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BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF:	)	
	)	
The Clean Air Act Title V Operating Permit	)	PETITION FOR OBJECTION
	)	
For PacifiCorp Hunter Power Plant	)	Renewal Permit No. 1500101004
In Castle Dale, Utah	)	
	)	
Prepared by the Utah Division of	)	
Air Quality	)	

PETITION FOR OBJECTION TO THE TITLE V RENEWAL PERMIT FOR PACIFICORP'S HUNTER POWER PLANT PROPOSED FOR ISSUANCE ON JULY 8, 2020 AND FINALIZED ON SEPTEMBER 4, 2020

Pursuant to section 505(b)(2) of the Clean Air Act, 42 U.S.C. § 7661d(b)(2), and 40 C.F.R. § 70.8(d), Sierra Club hereby petitions the Administrator of the United States Environmental Protection Agency ("EPA") to object to the Title V Renewal Operating Permit proposed for issuance by the Utah Division of Air Quality ("UDAQ") for PacifiCorp's Hunter Power Plant on July 8, 2020 and issued as final on September 4, 2020 (Renewal Permit No. 1500101004).[1]

The basis for this petition is that the 2020 Renewal Permit fails to assure the facility's compliance with Prevention of Significant Deterioration ("PSD") requirements required under Part C of the Act, 42 U.S.C. § 7470-7492, and Utah's federally approved state implementation plan. These requirements became applicable to Units 1, 2, and 3 when PacifiCorp modified these units between 1997 and 1999. Sierra Club described this deficiency in detailed comments filed with UDAQ on the facility's 2015 draft Title V renewal permit[2] and also petitioned EPA to object to the facility's proposed 2016 Title V renewal permit (Permit No. 1500101002) due to this deficiency.[3] Unfortunately, both Utah and EPA refused to consider Sierra Club's demonstration that the plant modifications triggered PSD applicability, contending that Sierra Club could not properly raise its concerns in the context of the plant's Title V permit proceeding.[4]

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[1] UDAQ, Title V Renewal Operating Permit for PacifiCorp's Hunter Power Plant, Permit No. 1500101004, issued 9/4/2020 (Ex. 1).
[2] Sierra Club Comments on the Draft Title V Renewal Permit for the Hunter Power Plant dated November 13, 2015 (Ex. 2). The comments describing the permit's unlawful omission of PSD requirements for Units 1, 2, and 3 appear on pages 6-49 and 79-94.
[3] Sierra Club Petition Seeking EPA's Objection to the Hunter Power Plant Title V Renewal Permit, dated April 11, 2016 ("2016 Hunter Petition") (Ex. 3). The final 2016 permit was issued on March 3, 2016.
[4] UDAQ, Response to Public Comments on draft Title V renewal permit for the Hunter Plant, dated Jan. 11, 2016 (Ex. 4); *In the Matter of PacifiCorp Energy, Hunter Power Plant*, Order on Petition No. VIII-2016-4 (U.S. EPA, Oct. 16, 2017, at https://www.epa.gov/sites/production/files/2017-10/documents/pacificorp_hunter_order_denying_title_v_petition.pdf (Ex. 5).

After EPA denied Sierra Club's 2016 petition on October 16, 2017, Sierra Club challenged EPA's denial in the U.S. Court of Appeals for the Tenth Circuit. On July 2, 2020, the Tenth Circuit ruled in Sierra Club's favor, issuing an opinion vacating EPA's Order and remanding Sierra Club's 2016 petition to EPA for further consideration.[5] Specifically, the Court held that the legal basis underlying EPA's and Utah's refusal to consider Sierra Club's demonstration that PSD requirements are applicable to the Hunter plant was unlawful. However, the State of Utah and PacifiCorp, both intervenors in the case, petitioned the Court for panel rehearing and rehearing en banc, which delayed issuance of the Court's mandate. On October 16, 2020, the Court denied both petitions.[6] Thus, pursuant to Rule 41(b) of the Federal Rules of Appellate Procedure, the Court's mandate will issue no later than 7 days from October 16, 2020.

Because Sierra Club's legal challenge to EPA's denial of its 2016 petition was still pending at the time that Utah took public comment on the 2020 draft Title V renewal permit—and because Utah was actively participating in the litigation and defending EPA's order—there was no reason for Sierra Club to repeat the same comments to Utah in the 2020 permit renewal proceeding. But the Tenth Circuit's October 16, 2020 denial of the petitions for rehearing changed the legal landscape. Now, the Tenth Circuit's decision is final, and upon the Court's issuance of its mandate EPA must reconsider its prior decision denying Sierra Club's 2016 petition and upholding Utah's refusal to consider Sierra Club's demonstration that PSD requirements apply to the Hunter plant. Because the Tenth Circuit's denial of petitions for rehearing filed by Utah and PacifiCorp did not occur until October 16 (four days prior to this petition, and well after the close of the comment period on the draft permit), the grounds for EPA's objection "arose after" the public comment period on the 2020 renewal permit. Thus Sierra Club is excused from the general requirement in 40 C.F.R. § 70.8(d) that a petitioner raise its objection in comments on the draft permit (and, in any event, Sierra Club already raised this exact issue in its comments to UDAQ on the draft 2015 renewal permit).

While Sierra Club's 2016 petition challenged the Hunter Plant's 2016 Title V renewal permit, the 2020 renewal permit does nothing to address Sierra Club's claim that the plant's prior modifications triggered PSD applicability. Specifically, as shown below, the 2020 renewal permit does not impose emission limits reflecting use of best available control technology ("BACT") on Hunter Plant Units 1, 2, or 3, or otherwise require PacifiCorp to comply with PSD requirements that became applicable when these units were modified in the late 1990s.

As explained in Sierra Club's "Supplemental Notice Re 2020 Permit Renewal and Sierra Club's April 11, 2016 Petition That Is Currently Pending Before the U.S. Court of Appeals for the Tenth Circuit," filed with EPA on October 15, 2020, Utah's issuance of the 2020 renewal Title V permit does not moot the 2016 petition issues pending before the Tenth Circuit. Thus, regardless of whether Sierra Club filed this petition, EPA would be required to respond to the Tenth Circuit's remand of EPA's 2016 Hunter Order. Out of an abundance of caution, however, Sierra Club files this petition to ensure that EPA promptly addresses its concerns now that the Court's decision is final. For the same reasons that EPA should have objected to the 2016 Title V renewal permit, EPA must object to UDAQ's issuance of the plant's 2020 Title V renewal

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[5] *Sierra Club v. U.S. EPA*, 964 F.3d 882 (10th Cir. 2020) (Ex. 6).

[6] Order Denying Petitions for Panel Rehearing and Rehearing En Banc in Case No. 18-9507, Oct. 16, 2020, Docket I.D. 010110424337 (Ex. 7).

permit. The petition claim set forth below raises the same issue, based on the same facts, as raised in Claim A of Sierra Club's 2016 petition.[7] This petition does not replace Sierra Club's 2016 petition, which is the subject of the Tenth Circuit's remand.

Petition Claim:
The Administrator Must Object to the Hunter Permit Because It Fails to Include PSD Requirements that Became Applicable When PacifiCorp Modified Units 1, 2, and 3 Between 1997 and 1999.

Rationale Provided by UDAQ as to Why it Did Not Require PacifiCorp to Comply with PSD Requirements Applicable to the 1990s Major Modifications: None. UDAQ did not prepare a Statement of Basis or any other explanatory document to accompany the 2020 renewal permit. In response to Sierra Club's 2015 comments raising the same issue in the context of the 2016 renewal permit,[8] UDAQ refused to consider Sierra Club's demonstration that PSD applies.[9]

Relevant Conditions in the 2020 renewal permit: It is undisputed that UDAQ did not require PacifiCorp to comply with PSD requirements for the late 1990s plant modifications, and thus, just as there were no relevant PSD permit conditions in the 2016 renewal permit, there are also no relevant PSD permit conditions in the 2020 renewal permit. Furthermore, as shown on Table 15, below, with only a couple of exceptions that do not involve application of PSD requirements, the sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter (PM/PM_{10}) limits applicable to Units 1, 2, and 3 in the 2020 renewal permit remain unchanged from the 2016 permit. None of these limits constitute BACT for the respective pollutants.

DETAILED DEMONSTRATION OF PERMIT DEFICIENCY

I. The Hunter Permit is Deficient Because it Fails to Include PSD Requirements that Became Applicable When PacifiCorp Modified Units 1, 2, and 3 Between 1997 and 1999

In the 1997 to 1999 timeframe, PacifiCorp performed modifications to Hunter Units 1, 2, and 3 which triggered the requirements to obtain a PSD permit, apply BACT for SO_2, NO_x, PM/PM_{10}, and other pollutants, and meet all other PSD permitting requirements. No such PSD permit was issued and, as a result, all three of the Hunter units have been operating in violation of BACT and other PSD requirements since approximately the 1997 to 1999 timeframe.

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[7] Sierra Club's 2016 petition incorporated by reference the more detailed comments filed with the State of Utah on the 2015 draft renewal permit. Since Utah had refused to respond to Sierra Club's comments regarding PSD applicability, Sierra Club's 2016 petition arguments were the same as the arguments made in its comments to Utah on the draft permit, and thus, there could be no confusion about what Sierra Club was arguing in its 2016 petition. In 2020, however, EPA promulgated new rules governing the content of Title V petitions, and those rules state: "Any arguments or claims the petitioner wishes the EPA to consider in support of each issue raised must be contained within the body of the petition, or if reference is made to an attached document, the body of the petition must provide a specific citation to the referenced information, along with a description of how that information supports the claim." 40 C.F.R. § 70.12(2). Accordingly, the more detailed arguments originally presented to Utah in comments on the draft 2015 renewal permit are included in the body of this petition.

[8] 2015 Comments to UDAQ at 6-49 and 79-94.

[9] UDAQ, Response to Comments on 2016 Title V Permit Renewal, at 2-3.

All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements."[10] "Applicable requirements" include the obligation under the state or federal implementation plan to obtain a PSD permit, BACT emission limits, and limits necessary to ensure protection of air quality standards and increments.[11] As defined in 40 C.F.R. § 70.2, "Applicable requirement means… (1) Any standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in part 52 of this chapter . . . ."[12] The requirements of the PSD program, contained in the federal implementation plan at 40 C.F.R. § 52.21, are just such "applicable requirements." The Act and implementing regulations require that UDAQ determine the "applicable requirements" the Hunter Plant must meet at the time of Title V permit issuance, determine whether the facility will be in compliance at the time of permit issuance, and if not, include a compliance schedule that sets forth enforceable steps leading to compliance with the applicable requirements.[13]

Hunter's proposed Title V permit is deficient because it does not include the "applicable requirements" of the PSD permitting program triggered by major modifications constructed during 1997-1999, nor does the permit include an enforceable schedule of compliance to ensure that the PSD permitting requirements are met.

In August of 1997, PacifiCorp submitted a "Notice of Intent" (1997 NOI) permit application to UDAQ that identified numerous boiler projects and turbine upgrades to be completed on Hunter Units 1, 2, and 3 in the 1997 through 1999 timeframe.[14] A few of the projects had already been completed at Unit 3 at the time that PacifiCorp submitted its Notice of Intent.[15] PacifiCorp's 1997 NOI indicated that the hourly heat input capacity would increase

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[10] *See* 40 C.F.R. § 70.1(b); CAA § 504(a), 42 U.S.C. § 7661c; Utah Admin. Code R307-415-6a(1).

[11] 40 C.F.R. § 70.2; Utah Admin. Code R307-415-3(2), definition of "Applicable requirement," subparagraphs (a) through (k); *In re Duke Energy Indiana Edwardsport Generating Station*, Permit No. T083-27138-00003 at 2 (Dec. 13, 2011), https://www.epa.gov/sites/production/files/2015-08/documents/edwardsport_response2010.pdf ("Edwardsport Petition Order") ("For a major modification of a major stationary source, applicable requirements include the requirement to obtain a preconstruction permit that complies with applicable new source review requirements (*e.g.*, Prevention of Significant Deterioration, or PSD, requirements). …The PSD program analysis must address two primary and fundamental elements before the permitting authority may issue a permit: (1) an evaluation of the impact of the proposed new or modified major stationary source on ambient air quality in the area, and (2) an analysis ensuring that the proposed facility is subject to BACT for each pollutant subject to regulation under the PSD program. CAA § 165(a)(3),(4), 42 U.S.C. § 7475(a)(3), (4).").

[12] *In re Columbia Generating Station*, Order in Response to Petition No. V-2008-1 (EPA, Oct. 8, 2009), at 3, available at https://www.epa.gov/title-v-operating-permits/order-denying-granting-part-columbia-gerating-station-pardeeville; Utah Admin. Code R307-415-3(2), definition of "Applicable requirement," subparagraph (a).

[13] Utah Admin. Code R307-415-1; 307-415-5c(3)(c), (4), (5) and (8); 307-415-6a(1); and 307-415-6c(1), (3), (4) and (5).

[14] *See* August 18, 1997 Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant ("1997 NOI") at 1 (Ex. 8).

[15] *Id.*, attachment at Table 1. Specifically, the following projects had already been completed at Hunter Unit 3 at the time of PacifiCorp's August 18, 1997 NOI to UDAQ: Rotating classifiers on mills, replacement of oil ignitors, installation of on-line performance manager, and installation of condensate polisher.

significantly above the levels PacifiCorp identified as the "baseline hourly heat input" at all three Hunter units.[16]

To avoid PSD applicability for these modifications, PacifiCorp requested limits on the potential to emit of all three units ostensibly so that post-project emissions would not exceed the "PSD baseline emission inventory."[17] According to PacifiCorp, "the PSD baseline inventory was established at the time the Hunter Plant received a permit for Hunter units 3 and 4."[18] However, as explained below, PacifiCorp's PSD baseline inventory was not based on actual emissions at the Hunter Plant, as required by the applicable PSD regulations in the Utah SIP. Instead, PacifiCorp's baseline was much higher than actual emissions and appeared to be akin to allowable emissions.

In November of 1997 and December of 1997, UDAQ issued Approval Orders to consolidate the (at that time) separate Approval Orders for Units 1, 2, and 3 and to also to establish limits on potential to emit at Hunter Units 1, 2 and 3.[19] However, the Approval Order[20] failed to limit potential to emit to ensure that there was no significant net emissions increase of the various PSD pollutants emitted by the three Hunter units because the pre-project baseline emissions relied on in establishing the ultimate permit limits were not based on actual emissions. When a proper PSD analysis is conducted and baseline emissions before the projects are compared to the potential to emit after the projects, the projects undertaken at Hunter Units 1, 2 and 3 are shown to be major modifications for SO_2, NOx and particulate matter (PM and PM10). Accordingly, these projects should have triggered the application of PSD, BACT and all other PSD requirements to these units. The details of these projects, a proper determination of actual emissions prior to the changes, and a proper determination of the net emissions increases from these projects is provided below.

A. PacifiCorp's Notice of Intent for the 1997 to 1999 Hunter Projects

On August 18, 1997, PacifiCorp submitted a request for modifications to the Hunter Plant Approval Orders to limit the potential to emit at the Hunter Plant.[21] The cover letter attached to PacifiCorp's August 18, 1997 submittal discussed planned physical changes to all three Hunter units and stated that "[i]t is apparent that some of the remaining proposed changes could cause an increase in annual emissions."[22] PacifiCorp elaborated as follows:

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[16] *Id.*, Attachments at Tables entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: EPA Baseline Emissions" and "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: Future Potential Emissions."
[17] *Id.* at 2, 5-6.
[18] 1997 NOI at 1 (Ex. 8)
[19] *See* November 20, 1997 Approval Order DAQE-1099-97 (Ex. 9), which UDAQ subsequently revised on December 18, 1997. *See also* December 18, 1997 Approval Order DAQE-1189-97 (Ex. 10). (DEQ intended the December 18, 1997 Approval Order to replace the November 20, 1997 Approval Order. *See* May 3, 2005 letter from UDAQ to PacifiCorp (Ex. 11).
[20] December 18, 1997 Approval Order DAQE-1189-97 (Ex. 10),
[21] *See* August 18, 1997 Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant, at 1 (Ex. 8).
[22] *Id.*, cover letter at 1.

Table 1 contains a list of the projects that are planned or have been completed at the Hunter plant. After further evaluation of the combined projects, PacifiCorp believes that the Hunter plant must accept voluntary emission limits that are federally enforceable to limit the post-change potential to emit from the facility. Many of the projects, in and of themselves, could not cause an increase in emissions. However, ***as a whole, the upgrades may increase the actual capacity and capacity utilization of the boilers. PacifiCorp believes that an increase in capacity utilization following the completion of the projects has the potential to cause an increase in annual emissions above that which could have been accommodated prior to the changes***.[23]

PacifiCorp's August 18, 1997 letter lists the following projects for each unit, some of which had already been completed:

Table 2. PacifiCorp's List of Planned or Completed Projects at the Hunter Plant, From Table 1 of PacifiCorp's August 18, 1997 Letter to UDAQ (Ex. 1).

Hunter Unit	Project	Estimated Date of Completion[24]
3	Rotating classifiers on mills	8/96
	Addition of riser and supply tubes	6/98
	Replacement of superheater outlet bank and manifolds	6/98
	Overfire air ports for added NOx control	6/98
	Replacement of oil ignitors	5/96
	Resizing of cold reheat safety valves	6/98
	Turbine changes including aeroderivative design	6/98
	Installation of on-line performance manager	10/95
	Installation of condensate polisher	8/97
1	Replacement of air heater elements	11/99
	Rotating classifiers on mills	Listed as "under evaluation"
	Addition of superheater surface area	Listed as "under evaluation"
	NOx control project including burner and/or windbox changes	11/99
	Turbine changes including ruggedized rotor design	11/99
2	Replacement of air heater elements	11/97
	Rotating classifiers on mills	Listed as "under evaluation"
	Addition of superheater surface area	Listed as "under evaluation"
	NOx control project including burner and/or windbox changes	11/97
	Turbine changes including ruggedized rotor	11/97

[23] *Id., emphasis added.*

[24] For any date listed here that is before the date of PacifiCorp's August 18, 1997 letter to UDAQ, it must be assumed that such projects had already been completed.

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Based on data provided in the August 18, 1997 Notice of Intent, PacifiCorp indicated that the hourly heat input capacity would be increasing with these modifications. This is shown in Table 2 below.

Table 2. Increase in Heat Input Capacity at Hunter Unit 1, 2 and 3 Identified in PacifiCorp's August 18, 1997 NOI[25]

Hunter Unit	Baseline Hourly Heat Input	Source of Information	Maximum Projected Heat Input	Source of Information
1	4,160 MMBtu/hr	EPA Review – Emissions calculations[26]	4,700 MMBtu/hr	Production data and heat and material balance
2	4,160 MMBtu/hr	EPA Review – Emissions calculations	4,700 MMBtu/hr	
3	4,160 MMBtu/hr	EPA Review – Emissions calculations	4,900 MMBtu/hr	Heat and material balance

In its August 18, 1997 Notice of Intent, PacifiCorp requested limits on potential to emit of all three units to show that post-project emissions would not exceed the PSD "baseline emission inventory."[27] According to PacifiCorp, "the PSD baseline inventory was established at the time the Hunter Plant received a permit for Hunter units 3 and 4."[28] Table 3 below identifies the new limits that PacifiCorp requested to be imposed on the Hunter units. Notably, PacifiCorp stated "[r]educed short-term limits for the Unit 3 boiler are requested, because ***the physical changes to this boiler have the potential to increase short term emission rates***."[29]

Table 3. PacifiCorp's Proposed New Emission Limits for Hunter Units 1, 2 and 3 Requested in its August 18, 1997 Notice of Intent[30]

Hunter Units	Pollutant	Existing Limit	Proposed Limit

[25] From Table with Heading "Hunter Plant and Coal Prep Plant Annual Emissions Inventory Production Data Input Sheet for Calendar Year: EPA Baseline Emissions" and from Table with Heading: "Hunter Plant and Coal Prep Plant Annual Emissions Inventory Production Data Input Sheet for Calendar Year: Future Potential Emissions" attached to PacifiCorp's August 18, 1997 cover letter. (Ex. 8).
[26] Because PacifiCorp stated that it was using the PSD baseline inventory that was established at the time EPA issued a PSD permit for Hunter Unit 3 (*see* August 18, 1997 NOI cover letter at 1), we assumed the references to EPA Review-Emissions Calculations indicate that EPA used this hourly heat input in determining emissions from Hunter Units 1, 2, and 3 at the time that it issued the PSD permit for Hunter Unit 3.
[27] *See* August 18, 1997 Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant, at 1 (Ex. 8).
[28] *Id.*
[29] *Id.* at 2, emphasis added.
[30] *Id.,* Attachment, at Table 4.

1&2	Particulate matter	0.10 lb/MMBtu (6-hour averaging period)	0.05 lb/MMBtu (6-hour average) Proposed in addition to existing limit
	SO_2	1.2 lb/MMBtu (3-hour averaging period)	0.21 lb/MMBtu (12-month average) Proposed in addition to existing limit
	NOx	0.70 lb/MMBtu (3-hour averaging period)	0.45 lb/MMBtu (12-month average) Proposed in addition to existing limit
Unit 3	Particulate Matter	0.03 lb/MMBtu (6-hour averaging period)	0.02 lb/MMBtu (6-hour average) Proposed to replace existing limit
	SO2	0.12 lb/MMBtu (30-day rolling averaging)	0.10 lb/MMBtu (30-day rolling average) Proposed to replace existing limit
	NOx	0.55 lb/MMBtu (30-day rolling average)	0.46 lb/MMBtu (30-day rolling average) Proposed to replace existing limit

The intent of these new lower limits was to limit the potential to emit of post-change emissions at the Hunter plant so that there would be no significant increase in emissions.[31] However, there was an overarching flaw in the methodology relied on here to establish that there would be no significant increase in emissions as a result of these projects at the Hunter units. Specifically, the post-change potential to emit was compared to what appears to be an "allowable emissions" baseline rather than an actual baseline, which is legally erroneous and inconsistent with the Utah SIP approved at the time. The Hunter units' actual emissions before the projects were much lower than the "PSD baseline emission inventory" that was used in the PSD applicability determination relied on by UDEQ for the Hunter projects. This fundamental legal error resulted in UDEQ allowing these projects to go forward despite the fact that they triggered PSD and the requirement to apply BACT.

B. UDAQ's 1997 Approval Orders for the Hunter Plant

On November 20, 1997, UDAQ issued an Approval Order for the Hunter Plant. According to the abstract, the Approval Order was to consolidate all three Hunter Power plant units into one permit and to establish enforceable limits on potential to emit to demonstrate that the "consolidation will not exceed the Prevention of Significant Deterioration (PSD) baseline emissions inventory."[32] Although the permit did not clearly identify all of the limitations that were being relied on to limit potential to emit of the Hunter units as is discussed further below, Condition 5 of the permit included new limitations on particulate matter, SO_2, and NOx that were identical to those requested by PacifiCorp in its August 18, 1997 Notice of Intent as presented in Table 3 above, except that the SO_2 and NOx limits for Units 1 and 2 identified in Table 3 above as 12-month average limits were imposed as 12-month rolling average limits.[33] The November 20, 1997 Approval Order also included a limit on the sulfur content of any coal burned to not exceed 1.0 pounds of sulfur per million BTU heat input.[34]

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[31] *Id.*, cover letter at 2 and Attachment at Table 5. (Ex. 8).
[32] *See* November 20, 1997 Approval Order DAQE-1099-97, at 2 under "Abstract." (Ex. 9).
[33] *Id.* at 3, Condition 5.
[34] *Id.* at 3, Condition 6.

On December 18, 1997, UDAQ issued a second Approval Order for the Hunter Plant.[35] It appears the only difference between the December and November Approval Orders is that the December 1997 Approval Order removed the limit on the sulfur content of any coal burned to not exceed 1.0 pounds of sulfur per million BTU heat input that had been in Condition 6 of the November 20, 1997 Approval Order. According to a May 3, 2005 letter that is in UDAQ's Hunter Title V Renewal Permit Record, the state administratively revoked the November 20, 1997 Approval Order on May 3, 2005.[36]

The 1997 Approval Orders indicated that the "total emissions from the consolidated source (all three Hunter units) will decrease as follows: PM10: -112, NOx -8551, SO_2 -679, CO -1063, VOC – 632 (all numbers are in tons per year)."[37] However, this permit did not result in any reduction of actual emissions. The 1997 Approval Orders did not even ensure a reduction in allowable emissions for all pollutants at all units as will be discussed further below. As will be shown in the next section, the Hunter projects completed in the 1997-1999 timeframe should have been projected to result in significant net emissions increases of all PSD pollutants at each of the Hunter units.

C. The Projects Completed at All Three of the Hunter Units Between 1997 and 1999 Should Have Been Subject to PSD Permitting Requirements Including Best Available Control Technology (BACT) for all PSD Pollutants

The projects identified by PacifiCorp in its August 18, 1997 NOI and which were completed between 1997 to 1999 at all three of the Hunter units should have been subject to PSD permitting requirements as major modifications.

1. Applicable PSD Permitting Requirements of the Utah State Implementation Plan (SIP)

EPA promulgated PSD permitting regulations in 1978.[38] The 1980 regulations were comprised of two basic components. First, at 40 C.F.R. § 51.24, EPA provided the minimum standards for states who choose to design their own PSD programs. These regulations were later recodified at 40 C.F.R. § 51.166. Second, at 40 C.F.R. § 52.21 (1980), EPA established a federal PSD permitting program and incorporated the federal program directly into the states' implementation plans, which would be applicable in states until each state adopted PSD regulations and received approval from EPA of such PSD regulations as part of each state's SIP.[39] States can choose to implement the federal PSD rules through a delegation agreement with EPA or states can implement their own PSD permitting programs by adopting PSD regulations and obtaining EPA approval of such regulations as part of their respective SIPs.

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[35] *See* December 18, 1997 Approval Order DAQE-1189-97 (Ex. 3).
[36] *See* May 3, 2005 letter from Richard W. Sprott, Utah Air Quality Board, to Mark Mansfield, Hunter Plant Managing Director (Ex. 11).
[37] *See* December 18, 1997 Approval Order DAQE-1189-97 at 2 (Ex. 10).
[38] 45 Fed. Reg. 52676 (Aug. 7, 1980): 40 C.F.R. §§ 51.24, 52.21 (1978). In response to a remand in *Alabama Power Co. v. Costle*, 636 F. 2d 323 (D.C. Cir. 1979), EPA significantly revised those PSD permitting regulations in 1980.
[39] 45 Fed. Reg. 52676 (Aug. 7, 1980). *See* 40 C.F.R. § 52.2320(c)(10).

Utah chose the latter option, and obtained approval from EPA to implement a PSD permitting program as part of the Utah SIP on February 12, 1982.[40]

a. Applicability Test under Utah's PSD Regulations in the SIP at the Time the Hunter Projects Were Performed

The PSD regulations in effect under the Utah state implementation plan (SIP) at the time of the Hunter projects completed in 1997 to 1999 were based on the same applicability test set forth in the 1980 federal PSD regulations. That is, PSD applicability was based on an analysis of actual emissions prior to the projects to potential to emit after the projects. *See* definitions of "major modification," "net emissions increase," and "actual emissions" in Utah Air Conservation Regulation (UACR) R307-1-1 (1995).[41] Although EPA adopted revised rules for PSD applicability at electric utility steam generating units as revisions to the federal PSD rules in 1992, Utah did not adopt those rule changes until July of 2001.[42] Those regulatory changes were not submitted to EPA until November 2001, and EPA did not approve those Utah regulatory revisions and some additional 2003 permitting revisions until August 19, 2004.[43]

Specifically, under the applicable PSD rules in the Utah SIP at the time of the Hunter projects completed in 1997 to 1999, a "major modification" is "any physical change or change in the method of operation of a major source that would result in a significant net emissions increase of any pollutant."[44] Whether a project results in a significant "net emissions increase" is determined by calculating the "increase in actual emissions" based on the different definitions of "actual emissions" for pre-project and post-project periods.[45] Once the "increase in actual emissions" is calculated for a project, it is compared to the emission thresholds defined under the definition of "significant" in UACR R307-1-1 (1995).[46]

"Actual emissions" were defined under the Utah SIP at the time of Hunter projects as follows:

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[40] Utah State Implementation Plan, Section VIII Prevention of Significant Deterioration, subsection A.1.

[41] It is difficult to re-create the EPA-approved SIP at the time of the 1997 NOI for the Hunter plant, because the Utah air permitting rules have been recodified since that time and the PSD rules have been significantly revised. The EPA does not have the older versions of the SIP-approved on its SIP website. However, we know that in 1994, EPA approved the entire Utah Air Conservation Regulations as in effect January 27, 1992 (*see* 40 C.F.R. § 52.2320(c)(25)(i)(A); 59 Fed. Reg. 35,036 (July 8, 1994)). Further, revisions to Utah's definitions and PSD provisions effective in 1994 were approved by EPA in 1995 (*see* 40 C.F.R. § 51.2320(c)(28)(i)(A) and (B), 60 Fed. Reg. 22,277 (May 5, 1995) and 40 C.F.R. § 51.2320(c)(31)(i)(A) and (B), 60 Fed. Reg. 55,792 (Nov. 3, 1995)). Since we were able to obtain the 1995 version of the rules in effect on 1/1/95 from Utah's Department of Administrative Services website, we are citing to this version of Utah's PSD rules as reflective of the PSD permitting requirements that were approved as part of the Utah SIP at the time of the Hunter 1997 NOI. A copy of Utah Air Conservation Rules R307-1 as in effect on 1/1/95 is attached as Ex. 12.

[42] 69 Fed. Reg. 51,368, 51,368-51,370 (Aug. 19, 2004).

[43] *Id.; see also* 40 C.F.R. § 52.2320(c)(58)(i)(A); Section VIIII.A.4. of the Utah State Implementation Plan.

[44] *See* Definition of "major modification" in UACR R307-1-1 (1995).

[45] 40 C.F.R. §§ 52.21(b)(3)(i), (b)(21) (1980); definitions of "net emissions increase" and "actual emissions" in UACR R R307-1-1 (1995).

[46] *See also* 40 C.F.R. § 52.21(b)(23) (1980).

1. In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the source actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operations. The Executive Secretary shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

2. The Executive Secretary may presume that source-specific allowable emissions for the source are equivalent to the actual emissions of the source.

3. For any source which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the source on that date.

See Definition of "Actual emissions" in UACR R307-1-1 (1995). This definition tracked the federal definition of "actual emissions" in the federal PSD regulations at 40 C.F.R. §52.21(b)(21) (1980).

According to EPA's interpretation of the PSD permitting regulations, the actual emissions before the change and after the change at an existing emissions unit are determined as follows:

> For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the change which resulted in the emissions increase. These emissions are calculated using the ***actual*** hours of operation, capacity, fuel combusted and other parameters which affected the unit's emissions over the 2-year averaging period. In certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level, the reviewing authority may presume that source-specific allowable emissions [or a fraction thereof] are equivalent to (and therefore are used in place of) actual emissions at the unit. For determining the difference in emissions from the change at the unit, emissions after the change are the potential to emit from the units.[47]

Under the PSD regulations in the Utah SIP at the time of the Hunter projects completed in 1997 to 1999, which reflected the EPA's 1980 PSD regulations, post-project emissions were

[47] EPA, New Source Review Workshop Manual, October 1990, at A.41, http://www2.epa.gov/nsr/nsr-workshop-manual-draft-october-1990; *see also* 45 Fed. Reg. 52,676, 52,699 and 52,718 (Aug. 7, 1980).

calculated differently than pre-project emissions because such emissions did not exist prior to the project -- which is the time the determination must be made regarding whether a project will result in an emissions increase. Thus, to account for post-project emissions, a regulatory presumption or projection of future emissions was required. EPA's definition of post-project "actual emissions" contained a presumption in 40 C.F.R. 51.21(b)(21)(iv) (1980) that post-project emissions would be the plant's maximum emissions, unless the plant accepted an enforceable limit to keep the emissions lower.[48] In other words, the potential-to-emit definition of "actual emissions" in 40 C.F.R. § 51.24(b)(21)(iv) is the appropriate projection of post-project emissions at a modified unit.[49] Over the years, EPA has confirmed and further explained that non-routine changes are subject to the actual-to-potential test because "normal operations" cannot be said to have "begun" prior to the project:

> [U]nder the current regulations, changes to a unit at a major stationary source that are non-routine or not subject to one of the other major source [PSD] exemptions are deemed to be of such significance that pre-change emissions for the affected units should not be relied on in projecting post-change emissions. For such units, "normal operations" are deemed not to have begun following the change, and are treated like new units. Put another way, the regulatory provision for units which have "not begun normal operations" reflects an initial presumption that a unit that has undergone a non-routine physical or operational change will operate at its full capacity year-round.[50]

In short, EPA's interpretation of its own 1980 regulations is that any modification that is not a "routine maintenance, repair and replacement" has not "beg[un] normal operations" for calculating post-project emissions and is subject to the actual-to-potential test.[51]

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[48] *See* 45 Fed. Reg. at 52,677 ("[T]he source owner must quantify the amount of the proposed emissions increase. ***This amount will generally be the potential to emit of the new or modified unit***.") (emphasis added).
[49] *Puerto Rican Cement Co. v. U.S. Envtl. Prot. Agency*, 889 F.2d 292, 297 (1st Cir. 1989) (citing 45 Fed. Reg. at 52,677 ("the expressed intent of the regulation's writers" was that the potential to emit should be used as the plant's post-project "actual" emissions)).
[50] 63 Fed. Reg. 39,857, 39,858 (July 24, 1998)*; see also* 56 Fed. Reg. 27,630, 27,633 (June 14, 1991) (explaining that the use of potential emissions is appropriate as a proxy because the pollution source's future emissions are "difficult to predict"). EPA has confirmed this in more recent guidance:

> [C]hanges to a unit that are not routine nor subject to one of the other [New Source Review, including Prevention of Significant Deterioration] exemptions are considered to be of such significance that pre-change emissions should not be relied on in projecting post-change emissions. For such units, "normal operations" refers to operations after the change, and are deemed not to have begun. The regulations initially presume that such units will operate year-round at full capacity, but a source owner is free to overcome the presumption by agreeing to limit its potential to emit to any level desired through enforceable restrictions on operations or the use of pollution controls. For example, if limiting the potential to emit results in an insignificant change in emissions. . . .

Detroit Edison Letter, Enclosure at 18 n.14 (May 23, 2000) ("Detroit Edison Letter") (Ex. 13).
[51] 45 Fed. Reg. at 52,677.

A facility's potential to emit is limited by both its design capacity and any federally and practically enforceable limitations on its potential to emit.[52] A facility can thus avoid the imposition of the PSD program requirements by seeking a limit on its permitted, or allowable, emissions through enforceable restrictions that effectively limit the post-project potential emissions of the facility.[53]

The "actual-to-potential" test was upheld by the First Circuit Court of Appeals as a controlling interpretation by EPA of its own regulations, consistent with their regulatory intent and reasonable, especially because future emissions are difficult to predict.[54] EPA's interpretation embodies an assumption that changed equipment "may lead the firm to decide to increase *the level of production*, with the result that, despite new machinery, overall emissions will increase."[55]

b. Routine Maintenance, Repair, and Replacement Exemption Under the Utah SIP and Federal PSD Permitting Regulations

The Utah PSD regulations and the federal PSD regulations include an exemption from PSD permitting for any projects that is routine maintenance, repair, and replacement (RMRR).[56] However, this exemption is exceedingly narrow.[57] To fall within this exception, the burden[58] is on the source to demonstrate that the project in question satisfies a rigorous four-factor test which assesses the nature and extent, purpose, frequency and cost of the work.[59] As stated in *Ohio Edison*, 276 F. Supp. 2d at 834:

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[52] 40 C.F.R. § 52.21(b)(4) (1980).

[53] *Puerto Rican Cement*, 889 F.2d at 297; 63 Fed. Reg. at 39,858; *see also* May 23, 2000 EPA Letter to Henry Nickel, Counsel for Detroit Edison Company, at 18, n. 14 (an owner can avoid the actual-to-potential test by accepting an emission limit) (Ex. 13).

[54] *Puerto Rican Cement*, 889 F.2d at 296-99 (citing the 1980 preamble and holding that "EPA's application of its [actual-to-potential] regulation to the facts of this case complies with the expressed intent of the regulation's writers.") (quoting *Udall v. Tallman*, 380 U.S. 1, 16-17 (1965) (quoting *Bowles v. Seminole Rock & Sand Co*., 325 U.S. 410, 414 (1945)).

[55] *Id*. at 297 (emphasis original).

[56] Definition of "major modification" in UACR R R307-1-1(1) (1995); 40 C.F.R. § 52.21(b)(3) (iii)(a) (1980).

[57] *United States v. So. Ind. Gas & Elec. Co.*, 245 F. Supp. 2d 994, 1009 (S.D. Ind. 2003) ("Giving the routine maintenance exemption a broad reading could postpone the application of NSR to many facilities, and would flout the Congressional intent evinced by the broad definition of medication."). EPA's 1988 Clay Memo at 3 reinforces the narrow scope of the routine maintenance exception, stating: "[t]he clear intent of the PSD regulations is to construe the term "physical change" ***very broadly***, to cover ***virtually any significant alteration*** to an existing plant. This wide reach is demonstrated by the ***very narrow*** exclusion provided in the regulations." (emphasis added).

[58] Similarly, through the permitting application process, the owners and operators of the Hunter Plant had the burden of asserting and proving that the routine maintenance exemption applied to the projects in question and of providing the documentation necessary to support such an exemption. *United States v. Cinergy*, 2006 WL 372726, at *4 (S.D. Ind. Feb. 16, 2006) ("The party claiming the benefit of an exemption to compliance with a statute bears the burden of proof as to the exemption.") (citing *United States v. First City Nat'l Bank of Houston*, 386 U.S. 361, 366 (1967)); *Ohio Edison*, 276 F. Supp. 2d, 829, 856 (S.D. Ohio 2003); *Sierra Club v. Morgan*, No. 07-C-251-S 2007 U.S. Dist. LEXIS 82760, at *34 (W.D. Wis. 2007); *Nat'l Parks Conservation Ass'n v. TVA*, 618 F. Supp. 2d 815, 824 (E.D. Tenn. 2009) ("Defendant TVA bears the burden of proof as to the applicability of the RMRR exception in this case."); *United States v. E. Ky. Power Coop., Inc.*, 498 F. Supp. 2d 976, 995 (E.D. Ky. 2007). *See also* 40 C.F.R. § 70.5(c)(6). As discussed below, they failed to make any showing on this critical issue.

[59] *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d, 901, 910 (7th Cir. 1990) (quoting September 9, 1988 Memorandum from Don R. Clay, USEPA, to David A. Kee, "Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the WEPCO Power Company Port Washington Life

> Routine maintenance, repair, and replacement occurs regularly, involves no permanent improvements, is typically limited in expense, is usually performed in large plants by in-house employees, and is treated for accounting purposes as an expense. In contrast to routine maintenance stand capital improvements which generally involve more expense, are large in scope, often involve outside contractors, involve an increase of value to the unit, are usually not undertaken with regular frequency, and are treated for accounting purposes as capital expenditures on the balance sheet.[60]

2. Review of Hunter Projects Completed in 1996-1999 for PSD Applicability

a. The Projects at the Hunter Units were Non-Routine

PacifiCorp did not claim that any of the projects at the Hunter Plant were routine maintenance, repair, or replacement in its August 18, 1997 NOI. As stated above, PacifiCorp stated to UDAQ that the projects at the Hunter plant outlined in the company's August 18, 1997 Notice of Intent, and repeated in Table 1 above, "may increase the actual capacity and capacity utilization of the boilers."[61] With respect to Hunter Unit 3, PacifiCorp stated that "[r]educed short term limits for the Unit 3 boiler are requested, because the physical changes to this boiler have the potential to increase the short-term emission rates."[62] Projects that increase efficiency (which typically leads to increased capacity utilization) or that increase capacity are not considered to be routine maintenance, repair, or replacement.[63]

Turbine projects and turbine upgrades that do not reflect so called "like-kind" routine replacements have not been considered to be routine maintenance, repair, or replacement.[64] Thus, the turbine changes at Hunter Units 1 and 2 which consisted of a new ruggedized rotor design would not be considered routine replacement, nor would the turbine changes including a new aeroderivative design at Hunter Unit 3 be considered by EPA to be a routine replacement. Further, the replacement of air heater elements, such as that replaced at Hunter Units 1 and 2,

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Extension Project.") (1988 Clay Memo) (Ex. 14); *Cinergy*, 2006 WL 372726, at *4 (S.D. Ind. Feb. 16, 2006) ("The party claiming the benefit of an exemption to compliance with a statute bears the burden of proof as to the exemption.") (citing *First City Nat'l Bank of Houston*, 386 U.S. at 366); *Ohio Edison*, 276 F. Supp. 2d at 856; *Morgan,* No. 07-C-251-S 2007 U.S. Dist. LEXIS 82760, at *34; *Nat'l Parks Conservation Ass'n*, 618 F. Supp. 2d at 824 ("Defendant TVA bears the burden of proof as to the applicability of the RMRR exception in this case."); *E. Ky. Power Coop., Inc*., 498 F. Supp. 2d 976, 995 (E.D. Ky. 2007).

[60] *Ohio Edison*, 276 F. Supp. 2d at 834 (citations omitted).

[61] August 18, 1997 Notice of Intent at 1. (Ex. 8).

[62] *Id.* at 2.

[63] *See, e.g.*, May 23, 2000 letter from EPA to Henry Nickel regarding a turbine upgrade at Detroit Edison's Monroe power plant (Ex. 13.

[64] *Id. See also* April 17, 2001 letter from EPA Region VIII to North Dakota Health Department, re Otter Tail Power Company's Coyote Station Low Pressure Rotor Upgrade Proposal (Ex. 15).

often improves the efficiency of the boiler[65], and EPA has thus not considered such replacements to be routine.[66]

EPA has also found that the addition of pressure parts not previously included in a boiler, such as to increase the superheater surface area of a boiler, was not routine maintenance, repair, or replacement.[67] Thus, the changes at Hunter Unit 3 to add riser and supply tubes and resize cold reheat safety valves would not be considered to be routine by EPA, nor would the projects to add superheater surface area at Hunter Units 1 and 2 be considered to be routine.

Further, physical changes that could increase coal burning capacity also are not considered to be routine maintenance, repair, or replacement. Such physical changes could include, but are not limited to, boiler modifications that allow the boiler to produce more steam such as addition of surface area to superheater (which typically will require more coal to be burned), changes to the turbine to allow for more steam flow and debottleneck the boiler, or changes to coal pulverizers and mills. For example, the retrofit of rotating classifiers on coal mills, such as was planned for Hunter Units 1, 2 and 3, may be utilized for additional coal flow.[68]

In addition, replacement of a major boiler component such as the finishing superheater as was apparently done at Hunter Unit 3[69] has not been considered to be a routine replacement because, among other reasons, including cost and extent of such a replacement, it is not a frequent occurrence at an electrical generating unit. EPA has not considered boiler component replacements that are intended to bring a boiler back to operations at design conditions to be routine maintenance, repair, or replacement.[70]

Moreover, EPA views equipment replacements/modifications being done concurrently in their entirety when evaluating whether such projects are routine maintenance, repair, or replacement. For example, EPA determined that the following projects at the No. 1 Recovery Furnace at the Packaging Corporation of America pulp and paper mill in Valdosta, Georgia were not routine maintenance, repair, or replacement:

(1) Replacement of water tubes in lower furnace walls from mid-wall headers to the bottom, including the floor tube section;

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[65] *See*, e.g., Kitto, Jr., J.B. et al, Upgrades and Enhancements for Competitive Coal-Fired Boiler Systems, at p. 7 (Ex. 16).

[66] *See* February 15, 1989 letter from EPA to WEPCO (Ex. 17), at 5-8; *see also* September 13, 2000 EPA Region IV letter to Georgia Environmental Protection Division re No. 1 Recovery Furnace Maintenance, Repair and Replacement Project, PCA Pulp and Paper Mill, Valdosta, Georgia (Ex. 18).

[67] *See* August 18, 1975 EPA Region X Memo re "Request of Ruling Regarding Modification of Weyerhaeuser's Springfield Operations," cited to in May 23, 2000 Detroit Edison memo, enclosure at 10 (Ex. 13).

[68] *See* Babcock&Wilcox, DSVS® Rotating Classifier, Improves pulverizer efficiency and operational flexibility, Ex. 19.

[69] PacifiCorp's August 1997 NOI indicates that replacement of the Unit 3 superheater outlet bank and manifolds was being done (see Table 1 of August 18, 1997 NOI, Ex. 8), and PacifiCorp's March 21, 1995 letter to UDAQ indicates the finishing superheater was being replaced "to reduce its pressure drop to maintain design drum pressure" (March 21, 1995 letter (Ex. 20) at 1).

[70] *See* November 5, 2001 EPA Region 10 letter to Washington Department of Ecology, re Recovery Furnace Modifications at Longview Fibre, Longview Mill and Boise Cascade Corporation, Wallula Mill (Ex. 21).

(2) Replacement of water tubes in upper furnace walls, including the roof tube section;

(3) Removal and replacement of outer casing, insulation and brick work (for access) from lower furnace to economizer outlet;

(4) Replacement of economizer casing, lagging and insulation;

(5) Replacement of dissolving tank shell after removal of existing tank shell for access;

(6) Annual inspection and repair, including tube thickness testing in the balance of the furnace, and inspection and repair as necessary of the electrostatic precipitator, air heater, liquor heater, cascade, auxiliary equipment and ductwork; and

(7) Removal of insulation and lagging on electrostatic penthouse for inspection, with repair as necessary.[71]

EPA determined, based on a review of the nature, extent, and frequency of the proposed work, that the collective project was not routine.

In the case of the projects at Hunter Units 1, 2 and 3, PacifiCorp stated in its August 18, 1997 NOI that, although "[m]any of the projects, in and of themselves, could not cause an increase in emissions...as a whole, the upgrades may increase the actual capacity and capacity utilization of the boilers."[72] Thus, PacifiCorp aggregated the projects at Hunter Unit 1, 2, and 3 in its 1997 NOI, which is required under the PSD regulations when such changes taken together are sufficiently related to be considered a single project.[73] Given that the projects as a whole could increase capacity and capacity utilization of Hunter Units 1, 2 and 3, the projects could not reasonably be considered to be routine maintenance, repair, or replacement under EPA's four factor analysis.

b. Determination of the Actual Emissions Baseline for Each Hunter Unit Prior to the Projects Shows the Baseline Emissions Were Much Lower than the "PSD Baseline Emission Inventory" Relied on by PacifiCorp to Show There Would be No Significant Emissions Increase As a Result of the Hunter Projects

As previously stated, UDAQ relied on PacifiCorp's "PSD Baseline Emission Inventory" to reflect emissions of each Hunter unit prior to the projects. It appears that PacifiCorp used a baseline that reflected what EPA considered to be allowable emissions at the time it issued a

[71] *See* September 13, 2000 EPA Region 4 Letter to Georgia Environmental Protection Division, re No. 1 Recovery Furnace Maintenance, Repair and Replacement Project PCA Pulp and Paper Mill, at 1-2 (Ex. 22).

[72] *See* August 18, 1997 NOI for Hunter Plant at 1 (Ex. 8).

[73] In determining whether projects should aggregated, EPA looks at whether projects are being done at the same time or within a short period of time, statements made by the source owners regarding plans for operation after the projects, the economic realities of projects considered together, among other things. *See* June 17, 1993 EPA Memo with Subject "Applicability of New Source Review Circumvention Guidance to 3M –Maplewood, Minnesota. (Ex. 23).

PSD permit for Hunter Units 3 and 4.[74] Instead, the applicable regulations required that baseline emissions be determined based on actual emissions from the Hunter units.

<u>Determination of Actual Emissions of the Hunter Plant Prior to the Project – Baseline Period</u>

With respect to determining baseline emissions, actual emissions are defined in pertinent part as follows:

> In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the source actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operations. The Executive Secretary shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the source's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

Definition of "actual emissions" in UACR 307-1-1 (1).[75] Thus, baseline emissions before a change must reflect the annual average actual emissions based on the two year prior to a project, unless a permitting authority determines that a different timeframe is more representative of normal source operations.

In 1992, EPA adopted a new presumption that would apply only for electric utility steam generating units that any two-year baseline period in the five-year period before a project is presumed to be representative of normal source operation.[76] Although it is not clear whether UDAQ followed this presumption in 1997 at the time the Hunter projects were permitted, Sierra Club evaluated the 5 years of data prior to the November 1997 issuance of the Approval Order authorizing the Hunter projects.

During part of the 5-year period prior to the Hunter projects, there was continuous emission monitoring system (CEMS) data available for SO_2 and NOx at the Hunter units. Such monitoring data is reported to the EPA's Acid Rain Database and is available to the public for the years 1995 to the present.[77] However, with the exception of NOx emission rates in lb/MMBtu, we did not use this CEM data for our baseline emission calculations for the following reasons:

(1) There was not five years of emissions data available before the Hunter projects;

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[74] *See* August 18, 1997 NOI (Ex. 8) at 1, Attachment, Table Entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: EPA Baseline Emissions." Note that while Unit 4 was originally proposed and permitted along with Hunter Unit 3, Unit 4 was never built.
[75] *See also* 40 C.F.R. § 52.21(b)(21)(ii) (1980).
[76] 57 Fed. Reg. 32,314, 32,323 (July 21, 1992).
[77] *See* EPA's Clean Air Markets Database at http://ampd.epa.gov/ampd/.

(2) Monthly data was not available in the EPA Air Markets Program Database (AMPD) to calculate rolling 24-month annual average baseline emissions;

(3) Data for heat input and ton per year emissions from the mid- to late-1990's were known to have a bias due to inaccurate flow measurements and EPA did not propose possible fixes for the bias until mid-1999;[78] and

(4) Emissions reported to the acid rain database during periods of missing CEM data are sometimes biased high, due to acid rain requirements for addressing missing data.

Nonetheless, we do note that such data was also available to PacifiCorp and UDAQ, and a review of the SO_2 and NOx emissions data reported to EPA's acid rain database for the Hunter units during 1995, 1996 and 1997 shows emissions of SO_2 and NOx that are lower than that assumed by PacifiCorp in its "PSD Baseline Emissions Inventory," as reflected in Ex. 27.[79]

The biases in the EPA acid rain emissions data were well-known in the industry, including for the Hunter Power Plant units. In fact, the Western Regional Air Partnership (WRAP) acknowledged that the Hunter Plant's CEM data was biased high in its Annex report for the Western Backstop Trading Program, and indicated that "compliance measurements for future milestone will be made with CEMs that have less bias than those used in the 1999 inventory."[80] Thus, the WRAP applied adjustment factors to account for the CEMs bias for comparison with the 1999 baseline year of the Western Backstop Trading Program.[81] In its 2004 Regional SO_2 Emissions and Milestone Report, the WRAP increased the 5,726 tons of SO_2 emissions for the Hunter Plant that had been reported to the acid rain database for 2004 by 866 tons for comparison to the 1999 baseline inventory that had been biased high due to the CEMs measuring techniques at that time.[82] Based on the information in the WRAP's 2004 milestone report, it is clear that PacifiCorp had changed the flow monitoring method by (or before) 2004, but it is not clear when such changes were made (except for being after 1999).

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[78] *See*, *e.g.*, RMB Consulting & Research, Inc., The Electric Power Research Institute Continuous Emissions Monitoring Heat Rate Discrepancy Project, What Has Been Learned and Future Activities, Presented at the 1997 EPRI CEM Users Group Meeting, Denver, CO, May 14-16, 1997 (Ex. 24); December 1996, RMB Consulting & Research, Inc., The Electric Power Research Institute Continuous Emissions Monitoring Heat Rate Discrepancy Project, An Update Report – December 1996 (Ex. 25); 64 Fed. Reg. 26484 (May 14, 1999); U.S. EPA, August 26, 1999, Approval of New Testing Procedures for Measurement of Stack Gas Flow Rate for Optional Application in Place of Method 2 under 40 CFR Parts 60, 61, and 63 (Ex. 26).

[79] It must be noted that Utah has recognized a bias in the 1990's CEM SO_2 data. Specifically, in evaluating compliance with the regional SO2 emissions for the Western Backstop Emissions Trading Program, the Western Regional Air Partnership (WRAP) included adjustments for the 2004 SO2 emissions at the Hunter Plant, increasing the reported SO_2 emissions for 2004 of 5,726 tpy by 15% due to the change in flow measurements. This adjustment was necessary because the original milestones of the Western Backstop Trading Program were based on SO2 data collected in the 1990's which was known to be biased high due to the faulty flow measurements. *See* March 31, 2006 WRAP Report, 2004 Regional SO_2 Emissions and Milestone Report, at 4-5 (Ex. 28).

[80] *See* Western Regional Air Partnership, Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program, An Annex Report to the Report of the Grand Canyon Visibility Transport Commission, submitted to the U.S. Environmental Protection Agency September 29, 2000, Appendix C at C-8 (Ex. 29).

[81] *Id.*

[82] *See* Western Regional Air Partnership, 2004 Regional SO_2 Emissions and Milestone Report, March 31, 2006, at 5-6, see also Table A-1 (Ex. 28).

Due to the biases in the mid-1990's CEMs emissions and heat input data along with the fact that there were not five years of data from prior to the 1997 NOI, Sierra Club used data from the Energy Information Administration and emission factors that reflected the effects of pollution controls in calculating baseline emissions for the Hunter units, with one exception. We did use the lb/MMBtu NOx emission rates reported to AMPD for 1995 – 1997, along with heat input calculated by EIA data on tons of coal burned and heat value, to estimate pre-project NOx emissions. Although the inaccuracies in the flow measurements in the 1990's CEM data resulted in overstatement of mass emissions of SO_2 and NOx as well as in the hourly heat input, the flow measurements cancel out in the calculation of lb/MMBtu emission rates.[83]

Baseline Emission Factors

To determine actual emissions before the projects, Sierra Club calculated actual emissions before the Hunter projects using actual coal throughput data and heat input for each unit as reported to the Energy Information Administration and emission factors based on the following assumptions:

(1) Uncontrolled filterable particulate emission factor based on the coal, heat value, and ash content reported to the Energy Information Administration[84] and AP-42 emission factors for PC-fired, dry-bottom, tangentially-fired boilers – *i.e.*, 10 x ash content lb of filterable PM per ton of coal. AP-42, Table 1.1-4. Assumed 99.5% control efficiency of ESPs at Units 1 and 2 and 99.7% control efficiency of baghouse at Unit 3, per PacifiCorp's 1997 NOI.[85]

(2) For Units 1 and 2 with ESPs, filterable PM10 emissions were assumed to be controlled by 67% of filterable total particulate, pursuant to AP-42, Table 1.1-6. For Unit 3 with a baghouse, filterable PM10 emissions were assumed to be controlled by 92% of filterable total particulate, pursuant to AP-42, Table 1.1-6. Condensable PM10 emissions were based on 0.02 lb/MMBtu, the AP-42 emission factor for all PC-fired boilers with PM controls and an FGD control. AP-42, Table 1.1-5. Total PM10 was based on the sum of filterable PM10 plus condensable PM10.

(3) SO_2 emission factors were based on sulfur and heat content of the coal and an assumed 80% control efficiency for Units 1 and 2 and an assumed 90% control

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[83] NOx mass rate (lb/hr) = conversion constant * hourly average NOx concentration (ppmv) * hourly average volumetric flow rate (scfh) * moisture correction term.
Heat input (mmBtu/hr) = (the hourly average volumetric flow rate * a moisture correction term)/(Fuel specific F factor * Diluent gas correction term).
lb/MMBtu = NOx mass rate (lb/hr)/Heat input (MMBtu/hr)
Since the hourly average volumetric flow rate is in both the numerator and denominator, the units cancel out.
See U.S. EPA, Plain English Guide to the Part 75 Rule, June 2009, at Table 6,
http://www2.epa.gov/sites/production/files/2015-05/documents/plain_english_guide_to_the_part_75_rule.pdf.

[84] Data reported to Energy Information Administration in Form EIA-767,
http://www.eia.gov/electricity/data/eia767/.

[85] *See* August 18, 1997 NOI (Ex. 8), Attachment, tables entitled "Emission Inventory Calculation Sheet", for Hunter Plant Steam Generating Units 1, 2, and 2, EPA Baseline Emissions, Emission Factor Equation for TSP.

efficiency for Unit 3. The permit conditions that existed at the time of the August 1997 NOI required the 80% control efficiency at Hunter Units 1 and 2 to be determined from the "potential combustion concentration ...that would result from combustion of the raw coal being fired without an emissions control system."[86] Thus, for Units 1 and 2, we used AP-42 emission factors for bituminous coal combustion (*i.e.*, 38 multiplied by actual sulfur content of coal for each month) to reflect the potential combustion concentration, and then assumed 80% reduction from that level. However, for Hunter Unit 3, the permit in effective at the time of the 1997 NOI provided that the 90% removal requirement would apply to the total available sulfur from the coal analysis, and should reflect "overall sulfur removal including that removed by FGD units, bottom ash, flyash, and coal treating."[87]

(4) NOx emission factors were based on the annual average NOx rates reported to EPA's Clean Air Markets Database as follows: For the years 1995, 1996, and 1997, we used the annual average NOx rate reported to EPA's Clean Air Markets Database for each unit. For 1992 (Nov – Dec), 1993, and 1994, we used the highest NOx rate from EPA's Clean Air Markets Database for each unit over 1995 – 1997 to conservatively estimate baseline emissions for those years (*i.e.*, 0.44 lb/MMBtu for Units 1 and 2, and 0.41 lb/MMBtu for Unit 3).

(5) CO emission factors based on AP-42 for bituminous coal combustion – 0.5 lb CO per ton of coal burned. AP-42, Table 1.1-3.

Using these emission factors and the monthly tons of coal burned and heat input for each unit reported to the Energy Information Administration, we determined annual average emissions for the Hunter Plant for every 24-month period between November 1992 and October 1997. We determined total annual average emissions from the Hunter Units 1-3 combined and determined that the 24-month period ended November 1995 had the highest total SO_2, NOx, and CO emissions. As shown in Table 5 below, the total emissions for Hunter Units 1-3 during this baseline period are much lower than the "PSD Baseline Emissions Inventory" relied upon by PacifiCorp in its 1997 NOI.

Although not allowed by the Utah PSD regulations in effect at the time of the 1997 Hunter projects,[88] we also determined the maximum 24-month annual average emissions of each pollutant at each Hunter unit over the five years before the projects in order to compare those emissions to the PSD Baseline Emissions Inventory relied upon by PacifiCorp in its 1997 NOI and apparently relied upon by UDAQ in its 1997 Approval Order. Table 4 below provides a comparison of this unit-specific and pollutant-specific maximum baseline out of the 5 years before the Hunter projects.

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[86] *See* April 3, 1986 Approval Order for Hunter Unit 1, Condition 2.B. (Ex. 30); and July 27, 1987 Approval Order for Hunter Unit 2, Condition 2.B (Ex. 31).

[87] *See* August 31, 1983 Approval Order for Hunter Unit 3, Condition 2.B. and C (Ex. 31).

[88] The federal PSD rules did not allow for different 24-month baseline periods to be used for different pollutants and separate units at the same source until rule revisions that were promulgated on December 31, 2002. 67 Fed.Reg. 80186-80189 (Dec. 31, 2002): definition of "Baseline actual emissions" in 40 C.F.R. § 52.21(b)(47). Utah did not adopt the December 31, 2002 PSD rule changes until 2007, and EPA did not approve these revised rules including the new definition of "baseline actual emissions" into the Utah SIP until 2011 (76 Fed.Reg. 41712 (July 15, 2011)).

Table 4. Comparison of PacifiCorp's PSD Baseline Emissions Inventory of its 8/18/97 NOI to Highest Annual Average (24-Month) Actual Emissions at Hunter Units 1-3 Between November 1992 and October 1997

PacifiCorp's PSD Baseline Emissions Inventory[89]					
Hunter Unit	**TSP (PM), tons/year**	**Filterable PM10[90], tons/year**	**SO_2, tons/year**	**NOx, tons/year**	**CO, tons/year**
1	893	598	4,373	12,755	789
2	893	598	4,373	12,755	789
3	547	503	2,186	10,021	789
Total Units 1-3	*2,333*	*1,699*	*10.932*	*35,531*	*2,367*
Actual Emissions for Hunter Units 1-3 For 24-month Period Ending November 1995[91]					
	TSP (PM), tons/year	**Filterable PM10[92], tons/year**	**SO_2, tons/year**	**NOx, tons/year**	**CO, tons/year**
Total Units 1-3	1,187	867	7,019	20,955	1,084
Max 24-Month Annual Avg Emissions for Each Pollutant at Each Hunter Unit Over 5-Year Period of November 1992 through October 1997					
Hunter Unit	**TSP (PM), tons/year**	**Filterable PM10[93], tons/year**	**SO_2, tons/year**	**NOx, tons/year**	**CO, tons/year**

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89 August 18, 1997 NOI, Attachments at Table 2. (Ex. 8). Note that it appears that UDAQ has relied on PacifiCorp's baseline inventory in its analysis of emission changes for its November 20, 1997 and December 18, 1997 Approval Orders.

90 PacifiCorp only accounted for filterable PM10 emissions in its "PSD Baseline Emissions Inventory." This is evident by reviewing the Emission Inventory Calculation Sheets for Hunter Steam Generating Units 1, 2, and 3, attached to the August 18, 1997 NOI (Ex. 8). TSP is only filterable particulate matter and does not include condensable particulate matter. *See* definition of "Total Suspended Particulate" in R307-1-1 of the Utah SIP (1995). (Ex. 12). PacifiCorp calculated PM10 emissions based on the assumption that PM10 is 67% of the TSP value for Hunter Units 1 and 2 (equipped with ESPs) and that PM10 is 92% of the TSP value for Unit 3 (equipped with baghouse). *See* the Emission Inventory Calculation Sheets for Hunter Steam Generating Units 1, 2, and 3, attached to the August 18, 1997 NOI (Ex. 8). Thus, PacifiCorp's PM10 emissions only reflect filterable PM10 and fail to reflect total PM10 (*i.e.*, including condensable PM10).

91 *See* Spreadsheet "Hunter Projects 1997-99 Emission Calculations (Ex. 32).

92 Although PSD applicability should be based on total PM10 (filterable PM10 plus condensable PM10), only filterable PM10 is presented here for comparison to PacifiCorp's PSD Baseline Inventory and also to its future potential emissions calculations.

93 PacifiCorp only accounted for filterable PM10 emissions in its "PSD Baseline Emissions Inventory." This is evident by reviewing the Emission Inventory Calculation Sheets for Hunter Steam Generating Units 1, 2, and 3,

1 [94]	505	338	2,956	7,524	379
2 [95]	446	299	2,704	6,922	355
3 [96]	291	268	1,534	6,724	374

As Table 4 demonstrates, PacifiCorp's use of the "PSD Baseline Emissions Inventory" greatly overstated the actual emissions of the Hunter units before the Hunter projects. In fact, in reviewing the Emissions Inventory Calculation Sheets for what is labeled "EPA Baseline Emissions," it is clear that PacifiCorp used "Permitted Allowables" (with one significant exception discussed in Section I.C.3. below) for PM (TSP), SO_2, and NOx, assumed a coal consumption rate that was based on an entirely unrealistic 100% capacity factor at 400 MW net, and assumed operation at 8,760 hours per year (every hour of the year).[97] Apparently, PacifiCorp used a baseline akin to allowable emissions in determining emissions prior to the Hunter projects completed in 1997-1999. As discussed above, EPA only allows the use of an allowable emissions baseline when data is not available to determine pre-project emissions and when the reviewing authority has reason to believe the source is emitting at or near its allowable emissions.[98] Data was available to calculate pre-project emissions, as evidenced by Sierra Club's ability to use data reported by the owners of the Hunter Plant to the Energy Information Administration and AP-42 emission factors to determine baseline emissions.

In summary, there was no justification for PacifiCorp or UDAQ to use an allowable emissions baseline for evaluating applicability to PSD for the projects at the Hunter Plant completed in 1995 to 1997. PacifiCorp's baseline inventory was unreasonably inflated above actual emissions of the Hunter units. For the purpose of the rest of this comment, Sierra Club will treat Units 1-3's total annual average actual emissions for the 24-month period ending November 1995 as representing the proper baseline emissions for the Hunter projects that were completed in the 1997-1999 timeframe.

c. Determination of Post-Project Emissions from the Projects Completed at the Hunter Units from 1997-1999

As discussed in Section I.C.1.A above, the applicable requirements of the Utah SIP at the time of the Hunter Plant projects completed in 1997 to 1999 was the actual-to-potential emissions test. The definitions of "major modification," "net emissions increase," and "actual emissions" in R307-1-1 of the Utah SIP in effect at the time of the Hunter projects were identical

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attached to the August 18, 1997 NOI (Ex. 8). TSP is only filterable particulate matter, and does not include condensable particulate matter. *See* definition of "Total Suspended Particulate" in R307-1-1 of the Utah SIP (1995). (Ex. 12). PacifiCorp calculated PM10 emissions based on the assumption that PM10 is 67% of the TSP value for Hunter Units 1 and 2 (equipped with ESPs) and that PM10 is 92% of the TSP value for Unit 3 (equipped with baghouse). *See* the Emission Inventory Calculation Sheets for Hunter Steam Generating Units 1, 2, and 3, attached to the August 18, 1997 NOI (Ex. 8). Thus, PacifiCorp's PM10 emissions only reflect filterable PM10 and fail to reflect total PM10 (*i.e.*, including condensable PM10).

[94] Spreadsheet, "Hunter Projects 1997-99 Emission Calculations," Hunter 1 Baseline tab, Row 63 (Ex. 24).

[95] *Id.,* Hunter 2 Baseline tab, Row 63 (Ex. 32).

[96] *Id.,* Hunter 3 Baseline tab, Row 63 (Ex. 32).

[97] *See* Emission Inventory Calculation Sheets for Hunter Steam Generating Units 1, 2, and 3 for the Year "EPA Baseline Emissions," attached to the August 18, 1997 NOI (Ex. 8).

[98] *See* EPA, New Source Review Workshop Manual, October 1990, at A.41*; see also* 45 Fed. Reg. 52676, 52699 and 52718 (August 7, 1980).

to EPA's 1980 definitions, and thus EPA's interpretation that the actual-to-potential test applies to non-routine physical and/or operational changes applies to the Hunter projects.[99]

Moreover, the modifications at the Hunter units were so significant, neither PacifiCorp nor UDAQ could argue that normal operations of the modified units had already begun. Many of the modifications were clearly not like-kind replacements, and the modifications were expected to both increase capacity and capacity utilization of the units.[100] Thus, applicability to PSD permitting for the Hunter projects completed in 1997-1999 must be based on potential to emit emissions post-change.

As discussed above, potential to emit is based on the maximum capacity of the source to emit a pollutant under its physical and operational design, taking into account enforceable restrictions on the capacity of the source to emit a pollutant including pollution controls and limitations on hours of operation, types of fuels combusted, etc.[101]

(1) Determination of Post Change Emissions Using PacifiCorp's Evaluation of Post-Change Potential to Emit

In its August 1997 NOI, PacifiCorp requested new emission limits on SO_2, NOx, and PM to limit potential to emit of these pollutants from Hunter Units 1, 2, and 3.[102] *See* Table 3 above for the requested new emission limits. These emission limits were ultimately imposed in the November 20, 1997 and December 18, 1997 Approval Orders issued by UDAQ.[103] Table 5 below shows PacifiCorp's potential to emit projections from its August 1997 NOI based in part on the requested emission limits. It appears that UDAQ agreed with these potential emission calculations as well as with PacifiCorp's baseline emissions, because the 1997 Approval Orders show the same decrease in emissions as shown in PacifiCorp's August 18, 1997 NOI.[104] However, as will be discussed further below, PacifiCorp's calculation of future potential emissions did not reflect true potential to emit of the units, nor did PacifiCorp's "PSD Baseline Emissions Inventory" reflect allowable emissions before the Hunter projects.

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[99] As EPA said in its initial approval of Utah's PSD rules, the state provisions "are practically identical to EPA's regulations...." 47 Fed. Reg. 6427 (Feb. 12, 1982).

[100] *See* August 18, 1997 NOI for the Hunter Plant, cover letter at 1 (Ex. 8).

[101] *See* definition of "potential to emit" in R307-1-1 of the Utah SIP in effect at the time of the Hunter projects.

[102] *Id.*, Attachment, Tables 3 and 4. This definition is unchanged today. *See* 40 C.F.R. § 52.21(b)(4), incorporated by reference into Utah Rule R307-405-3.

[103] *See* November 20, 1997 Approval Order at 3-4 (Condition 5) (Ex. 9); December 18, 1997 Approval Order at 2-3 (Condition 5) (Ex. 10).

[104] *See* August 18, 1997 NOI, Attachment, Table 5 "PSD Applicability Determination," compared to November 20, 1997 Approval Order at 2 (under Abstract) and December 18, 1997 Approval Order at 2 (under Abstract).

Table 5. PacifiCorp's Future Potential Emissions for the Hunter Units from its August 18, 1997 Notice of Intent[105]

Hunter Unit	SO_2, tpy	NOx, tpy	TSP (PM), tpy	PM10, tpy	CO, tpy
1	4,107	8,801	858	579	429
2	4,107	8,801	858	579	429
3	2,039	9,379	408	408	447
Total	***10,253***	***26,981***	***2,124***	***1,566***	***1,305***

As shown in Table 6 below, use of a proper actual emissions baseline for Hunter Units 1, 2 and 3 as opposed to the "PSD Baseline Emissions Inventory" used by PacifiCorp in its August 18, 1997 NOI shows that, based on an actual-to-potential emissions test and using PacifiCorp's calculation of potential emissions, the Hunter projects should have been projected to result in significant emissions increases of all of the pollutants listed in Table 6 at the entire Hunter power plant. Further, the projects at each of the Hunter Plant's units, Units 1, 2 and 3, should have been projected to result in a significant emission increase of SO_2, NOx, TSP, and Filterable PM10 at each of these three units. For the purpose of this comparison, Sierra Club used an actual emissions baseline based upon the 24-month period ending November 1995.

Table 6. Proper Evaluation of Emission Increases for Hunter Projects Announced in 1997 NOI: Actual Emissions of the Hunter Units 1-3 Compared to Potential to Emit After the Hunter Projects

Total Hunter Units 1, 2 and 3				
Pollutant	**PSD Significant Emission Rate, tpy**	**Annual Average Actual emissions for 24-month period ending Nov 1995, tpy[106]**	**PacifiCorp's Post-Change Potential Emissions, tpy[107]**	**Emission Increase/Decrease**
SO_2	40	7,019	10,253	+ 3,234 tpy

[105] As will be discussed further below, PacifiCorp's future potential emissions were not based on enforceable conditions adopted into the November 20, 1997 and/or December 18, 1997 Approval Orders. PacifiCorp's calculations of future potential emissions were based on an assumed 95% capacity factor, which was not imposed as a limit in the 1997 Approval Orders. *See* August 18, 1997 NOI, Attachment, Table entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: Future Potential Emissions." (Ex. 8). The Approval Orders did impose new limitations on lb/MMBtu emission rates for particulate matter, SO_2 and NOx. December 18, 1997 Approval Order at 2-3 (Condition 5) (Ex. 10). The Approval Orders also possibly included limitations on annual SO_2 and NOx emissions from Hunter Units 1 and 2 of 4,107 tpy and 8,801 tpy, respectively. *Id.* However, these tpy limits were not carried over into the Title V permit issued January 7, 1998, even though the lb/MMBtu limits were, so it is not clear if the stated tpy emissions levels for Units 1 and 2 were intended to be limits on annual emissions. *See* Title V Operating Permit for Hunter Power Plant, Permit Number 1500101001, January 7, 1998 (Ex. 33). To account for the possibility that UDAQ considers PacifiCorp's August 18, 1997 NOI as inherently part of the 1997 Approval Orders and as legitimately limiting the Hunter Plant, we are using PacifiCorp's calculation of future potential emissions for Hunter Units 1, 2 and 3.

[106] *See* Spreadsheet, "Hunter Projects 1997-99 Emission Calculations," at tabs "PW Baseline," "Hunter 1 Baseline," "Hunter 2 Baseline," and "Hunter 3 Baseline" (Ex. 32).

[107] *See* August 18, 1997 NOI, Attachment at Table 3 (Ex. 8).

NOx	40	20,955	26,981	+ 6,026 tpy
TSP (PM)	25	1,187	2,124	+ 937 tpy
PM10 (Filterable)	15	867	1,566	+699 tpy
CO	100	1,084	1,305	+221 tpy
Hunter Unit 1				
SO2	40	2,857	4,107	+ 1,250 tpy
NOx	40	7,348	8,801	+1,453 tpy
TSP (PM)	25	463	858	+395 tpy
PM10 (Filterable)	15	310	579	+ 269 tpy
CO	100	368	429	+ 61 tpy
Hunter Unit 2				
SO2	40	2,641	4,107	+ 1,466 tpy
NOx	40	6,901	8,801	+ 1,900 tpy
TSP (PM)	25	438	858	+ 420 tpy
PM10 (Filterable)	15	293	579	+ 286 tpy
CO	100	344	429	+85 tpy
Hunter Unit 3				
SO2	40	1,521	2,039	+518 tpy
NOx	40	6,706	9,379	+2,673 tpy
TSP (PM)	25	286	408	+122 tpy
PM10 (Filterable)	15	263	408	+145 tpy
CO	100	372	447	+75 tpy

As the above table demonstrates, an actual-to-potential emissions evaluation for the Hunter projects completed in the 1997-1999 timeframe shows that, based on a proper evaluation of the PSD permitting rules, these projects should have been subject to PSD permitting requirements for SO2, NOx, TSP, PM10, and CO, with significant emission increases projected for each Hunter Unit 1, 2, and 3 for SO2, NOx, TSP and PM10. UDAQ's 1997 Approval Orders did not limit potential to emit of the Hunter units to ensure no significant emissions increase in actual emissions of these pollutants. Moreover, UDAQ's 1997 Approval Orders did not effectively limit potential to emit to the levels assumed by PacifiCorp, as is discussed further below.

The net emission increases at the Hunter Plant show similar and greater increases for all of these pollutants. Under the applicable PSD rules of the Utah SIP, to determine whether a project will result in a significant net emissions increase at the source, a source owner must subtract creditable emission decreases and also add in creditable emission increases that are contemporaneous with the projects being permitted.[108] An increase or decrease in emissions is contemporaneous "if it occurs between the date five years before construction on the particular change commences; and the date that the increase from the particular change occurs." *See*

[108] *See* definition of "net emissions increase" in UACR R307-1-1 of the Utah SIP (1995).

definition of "net emissions increase," subsection 2.A., in UACR R307-1-1 of the Utah SIP (1995). Since construction on the projects that could have increased emissions should not have occurred until an Approval Order was issued[109], the contemporaneous period started 5 years before the issuance of the first Approval Order for these Hunter projects, which was issued November 20, 1997. The end of the contemporaneous period for each unit would be when each unit's projects were completed, or approximately 11/99 for Unit 1, 11/97 for Unit 2, and 6/98 for Unit 3.[110]

Based on the information provided by PacifiCorp, the primary contemporaneous emission increases are those associated with the increased coal use at the Hunter units. Specifically, PacifiCorp provided "EPA Baseline Emissions" and "Future Potential Emissions" for several emission points associated with coal transfer and ash transfer that projected an increase in emissions from these emission points due to an increase in coal usage and an increase in ash production. Table 7 below provides the details of these emission increases, as provided in PacifiCorp's August 18, 1997 NOI. It must be noted that, as with the PSD Baseline Emissions Inventory for Units 1, 2 and 3, the "EPA baseline emissions" for these sources appears to be erroneously based on allowable emissions at the time of the PSD Permit for Hunter Unit 3.[111] A determination of actual emissions from these emission points prior to the Hunter projects would likely be lower. Despite these deficiencies which, when corrected, would have only made the emissions increases greater, Sierra Club used PacifiCorp's PSD Emissions Inventory and Future Potential Emissions for the purpose of estimating the emission increases from these emission points at the Hunter Plant.

Table 7. Other Emission Points Identified by PacifiCorp in the August 18, 1997 NOI as Increasing Emissions with the Hunter Projects

Unit ID#	Description	Baseline TSP, tpy	Future Potential TSP, tpy	TSP Emission Increase, tpy	Baseline PM10[112], tpy	Future Potential PM10, tpy	PM10 Emission Increase, tpy
304	Loading ash into haul trucks (U1&U2)	0.0114	0.0187	0.0073	0.0040	0.0066	0.0026
305	Loading	0.0057	0.0098	0.0041	0.0020	0.0034	0.0014

[109] *See* UACR 307-3.1.1 (1995) (Approval Order required prior to modifications "which will or might reasonably be expected to increase the amount of...air contaminants discharged...,") and definitions of "major modification," "net emissions increase," and "commence" at UACR 307-1-1 (1995).
[110] *See* August 18, 1997 NOI for the Hunter Plant, Attachment, Table 1 (Ex. 8).
[111] *Id.,* Attachment, see Table with title "Emissions Inventory Calculation Sheet," Hunter plant, Coal haul road (paved), ID# 1001-1008, Year: EPA Baseline Emissions, in which the amount of coal hauled is based on "potential throughput based on unit info." Specifically, the amount of coal hauled of 4,758,217 tons per year is based on "potential throughput based on unit info." The amount of coal haul on the haul roads is identical to the sum of the coal consumption identified for Hunter Units 1, 2 and 3, which was based on 100% capacity factor at 400 MW net. *See* Tables entitled Emissions Inventory Calculation Sheet, Hunter Plant, EPA Baseline Emissions, for Steam Generating Units 1, 2, and 3 in August 18, 1997 NOI.
[112] PM10 emissions in this table are filterable PM10.

	ash into haul trucks (U3)						
401	Coal transfer to coal pile at power plant	0.31	0.34	0.03	0.11	0.12	0.01
501-503	Fly ash unloading at landfill	0.07	0.11	0.04	0.02	0.04	0.02
601-637	Ash haul road	30.62	48.36	17.72	11.02	17.41	6.39
701	Baghouse No. 1 (3DC1-screen building)[a]	Not Included	8.70	8.70	Not Included	8.70	8.07
702	Baghouse No. 2 (5DC1-transfer building)[a]	Not Included	2.77	2.77	Not Included	2.77	2.77
801	Coal transfer from truck	0.31	0.36	0.05	0.11	0.13	0.02
1001-1008	Coal haul road (paved)	8.36	9.66	1.3	1.63	1.89	0.26
1009-1014	Coal haul road (paved)	80.36	92.89	12.53	15.68	18.13	2.45
1101-1102	Coal haul road (loaded truck, unpaved)	7.90	9.13	1.23	2.84	3.29	0.45
1201-1205	Coal haul road (Empty truck, unpaved)	4.50	5.21	0.71	1.62	1.87	0.25
1301-1309	Refuse haul road (unpaved)[a]	Not included	Not included	1.50	Not included	0.54	0.54

Total TSP Increases	46.6 tpy	Total PM10 Increases	21.2 tpy

[a] Note that it appears these emission points should have been included in the baseline emissions and not as contemporaneous emission increases, because the August 18, 1997 NOI identifies these sources as permitted in a May 15, 1990 Approval Order.

These TSP (PM) and PM10 increases are likely understated, not only because the baseline emissions appear to be based on allowable emissions, but also because the future potential emissions are based on coal limitations and control efficiencies based on the application of fugitive dust measures that are not reflected in permit conditions in the 1997 Approval Orders. For example, a 94.8% control efficiency was assumed for unpaved ash haul roads, based on "application of chemical agent or watering."[113] For the coal haul roads, the amount of coal hauled was assumed to be 5,500,000 tons per year with a reference of "Future allowable (modify AO condition).[114] It does not appear that these limitations were included as enforceable conditions in the 1997 Approval Orders.

Moreover, it does not appear that there are any contemporaneous, creditable emission decreases at the Hunter Plant to take into account with the Hunter projects.

Assuming for the purpose of these comments that the above projected increases in TSP and PM10 were based on a proper actual-to-potential emissions analysis and assuming that PacifiCorp's calculation of potential emissions at Hunter Units 1, 2, and 3 truly reflected potential to emit of those units considering enforceable limitations imposed in the 1997 Approval Orders, Sierra Club projects the total net emissions increase from the Hunter projects (based on an actual-to-potential emissions test for at least Hunter Units 1, 2 and 3) to be as shown in Table 8.

Table 8. Determination of Net Emissions Increase Considering Contemporaneous Emission Increases and Decreases, Based on Proper Actual-to-Potential Test for Hunter Units 1-3

Pollutant	**PSD Significant Emission Rate, tpy**	**Baseline Emissions (Actual Emissions for 24-month period ending Nov 1995 for Hunter Units 1-3 + PacifiCorp's baseline emissions for other units), tpy**	**Post-Change Potential Emissions, tpy**	**Emission Increase/Decrease**
SO2	40	7,019	10,253	+ 3,234 tpy

[113] *See* August 17, 1997 NOI, Attachment, Table entitled: "Emission Inventory Calculation Sheet, Hunter Plant, Ash haul road (ash), ID# 601-637, Future Potential Emissions. (Ex.8).

[114] *Id.,* Table entitled Emission Inventory Calculation Sheet, Coal prep plant, coal haul road (paved), ID# 1009-1014, Future Potential Emissions. (Ex. 8).

NOx	40	20,955	26,981	+ 6,026 tpy
TSP (PM)	25	1,541	2,525	+ 984 tpy
PM10 (Filterable)	15	1,069	1,789	+ 720 tpy
CO	100	1,084	1,305	+221 tpy

As Table 8 demonstrates, a more proper analysis of the projects proposed at Hunter Units 1, 2 and 3 to be completed in 1997-1999 which is based on the appropriate legal requirements in the EPA-approved Utah SIP applicable at the time shows that these projects should have been projected to result in significant net emissions increases of SO2, NOx, TSP, PM10 (filterable) and CO. Table 7 above also shows that each Hunter Unit 1, 2, and 3 should have been projected to have a significant emission increase of SO2, NOx, TSP, and PM10 (filterable). The 1997 Approval Orders limiting potential to emit of the Hunter units in an attempt to allow the modifications at the plant to avoid PSD did not impose sufficient enforceable emission reductions to ensure no significant increase of these pollutants. Thus, when PacifiCorp constructed and operated these modifications, it did so in violation of PSD permitting requirements, without applying BACT at each Hunter unit for these significant emission increases of SO2, NOx, TSP, and PM (filterable) and without meeting other PSD permitting requirements including ensuring compliance with the PSD increments and Class I air quality related values.[115]

(2) The 1997 Approval Orders Did Not Effectively Limit Post-Change Potential to Emit to the Levels Assumed by PacifiCorp and UDAQ

PacifiCorp relied on an assumed 95% capacity factor in its calculation of post-change potential to emit of Hunter Units 1, 2, and 3 in its August 1997 NOI.[116] However, PacifiCorp did not request the capacity factor to be made into an enforceable limitation on any of Hunter Units 1, 2 or 3. Thus, it was inappropriate for PacifiCorp to rely on a 95% capacity factor in calculating post-change potential to emit of the Hunter units. Further, in calculating potential to emit of PM and filterable PM10, PacifiCorp did not take into account the 0.05 lb/MMBtu emission limit for Units 1 and 2, although PacifiCorp did take into account the 0.02 lb/MMBtu emission limit in calculating potential to emit PM and PM10 for Unit 3.[117] For Hunter Units 1 and 2, PacifiCorp calculated future potential emissions based on AP-42 emission factors.[118] The PM emission factor was calculated to be 1.000 lb/ton of coal burned, which is less stringent than the 0.05 lb/MMBtu PM emission limit imposed in the 1997 Approval Order. Specifically,

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115 *See* UACR R307-1-3.1.1. (1995) (Approval Order required prior to modifications "which will or might reasonably be expected to increase the amount of...air contaminants discharged...,"), UACR R307-1-3.1.8.A. (1995) (approval orders must ensure that "[t]he degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology...," and UACR R307-1-3.1.8.B (1995) (requiring that the source be in compliance with the national ambient air quality standards and maximum allowable concentration requirements for Prevention of Significant Deterioration, among other requirements).

116 August 18, 1997 NOI, Attachment, Table entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: Future Potential Emissions," under Coal Consumption source of information. (Ex. 8).

117 *Id.*, under PM emission rate, lb/mmBtu for Steam Generating Unit 1 and Unit 2, *see also* Tables entitled: "Emission Inventory Calculation Sheet, Hunter Plant, Year: Future Potential Emissions" for Units 1 and 2. (Ex. 8).

118 *Id.*

assuming 11,400 Btu/lb of coal at each Hunter Units 1 and 2, a 1.00 lb/ton emission factor equates to 0.044 lb/MMBtu. Future potential to emit of PM at Hunter Units 1 and 2 should have been based on the PM emission limit requested of 0.05 lb/MMBtu and 100% capacity factor. For PM10 emissions, since the PacifiCorp did not request a limit on filterable PM10, the potential to emit of PM10 should have been based on the PM limit requested and imposed in the 1997 Approval Order. This was how PacifiCorp calculated the potential to emit of Unit 3.

Table 9 below shows the proper potential to emit of each unit based on the 1997 Approval Order emission limitations and the future maximum hourly heat input capacity of the Hunter units as listed in PacifiCorp's 1997 NOI.

Table 9. Proper Determination of Future Potential to Emit NOx, SO2, and PM at Hunter Units 1, 2 and 3 After Projects Listed in 1997 NOI

Hunter Unit	1	2	3
Future PTE NOx, tpy	9,264	9,264	9,873
Future PTE SO2, tpy	4,323	4,323	2,146
Future PTE PM/Filterable PM10 tpy	1,029	1,029	429

Based on these calculations of potential to emit which in turn are based on the enforceable limitations in the 1997 Approval Orders, the net emissions increase from the Hunter projects completed in 1997-1999 would be even greater than shown in Table 8 above. However, we used PacifiCorp's post-change potential to emit calculations in our calculations in Table 8 above to account for the possibility that UDAQ considers PacifiCorp's August 18, 1997 NOI as inherently part of the 1997 Approval Orders and as legitimately limiting the Hunter Plant. If UDAQ does consider the operating conditions set forth in the NOI to be inherently part of the 1997 Approval Orders, Sierra Club requests UDAQ to identify the provisions of the permit or state law that provide for this.

It is also worth noting that the potential to emit based on 100% capacity factor and allowable PM emission limits for the Hunter Units as shown in Table 10 above results in a significant emission increase of PM/filterable PM10 in comparison to the PSD Baseline Emissions Inventory that PacifiCorp (and apparently UDAQ) relied on to reflect actual emissions at the Hunter Plant before the projects. Specifically, the PSD baseline PM/filterable PM10 emission inventory for Hunter Units 1 and 2 was 893 tpy each[119] and the properly calculated potential to emit based on enforceable emission limits and 100% capacity factor shown in Table 9 above is 1,029 tpy for each Unit 1 and 2, which reflects an emission increase of 136 tpy per unit. Thus, even using PacifiCorp's unjustified and flawed methodology of comparing something akin to allowable emissions before the projects to potential to emit after the project, significant increases in PM/PM10 should have been projected.

[119] *See* August 18, 1997 NOI, Attachment at Table entitled "EPA Baseline Emissions." (Ex. 8).

d. The Hunter Projects Completed in 1997-1999 Resulted in Actual Increases in Heat Input and Emissions

PSD permits are supposed to be obtained before construction commences on a modification, and thus applicability is based on a projection of post-change emissions, based on potential to emit under the Utah SIP in effect at the time of the Hunter projects and based on actual-to-projected actual emissions under the current PSD rules. Although the applicability test under the applicable PSD rules was not based on actual emissions pre-project to real actual emissions post-project, Sierra Club evaluated emissions post-project to see, as a practical matter, if in this case there was an increase in emissions and heat input after the Hunter projects. However, this analysis is not intended to be used in lieu of the proper PSD applicability emissions increase analysis outlined in Sections I.C.2.b) and c) above, because PSD applicability is to be determined *prior* to construction/modification.

For the purpose of this analysis, Sierra Club used the same methodology for determining post-change actual emissions as it did for pre-change actual emissions, relying primarily on tons of coal burned per month, heat value, sulfur, and ash content per month reported to the Energy Information Administration for Hunter Units 1, 2 and 3. This was done to provide for an "apples-to-apples" comparison of pre-project and post-project actual emissions. For SO2 emissions at Unit 3, Sierra Club calculated SO2 emissions at 90% reduction from the post-combustion SO2 emission rate (calculated by actual sulfur content and AP-42 emission factors) because UDAQ changed the 90% SO2 control requirement in the 1998 Title V permit to be based on inlet and outlet CEM monitoring to the SO2 scrubber, rather than based on 90% removal from the sulfur in the coal.[120] For NOx emissions, Sierra Club continued to use the annual average NOx rates as reported to the EPA's Air Markets Program Database for each unit along with the calculated heat input from EIA data. Since PacifiCorp indicated that some type of NOx controls were being constructed at each unit along with the other projects, using lb/MMBtu NOx rates submitted to the Clean Air Markets Database would best reflect the true NOx emission reductions that occurred as part of these control projects.[121] Sierra Club calculated post-change emissions for rolling 12-month periods and compared to the baseline emissions which were based on the 24-month period ending November 1995.

Tables 10, 11, and 12 below provide data on post-change emissions and heat input at each Hunter unit, calculated as described above, compared to the baseline emissions for 2 to 3 years after completion of the projects at the Hunter units. Shortly after the Hunter Unit 1 projects were constructed, the Unit 1 generator failed and the unit was out for 5 months from December 2000 to May 2001,[122] so Sierra Club presents post-change emissions after Unit 1 came back on-line after the generator failure. One thing is clear from this analysis of pre-project actual emissions to post-change actual emissions; each unit increased heat input significantly. This is most evident at Hunter Units 2 and 3, but heat input increases also occurred at Unit 1. Moreover, all three Hunter units had significant increases in SO2 and Units 2 and 3 had significant increases in NOx and filterable PM10. For Unit 3, Table 12 includes calculated emissions and heat input

[120] *See* January 7, 1998 Title V Permit for Hunter Plant, Condition II.B.3.d, at 29 (Ex. 33).
[121] *See* August 18, 1997 NOI, Attachment at Table 1.
[122] *See* Exhibit Accompanying Direct Testimony of Barry G. Cunningham before the Wyoming Public Service Commission, The Marsh Report, January 2, 2001 (Ex. 34).

for three years after completion of the projects because the most significant increases in emissions and heat input occurred in 2003 at this unit. Sierra Club evaluated post-change emissions through the end of 2005, five years after the last unit (Unit 1) was upgraded. As shown in the last row of each Table 10, 11, and 12, there were numerous 12-month periods post-project at each unit with significant SO2 emission increases, NOx and PM10 emission increases (Units 2 and 3), and heat input increases.

Table 10. Actual Emission Increases above 24-Month Baseline Period Ending November 1995 at Hunter Unit 1, for 12-month Periods after Projects Completed in 11/99 and After Unit Brought Back On-line After Generator Failure[123]

12-month period ending	SO2 Increase above Baseline, tpy	NOx Increase above Baseline, tpy	Filterable PM10 Increase above Baseline, tpy	Heat Input Increase Above Baseline, MMBtu/yr
June 2002	26			
July 2002	**73**			
Aug 2002				
Sept 2002				
Oct 2002	**44**			
Nov 2002	**44**			
Dec 2002	**153**			376,972
Jan 2003	**114**			575,034
Feb 2003	**72**			546,239
Mar 2003				517,493
Apr 2003				24,399
May 2003				104,540
June 2003				54,714
July 2003				295,535
Aug 2003				1,621,632
Sept 2003				1,595,689
Oct 2003				1,468,913
Nov 2003				2,150,809
Dec 2003				2,030,959
Jan 2004				1,945,960
Feb 2004				630,481
Mar 2004				115,696
Apr 2004				155,097
May 2004				94,686
# of 12 month periods from June 2002 through Dec 2005 >	**61**	**0**	**0**	**22 twelve-month periods with annual**

[123] *See* Spreadsheet, "Hunter Projects 1997-99 Emission Calculations," at tab "U1 00-05" (Ex. 32).

significant emission increases				**heat input increases**

Table 11. Actual Emission Increases above 24-Month Baseline Period Ending November 1995 at Hunter Unit 2, After Projects Completed in 11/97[124]

12-month period ending	SO2 Increase above Baseline, tpy	NOx Increase above Baseline, tpy	Filterable PM10 Increase above Baseline, tpy	Heat Input Increase Above Baseline, MMBtu/yr
Nov 1998	**616**	**554**	**21**	5,074,273
Dec 1998	**616**	**607**	**26**	5,256,695
Jan 1999	**633**	**545**	**27**	5,332,534
Feb 1999	**693**	**482**	**24**	5,380,485
Mar 1999	**107**	**370**	**22**	5,226,495
Apr 1999	**71**	**206**	**23**	4,752,038
May 1999	**123**	**188**	**28**	5,021,855
June 1999	**136**	**97**	**30**	4,937,815
July 1999	**96**		**27**	4,488,575
Aug 1999	**56**		**16**	3,811,574
Sept 1999	**85**		12	3,782,790
Oct 1999	**128**		**15**	4,297,662
Nov 1999	**138**		11	4,368,798
Dec 1999	**99**			3,811,638
Jan 2000	**49**			3,931,870
Feb 2000				3,796,767
Mar 2000				2,914,164
Apr 2000				3,248,104
May 2000				3,498,773
June 2000				3,572,694
July 2000				3,437,800
Aug 2000		**181**		4,095,945
Sept 2000		**196**		3,739,793
Oct 2000		**190**		3,244,496
Nov 2000		**85**		2,303,363
Dec 2000		**210**		2,495,426
# of 12 month periods from Nov 1998 through Dec 2005 > significant emission increases	**32**	**17**	**16**	**74 twelve-month periods with annual heat input increases**

[124] *See* Spreadsheet, "Hunter Projects 1997-99 Emission Calculations," at tab "U2 98-05" (Ex. 32).

Table 12. Actual Emission Increases above 24-Month Baseline Period Ending November 1995 at Hunter Unit 3, After Projects Completed in 6/98[125]

12-month period ending	SO2 Increase above Baseline, tpy	NOx Increase above Baseline, tpy	Filterable PM10 Increase above Baseline, tpy	Heat Input Increase Above Baseline, MMBtu/yr
June 1999				
July 1999				
Aug 1999				
Sept 1999				
Oct 1999				574,532
Nov 1999				
Dec 1999				
Jan 2000				
Feb 2000				
Mar 2000		**356**		2,569,441
Apr 2000		**469**		2,903,238
May 2000		**496**		2,807,422
June 2000		**528**		2,740,785
July 2000		**643**		3,081,447
Aug 2000		**674**		2,991,549
Sept 2000		**585**		2,325,805
Oct 2000		**387**		1,113,852
Nov 2000		**548**		1,732,148
Dec 2000		**534**		1,427,495
Jan 2001		**539**		1,450,440
Feb 2001		**438**		959,640
Mar 2001		**376**		656,215
Apr 2001				
May 2001				
June 2001				
July 2001				
Aug 2001			5	
Sept 2001			**18**	
Oct 2001		**132**	**34**	
Nov 2001		**257**	**50**	72,887
Dec 2001	33	**391**	**65**	726,848
Jan 2002	**53**	**481**	**65**	1,254,605
Feb 2002	**53**	**615**	**70**	1,984,653
Mar 2002	**50**	**647**	**67**	2,212,715
Apr 2002	**168**	**1222**	**99**	5,090,789
May 2002	**180**	**1168**	**104**	4,887,705

[125] *See* Spreadsheet, "Hunter Projects 1997-99 Emission Calculations," at tab "U3 98-05" (Ex. 32).

# of 12 month periods from June 1999 through Dec 2005 > significant emission increases	**14**	**53**	**52**	**64 twelve-month periods with annual heat input increases**

3. PacifiCorp's "PSD Baseline Inventory" Ignored the Fact that a Lower NOx Limit Was Imposed on Hunter Unit 2 in a July 27, 1987 Approval Order

As discussed in Section I.C.2.b) above, it appears that PacifiCorp used the "PSD Baseline Emission Inventory" to reflect emissions before the Hunter projects as something akin to allowable emissions. Putting aside the argument made in Section I.C.2.b above that an allowable emissions baseline is not justified for the Hunter projects reflected in PacifiCorp's 1997 NOI, UDAQ and PacifiCorp should not have relied on a baseline emissions inventory that was higher than the allowable emissions for the units. Yet, for NOx emissions at Hunter Unit 2, the PSD baseline emissions inventory was higher than the Unit's allowable emissions. Specifically, the PSD Baseline Emission Inventory NOx emissions for Unit 2 were based on a NOx emission limit of 0.70 lb/MMBtu.[126] However, Unit 2 was subject to a much more stringent NOx limit of 0.49 lb/MMBtu, pursuant to a July 27, 1987 Approval Order.[127]

PacifiCorp acknowledged this in its 1997 NOI, but stated that "[t]his limit was established because a unit subject to 40 CFR 60 Subpart D is not required to install a CEM if the NOx emissions are demonstrated to be less than 70% of the 0.70 lb/MMBtu standard during the performance test."[128] PacifiCorp went on to state that it had installed a CEM system to monitor NOx emissions, and it proposed to "re-establish the limit as per the applicable standard, (*i.e.*, 0.70 lb/MMBtu).[129] Regardless of what PacifiCorp proposed in the 1997 NOI, that does not negate the fact that the enforceable NOx limit at Hunter Unit 2 was 0.49 lb/MMBtu and that limit defined the Unit 2's allowable NOx emissions since 1987. Thus, even if it were appropriate to use an allowable emissions baseline for the projects of the 1997 NOI, Hunter Unit 2's allowable NOx emissions before the Hunter projects were based on a 0.49 lb/MMBtu limit, not a 0.70 lb/MMBtu limit. The allowable NOx emissions for Unit 2 at the time of the 1997 NOI were thus 8,928 tpy, rather than the 12,755 tpy as reflected in PacifiCorp's 1997 NOI. A comparison of allowable NOx emissions at Hunter Unit 2 before the projects to potential to emit with the permit limit in the 1997 Approval Order shows that the ***1997 Approval Order actually allowed for a***

[126] *See* August 18, 1997 NOI, Table Entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: EPA Baseline Emissions." (Ex. 8)
[127] *See* July 27, 1987 Approval Order, Hunter Unit 2, Condition 4 at page 3 (Ex. 31).
[128] *See* August 18, 1997 NOI, Attachment at Table 4, note B (Ex. 8).
[129] *Id.*

336 tpy increase in allowable NOx emissions at Hunter Unit 2 based on the unjustified allowable emissions to potential to emit comparison.

4. In 1998, UDAQ Relaxed the Emission Limits it Imposed in the 1997 Approval Order that Were Intended to Limit Potential to Emit of the Hunter Units in a Manner that Made Any Purported Limits on Potential to Emit Ineffective.

As discussed extensively above, the projects that were constructed at Hunter Units 1, 2 and 3 in 1997-1999, which could increase the capacity or capacity utilization of the Hunter units, should have been permitted as PSD major modifications. Instead, UDAQ issued a permit to limit potential to emit of these units on November 20, 1997 (revised on December 18, 1997) in an attempt to allow the projects at these units to avoid PSD permitting requirements.[130] Section I.A.C. above discusses how these projects should have been permitted as major modifications for SO2, NOx, PM/PM10, and CO because PSD applicability was determined incorrectly due to the baseline emissions being premised on permitted allowable emissions rather than actual emissions.

Assuming, for the purpose of this comment, that the 1997 Approval Order[131] issued by UDAQ did lawfully exempt the projects at Hunter Units 1, 2, and 3 from PSD permitting requirements via the imposition of the limits on potential to emit imposed by UDAQ in the 1997 Approval Order, UDAQ subsequently relaxed those limits on potential to emit. Specifically, very shortly after issuance of the 1997 Approval Order, UDAQ issued a Title V permit for the Hunter Plant that provided for exemptions from these limits on SO2, NOx, and PM that were intended to limit potential to emit of the units. That Title V permit was issued on January 7, 1998.[132] Those exemptions remained in the Title V permit for the Hunter units until at least 2008, when a different set of emission limits was imposed.[133] These relaxations of limits imposed in the 1997 Approval Order that were intended to limit to the potential to emit of the Hunter units to avoid PSD permitting requirements should have subjected Hunter Units 1, 2 and 3 to PSD permitting requirements as though construction had not yet commenced.[134]

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[130] *See* November 20, 1997 Approval Order (Ex. 9) and December 18, 1997 Approval Order (Ex. 10).

[131] In a May 3, 2005 letter to PacifiCorp, UDAQ administratively revoked the November 20, 1997 Approval Order. (Ex. 11).

[132] *See* Title V Operating Permit for Hunter Power Plant, Permit Number 1500101001, issued January 7, 1998 (Ex. 33).

[133] In 2008, UDAQ issued an Approval Order and a revised Title V permit that imposed a different set of emission limits that would apply upon upgrade of pollution control at each unit. The 2008 permit is discussed elsewhere in these comments.

[134] *See* UACR R307-1-3.1.11; 40 C.F.R. § 52.21(r)(4).

a. Relaxation of Limits Taken to Avoid PSD Are Required by Utah and Federal Law to Be Evaluated for PSD As Though Construction or Modification Had Not Yet Commenced

Since 1980, the federal PSD regulations have included provisions to ensure that sources which took limitations on potential to emit to avoid PSD permitting do not escape PSD if those emission limitations are later relaxed. EPA stated in the preamble to the 1980 regulations:

> a potential problem exists concerning the future relaxation of a preconstruction permit that previously caused a proposed stationary source to enjoy minor rather than major status. For example, a source might evade [new source review] through agreement to unrealistically stringent operating limitations in its permit, and later obtain a relaxation of the condition. The [EPA] believes that the problem can be dealt with by 40 CFR 52.21(r)(4), entitled "Source Obligation." That paragraph provides that any owner or operator of a source, who would receive a relaxation of a permit condition that had enabled avoidance of NSR, would then become subject to review for all units subject to the original permit, as if they were new sources. In other words, if operational limitations are to be considered as an aspect of a source's design, it is reasonable that the permit accurately incorporate that design. If such operation is changed, the permit, and concomitant obligations, should be correspondingly changed.[135]

Accordingly, the federal PSD permitting regulations include a provision at 40 C.F.R. 52.21(r)(4) that requires evaluation of any relaxation of a limit taken to avoid PSD permitting as though construction has not yet commenced on the source or modification. State with SIP-approved PSD programs are also required to include such provisions as required by 40 C.F.R. 51.166(r)(2), and Utah has adopted such a provision as part of its construction permitting regulations. For example, its permitting regulations at the time of the 1997 Approval Order stated as follows:

> 3.1.11 At a time that a source or modification becomes a major source or major modification because of a relaxation of any enforceable limitation which was established after August 7, 1980, on the capacity of a source or modification otherwise to emit a pollutant, such as a restriction on the hours of operation, then the preconstruction requirements shall apply to the source as though construction had not yet commenced on the source or modification.[136]

b. In the January 7, 1998 Title V Permit, UDAQ Relaxed Limits It Had Imposed in the 1997 Approval Order to Limit the Potential to Emit of Hunter Units 1, 2, and 3.

As discussed in Section I.B above, in 1997, UDAQ imposed limits on the potential to emit SO2, NOx, and PM at Hunter Units 1, 2, and 3. Specifically, the limits imposed by UDAQ

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[135] 45 Fed. Reg. 52676-52748 at 52689 (August 7, 1980).
[136] UACR 307-1-3.1.11 of the Utah SIP (1995).

to limit potential to emit, as provided in Condition 5 of the December 18, 1997 Approval Order, are shown below:

> 5. Emissions to the atmosphere ***at all times*** from the indicated emission point(s) shall not exceed the following rates and concentrations:
>
> Source: PacifiCorp Hunter Plant

Unit 1		
Pollutant	New Limitation	Details
Particulate Matter	0.05 lb/MMBtu (6-hour averaging period)	This limit will replace the existing limitation of 0.10 lb/MMBtu
SO_2	0.21 lb/MMBtu (12-month rolling average)	This is an additional limit reducing PTE to 4107 tons per year
NO_x	0.45 lb/MMBtu (12-month average)	This is an additional limit reducing PTE to 8801 tons per year
Unit 2		
Pollutant	New Limitation	Details
Particulate Matter	0.05 lb/MMBtu (6-hour averaging period)	This limit will replace the existing limitation of 0.10 lb/MMBtu
SO_2	0.21 lb/MMBtu (12-month rolling average)	This is an additional limit reducing PTE to 4107 tons per year
NO_x	0.45 lb/MMBtu (12-month average)	This is an additional limit reducing PTE to 8801 tons per year
NO_x	0.70 lb/MMBtu (3-hour averaging period)	This limit will replace the existing limitation of 0.49 lb/MMBtu
Unit 3		
Pollutant	New Limitation	Details
Particulate Matter	0.02 lb/MMBtu (6-hour averaging period)	This limit will replace the existing limitation of 0.03 lb/MMBtu
SO_2	0.10 lb/MMBtu (30-day rolling average)	This limit will replace the existing limitation of 0.12 lb/MMBtu
NO_x	0.46 lb/MMBtu (30-day rolling average)	This limitation will replace the existing limitation of 0.55 lb/MMBtu

December 18, 1997 Approval Order, DAQE-1189-97, at 2-3 (Ex. 10) (emphasis added).

The limits imposed in Condition 5 of the December 18, 1997 Approval Order DAQE-1189-97 were the limits requested by PacifiCorp in its August 18, 1997 NOI to limit potential to emit of the Hunter units so the projects planned to be constructed at the units would not trigger PSD permitting requirements.[137] These limits formed the basis of PacifiCorp's future potential to emit calculations for Hunter Units 1, 2, and 3.[138] UDAQ clearly relied on PacifiCorp's

[137] *See* August 18, 1997 NOI, cover letter at 2, Attachment at Table 4. (Ex. 8).

[138] *Id.*, Attachment, Table Entitled "Hunter Plant and Coal Prep Plant Annual Emissions Inventory, Production Data Input Sheet for Calendar Year: Future Potential Emissions, *see* rows in Table with source of information "voluntarily reduced" emission limit.

calculations, as UDAQ's December 18, 1997 Approval Order identifies the same reductions in "total emissions" for SO2, NOx, and PM as PacifiCorp identified in its August 18, 1997 NOI.[139] The only possible exemption that was in the 1997 Approval Order pertained to the Utah breakdown rule. Specifically, Condition 9 required PacifiCorp to comply with R307-1-4.7, which was Utah's unavoidable breakdown rule. However, Condition 9 of the 1997 Approval Order did not specifically exempt the Hunter units from compliance with the emission limits of the Approval Order during unavoidable breakdowns.[140] In fact, as highlighted above, Condition 5 of the permit required the emission limits to be met "at all times."[141]

Moreover, by definition, the potential to emit of an emissions unit is required to account for emissions during startup and shutdown. "Potential to emit" is defined as the "maximum capacity of a source to emit under its physical and operational design."[142] EPA has stated that startup and shutdown emissions "are part of normal operation of a source and should be accounted for in planning, design, and implementation of operating procedures for process and control equipment."[143] Thus, it follows that any limit on potential to emit a pollutant at an emission unit must apply at all times. Otherwise, the limit would not limit unit's potential to emit. And that is how UDAQ drafted Condition 5 of the December 18, 1997 Approval Order—so that the limits applied at all times.

However, when UDAQ incorporated the requirements of Condition 5 of the December 18, 1997 Approval Order into the Hunter Title V permit, which was issued just a few weeks later on January 7, 1998, UDAQ incorporated exemptions for startup, shutdown, maintenance/planned outage, and malfunction from those limits that were imposed to reduce potential to emit of the Hunter units.[144] This condition indicates that the condition originated in DAQE-1189-97 (the December 18, 1997 Approval Order). The numeric limit did originate in that 1997 Approval Order, but with no exemptions. *See also* Condition II.B.2.c. of 1998 Title V Permit (PM limit for each Unit 1 and 2 of 0.05 lb/MMBtu, except during periods of startup, shutdown,

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[139] *Id.* Attachment at Table 5; *see also* December 18, 1997 Approval Order, at 1 (under "Abstract") (Ex. 10).

[140] *See* December 18, 1997 Approval Order at 4 (Ex. 10). While Condition 9 required the owner/operator to comply with the Equipment Breakdown rule, those conditions – which appear to be reiterated in Condition 9 of the Approval Order – pertain to reporting of breakdowns lasting more than 2 hours, providing a written report within 7 days that includes calculation of excess emissions above Approval Order limits, and the submittal of the total excess emissions per calendar year to be reported to UDAQ with the annual emission inventory submittal. Nothing in Condition 9 states that emissions during unavoidable breakdowns are exempted from the emission limitations stated in Condition 5 of the Approval Order.

[141] *Id.* at 2.

[142] UACR R307-1-1 (1995).

[143] *See* May 21, 2008 Letter from Jeff Robinson, Chief, Air Permits Section, EPA Region 6 to Mr. Richard Hyde, Director, Texas Commission on Environmental Quality, Enclosure at 1. (Ex. 35). In the footnote to this quoted sentence, EPA also cited the January 28, 1993 Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, US EPA Region I (Ex. 36), and February 15, 1983 Memorandum from Kathleen M. Bennett, Assistant Administrator for Air and Radiation, to the Regional Administrators, entitled "Policy Regarding Excess Emissions During Startup, Shutdown, Scheduled Maintenance, and Malfunctions" (Ex. 37).

[144] *See,* e.g., Condition II.B.2.b. of 1998 Title V Permit (specifying a NOx limit for each Unit 1 and Unit 2 of 0.45 lb/MMBtu based on a 12-month rolling average "as determined by the arithmetic average of all valid hourly emission rates for the preceding 12 months except during periods of startup, shutdown, maintenance/planned outage or malfunction.").

maintenance/planned outage, or malfunction); Condition II.B.2.e. (SO2 limit for each Unit 1 and Unit 2 of 0.21 lb/MMBtu, 12-month rolling average except for periods of startup, shutdown, maintenance/planned outage, or malfunction); Condition II.B.3.a. (NOx limit for Unit 3 of 0.46 lb/MMBtu, 30-day rolling average, except during periods of startup, shutdown, maintenance/planned outage, or malfunction); Condition II.B.3.b. (PM limit for Unit 3 of 0.02 lb/MMBtu except during periods of startup, shutdown, maintenance/planned outage, or malfunction); and Condition II.B.3.c. (SO2 limit for Unit 3 of 0.10 lb/MMBtu, 30-day rolling average, except during periods of startup, shutdown, maintenance/planned outage, or malfunction).[145]

Not only did the January 7, 1998 Title V Permit for Hunter incorporate exemptions to the limits intended to define the potential to emit for Hunter Units 1, 2, and 3, but the 1998 Title V permit stated that it superseded DAQE-1189-97[146] along with superseding other prior Approval Orders.[147] Thus, without question, the January 7, 1998 Title V permit for the Hunter Plant relaxed the limits on potential to emit that UDAQ imposed in DAQE-1189-97 issued December 18, 1997. Accordingly, these relaxations should have been reviewed for PSD applicability as though construction or modification had not yet commenced.

c. The Relaxations to the Limits on Potential to Emit SO2, NOx, and PM at the Hunter Units Adopted Into the 1998 Hunter Title V Permit Made the Limits Adopted in the 1997 Approval Order Ineffective.

UDAQ's relaxation of the SO2, NOx, and PM emission limits for Hunter Units 1, 2 and 3 in the January 8, 1998 Title V Permit essentially made the limitations ineffective for limiting potential to emit. As described above, the 1998 Title V permit added exemptions from the SO_2, NOx, and PM emission limits for Hunter Units 1, 2 and 3 for startup, shutdown, maintenance/planned outage, and malfunctions. There is no limit on the number of startup, shutdown, maintenance/planned outage, or malfunction periods that can be exempted from the emission limits. There is no limit on the length of time per year that such exemptions are allowed. Further, there are no other NOx, SO_2, or PM emission limitations that would apply during such periods that could be relied on to define the potential to emit of the units, because virtually all of the other NOx, SO_2, and PM emission limits in the Title V permit included exemptions for startup, shutdown, maintenance/planned outage and malfunction.[148] The only limits in the 1998 Title V permit that do not have exemptions are the SO_2 removal efficiency

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[145] The Conditions relating to Hunter Units 1 and 2 all cite to DAQE-1189-97 (the December 18, 1997 Approval Order) as where the conditions originated. However, the Conditions relating to Hunter Unit 3 cite to an August 31, 1983 Approval Order as the basis for the emission limits for Unit 3, which is incorrect. We have attached a copy of the August 31, 1983 Approval Order (Ex. 38), and the emissions limits for NOx, SO_2, and PM are all higher than the limits in these Conditions of the Title V Permit. Clearly, these conditions for Unit 3 originated in DAQE-1189-97 (the December 18, 1997 Approval Order (Ex. 10)), with the exception of the exemptions for startup, shutdown, maintenance/planned outage, or malfunction.

[146] The January 7,1998 Title V permit for Hunter mistakenly lists the date of issuance for DAQE-1189-97 as December 15, 1997 rather than December 18, 1997. (Ex. 33).

[147] *See* January 7, 1998 Title V Permit for Hunter Plant at 4. (Ex. 33).

[148] *See*, *e.g.*, January 8, 1998 Title V Permit, Condition II.B.2.a. (NOx limit of 0.70 lb/MMBtu, 3-hour average, for Units 1 and 2), Condition II.B..2.d (1.2 lb/MMBtu 3-hour average SO_2 limit for Units 1 and 2). (Ex. 33). All of these limits include exemptions for startup, shutdown, maintenance/planned outage and malfunction.

requirements of 80% SO_2 removal for Hunter Units 1 and 2 (Condition II.B.2.g. of the 1998 Title V Permit) and the 90% SO_2 removal for Hunter Unit 3 (Condition II.B.3.d if 1998 Title V Permit). Because there is no limit on sulfur content of the coal burned at the Hunter units, these limits cannot define potential to emit SO_2

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Thus, by incorporating exemptions for startup, shutdown, maintenance/planned outage, and malfunction into the emission limits intended to limit potential to emit, the 1998 Title V made those emission limits meaningless for limiting the units' potential to emit. Regardless of whether the PSD applicability test of using an allowable emissions baseline was appropriate, the Hunter units were no longer subject to limits on potential to emit as of January 8, 1998. Consequently, the Hunter projects should have been permitted as though there were no limits on potential to emit and the modification had not commenced on the units.[149]

5. The Projects Proposed by PacifiCorp in its 1997 NOI Upon Which Construction Was Completed During 1997 to 1999 at Hunter Units 1, 2, and 3 Must Be Subject to PSD Permitting Requirements Including Best Available Control Technology and Protection of NAAQS and PSD Increments

As shown in Tables 6 and 8 above, the projects identified in PacifiCorp's August 18, 1997 NOI were non-routine projects that, based on a proper evaluation of emissions before and after the projects, should have been projected to result in significant net emission increases of SO_2, NOx, PM, and PM10 at Hunter Unit 1, Unit 2 and Unit 3. PacifiCorp's and UDAQ's evaluation of baseline emissions based on the "PSD Baseline Inventory" appears to akin to an allowable emissions inventory,[150] which was not justified because actual emissions at the Hunter Units were well below the PSD Baseline Inventory. Further, the PSD applicability methodology relied on by PacifiCorp and adopted by UDAQ was essentially a potential-to-potential analysis (or an allowable-to-allowable analysis because enforceable emission limitations were taken into account). EPA took public comment on such an approach in 1996, but EPA never finalized this PSD applicability methodology.[151]

Even if it were appropriate to use the PSD Baseline Emissions Inventory to reflect emissions before the Hunter projects, the 1997 Approval Orders did not impose all of the conditions necessary to limit potential to emit unless the assumptions of the 1997 NOI were considered to be inherently part of the Approval Order, as discussed in Section I.C.2.c.(2) above. Moreover, if the 1997 Approval Orders did effectively limit potential to emit to allow the projects at Hunter Units 1, 2 and 3 to lawfully avoid PSD permitting, UDAQ relaxed those limits almost immediately in the January 8, 1998 Title V permit, and those relaxations effectively negated any limits on potential to emit of NOx, SO_2, or PM at Hunter Units 1, 2, or 3. In such

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[149] UACR 307-1-3.1.11 of the Utah SIP (1995); 40 C.F.R. § 52.21(r)(4).

[150] The PSD Baseline Emission Inventory relied upon by PacifiCorp and UDAQ was not reflective of allowable emissions for NOx at Hunter Unit 2, as discussed in Section I.C.3 of these comments.

[151] *See* 61 Fed. Reg. 38,250, 38,268-70 (July 23, 1996) and 67 Fed. Reg. 80,186, 80,189, 80,204-06 (December 31, 2002).

cases, sources are required to obtain a PSD permit as though construction or modification has not yet commenced.[152]

All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements."[153] Because of the violations of PSD permitting requirements due to the projects completed at Hunter Units 1, 2 and 3 during 1997 to 1999, the Title V permit for the Hunter Plant must include a compliance schedule to bring the units into compliance with PSD due to these PSD violations. Those requirements include the application of best available control technology (BACT) for all pollutants for which there would be projected significant net emissions increases at each unit, which in the case of the projects completed in 1997-1999 at the Hunter Units would subject the units to BACT for SO_2, NOx, PM (TSP), and filterable PM. [154] See Tables 6 and 8 above. BACT must be imposed for fugitive emissions and fugitive dust as well. As discussed in Section IV. of these comments, the Hunter Units are not meeting BACT.

Further, the source will have to show that it can be expected to operate in compliance with the National Ambient Air Quality Standards (NAAQS) and PSD increments. [155] As discussed in Section V. of these comments, modeling has shown that the Hunter Plant's allowable and actual SO_2 emissions causes exceedances of the 1-hour average SO_2 NAAQS.

Thus, the Title V permit for the Hunter Plant must include a schedule of compliance to ensure that a PSD permit is issued for these projects, BACT is imposed, and that the 1-hour SO_2 NAAQS is complied with by the Hunter Plant.

II. THE HUNTER UNITS ARE NOT MEETING BACT FOR SO_2, NO_X, OR PM/PM_{10}

As demonstrated above, major modifications made at the Hunter Power Plant in the 1997-1999 timeframe should have been subject to PSD permitting requirements including application of BACT for SO_2, NO_x, and PM. Utah's air permitting rules provide that an Approval Order[156] can be issued if "the degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology...."[157] BACT is defined in the air permitting rules of the Utah SIP as follows:

> "Best available control technology" means an emission limitation (including a visible emissions standard) based on the maximum degree of reduction for each

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[152] *See* UACR 307-1-3.1.11 of the Utah SIP (1995); 40 C.F.R. § 52.21(r)(4).
[153] *See* 40 C.F.R. § 70.1(b); CAA § 504(a), 42 U.S.C. § 7661c; Utah Administrative Code R307-415-6a(1).
[154] *See* Utah Admin. Code R307-405-11. Note that, because applicability to the PSD permitting requirements are determined at the time modification (or major modification) is proposed by a source, applicability to the permitting requirements is based on the rules in effect at the time of the proposed modifications. Since the obligation to obtain an Approval Order and a PSD permit applies now (because PacifiCorp failed to obtain the necessary Approval Order and PSD permit in 1997 for these projects), the current requirements that apply to the processing and issuance of the Utah SIP are applicable.
[155] *Id. See* Utah Admin. Code R307-405-12.
[156] Utah's Approval Order is an umbrella permit that would incorporate all preconstruction requirements, whether for PSD major modifications or minor modifications (or both).
[157] UACR R307-1-3.1.8.A (1995)*; see also* Utah Admin. Code R307-401-8(1)(a), most recently approved as part of the Utah SIP effective 3/10/14; 79 Fed. Reg. 7072 (February 6, 2014)).

air contaminant which would be emitted from any proposed stationary source or modification which the executive secretary, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the executive secretary determines that technological or economic limitations on the application of measurement methodology to a particular emission unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[158]

Utah also has incorporated by reference the federal definition of BACT into its PSD permitting rules.[159] The definition quoted above and the federal PSD definition of BACT are substantially the same, with the main difference being that the federal definition applies to any pollutant regulated under the Clean Air Act and the Utah permitting rule definition of BACT applying to "air contaminants," as "air contaminants" appears to be defined more broadly that just pollutants regulated under the Clean Air Act.[160]

The Hunter Plant became subject to the requirement to obtain a PSD permit at the time it initiated construction of the modifications to the Hunter units that are described in Section I above.[161] Had PacifiCorp complied with PSD requirements in a timely fashion, the Hunter units would have been subject to BACT as determined at the time of permit issuance. However, because no PSD permit or Approval Order was issued that including BACT requirements, BACT must be determined based on the information available today.

[158] Utah Admin. Code R307-401-2, most recently approved as part of the Utah SIP effective 3/10/14; 79 Fed. Reg. 7072 (February 6, 2014). Note that this definition is very similar to the definition of BACT in the Utah SIP at the time of the 1997 Hunter projects. *See also* definition of "Best Available Control Technology" in R307-1-1 (1995) (Ex. 12).

[159] *See* 40 C.F.R. § 52.21(b)(12), incorporated by reference into Utah Admin. Code R307-405-3(1), most recently approved as part of the Utah SIP effective 9/19/2016; 81 Fed. Reg. 46,838 (July 19, 2016).

[160] "Air contaminant" is defined as "any particulate matter or any gas, vapor, suspended solid or any combination of them, excluding steam and water vapors." *See* Utah Admin. Code R307-101-2, most recently approved as part of the Utah SIP effective 8/26/2018; 84 Fed. Reg. 35832 (July 25, 2019).

[161] *See* UACR R307-1-3.1.1 (1995) (Approval Order required to be issued prior to initiating construction or modification).

EPA has always held that a BACT determination must be made at the time a permit is issued, even if the modification triggering BACT review occurred in the past, and even if EPA is correcting a permitting error. The cost effectiveness of a BACT control option is a relative determination, based on costs borne by other similar projects, and a control can only be rejected for economic impacts if costs are outside of the range of the costs incurred at other similar facilities. To make a proper comparison, the cost effectiveness of a project must be estimated in same way and at the same time as similar projects.

Since the modifications made in the late 1990s, PacifiCorp installed new pollution controls or upgraded existing pollution controls on the Hunter Units. Specifically, PacifiCorp upgraded the wet FGD systems on Hunter Units 1 and 2 to eliminate bypass and to support higher reagent and waste flows.[162] The internal components of the existing electrostatic precipitators were removed and were replaced with a pulse jet fabric filter baghouse at Hunter Units 1 and 2.[163] Further, new Alstom TFS 2000™ low NOx firing systems with two elevations of overfire air were installed at Hunter Units 1 and 2.[164] The upgrades to the Unit 2 FGD system and installation of baghouse and low NOx firing system were completed April 2011[165] and the upgrades to the Unit 1 FGD system and installations of baghouse and low NOx firing system were supposed to be completed by the end of the second quarter of 2014.[166] At Hunter Unit 3, new DRB-4Z low NOx burners were installed, along with a new overfire air system.[167] These NOx controls were installed at Unit 3 in the spring of 2007.[168]

UDAQ has imposed the following emission limitations on the Hunter units that applied upon completion of the pollution control upgrades:[169]

Table 15: SO_2, NO_x, and PM Emission Limits in the 2016 and 2020 Title V Renewal Permits Applicable to Hunter Units 1, 2, 3

Hunter Unit	Pollutant	Limit	Averaging Time	Condition in 2016 Title V Renewal Permit	Condition in 2020 Title V Renewal Permit
1&2[170]	PM	0.015 lb/MMBtu	3-test average	II.B.2.a.	Same

[162] These were the upgrades discussed in PacifiCorp's November 27, 2007 NOI, at 5-1 to 5-2. (Ex. 40). It is not clear whether the upgrades were made precisely in this manner or whether other changes have been made that could impact SO_2 emissions.
[163] *Id.*
[164] *Id.*
[165] *See* May 13, 2011 letter from PacifiCorp to UDAQ, RE: Status of the Hunter Plant's Pollution Control Equipment and Capital and O&M Projects, Attachment 1 (Ex. 42).
[166] *See* December 7, 2011 letter from PacifiCorp to UDAQ, RE: Status of the Hunter Plant's Pollution Control Equipment and Capital and O&M Projects, Attachment 1 (Ex. 44).
[167] These were the upgrades discussed in PacifiCorp's November 27, 2007 NOI, at 5-1 to 5-2. (Ex. 40).
[168] *See* December 18, 2009 letter from PacifiCorp to UDAQ, Re: Status of the Hunter Plant's Pollution Control Equipment and Capital and O&M Projects, Attachment 1 at 1 (Ex. 41).
[169] *See* March 13, 2008 Approval Order, Conditions 10.B. and 11.B. (Ex. 39).

	Visible Emissions	20%, except as provided in R307-201-3(7)	6-minute average	II.B.2.f.	Same
	NO_x	0.70 lb/MMBtu	3-hour average	II.B.2.b.	Same
	NO_x	0.26 lb/MMBtu	30-day rolling average	II.B.2.c.	Same
	SO_2	1.2 lb/MMBtu	3-hour average	II.B.2.d.	Same
	SO_2	0.12 lb/MMBtu	30-day rolling average	II.B.2.e.	Same
	SO_2	20% of the potential combustion concentration based on inlet and outlet SO2 emissions	Arithmetic average of all hourly emission rates for 30 successive boiler operating days	II.B.2.g.	Same
	PM	0.03 lb/MMBtu		Not Present	II.B.2.j(1)(a)
	SO_2	0.20 lb/MMBtu		Not Present	II.B.2.j(1)(b)
Unit 3	PM	0.02 lb/MMBtu	6-hour test average	II.B.3.a.	Same
	Visible Emissions	20%, except as provided in R307-201-3(7)	6-minute average	II.B.3.d.	Same
	SO_2	0.12 lb/MMBtu	30-day rolling average	II.B.3.b	Same
	SO_2	10% of the potential combustion concentration based on inlet and outlet SO2 emissions	Arithmetic average of all hourly emission rates for 30 successive boiler operating days	II.B.3.c.	Same
	NO_x	0.34 lb/MMBtu	30-day rolling average	II.B.3.f.	Same
	PM	0.03 lb/MMBtu		Not Present	II.B.3.h(1)(a)
	SO_2	0.20 lb/MMBtu		Not Present	II.B.3.h(1)(b)

As explained in Sierra Club's 2016 petition and in its 2015 comments to UDAQ and repeated below, the limits identified above do not reflect BACT for NO_x, SO_2 or PM.[171] The only new limits in the 2020 renewal permit are the PM and SO_2 limits set forth at II.B.2.j(1)(a) and (b), and II.B.3.h(1)(a) and (b), which, as noted in the permit, are derived from the Mercury and Air Toxics Standards (MATS) at 40 C.F.R. Part 63, Subpart UUUUU. Because these MATS

[170] Both Unit 1 and Unit 2 are subject to the emission limits listed in this table.
[171] *See* 2016 Petition at 16 n.58; 2015 Comments to UDAQ at 79-94.

limits are *higher* than the other pre-existing SO_2 and PM permit limits, they obviously do nothing to address Sierra Club's PSD claims.

A. BACT for NOx at Hunter Units 1, 2, and 3 Would Require Installation of Selective Catalytic Reduction

BACT is determined through a top-down approach. EPA's New Source Review Workshop Manual lists the following steps for determining BACT.

Step 1: Identify All Control Technologies
Step 2: Eliminate Technically Infeasible Options
Step 3: Ranke Remaining Control Technologies by Control Effectiveness
Step 4: Evaluate Most Effective Controls and Document Results
Step 5: Select BACT –"Most effective option not rejected is BACT"[172]

A BACT analysis involves review of all potentially applicable control technologies with a focused review on the top control technologies that are available and are technically feasible to implement at an emissions unit. Once the available and technically feasible pollution control technologies have been determined for control of a pollutant at a particular emissions unit, the top control is generally considered to be BACT unless it is eliminated based on clear and documented justification that the top control is not justifiable based on costs, energy, or non-air quality environmental impacts.[173]

Evaluation of BART under the regional haze are done in a similar fashion as evaluations of BACT, except that the visibility benefits of a pollution control are taken into account in Step 4 of the BART analysis.[174]

In 2012, PacifiCorp submitted to UDAQ BART analyses for Hunter Units 1 and 2.[175] PacifiCorp did not submit a BART analysis for Hunter Unit 3 because it was not subject to BART, but the company's analysis of available and technically feasible pollution controls would be essentially the same for all three units, as the units are all bituminous coal-fired EGUs that are of similar generating capacities. For evaluation of NOx controls, the only differences would be that the available and technically feasible combustion controls might be different because the Hunter Unit 3 boiler is a wall-fired boiler, whereas Hunter Units 1 and 2 are tangentially-fired boilers.

PacifiCorp's analyses of available and technically feasible NOx controls for the Hunter units shows that selective catalytic reduction (SCR) along with low NOx burners and overfire air (LNB/OFA) is the most effective NOx control technology for the Hunter units, identifying the expected NOx emission rate with these controls as 0.07 lb/MMBtu.[176] SCR along with

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[172] EPA, October 1990 New Source Review Workshop Manual, at B5- B6.
[173] *See* October 1990 EPA New Source Review Workshop Manual, at B.26 to B.54.
[174] 40 C.F.R. Part 51, Appendix Y, Section IV.D.
[175] *See* July 2, 2012 PacifiCorp BART Analysis for Hunter Unit 1 (Ex. 53); June 7, 2012 PacifiCorp BART Analysis for Hunter Unit 2 (Ex. 45).
[176] *See* July 2, 2012 PacifiCorp BART Analysis for Hunter Unit 1 at 10 (Ex. 43); June 7, 2012 PacifiCorp BART Analysis for Hunter Unit 2 at 10 (Ex. 45).

combustion controls is indeed the top NOx control technology for coal-fired boilers. This technology has been installed at scores of coal-fired EGUs and has achieved NOx emission rates well below 0.07 lb/MMBtu.

This "add-on" control technology is not currently installed at any of the Hunter units. Further, the NOx limits in the Title V renewal permit for the Hunter plant are nowhere near as low as 0.07 lb/MMBtu. Thus, clearly the Hunter units are not operating with the top level of NOx control.

In fact, SCR is widely used for NOx control at coal-fired EGUs. Currently, the EPA's Clean Air Markets Database shows 267 coal-fired EGUs that are using SCR for NOx control based on 2015 data (in the database as of November 5, 2015). Moreover, there are numerous BACT determinations for coal-fired EGUs from the last 15-20 years that found SCR plus combustion controls to be BACT.[177] Even in 1990's, EPA's expert Matt Haber found that SCR would be BACT for NOx at modified units.[178]

When a technology is widely used, as SCR is, the control can only be eliminated from consideration in setting BACT when unusual site-specific circumstances are documented in the permitting record. In 1998, EPA Region 5 wrote the Ohio Environmental Protection Agency that:

> before a BACT control option that has been demonstrated successful in practice can be rejected from consideration, the application must demonstrate in the public record that, 'circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously… ***In the absence of unusual circumstances, the presumption is that sources within the same category are similar in nature and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category***.' This means that, in the absence of a unique technical demonstration, if nitrogen dioxide from an annealing furnace is controlled by SCR at another source, then Pro-Tec should be expected to use that technology at their annealing furnace.[179]

In another 1998 EPA letter, Region 4 explained in correspondence with the Alabama Dept. of Environmental Management regarding a pending BACT analysis:

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[177] *See*, *e.g.*, List of NOx Emissions from Pulverized Coal Boilers Taken from the RACT/BACT/LAER Clearinghouse, from the January 17, 2008 Prevention of Significant Deterioration Air Permit Application for Plant Washington, Power4Georgians (excerpted) (Ex. 46).

[178] *See* Report of Matt Haber: Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois (April 2002), prepared for the United States in connection with United States v. Illinois Power Company and Dynergy Midwest Generation, Inc., (cv-99-833-MJR, S.D. IL) ("Haber Expert Report") (Ex. 47).

[179] Letter from Cheryl Newton, Chief, Permits and Grants Section, Region 5, to Robert Hodanbosi, Chief, Division of Air Pollution Control, Ohio Environmental Protection Agency, March 20, 1998 (emphasis added) (Ex. 48). The letter goes on to state that "...a simple rejection of that cost level [$5,727/ton] because it is too high is not an accepted basis for such rejection." *Id.* at 2.

> The appropriate use of economics in the BACT analysis is based on the ***rebuttable presumption that if sources within a specific industry are utilizing a control device, then the cost of that control is reasonable for that industry***. The economic analysis provided by the applicant should focus on those costs which would differentiate an individual source from similar sources….In any case, ***the use of an arbitrary "bright line" cut-off for determining what is economically reasonable conflicts with the statutory requirement that a determination of BACT for a particular source be done on a case-by-case basis***. This is why the Agency has not specified any maximum cost which should be considered unacceptable or framed any such range of costs for making such determinations. Although we have indicated in past correspondence that $4,000 to $5,000/ton is generally considered to be an acceptable cost for the control of NOx emissions, we have not specified any maximum cost which should be considered to be unacceptable and have no intention of doing so.[180]

In the BART analyses for Hunter Units 1 and 2, PacifiCorp calculated the cost effectiveness of low NOx burners w/OFA and SCR to be $3,946/ton removed at Unit 1 and $3,936/ton of NOx removed at Unit 2.[181] In 2014, PacifiCorp provided an updated cost analysis for NOx controls, which showed a cost effectiveness for LNB/OFA and SCR to be $4,462/ton of NOx removed at Hunter Unit 1 and $4,616/ton of NOx removed at Hunter Unit 2.[182] In the Technical Support Document to Comments of Conservation Organizations submitted to UDAQ on December 22, 2014 regarding the proposed amendments to Utah's Regional Haze Rule, many deficiencies were noted in PacifiCorp's 2014 updated cost analyses for LNB/OFA and SCR, and correction of just some of those deficiencies brought the cost effectiveness for LNB/OFA and SCR at Hunter Units 1 and 2 down to $3,330/ton at Unit 1 and $3,491/ton at Unit 2.[183] The Conservation Organizations also submitted an alternative cost analysis of LNB/OFA and SCR which found that these controls would cost $2,263/ton at Unit 1 and $2,276/ton at Unit 2.[184] Due to the similar size of the Hunter Unit 3 EGU, it is reasonable to assume that the cost effectiveness for LNB/OFA and SCR at Hunter Unit 3 would be within these cost ranges.

Regardless of which of these cost analyses are used, the costs for LNB/OFA plus SCR at Hunter Units 1 and 2 are not unreasonable. Other similar sources have had to bear similar costs to control NOx. As discussed in the Technical Support Document to Comments of the Conservation Organizations, costs as high as $4,489/ton have been considered reasonable to just requiring SCR plus combustion controls to meet BART and thus such costs would be considered reasonable to meet BACT.[185] In a 2002 expert report, EPA's Expert Matt Haber found that costs

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[180] Letter from R. Douglas Neeley, USEPA, to Ronald W. Gore, ADEM, re: PSD Permit for Alabama Power, Olin Cogeneration Facility, McIntosh, Alabama (SPD-AL-187), January 15, 1998 (emphasis added) (Ex. 49).

[181] *See* July 2, 2012 PacifiCorp BART Analysis for Hunter Unit 1 at 11; June 7, 2012 PacifiCorp BART Analysis for Hunter Unit 2 at 11.

[182] *See* August 5, 2014 PacifiCorp's BART Analysis Updated for Hunter Units 1 and 2 and Huntington Units 1 and 2, Appendix A (Ex. 50).

[183] *See* Technical Support Document to Comments of Conservation Organizations, Determination of Best Available Retrofit Technology (BART) for Nitrogen Oxide Emissions at Units 1 and 2 of the Hunter Plant and Units 1 and 2 of the Huntington Power Plant, December 18, 2014 at 6-17 (Ex. 51).

[184] *Id.* at 27.

[185] *Id.* at 30.

as has as $13,196/ton were cost effective to require SCR as BACT, based on BACT determinations made back in 1990 and 1991.[186]

It must also be noted that limits must be imposed with averaging times consistent with the NAAQS.[187] Such limits could be based on the BACT determination or be more stringent than BACT, if necessary, to comply with the NAAQS.[188] For NOx, there are NAAQS based on an annual average and a 1-hour average.[189] The limits on NOx in the Title V renewal permit are only based on rolling 30-day averages, as shown in Table 15 above. Thus, the Title V renewal permit NOx limits also fail to reflect BACT because there is no 1-hour average NOx limit.

In summary, BACT for NOx at Hunter Units 1, 2, and 3 would undoubtedly be based on the application of SCR along with the recently installed low NOx burners and overfire air, and the units would be subject to NOx BACT emissions limits based on such controls that would be significantly lower than the 0.26 lb/MMBtu limit and the 0.34 lb/MMBtu limit that currently applies to Units 1, 2 and Unit 3, respectively. Even if the Hunter Units would have obtained a PSD permit and applied NOx BACT in 1997 before completing the 1997-1999 projects, NOx BACT would require the installation of SCR.[190] Thus, the Title V renewal permit for the Hunter plant does not imposed limits consistent with BACT for NOx at Units 1, 2 or 3.

B. BACT for SO2 at Hunter Units 1, 2, and 3 Would Require Higher SO2 Removal Efficiencies and Lower Emission Limits

For SO2 control, wet flue gas desulfurization (FGD) systems are typically considered the top SO2 control technology for coal-fired EGUs. Such SO2 controls can achieve 98-99% SO2 removal. A prime example is the Chiyoda CT-121 FGD. Vendor information for this technology indicates that this scrubber has achieved 98-99% SO_2 removal even with low sulfur coal.[191] Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including for coal-fired boilers.[192, 193,194] Sargent & Lundy has indicated that the lowest achievable SO2 emission rate with low sulfur Powder River Basin coal for a limestone forced oxidation (LSFO) wet scrubber would be 0.03-0.06 lb/MMBtu.[195] Although the Hunter units do not burn Powder River Basin coal, the sulfur content of the western

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[186] *See* Haber Expert Report, 2002, pp. 29, 37, 44, and Appendix A, Table 10 (Ex. 47).
[187] *See* November 4, 1986 EPA Memo with Subject: Need for a Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant (Ex. 52).
[188] *Id.*
[189] 40 C.F.R. § 50.11.
[190] *See* Report of Matt Haber: Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois (April 2002), prepared for the United States in connection with United States v. Illinois Power Company and Dynergy Midwest Generation, Inc., (cv-99-833-MJR, S.D. IL) ("Haber Expert Report") (Ex. 47).
[191] *See* Black & Veatch vendor brochure on CT-121 (Ex. 53).
[192] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4 (Ex. 54).
[193] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD (Ex. 55).
[194] Mitsubishi High SO2 Removal Experience (Ex. 56).
[195] *See* White Bluff Station Units 1 and 2 Evaluation of Wet vs Dry FGD Technologies, Rev. 3, October 28, 2008, prepared by Sargent & Lundy at 3-7 (Ex. 57).

Utah bituminous coal burned at the units of 0.5%[196] is on par with the sulfur content of Power River Basin coal.

Based on the coal data presented in PacifiCorp's Title V renewal permit application in 2001, the uncontrolled SO_2 emission rate from the Hunter units is approximately 0.81 lb/MMBtu.[197] The SO_2 emission limits in the Title V renewal permit, which are based on the SO_2 limits imposed upon upgrade of pollution control equipment in the March 2008 Approval Order, are 0.12 lb/MMBtu as shown in Table 3 above, which only reflects 85% SO_2 removal. This level of control is not reflective of BACT level.

For Hunter Unit 3, the 90% SO2 reduction requirement would likely mandate that a more stringent SO_2 rate be met than 0.12 lb/MMBtu, based on an uncontrolled rate of 0.81 lb/MMBtu. But even 90% control would not be considered BACT today.

In its proposed rulemaking for regional haze in Texas, EPA found based on review of cost data provided by source owners that wet FGD upgrades to achieve 95% SO_2 removal were cost effective for several coal-fired EGUs in Texas.[198]

There are many available options to improve SO_2 removal with physical and/or operational changes to existing wet scrubbers, and 95% control or better should be achievable. Indeed, the technology used in modern wet FGD systems that can achieve 98%-99% control can be incorporated into older wet FGD systems.[199] Many of the improvements in state-of-the-art wet FGDs are based on improving the liquid-to-gas contact and residence time, and thus adding wall rings and/or scrubber trays and new designs of spray headers that ensure more complete contact with the flue gas[200] can be often be readily incorporated into existing wet FGD systems. Further, chemical additives can be added to the scrubber slurry to enhance SO_2 removal. Older generation mist eliminators can be replaced with modern mist eliminator designs that more effectively wash the mist eliminators and prevent solids deposition, which ultimately makes the wet scrubber work more efficiently.[201] Further, existing wet FGDs can be converted to the limestone forced oxidation system that is currently the most common system for wet FGDs.[202] Thus, the technology of today's wet FGD systems can in many cases be incorporated into older scrubbers to raise SO_2 removal efficiencies to the control levels expected with a new FGD system.

For example, the wet FGD scrubber at Unit 3 of the Fayette Power plant was upgraded to achieve an emission limit that was reflective of 95.5% SO_2 removal without any scrubber bypass

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[196] *See* Hunter Plant Operating Permit Renewal Application, December, 2001, at D-9, D-11, and D-13.

[197] Based on AP-42 emission factors, the post-combustion SO2 concentration is 38 x Sulfur Content. AP-42, Using an average sulfur content of 0.5% and an average heat value of 11,750 Btu/lb, this equates to an uncontrolled SO_2 emission rate of 0.81 lb/MMBtu.

[198] 79 Fed. Reg. 74,818, 74,877 (Dec. 16, 2014).

[199] Moretti, Albert L., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Presented to Power-Gen Europe, Cologne, Germany, June 3-5, 2014, at 1-2 (Ex. 58).

[200] *Id.* at 5-6.

[201] *Id.* at 6-7.

[202] *Id.* at 7-8.

while burning 1% sulfur Powder River Basin coal.[203] The original wet scrubber was designed to achieve 90% control with up to 20% bypass, while burning high sulfur lignite coal.[204] Prior to the upgrade, the unit was achieving approximately 81% to 84% SO2 removal.[205] To meet an SO2 limit reflective of 95.5% control and no bypass, it was decided that the most cost effective solution for Fayette Power Unit 3 was to install one tray in each FGD absorber, increase the number of spray nozzles for each spray level, replace the original turning veins, and convert the chimney to wet stack operation.[206] The performance testing results of the upgraded wet scrubber greatly exceeded the 95.5% SO2 removal efficiency target, achieving on average 99.2% SO2 removal efficiency (based on scrubber inlet and scrubber outlet testing).[207]

Babcock Power provided evaluations of two sets of upgrades to the Mill Creek Unit 1, 2, and 4 wet FGD systems (which Unit 3 would be routed to): (1) to enable the wet FGD to achieve 96% SO2 removal efficiency and (2) to achieve 98% SO2 removal efficiency.[208] It was first determined that Units 1 and 2 FGD scrubbers could achieve a maximum of 88% SO_2 removal and the Unit 3 scrubber could be expected to achieve a maximum of 91% SO_2 removal without modifications.[209] It was next determined that these three scrubbers could achieve 96% SO2 removal efficiency with changes to spray nozzles, the addition of wall baffles, removing existing spargers, an increase in recycle pump capacity to handle an increase in liquid-to-gas ratio, and installation of agitators and oxidation air lancers on reactor tanks.[210] Last, it was determined that these scrubbers could achieve 98% SO_2 removal with additional modifications.

In general, those modifications included changes in spacing of spray levels, changes in the types of spray level nozzles, changes in the angles of spray nozzles, increasing number of spray nozzles, staggering of spray header layout, adding wall baffles, along with increasing the liquid-to-gas ratio and recycle pump capacity and other modifications.[211] Babcock Power predicted SO_2 removal efficiencies in excess of 98% with these modifications.[212] It was estimated that the wet FGD upgrades to achieve 96% removal would cost $10.5 to $14 million per unit, and upgrades to achieve 98+% removal would cost $20 to $33 million per unit.[213] This reflects a range of installation costs of $32/kW to $75/kW. Ultimately, it appears that the owners of the Mill Creek units are opting to install new scrubbers at Units 1 and 2 and just upgrade the Unit 3 scrubber.[214]

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[203] Frazer, C., A. Jayaprakash, S.M. Katzberger, Y.J. Lee, B.R. Tielsch, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO2 Reduction, presented to EPRI Power Plant Air Pollutant Control Mega Symposium, August 30 – September 2, 2010, Baltimore, MD, at 1 (Ex. 59).
[204] *Id.*
[205] *Id.* at 2.
[206] *Id.* at 3.
[207] *Id.* at 6.
[208] *See* February 2011, Babcock Power, LG&E Services Company Contract No. 501654, Mill Creek FGD Performance Upgrade Study, Assess the feasibility of upgrading the Mill Creek Units 1 & 2 FGD's and upgrading the existing Mill Cree 4 FGD and utilizing it for Mill Creek Unit 3 (Ex. 60).
[209] *Id.* at 2.
[210] *Id.* at 3-6.
[211] *Id.* at 6-10.
[212] *Id.* at 11.
[213] *Id.* at 6 and 10.
[214] *See* https://lge-ku.com/our-company/community/neighbor-neighbor/mill-creek-generating-station.

In its proposed rulemaking for Texas regional haze, EPA found that wet scrubber upgrades were cost effective, with cost data less than $600/ton.[215] In fact, SO_2 scrubber upgrade costs as high as $3,200/ton have been considered cost effective for regional haze and BART determinations.[216]

For all of these reasons, it is expected that, at the minimum, BACT for SO_2 at the Hunter units would be 95% removal with upgrades to the existing wet FGD systems, if not higher levels of SO_2 removal. Ninety-five percent removal from an uncontrolled SO_2 emission rate of 0.81 lb/MMBtu equates to an emission rate of 0.04 lb/MMBtu. The SO_2 limits in the Title V renewal permit for the Hunter plant, which were established in the March 2008 Approval Order as the limited that applied upon upgrades to control equipment and are listed in Table 15 above, do not reflect 95% removal from current coal and thus do not reflect current SO2 BACT for SO_2 at the Hunter units.

It must also be noted that limits must be imposed with averaging times consistent with the NAAQS.[217] Such limits could be based on the BACT determination or be more stringent than BACT, if necessary, to comply with the NAAQS.[218] For SO_2, there are NAAQS based on an annual average, a 24-hour average, a 3-hour average, and a 1-hour average. 40 C.F.R. §§ 50.4, 50.5, and 50.17. The only short term average limit on SO_2 emissions in the Title V renewal permit for Hunter is the 1.2 lb/MMBtu SO2 limit that applies on a 3-hour average basis. However, given that uncontrolled SO_2 emissions are less than 1.2 lb/MMBtu, this limit does not require any reduction in SO_2 emissions and therefore cannot be considered to satisfy BACT. Further, modeling of Units 1 and 2 at this 1.2 lb/MMBtu SO_2 limit and Unit 3 at the 0.12 lb/MMBtu 30-day rolling average SO_2 limit predicted significant violations of the 1-hour SO_2 NAAQS, as discussed in Section V. Thus, the SO_2 limits of the Title V renewal permit for the Hunter plant also fail to reflect BACT for SO_2 because of the lack of short term average limits requiring SO_2 emissions control.

In summary, BACT for SO_2 at Hunter Units 1, 2 and 3 would undoubtedly be based on FGD upgrades to achieve at least 95% SO_2 removal efficiency, and the units would be subject to SO2 BACT emissions limits based on such controls that would be significantly lower than the 0.12 lb/MMBtu limits and the 80% (for Units 1&2) and 90% control (for Unit 3) SO_2 removal requirements in the Title V renewal permit. Wet scrubbers achieving ninety-five percent control would have also been BACT for SO_2 had the Hunter projects completed in 1997-1999 been properly permitted in 1997.[219] Thus, the Title V renewal permit for the Hunter Plant does not imposed limits consistent with BACT for SO_2 at Units 1, 2 or 3.

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[215] 79 Fed. Reg. 74877 (Dec. 16, 2014).

[216] *See* Technical Support Document to Comments of Conservation Organizations on EPA's Proposed Texas Regional Haze Plan, Prepared by Vicki Stamper, April 17, 2015, at 37-39 (Ex. 61).

[217] *See* November 4, 1986 EPA Memo with Subject: Need for a Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant (Ex. 52).

[218] *Id.*

[219] *See* Report of Matt Haber: Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois (April 2002), prepared for the United States in connection with United States v. Illinois Power Company and Dynergy Midwest Generation, Inc., (cv-99-833-MJR, S.D. IL), at 13-17. (Ex. 47).

C. BACT for PM/PM10 for Hunter Units 1, 2, and 3 Would Require Lower Emission Limits and More Restrictive Visible Emissions Limits

For PM and filterable PM10 control, a baghouse is typically considered the top pollution control technology. As of mid-2014, all three Hunter units were equipped with baghouses. While the units are equipped with the top PM control technology, the units are not subject to emission limits reflective of BACT.

There have been several recent PSD permits issued with best available control technology (BACT) limits at 0.010 lb/MMBtu based on installation of a fabric filter baghouse, including the Plant Washington permit, the Longleaf permit, and the Desert Rock permit.[220]

Even these lower emission limits fail to reflect the low levels of filterable PM emissions can be achieved with fabric filter baghouses. Source test data have shown that lower emission levels can be achieved. At least 147 performance tests at coal-fired plants in Florida, as early as May 2004, measured filterable PM/PM_{10} at less than 0.010 lb/MMBtu and 82 recorded PM/PM_{10} emissions less than 0.005 lb/MMBtu. The lowest reported PM/PM_{10} emission rate was 0.0004 lb/MMBtu.[221]

Further, Matt Haber, EPA Region 9's BACT expert and current Deputy Director of the Air Division, concluded back in 2002 that BACT for filterable PM at two existing PC boilers firing Powder River Basin coal and equipped with a baghouse was 0.006 lb/MMBtu based on a 3-hour average and monitored via EPA Method 5 and continuously using triboelectric broken bag detectors.[222]

Thus, the 0.015 lb/MMBtu PM limits applicable to Hunter Units 1, 2, and 3 in the Title V renewal permit do not reflect the maximum degree of PM or PM10 reduction that can be achieved with a baghouse and are less stringent than BACT.

In addition, BACT is to include a visible emissions limit. Utah Admin. Code R307-401-2. The Title V renewal permit for Hunter includes 20% opacity limits, "except during periods of startup, shutdown, and malfunction ad except for one 6-minute period per hour of not more than 27 percent opacity." *See* 2020 Title V Renewal Permit for Hunter Plant at 27 (Condition II.B.2.f) and 37 (Condition 2.B.3.d). First, it must be noted that there are several permits with BACT opacity limits lower than 20% opacity.

Many coal plant permits include visible emissions as part of the BACT limits for those facilities. Utah issued two permits for coal-fired power plants to be equipped with fabric filter baghouses—Intermountain Power Unit 3[223] and the Sevier power plant[224]—which both have 10 percent opacity limits required as BACT. The MidAmerican facility in Council Bluffs, Iowa,

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[220] These Permits are attached as Ex. 62 (Plant Washington), Ex.63 (Longleaf), and Ex.64 (Desert Rock).
[221] Florida Source Tests compilation (Ex.65).
[222] Haber Expert Report, at 3 (Ex. 47).
[223] *See* October 15, 2004 Approval Order DAQE-AN0327010-04 for Intermountain Power Generating Station Unit 3 (Ex. 66).
[224] *See* October 12, 2004 Approval Order DAQE-AN2529001-04 for Sevier Power Company (Ex. 67).

has an opacity limit of 5 percent.[225] The Plum Point facility in Osceola, Arkansas, has a BACT limit of 10 percent opacity.[226] Thus, the 20% opacity limits in the Title V renewal permit for the Hunter units do not reflect BACT for visible emissions.

In summary, while the Hunter Units 1, 2 and 3 may be equipped with the top control for particulate matter—*i.e.*, a baghouse—the units are not subject to PM or visible emission limits that reflect BACT. PM BACT limits would include a PM limit at least as low as 0.010 lb/MMBtu and a 10% opacity limit. Moreover, there are no limits in the 2020 Title V renewal permit for PM10 at Hunter Units 1, 2 or 3.

CONCLUSION

As demonstrated above, modifications made to the Hunter Units 1, 2, and 3 in 1997-1999 triggered the need to apply BACT for NOx, SO_2, and PM/PM10 under the applicable PSD requirements. All sources subject to Title V must have a permit to operate that "assures compliance by the source with all applicable requirements."[227] Like the Hunter Plant's 2016 renewal Title V permit, the 2020 renewal Title V permit is deficient because it fails to assure compliance with applicable PSD requirements. Accordingly, pursuant to Clean Air Act § 505(b)(2) and 40 C.F.R. § 70.8(d), EPA must object to UDAQ's issuance of this deficient permit.

DATED: October 20, 2020

[225] Iowa Dep't Natural Resources Air Quality PSD Construction Permit # 03-A-425-P2 at 5 (Ex. 68).
[226] Ark. Dep't Envtl. Quality Operating Air Permit # 1995-AOP-R0 at 9 (Ex. 69).
[227] *See* 40 C.F.R. § 70.1(b); CAA § 504(a), 42 U.S.C. § 7661c: Utah Administrative Code R307-415-6a(1).

Sincerely,

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LIST OF EXHIBITS

Exhibit 1: UDAQ, Title V Renewal Operating Permit for PacifiCorp's Hunter Power Plant, Permit No. 1500101004, issued 9/4/2020

Exhibit 2: Sierra Club Comments on the Draft Title V Renewal Permit for the Hunter Power Plant dated November 13, 2015 (without attachments)

Exhibit 3: Sierra Club Petition Seeking EPA's Objection to the Hunter Power Plant Title V Renewal Permit, dated April 11, 2016 (without attachments)

Exhibit 4: UDAQ, Response to Public Comments on draft Title V renewal permit for the Hunter Plant, dated Jan. 11, 2016

Exhibit 5: *In the Matter of PacifiCorp Energy, Hunter Power Plant*, Order on Petition No. VIII-2016-4 (U.S. EPA, Oct. 16, 2017)

Exhibit 6: *Sierra Club v. U.S. EPA*, 964 F.3d 882 (10th Cir. 2020)

Exhibit 7: Order Denying Petitions for Panel Rehearing and Rehearing En Banc in Case No. 18-9507, Oct. 16, 2020, Docket I.D. 010110424337

Exhibit 8: August 18, 1997 Request for Approval Order Modifications to Limit the Potential to Emit at the Hunter Plant

Exhibit 9: November 20, 1997 Approval Order DAQE-1099-97

Exhibit 10: December 18, 1997 Approval Order DAQE-1189-97

Exhibit 11: May 3, 2005 letter from UDAQ to PacifiCorp

Exhibit 12: Utah Air Conservation Rules R307-1 as in effect on 1/1/95

Exhibit 13: EPA Letter to Henry Nickel, Counsel for Detroit Edison Company (May 23, 2000)

Exhibit 14: September 9, 1988 Memorandum from Don R. Clay, USEPA, to David A. Kee, "Applicability of Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) Requirements to the WEPCO Power Company Port Washington Life Extension Project"

Exhibit 15: April 17, 2001 letter from EPA Region VIII to North Dakota Health Department, re Otter Tail Power Company's Coyote Station Low Pressure Rotor Upgrade Proposal.

Exhibit 16: Kitto, Jr., J.B. et al, Upgrades and Enhancements for Competitive Coal-Fired Boiler Systems

Exhibit 17: February 15, 1989 letter from EPA to WEPCO

Exhibit 18: September 13, 2000 EPA Region IV letter to Georgia Environmental Protection Division re No. 1 Recovery Furnace Maintenance, Repair and Replacement Project, PCA Pulp and Paper Mill, Valdosta, Georgia

Exhibit 19: Babcock&Wilcox, DSVS® Rotating Classifier, Improves Pulverizer Efficiency and Operational Flexibility

Exhibit 20: PacifiCorp's March 21, 1995 letter to UDAQ

Exhibit 21: November 5, 2001 EPA Region 10 letter to Washington Department of Ecology, re Recovery Furnace Modifications at Longview Fibre, Longview Mill and Boise Cascade Corporation, Wallula Mill

Exhibit 22: September 13, 2000 EPA Region 4 Letter to Georgia Environmental Protection Division, re No. 1 Recovery Furnace Maintenance, Repair and Replacement Project PCA Pulp and Paper Mill, at 1-2

Exhibit 23: June 17, 1993 EPA Memo with Subject "Applicability of New Source Review Circumvention Guidance to 3M –Maplewood, Minnesota

Exhibit 24: RMB Consulting & Research, Inc., The Electric Power Research Institute Continuous Emissions Monitoring Heat Rate Discrepancy Project, What Has Been Learned and Future Activities, Presented at the 1997 EPRI CEM Users Group Meeting, Denver, CO, May 14-16, 1997

Exhibit 25: December 1996, RMB Consulting & Research, Inc., The Electric Power Research Institute Continuous Emissions Monitoring Heat Rate Discrepancy Project, An Update Report – December 1996

Exhibit 26: U.S. EPA, August 26, 1999, Approval of New Testing Procedures for Measurement of Stack Gas Flow Rate for Optional Application in Place of Method 2 under 40 CFR Parts 60, 61, and 63

Exhibit 27: Hunter Emissions Data

Exhibit 28: March 31, 2006 WRAP Report, 2004 Regional SO_2 Emissions and Milestone Report, at 4-5

Exhibit 29: Western Regional Air Partnership, Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program, An Annex Report to the Report of the Grand Canyon Visibility Transport Commission, submitted to the U.S. Environmental Protection Agency September 29, 2000

Exhibit 30: April 3, 1986 Approval Order for Hunter Unit 1

Exhibit 31: July 27, 1987 Approval Order for Hunter Unit 2

Exhibit 32: Spreadsheet "Hunter Projects 1997-99 Emission Calculations"

Exhibit 33: Title V Operating Permit for Hunter Power Plant, Permit Number 1500101001, January 7, 1998

Exhibit 34: Exhibit Accompanying Direct Testimony of Barry G. Cunningham before the Wyoming Public Service Commission, The Marsh Report, January 2, 2001

Exhibit 35: May 21, 2008 Letter from Jeff Robinson, Chief, Air Permits Section, EPA Region 6 to Mr. Richard Hyde, Director, Texas Commission on Environmental Quality, Enclosure

Exhibit 36: January 28, 1993 Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, US EPA Region I

Exhibit 37: February 15, 1983 Memorandum from Kathleen M. Bennett, Assistant Administrator for Air and Radiation, to the Regional Administrators, entitled "Policy Regarding Excess Emissions During Startup, Shutdown, Scheduled Maintenance, and Malfunctions"

Exhibit 38: August 31, 1983 Approval Order

Exhibit 39: March 13, 2008 Approval Order

Exhibit 40: PacifiCorp, November 27, 2007 NOI

Exhibit 41: December 18, 2009 letter from PacifiCorp to UDAQ, Re: Status of the Hunter Plant's Pollution Control Equipment and Capital and O&M Projects

Exhibit 42: May 13, 2011 letter from PacifiCorp to UDAQ, RE: Status of the Hunter Plant's Pollution Control Equipment and Capital and O&M Projects

Exhibit 43: July 2, 2012 PacifiCorp BART Analysis for Hunter Unit 1

Exhibit 44: December 7, 2011 letter from PacifiCorp to UDAQ, RE: Status of the Hunter Plant's Pollution Control Equipment and Capital and O&M Projects

Exhibit 45: June 7, 2012 PacifiCorp BART Analysis for Hunter Unit 2

Exhibit 46: List of NOx Emissions from Pulverized Coal Boilers Taken from the RACT/BACT/LAER Clearinghouse, from the January 17, 2008 Prevention of Significant Deterioration Air Permit Application for Plant Washington, Power4Georgians (excerpted)

Exhibit 47: Report of Matt Haber: Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois (April 2002), prepared for the United States in connection with United States v. Illinois Power Company and Dynergy Midwest Generation, Inc., (cv-99-833-MJR, S.D. IL) ("Haber Expert Report")

Exhibit 48: Letter from Cheryl Newton, Chief, Permits and Grants Section, Region 5, to Robert Hodanbosi, Chief, Division of Air Pollution Control, Ohio Environmental Protection Agency, March 20, 1998

Exhibit 49: Letter from R. Douglas Neeley, USEPA, to Ronald W. Gore, ADEM, re: PSD Permit for Alabama Power, Olin Cogeneration Facility, McIntosh, Alabama (SPD-AL-187), January 15, 1998

Exhibit 50: August 5, 2014 PacifiCorp's BART Analysis Updated for Hunter Units 1 and 2 and Huntington Units 1 and 2

Exhibit 51: Technical Support Document to Comments of Conservation Organizations, Determination of Best Available Retrofit Technology (BART) for Nitrogen Oxide Emissions at Units 1 and 2 of the Hunter Plant and Units 1 and 2 of the Huntington Power Plant, December 18, 2014

Exhibit 52: November 4, 1986 EPA Memo with Subject: Need for a Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant

Exhibit 53: Black & Veatch Vendor Brochure on CT-121

Exhibit 54: Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003

Exhibit 55: Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD

Exhibit 56: Mitsubishi High SO_2 Removal Experience

Exhibit 57: White Bluff Station Units 1 and 2 Evaluation of Wet vs Dry FGD Technologies, Rev. 3, October 28, 2008, prepared by Sargent & Lundy

Exhibit 58: Moretti, Albert L., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Presented to Power-Gen Europe, Cologne, Germany, June 3-5, 2014

Exhibit 59: Frazer, C., A. Jayaprakash, S.M. Katzberger, Y.J. Lee, B.R. Tielsch, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, presented to EPRI Power Plant Air Pollutant Control Mega Symposium, August 30 – September 2, 2010, Baltimore, MD

Exhibit 60: February 2011, Babcock Power, LG&E Services Company Contract No. 501654, Mill Creek FGD Performance Upgrade Study, Assess the feasibility of upgrading the Mill Creek Units 1 & 2 FGD's and upgrading the existing Mill Cree 4 FGD and utilizing it for Mill Creek Unit 3

Exhibit 61: Technical Support Document to Comments of Conservation Organizations on EPA's Proposed Texas Regional Haze Plan, Prepared by Vicki Stamper, April 17, 2015, at 37-39

Exhibit 62: Plant Washington Permit

Exhibit 63: Longleaf Permit

Exhibit 64: Desert Rock Permit

Exhibit 65: Florida Source Tests Compilation

Exhibit 66: October 15, 2004 Approval Order DAQE-AN0327010-04 for Intermountain Power Generating Station Unit 3

Exhibit 67: October 12, 2004 Approval Order DAQE-AN2529001-04 for Sevier Power Company

Exhibit 68: Iowa Dep't Natural Resources Air Quality PSD Construction Permit # 03-A-425-P2

Exhibit 69: Ark. Dep't Envtl. Quality Operating Air Permit # 1995-AOP-R0