BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of the Title V Air Quality Operating Permit	)))	
Issued to the Golden Valley Electric Association, Inc. for the Operation of the Healy Power Plant	))))	**Permit No. AQ0173TVP02**
By the State of Alaska Department of Environmental Conservation	)))	

Petition to Object to the Title V Air Quality Operating Permit Issued to the Golden Valley Electric Association, Inc. for the Operation of the Healy Power Plant By the State of Alaska Department of Environmental Conservation

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March 12, 2012

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INTRODUCTION

Pursuant to § 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d), the Northern Alaska Environmental Center, Denali Citizens Council, National Parks Conservation Association, Resurrection Bay Conservation Alliance, and the Sierra Club ("Petitioners") hereby petition the Administrator of the United States Environmental Protection Agency ("EPA") to object to a Title V permit issued by the Alaska Department of Environmental Conservation ("ADEC") for the Healy Power Plant, a coal-fired electric power generating facility located less than four miles from the Denali National Park Class I area. *See* 58 Fed. Reg. 8058 (Feb. 11, 1993). The Title V permit, # AQ0173TVP02, authorizes operation of Unit 2, a 54 megawatt steam generator that has not operated for over a decade. As shown below, restart of Unit 2 will trigger PSD applicability under EPA's reactivation policy and under EPA's major modification regulations. Nevertheless, the Title V permit fails to incorporate updated PSD requirements for this unit, thereby violating the Clean Air Act and necessitating this petition.

REGULATORY FRAMEWORK AND PROCEDURAL BACKGROUND

Title V of the Clean Air Act, 42 U.S.C. §§ 7661 - 7661f, prohibits any person from operating a major stationary air pollution source such as the Healy plant without an operating permit. A Title V operating permit must include all applicable requirements including emission limitations and standards for the source and must include provisions assuring compliance with those requirements. 42 U.S.C. §7661c(a), 40 C.F.R. §70.1(b). The federal operating permit regulations provide that "[w]hile title V does not impose substantive new requirements. . .[a]ll sources subject to these regulations shall have a permit to operate that assures compliance by the source with all applicable requirements." 40 C.F.R. § 70.1(b).

The regulations in 40 C.F.R. Part 70 which govern state operating permit programs required under Title V of the Clean Air Act require Title V permits to assure compliance with all "applicable requirements." The term "applicable requirements" is defined in the federal rules as including any provision of the state implementation plan ("SIP"), any term or condition of a preconstruction permit issued pursuant to regulations approved under Title I of the Clean Air Act including under Parts C and D of the Act, any standard or requirement under Sections 111, 112, 114(a)(3), or 504 of the Act, as well as the Act's Acid Rain program requirements. 40 C.F.R. §70.2.

A Title V permit is issued for up to five years, 40 C.F.R. §70.6(a)(2), and the source owner must submit an application for renewal of a permit "at least six months prior to the date of permit expiration, or such other longer time as may be approved by the Administrator that ensures that the term of the permit will not expire before the permit is renewed," 40 C.F.R. § 70.5(a)(1)(iii). Permits being renewed are subject to the same procedural requirements, including those for public participation and affected state and EPA review that apply to initial permit issuance. 40 C.F.R. §70.7(c)(1)(i). Under the federal law, the public has the right to petition EPA to object to a Title V permit if EPA fails to object to the proposed permit during its 45 day review period. 40 C.F.R. §70.8(d).

The plant operator, Golden Valley Electric Association, applied for a renewal of the plant's Title V permit on June 16, 2008, with supplements through August 25, 2009. Thereafter, ADEC proposed to approve the permit and petitioners provided comments on August 29, 2011. A copy of those comments (without attachments) are appended hereto as Exhibit 10. ADEC submitted Permit # AQ0173TVP02 to EPA for its review on November 28, 2011. Consequently, EPA's 45 day review period, *see* 42 U.S.C. § 7611d(b)(1) ended January 12, 2012. Therefore, this petition is timely filed because it is being filed today March 12, 2012, within sixty days from the end of EPA's 45 day review period as required by Clean Air Act §505(b)(2) and 40 C.F.R. §70.8(d). The Administrator must grant or deny this petition within sixty days after it is filed. 42 U.S.C. §7661d(b)(2). If the Administrator determines that the permit does not comply with any applicable requirement or the requirements of 40 C.F.R. Part 70, she must object to the permit and EPA must terminate, modify, or revoke the permit. 40 C.F.R. §§ 70.8(c)(1), 70.8(d).

GROUNDS FOR OBJECTION

Among the requirements that must be included in a source's Title V permit, if applicable, are emission limits and operational standards needed to prevent the significant deterioration of local air quality ("PSD limits"). *See LaFleur v. Whitman,* 300 F.3d 256, 262 (2nd Cir. 2002) (explaining that a Title V permit "must include limitations on emissions and other conditions (such as regular monitoring, recordkeeping, and reporting) necessary to ensure compliance with the provisions of the CAA, including the PSD program (if applicable)."). Fundamentally, EPA must grant this petition and object to the Healy permit because the permit fails to contain mandatory PSD requirements and fails to contain a compliance schedule necessary for the facility to comply with PSD requirements..

The Healy Title V permit must contain PSD requirements and an accompanying compliance schedule because operation of the plant now would constitute either operation of a new source without a PSD permit under EPA's Reactivation Policy or operation of a major modification without a PSD permit.

I. Unit 2 Must Be Considered a New Source Under EPA's Reactivation Policy

A. EPA's Reactivation Policy

EPA has well-established guidelines defining when re-opening a shuttered plant triggers PSD review. *See* U.S. EPA Memorandum from Edward Reich, Director, Division of Stationary Source Enforcement to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II, Sep. 6, 1978, Re: PSD Requirements (1978 Memorandum). Under those guidelines, PSD review for reactivation is required when the shutdown is considered permanent. EPA evaluates permanence based upon the intent of the owner or operator at the time of the shutdown.

Intent is determined from the circumstances of the case, including the cause and handling of the shutdown. *See* U.S. EPA Memorandum from Edward Reich, Director, Stationary Source Enforcement Division to William Sawyer, Attorney, General Enforcement Branch, Region II, Aug. 8, 1980, Re: PSD Applicability Determination: Babylon 2. A shutdown lasting two years or more (or resulting in removal of the source from the State's emissions inventory) is presumed to be permanent. 1978 Memorandum at 2.

EPA has consistently required PSD compliance when the re-start of a shuttered plant demands massive investments in time and money. In 1987, EPA found that a shutdown was permanent and that the restart of the plant must meet PSD requirements when the facility was idled due to market conditions, remained closed for ten years, was deleted from the operating permits, had been removed from the State's emissions inventory, and would require at least several hundred thousand dollars worth of work over at least four months before being operable. *See* EPA Memorandum from John S. Seitz, Director, Stationary Source Compliance Division to David Howekamp, Director, Air Management Division, Region IX, May 27, 1987, Re: Reactivation of Noranda Lakeshore Mines RLA Plant and PSD Review (hereinafter the "Noranda Mine Determination").

Finally, under EPA's Reactivation Policy, once a facility is shuttered, unless the owner or operator can demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future, restart of that facility will constitute the startup of a new source. As EPA itself has said:

> EPA believes owners and operators of shutdown facilities must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. If they cannot make such a demonstration, it suggests that for at least some period of the shutdown, the shutdown was intended to be permanent. Once it is found that an owner or operator has no real plan to restart a particular facility, such owner or operator cannot overcome this suggestion that the shutdown was intended to be permanent by later pointing to the most recent efforts to reopen the facility. . . . This approach for assessing the intent of the owner or operator is consistent with the general notion that a company cannot sit indefinitely on a governmental permission to emit air pollution without showing some definite intention to use it.

Id. at pp. 9-10 & n. 11.

B. Under EPA's Reactivation Policy, the Restart of Unit 2 Requires a PSD Permit.

There is no dispute that the unit in question has not operated since 1999. Under EPA's 1978 guidance, ADEC and EPA should therefore presume that the operators shutdown the facility, and an exploration of the facts shows little that rebuts that presumption.

According to the permittee here, Golden Valley Electric Association, Inc. ("Golden Valley"), Healy Unit 2, also known as the Healy Clean Coal Project ("HCCP"), grew out of the U.S. Department of Energy ("DOE") Clean Coal Technology Demonstration Program. Exhibit 2, p. 1. DOE made a grant to the Alaska Industrial Development and Export Authority ("AIDEA") and the Usibelli Coal Mine to build an experimental coal plant. *Id*. at 1-2. As it was developing Unit 2, AIDEA approached Golden Valley to purchase Unit 2's output, but Golden Valley initially refused. *Id*. The two parties eventually came to an agreement however, and significantly, under this agreement, Golden Valley agreed that it would purchase Unit 2's electricity, but only if the plant could pass a rigid and strict 90-day reliability test. *Id.*

The test occurred in 1998, and Unit 2 failed. *Id*. at 5. According to Golden Valley, "[d]uring the engineers' testing of the technology, and as each major system was verified and brought on, it became clear to [Golden Valley] that [Unit 2] had no chance of actual commercial operation using the experimental technology. . . ." Exhibit 2 (Golden Valley Narrative Statement of Facts), p. 5. An independent audit of the 90-day test concluded that if Unit 2 were operated on design coal, "in its present configuration [it] will not perform acceptably for 30 years, even if operated and maintained in accordance with standard utility practices." Exhibit 1, pdf p. 92.

In 1999, Golden Valley requested that the AIDEA declare the Unit 2 technology was not commercially feasible. Exhibit 2, p. 6. According to Golden Valley:

> At the end of 1999, the AIDEA had spent all of the project funds (including the retrofit budget) and [Unit 2] was still not finished. There was millions of dollars worth of work yet to be completed. The plant had failed to pass the commercial operation test. [Unit 2] was 'shuttered' and has been sitting in that condition . . . .

Id.

In 2000, Golden Valley reached a settlement with AIDEA that would allow Golden Valley to retrofit the plant to conventional combustor technology, signaling its intent to abandon operation of the plant as originally built. *Id*. at 8-9. The settlement set out that Golden Valley would take over custodial care. *Id.* at 9. Golden Valley and AIDEA agreed to further custodial terms on August 8, 2001. *Id*. In March 2002, Trustees for Alaska and other groups contested Golden Valley's permit modification request to retrofit the facility. *Id*. at 13. In April 2002, ADEC rejected Golden Valley's request for an administrative permit modification, finding that a full permit process would be required. *Id*. As a result, Golden Valley abandoned its efforts to retrofit the facility into a common coal-fired power plant. *Id*. After that, in 2003, Golden Valley referred to the facility as "mothballed." Exhibit 3, p. 3. This characterization is consistent with Golden Valley's statement in its 1999 annual report that: "The plant was shut down on December 31, 1999 until new agreements can be made for the operation of the plant and for power sales. Exhibit 13, p. 1.

In 2006, AIDEA retained Shaw, Stone & Webster to evaluate what it would take to restart the facility. Shaw personnel started visiting the site that year. An April 16, 2008 trip report filed by Gene Scott of Shaw observed that the areas inside of the facility: "are cluttered with materials, spare parts, tools, equipment work tables, debris, empty pallets; etc, and the ash loading facility and intake structure are being used for storage of heavy equipment and emergency vehicles. It will take considerable time and effort to sort through all the materials and determine ownership and proper storage of anything salvageable." Accompanying photographs demonstrate that the facility was not in "hot standby" in 2006. *See* Exhibit 4.

Reactivating the plant will take a major capital investment and a significant period of time. The March 28, 2006, HCCP Condition Assessment and Restart Study, prepared by Shaw, Stone & Webster, estimated capital costs for the restart of Unit 2 at $29,836,000. Exhibit 5, p. 9. At that time, it was noted that it would take at least six months for a basic startup of Unit 2, with an additional four to five weeks for combustor and controls tuning. *Id.* at 73.

In February 2009, Mr. Hoffman, Supervisor for Unit 2, stated in a Denali Borough meeting that there is significant planning, scheduling, and engineering to be accomplished to determine what must be done to get the plant operational since it has been idle for nine years. He noted that all of the equipment has gathered dust and that it will take time to determine what measures will be needed to refurbish the existing equipment. Further, in a letter to its members, Golden Valley stated that it "estimate[s] that it may take 18 to 24 months to replace some of the equipment that failed during HCCP's experimental testing and to make sure the plant is equipped with the proper and most up-to-date safety systems." *See* Exhibit 12, Letter from Bill Nordmark, Golden Valley Board Chairman, and Brian Newton, GVEA President & CEO, to Golden Valley Members (Feb. 12, 2009). *Cf* Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division to Douglas M. Skie, Chief, Air Programs Branch (8AT-AP), Nov. 19, 1991, Re: Applicability of PSD to Watertown Power Plant, South Dakota (noting that PSD review may not be required only under unique circumstances, including inter alia, the ability of the plant to reactivate in a number of weeks).

Given these facts, one can only conclude that the plant, during the last decade, has been permanently shuttered. The lack of operation of the plant for over a decade exceeds the two-year presumption by five times. Also, the tremendous expense involved in bringing the plant back to operational status strongly weighs against any finding that the plant has been in continuous operation. Moreover, there were certainly periods during the past decade when no real plan existed to restart Unit 2. Consequently, under EPA's reactivation policy, operation of the facility must be considered a restart, meaning the facility must obtain a PSD permit.

In its February 3, 2011 Response to Comments document, Exhibit 11, p. 25, ADEC maintains that this is not a situation where "a plant that has operated for years, recovered its initial investment and has become obsolete or has worn out, and the owner needs to decide whether to rejuvenate it." True enough, but the point is irrelevant. The reactivation policy does not apply only to the restart of old, obsolete plants; it applies to any idled plant – even a plant that never operated properly in the first place.

II. Unit 2's Restart Would Be a Major Modification.

Alaska has incorporated the federal PSD rule, 40 C.F.R. § 52.21 into the Alaska SIP by reference. *See* 18 AAC 50.306 and 72 Fed. Reg. § 45378 (Aug. 14, 2007). Under 40 C.F.R. § 52.21(b)(2), a major modification is "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of any regulated NSR pollutant . . . and a significant net emissions increase of that pollutant from the major stationary source." As shown below, here there has been a non-routine physical change that will result in a significant emission increase and a significant net emissions increase.[1]

A. <u>The Physical and Operational Changes Necessary to Make Unit 2 Operational Again Would Not Be Routine Maintenance</u>.

ADEC has suggested that the physical changes necessary to restart Unit 2 could be considered routine maintenance, but analysis of the facts shows that such a finding would be inconsistent with EPA policy regarding this exception.

In examining whether physical changes constitute routine maintenance, EPA applies a four-factor test, looking at the nature and extent, purpose, frequency, and cost of the work being

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[1] There is no issue in this matter regarding netting.

performed. *In the Matter of Tennessee Valley Authority, Paradise Fossil Fuel Plant Drakesboro, Kentucky Title V Air Quality Permit # V-07-018 RI* , Petition No. IV-2010-1 (U.S. E.P.A. May 2, 2011) (Exhibit 8):

> Importantly, in undertaking the [routine maintenance] analysis, it is critical not to focus inappropriately on any one factor such that the fundamental purpose of the narrow exclusion is forgotten. In *New York II.* 443 F.3d at 883-84, the D.C. Circuit Court underscored that, "EPA has for over two decades defined the [routine maintenance] exclusion as limited to 'de minimis circumstances.'"

Particularly relevant here is EPA's 1987 Applicability Determination regarding the restart of the Cyprus Casa Grande copper mining and process facility. This determination, dated November 7, 1987 followed up on an earlier Noranda Mine Determination from May of that year. In the November determination, EPA found that even if startup of an acid plant after a ten-year operational hiatus was not a new source under EPA's reactivation policy, the restart nevertheless constituted a major modification. EPA noted that although the company characterized the work necessary to restart the facility as minor or moderate, "the minimum necessary rehabilitation effort is extensive, involving replacement of key pieces of equipment (e.g., the CCD thickener tanks, pumps, external insulation), and substantial time and cost." EPA went on to note that while some of the work, "if performed regularly as part of standard maintenance procedure while the plant was functioning or in full working order, could be considered routine," when put in the context of the "extensive rehabilitation work" being undertaken, the physical change was non-routine in nature. *Id.* at 6.

As will be shown below, ADEC appears to ignore Cyprus Casa Grande determination. As in that case, here there is a facility being restarted after being idled for a decade. In a newly operating plant, some of the isolated tasks set out for Unit 2 could be considered routine. In a plant that has been mothballed for ten years with no emissions, however, the activities are neither routine nor maintenance.

1. *Nature and Extent and Cost*

The nature and extent of the activity required to bring Unit 2 back to life is significant. In order to try to argue that this activity is nothing more than routine maintenance, Golden Valley has, in the last few years, attempted to downplay the amount of work necessary for restart. First, as ADEC acknowledges, *see* Exhibit 11, p. 36, in June 2008, AIDEA's startup engineers estimated it would take 19 months to startup Unit 2 at a cost of $62 million, or about a quarter of the original cost of the plant. Golden Valley now discounts that estimate because it claims that high cost would only be necessary if Unit 1 were completely separated from Unit 2.

Meanwhile, in February 2009, Golden Valley advised its members that startup would take 18 to 24 months and that AIDEA would loan Golden Valley up to $45 million "to fix known deficiencies, to startup up the plant." *See* Exhibit 12. Golden Valley now discounts the $45 million dollar figure. ADEC notes that: "It is the Department's understanding that much of the $45 million was not intended for physical changes." Exhibit 11, p. 36. However, review of the press release announcing an agreement between Golden Valley and AIDEA regarding purchase of Unit 2 says that AIDEA will: "provide GVEA a $45 million line of credit at six and one-half percent for **HCCP restart costs**." Exhibit 15, p. 1 (emphasis added). Furthermore, the AIDEA - GVEA - HEA HCCP Settlement Term Sheet, dated January 9,2009 states that:

> AIDEA will provide up to $45,000,000 as a secured credit facility to GVEA or a GVEA wholly-owned entity, collateral acceptable to AIDEA, for **the repairs and modifications to HCCP** (including an upgrade of GVEA's BESS system required to mitigate HCCP issues and up to $500,000 each for GVEA and HEA's development costs associated with making HCCP operational) that GVEA deems necessary.

Exhibit 15, p. 3 (emphasis added).

To address the routine maintenance issue, ADEC asked Golden Valley to advise it "of all activities GVEA would like to pursue in course of [Unit 2's] restart." Exhibit 14, p. 1. In response, Golden Valley identified 105 separate activities that had to be completed to startup Unit 2, costing a total of $16.2 million. *See* Startup Project List, Exhibit 14. Costs for many individual activities reported to ADEC are substantially lower than the costs estimated by AIDEA's engineers. Indeed, the total cost to startup Unit 2 reported to ADEC, $16.2 million, is nearly four times lower than the $62 million estimated by AIDEA's startup engineers.

Many of the activities proposed for restart thus involve completing construction activity that was abandoned when the owners ran out of money. Furthermore, the original facility was designed to test an experimental combustor, the TRW slagging bed combustor, and a new SO_2 control technology, the Joy/Niro spray drier absorber. The focus of the work was to scale up a pilot version of the combustor, which necessarily involves a lot of trial and error. The numerous design errors and scaleup problems are catalogued in engineering studies. The startup Project List, Exhibit 14, includes many modifications to correct design errors, reduce maintenance costs, and improve safety so that Unit 2 can operate commercially. Some of these are discussed below to illustrate the fact that what is now contemplated at the site cannot be considered routine maintenance.

a. Access Platforms

The facility tested in 1998-1999 was not designed for commercial operation because it excluded many features that would be required for safe routine operation, such as access platforms, walkways, heat tracing of piping and valves (critical given the local weather), and adequate ventilation. Similarly, piping blocked access required for routine maintenance. The access modifications include adding the following:

- Task F.4.e: Precombustor access platform stairs, south end (Exhibit 14, p. 3).
- Task F.6: Mill tensioners access platforms (*Id.*)
- Task F.7: Walkway from floor 3 to top of mills (*Id.*)
- Task F.8: Relocate air piping to resolve interferences around mills (*Id.*)
- Task G.4: Stairway to access boiler manway (*Id.* p. 4)
- Task Q.4: SDA access platform (*Id.*, p. 6)
- Task Q.6: Walkway from upper DA platform to 6th floor (*Id.*)
- Task R.2: Heat trace ash piping and valves (*Id.*)
- Task AC.1: Battery room ventilation improvements (*Id.*, p. 8)
- Task AD.1: Install CO_2 monitor in Unit 2 relay room per regulations (*Id.*)
- Task AH.1 Reroute seal air piping that blocks pulverizer maintenance door (*Id.*, p. 9)
- Task AL.1: Reroute deaerator overflow piping to improve efficiency (*Id.*)
- Task AP.1: Reroute sample lines to eliminate blocking ventilation hood door (*Id.*)

b. Tagging and Labeling

During initial construction and startup, all equipment, piping systems, and valves are commonly labeled to facilitate operator training and safety. Tagging and labeling was not completed at Unit 2. Task AV.1 finishes this job for $80,000. (*Id.* p. 11)

c. Electrical Breakers

Several plant electrical breakers may have been designed and/or installed with the wrong cable size. Task K.2 would confirm that suitable service is installed and replace as necessary. (*Id*. p. 5)

d. HCCP Dry Ash Transfer System

This system transfers dry ash between Unit 1 and Unit 2. "This system is part of the original design, but was never fully commissioned in 1998 and 1999." Task V.1 would commission this system, evaluate its operability, and make repairs as necessary for $32,500. It is not clear whether repairs are included in the task cost. (*Id*., p. 21)

e. Unit #1 Wet Ash Transfer System

This system transfers wet ash between Units 1 and 2. "This system is part of the original design, but was never fully commissioned in 1998 and 1999." Task W.1 would evaluate the performance of this system and make repairs as necessary for $8,000. It is not clear whether repairs are included in the task cost. (*Id*.)

f. Second Coal Bucket Elevator

The original Unit 2 design made provisions for the addition of a second coal bucket elevator. However, this system was not installed. A second coal bucket elevator will provide a redundant system, allowing coal loading to the silos when the primary bucket elevator is down for repairs. Task AG.2 evaluates the cost and benefits of this second elevator for $678,000. (*Id*., p. 21).

g. September 1999 Explosion

A large explosion occurred on September 6, 1999, on the 20th day of the 90-day test during plant shutdown, originating in Pulverizer B. Considerable damage was done to the area around the pulverizer. Exhibit 6, pp. 1-2, 6-11. The explosion was caused by faulty equipment and extended operation at low load. Exhibit 5, p. 21. This explosion damaged a section of the primary air duct to the B Pulverizer. The damage from this explosion was never repaired. The Project List includes modifications to repair this damage. These repairs include inspecting and repairing damaged parts including the pulverizer primary air ducts and transport tubes and the coal feeder system both upstream and downstream from where the explosion occurred.

Such explosions are not routine and are attributable to the experimental nature of Unit 2. These are more properly considered development costs because this is first generation technology. The costs should have been incurred during the demonstration period to facilitate commercial operation. They are just one of many indications that Unit 2 cannot be operated in its current state and never could have been commercially operated at the time it was shuttered. Some of the modifications to repair the damage are discussed below.

(i) Coal Silos

The fires that occurred in coal silo B in September 1999 damaged several coal silo liners. This damage was never repaired. Exhibit 5, pp. 19-20. Task M.1 would repair the damage to the silo and install new liners for $300,000. (Exhibit 14, p. 5).

(ii) Coal Feeder System

The TRW coal feed system is a new process. Two pulverizer explosions occurred that may result in premature failure and safety issues. Exhibit 6, p. 8-4. The explosion damaged a section of the primary air duct to the B Pulverizer. The modifications include Task F.1.b, Exhibit 14, p. 2, which will evaluate the ductwork and if necessary, replace it, for $310,000.

(iii) Transport Tubes

The explosion may have damaged some of the ceramic tiles lining the coal transport tubes. The modifications include Task F.1.c, which will inspect these tubes and replace any tiles, as necessary, at a cost of $24,000. It is unclear whether this cost includes replacing the tubes, or just the study to inspect them. (*Id*., p. 12)

h. November 1999 Explosion

A duct explosion occurred in November 1999 during the shutdown of the coal feed system, while the unit was decreasing load. In the lead-up to this explosion, coal being fed from the coal silo to the coal feeders plugged in the downspouts. Maintenance workers used sledge hammers throughout the night in an effort to keep the coal flowing. In spite of these efforts, a duct explosion occurred, causing Pulverizer A to trip. Exhibit 6, p. 6-12.

This explosion was attributed to the elevated temperatures of the air exiting the pulverizer and reduction in air flow through the pulverizer and exhaust fan. Shaw recommended a number of measures to prevent the recurrence of these conditions, including replacing the mill exhaust fans with new smaller fans, revising the operation of the capacity dampers, modifying the control logic, and repairing or replacing the leaking automatic valves. 12/18/08 Shaw Closeout Report, Section 9.0 Studies & Reports, Coal Feed and Mill Exhaust Fan Analysis, October 16, 2008. The Project List only identifies one of these recommendations, new mill exhaust fans.

i. Mill Exhaust Fans

The mill exhaust fans pull hot air and pulverized coal out of the pulverizers and transport it to the pre-combustor and slagging combustor via a splitter system with cyclones. Task F.2.a will replace the exhauster fans in the coal feed system for $2,000,000. (*Id*. at pdf. p. 12). This change is required to correct an original design flaw discovered during the 90-day trial period. The mill exhauster fan blades and scrolls eroded faster than expected due to the high ash content and abrasive properties of the Usibelli coal, requiring an unacceptable amount of repair. Exhibit 6, p. 1-2. Numerous unsuccessful attempts were made during plant operation to correct this problem. Exhibit 5, p. 2. The problem was not corrected.

As explained by Shaw: “There is general agreement between the information sources and SSW [Shaw, Stone & Webster] that the demonstrated service life of 90 days resulting from operation of this equipment under the conditions of the demonstration test was unusually low and not acceptable for a typical power plant application.” Exhibit 5, p. 44. Thus, these fans are not capable of commercial operation. This task will evaluate installation of new mill exhauster fans lined with a more erosion resistant material and possibly include variable frequency drives to control fan speed. Exhibit 14, p. 18.

The Shaw Closeout Report indicates that the new mill exhaust fans, equipped with smaller diameter rotors, would increase pulverizer inlet coal flow from 44,827 lb/hr in August 1999 to a design level of 48,842 lb/hr. 12/18/08 Shaw Closeout Report, Section 9.0 Studies & Reports, Coal Feed and Mill Exhaust Analysis, October 16, 2008. This increase in coal flow rate could lead to an increase in emissions.

j. Redesign Swirl Dampers

The demonstration showed that it may be beneficial to use a fixed cross sectional area in the swirl dampers, rather than an adjustable cross-sectional area, as in the original design. Task

F.4.g will evaluate the cost and feasibility of changing the design of the swirl dampers from adjustable to fixed for $99,000. Exhibit 14, pp. 18-19. It is unclear whether this cost includes the cost to make the design change, but design changes cannot be considered routine maintenance.

k. Slag Ash Clinker Grinder

During operation of Unit 2, staff reported numerous occurrences of large pieces of slag ash accumulating on the oversize grate upstream of the slag ash bucket elevator that loads ash into trucks. This material had to be manually removed from the grates and reduced in size using rods, water spray, and air-powered tools, a situation that would never be tolerated in a commercial facility due to labor costs. Exhibit 5, pp. 3, 27; Exhibit 6, p. 6-12. Task H.1 is a study to evaluate the need for a slag ash clinker grinder at a cost of $205,000 to automate this process. Exhibit 14, pp. 19-20. Shaw estimated the cost of the new grinder at $302,570. Exhibit 16, pdf p. 7.

The Project List claims that clinker grinding would not increase emissions because the clinker would be wet when they enter the grinder and would thus produce no dust. Exhibit 14, p. 19. However, grinding produces some dust, regardless of the moisture content. A related study, in Task AM.1, would consider an alternate design to bypass the bucket elevator when it is out of service. The clinker grinder would alleviate the need for this bypass system. *Id.,* p. 23.

l. Bottom Ash Bucket Elevator Conveyor Bypass

During 1998 - 1999 testing, slag ash could not be handled by the ash loadout bucket elevator feeding material to the bottom ash silo (while burning a coal with less ash than design basis). A temporary conveyor was installed to bypass the bucket elevator and load ash directly into trucks. Exhibit 5, p. 27. Task M.1 installs a dedicated slag ash bypass for $90,000. Exhibit 14, p. 5. Shaw estimates the cost for this bypass as $281,770. Exhibit 16, pdf p. 7.

m. Combustor Flame Scanners

The original purge air flame scanners have inadequate purge air flow. Task F.4.b will modify them to increase air pressure and air flow to the scanners. Exhibit 14, p. 2-3.

n. Coal Bucket Elevator Chute

Task E.2 will add vibrators and modify the coal bucket elevator inlet chute for $282,000. *Id*., p. 17. These changes are required because the 90-day trial showed plugging problems existed at the coal bucket elevator inlet chute. This task redesigns the inlet chute and adds vibrators to prevent plugging the bucket elevator with coal. *Id.* Unit 2 will not be able to operate commercially without this modification.

o. Bottom Ash Conveyor

Operating reports indicated the bottom ash bucket elevator periodically plugged. Task R.1 will inspect and review this elevator and modify as appropriate. The stated cost of $4,000 is not adequate to cover any modifications. Exhibit 14, p. 20.

p. Coal Handling System

The automated coal blending system never worked properly and did not meet project design requirements. *See* Exhibit 6, p. 1-2 ("The coal blending system does not operate as designed. The coal feed system exhibits high rates of wear of various components, in particular the exhauster fans and cyclones. The existing exhauster fans are unsuitable for long term operation due to the unacceptable amount of repairs required.") and 8-4 ("The automated HCCP coal blending system is not working properly and does not meet project design requirements.").

Rather, the run-of-mine coal and waste coal were blended in the yard by operators using wheeled loaders. This is a very inaccurate method to maintain a uniform coal supply, which is required for commercial operation. The 12/99 Harris Report recommended an automated coal blending system to address this situation. *See* Exhibit 1, at pdf p. 42 and pdf p. 108. Similarly, the 3/28/06 Shaw Report opined: "Numerous operating problems encountered during initial plant startup and subsequent operation demonstrates that the combined coal handling system as currently configured, is limited in its ability to ensure reliable delivery of coal to both plants." Exhibit 5, p. 61.

The modifications include Task AG.3, which would study coal pile management for $400,000. The 12/18/08 Shaw Closeout Report contemplates far more than a study, specifying design for a new coal handling system. In 2008, Shaw estimated that a new coal handling system would cost slightly less than $16 million. Exhibit 16, pdf p. 7.

q. Replace Worn Air Nozzles

Air is injected into the precombustor. During testing, the Precombustor B staged air annulus was completely blocked by slag, and the majority of the radial startup air nozzles were covered with slag. Because this precombustor was designed to be non-slagging, this precombustor did not operate per design. 12/18/08 Shaw Closeout Report, Section 4.0 Coal Handling, Section 4.1 Bid Package, Engineering, Design and Supply of Coal Handling System, October 14, 2008, Document No. 128569-S-M-00002-0. Task F.4.a would replace several air nozzles for $100,000. Exhibit 14, at 2-3. The Project List fails to mention slagging or include any design changes to mitigate it.

r. Limestone Feeder/Control

During the test period, the response time between changes in limestone feed rate to the furnace and resulting changes in SO_2 at the inlet to the scrubber were much longer than required to adequately control SO_2 emissions. Exhibit 5, p. 12; Exhibit 7, pp. D-6 to D-7. The test data indicate a five-day lag between the addition of limestone to the furnace and the point in time when the composition of the slurry fed to the SDA changes significantly. This is too long to effectively control SO_2 emissions. Exhibit 6, p. 6-28. Thirty-five hours of SO_2 violations were recorded during the 90-day test. *Id.,* p. 6-23. The startup modifications include Task U.1, a $53,000 study to resolve this issue. Exhibit 14, p. 20.

The only other modifications to the SDA identified in the Project List are Task Q.4, SDA access platforms ($37,000), and Task Q.5, replace SO2 process monitors and probe at SDA inlet ($20,000). Exhibit 14, pp. 6, 25. Shaw's cost estimate includes: "SDA & Flue Gas System Inspection & Refurb" for $463,261. Exhibit 16, pdf p. 7.

s. Turbine Efficiency

At the conclusion of the test period, the steam turbine was reported to have a 2% loss in efficiency compared to the original guarantee. Exhibit 5, p. 3. The restart projects include $600,000 to disassemble the turbine to investigate the cause of this loss and to perform minor turbine refurbishment to mitigate the loss. Exhibit 14, p. 4. In 2008, Shaw estimated the cost at $949,794. Exhibit 16, pdf p. 7. The Project List, however, fails to disclose this intent, instead containing only generic Task J.1, to inspect the steam turbine and generator, claiming it as routine maintenance, Exhibit 14, p. 4, when, in fact, its purpose is to correct design error(s).

t. Waste Water Treatment System

The original installation injected acid and caustic into the top of the neutralization tank. The 90-day test demonstrated this design resulted in substandard mixing of chemical and thus slow neutralization of tank contents. Task Z.2 will move the injection points to the suction line of the neutralization pumps to improve mixing of acids and caustic chemicals for $37,000. Exhibit 14, p. 7.

2. *Purpose*

Analysis of the "purpose" factor weighs strongly in favor of a finding that the proposed changes are not routine. The changes discussed above are not "regular, customary, or standard undertaking[s] for the purpose of maintaining the plant in its present condition." Exhibit 8, at p. 10. The "present condition" of the plant is not operable on a long-term basis. Thus, routine maintenance would consist of doing whatever is necessary to keep the plant in its non-operational mode. In contrast, the purpose of the proposed changes is to take a plant which is incapable of long-term commercial operation and make it viable; in other words, the changes are designed to improve the plant - not keep it in its current condition.

It must be remembered that in the late 90's, the project ran out of money. As a consequence, the facility, as it was tested in 1998 and 1999, was considered to be unsafe and uneconomical to operate. Things were patched together using riveted steel plates and unusual interventions that could not be sustained in the long run. During the 90-day test period, for example, rapid deterioration of equipment forced workers to weld and reinforce equipment while it was running. At other times, coal silos to the coal feeder plugged and "maintenance workers used sledge hammers throughout the night in an effort to keep the coal flowing." Common operating practices during the 90-day test included patching leaking equipment with bolted steel plates, manual clearing of slag that appeared in places it was not supposed to be, manually cleaning screens that should not plug, and banging on hoppers and chutes to maintain coal flow. Further, during testing, Unit 2 tripped offline 78 times, unacceptable for a commercial facility.

The results of the 90-day test were inconclusive because the test was performed with coal having a heating value slightly above the design specification, resulting in 23% less ash than design. Moreover, more staff was on-site than required to run the facility during the test to make real time repairs while the facility was operating. The excess staffing, equivalent to 15 full time maintenance people on a 40-hour week basis, did emergency work to the keep the facility running, tasks that would not be required in a commercial facility. These tasks included clinker breaking, atomizer replacement, pyrites hopper cleaning, repairing the head pulley on the ash bucket conveyor and silo discharge chute battering to clear plugging, and repairing the mill and surrounding equipment.

An engineering assessment prepared in December 1999 for Golden Valley of the 90-day test run and plant equipment concluded: "Overall, DE&S [Duke Engineering & Services] found during the 90-Day Test, the subsequent equipment inspections, the performance tests, and the turbine test, that [Unit 2] has several serious deficiencies. These deficiencies need to be resolved before [Unit 2] can operate reliably as a cost competitive power plant for extended periods of time." Exhibit 6, p. 1-3. Duke opined:

> [C]ertain systems and equipment failed to meet an acceptable level of reliability. The coal feed system has both reliability and safety concerns. The pulverizer explosion is an obvious example that additional instrumentation and/or controls work needs to be done to assure that a similar incident does not happen again. The reliability and safety of the existing pulverizer exhauster fans and the variable coal splitter is unsatisfactory. The 90-Day Test proved that these components will require frequent repair to stop pulverized coal leakage and are not capable of sustained operation in their current state."

Id., p. 6-27.

Completion work on Unit 2 was discontinued at the end of 1999 after the initial 90-day test (8/17/99 - 11/15/99) and has not yet resumed, over a decade later. In fact, the Long-Term

Commercial Operation Demonstration beyond the initial 90-day, required by the DOE contract, was never performed. Exhibit 7, p. 4-3. The patches made to get through the test phase were never made permanent.

As Robert H. Koppe points out in his declaration, several of the changes now contemplated in order to get the facility operating again are in the nature of design changes being made to facility. *See* Exhibit 17 ("I determined that most of the projects appear to be aimed at correcting design deficiencies in the unit. These projects involve improving (upgrading) the original design of the unit and projects could not reasonably be considered to be routine maintenance."). Design changes do not qualify as routine maintenance – they are not maintenance at all. *See* Detroit Edison Applicability Determination, Exhibit 9.

In Mr. Koppe's view, much of the work to be done "is likely to be the result of some combination of design defects, pushing the unit too hard during the test period, or the effects of 10 years of layup." ADEC appears to agree that what is going on here is not maintenance at all, and that is significant: "the changes GVEA plans are in their nature post construction changes based on difficulties encountered during shakedown."

In summary, because some of this work involves changes in design and because most of it is necessary in order for the plant to move from an inoperative status to startup, the purpose of the work is inconsistent with a finding of routine maintenance.

3. *Frequency*

As mentioned above, with respect to the "frequency" factor, many of the changes being made at this facility are the result of a situation where the facility was started up and operated even though construction was never really completed. Thus, many of these changes are not those that would be either regular or customary, but rather they are actions more properly associated with initial construction. Furthermore, because the facility has not been operated for more than a year, several of the projects being undertaken now are probably once-in-a-lifetime events. These include: the installation of new equipment to allow the unit to operate with all-volatile treatment (AVT); the installation of traveling screens in the condenser cooling water intake; the installation of new pulverizer parts; the correction of design defects in the unit's heating system, the replacement of undersized electrical cables, and the inspection and repair of the turbine. *See* Koppe Declaration ¶¶ 10, 11, and 12.

4. *ADEC's Response to Comments*

In public comments, Exhibit 10, the Petitioners pointed out the non-routine nature of work to be undertaken by Golden Valley to restart Unit 2. In response to those comments, ADEC engaged in some *ex parte* conversations with Golden Valley through which Golden Valley attempted to convince ADEC that all of the work it was going to undertake was routine. *See* Exhibit 11. ADEC accepted these arguments based upon some false premises that should be rejected by EPA.

First, regarding the cost of the project, ADEC appears to accept the idea that the $16 million dollar figure Golden Valley generated for the cost to prepare Unit 2 for startup should be discounted to $11 million or lower because the projects are "not related to air pollutant emitting activities." Exhibit 11, p. 36. In a similar vein, ADEC disregarded certain activities, refusing to credit them as "being modifications because they are not physical changes to pollutant emitting activities." *Id*., p. 37. These distinctions are inappropriate because the facility has not been operating at all and cannot do so unless these changes are made. Thus, everything necessary to make the plant run again should be considered as part of the physical change analysis.

Second, Golden Valley's efforts at deriving the $16 million dollar figure should be evaluated with deep skepticism. For example, even though both Shaw and Harris stated that the plant could not be operated commercially without automated coal blending, *see* Section II(A)(1)(p) above, Golden Valley attempts to avoid this issue by claiming it can continue to wheeled equipment to blend coal, Exhibit 11, p. 37, while it spends $400,000 to study the issues. Thus, Golden Valley is attempting to conceal an additional $15,853,308 cost, *see* Exhibit 16 at pdf p. 7, (making the total restart cost $32 million) which is assuredly coming down the pike. To add insult to injury, Golden Valley does not believe that even the $400,000 should be counted because it is only a "study." *Id*. Another implausibility is Golden Valley's assertion that it will not need the bottom ash bucket elevator conveyor bypass, *see* Exhibit 11, p. 37, even though operating without it will require the plant to rely permanently on a temporary conveyor. Section II(A)(1)(l) above. Thus, Golden Valley attempts brush aside this $90,000 cost. (Actually, according to Shaw, this cost will be $281,770). *Id.* Similarly, Golden Valley asserts that the turbine investigation and repair will cost only $600,000, even though Shaw determined in 2008 that the cost would be $949,794. *See* Section II(A)(1)(s) above.

It must be said, however, that even if the startup costs are as low as $11 million, for a 54 MW plant, that cost cannot be considered *de minimis*.

ADEC's analysis also improperly attempts to isolate each project rather than recognizing the need for them all to restart the plant.

Robert Koppe's analysis has hit the nail on the head:

A small fraction of the projects appear to involve maintenance of equipment rather than

> upgrading or adding equipment. Much of this maintenance appears to be more extensive than I would expect after only a few months (or even a year or more) of operation. Much of this maintenance is likely to be the result of some combination of design defects, pushing the unit too hard during the test period, or the effects of 10 years of layup. More than 75% of the money for the projects is to add new equipment or to upgrade existing equipment. Given how little the unit has operated, all this work should be regarded as once-in-a-lifetime efforts to correct deficiencies in the original design of the unit.

See Exhibit 17. Accordingly, the changes necessary to startup the facility cannot be considered routine maintenance.

B. The Physical Changes Necessary to Restart the Plant Will Result in an Emissions Increase.

Under the PSD rules, a major modification occurs if physical changes will result in a significant emissions increase and a significant net emissions increase. 40 C.F.R. § 52.21(b)(2)(i) and (a)(2)(iv)(c). A significant emissions increase will occur for an existing unit if the difference between projected actual emissions and baseline actual emissions (as defined in 40 C.F.R. § 52.21(b)(48)) exceeds the significance level. EPA's regulations provide that:

> For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

in 40 C.F.R. § 52.21(b)(48)(i). Because Unit 2 has not operated in the past five years, its baseline actual emissions for all pollutants are zero. Consequently, given the projected actual emissions of the unit, *see* Statement of Basis, Appendix C, p. 27, restart of the plant will be a major modification for SO_2 and NO_x.

ADEC asserts that baseline actual emissions for SO_2 and NO_x will be 154 and 717 tons respectively or higher. It derives these numbers by using as a baseline period the two years immediately after the unit began operation. *Id.*, p. 21. In selecting these two years as the baseline, ADEC has ignored EPA guidance interpreting the phrase: "more representative of normal source operation." 40 C.F.R. § 52.21(b)(48)(i). Because the Alaska SIP has incorporated section 52.21 by reference, and this regulation was written by EPA, it is EPA's interpretation of this regulation that counts. *See Auer v. Robbins*, 519 U.S. 452 (1997) (an agency's interpretation of its own regulation is controlling).

EPA guidance on when a period is "more representative" would not permit selection of the first two years of operation as the baseline period. As EPA has explained, the "power to use a different baseline period is limited to those circumstances where the source demonstrates that some time period other than the 2 years that precede the change is more representative of normal source operation. In general, EPA has indicated that this provision is to apply to catastrophic occurrences such as strikes and major industrial accidents (*see* NSR Workshop Manual, p. A.39)." *See* Memorandum from Calcagni to Kee, "Subject: Proposed Netting for Modifications at Cyprus Northshore Mining Corporation, Silver Bay, Minnesota" (August 11, 1992), p. 5. Moreover, "EPA has declined to consider a stop in operations, in and of itself, to constitute grounds to change the baseline years." *Id.* Based on this interpretation, EPA refused to allow the shutdown of two straight-grate furnaces to be given netting credit when the two furnaces had been shuttered for the immediately preceding ten years. EPA noted that no "catastrophic occurrences or other extraordinary circumstances" had disrupted operation of the shutdown furnaces for entire shutdown period. Rather the idling of the furnaces had been due to longstanding market conditions, and a zero baseline most appropriately reflected those conditions. *Id.*, p. 6. EPA followed similar reasoning in a PSD applicability determination by Region 4 in 2000. *See* Letter from R. Douglas Neeley, EPA to Mr. John Yntema, Georgia Environmental Protection Division, "SUBJ: Establishing Emissions Representative of Normal Source Operation for Furnace E, Owens-Brockway Glass Container, Inc., Atlanta, Georgia (March 2, 2000).

Turning to Healy Unit 2, no catastrophe or other extraordinary circumstance has kept Unit 2 shuttered for the past decade. Rather, as was the case in the Cyprus Northshore Mining situation, it simply was not economic to run Unit 2 for the past five years. Accordingly, a baseline of zero is the most representative of how the plant has functioned.

Moreover, even if the first two years of operation are treated as the most representative period, the level of emissions from that period must be "the average rate, in tons per year, at which the unit **actually emitted** the pollutant during a consecutive 24-month period." 40 C.F.R. § 52.21(b)(21)(ii). Neither of the approaches used by ADEC to calculate baseline emissions meet this requirement. Rather, under one approach, ADEC claims that baseline emissions should equal potential to emit, and under the other approach, ADEC extrapolates the emissions from the limited 90-day run into a two-year figure.

ADEC's "potential-to-emit" approach is logically and legally flawed. First, any argument that concludes that two years of emissions at potential-to-emit levels is "representative" of normal operations at a plant that has operated for a maximum of a few months in its entire life and not at all for the last decade is absurd on its face. Second, ADEC concedes that Unit 2 cannot be treated as a "new emissions unit" as defined in 40 C.F.R. 52.21(b)(7). Nevertheless, ADEC awards Unit 2 the baseline of a new emissions unit by arguing that the unit should be awarded the baseline set aside for new units that have commenced operation. Thus, ADEC is simultaneously treating Unit

2 as new and existing. The facility is either new or it is not. Legally, it cannot be both. Since ADEC concedes that Unit 2 is existing, baseline emissions must be based on what the unit actually emitted during the 24-month period selected. Accordingly, it is inappropriate to use a potential-to-emit figure or to extrapolate 90 days of emissions into a 24-month figure.

Fundamentally, over the life of this plant, this facility's most "representative" mode is when it is not operating. Not surprisingly then, the most appropriate baseline for this facility is one based on no emissions at all. Legally, ADEC must use zero for baseline actual emissions from this facility. When the proper baseline is used, ADEC must conclude that a significant emissions increase will occur when Unit 2 restarts.

CONCLUSION

For the reasons set forth above, this Petition should be granted.

Respectfully submitted,

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Exhibit List

Exhibit 1: Healy Clean Coal Project, 90-day Commercial Operation Test and Sustained Operations Report: A Participant Perspective, Prepared by the Alaska Industrial Development and Export Authority (March 27, 2000)

Exhibit 2: Golden Valley Electric Association Narrative Statement of Facts

Exhibit 3: Golden Valley Electric Association 2003 Annual Report

Exhibit 4: Shaw Power Group Trip Report (April 16, 2008)

Exhibit 5: Shaw, Stone & Webster, HCCP Condition Assessment and Restart Study (March 28, 2006)

Exhibit 6: Duke Engineering & Services, 90-Day Test Run Systems Evaluation & Plant Assessment, Prepared for GVEA, December 1999

Exhibit 7: AIDEA, Healy Clean Coal Project Performance and Economics Report, Final Report: Volume 2 (April 2001)

Exhibit 8: *In the Matter of Tennessee Valley Authority, Paradise Fossil Fuel Plant Drakesboro, Kentucky Title V Air Quality Permit # V-07-018 RI* , Petition No. IV-2010-1 (U.S. E.P.A. May 2, 2011)

Exhibit 9: Detroit Edison Applicability Determination (May 23, 2000)

Exhibit 10: Comments by Northern Alaska Environmental Center, Denali Citizens Council, National Parks Conservation Association, Alaska Community Action on Toxics and the Sierra Club regarding Renewal of Air Quality Control Operating Permit No. AQ0173TVP02 for the Golden Valley Electric Association Healy Power Plants (Aug. 29, 2011)

Exhibit 11: Department of Environmental Conservation Air Quality Operating Permit Response to Comments (Feb. 3, 2012)

Exhibit 12: Letter from Bill Nordmark, Golden Valley Board Chairman, and Brian Newton, GVEA President & CEO, to Golden Valley Members (Feb. 12, 2009)

Exhibit 13: Golden Valley Electric Association 1999 Annual Report

Exhibit 14: Letter from Kristen DuBois, GVEA, to Sally Ryan, ADEC, August 17, 2009, Re: Response to ADEC Request for Further Analysis, August 17, 2009

Exhibit 15: .AIDEA Press Release, "AIDEA, GVEA, HEA Announce HCCP Sale Agreement" (Jan. 14, 2009)

Exhibit 16: Healy Clean Coal Restart Project Cost Estimate Summary (June 2008)

Exhibit 17: Declaration of Robert H. Koppe (March 11, 2012)

Certificate of Service

I certify that on March 12, 2012, I sent, via e-mail, a copy of the foregoing, including a link to download all exhibits, to the addressees listed below.

s/George E. Hays

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