity needs are being met, and have for many decades been met, through a grid formed by a network connecting groups of EGUs with each other and, ultimately, with the end-users of electricity. … Through the interconnected grid, fungible products – electricity and electricity services – are produced and delivered by a diverse group of EGUs operating in a coordinated fashion in response to end-users' demand for electricity.[45]

EPA's determinations respecting the impact on the reliability of electric service and the cost of these measures also clearly reference the assumption that "affected EGUs" will be connected to this integrated grid.[46] EPA's BSER determinations for three of the building blocks explicitly rely on the "inherent flexibility of the current regionally interconnected and integrated electricity system."[47] In theory, this interconnected system will enable utilities to reliability and affordably reduce generation, and therefore CO_2 emissions, from "affected EGUs" by generating power with less carbon intensive units or by reducing the demand altogether.[48]

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45 EPA Legal Memorandum 43-44.

46 Proposed Rule, 79 Fed. Reg. at 34,836/3.

47 *Id.*

48 Proposed Rule, 79 Fed. Reg. at 34,835/2-34,836/3; EPA Legal Memorandum 49-50 (reasoning that building blocks 2, 3, and 4 qualify as a "system of emission reduction" because "through the integrated grid, the measures reduce overall demand for, and therefore utilization of, higher emitting, fossil fuel –fired EGUs, which, in turn, reduces CO_2 emissions from those EGUs.").

However, as described in detail above, Alaska does not have "a regionally interconnected and integrated transmission system." Our limited transmission capacity is already fully utilized to replace petroleum fuel generation with hydroelectric or natural gas power. Thus, the EGUs EPA assumes may be re-dispatched under building block 2 are located at opposite ends of a 200 mile long transmission system that is subject to single contingency outages. Integration of significant new renewable generation resources would likewise be limited by these transmission constraints. The lack of interconnection also has significant implications for any evaluation of how the BSER measures may affect electric service reliability. Our generation is neither interconnected nor interchangeable in the manner envisioned by EPA in its BSER determinations.

EPA's supporting technical analyses, the Integrated Planning Model (IPM) and Regulatory Impact Analysis (RIA), only examine the continental U.S. and southern Canadian Provinces, ignoring Alaska.[49] Even for these interconnected regions, the IPM did not account for the situation facing Alaska – inadequate transmission capacity to deliver resources within a region.[50] EPA has not yet articulated a basis to conclude that the proposed BSER measures, premised upon an interconnected grid, are technically feasible in Alaska or that they can be implemented at a reasonable cost without compromising the reliability of electric service or public safety.

2. Constructing 200 miles of new electric transmission line to improve connectivity amongst load centers and generating resources is not a reasonable solution for Alaska.

EPA recognizes that implementation of these BSER building blocks may require new investment in infrastructure.[51] EPA dismisses infrastructure constraints out of hand by reasoning that "these considerations have not limited past rapid increases in NGCC generation levels."[52] EPA concludes that natural gas supply and delivery systems as well

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49 EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, at ES-15 n.7 (June 2014) (noting EPA's lack of information regarding impacts in Alaska and Hawaii); *Id.* at 3-46 (noting that IPM does not account for costs or benefits of Proposed Rule in Alaska) ("RIA").

50 Proposed Rule, 79 Fed. Reg. at 34,864/2; EPA, Resource Adequacy and Reliability TSD, EPA-HQ-OAR-2013-0602-0163, at 2.

51 Proposed Rule, 79 Fed. Reg. at 34,857-34,858.

52 *Id.*

as electric transmission systems "would be capable of supporting the degree of increased NGCC utilization needed for states to achieve the proposed goals." EPA provides three reasons for this conclusion: (1) transmission systems can sustain usage levels achieved during peak periods for longer periods of time;[53] (2) isolated system constraints would not prevent an increase in NGCC generation overall across a region;[54] and (3) "pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity. Further, EPA believes "the proposal's compliance schedule provides flexibility and time for investment in additional natural gas and electric industry infrastructure if needed."[55] However, historic pipeline and transmission expansion trends in the continental U.S. have no bearing on unique conditions in Alaska.

Significant upgrades to the electric transmission infrastructure would be necessary to re-dispatch natural gas generation to offset coal generation capacity in Alaska. Both of the Alaska coal fueled EGUs are located at the coal mine mouth in Healy. All of Alaska's natural gas generation capacity is located more than 200 miles south - in the Matanuska, Anchorage, and Kenai load centers. A single transmission line operated at 138kV connects Healy to the Teeland Substation, where multiple interconnections with the Matanuska and Anchorage load centers exist. The 80 MW capacity limit and single-contingency outage nature of the existing transmission tie-lines between Healy and Teeland prevents firm energy transfers and the sharing of reserves between the Fairbanks, and Anchorage or Matanuska load centers.

Although prepared for other purposes, the State of Alaska recently commissioned a planning study that looked at the cost of constructing a second transmission line from the Matanuska load center to the Fairbanks load center.[56] This possible line would run from a new Lorraine Substation to Healy, through Douglas Substation, and would cost an estimated $387.9 million.[57] This second line would allow firm energy transfers from the Matanuska and Anchorage load centers to the Fairbanks load center.[58] It would increase

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53 *Id.* at 34,863/3.

54 *Id. at* 34,864/1.

55 *Id.*at 34,857-58; 34,864/1-2.

56 Alaska Energy Authority, Pre/Post – Watana Transmission Study Draft Report (March 17, 2014) ("Watana Transmission Study").

57 *Id.* at 13.

58 *Id.* at 12.

total transmission transfer capacity to 125 MW, although system operating stability limits dictate that no more than 110 MW actually be transferred.[59] Upgrade of the Northern Intertie from Healy to Fairbanks to 230 kV operations, at a cost of $106.8 million, may be required to actually get this additional capacity and Healy generation output to Fairbanks.[60]

Based upon the recently commissioned study, it would cost at least $387.9 million, and possibly $494.7 million to create enough additional transfer capacity to offset the 27 MW Healy Unit 1 coal generation with natural gas generation. If the $387.9 million were amortized over forty years, using the three percent discount rate utilized in the RIA, this second transmission line would have approximately $16.7 million per year in capital costs. If the $387.9 million were amortized over forty years, using GVEA's average 3.735% cost of debt and authorized 1.79 TIER, this second transmission line would have approximately $27.9 million per year in capital costs.

For the twelve-month period ending July 31, 2014, GVEA averaged spending $0.0477/kWh on incremental costs for 199,966,700 kWh of energy generated by Healy Unit 1.[61] For that same period, GVEA spent $0.11160/kWh for economy energy purchased from Chugach,[62] plus $0.00373 to wheel that energy to GVEA's system.[63] If you assume that GVEA could purchase an additional 199,966,700 kWh of economy energy from Chugach at this same average price as paid during the twelve-month period ending July 31, 2014, and assume that the MEA/Alaska Intertie wheeling rate during that time period would equal the wheeling rate for the new transmission line, use of the second transmission line to offset coal-fueled generation by Healy Unit 1 with Chugach natural gas generation would cost GVEA an additional $13.5 million per year.[64]

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59 *Id.* at 12, 34.

60 *Id.* at 13.

61 GVEA, Tariff Advice Letter 255-13, filed with the RCA, at Ex. 7c (filed August 29, 2014) ("TA255-13").

62 TA255-13 Ex. 7a.

63 TA255-13 Ex. 4a (this is the price GVEA paid to MEA and the State to transmit the energy purchased from Chugach and delivered by Chugach to Teeland Substation over the MEA transmission system and Alaska Intertie to Healy).

64 ([$0.11160/kWh + $0.00373/kWh]- [$0.0477/kWh]) X (199,966,700 kWh) = $13,523,747.92

GVEA is currently reporting an emission rate for Healy Unit 1 of 3,564.89 pounds of carbon dioxide per MWh. Chugach currently reports an emission rate of 1,717.16 pounds of carbon dioxide per MWh from a simple cycle natural gas unit. Thus replacing 199,966,700 kWh of energy generated by Healy Unit 1 with an equivalent amount of energy[65] generated at a simple cycle Beluga unit would save approximately 163,000 metric tonnes of carbon dioxide emissions.[66] Using the annual capital costs $16.7 to $27.9 million for the second transmission line and energy replacement costs of $13.5 million as discussed above, it would cost between $185.28 and $253.99 per metric ton of carbon emission saved to replace generation from Healy Unit 1 with output from a simple cycle natural gas unit at Beluga. In the public notice for the Proposed Rule, the EPA could not find that a cost of converting coal fueled units to natural gas fuel ranging from $83 - $150 per metric ton of carbon dioxide emission reduction was reasonable for inclusion as BSER.[67] The EPA did find redispatch costing on average $30 per metric ton of carbon dioxide emission reduction to be reasonable for inclusion as BSER. For Alaska, the cost of even partial redispatch is six times the range found reasonable, and is greater than the range that could not be found reasonable, thus Alaska should be exempted from the Proposed Rule.

C. Alaska should be exempted from the Proposed Rule because we cannot reasonably implement the "best system of emission reductions."

The Proposed Rule suggests compliance mechanisms that have limited, if any, application in Alaska and presupposes an energy market that does not exist here. Application of the Proposed Rule to Alaska, notwithstanding the physical impossibility of implementing the building blocks, would result in extraordinary costs, severely impair the reliability of electric service, and aggravate air quality concerns in the Fairbanks area. Therefore, our state should be exempted from the Proposed Rule.

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65 103 % to account for line losses. *See*, Watana Transmission Study 35 fig. 7-1.

66 [(199,966.7 MWh) X (3,564.89 pounds/MWh) ÷ (2,204.62 pounds/MT)] Healy Unit 1 – [({199.966.7 MWh} X {1.03}) X (1,717 pounds/MWh) ÷ (2,204.62 pounds/MT)] SPP = 162,937.9

67 EPA, GHG Abatement Measures TSD, EPA-HQ-OAR-2013-0602-0437, at 6-9 (June 10, 2014).

1. Heat rate improvements of six percent cannot be achieved at the Healy Power Plant.

The first BSER measure proposed by EPA is a six percent heat rate improvement (HRI) at coal-fired steam generating units. EPA evaluated two general approaches to improving heat rates: (1) implementing "best practices" in operations and maintenance and (2) equipment upgrades.[68] Applying this building block to Alaska, EPA assumed a six percent reduction in the CO_2 emission rate at Healy Unit 1 – from 2,852 to 2,681lb/MWh.[69] This element of the goal calculation is not reasonable as applied to Alaska.

First, as EPA recognizes, heat rate improvements may be accomplished through the use of "best practices" or equipment upgrades only to the extent those measures have not already been implemented at a facility.[70] However, although EPA applies this element to Healy Unit 1 in the goal calculation, the agency does not provide information to support a determination that "best practices" or equipment upgrades are available to that EGU. Worse, the baseline and goal calculations ignore Healy Unit 2 altogether.

Second, EPA's analysis of equipment upgrades relies on Sargent & Lundy (2009), a study that evaluated HRI at coal units between 200 MW and 900MW.[71] The units evaluated in that report are an order of magnitude larger than the 27 and 52.5MW Healy units. Without closer study, EPA cannot reasonably conclude that the same equipment upgrades evaluated for those large units are technically feasible for the Healy units. Even if some of the equipment upgrades are technically feasible, EPA failed to support a conclusion that those upgrades otherwise qualify as BSER for small coal EGUs.[72]

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68 Proposed Rule, 79 Fed. Reg. at 34,851, 34,856, 34,860.

69 This figure appears to be in error. According to GVEA's GHG emissions report, the emission rate at Healy Unit 1 was actually 3,564.89 lbs/MWh in 2012.

70 Proposed Rule, 79 Fed. Reg. at 34,859.

71 GHG Abatement Measures TSD 2-33, 2-36 ("The EPA also reviewed the engineering studies available in the literature and selected the Sargent & Lundy 2009 study as the basis for our assessment of heat rate improvement potentials from equipment and system upgrades."); *see* Sargent & Lundy, LLC, Coal-Fired Power Plant Heat Rate Reductions: Final Report at 1-1 (Jan. 22, 2009).

72 For example, one BSER criterion is cost. EPA recognizes that economy of scale causes most HRI methods to be more costly ($/kW) on smaller unit sizes. GHG Abatement Measures TSD 2-36 n. 31.

The only information currently available reveals that a six percent HRI cannot be achieved by the Healy units. GVEA reports that a number of the HRI measures recommended by EPA have already been implemented at the coal plant and some are not available to the Healy units.[73] GVEA's initial evaluation suggested that heat rate improvements of 2.11% and 2.15% might be achievable at Healy Unit 1 and Unit 2, respectively.[74] Although, given variability in operating conditions, application of these measures would not necessarily result in the forecasted improvement as compared to the 2012 baseline.[75]

Installation of pollution control technologies, as required by a consent decree with EPA will reverse these gains.[76] The consent decree requires GVEA to install (1) selective catalytic reduction (SCR) equipment at Unit 2[77]; selective non-catalytic reduction (SNCR) controls at Unit 1[78]; and (3) SCR controls at Unit 1.[79] GVEA anticipates that the SNCR equipment will degrade the heat rate of Healy Unit 1 by about 0.1% and that the installation of SCR equipment will result in a 2.87% degradation of the heat rate at each unit.[80] Thus, there are no net heat rate improvements possible in Alaska and application of this measure to determine Alaska's goal is unreasonable.

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73 GVEA Response, RCA Docket I-14-007, at 2 (Oct. 16, 2014).

74 GVEA Response, RCA Docket I-14-007, Exh. A-1 (Oct. 31, 2014).

75 GVEA Response, RCA Docket I-14-007, at 2 (Oct. 31, 2014).

76 See Proposed Rule, 79 Fed. Reg. at 34,859 n.111; Sargent & Lundy at 5.1 (noting that emission control technologies can consume large amounts of auxiliary power).

77 Consent Decree, *United States v. Golden Valley Elec. Ass'n, Inc.*, No. 4:12-cv-00025–RRB ¶59 (D. Alaska 2012) ("GVEA Consent Decree").

78 *Id.* at ¶60.

79 *Id.* at ¶¶61-63.

80 GVEA Response, RCA Docket I-14-007, Exh. A-1 (Oct. 31, 2014).

2. Re-Dispatch cannot be executed as EPA describes because our transmission lines already operate at, or near, capacity to replace carbon intensive generation with hydroelectric and natural gas generation.

The second general category of measures that EPA identifies as BSER is to substitute generation at carbon-intensive units with generation from less carbon-intensive EGUs. Specifically, EPA evaluates displacing coal-fired steam (and oil/gas-fired steam) generation in each state by increasing generation from existing NGCC capacity toward a 70 percent target utilization rate. [81] For Alaska, EPA reassigned the 2012 baseline generation at Healy Unit 1 to NGCC units to arrive at a final goal of 47% capacity factor for Alaska's NGCC units.[82] Again, the calculation does not account for Healy Unit 2. Essentially, EPA calculated Alaska's goal based on the assumption that all generation at the Healy Power Plant could be displaced by NGCC generation. This assumption is false, both because of the transmission system limitations discussed above and because of the planned retirement of the Beluga and Sullivan NGCC EGU's.[83]

The Healy Power Plant will provide a total of 80 MW of generation capacity for the Fairbanks load center. The plant is located adjacent to the Usibelli Coal Mine and has two coal-fired steam generating units. Healy Unit 1 commenced generation in 1967 and has a gross capacity of 27MW. Healy Unit 2, or the Healy Clean Coal Project, has a nameplate capacity of 52.5MW and, like Healy Unit 1, uses the locally produced coal.[84]

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[81] Proposed Rule, 79 Fed. Reg. at 34,851; GHG Abatement Measures TSD 3-9, 3-26.

[82] *See* Proposed Rule, 79 Fed. Reg. at 34,858 n. 106 (substitution would only occur to the extent that there is both NGCC capacity whose generation could be increased and steam EGUs whose generation could be decreased); Goal Computation TSD, App. 1.

[83] Chugach Response, RCA Docket I-14-007, at 11, Table 3 (Oct. 31, 2014). The Beluga and George Sullivan steamer units are being retired, converting those NGCC EGUs to simple cycle units. Chugach and ML&P have jointly built SPP as an NGCC plant, and ML&P is building George Sullivan Plant 2A as an NGCC plant. Overall, Railbelt NGCC capacity is decreasing by approximately 60 MW, reflecting the disaggregation of generation plant within the Railbelt. Simple cycle natural gas generation capacity in the Railbelt is increasing.

[84] Healy Unit 2 was constructed in 1998 as an experimental waste coal demonstration plant under the U.S. Department of Energy's Clean Coal Technology Program. However, the unit did not perform as expected and federal testing ceased in 1999.

GVEA is investing significant resources to reconstruct Healy Unit 2. This includes $190 million in investments and a recent consent decree with EPA requiring additional pollution control measures at both Healy units. The Healy Power Plant is connected to Fairbanks, 97 miles to the north, by two transmission lines owned and operated by GVEA.

The NGCC EGUs that EPA's goal computation assumes can replace Healy's 80MW of coal generation are located more than 200 miles south of Healy, beyond the other end of the Alaska Intertie. As discussed above, this 80MW transmission line is already generally operated at capacity to deliver hydroelectric and natural gas generation to GVEA's customers in the Fairbanks load area.[85] There are no NGCC EGUs connected to the Fairbanks load center other than those connected through the south end of the Alaska Intertie. Given the current generating and transmission resources, Alaska cannot execute the second building block.

Hypothetically, GVEA could have two options to replace Healy power – (1) upgrading the Alaska Intertie to allow more power north or (2) generating power locally from other fossil-fuel fired units. Both scenarios would substantially increase the cost of power in Fairbanks – already among the most expensive regions in the country for power– significantly, raise serious resource availability and reliability concerns, and compromise the state's ability to address the $PM_{2.5}$ non-attainment finding for Fairbanks. These options are not realistic.

a. Premature retirement of the Healy units would result in incredible costs for the utility's 45,000 ratepayers.

In any scenario, requiring GVEA to generate or purchase power from a source other than the Healy Power Plant would increase the cost of electricity. First, retiring the Healy units prematurely would involve nearly $450 million in stranded capital costs and remaining loan principal payments.[86] Second, because coal is GVEA's least expensive power, replacing Healy coal-fueled generation would also result in significant additional annual variable costs between $47.4 and $60.7 million per year.[87] Upgrading the Alaska

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85 Notably the Healy units provide voltage support to the Intertie. If the Healy units were not operating, the loss of the Healy SVC would result in a reduction of transfer capacity of approximately 11 MW.

86 H. Dale LLC, Stranded Cost Calculations for Healy Unit 1 and Unit 2 (Sept. 2014) (Attachment B).

87 H. Dale LLC, Cost Analysis for Shutting Down GVEA Coal Units (Sept. 2014) (Attachment C).

Intertie to transport more natural gas generation north would also result in approximately $30.2 - $41.4 million of additional annual costs to consumers, as discussed above.

To put this in perspective, GVEA residential ratepayers already pay $0.235668/kWh for electric utility service.[88] This is substantially higher than the rates paid anywhere else in the nation, except other parts of Alaska and Hawaii.[89] In 2013, GVEA sold a total of 1,253,161,000 kWh at retail.[90] Inflating that at the 0.78% growth rate used in the Proposed Rule would leave GVEA with sales of 1,529,731,800 kWh in 2030. Just the annual cost increases of $90.9 million related to shutting down the Healy units identified above would result in rate increases for GVEA consumers of between $0.05 and $0.07/kWh. The EPA indicates that implementation of the Proposed Rule will result in rate increases of approximately $0.01/kWh nationwide.[91] There is no justification for making Fairbanks consumers bear a burden roughly six times greater than the rest of the nation, particularly when, as discussed above, the carbon emissions at issue are minimal.

b. Premature retirement of the Healy units would compromise the reliability of electric service and create risk to human health and safety as well as risk for property damage.

In any scenario, requiring GVEA to prematurely retire the Healy units would create unreasonable risks for Fairbanks area residents. First, relying on other Fairbanks area generation would be problematic because the units that would be replacing the Healy generation are scheduled to retire before 2030. Second, even if the Alaska Intertie could transport more energy north, relying on hundreds of miles of remote, difficult to access transmission line to deliver the region's energy requirements would raise reliability concerns.

As succinctly stated by GVEA's vice president of transmission and distribution, relying on NGCC generation from Southcentral Alaska would essentially put Fairbanks

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88 GVEA's Tariff at Tariff Sheets 33, 39, 39.1.

89 RIA 2-22, fig. 2-6.

90 GVEA's Annual Report, filed with the RCA 304 (May 1, 2014).

91 RIA 2-20 (indicating 2011 average price of just under $0.10/kWh); *Id.* 3-42 (indicating 2030 average price of $0.109/kWh).

"on a 350-mile extension cord."[92] If 100-140MW of power was carried on one line north to Fairbanks and it tripped, GVEA may experience a system-wide blackout or at the very least experience an outage for approximately 60% of its members.[93] In Fairbanks, loss of electric service in the winter months poses a threat to health and safety of residents. At minus 50 degrees Fahrenheit (a regular feature of our sub-arctic winters), a significant power outage would have devastating consequences for Fairbanks residents in a matter of hours.

Premature retirement of the Healy units would also compromise fuel source diversity, another essential component of reliable electric service. Generation from natural gas and hydroelectric resources is currently available to the Fairbanks load center only through the single outage contingency Alaska Intertie and only up to that line's capacity. Petroleum fuel is available to the Fairbanks load center through the single outage contingency Trans-Alaska Pipeline System (TAPS). Coal fueled generation at Healy is available to the Fairbanks load center through both the Alaska Intertie and the Northern Intertie. The limited availability of generation and transmission resources heightens the importance of each resource to reliability.

Geographic circumstances render the continued availability of coal of particular importance to Fairbanks. To illustrate, in the event a major earthquake damaging the transmission lines and TAPS Fairbanks would be left with limited fuel and generation resources.[94] Coal from the mine that supplies the Healy Plant would be one of those few resources. Coal could be hauled to the small co-generation units in Fairbanks, which have sufficient capacity to meet emergency electric service requirements.[95]

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92 Alan Baily, EPA emission rule comes under scrutiny: Utilities say one size fits all approach to regulating power plant CO2 emissions may not work in Alaska's unique situation, 19 Petroleum News 47, at 7 (Nov. 23, 2014).

93 GVEA Supplemental Response, RCA Docket I-14-007, at 3 (Oct. 31, 2014).

94 The southern portion of Alaska, which includes the Railbelt, suffers a greater than magnitude 8 earthquake on average every thirteen years. In 1964, Railbelt Alaska suffered the second largest earthquake ever recorded worldwide. Alaska Seismic Hazards Safety Commission, Earthquake Risk in Alaska, http://seismic.alaska.gov/earthquake_risk.html (last visited November 26, 2014). The Alaska Intertie and TAPS were constructed after 1964, and although designed to withstand an earthquake of similar magnitude, that design has not yet been tested by nature.

95 These small coal-fueled co-generation units also provide essential space and water heating utility services to buildings on the University of Alaska Fairbanks campus, in downtown Fairbanks, and on local military bases. The water heating utility service is

Because the mine in Healy is the only operating coal mine in Alaska, emergency coal for Fairbanks will only be available if that mine remains economically viable. The mine mouth Healy 1 unit has long been part of the market keeping the coal mine operating, and as the world coal export markets retract, the Healy 2 unit will be an important factor in keeping that mine operating in the future. Without coal as a fuel source, the Fairbanks load center is just two contingencies away from inadequate electric service once locally stored petroleum fuel products have been consumed.

The importance of reliability should not be underestimated as it directly impacts the health and safety of Alaskans in our frequently extreme climatic conditions. Wintertime power disruptions caused by system integration and stability problems become life threatening in a manner of minutes when temperatures dip below minus 50 degrees Fahrenheit, as happens annually in Fairbanks. Keeping coal fuel available for use in Fairbanks is an important part of public safety.

c. Premature retirement of the Healy units may aggravate the $PM_{2.5}$ pollution in Fairbanks.

Either option for premature retirement of the Healy units may also aggravate the $PM_{2.5}$ pollution in the Fairbanks air shed. The increased cost of energy would encourage more residents to burn wood, a more affordable option, for space heat. And, were GVEA to rely on Fairbanks area generation, more fossil-fuel (diesel) electric generation in the Fairbanks region would again add more $PM_{2.5}$ to the air shed.

d. Premature retirement of the Healy units would not result in significant reductions in carbon emissions.

Without upgrades to the Alaska Intertie, which is currently operating at or near capacity, the only generation resources that could replace the Healy coal generation are old, oil-fueled generation resources in North Pole and Fairbanks. Such a substitution would not result in a significant net reduction in carbon emissions. In fact, such a substitution may result in no net carbon emission reduction as the substitution could result in curtailment of non-firm renewable energy generation resources – some spill of Eva Creek wind may be required in the absence of load following generation resources at Healy. Furthermore, the total carbon footprint of these other generating resources also

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essential to both the local water and sewer utility service, as their pipes would freeze during the winter in the absence of heat purchased from the coal-fueled cogeneration units in downtown Fairbanks.

includes the cost of transporting the fuel. By contrast, Healy is co-located with its fuel source, Usibelli Coal Mine.

e. Premature retirement of the Healy units conflicts with the spirit of EPA's recent consent decree with GVEA and the State.

Significantly, in November 2012, the EPA entered into a consent decree with GVEA and the Alaska Industrial Development and Export Authority (AIDEA) resolving the EPA's concerns regarding possible adverse impacts on air quality from restarting Healy Unit 2. In reliance on that consent decree, GVEA purchased Healy Unit 2 from the State and has invested nearly $190 million to acquire, upgrade, and restart the unit.[96] Upgrades have been accomplished through a loan from the U.S. Department of Agriculture, Rural Utilities Service (RUS).

Prior to approving this loan, in April 2013, RUS prepared a Supplemental Final Environmental Impact Statement (SFEIS).[97] This SFEIS incorporated the GVEA, EPA consent decree.[98] The SFEIS specifically found that restarting Healy Unit 2 would have no "significant cumulative effects on water, air quality, or fisheries and aquatic habitat in the vicinity of the Healy Plant."[99]

The EPA issued the a finding in 2009 that well mixed GHG emissions, including carbon dioxide emissions, "may reasonably be anticipated both to endanger public health and to endanger public welfare."[100] The EPA relied upon this finding in development of

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96 Comment letter from Cory R. Borgeson, President & CEO, GVEA, to U.S. Environmental Protection Agency at 3 (Oct. 15, 2014) (filed in docket EPA-HQ-OAR-2013-0603) ("GVEA Comment").

97 Rural Utilities Services, U.S. Dep't of Agriculture, Supplemental Final Environmental Impact Statement for the Restart of Healy Power Plant Unity #2 (April 2013) ("SFEIS").

98 SFEIS 1-15 to 1-16, 3-14 to 3-5.

99 SFEIS 4-10.

100 EPA, Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009) ("Endangerment Finding").

the Proposed Rule,[101] and thus this information was known in 2012 when EPA signed the consent decree with GVEA and the State of Alaska, and in 2013 when RUS prepared the SFEIS. The EPA did not indicate in either the 2012 consent decree or the 2013 SFEIS that the Healy Unit 1 and Unit 2 would not be allowed to operate for their full economic lives. Nor did EPA indicate that GVEA would be economically penalized for operating these plants beyond the penalties specifically stated in the consent decree.

GVEA, the State of Alaska, and RUS have all proceeded with restarting operation of Healy Unit 2 in reasonable reliance on the consent decree and EPA's silence during development of the SFEIS. As discussed above, neither Healy Unit 1 nor Healy Unit 2 can execute building block one to improve their heat rates as EPA assumes in the goal calculation. Applying building blocks two, three, or four to avoid use of these units would effectively be a federal taking of the investment GVEA is reasonably making to restart Healy Unit 2. Nor would it be reasonable for EPA to penalize other entities for the reasonable actions of GVEA through the imposition lower emission limits to offset the emissions the Healy units. EPA should exclude Healy Unit 1 and Unit 2 from the list of affected EGUs in Alaska for purposes of determining compliance with the Proposed Rule.

3. There are real limits to our ability to include new renewable energy resources in the generation mix.

EPA's third building block requires substituting generation at affected EGUs with expanded low-or zero-carbon generation. Specifically, EPA proposes completing all nuclear units currently under construction, thereby avoiding retirement of about six percent of existing nuclear capacity,[102] and increasing renewable electric generation capacity over time through state-level renewable generation targets consistent with renewable generation portfolio standards that have been established by states in the same region.[103] EPA assumes that new and incremental renewable energy can be integrated into electric distribution and transmission systems at a reasonable cost and without compromising safety or reliability. There are significant limits to our ability to implement building block 3 in Alaska.

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101 RIA 1-1.

102 The measures relating to nuclear generation do not relate to Alaska. *See* AS 44.99.120.

103 Proposed Rule, 79 Fed. Reg. at 34,851.

First, geographic and economic constraints limit the availability of utility grade renewable energy resources. Utility grade wind and geothermal generation resources are generally located in southwest and western Alaska, hundreds of miles away from transmission facilities connected to affected EGUs.[104] Given the current state of technology and the low angle of sunlight during much of the year, our solar resources are not utility grade.[105] Alaska is actively investigating biomass, hydrokinetic, and hydroelectric resources, and developing those that appear viable. However, again, many of these resources are also not located within economic reach of load served by an affected EGU.[106]

Second, transmission and economic constraints dictate that only smaller renewable energy projects can be integrated. As previously described, the relevant transmission lines are already operated substantially at capacity to transfer hydroelectric and natural gas generation to load. The cost of making substantial upgrades to the existing transmission infrastructure would make most renewable energy projects uneconomic. Therefore, most new renewable energy projects will have to be sized to interconnect with their local distribution system. Generally only projects producing 2 MW or less can be interconnected with local distribution systems. This lack of scale substantially affects project economics. Without economies of scale, Alaska does not have the same opportunities to develop projects as the interconnected continental states.

Third, the affected utilities in Alaska have limited capacity to accommodate additional non-firm energy, particularly intermittent generation sources such as wind and solar.[107] To ensure reliability of the system, firm generation resources must be available to follow intermittent generation resources. Firm generation resource capacity that is sufficiently nimble to continuously follow load in addition to intermittent generation resources such as wind and solar must be continuously online. The availability of this type of firm generation capacity is limited in Alaska. Additionally, increased cycling of fossil units occasioned by following intermittent generation will decreases the unit's efficiency, leading to an increase in CO_2 emissions.

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[104] Renewable Energy Atlas 2-4 (existing); 8-9 (geothermal); 16-17 (wind).

[105] *Id.* at 14-15.

[106] *Id.* at 6-7 (biomass); 10-11 (hydroelectric); 12-13 (hydrokinetic).

[107] Storage hydroelectric generation can be firm. However, in Alaska, many water resources freeze in winter – seasonally limiting the availability of storage hydroelectric generation capacity to the amount of water in storage at the time of freeze-up. Because the output of these resources tends to fluctuate seasonally in a predictable manner, continuous following is not required.

Measures to regulate wind and solar generated energy could include installation of large batteries and flywheels at cost of about $2,000 per kW.[108] The integration of significant amounts of non-firm power may also significantly de-optimized dispatch and result in higher fuel and generation operation and maintenance costs.[109] While our utilities are actively examining options for new renewable energy resources, many renewable energy projects are simply uneconomic. At least one utility notes that the projects typically cost two to three times the avoided cost of gas-fired generation.[110]

Fourth, our ability to incorporate new renewable energy, particularly on the timeline required by this rule, is infused with substantial uncertainty. In many cases, federal environmental studies and permitting requirements and policy create significant barriers to developing even reliable firm renewable energy resources that could be safely absorbed into Alaska's electric utility systems, such as storage or lake tap hydroelectric generation. Declining prices for Alaska oil is reducing the State's ability to provide financing for new renewable energy projects.

4. Demand side energy efficiency programs are not sufficiently supported and are not suitable for inclusion in a state plan.

The fourth BSER measure proposed by EPA is demand side energy efficiency programs. EPA proposes adjusting the CO_2 emission rate for affected EGUs by the amount of generation that is avoided as a result of demand-side energy efficiency measures. Specifically, EPA proposes increasing demand side energy efficiency efforts by an additional increment each year from 2020 to 2029.[111]

To calculate the impact of demand side energy efficiency measures, EPA estimated that each state's annual incremental savings rate increases from its 2012 baseline to a target rate of 1.5 percent of statewide generation over a period of years starting in 2017. States are estimated to increase their savings rate level by 0.2% per year. Once reached, the 1.5% incremental annual savings is maintained through 2029. Alaska would achieve 1.2% cumulative savings by 2020 and 9.45% savings by 2029.[112] The

108 Chugach Response, RCA Docket I-14-007, at 4 (Oct. 31, 2014).

109 *Id.*

110 *Id.*

111 Proposed Rule, 79 Fed. Reg. at 34,858.

112 Proposed Rule, 79 Fed. Reg. at 34,843.

avoided generation is a percent of *statewide* electric generation which here translates to avoiding 744GWh of generation annually by 2030.[113]

EPA's record does not contain a basis for the mandated implementation of demand side energy efficiency measures. First, EPA acknowledges that the proposed level of DSM performance is beyond what may be achievable – the proposed level of performance has not been previously sustained nationally and that the presumed cumulative energy efficiency savings are well above the average savings that most states have achieved to-date. Second, EPA relied on very limited data. EPA used information reported by only 792 utilities in EIA Form 861 to determine the historic and current impacts of EE programs.[114] Of the 792 reporting utilities, only six are in Alaska. Of those, only one, GVEA, is connected to an affected EGU. GVEA reported a total savings of 1,517 MWh in 2012 from energy efficiency efforts of 982 residential and 535 commercial customers.[115] These savings, around 0.2% per year, do not match the rate of EE implementation dictated by EPA, 1.5% per year. The experience of one utility does not provide adequate support for the magnitude of electric energy efficiency measures EPA forecasts as achievable statewide over the next 13 years.

The high cost of power in Alaska already incentivizes consumers to implement energy efficiency measures without government intervention. This conclusion is supported GVEA's and Chugach's reports of declining trends in per customer usage since 2004 and 2000 respectively.[116] Our utilities also note that they have actively educated their customers about measures to reduce energy consumption.[117] At some point, the reasonable cost options for reducing energy consumption will be exhausted. Presuming, as EPA does in this Proposed Rule, that declining trends will be maintained at the same pace indefinitely is irrational.

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113 GHG Abatement Measures TSD, App. 5-4, Opt 1 – Cum Savings GWh, at Q55.

114 GHG Abatement Measures TSD 5-16, 5-31; EIA, Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files for 2012, dsm_2012.xls, *available at* http://www.eia.gov/electricity/data/eia861/.

115 EPA, GHG Abatement Measures TSD, App. 5-4, Comprehensive Results: State Goal Setting and Impacts Assessment, EPA-HQ-OAR-2013-0602-1294.

116 Chugach Response, RCA Docket I-14-007, at 4 (Oct. 31, 2014); ML&P Response, RCA Docket I-14-007, at 5 (Nov. 3, 2014).

117 Chugach Response, RCA Docket I-14-007, at 8.

This does not mean that the State of Alaska has not implemented energy efficiency programs. The attached November 25, 2014 Alaska Housing Finance Corporation Board Report shows that since 2008, the Alaska Legislature has appropriated $602.5 million just for home energy efficiency and weatherization programs. These programs have resulted in upgrades to over 37,000 residences, with an annual savings of the equivalent of 932 GWh of electricity. Of course, most of these residences are not interconnected with our EGUs and what we are saving is fuel oil or firewood consumed in relatively inefficient residential units. The net carbon dioxide emission savings from this investment cannot be calculated, but is almost certainly greater than would have been saved if an equivalent number of MWh of generation had been reduced from our comparatively efficient EGUs.

Demand side energy programs are popular, because they provide low income consumers an opportunity to reduce their cost of living and provide public benefits. However, in Alaska we have determined that the emphasis of demand side energy programs needs to be placed on the space heating needs of our residents. In our climate, space heating is a health and safety concern that simply has to have priority over other potential demand side energy efforts. Our efforts have probably resulted in, and will continue to result in, a greater reduction in total carbon dioxide emissions than the goal established by the EPA for Alaska under the fourth BSER. The EPA should exempt Alaska from the fourth BSER rather than try to force us into divert limited resources into efforts that are unlikely to be as effective at reducing carbon dioxide emissions.

Several other characteristics of energy efficiency programs call into question the appropriateness of this measure as a building block generally. First, as a non-dispatchable resource, energy efficiency cannot be reasonably relied upon to replace generation. Second, DSM energy efficiency programs are voluntary on the part of consumers and inclusion of these programs expands enforceability into the homes and businesses of Alaskan residents. The state cannot guarantee or enforce consumer participation in any energy efficiency programs designed to meet an emissions limit. Third, DSM energy efficiency cannot be measured or verified – measurement of these types of programs is based on multiple layers of estimates.[118] In addition, energy efficiency programs are subject to a rebound effect as customers use the more efficient technology more than the old inefficient technology. Therefore, energy efficiency savings rarely result in the savings expected.

5. Attempt to implement the Proposed Rule in Alaska would likely result impose unreasonable costs.

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[118] State Plan Considerations TSD 42 (recognizing that "many states with energy efficiency programs use different input values and assumptions" to estimate energy savings from such programs).

It must be recognized that ratepayers in Alaska will bear a substantially greater burden under this rule than ratepayers in the interconnected states. The cost of electric service is already high here. In 2010, Alaska had the seventh highest cost of electricity, 13.28 cents/kWh, compared to other states (average 9.1 cents/kWh).[119] GVEA customers paid approximately 19.08 cents/kWh in 2010 – more than any other state except Hawaii.[120] GVEA's current tariffs reflect residential rates of approximately 23.56 cents/kWh.

With so few ratepayers, Alaska cannot take advantage of economies of scale that may be available to other states. The Midcontinent Independent System Operator (MISO) concluded that "bigger is better" when meeting the Proposed Rule – that compliance costs could be reduced substantially through a regional approach to compliance.[121] However, Alaska does not have economies of scale itself, and does not have the opportunity to participate in a regional compliance approach. Alaska's population and energy market are small compared to other states; the costs of implementation borne by fewer ratepayers than elsewhere in the U.S. Moreover, the affected EGUs in Alaska all belong to either cooperative or municipal utilities. As a result, the financial impact of this rule will be unavoidably felt by utility members and resident ratepayers, not investors.

6. EPA's BSER measures cannot be implemented or enforced within the scope of current state law and policy.

Under this Proposed Rule, the EPA requires that all measures in an implementing State Plan must be enforceable and verifiable. Given the current statutory authority of the relevant state agencies, and how those statutory provisions have been interpreted historically, it is unlikely that Alaska's state agencies currently have the statutory authority to implement EPA's regulations. In fact, the BSER measures will likely directly conflict with the ratemaking principles employed by the RCA.[122]

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119 Alaska RIRP 3-2.

120 Alaska RIRP 3-4 to 3-5.

121 *See also*, EPA Legal Memorandum 90 n. 73, 91 (acknowledging costs are less for region-wide re-dispatch as compared to an intra-state approach).

122 FERC Commissioner Clark observes that "it's not hard to envision a future jurisdictional train wreck."

For example, in ensuring utility rates are set according to the "cost-causer, cost-payer principle -- costs are assigned to each class of customer (e.g., residential, commercial, and industrial) in accordance with costs incurred to provide service to the class. Anytime one class of customer pays more than its respective allocated costs, the class is cross-subsidizing other classes. Here, because the Proposed Rule sets an emission rate for all "affected EGUs" in the state, rather than the specific affected EGUs, cross-subsidies may occur amongst ratepayers of the various utilities in the state. While cross-subsidies may be sorted out in context of setting rates for a single utility – sorting out the allocation of compliance costs amongst several utilities may prove challenging.

Consequently, implementation of this rule will likely require involvement of the Governor's office and the legislature. New legislation may be required to (1) allocate responsibility for compliance and enforcement amongst state agencies; (2) require mandatory integrated resource plans (IRPs) based on models consistent with the Proposed Rule; (3) provide the RCA with siting authority; (4) authorize new energy efficiency and demand side energy efficiency standards as well as the accompanying evaluation, measurement and verification (EM&V) methods. The necessary remedial legislation may be difficult to obtain and would involve some additional costs for the state. Given the rule's potential impact on the cost and reliability of electric service, as well as, the recurring observation that this rule would require states to cede authority to EPA[123] – obtaining the necessary remedial legislation may be difficult.

D. Alaska should be exempted from the rule because we are already reducing carbon emissions using methods tailored to our unique circumstances - focused on rural communities and non-affected EGUs – that are incompatible with EPA's approach.

While Alaska cannot reduce carbon emissions from the specific "affected EGUs" in a timely manner without exorbitant cost or compromising reliability of electric service, Alaska's existing informal energy policy has the impact of reducing carbon emissions –

[123] FERC Commissioner Tony Clark observed that the Proposed Rule has the potential to "comprehensively reorder the jurisdictional relationship between the federal government and the states, dramatically altering these traditional lines of authority" and in spite of EPA's promises of flexibility, states are "ceding ultimate authority to EPA" by "voluntarily agreeing to seek EPA approval of its overall integrated regulation of the electrical industry." testimony before the House Committee on Energy and Commerce (July 29, 2014). Commenting on the reliability implications of the rule, FERC Commissioner Mueller cautioned that EPA must involve state and federal agencies with expertise governing the electric utility sector since "the laws of physics trump written words."

the state supports several renewable energy, energy efficiency, and natural gas development programs. However, these efforts likely will not count toward compliance with the Proposed Rule because they impact non-affected EGUs or target space heat, rather than electric, efficiency. Furthermore, our Railbelt utilities are just completing a substantial upgrade of their generation fleet, resulting in substantial heat rate improvements. EPA should exempt Alaska from this rule and allow the state to continue with ongoing energy projects.

1. New Generation Fleet

Five of the Railbelt utilities have new generation units with useful lives exceeding 30 to 40 years. In 2012, Chugach began receiving energy from the privately owned 17.6 MW Fire Island Wind Project in Anchorage. Later in 2012, GVEA began taking energy from its 25 MW Eva Creek Wind Project. In 2013, Chugach and ML&P jointly commissioned the 183 MW NGCC the Southcentral Power Plant (SPP) in Anchorage. Later in 2013, HEA completed addition of a steamer unit to their Nikiski simple cycle unit, making that an 80 MW NGCC. In 2013, MEA began construction of a 170 MW, ten-unit reciprocating engine natural gas fueled generation plant in Eklutna, which is anticipated to be completed in 2015. In 2014, HEA installed a new 47 MW simple cycle natural gas unit in Soldotna. In 2014, ML&P began construction of the new 120 MW NGCC George Sullivan Plant 2A, next door to its existing George Sullivan Plant 2. Plant 2A is expected to be complete in 2016. In 2013, GVEA acquired Healy Unit 2 from the State of Alaska, and in 2014 began construction of the upgrades required to restart that 52.5 MW coal fueled unit. Healy Unit 2 is expected to be restarted in 2016.

With the installation of these new units, Chugach plans on retiring the steamer unit 8 at Beluga in 2015, and retiring the remaining Beluga units over the following few years. ML&P plans on retiring the George Sullivan Plant 2 steamer unit 6 immediately, and using the remaining Plant 2 units in simple cycle. With Healy Unit 2 in operation, GVEA plans on substantially reducing generation from its oil fueled units. The new NGCC units have substantially better heat rates than the retired units, and the new simple cycle units have substantially better heat rates than the older simple cycle units. By 2016, it is anticipated the three George Sullivan Plant 2A units and Healy Unit 2 will qualify as affected EGUs. By 2017, it is anticipated that no Beluga or George Sullivan Plant 2 units will qualify as affected EGUs. It is not anticipated that the MEA Eklutna units or the HEA Soldotna unit will ever qualify as affected EGUs.

Given the recent installation of these new units, Alaska has already made strides towards improving our carbon profile from our electric utility sector – federal intervention at this juncture may only result in unintended financial consequences for our utilities. This would be particularly irrational given the limited significance of carbon emissions from this sector in Alaska.

2. Significant renewable energy generation and energy efficiency programs have been implemented in Alaska

Second, though many of these projects would not be eligible for inclusion in a state plan under the Proposed Rule, Alaska has, and continues to, aggressively pursue renewable energy generation and energy efficiency opportunities. To promote development of renewable energy generation and energy efficiency measures, Alaska's legislature established aspirational energy goals[124] to source fifty percent of the state's total yearly electric load from renewable and alternative energy sources by 2025 and to facilitate a fifteen percent increase in energy efficiency by 2020. Since 2008, Alaska has appropriated in excess of $1.34 billion pursuing this informal energy policy.[125] These funds have created and supported the Renewable Energy Fund,[126] the Emerging Energy Technology Fund,[127] the Alaska Housing Finance Corporation's Energy Rebate Program,[128] the Power Project Fund,[129] and others.

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[124] Sec. 1, ch. 82, SLA 2010.

[125] Chapter 11, Section 22, 2008 Alaska Session Laws ($300,000,000); Chapter 1, Sections 4 and 6, 2008 Alaska Fourth Special Session Laws ($110,000,000); Chapter 12, Sections 1 and 2, 2009 Alaska Session Laws ($1,149,700); Chapter 15, Section 1, 2009 Alaska Session Laws ($31,200,000); Chapter 17, Section 7, 2009 Alaska Session Laws ($56,622,700); Chapter 41, Sections 1 and 2, 2010 Alaska Session Laws ($2,481,300); Chapter 43, Sections 7, 10, and 23(c), 2010 Alaska Session Laws ($84,383,050); Chapter 3, Sections 1 and 2, 2011 Alaska First Special Session Laws ($4,492,400); Chapter 5 Sections 1, 4, and 19(c), 2011 Alaska First Special Session Laws ($370,602,031); Chapter 15, Section 1 2012 Alaska Session Laws ($5,769,000); Chapter 17, Sections 1 and 15(b), 201 Alaska Session Laws ($95,051,159); Chapter 14, Section 1, 2013 Alaska Session Laws ($6,728,700); Chapter 16, Sections 1, 4, and 21(b), 2013 Alaska Session Laws ($180,250,000); Chapter 16, Section 1, 2014 Alaska Session Laws ($6,728,700); Chapter 18, Sections 1 and 4, 2014 Alaska Session Laws ($89,115,060).

[126] AS 42.45.045.

[127] AS 42.45.375.

[128] AS 18.56.410.

[129] AS 42.45.010.

Just one of these programs, the Renewable Energy Fund (REF), has resulted in substantial gains towards our renewable energy goals. The REF assists communities in reducing and stabilizing the cost of energy by providing public funding for the development of qualifying and competitively selected renewable energy projects. The program is designed to produce cost-effective renewable energy for heat and electric power to benefit Alaskans statewide.

Renewable Energy Fund Rounds 1-6 Funding Summary	Totals
RE Project Applications Funded	251
Appropriated ($M)	$ 227.5
Match Provided ($M)	$ 102.6
Other Known Funding ($M)[130]	$ 26.1
Total appropriated, match and other known funding	$ 356.2

Between its inception in 2008 and 2012, the Renewable Energy Fund has contributed to the completion of 38 renewable energy projects, 23 of which produce electricity.[131] These early projects avoided the emission of 115,527 tonnes of carbon emissions in 2012.[132] Statewide, another 72 projects have been funded through construction, and 66 more have been funded for earlier phases of development such as final design and feasibility.[133]

In 2013, the constructed REF projects displaced over 12.9 million gallons of diesel fuel equivalent and avoid approximately 131.7MT of CO_2.[134] Most of the displaced fuel

130 Represents only amounts recorded in grant document, does not capture all other funding.

131 Alaska Energy Authority, Renewable Energy Grant Recommendation Program: Impact Evaluation Report 7-11 (October 29, 2012) available at http://www.akenergyauthority.org/re-fund-6/4_Program_update/AlaskaREF undImpactEvaluationReport_Volume2.pdf (annual savings of 9.8 million gallons of diesel consumption through first 38 projects completed) (“AEA Impact Report”).

132 AEA Impact Report at 11.

133 AEA Impact Report at 9.

134 Alaska Energy Authority, Renewable Energy Fund: Status Report and Round VII Recommendations 2 (Rev. April 2014) *available at* http://www.akenergyauthority.org/re-fund-7/4_Program_update/REFStatusReport 2014_0426_Final_LowRes.pdf (“REF Status Report”).

is diesel fuel, with smaller displacement of naptha, natural gas, and propane. As more of the projects complete construction, the renewable energy generation and displacement of fossil fuels will continue to grow. By 2015, these efforts are forecast to displace nearly 20 million gallons fuel equivalent annually – avoiding 204.2 MT of CO_2 emissions.[135]

Notably, State funds have been used to finance hydroelectric projects serving communities throughout the state. By example, the state has financially supported the Terror Lake Project on Kodiak, the Solomon Gulch and Allison Creek Projects near Valdez, the Power Creek and Humpback Creek projects near Cordova, Chuniisax Creek Project in Atka, Town Creek Project in Akutan, Delta Creek Project near King Cove, and the Yerrik Creek Project in Tok. The state is also currently assessing the Susitna-Watana hydroelectric project to serve the affected EGU's service areas. New wind generation from Eva Creek and Fire Island are other recent, and significant, additions to Alaska's renewable energy generation.

The state of Alaska also funds demand-side energy programs[136] The Commercial Building Energy Audit (CBEA) program reimburses owners for the cost of an ASHRAE level II audit. The Village Energy Efficiency Program (VEEP) provides grants to small communities (population up to 8,000) with high energy costs for efficiency measures in public buildings and facilities, including water systems. The state also supports public education and outreach campaigns. Other programs focus on the residential sector. Our weatherization program provides efficiency upgrades for income eligible households. The Home Energy Rebate program provides rebates of up to $10,000 for efficiency upgrades to owner-occupied homes regardless of income. There are also interest rate credits available for home mortgages. Like, renewable energy projects, energy efficiency projects are frequently implemented in rural communities with islanded electric systems.

3. EPA's proposed approach to reduce carbon emissions does not align with Alaska's policies.

Alaska's energy efficiency programs often focus on improving thermal, rather than electric, efficiency. More than 35% of total REF funding has gone to heat recovery and biomass heat projects. This focus is appropriate. First, thermal energy efficiency measures displace diesel fuel and reduce carbon emissions. But this approach also serves to reduce, rather than increase, costs to customers. In a typical Alaska household, 80% of

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135 REF Status Report 5.

136 Weatherization, Home Energy Rebate Program, Energy Efficiency and Education and Outreach, Commercial Building Energy Audit Program, Village Energy Efficiency Program, and loan funds for both public and private building efficiency retrofits.

the energy consumed is used for space and water heat. Consequently, the programs tend to be more successful as homeowners are more inclined to invest in energy efficiency measures that reduce thermal energy consumption. Furthermore, in our arctic and sub-arctic climate, thermal energy has significantly greater import for health and human safety.

Alaska's renewable energy and energy efficiency projects also often focus on communities with the highest costs. Of the nearly quarter of a billion dollars committed to renewable energy projects in Alaska through the REF, only 12% has been for projects in the affected EGU's service areas.[137] There are also good reasons to focus on projects in rural communities. In rural communities, power costs can be as high as $2.16 /kwh.[138] By comparison, the weighted average cost of power in Anchorage, Fairbanks and Juneau is approximately $0.1482 /kwh.[139] Alaskan consumers pay among the highest rates for heating and electricity in the country—50% higher than the U.S. average. According to the Energy Information Administration, in 2012, Alaska ranked second in residential electricity costs with an average price of 17.91 cents/kWh as compared to the national average of 11.52 cents/kWh. However, 159 rural villages or 85% of Alaska's communities surpass 1st ranked Hawaii's 37.05 cents/kWh. Remote communities face greater challenges in ensuring electric service reliability.[140]

To be credited towards compliance with this Proposed Rule, energy efficiency measures must relate to electric energy produced at affected EGUs. Thus, the rule will likely forcibly refocus state energy efficiency programs from thermal energy to electric generation. Similarly, because many rural communities are not connected to the "affected EGUs" the renewable energy and energy efficiency measures may not qualify for inclusion in Alaska's State Plan. Forcing Alaska to focus on reducing carbon emissions within the Railbelt could jeopardize funding for existing and future energy programs in

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[137] REF Status Report 3.

[138] Alaska Energy Authority, Power Cost Equalization Program Statistical Data by Community: July 1, 2012 to June 30, 2013, at 98 (February 2014), *available at* http://www.akenergyauthority.org/PDF%20files/pcereports/FY13StatisticalRptComt.pdf (Lime Village).

[139] Order U-14-080(1), *Order Issuing Notice of Proposed Base Amount for Power Cost Equalization Calculations, Setting Comment Deadline, Scheduling Hearing, Addressing Statutory timeline, Designating commission Panel, and Appointing Administrative Law Judge*, at Appendix A (RCA May 19, 2014).

[140] AEA Impact Report 15.

rural communities where the state is partnering with Village Corporations, Tribal entities and Village Utility Cooperatives.[141] This result is contrary to common sense and Alaska's current energy policy; and furthermore, inconsistent with EPA's environmental justice mandate to avoid disproportionately high and adverse human health or environmental effects on minority and low income communities.

4. The several projects seeking to bring natural gas to Fairbanks would not be "enforceable" measures qualifying for inclusion in a State Plan.

There are a number of concurrent, ongoing efforts to bring natural gas to Fairbanks that may be compromised by the application of this rule.[142] For example, the State of Alaska is investing approximately $350 million dollars through the Interior Energy Project to bring liquefied natural gas (LNG) into Fairbanks by 2016.[143] Work on this "supply chain" project construction of a North Slope LNG plant, securing long range transport contracts, increasing community LNG storage capacity, expanding the existing limited natural gas distribution system in Fairbanks and starting a new distribution utility in the outlying area. An important aspect of this effort is engaging potential large anchor consumers of natural gas to purchase the LNG from this project. Converting from liquid fuels to cost-effective natural gas for local electrical generation will help to solidify the economics of the natural gas project, thus helping to ensure that cleaner burning fuel is also available for distribution for space heating through a local utility. Delivering natural gas to Fairbanks and converting electric generation from liquid fuels would also reduce carbon emissions.

However, these extraordinary efforts would not qualify for inclusion in any state plan under this Proposed Rule. First, these projects are not measures that could be "enforceable" or that should be subject to citizen suits. Second, many of the generators that may be affected by the arrival of natural gas in Fairbanks are diesel or naphtha units not covered by the rule. Third, to the extent these efforts focus on space heating, those

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[141] This result is also inconsistent with EPA's environmental justice mandate to avoid disproportionately high and adverse human health or environmental effects on minority and low income communities. *See* Executive Order 12,898, 59 Fed. Reg. 7629 (February 16, 1994).

[142] Bill White, Guide to Alaska natural gas projects (September 10, 2014) available at http://www.arcticgas.gov/guid-alaska-natural-gas-projects#lng.

[143] Interior Energy Project: Bringing North Slope Natural Gas to Alaskans, http://www.interiorenergyproject.com (updated Oct. 8, 2014).

measures would not reduce emissions at "affected EGUs" and would not be credited to the state.

As with the retirement of the Healy coal units, disrupting Alaska's plans to bring natural gas to Fairbanks may also have the irrational result of contributing to air quality problems. A portion of the Fairbanks North Star Borough, including the cities of Fairbanks and North Pole, is designated as a fine particulate matter nonattainment area. Space heating from wood, coal, and fuel oil all contribute to the issue. One of the challenges in reducing $PM_{2.5}$ air pollution in these communities is a lack of available, affordable, cleaner-burning natural gas in the community. The increasing cost of electricity in this region has contributed to a significant increase in the use of wood burning stoves for space heating, increasing both particulate and carbon emissions as residents try desperately to lower their overall monthly energy costs. EPA's Proposed Rule would only further increase energy costs. By contrast, projects already being assessed in Alaska could have substantial benefits to the state and national economy while simultaneously reducing carbon emissions.

III. Alternatively, the proposed interim and final emission rates should be clarified and revised.

If EPA applies a 111(d) rule to existing EGUs in Alaska, several modifications should be made to the rule. First, EPA should clarify the criteria for "affected EGUs. EPA should apply correct data to the goal calculation. Additionally, while EPA may not have the authority to require certain measures, EPA should allow compliance credit for actions that reduce CO2 emissions even if the action does not relate to an "affected EGU."

A. Affected Electric Generating Units

1. States should be given compliance credit for the full measure of CO_2 emissions avoided by fuel conversion.

The Proposed Rule is unclear on how existing units that convert from liquid fuel to natural gas are to be addressed in any state plan to implement and attain the proposed CO_2 emission target. This is relevant for Alaska. GVEA has a combined cycle unit in North Pole that currently operates on naptha. Naptha is a liquid fuel, sometimes referred to as jet fuel, and thus the carbon emissions from this unit were excluded from the calculation of the EPA's proposed goal for Alaska.[144] However, the North Pole combined

[144] Goal Computation TSD 29-30; EPA, 2012 Unit-Level Data Using the eGRID Methodology (xls), EPA-HQ-OAR-2013-0602-0254, Lines 9220, 9221, column F (showing that these units use Jet Fuel) ("2012 Unit-Level Data").

cycle unit was designed for economic conversion to use of natural gas as fuel, should natural gas fuel become economically available in North Pole.

In 2012, the North Pole combined cycle unit produced 423,592 MWh of energy and emitted 222,586.3 tons of carbon dioxide according to the EPA.[145] This equates to an emission rate of 1,158.5 pounds/MWh.[146] Also according to EPA, on average use of natural gas as fuel would result in a 26.6% lower carbon dioxide emission rate than jet fuel.[147] Assuming that there is no heat rate penalty in converting the North Pole combined cycle unit to natural gas, at 2012 energy production levels such conversion would result in a net savings of 59,208 tons of carbon dioxide for a net emission rate of 850 pounds/MWh.

It appears that, as currently drafted, the Proposed Rule would give Alaska credit for producing 423,592 MWh of energy from an affected EGU with an emission rate of 850 pounds/MWh. This would effectively ignore the emissions savings achieved between the 1,158.5 pounds/MWh actually achieved by the North Pole combined cycle unit in 2012, and the 1,003 pounds/MWh goal established by the EPA. In effect, in paying to get natural gas fuel to North Pole, GVEA ratepayers would be reducing their carbon dioxide emissions by nearly 30,000 tons, and getting no credit for that expenditure under the Proposed Rule.[148] The Proposed Rule needs to be rewritten to provide incentives for ratepayers to make this sort of investment.

2. EPA should clarify the actual sales criteria for affected EGUs.

The "affected EGU" criteria in proposed 40 C.F.R. §60.5795 (b)(1) should include the "and supplies" language included in (b)(2). This would be consistent with EPA's intent to include an actual sales threshold in the "affected EGU" criteria for existing steam boilers.[149] However, as currently drafted, without the "and supplies" component,

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145 2012 Unit-Level Data, Lines 9220, 9221, columns M, N.

146 [(222,586.3 MT) X (2,204.62 pounds/MT)} ÷ 423,592 MWh = 1,158.469 pounds/MWh.

147 2012 Unit-Level Data, EFCO2eGRIDyr2010.xls, lines 13, 21 [(19.70 – 14.46) ÷ 19.70] = 0.265989.

148 [(1,158.5 pounds/MWH – 1,003 pounds/MWh) X 423,592 MWh] ÷ 2,204.62 pounds/MT = 29,877.5

149 Proposed Rule, 79 Fed. Reg. at 34,854/2. Alaska supports EPA's intention to include an actual sales threshold to the "affected EGU" criteria. It would be unreasonable

the proposed regulation fails to clearly convey this intent. EPA should also clarify that when a unit is de-rated such that the potential electric output falls under the 25MW net capacity or 219,000MWh net output threshold, the unit no longer qualifies as an affected EGU.

This clarification is necessary to understand the status of Healy Unit 1under the Proposed Rule. Healy Unit 1 is a coal fueled steam generating unit constructed for the purpose of supplying 22 MW of net electric output to the grid.[150] Today, Healy Unit 1 is capable of providing a gross output of 27 MW.[151] Still, in practice, the net output of Healy Unit 1 typically falls short of 219,000MWh per year.[152]

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to expect small, low generating steam units to bear the burden of complying with this rule – especially where EPA has only evaluated the feasibility and cost of compliance for larger units.

150 Comment letter from Cory R. Borgeson, President & CEO, GVEA, to U.S. Environmental Protection Agency at 1 (Oct. 15, 2014) (filed in docket EPA-HQ-OAR-2013-0603) ("GVEA Comment"). At the time the unit was constructed Healy Unit 1 likely did not meet the "affected EGU" criteria outlined in proposed 40 C.F.R. §60.5795. Proposed Rule, 79 Fed. Reg. at 34,954; *also see id.* at 34,854/2.

151 GVEA Comment 1.

152 For the twelve month period ending April 2014, Healy Unit 1 net output was **202,687.2 MWh**. GVEA, TA254-13 at Exhibit 7c filed (May 30, 2014). For the twelve month period ending December 31, 2013, Healy Unit 1 net output was **190,763.5 MWh**. GVEA, 2013 Annual Report, 402 (filed May 1, 2014). For the twelve month period ending December 31, 2012, Healy Unit 1 net output was **215,203.5 MWh**. GVEA, 2012 Annual Report, 402 (filed May 1, 2013) For the twelve month period ending December 31, 2011, Healy Unit 1 net output was **177,552.2 MWh**. GVEA, 2011 Annual Report, 402 (filed April 26, 2012). For the twelve month period ending December 31, 2010, Healy Unit 1 net output was **189,306.0 MWh**. GVEA, 2010 Annual Report, 402 (filed April 4, 2011). For the twelve month period ending December 31, 2009, Healy Unit 1 net output was **212,950.0 MWh**. GVEA, 2009 Annual Report, 402 (filed April 2, 2010). For the twelve month period ending December 31, 2008, Healy Unit 1 net output was **220,576.0 MWh**. GVEA, 2008 Annual Report, 402 (filed May 5, 2009). For the twelve month period ending December 31, 2007, Healy Unit 1 net output was **213,900.0 MWh**. GVEA, 2007 Annual Report, 402 (filed April 1, 2008). For the twelve month period ending December 31, 2006, Healy Unit 1 net output was **210,713.0 MWh**. GVEA, 2006 Annual Report, 402 (filed April 2, 2007). For the twelve month period ending December 31, 2005, Healy Unit 1 net output was **219,800.0 MWh**. GVEA, 2005 Annual Report, 402 (filed April 4, 2006). For the twelve month period ending December 31, 2004, Healy

Both, the potential and actual output of Healy Unit 1 may decrease in the future. First, the parasitic load associated with additional pollution control equipment, required by GVEA's consent decree with EPA, will reduce the unit's net output -- perhaps below 25 MW.[153] Second, Second, GVEA's utilization of Healy Unit 1 may decrease once Healy Unit 2 recommences commercial operation in 2015 or 2016. If Healy Unit 1 continues to be operational at a reasonable cost to GVEA may choose to retire its diesel units in Fairbanks and North Pole first.[154] In fact, depending on future energy availability, GVEA may operate Unit 1 beyond 2030.[155]

Unit 1 net output was **211,264.0 MWh**. GVEA, 2004 Annual Report, 402 (filed April 11, 2005).

153 *See* discussion *supra* in Part II.C.1; GVEA Consent Decree ¶¶ 60-63 (requiring installation of SNCR at Healy Unit 1 on or before September 30, 2015 or 18 months after Unit 2 first fires coal, whichever is later; and, requiring either installation of SCR at Healy Unit 1 or retirement of the EGU by December 31, 2024); GVEA anticipates that SNCR will be installed and operational by 2017and will cause a 0.01% degradation to heat rate attributable to the parasitic load. GVEA reports a 1.5MW energy penalty and 2.87% degradation in heat rate may be caused by installation of SCR. GVEA, Supplemental Response, RCA Docket I-14-007, Ex. A-1 (Oct. 31, 2014).

154 GVEA, Supplement Response, RCA Docket I-14-007, Exh. D (Oct. 31, 2014) (outlining anticipated retirement dates and remaining depreciable value of GVEA's generation fleet). A number of the diesel units in GVEA's generation fleet have a lower remaining depreciable value than Healy Unit 1. *Id.* Also, at 30.8 or 54.7 cents/kWh in 2013, diesel is GVEA's most expensive fuel source. P. Ashbridge, Rates & Regulatory Section, GVEA, 2013 Annual Fuel Cost Breakdown (Feb. 5, 2014). In comparison; at 4.8 cents/kWh, Healy Unit 1 uses GVEA's least cost fuel. *Id.*

155 Comment letter from Cory R. Borgeson, President & CEO, GVEA, to U.S. Environmental Protection Agency 3 (Oct. 15, 2014) (filed in docket EPA-HQ-OAR-2013-0603). In the context of GVEA's comment regarding "future energy availability," EPA should consider that GVEA anticipates a possibility of retiring other significant generation resources during the compliance period for this Proposed Rule. GVEA Supplemental Response, RCA Docket I-14-007, Ex. D (Oct. 31, 2014). The age of GVEA's generation fleet dictates careful consideration of resource adequacy and reliability service before finalizing a rule that may require premature retirement of a significant generation resource.

Continued generation at Healy could provide net benefits from an environmental and human health perspective. Some of GVEA's diesel units are more carbon intensive than Healy Unit 1.[156] Avoiding generation from the Fairbanks and North Pole diesel units would also reduce particulate matter loading in the Fairbanks air-shed would reduce the likelihood of non-attainment area. Available generation capacity on the west side of GVEA's service territory may also make a greater contribution to the reliability of the system when Healy Unit 2 is down for maintenance or other reasons. These cost, emission, and energy considerations support clarifying the proposed regulation to remove small or low-utilization steam generating units from the category "affected EGU."

B. Heat Rate Improvements and Coal

As explained above, the coal EGUs in Alaska cannot achieve heat rate improvements through any reasonable measures. If the Proposed Rule is applied to Alaska, EPA cannot assume any savings through heat rate improvements when calculating our goal. Further, if EPA applies the Proposed Rule to Alaska, the following corrections should be made to properly account for coal EGUs in the baseline.

Alaska's emission baseline and goal should be adjusted to reflect the actual emissions from Healy Unit 1.[157] EPA's materials contained conflicting data regarding the CO_2 emission rate and total emissions from Healy Unit 1 in 2012. In one file, EPA reported an emission rate of 2,901.4 lb/MWh and total emissions of 312,493.2 tons from the unit.[158] In another spreadsheet EPA reported total emissions of 307,155.732 for the same unit over the same period.[159] In a third file, EPA reported an emission rate of 2,852 lb/MWh.[160] However, GVEA measured, and reported an actual CO_2 emission rate of

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156 *Compare*, 2012 Unit-Level Data, Lines 9224, 9225, columns M and N (Fairbanks diesel output and emissions) *with* Line 9226, columns M and N (Healy Unit 1 output and emissions).

157 The figure provided in GVEA's GHG reports reflects the actual emissions from the unit as measured by the continuous emission monitoring system (CEMS). The CEMS data should be used here since EPA contemplates using the CEMS measurements for compliance purposes. *See* Proposed Rule, 79 Fed. Reg. 34,954 (proposed 40 C.F.R. §60.5805(a)(2)(i)).

158 2012 Unit Level Data, "State yr 2012 data ELEC GEN" worksheet at D6 & E6

159 2012 Unit Level Data, "All Units yr 2012 data" worksheet at N79

160 Goal Computation TSD, Appendix 7: "Plant Level Data," at G6, C9, EPA-HQ-OA-2013-0602-0256.

3,564.89 lb/MWh for Healy Unit 1 in 2012.[161] Alaska's emission baseline and goal should be adjusted to reflect this rate.

Alaska's emission baseline and goal should also be adjusted to recognize Healy Unit 2. The EIA materials incorrectly assign Healy Unit 2 an "indefinitely postponed" status. GVEA anticipates commencing generation at this unit in 2015 or early 2016. Thus, if the Proposed Rule is applied to Alaska, our baseline should be adjusted to account for anticipated operations at Healy Unit 2 because it is an existing unit to which the utility is financially committed. GVEA anticipates that Healy Unit 2 will operate at about an 85% capacity factor with an emission rate of approximately 2,700lbs/MWh. An allowance for Healy Unit 2 – generating approximately 391,000MWh with an emission rate around 2,700lbs/MWh – should be included when calculating Alaska's 2012 baseline and targets if the Proposed Rule is applied to Alaska.

C. Re-Dispatch

If the rule is applied to Alaska, the goal calculation should not include any provision for re-dispatch from coal units to NGCC units. As discussed above, the coal and NGCC units in Alaska are separated by over 200 miles. Our transmission capacity is already used to its limit and reliance on the single contingency line would have significant implications for reliability and resource adequacy in the Fairbanks area. Alaska cannot re-dispatch coal generation at a reasonable cost.

D. New Renewable Generation

There may be potential for new renewable (RE) generation in Alaska; however, if the rule is applied here, EPA should clarify what RE generation qualifies for compliance purposes. First, EPA should calculate the goal in a manner that is consistent with recognized compliance measures. As currently drafted, EPA appears to have calculated the goal on the basis of statewide renewables (in 2002 and 2012). However, these projects are not all interconnected with affected EGUs and therefore would not qualify as standards of performance "for" affected stationary sources. If the rule is applied to Alaska, while EPA cannot require off-grid projects, EPA should allow states to count the carbon dioxide emission reductions achieved in rural locations (not interconnected with an affected EGU) towards compliance. This principle applies to both the RE and EE building blocks and is discussed below as an in-state renewable energy credit (REC).

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161 GVEA Supplemental Response, RCA Docket I-14-007, Revised Ex. B-1 (Oct. 31, 2014); *also see* GVEA, 2012 GHG Annual Report for Healy Power Plant (March 15, 2013); *compare* GVEA, 2013 GHG Annual Report for Healy Power Plant (Feb. 28, 2014).

Second, Alaska should receive credit for renewable projects that came online between 2012 and June 18, 2014. EPA states that State Plans cannot claim credit for reductions in CO_2 emissions resulting from pre-existing programs, measures etc. unless the "action" leading to the reduction took place after the date of the proposal – June 18, 2014.[162] EPA takes the position that this provision "would not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of the proposal of the emission guidelines was factored into the state-specific CO_2 goals as a part of building block 3."[163] However, the proposed regulatory language creates an ambiguity that would be significant to the State of Alaska. Eva Creek Wind commenced generation in 2013. If the final rule is applied to Alaska, EPA should clarify that all RE projects that commenced generation between December 31, 2012 and June 18, 2014 may also count toward state compliance.

Alaska supports EPA's apparent position that new and incremental hydroelectric generation may be credited to compliance. However, there is some ambiguity in the materials overall. Alaska would like an unambiguous statement regarding how hydroelectric will be treated if the proposal advances. We ask that EPA clarify that new renewable hydroelectric generation, and upgrades to existing hydroelectric generation, would be a qualifying adjustment to the state's emission rate.

EPA should also credit states with actions taken to replace hydroelectric generation capacity lost because of federal permitting requirements. For example, the generation capacity of Chugach's Cooper Lake Hydroelectric project will be reduced substantially, by about 50%, due to a FERC relicensing requirement to divert water for fisheries restoration. To offset this loss, Chugach and the state have invested substantial funds to divert another stream, Stetson Creek, into Cooper Lake.[164] The full measures of generation capacity made possible by the Stetson Creek diversion should be treated as an incremental gain (even to the extent it replaces the incremental loss).

EPA should also allow compliance credits for actions that make more renewable generation available to offset generation from "affected EGUs." For example, the amount

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162 Proposed Rule, 79 Fed. Reg. at 34,918/2 (proposed 40 C.F.R. §60.5750).

163 Proposed Rule, 79 Fed. Reg. at 34,918 n. 293.

164 Rindi White, Cooper Lake Hydroelectric Upgrade: Restoring stream habitat, improving aquatic conditions, Alaska Business Monthly (July 2013) *available at* http://www.akbizmag.com/Alaska-Business-Monthly/July-2013/Cooper-Lake-Hydroelectric-Upgrade/.

of Bradley Lake hydroelectric power that can move north to the Anchorage and Fairbanks load centers is limited by the capacity of the transmission lines. Any future upgrades to the transmission system that allow generation at "affected EGUs" to be replaced by renewable (or less carbon intensive) generation should be credited against emission target.

EPA should also allow compliance credit for electric generation from landfill gas. Using landfill methane for electric generation captures significant efficiencies and reduces overall GHG emissions.

E. Demand Side Energy Efficiency

As discussed above, the demand side efficiency (EE) goals proposed by the EPA are problematic because they are based on very limited data, have uncertain funding and may require legislative action.[165] State funding for energy efficiency programs is variable and uncertain. With the exception of the weatherization program (which receives a portion of program funds from federal sources), all of the efficiency programs noted above run on state general funds as part of capital appropriations. There is not a secure or consistent source of funds for these programs and appropriations have been highly variable year to year. Decreasing oil production and thus revenue to the state has created an uncertain fiscal situation. Future state funding for efficiency programs is not certain as revenues continue to decline.

In light of the paucity of data to evaluate the reasonableness of the EE measures assigned by EPA, the EM&V which must accompany each EE program under the rule, and the uncertainty of funding, EPA should use a more conservative annual incremental savings target. Between EPA's proposals of 1.5% or 1.0% incremental savings – the smaller increment would be less problematic. We also note however, that the demonstrated savings for GVEA runs around 0.2%.

There should be some symmetry between the goal calculation and the measures permitted for compliance. Currently, EPA calculates the contribution of EE measures to Alaska's target rate on the basis of statewide electric sales. EPA should calculate the amount generation is avoided due to EE measures as a percent of forecasted generation from affected EGUs or, in the alternative, allow statewide EE measures to count for compliance purposes.

EPA should adjust the scope of EE programs that would qualify for compliance credit under this Proposed Rule. States should be credited with the generation avoided

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165 GHG Abatement Measures TSD 5-2; State Plan Considerations TSD.

because of energy efficiency measures implemented before June 2014, the date of this Proposed Rule, and which continue to have an impact within the compliance period. Given the significant health and human safety concerns associated with heating in Alaska, EPA should also allow credit for thermal energy efficiency programs that reduce fossil-fuel consumption.

F. EPA should allow an in-state administrative REC that captures renewable energy and energy efficiency projects that are not connected to an affected EGU.

Given the lack of interconnections between Alaska's EGUs and its rural electric utilities, and the compelling policy rationale for continued investment in rural communities, EPA should allow offsets for reduced or avoided carbon emissions in rural communities to count toward compliance. Conceptually, such an in-state REC program would parallel the interstate REC programs. An in-state REC would recognize, but not require, reduced carbon emissions resulting from replacing diesel (or other fossil fuel) generation with less-carbon intensive generation, such as renewables. The quantifiable emission reductions would then be applied in the formula for determining compliance with the mandated state-wide emission rate.[166]

We recognize that EPA proposes to require that the RE/EE be grid-connected generally. EPA expresses uncertainty as to whether, under §111(d), RE and EE may be considered implementing measures in state plans if they are not directly tied to required emission reductions at affected "sources."[167] However, certain implementation measures already proposed by EPA do not, in fact, require a direct, physical relationship between a particular affected EGU and RE/EE.[168] The CAA may limit the measures EPA may require, but should not limit what EPA allows.

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166 The accounting of avoided CO_2 emissions or avoided fossil generation could be the same accounting proposed by EPA for RE and EE grid-connected to an affected EGU. *See* State Plan Considerations TSD 21-23.

167 Proposed Rule, 79 Fed. Reg. at 34,902/1-34,903/2.

168 *See* Proposed Rule, 79 Fed. Reg. at 34,922 (EPA proposes that RE/EE credits may be traded amongst states and EGUs); State Plan Considerations TSD 22 (EPA proposes allowing states the option of adjusting regional CO_2 emissions based on the avoided CO_2 emissions from RE and EE within the same region); State Plan Considerations TSD 22-23 (EPA also discusses the option of crediting the RE and EE to the overall statewide emission performance for affected EGUs); State Plan Considerations TSD at 67, 94 (EPA recognizes a REC model for EM&V documentation and tradable regional RE/EE credit markets for adjusting emission rates from affected EGUs); State Plan Considerations

An in-state REC for Alaska could capture synergies between EPA and Alaska's policy goals. Here an in-state REC program would apply to the same industry sector and would achieve the same goal of reducing CO_2 emissions. The emission reductions would be accomplished through the same mechanism of replacing or reducing fossil generation with RE and EE programs. In many cases, the off-grid projects would affect small electric systems – consisting of a single, identifiable fossil-fuel powered EGU. Consequently, there is no possibility that the new RE or EE measures would be offsetting emissions from a new EGU (regulated under 111(b)), offsetting other RE generation, or are otherwise already required by another regulatory requirement for a different source category. Nor would there be a potential for double counting RE/EE credits. The offset of fossil generation is direct and quantifiable. This common-sense approach would provide Alaska greater access to building blocks 3 and 4, achieve EPA's goal of reducing carbon emissions from fossil fuel electric generating units, and avoid the counterproductive result of depriving our rural communities of state support.

The Proposed Rule does not clearly explain what RE and EE measures may be used to adjust the statewide emission rate for compliance purposes. In particular the rule is unclear with respect to the extent to which a state must demonstrate that RE and EE measures factually result in reduced generation at "affected EGUs." Most electric power in Alaska is generated from fossil fuels such as natural gas or diesel fuel and carbon reductions are being achieved in many communities not connected to "affected EGUs." Crediting Alaska for new RE generation not connected to "affected EGUs" also makes sense because EPA used statewide RE generation figures for our baseline and target rate. Therefore we ask that EPA clarify that the rule would allow states to adjust the emission rate from "affected EGUs" to reflect reductions in carbon emissions from other fossil fuel carbon emission sources.

G. EPA should adjust requirements for State Plans.

EPA should allow more time for states to develop plans pursuant to these regulations. The Proposed Rule requires states to submit plans by June 30, 2016, with the option of requesting a one-year extension to submit a complete plan by June 30, 2017. One year is insufficient for a state to prepare a complex air quality plan; two years is

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TSD 20 (EPA also proposes that to account for RE and EE states may "administratively adjust the average CO_2 emission rate of affected EGUs through [the use of credits] when demonstrating achievement of the required emission rate performance level in the state plan."); State Plan Considerations TSD 20 n. 22 (explaining that the credits could be non-tradable credits administratively apportioned to affected EGUs – an administrative adjustment applied by the state).

marginal given that 111(d) plans, and particularly a plan covering CO_2, is a new type of plan for states to develop. In addition to developing and adopting new regulations, multiple regulatory agencies will be involved in the process, increasing the complexity and time needed to complete the process. Additional time may likely be required to receive additional grants of legislative authority and funding. One or two years is simply not adequate to complete the technical analyses as well as legislative and regulatory processes.

EPA should allow states to determine when their plans need to be updated. Given the accelerated timeline for developing state plans, in addition to the length of the period the plan will cover and changing nature of the power sector, state plans will likely need to be updated during the plan's lifetime. States should have the flexibility to determine when plan updates are needed, with the expectation that EPA will review submittals for adequacy.

EPA must provide guidance on plan development at the time the rule is promulgated. The planning window for this complex rule is very short and states need to be able to make maximum use of the time available.

H. EPA should introduce flexibility into the rule by allowing revisions to the emission target.

It is essential that the final rule allow flexibility in the assigned target emission rate. Currently, EPA proposes that "once the final goals have been promulgated, a state would no longer have an opportunity to request that the EPA adjust its CO_2 goal."[169] EPA also proposes to remove flexibility that is generally permitted in implementing EPA regulations to deviate from a standard of performance based on facility specific considerations.[170] This proposal takes the rule in the wrong direction. In Alaska, there are a limited number of affected EGUs, a limited transmission system, and a small ratepayer base. We have serious reservations about our ability to implement this rule in the first instance. Further, EPA has not evaluated the feasibility of impact of the rule here and the data provided by EPA contained errors and imprecise data. If Alaska is not exempted, there must be a mechanism to re-evaluate the target rate after the rule is finalized.

EPA's proposal to limit the flexibility usually allowed by EPA appears to be based on the belief that the framework of this Proposed Rule creates compliance flexibility. EPA emphasizes that BSER elements may be used in any combination and at any level

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169 Proposed Rule, 79 Fed. Reg. at 34,835/1.

170 Proposed Rule, 79 Fed. Reg. at 34,925/1-2 (citing 40 C.F.R. §60.24(f)).

and measures other than those identified as BSER may be used to achieve state goal.[171] EPA also points to the availability of multistate or regional compliance strategies, the timeline for reaching a emissions target, and the option of rate or mass based goals as elements of the rule that create compliance flexibility.[172] This "compliance flexibility" is illusory however.

The existence of flexibility depends on specific circumstances; Alaska's circumstances restrict compliance options. The flexibility available to Alaska is limited by the number of EGUs at issue, the role of those EGUs in the generation mix, the number of ratepayers to bear compliance costs, transmission constraints, climate and geography, as well as other factors. In particular, our review of available data during the comment period suggests that achieving the mandated emission rate will require retiring one of the Healy coal units. In fact, EPA's goal calculation presumed that neither of the Healy units would operate. Given the importance of maintaining reliability of electric service for the Fairbanks load center, EPA should not promulgate a rule that would require such a result.

We do support EPA's proposal to allow an alternative mass-based emission target. This provision introduces a degree of flexibility that may avoid penalizing states for reducing total CO_2 emissions from affected EGUs when the same event increases the per megawatt hour emission rate because of a shift in the proportion of fuel sources.

I. Re-Publication to Provide Meaningful Opportunity to Comment

The vagueness and uncertainty of this Proposed Rule, as well as the absence of a BSER analysis relevant to Alaska, dictates an additional opportunity to evaluate and comment on a revised and re-published rule. Alaska has spent considerable resources studying and analyzing the Proposed Rule designed for states with highly interconnected electricity systems.[173] It is apparent that the Proposed Rule is not crafted for a state

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171 Proposed Rule, 79 Fed. Reg. at 34,835, 34,837; Goal Computation TSD 19.

172 Proposed Rule, 79 Fed. Reg. at 34,837.

173 The errors and inconsistent data in EPA's record created confusion and required time to evaluate. The conflicting data for the emission rate of Healy Unit 1 has already been outlined. Another example – EPA's materials reported that unit 7 at Sullivan Plant 2 has a 102.6MW generation capacity. However, no unit with 102.6 MW capacity exists. Unit 7 has a nameplate capacity of 81.7MW.

The 2012 RE baseline of 39,958MWh for Alaska conflicts with the data provided in the docket. The 2012 unit level data reported a total of 19,268MW of nonlacking such interconnectedness and that its potential application to Alaska has not been sufficiently analyzed. A thorough evaluation of the Proposed Rule proved challenging within even the extended comment period. The absence of a relevant BSER analysis and the sheer volume of information, compounded by the release of additional data late in the comment period, contributed to this challenge. Further, the absence of final 111(b) rules for new electric generating units inhibits our ability to fully understand the impacts of the Proposed Rule for existing units. If EPA does not withdraw the Proposed Rule or exempt Alaska, we urge EPA to re-publish a more concrete Proposed Rule with some analysis of the relevant impacts on Alaska to allow for meaningful comment.[174]

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hydroelectric renewable power generation in Alaska for 2012. This power was generated from wind units – Kotzebue and Pillar Mountain. After considerable effort, we discovered the source of the 39,958MWh baseline on the EIA website. While the data provided in the docket reported no generation from Delta Wind and Fire Island Wind in 2012, the EIA website reported 18,125MWh from these two facilities. The EIA website also pointed to a biomass facility in Dutch Harbor that is not listed in the EPA's 2012 unit level data – which added another 2,565MWh to our RE baseline.

174 See *Kennecott Corp. v. E.P.A.*, 684 F.2d 1007 (D.C. Cir. 1982) (the notice and comment proceeding contemplated by the Clean Air Act includes availability of relevant data during the public comment period).

IV. Conclusion

The Proposed Rule would mandate changes in how electricity is generated, distributed, transmitted, and used by a subset of mostly residential consumers at a cost those ratepayers cannot afford. Moreover, EPA did not adequately analyze or consider Alaska's circumstances in designing the Proposed Rule. Because the approach taken by this rule is unworkable for our state, EPA should exempt Alaska from the Final Rule.

Sincerely,

Larry Hartig
Commissioner
Alaska Department of Environmental
Conservation

Robert M. Pickett
Chairman
Regulatory Commission of Alaska

Sara Fisher-Goad
Executive Director
Alaska Energy Authority

Enclosures

Attachment A: Legal Memorandum

The Proposed Rule exceeds the authority granted to the Environmental Protection Agency (EPA) under 111(d) of the Clean Air Act (CAA). First, EPA's application of §111(d) to a source category already regulated under §112 and before finalizing a rule under §111(b) contradicts the regulatory framework outlined by the statute. Second, the Proposed Rule seeks to regulate considerably more than existing sources or air emissions. The Proposed Rule would govern the generation, transmission, distribution, sale, and consumer use of electricity, effectively preempting state regulation of intrastate electric utility service.

Many states and organizations may raise similar concerns regarding EPA's authority to issue this rule; however, these issues are especially acute in Alaska because of our unique circumstances. The factual underpinnings for this Proposed Rule do not apply here. Consequently, the technical feasibility and impacts analyses EPA has provided in this docket are incorrect for Alaska. Given the shortcomings of this proposal, EPA should withdraw the Proposed Rule or exempt Alaska from its application.

I. EPA may not regulate CO_2 emissions from power plants under §111(d) of the Clean Air Act.

A. Having elected to regulate fossil fuel-fired power plants under §112 of the Clean Air Act, EPA may not also regulate the same source category under §111(d).

The Clean Air Act (CAA) prohibits regulation of emissions from a "source category" under §111(d) where that source category is already regulated under §112.[1] EPA classified power plants a "source category" under §112 in 2000.[2] In 2012, under §112, EPA promulgated the Mercury and Air Toxics Standard for utility power plants.[3]

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[1] 42 U.S.C. § 7411(d)(1)(A)(i); *see Am. Elec. Power Co., Inc. v. Connecticut*, 131 S. Ct. 2527, 2537 n.7 (2011) ("EPA may not employ §7411(d) if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§ 7408 – 7419, or the 'hazardous air pollutants' program, § 7412.").

[2] EPA, Notice of Regulatory Finding, 65 Fed. Reg. 79,825, 79,830 (Dec. 20, 2000).

[3] EPA, National Emission Standards for Hazardous Air pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg. 9,304 (Feb. 16, 2012).

Given that existing coal-fired power plants are now regulated under §112, what EPA recognizes as the "literal" terms of the CAA prohibit EPA's effort to impose additional regulations on these same sources under §111(d).[4]

B. The conforming amendment cannot override the concurrent substantive amendment to §111(d) to authorize regulation of electric generating units already regulated under §112.

To avoid the literal terms of the §111(d), EPA relies on a clerical error in the 1990 amendments to §111(d).[5] The U.S. House of Representatives and the U.S. Senate passed different versions of §111(d) in the 1990 Amendments. The version passed by the Senate included only a conforming amendment to §111(d), striking "(1)(A)" from "7412(b)(1)(A)" to correct the cross reference. The version passed by the House included a substantive amendment to §111(d). The House amendment first struck "or 7412(b)(1)(A)" from §111(d) and then added "or emitted from a source category which is regulated under section 7412" to the enumerated exclusions. Both versions were incorporated in the amendments signed by the President and included in the Statutes at Large. In keeping with uniform practice, the U.S. Code excludes the conforming amendment.[6] EPA reasons that the conforming amendment conflicts with the substantive revision, rendering §111(d) ambiguous and subject to EPA's interpretation.[7]

Contrary to EPA's interpretation, the House and Senate amendments are, in fact, compatible. Read together, the two versions prohibit using §111(d) as authority to regulate both (1) source categories actually regulated under §112, and (2) pollutants already subject to regulation under §112. EPA can give full effect to both versions of the statute.

To the extent the two versions do conflict, the substantive amendment made by the House must control. Where conforming and substantive amendments are inconsistent, the

4 EPA, Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units at 26 (EPA Legal Memorandum).

5 EPA Legal Memorandum at 20-26.

6 Revisor's Note, 42 U.S.C. § 7411.

7 EPA Legal Memorandum at 25-27.

substantive change is given effect and the conforming amendment is ignored as a scrivener's error.[8] Here, the Senate amendment simply corrected a cross-reference.[9] The House amendment defined the entities that could be regulated under the section and substantively altered the statute. The mistake should not be considered when construing the substantive provision.[10] The House version, which prohibits dual regulation under both §111(d) and §112, properly controls.

C. EPA may not prescribe regulations for existing sources under §111(d) before finalizing regulations for new sources of the same type under §111(b).

Section 111(d) authorizes EPA to prescribe regulations under which states establish standards of performance for "any existing source for any pollutant . . . to which a standard of performance under this section would apply if such source were a new source."[11] This provision limits regulation of existing sources under §111(d) until EPA has issued a final rule for "new sources of the same type."[12] Here, EPA identifies the ongoing rulemaking dockets for new electric generating units (EGUs) and modified and reconstructed EGUs as the §111(b) predicate.[13] However, these rules must be finalized before undertaking the process to issues regulations for existing sources.

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[8] *See, e.g.,* Revisor's Note, 23 U.S.C. § 104; Revisor's Note, 26 U.S.C. § 105; Revisor's Note, 26 U.S.C. § 219; Revisor's Note, 26 U.S.C. § 613A; Revisor's Note, 26 U.S.C. § 1201; Revisor's Note, 26 U.S.C. § 4973; Revisor's Note, 26 U.S.C. § 6427; Revisor's Note, 29 U.S.C. § 1053; Revisor's Note, 33 U.S.C. § 2736; Revisor's Note, 37 U.S.C. § 414; Revisor's Note, 38 U.S.C. § 3015.

[9] Revisor's Note, 42 U.S.C. § 7411.

[10] *See, e.g., Am. Petroleum Inst. v. SEC*, 714 F.3d 1,329, 1,336-37 (D.C. Cir. 2013).

[11] 42 U.S.C. § 7411(d)(1)(A)(ii).

[12] *Am. Elec. Power Co., Inc. v Connecticut*, 131 S.Ct. 2527, 2437 n. 7 (2011); *See* EPA, Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1,430, 1,496 (Jan. 8, 2014) (Proposed Rule for New EGUs) (explaining the proposed rule for new sources will serve as a necessary predicate for the regulation of existing sources within this source category under CAA section 111(d)).

[13] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units, Proposed Rule,* 79 Fed. Reg. 34,830 at 34,852 (June 18, 2014) (Proposed Rule).

This statutorily mandated sequence, regulating "new" and modified sources before instituting parallel regulations for existing sources, recognizes the reliance and sunk cost concerns involved with regulating existing sources. Here, the concurrent rulemaking efforts undermine the goal of ensuring the owners or operators of an existing source have clear notice of and a chance to prepare for the application of a new regulatory scheme. EPA's reliance on regulations that are not finalized also compromises stakeholders' opportunity to comment on the Proposed Rule. Because the §111(b) rule for new sources has not been finalized, stakeholders cannot know with certainty which existing units will be affected by the §111(d) proposal.

This has been a particular challenge for Alaska. For example, EPA proposes different applicability criteria for existing and new steam generating units. A new steam generating unit would be covered by the 111(b) rule only if it "was constructed for the purpose of supplying, and supplies" a threshold amount of electric output.[14] By comparison, and contrary to the intent articulated in the preamble,[15] the proposed §111(d) rule omits the "and supplies" from the applicability criteria for existing EGUs.[16] If this disjuncture persists, EPA would be seeking to regulate existing sources under §111(d) that would not be regulated as new sources under §111(b). Without a final 111(b) rule, we cannot evaluate whether one of our coal units will be an "affected EGU." This information is critical to understanding the possible impact of the rule in Alaska for evaluating what concerns should be raised in our §111(d) our comments.

II. Even if EPA could properly regulate existing utility generating units under §111(d), the Proposed Rule exceeds EPA's authority.

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14 Proposed Rule for New EGUs, 79 Fed Reg. at 1,511/1 (proposed 40 CFR §60.5509(1)).

15 Proposed Rule, 79 Fed. Reg. at 34,854/2 ("The minimum electricity sales condition applies on an annual basis for boilers and IGCC facilities and over rolling three-year periods for combustion turbines (or as long as the unit has been in operation, if less)."). EPA also states other than the "commence construction" date, the proposed 111(d) rule covers existing sources, that the "meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs" Proposed Rule, 79. Fed. Reg. at 34,854/1 (citing Proposed Rule for New EGUs, 79 Fed. Reg. at 1,430).

16 Proposed Rule, 79 Fed. Reg. 34,954 (proposed 40 C.F.R§§ 60.5795(b)(1)).

A. As "standards of performance" the strict emission rates proposed exceed EPA's authority to promulgate emission guidelines.

Section 111(d) establishes specific roles for EPA and states. First, §111(d) authorizes EPA to promulgate regulations establishing the "procedure" under which states submit plans for regulating emissions from affected existing sources.[17] In turn, state plans establish standards of performance for existing sources.[18] When evaluating the sufficiency of state plans, §111(d) directs EPA to allow states to vary a standard for a particular source in light of cost, practical achievability, remaining useful life, and other source specific factors. [19] Only if a state fails to submit a satisfactory plan does §111(d) contemplate that EPA would prescribe a plan that establishing standards of performance.[20]

EPA proposes specific mandatory "goals," or target emission rates, for each state – characterizing these numerical limits as "emission guidelines."[21] EPA will not adjust the mandated emission rate where a state cannot implement one of the building blocks, unless the state demonstrates that it cannot achieve the rate by other means – by applying the *other* BSER building blocks more aggressively or through some other "related, comparable measures."[22] Once finalized, EPA does not intend to allow states to alter the target emission rates.[23] These inflexible emission limits are inconsistent with the state role defined by Congress in §111(d).

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[17] 42 U.S.C. § 7411(d)(1).

[18] *Id.*; c*f* 42 U.S.C. § 7411(b)(1)(B) (authorizing EPA to establish Federal standards of performance for new sources directly).

[19] 42 U.S.C. § 7411(d)(1); *see also* 40 C.F.R. § 60.24(f).

[20] 42 U.S.C. § 7411(d)(2); *see also* 40 C.F.R. § 60.27(c)(3); *Cf. Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, 494 (2004) (ultimate issue in Prevention of Significant Deterioration program is whether state agency's determinations are "reasonable, in light of the statutory guides and the state administrative record").

[21] EPA Legal Memorandum at 32. Compare 40 C.F.R. §60.21(d), discussed in EPA's Legal Memorandum at 31, with 42 U.S.C. §7411(a) (EPA's definition of "emission guideline" is nearly identical to the statutory definition of "standard of performance" in §111 of the Clean Air Act.)

[22] Proposed Rule, 79 Fed. Reg. at 34,893.

[23] Proposed Rule, 79 Fed. Reg. at 34,835 ("Once the final goals have been promulgated, a state would no longer have an opportunity to request that the EPA adjust

EPA argues that states retain the flexibility to apply less stringent standards to individual sources because the goals represent an average emission rate for all "affected EGUs" in a state.[24] In Alaska, this flexibility does not exist. There are only a handful of affected sources, very few ratepayers to bear the costs of compliance, and very real geographic challenges that limit the compliance options available to our state. Our initial evaluation of the rule suggests that, despite recent installation of highly efficient new NGCC units and considerable new renewable generation already online, Alaska cannot meet the goal with both of the potentially covered coal units operating as planned. This is not "flexibility."

More to the point, §111(d) is properly read to allow a range of actual state-wide emission rates achieved through state plans. As a state exercises its authority to adjust EPA's "guidelines" for certain sources and classes of sources, affected sources may collectively achieve a higher or lower emission rate. EPA's §111(d) regulations must be limited to guidelines for source emissions—not absolute, inflexible emission limits.

B. The proposed rule exceeds EPA's authority to regulate emissions from individual sources under the Clean Air Act.

A "standard of performance" is a source-specific limit. The CAA defines "standard of performance" generally as "a requirement of continuous emission reduction, including any requirement relating to the operation or maintenance *of a source* to assure continuous emission reduction."[25] In §111 specifically, a "standard of performance" is defined as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair

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its CO_2 goal."); *Id.* at 34,897-98 (rejecting suggestion that states be allowed to treat EPA's goals "as advisory rather than binding"); *Id.* at 34,892 (noting that the emission rates promulgated in the final rule will be binding emission guidelines for state plans).

24 *See* Proposed Rule, 79 Fed. Reg. at 34,925-26.

25 42 U.S.C. § 7602(l) (emphasis added). The use of the term "applied" or "application" supports the conclusion that standards of performance- and the underlying BSER measures – are limited to actions at the source. The term "apply" consistently references individual sources in the context of various emission standards. *See* 42 U.S.C. § 7479(3); 42 U.S.C. § 7501(3).

quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[26] Consistent with the interpretation of "standard of performance" as a source specific requirement, Congress directed that "in applying a standard of performance to any particular source" states may "take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[27] A standard of performance is "a requirement" which 111(d) contemplates states "applying" to a "particular source."

This Proposed Rule would require compliance measures beyond the physical or legal control of the emission sources.[28] Of the four measures, or BSER "building blocks" used by EPA to establish statewide standards of performance, only the first—heat-rate improvements at coal-fired steam generating units— may be executed at an affected source.[29] The remaining three "building blocks" involve shifting generation function from coal- to gas-fired plants, replacing fossil fuel generation with renewable energy resources, and avoiding generation through end-use efficiency measures.[30] In general, and in Alaska specifically, the standards of performance assigned in this Proposed Rule cannot be achieved through measures at the regulated sources.

In the Proposed Rule, EPA interprets the use of "system" in "best system of emission reduction" to encompass "outside-the-fenceline" measures.[31] EPA reasons that a "system" is a "set of things"; and, in turn, a "system of emission reduction" is a "set of things" which an affected source may utilize to reduce CO_2 emissions.[32] EPA presumes that reducing generation and fuel use at an "affected EGU" would reduce the CO_2 emissions from an affected source.

26 42 U.S.C. § 7411(a)(1).

27 42 U.S.C. § 7411(d)(1).

28 Proposed Rule, 79 Fed. Reg. at 34,872 n. 174 ("All end-use sectors (residential, commercial, and industrial) are targeted by energy efficiency programs…").

29 *Id.* at 34,859-62.

30 Proposed Rule, 79 Fed. Reg. at 34,862-75.

31 Proposed Rule, 79 Fed. Reg. at 34,885-86; EPA Legal Memorandum 36.

32 EPA Legal Memorandum 81.

EPA's interpretation of "system" conflicts with standard canons of statutory interpretation. "The definition of words in isolation … is not necessarily controlling." Rather, interpretation of a word or phrase depends upon reading the whole statutory text, considering the purpose and context of the statute, and consulting any precedents or authorities that inform the analysis."[33] Here, in the context of emission controls, the Clean Air Act consistently refers to "systems" as source-specific measures.[34] There is no basis for departing from this usage in §111(d).

EPA's interpretation of "system" conflicts with the agency's past application of §111(d). Only five source categories have been subject to regulation under § 111(d).[35] Where EPA has regulated existing sources under §111(d), the impact of the rule was generally limited. In one rule, EPA regulated a source category that contained as few as

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33 *Dolan v. U.S. Postal Serv*., 546 U.S. 481, 486 (2006).

34 *See* 42 U.S.C. § 7410(j) (conditioning issuance of permits on a showing by the owner or operator of each source "that the technological *system* of continuous emission reduction *which is to be used at such source* will enable it to comply with the standards of performance which are to apply to such source . . . .") (emphases added); 42 U.S.C. § 7411(b)(5) (limiting the Administrator's authority to require "any new or modified source *to install and operate* any particular technological *system* of continuous emission reduction to comply with any new source standard of performance") (emphases added); 42 U.S.C. § 7412(r)(7)(A) (providing that regulations may "make distinctions between various types, classes, and kinds of facilities, devices and *systems* taking into consideration factors including, but not limited to, the size, location, process, process controls, quantity of substances handled, potency of substances, and response capabilities present *at any stationary source*") (emphases added); 42 U.S.C. § 7479(3) (defining best available control technology as an "emission limitation based on maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable *for such facility* through application of production processes and available methods, *systems*, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant") (emphasis added); CAA § 206(a)(2), 42 U.S.C. § 7525(a)(2) ("The Administrator shall test any emission control *system incorporated in a* motor vehicle or motor vehicle engine submitted to him by any person . . . .") (emphasis added).

35 EPA Legal Memorandum 9-10.

31 sources.[36] In another, affected source categories existed in only a limited number of states.[37] The only previous application of §111(d) to regulate a common source category was projected to impose annual costs of about $90 million.[38] EPA's current §111(d) proposal, with an annualized of over $8.8 billion and affecting 1,228 sources, will have a substantially greater impact than any of these past §111(d) regulations.[39]

EPA's interpretation of "system" conflicts with precedent defining the scope of compliance measures contemplated by the CAA. The D.C. Circuit previously rejected interpretations of "best system of emission reduction" that resulted in aggregate, facility-wide, emission limits rather than an emission limit for individual sources. In *ASARCO v. EPA*, the court invalidated EPA regulations that would "allow a plant operator who alters an existing facility in a way that increases its emissions to avoid application of the NSPSs by decreasing emissions from other facilities within the plant."[40] The court rejected EPA's assertion of "'discretion' to define a stationary source as either a single facility or a combination of facilities,"[41] reasoning:

> EPA has attempted to change the basic unit to which the NSPSs apply from a single building, structure, facility or installation the unit prescribed in the

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[36] 45 Fed. Reg. 26,294 (Apr. 17, 1980); Primary Aluminum: Guidelines for Control of Fluoride Emissions from Existing Primary Aluminum Plants, EPA-450/2-78-049b, § 3.1.1, at 3-1 (Dec. 1979).

[37] Final Guideline Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants, EPA-450/2-77-005, § 3.1, at 3-5 to 3-15 (Tables 3-3 to 3-6) (March 1977) (affected sources found in 17 states); Primary Aluminum: Guidelines for Control of Fluoride Emissions from Existing Primary Aluminum Plants, EPA-450/2-78-049b, § 3.1.1, at 3-3 to 3-5 (Table 3-1) (affected sources found in 16 states).

[38] 61 Fed. Reg. 9,905, 9,916 (March 12, 1996).

[39] Proposed Rule, 79 Fed. Reg. at 34,839, 34,840; EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants at 3-47 (June 2014).

[40] *ASARCO Inc. v. EPA*, 578 F.2d 319, 326-27 (D.C. Cir. 1978).

[41] *Id.* at 326.

> statute to a combination of such units. The agency has no authority to rewrite the statute in this fashion.[42]

Here, by applying standards of performance to the entire power sector rather than individual "existing sources," EPA has asserted even broader authority. If EPA cannot apply performance standards to several sources at a single industrial site collectively, the narrower "best system of emission reduction" cannot be interpreted to encompass measures and emission limits applied to the entire electric utility sector.

Since the publication of this Proposed Rule, the Supreme Court issued a decision noting limits on EPA's authority expand the scope of measures that may be required to achieve an emission limit. In *Utility Air*, the Court upheld EPA's decision to require "best available control technology" (BACT) for greenhouse gases emitted by sources already otherwise subject to prevention of significant deterioration (PSD) review.[43] The Court observed that the petitioners' concerns about unbounded regulatory authority were mitigated by limitations on what EPA could reasonably require as BACT stating, "for one, BACT is based on 'control technology' for the applicant's "proposed facility,'' therefore it has long been held that BACT cannot be used to order a fundamental redesign of the facility."[44] The Court's reasoning hinged on the petitioners' failure to demonstrate that EPA would implement its proposal broadly and that the relevant emission standard, BACT, was limited.

For several reasons, the Supreme Court's observations with respect to BACT should inform the scope of §111(d) "standards of performance." Both terms are "emission limitations." But BACT represents the most stringent limitation achievable, whereas "performance standards" represent the "best system ... adequately demonstrated" after taking into consideration a number of additional factors.[45] BACT is stricter, authorizing EPA to apply more burdensome requirements, than a "standard of performance." Similarly, the statutory definitions of "emission limitation" and "standard of performance" indicate that BACT "emission limitations" encompass a broader range

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42 *Id.* at 327.

43 *Utility Air Regulatory Group v. EPA*, 134 S.Ct. 2427 (2014) ("Utility Air").

44 *Id.* at 2448.

45 42 U.S.C. § 7479(3); 42 U.S.C. § 7411(a)(1).

of measures than "standards of performance."[46] Thus, any constraint on "emission limitation," and therefore on BACT, to inside-the-fenceline measures must apply to "standards of performance" as well.[47] If EPA cannot define BACT to include measures applied to an entity other than the source, EPA cannot define §111(d) standard of performance to include a broader universe of compliance strategies.

C. EPA's reliance on outside the fence measures impermissibly preempts state regulation of electric utilities and state energy policy.

EPA's broad interpretation of "standard of performance" and "best system of emission reduction" would result in a profound shift in the balance of state and federal authority over electric utilities and energy policy. EPA asserts jurisdiction over the production and dispatch of electricity by requiring reduced generation from some affected EGUs – coal plants – and increased use of gas-fired combined cycle generation, renewable generation, and demand side management energy efficiency. The mix of electric generation and fuel resources used by the public utility sector is a regulatory field beyond the scope of the Clean Air Act, traditionally occupied by the states, and explicitly left to the states under the Federal Power Act.

1. State Authority

Significant changes in our generation mix would be required to achieve our assigned emission rate. Our initial review suggests that Alaska's compliance options would be very limited – the premature retirement of at least one coal plant, at great and unreasonable expense to ratepayers, may be necessary. EPA's goal also assumes Alaska can mandate consumer energy efficiency practices with the impact of avoiding 744 GWh of generation (almost a quarter of the total generation from "affected EGUs" in 2012 and perhaps a third of "affected EGU" generation in 2030). Our small population and limited electric utility infrastructure render the EPA's hypothetical compliance strategies impossible to implement at a cost that provides affordable and reliable essential electric utility service to Alaska ratepayers.

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46 *Compare* 42 U.S.C. § 7602(k) and 42 U.S.C. § 7602(l).

47 Other sources confirm the relationship between BACT in the PSD program and "standards of performance" under §111. For example, Congress restricted EPA's ability to rely on data from facilities receiving assistance under the Energy Policy Act of 2005 when establishing either BACT or standards of performance under the Clean Air Act. 42 U.S.C. § 15962(i).

EPA points to the state role in implementing this rule, suggesting that the regulatory framework respects state authority. EPA notes that the "building blocks" are measures that some states are already undertaking and[48] that the beyond-the-fenceline "building blocks" may reduce emissions "by significant amounts and at lower costs" than inside-the-fenceline strategies.[49] But a state's exercise of its own policy making discretion does not confer authority on a federal agency and EPA may require measures only to the extent they are within EPA's power to propose. EPA places great emphasis on the "compliance flexibility" the agency believes to be inherent in its approach. While EPA may be able to imagine limitless scenarios by which utilities can dispatch generation resources to achieve the mandated emission limit, individual states and the utilities they regulate are constrained by facts and the laws of physics.

This rule has less compliance flexibility than what is typically allotted to states under §111(d). Section 111(d) grants states the authority, in applying a standard of performance to particular sources, to take into account the source's remaining useful life or other factors. However, in this case, EPA proposes that, given the degree of flexibility allegedly inherent in the BSER approach, the statutory allowance for source specific considerations will not be allowed.[50] The statutory directive to allow states to take those factors into consideration should not be ignored in any context, but especially here where our options are so limited already.

These emission limits are not just suggestions, EPA points to its enforcement authority. EPA requires that the states' standards of performance must not be less stringent than the EPA's emission guideline.[51]If a state does not submit an implementation plan, or if EPA finds a submitted plan unsatisfactory, the agency will then prescribe a *federal* implementation plan for that state.[52] Presumably, a federal plan would apply the "building blocks" to the state in whatever measure EPA believes necessary to achieve the assigned emission rate. Such a plan may regulate an affected source by establish binding emission limits for coal - and gas-fired power plants. Application of the other three components of EPA's "system of emission reductions"

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48 Proposed Rule, 79 Fed. Reg. at 34,856.

49 Proposed Rule, 79 Fed. Reg. at 34,856.

50 Proposed Rule, 79 Fed. Reg. at 34,925.

51 EPA Legal Memorandum at 3-4.

52 42 U.S.C. § 7411(d)(2).

extend EPA's reach to other "affected entities." EPA would regulate dispatch protocols and the mix of generation resources and fuels used in a state. Implementation of building block three may involve mandatory renewable portfolio requirements that require construction of renewable generation resources. A federal implementation plan that reflected EPA's BSER determination would also involve EPA mandated efficiency standards for consumers of electricity. Moreover, any federally enforceable plan, whether authored by a state or EPA, would subject the state, utilities, and numerous other private parties to citizen suits to compel compliance with a state or federal plan.

2. Congress did not authorize EPA to preempt the role of states in regulating the power sector or establishing state energy policy.

Given the traditional state role regulating electric utilities and setting energy policy, Congress must make an explicit statement of its intention to authorize a federal agency to preempt the state's role.[53] Here, Congress has given no clear indication of its intent to authorize EPA to invade state authority to decide energy and resource-planning policy. Rather, under the "usual constitutional balance," areas of traditional state jurisdiction, and that any arguable ambiguity found, must be resolved in the states' favor by reference to the "basic principles of federalism."

However ambiguous the statutory term "system" may be, statutes cannot be read so broadly as to extend an agency's reach into an entirely new area of regulation. Administrative agencies may not transform limited grants of statutory authority into broad mandates on the basis of arguably "ambiguous" statutory terms. The D.C. Circuit rejected the Federal Energy Regulatory Commission's recent attempt to regulate retail energy demand in the guise of regulating wholesale electric markets.[54] The court noted that FERC's regulation would impair states' exclusive right to regulate retail electric

53 *Bond v. United States*, 134 S. Ct. 2077 (2014) (overturning a conviction under the implementing legislation for the Chemical Weapons Convention, the Court reasoned "because our constitutional structure leaves local criminal activity primarily to the States, we have generally declined to read federal law as intruding on that responsibility, unless Congress has clearly indicated that the law should have such reach."); *American Bar Association v. FTC*, 430 F.3d 457, 471-72 (D.C. Cir. 2005).

54 *Electric Power Supply Association v. FERC*, 753 F.3d 216 (D.C. Cir. 2014).

markets and lacked any meaningful "limiting principle."[55] Similarly, the D.C. Circuit also rejected FERC's attempt to replace the California Independent System Operator Corporation's governing board under its authority to regulate "practice[s]" affecting "rates and charges" in the wholesale electric markets.[56] The lack of a limiting principle on FERC's assertion of authority again undermined the agency's proposed interpretation of statutory language.

In *Utility Air*, the Court considered EPA's interpretation of its permitting authority under the Act's prevention of significant deterioration preconstruction permitting program.[57] EPA interpreted "air pollution" to include greenhouse gases among those pollutants that trigger an emitting source's permitting obligation, thereby massively expanding the program. The Court held EPA's interpretation unreasonable in part "because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization."[58]

By contrast, when upholding EPA's authority to require BACT to limit GHG emitted from sources already regulated under the PSD program in the same decision, the Court placed great weight on the fact that EPA had not yet applied the BACT requirements in a manner that would have such far reaching consequences:

> [A]pplying BACT to greenhouse gases … need not result in such a dramatic expansion of agency authority, as to convince us that EPA's interpretation is unreasonable. We are not talking about extending EPA jurisdiction over millions

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[55] *Id.* at 221. The lack of a limiting principle was key to the court's reasoning. If this justification for FERC's exercise of its authority prevailed, it could authorize virtually any intrusion on state retail electric market regulatory authority, allowing FERC to arrogate broad authority that Congress did not confer. Notably, the connection between FERC's area of authority (wholesale electricity market) and the challenged regulation (retail energy demand) was considerably more direct than here yet the regulation was nonetheless held to exceed the Commission's statutory authority.

[56] *California Independent System Operator Corp. v. FERC ("CAISO"),* 372 F.3d 395, 399 (D.C. Cir. 2004).

[57] *Utility Air*, 134 S. Ct. 2427 (2014).

[58] *Id.* at 2444.

> of previously unregulated entities, but about moderately increasing the demands EPA (or a state permitting authority) can make of entities already subject to its regulation. And it is not yet clear that EPA's demands will be of a significantly different character from those traditionally associated with PSD review. In short, the record before us does not establish that the BACT provision as written is incapable of being sensibly applied to greenhouse gasses.[59]

In sum, the standard of performance in the PSD permitting program – BACT – could not be interpreted to bring about a "transformative expansion in EPA's regulatory authority." This line of authority prohibits EPA's attempt in this Proposed Rule to interpret the Clean Air Act to regulate greenhouse gases in a manner far beyond the usual scope of the statute and without any meaningful limiting principle.

3. Congress explicitly preserved the role of states in regulating the electric utility sector in the Federal Power Act.

Congress expressly reserved regulation of intrastate electric generation and transmission to the states. The Federal Power Act (FPA) delineates the respective state and federal roles in regulating the electric industry and developing energy policy. While states regulate most intrastate matters, interstate electric power transmission and interstate wholesale electric sales fall within federal authority. There are a few exceptions to this delineation – which are specifically outlined in the statute.[60].

EPA argues §111(d) authorizes EPA to regulate inter- and intrastate generation, sale, and transmission of electric power because Congress did not expressly constrain it from doing so. But "[w]here a problem of interpretation was apparently not foreseen by Congress, it is appropriate to consult and be guided by those areas covering the same subject where the expression of legislative intent is clear."[61] When Congress passes new legislation, "it acts aware of all previous statutes on the same subject."[62] Presumably

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59 *Utility Air*, 134 S.Ct. at 2448-2449.

60 16 U.S.C. § 824(b)(1); *New York v. FERC*, 535 U.S. 1, 21 (2002).

61 *U.S. v. Stauffer Chem. Co.*, 684 F.2d 1174, 1187 (6th Cir. 1982); *Erlenbaugh v. United States*, 409 U.S. 239, 245 (1972) (statutes "intended to serve the same function" are construed together).

62 *Erlenbaugh*, 409 U.S. at 244.

aware of the FPA when subsequently enacting the Clean Air Act, Congress would not have granted EPA broader regulatory authority than that given to FERC without an explicit statement.

Furthermore, the state and federal commissions charged with regulating the energy sector are chosen for their subject matter expertise and the respective legislative bodies have granted the commissions powers with a view to that subject matter.[63] EPA's authority to regulate air pollution from stationary sources should not be read to cut across this complex scheme of federal and state regulation.

Given the general delineation of state and federal authority and the care taken to define those specific areas where federal authority would be asserted over matters previously governed by states, §111(d) should not be interpreted to grant EPA authority to govern state electric generation and energy-efficiency policies without limit.[64]

III. Even if the Clean Air Act did confer broad authority regulate electric power, application of the rule to Alaska would be arbitrary and capricious.

EPA's rationale for this rule does not apply to Alaska. As set out in the State of Alaska's main comment letter, Alaska's electric utility sector differs in several respects from the interconnected and integrated industry described by EPA. In particular, Alaska's electric utility sector lacks connectivity – transmission connections between load centers and "affected EGUs" are limited. These characteristics are significant in this rulemaking because EPA explicitly bases its evaluation of three of the proposed BSER measures on the existence of an "integrated electricity system."[65] Applying a rule developed for different factual circumstances would be arbitrary and capricious.

The criteria considered in determining "best system of emission reductions" (BSER) include: (1) technical feasibility, including whether the proposed emission levels are "achievable" with "adequately demonstrated" technology, (2) cost; (3) health and

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63 *CAISO*, 372 F.3d at 404.

64 *Cf. Boumediene v. Bush*, 553 U.S. 723, 777 (2008) ("If Congress had envisioned [Detainee Treatment Act] review as coextensive with traditional habeas corpus, it would not have drafted the statute in this manner.") (noting absence of savings clause in that Act).

65 Proposed Rule, 79 Fed. Reg. at 34880.

environmental impacts; (2) energy requirements.[66] EPA must offer a reasonable evaluation of these statutory factors.[67]

EPA's Regulatory Impact Analysis (RIA) and Integrated Planning Model (IPM) figured prominently in the agency's evaluation of the BSER criteria.[68] These technical documents evaluate the application of the Proposed Rule in the continental U.S. (and some Canadian Provinces) but do not include Alaska. Similarly, EPA's Resource Adequacy and Reliability TSD failed to evaluate the impact of the Proposed Rule in Alaska.[69] The record is not entirely silent, however; EPA acknowledges the lack of information to inform the BSER analysis for Alaska.[70]

EPA appears to believe the perceived "compliance flexibility" in its building block approach adequately accounts for variability in factual circumstances.[71] As noted, the existence of flexibility in compliance pathways hinges on specific circumstances. The flexibility available to Alaska is limited by the number of EGUs at issue, the role of those

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66 Proposed Rule, 79 Fed. Reg. at 34,890.

67 *See Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981).

68 Proposed Rule, 79 Fed. Reg. at 34,839/2 (identifying role of RIA and IPM in evaluating degree of emission reductions achievable, costs and benefits), 34,861 n. 119 & 120 (HRI) 34,864/3 -34,865/1 (outlining role of RIA and IPM in evaluating re-dispatch), 34875 (demand side energy efficiency);34968 (new renewable generation); 34,934/3 (energy market impacts discussed in RIA); 34,935/1 (RIA evaluates compliance costs); 34941 (RIA evaluates benefits); 34,949 (RIA provides economic impact analysis and evaluation of energy effects; 34,949/3 (RIA provides EPA's analysis regarding the health and ecosystem effects).

69 See Resource Adequacy and Reliability TSD, EPA-HQ-OAR-2013-0602-0163, Appendix C (Maps) (illustrating the regions evaluated in the TSD).

70 See Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, EPA-HQ-OAR-2013-0602-0391, at ES-15 n. 7 (June 2014) ("We do not have emission reduction information or air quality modeling available to estimate the air pollution health co-benefits in Alaska and Hawaii anticipated from implementation of the proposed guidelines."); Id at 3-46 (IPM does not represent electricity markets in Alaska, Hawaii, and U.S. territories outside the contiguous U.S. and therefore the costs (and benefits) that may be expected from the proposed rule in this [sic] states and territories are not accounted for in the compliance cost modeling")

71 Proposed Rule, 79 Fed. Reg. at 34837; Goal Computation TSD at 19.

EGUs in the generation mix, the number of ratepayers to bear compliance costs, transmission constraints, climate and geography, as well as other factors will restrict our compliance options. The "compliance flexibility" gloss does not resolve our concerns about the feasibility and impact of the Proposed Rule in Alaska.

When promulgating regulations under the Clean Air Act, EPA must articulate a reasonable explanation of the specific analysis and evidence relied upon as a basis for the rule.[72] A generalized discussion of relevant factors does not satisfy this responsibility – EPA must explain how it arrived at the specific conclusion.[73] This requirement persists even where there is no evidence in the record contradicting the agency's decision.[74] Here, EPA's analysis variously excludes or ignores Alaska's utility sector. Furthermore, the facts presented in our main comment letter affirmatively demonstrate that the proposed measures do not satisfy the statutory criteria in Alaska. Given that Alaska's utility sector differs from the industry in the continental U.S. – with respect to the precise characteristic that EPA's BSER analysis relies upon – EPA has not articulated a reasonable basis for applying the Proposed Rule to our state.

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72 *See Bluewater Network v. EPA*, 370 F.3d 1, 21 (D.C. Cir. 2004).

73 *Id.*

74 *Id.*

Stranded Cost Calculations for Healy 1 and 2

	Book Value 1/1/2020	Book Value 1/1/2025	Book Value 1/1/2030
Healy Unit 1			
Land	188,306	188,306	188,306
Current Assets	5,680,817	1,172,739	138,185
Interest	2,180,463	1,409,950	779,556
	8,049,586	2,770,995	1,106,046
Healy EMD			
Current Assets	288,817	220,860	152,903
Healy Unit 2			
Land	126,013	126,013	126,013
Assets	188,228,247	163,670,827	139,113,407
Interest	82,871,961	53,217,958	29,335,404
	271,226,221	217,014,798	168,574,824

Total Stranded Costs Calculation

Combined	**1/1/2020**	**1/1/2025**	**1/1/2030**
Land	$ 314,319	$ 314,319	$ 314,319
Assets	$ 194,197,881	$ 165,064,426	$ 139,404,494
Interest	$ 85,052,424	$ 54,627,908	$ 30,114,960
	$ 279,564,624	$ 220,006,653	$ 169,833,773
	-	-	-

Remaining Loan Principal Payments

	1/1/2020	**1/1/2025**	**1/1/2030**
Healy 1	$ 4,573,146	$ 3,865,276	$ 3,022,102
Healy 2	$ 164,848,693	$ 137,329,678	$ 105,996,212
	$ 169,421,839	$ 141,194,954	$ 109,018,314

Stranded Costs and Remaining Loan Principal Payments

	1/1/2020	**1/1/2025**	**1/1/2030**
Stranded Costs	$ 279,564,624	$ 220,006,653	$ 169,833,773
Debt Principal	$ 169,421,839	$ 141,194,954	$ 109,018,314
	$ 448,986,463	$ 361,201,607	$ 278,852,087
	-	-	-

Assumes no capital additions to either plant

	Book Value 1/1/2020	Book Value 1/1/2025	Book Value 1/1/2030
Healy Unit 1			
Land	188,306	188,306	188,306
Current Assets	5,680,817	1,172,739	138,185
Healy EMD			
Current Assets	288,817	220,860	152,903
Healy Unit 2			
Land	126,013	126,013	126,013
Assets	188,228,247	163,670,827	139,113,407
Combined			
Land	314,319	314,319	314,319
Assets	194,197,881	165,064,426	139,404,494

Assumes no capital additions to either plant

Stranded Cost Calculations - Debt - Healy Unit 1

Assumptions: **AW-8 RUS Loan**

Draws	$30,000,000	June, 2016
Interest Rate	3.500% Fixed	
Interest Fee	0.125% Fixed	
Maturity	December, 2042	
Amortization Type	Level Debt	

	AW-8 RUS Loan Remaining Principal Payments As of Jan 1, 20XX	NRUCFC 9034 Loan Remaining Principal Payments As of Jan 1, 20XX	Total Hly Unit 2 Remaining Principal Payments As of Jan 1, 20XX	AW-8 RUS Loan Remaining Interest Payments As of Jan 1, 20XX	NRUCFC 9034 Loan Remaining Interest Payments As of Jan 1, 20XX	Total Hly Unit 2 Remaining Interest Payments As of Jan 1, 20XX	Total Hly Unit 2 Remaining Debt Service As of Jan 1, 20XX
1-Jan-2020	4,573,146	0	4,573,146	2,180,463	0	2,180,463	6,753,610
1-Jan-2025	3,865,276	0	3,865,276	1,409,950	0	1,409,950	5,275,227
1-Jan-2030	3,022,102	0	3,022,102	779,556	0	779,556	3,801,658

	AW-8 RUS Loan Annual Principal Payment	NRUCFC 9034 Loan Annual Principal Payment	Total Hly Unit 2 Annual Principal Payment	AW-8 RUS Loan Annual Interest Payment	NRUCFC 9034 Loan Annual Interest Payment	Total Hly Unit 2 Annual Interest Payment	Total Hly Unit 2 Annual Debt Service
2013	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	57,216	0	57,216	91,084	0	91,084	148,300
2017	118,945	0	118,945	177,546	0	177,546	296,491
2018	123,163	0	123,163	173,177	0	173,177	296,340
2019	127,530	0	127,530	168,654	0	168,654	296,184
2020	131,603	0	131,603	164,420	0	164,420	296,023
2021	136,720	0	136,720	159,136	0	159,136	295,856
2022	141,568	0	141,568	154,115	0	154,115	295,683
2023	146,588	0	146,588	148,915	0	148,915	295,503
2024	151,391	0	151,391	143,927	0	143,927	295,318
2025	157,155	0	157,155	137,971	0	137,971	295,126
2026	162,728	0	162,728	132,199	0	132,199	294,927
2027	168,499	0	168,499	126,222	0	126,222	294,721
2028	174,142	0	174,142	120,366	0	120,366	294,508
2029	180,650	0	180,650	113,637	0	113,637	294,287
2030	187,056	0	187,056	107,002	0	107,002	294,058
2031	193,689	0	193,689	100,132	0	100,132	293,821
2032	200,298	0	200,298	93,278	0	93,278	293,576
2033	207,661	0	207,661	85,661	0	85,661	293,322
2034	215,025	0	215,025	78,034	0	78,034	293,059
2035	222,650	0	222,650	70,137	0	70,137	292,787
2036	230,369	0	230,369	62,136	0	62,136	292,505
2037	238,715	0	238,715	53,498	0	53,498	292,213
2038	247,181	0	247,181	44,730	0	44,730	291,911
2039	255,946	0	255,946	35,652	0	35,652	291,598
2040	264,941	0	264,941	26,333	0	26,333	291,274
2041	274,418	0	274,418	16,520	0	16,520	290,938
2042	284,151	0	284,151	6,442	0	6,442	290,593
2043	0	0	0	0	0	0	0
	$ 5,000,000	**$ -**	**$ 5,000,000**	**$ 2,790,924**	**$ -**	**$ 2,790,924**	**$ 7,790,924**

Stranded Cost Calculations - Debt - Healy Unit 2

Assumptions:	NRUCFC 9034 Loan		
	Draws	$45,000,000	December, 2013
	Interest Rate	5.113% Fixed	
	Maturity	September, 2043	
	Amortization Type	Level Principal	
	AW-8 RUS Loan		
	Draws	$30,000,000	December, 2014
		$30,000,000	June, 2015
		$30,000,000	September, 2015
		$30,000,000	December, 2015
		$22,800,000	June, 2016
	Interest Rate	3.500% Fixed	
	Interest Fee	0.125% Fixed	
	Maturity	December, 2042	
	Amortization Type	Level Debt	

	AW-8 RUS Loan Remaining Principal Payments As of Jan 1, 20XX	NRUCFC 9034 Loan Remaining Principal Payments As of Jan 1, 20XX	Total Hly Unit 2 Remaining Principal Payments As of Jan 1, 20XX	AW-8 RUS Loan Remaining Interest Payments As of Jan 1, 20XX	NRUCFC 9034 Loan Remaining Interest Payments As of Jan 1, 20XX	Total Hly Unit 2 Remaining Interest Payments As of Jan 1, 20XX	Total Hly Unit 2 Remaining Debt Service As of Jan 1, 20XX
1-Jan-2020	128,924,323	35,924,370	164,848,693	61,470,757	21,401,204	82,871,961	247,720,654
1-Jan-2025	108,968,333	28,361,345	137,329,678	39,748,764	13,469,195	53,217,958	190,547,636
1-Jan-2030	85,197,893	20,798,319	105,996,212	21,976,937	7,358,467	29,335,404	135,331,616

	AW-8 RUS Loan Annual Principal Payment	NRUCFC 9034 Loan Annual Principal Payment	Total Hly Unit 2 Annual Principal Payment	AW-8 RUS Loan Annual Interest Payment	NRUCFC 9034 Loan Annual Interest Payment	Total Hly Unit 2 Annual Interest Payment	Total Hly Unit 2 Annual Debt Service
2013	$ -	$ -	$ -	$ -	$ 189,111	$ 189,111	$ 189,111
2014	0	1,512,605	1,512,605	0	2,164,618	2,164,618	3,677,223
2015	490,865	1,512,605	2,003,470	1,909,598	2,092,260	4,001,858	6,005,327
2016	2,964,132	1,512,605	4,476,737	4,722,098	2,019,894	6,741,992	11,218,729
2017	3,353,241	1,512,605	4,865,847	5,005,303	1,947,616	6,952,919	11,818,766
2018	3,472,154	1,512,605	4,984,759	4,882,144	1,875,428	6,757,572	11,742,331
2019	3,595,284	1,512,605	5,107,889	4,754,617	1,803,092	6,557,709	11,665,598
2020	3,710,089	1,512,605	5,222,694	4,635,271	1,730,732	6,366,003	11,588,697
2021	3,854,347	1,512,605	5,366,953	4,486,302	1,658,452	6,144,754	11,511,706
2022	3,991,031	1,512,605	5,503,636	4,344,738	1,586,282	5,931,020	11,434,656
2023	4,132,561	1,512,605	5,645,166	4,198,154	1,514,306	5,712,460	11,357,625
2024	4,267,963	1,512,605	5,780,568	4,057,528	1,442,237	5,499,766	11,280,333
2025	4,430,460	1,512,605	5,943,065	3,889,615	1,368,962	5,258,578	11,201,643
2026	4,587,574	1,512,605	6,100,179	3,726,891	1,295,541	5,022,433	11,122,611
2027	4,750,258	1,512,605	6,262,863	3,558,397	1,222,130	4,780,527	11,043,390
2028	4,909,341	1,512,605	6,421,946	3,393,308	1,148,735	4,542,043	10,963,988
2029	5,092,808	1,512,605	6,605,413	3,203,615	1,075,359	4,278,974	10,884,387
2030	5,273,409	1,512,605	6,786,014	3,016,564	1,001,993	4,018,557	10,804,571
2031	5,460,415	1,512,605	6,973,020	2,822,880	928,588	3,751,468	10,724,488
2032	5,646,722	1,512,605	7,159,327	2,629,665	855,189	3,484,854	10,644,181
2033	5,854,297	1,512,605	7,366,902	2,414,932	802,397	3,217,329	10,584,231
2034	6,061,902	1,512,605	7,574,507	2,199,913	725,058	2,924,971	10,499,478
2035	6,276,869	1,512,605	7,789,474	1,977,269	647,718	2,624,987	10,414,461
2036	6,494,477	1,512,605	8,007,082	1,751,717	570,379	2,322,096	10,329,178
2037	6,729,767	1,512,605	8,242,373	1,508,197	493,039	2,001,236	10,243,609
2038	6,968,419	1,512,605	8,481,024	1,261,023	415,700	1,676,723	10,157,747
2039	7,215,533	1,512,605	8,728,138	1,005,084	338,360	1,343,444	10,071,583
2040	7,469,125	1,512,605	8,981,730	742,356	261,021	1,003,377	9,985,107
2041	7,736,281	1,512,605	9,248,886	465,739	183,681	649,421	9,898,307
2042	8,010,676	1,512,605	9,523,282	181,598	106,342	287,940	9,811,221
2043	0	1,134,454	1,134,454	0	29,002	29,002	1,163,456
	$ 142,800,000	**$ 45,000,000**	**$ 187,800,000**	**$ 82,744,516**	**$ 33,493,223**	**$ 116,237,739**	**$ 304,037,739**

H Dale LLC

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GVEA requested H Dale LLC to do an analysis of the cost of shutting down its coal fired units evaluated for the years 2020, 2025, and 2030 to be completed by 9/17/14. The economic analysis was to use GVEA's production costing program and was to be presented in today's dollars. GVEA's production forecasting program returns only the variable (purchased power, fuel and VOM).

The results of the forecasts are shown below. GVEA's base case is that both units are available, i.e. H1 & H2. The value of the coal units can be determined by taking the difference, for example, the value of having both H1 and H2 available versus both of the coal units removed from service in 2030 is $124.1M – 63.2M = $60.9M for that year, or in other words, it would cost $60.9M in replacement energy (fuel and/or purchased power) to replace the output of these units in that year.

	Annual Variable Costs in $M		
Unit Avaialble	2020	2025	2030
H1 & H2	$73.9	$63.3	$63.4
H1 only	$112.1	$104.3	$110.9
H2 only	$83.8	$70.3	$76.6
No H	$121.3	$116.8	$124.1

In general, it is clear that removal of any of GVEA coal units result in significantly higher fuel and purchased power costs to its members. The general reduction in dollars between 2020 and 2025 runs are due to reduced loads (and consequently less fuel and purchased power) required. The increase in 2030 is due to the expiration of the Aurora Energy (coal based units) contract.

ASSUMPTIONS

Load: GVEA staff recommended using the 2012 PRS low load case (due to the less than expected load growth these last several years) with manual changes to some of the GS3 customers. In particular, Ft. Knox was modeled to shutdown prior to 2020, but have a residual 6 MW load up to but not including 2025. Pogo has an end of life scheduled for prior to 2020, but have been on record as having expected reserves that will allow them to extend its life. It is modeled to continue until just before 2025. In the near term, Pump 9 is expected to draw heavily as a method to heat crude due to the recent shutdown of Flint Hills Refinery. It is expected they will find a more economic method to heat crude prior to 2020, so an increase is not modeled in these runs. Flint Hills Refinery is removed from the model. Clear AF site is modeled as a 6 MW load.

Generation: With the exception of the Healy units being evaluated, all units are assumed to be available for use (no retirements and no new units) through the study period. It is assumed for convenience only, that Eva Creek Wind farm turbines will be replaced as they fail which is statistically expected during this time period. There is no accommodation in the model for forced outages while waiting for cranes and replacement turbines. No changes have been made to accommodate any potential UAF or DoD generation changes.

Generation maintenance generally follows a pattern with some outages longer than others, for example, a major overhaul takes longer than an inspection. The pattern generally exceeds 1 year in periodicity. To treat all three years the same, a typical annual maintenance profile was applied the same to each year.
March NPC borescope - 2 days
April CH5 spring maint - 14 days
April H1 1 ½ yr maint - 16 days
May H2 - 14 days
Oct CH5 fall maint - 7 days
Nov NPC borescope - 2 days

Purchased Power: It is assumed that energy from south central is available up to the operational limits of the Alaska Intertie, and that up to 70 MW of energy may flow on the Intertie when Healy 1, Healy 2, and Eva Creek are all at full load. Anchorage natural gas fuel prices are assumed to be based on Henry Hub with a $3.55/Mcf adder to reflect what we are currently seeing between Cook Inlet and Henry Hub as it is applied to northbound energy sales. The Battle Creek diversion at Bradley Lake is expected to happen. **The Aurora Energy contract is due to expire at the end of 2030. The 2030 model has been modified to allow the Aurora Energy contract to have already been expired in 2030, so that this year would be more representative of expected post 2030 operation.** The Aurora Contract annual escalation has been reduce by 2.5% to approximate "real" dollars.

Fuel: Fuel contracts are assumed to have been negotiated with similar pricing structure as current contracts, and in the quantities needed in the three evaluation years. NPE is expected to burn a Naphtha/LSR mix, the remaining combustion turbines are modeled using HS diesel. The commodity fuel prices are from EIA and in today's dollars. Coal is assumed to have similar terms and appropriate end dates for the units being removed from service in the study. To capture "real" dollars, coal prices have been held constant. It is recognized, but not modeled, that the coal production escalation indices may not be the same as inflation.

Major Projects: The model did not simulate Livengood Mine, Watana, and availability of fuel via a gas line or via trucked LNG as these projects are still speculative.

Dispatch: Economic commitment and dispatch was used. An exception is that commitment was set to allow Eva Creek to fully swing randomly during the course of a day. It is likely that there are cases were it would be more economical to spill small amounts of wind rather than to run, for example, NPE in simple cycle which would give the system room to swing during certain hours of the month. An analysis has not been made to determine where this economic breakpoint may occur. When, the only other option was to shut down a coal unit, small amounts of potential wind was curtailed.

Other: 2020 is a leap year, it has an additional day of costs as compared to the other years. It is assumed there is no major transmission outages for maintenance, retirement, or construction of new lines.