UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.; PacifiCorp; NextEra Energy Resources, LLC; Invenergy Wind North America LLC; and Horizon Wind Energy LLC, Complainants, v. Bonneville Power Administration, Respondent.	Docket No. EL11-44-000

ANSWER OF THE
BONNEVILLE POWER ADMINISTRATION

Pursuant to Rules 206 and 213 of the Federal Energy Regulatory Commission ("Commission") Rules of Practice and Procedure,[1] the Bonneville Power Administration ("Bonneville") hereby submits its Answer to the Complaint and Petition for Order Under Federal Power Act Section 211A (hereafter "Complaint") filed on June 17, 2011, by Iberdrola Renewables, Inc; PacifiCorp; NextEra Energy Resources, LLC; Invenergy Wind North America, LLC and Horizon Wind Energy, LLC (hereafter "Complainants"). Complainants challenge Bonneville's emergency replacement of their wind-generated power with free Federal hydro power under the agency's Interim Environmental Redispatch and Negative Pricing Policies.

[1] 18 C.F.R. §§ 385.206, 213 (2011).

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CORRESPONDENCE AND COMMUNICATIONS

All correspondence and communications concerning the above-captioned proceeding should be addressed to the following persons:[2]

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I. INTRODUCTION

On May 13, 2011, following a regional notice and comment process, the Bonneville Administrator issued a Record of Decision adopting the Interim Environmental Redispatch and Negative Pricing Policies ("the Policies").[3] The Policies are narrowly tailored to ensure that, consistent with Bonneville's contracts, the agency can meet its reliability requirements, its legal responsibilities under the Clean Water Act, Endangered Species Act, and Federal court order, and its statutory responsibilities under the Northwest Power Act, when high stream flows, wind generation, and insufficient load combine to endanger fish protected under Federal environmental law.

Complainants challenge Bonneville's Policies. Knowing the Commission does not have authority to order Bonneville to pay them to reduce generation or to adjudicate

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[2] Bonneville requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3) (2010), to the extent necessary to permit more than two persons to be included on the official service list on its behalf in this proceeding.
[3] Attachment A, Final Record of Decision on BPA's Interim Environmental Redispatch and Negative Pricing Policies ("ROD").

breach of contract claims against Bonneville, they have requested other remedies calculated to leave Bonneville with no alternative during high water/low load events other than to pay Complainants and others in order to meet Bonneville's environmental, reliability, and other statutory responsibilities. The Complaint challenges a Bonneville final action taken under the Northwest Power Act and is therefore within the exclusive jurisdiction of the U.S. Court of Appeals for the Ninth Circuit. Moreover, the relief sought exceeds the Commission's authorities and, in any case, should not be granted.

Dams comprising the Federal Columbia River Power System are multi-purpose projects requiring the system operators -- Bonneville, the U.S. Bureau of Reclamation and U.S. Army Corps of Engineers ("Corps of Engineers") -- to balance multiple authorized purposes, including flood control, recreation, transportation, irrigation, and power generation. Harm to fish in the river from gas bubble trauma can occur when water spilled through dam spillways exceeds certain levels. Too much spill injects dangerous amounts of nitrogen, oxygen and other gases into the water that can harm fish.

Conversely, water moved through turbines introduces significantly less gas into the river. One of the management tools available to avoid harmful spill has been to run the excess water through the turbines to generate more power which is then sold to generators (at zero price if necessary) that use it to displace their own generation and serve their loads. The displacement offsets the additional hydro power generation to maintain system reliability. However, the recent integration of large amounts of wind generation into the Bonneville transmission system has threatened Bonneville's ability during high flows to generate more power to avoid spill harmful or even fatal to fish, because wind generators have refused Bonneville's offer of free Federal hydro power to displace their wind generation.

Under the Environmental Redispatch Policy, if voluntary redispatch of non-Federal generators does not fully satisfy the need to generate more Federal hydro power and thereby manage spill, Bonneville requires thermal and other generation in Bonneville's balancing authority area to back down as needed and use free Federal hydro power to serve their loads. Bonneville first issues redispatch orders to non-Federal thermal and hydroelectric generators that are still generating above minimum generation levels and substitutes free Federal hydroelectric power to serve their loads. Only if still more load is needed does Bonneville redispatch wind generators as a last resort with free Federal hydroelectric power. Thus, the Environmental Redispatch Policy favors wind generators over other non-Federal generation before substituting carbon-free Federal hydro power is substituted for carbon-free wind power.

From a public policy standpoint it is clear what needs to happen physically when gas cap limits are approached. In order to maintain reliability and meet ESA requirements, generation needs to be limited; for economic reasons thermal plants should be maximally displaced before wind power is displaced. Wind should not be operating in this situation and does not receive production and renewable energy credits under existing law. In this proceeding, wind operators are seeking to export their lost opportunity cost to another party.

Complainants nevertheless argue that if Bonneville and the region's ratepayers want to avoid the harm to aquatic life and Federal ESA-listed fish that would occur if the wind generators continued to produce at full output, Bonneville should not only provide the wind generators with free federal hydro-power but should also pay them not to produce, thus replacing the Production Tax Credits (PTCs) and Renewable Energy Credits (RECs) they receive from other government entities. They portray such payments as incidental to Bonneville's power operations rather than having been caused by their recent integration onto Bonneville's system.

However, Bonneville has appropriately determined under its Negative Pricing Policy that payment of negative prices is unreasonable, as a matter of both law and policy. Bonneville and its public and private customers have incurred billions of dollars in costs to protect and enhance salmon and other species and should not have to pay any generators, including wind generators, to protect the region's aquatic life, including ESA-listed fish. Bonneville's contracts with interconnected generators, including wind generators, assure Bonneville's ability to fulfill its responsibilities under the Endangered Species Act, the Clean Water Act, and other laws without having to pay other parties in order to do so.

For years now, Bonneville has successfully encouraged renewable resource development while meeting its reliability and environmental obligations and assuring cost recovery. In the Pacific Northwest, the wind industry is no longer nascent due in large part to Bonneville's efforts. Wind generation now far exceeds the amounts needed to meet Pacific Northwest state renewable portfolio standards and at times even to meet Northwest loads. Bonneville aggressively integrated wind to support Federal and state public policy objectives to diversify power supply away from greenhouse gas emitting resources.

Complainants disregard the financial impact of forcing the costs of their demanded payments onto regional ratepayers, particularly in the Bonneville balancing authority area, whose wind resources are largely exported. They ignore the potential for political repercussions from Northwest consumers questioning the value of additional wind resources that must be paid when the federal hydroelectric system must generate to protect fish. Ultimately, their demands, if fulfilled, would likely have negative implications for large scale expansion of wind power in local transmission and resource siting decisions.

Complainants argue that Bonneville's Environmental Redispatch Policy discriminates because it favors Federal generation. When one compares Bonneville's action to the activities the Commission sought to prevent through open access, however, radical differences emerge. In the Notice of Proposed Rulemaking (NOPR) that preceded the issuance of Order No. 888, the Commission noted that utilities discriminate because they "are naturally profit maximizers and monopoly suppliers to their native load."[4] Therefore, they resisted open access, which placed their existing generation at risk because "their wholesale customers may seek alternative lower price suppliers."[5] Instead, they used their market power "to retain (or expand) market share for their existing generation facilities."[6]

[4] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* FERC Stats. & Regs. ¶ 32,514, at 33,071 (1995) ("Order No. 888").
[5] *Id.*
[6] *Id.*

Although the use of market power can harm competing sellers, the Commission concluded that "[t]he ultimate loser in such a regime is the consumer."[7] Discrimination "can harm consumers by denying them the benefits of competitively priced power."[8] *Id.* at 33,076.

The above motivations are absent here. Bonneville is not curtailing generators to maximize profits. It is not denying open access to foreclose lower-cost suppliers. It is not seeking to retain or expand market share. Bonneville is not even serving its own load with the additional hydro power. Instead, Bonneville is generating additional power to serve non-Federal loads at no cost. Bonneville is acting to protect aquatic life, including ESA-listed fish, while protecting itself and its customers from exposure to costs that the Federal and state governments have placed on taxpayers and consumers of wind power. "Favoritism" has little meaning under these circumstances.

Complainants devote a significant portion of their complaint to surveying Bonneville's alleged failings as a reciprocity transmission provider, trying to portray Bonneville as a bad actor in the hope that the Commission will rule on that basis. In fact, Bonneville, one of the few non-jurisdictional utilities that has continued filing open access tariffs with the Commission over the years, is conducting an on-going, open and fully transparent public process to continue to ensure its tariff best meets the region's needs. Nevertheless, Complainants seek to have the Commission resolve issues that are currently being discussed in the region. Most importantly, however, Bonneville's reciprocity status is irrelevant to this dispute. Congress debated and rejected in both the

[7] *Id.*
[8] *Id.* at 33,076.

1992 and 2005 Energy Policy Acts the expansive relief the Complainants now seek from the Commission to address their reciprocity-related allegations.

Complainants are well aware of that. They appear to be unaware that by focusing on the broad range of issues under regional discussion concerning Bonneville's open access tariff, the vast majority of which have nothing to do with Environmental Redispatch, they make it much more likely that parties' energies will be devoted to litigation rather than problem solving. Instead, Complainants focus on fully maintaining their PTC and REC benefits, failing to acknowledge their contributions to the environmental problem that occurs in times of high water and high wind generation. Bonneville urges the Commission to reject the Complainants' requests for relief, and thereby send them a clear signal that they and all parties need to return to regional problem solving, support reliability and environmental protection, and focus on actions that will encourage renewable resource development over the long term.

Finally, contrary to Complainants' conclusory and unsubstantiated assertions, the Bonneville Administrator is not acting in derogation of his contractual obligations. To the contrary, throughout the 87-page Record of Decision ("ROD") he issued after taking comment on Bonneville's proposed Policies, the Administrator analyzed his statutory responsibilities and contractual rights and obligations, and adopted a policy that would ensure he honored both. The contract fully accommodates Bonneville's actions at issue here.

If Bonneville is to integrate wind into its system, reasonable and cost-effective measures *must* be available to ensure that Bonneville can continue to meet its responsibilities to fish and wildlife. At this point, the Policies are a necessary measure.

In the hope that alternative measures can be found, Bonneville adopted the Policies only as an interim measure. Bonneville and parties throughout the region are working earnestly and in good faith to explore alternative measures that can avoid the need for Environmental Redispatch in the future.

II. EXECUTIVE SUMMARY

Bonneville has adopted and implemented Environmental Redispatch to fulfill its environmental and reliability responsibilities under the Endangered Species Act, the Clean Water Act, the Northwest Power Act, and the orders of the U.S. District Court for the District of Oregon. Bonneville adopted the policy after conducting a regional notice and comment process and issuing a record of decision. The policy constitutes a final action or decision by the Bonneville Administrator under the Northwest Power Act and consequently challenges to the policy are within the exclusive jurisdiction of the Ninth Circuit Court of Appeals.

Should the Commission nevertheless conclude that it has the authority to review the Administrator's action, it should dismiss the Complaint. Complainants seek relief under sections 210 and 211A of the Federal Power Act. The Environmental Redispatch policy does not violate comparability and is not unduly discriminatory. In addition, in applying sections 210 and 211A to Bonneville, the Commission must assure that Bonneville's organic statutes and the other Federal laws that apply to Bonneville continue in full force and effect. Bonneville's action was taken in order to ensure that Bonneville fulfilled the requirements of these laws. The Commission should not disturb the Administrator's determination.

Complainants ask the Commission to invalidate Bonneville's Environmental Redispatch policy and force Bonneville to pay negative prices; that is, to sell its generation into the market when electricity is negatively priced, or to pay wind generators not to generate. This action could severely compromise Bonneville's ability to fulfill its statutory requirement to recover all its costs and repay the U.S. Treasury for the Federal investment in the Federal Columbia River Power System, and to fulfill its environmental responsibilities.

Moreover, the Commission cannot award the relief Complainants request. The Commission does not have the authority to remedy Bonneville's alleged violations of the Northwest Power Act. As to the Federal Power Act allegations, section 210 applies to the Commission's ordering of a physical interconnection of a generator with a utility's transmission system. Complainants are already physically interconnected with the Bonneville system and therefore are not seeking such an order. In addition, they have not made the showings required by that section before the Commission may issue an order.

Similarly, the Commission may not order Bonneville to submit an open access tariff for approval under section 211A. First, this remedy is far too broad for the alleged wrong Complainants are challenging. Second, section 211A does not give the Commission the authority to order an unregulated transmitting utility to adopt the *pro forma* tariff or to submit an open access tariff for Commission approval.

Contrary to Complainants' claims, Bonneville's actions are consistent with its transmission tariff and with its Large Generator Interconnection Agreement. Bonneville implements Environmental Redispatch to maintain reliability and to adhere to applicable laws and regulations, as contemplated by the agreement. In addition, the Commission does not have the authority to rule on alleged breaches of contract by Bonneville or to issue remedies for breach of contract by Bonneville.

Finally, an order by the Commission may affect species listed under the Endangered Species Act, and therefore the Commission may have an obligation to consult under the act before issuing an order.

III. PROCEDURAL MATTERS

Complainants' factual allegations are woven throughout the Complaint. They are addressed throughout the answer, as the answer responds to the arguments to which the allegations relate.[9]

Bonneville and Complainants have been involved in a regional process to resolve the issues raised in the Complaint. Bonneville proposes that this process be used to resolve these issues.[10]

IV. EVOLUTION OF BONNEVILLE'S STATUTORY RESPONSIBILITIES

Bonneville, like the Commission, is a creature of statute, laden with all the authorities and responsibilities Congress has legislated. This section of Bonneville's Answer provides an overview of Bonneville's organic statutes. In subsequent sections, Bonneville demonstrates that provisions of the Energy Policy Act of 1992 and the Energy Policy Act of 2005 did not repeal Bonneville's organic responsibilities, but must be construed consistent with them.

As detailed in the Policies ROD, Bonneville was created as a Federal agency in 1937 to market the output of the Federal Bonneville project, and later designated as the marketing agent for the output of other U.S. Army Corp of Engineers and Bureau of

[9] 18 C.F.R. § 385.213(c)(1)(i) and (c)(2)(i).
[10] *Id.* § 385.213(c)(4).

Reclamation hydro power projects in the Pacific Northwest.[11] These projects are collectively known as the Federal Columbia River Power System (FCRPS). Many of the generating plants comprising the FCRPS are components of projects that are operated for many public purposes, including flood control, fish and wildlife protection, irrigation, power production, navigation, recreation, municipal water supply, and other purposes.[12]

The Bonneville transmission system was first built and operated by Bonneville with appropriated monies to allow it to successfully market the Federal hydro power by integrating Federal generation to load.[13] The capability of the transmission system was tied to generation levels, especially at the critical hydroelectric projects along the Lower Columbia and Lower Snake Rivers. Bonneville's rates were to be established having regard to the recovery of the cost of producing and transmitting such electric energy, including the amortization of the Federal capital investment over a reasonable period of years.[14]

With the passage of the 1974 Transmission System Act,[15] the Administrator was vested with broad authority to operate and maintain the Bonneville transmission system and to

> construct improvements, betterments, and additions to and replacements of such system within the Pacific Northwest as he determines are appropriate and required to:
>
> (a) integrate and transmit the electric power from existing or additional Federal or non-Federal generating units;

[11] ROD at 2-5.
[12] *See*, *e.g.*, Bonneville Project Act, 16 U.S.C. § 832 (2009); 43 U.S.C. § 485h(a)-(b) (2009); Federal Water Project Recreation Act, 16 U.S.C. §§ 460l-12, 460l-13, 460l-18 (2009); Flood Control Act of 1962, Pub. L. No. 87-874, § 203, 76 Stat. 1180 (1962); Flood Control Act of 1950, Pub. L. No. 81-516, § 204, 64 Stat. 170 (1950); Rivers and Harbors, Improvements Act, Pub. L. No. 79-14, 59 Stat. 10 (1945); Columbia Basin Project Act, 16 U.S.C. § 835l; H.R. Rep. No. 80-1507, at 2 (1948).
[13] *Id.; see also, e.g.*, 16 U.S.C. § 832a(b) (2009); 16 U.S.C. § 825s (2009).
[14] 16 U.S.C. § 832a(f) (2009); 16 U.S.C. § 825s (2009).
[15] 16 U.S.C. § 838-838k (2009).

(b) provide service to the Administrator's customers;
(c) provide interregional transmission facilities; or
(d) maintain the electrical stability and electrical reliability of the Federal system.[16]

To effectuate these and other responsibilities, Bonneville was placed on a self-financing basis and provided with authority to borrow from the U.S. Treasury "to assist in financing the construction, acquisition, and replacement of the transmission system."[17] Construction of major and extra-regional transmission facilities remained subject to approval by an Act of Congress, but other planned expenditures of the Administrator are submitted to Congress as part of Bonneville's annual budget and may be implemented subject only to such specific directives or limitations as may be included in appropriation acts.[18]

Bonneville's mission and responsibilities expanded significantly with passage of the Northwest Power Act (NWPA), which, among other things, imposed on Bonneville a native-load like duty to serve preference loads, and the authority to acquire conservation and the output of resources to serve those loads.[19] The Administrator was also charged with using "the authorities available to the Administrator under this chapter [the Northwest Power Act] and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries . . ."[20]

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[16] 16 U.S.C. § 838b (2009).
[17] 16 U.S.C. §§ 838i, 838j (2009).
[18] 16 U.S.C. §§ 838b, 838i(b) (2009).
[19] 16 U.S.C. §§ 839c(b)(1), 839d (2009). 16 U.S.C. §§ 839c(b)(1) begins: "Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds— . . . ."
[20] 16 U.S.C. §§ 839b(h)(10)(A) (2006).

Furthermore, the Administrator and other Federal agencies responsible for managing, operating, or regulating hydroelectric projects on the Columbia River and its tributaries must exercise their responsibilities "in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are managed and operated;"[21] the Administrator must act "consistent with" the Pacific Northwest Electric Power Planning and Conservation Council's ("Council") Fish and Wildlife Program ("the program");[22] and the Administrator and Federal water managers must take the program "into account . . . to the fullest extent practicable" at each relevant stage of decision making.[23]

First with the 1974 Transmission System Act and later with the Northwest Power Act, Congress was also clear that Bonneville must establish its power and transmission rates to ensure total cost recovery.[24] As the Administrator observed in the ROD, "The

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[21] *Id*. § 839b(h)(11)(A)(i) (2009). Bonneville provides equitable treatment to fish and wildlife by undertaking mitigation measures on a system-wide basis as described in greater detail in *NW Env'l Def. Center v. Bonneville Power Admin*., 117 F. 3d 1520, 1532-34 (9th Cir. 1997). In other contexts, the Ninth Circuit Court of Appeals has determined that Bonneville has authority to protect fish and wildlife by imposing restrictions on transmission access. *Cal Energy Res. Conservation and Dev. Comm'n v. Bonneville Power Admin.,* 831 F.2d 1467, 1477-78 (9th Cir. 1987), *cert denied,* 488 U.S. 818 (1988).

[22] The program, by statute, consists of "measures to protect, mitigate, and enhance fish and wildlife affected by the development, operation, and management of [hydroelectric facilities on the Columbia River and its tributaries] while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply." 16 U.S.C. § 839b(h)(5) (2009). Congress directed the Council to include in the program measures that would "provide flows of sufficient quality and quantity between [the dams] to improve production, migration, and survival of such fish. . . ." *Id.* § 839b(h)(6)(E)(ii) (2009).

[23] *Id.* § 839b(h)(11)(A)(ii) (2009).

[24] *See*, *e.g.*, 16 U.S.C. § 838g (2009); 16 U.S.C. § 839e(a)(1) (2009). Congress intended that the Bonneville's rate directives be "[s]ubject to the general requirements (contained in section 7(a) of the Northwest Power Act) that Bonneville must continue to set its rates so that its total revenues continue to recover its total cost, . . ." H.R. Rep. No. 96-976, 96th Cong., 2nd Sess., pt. 2, at 36 (1980). *See also* H.R. No. 91-1219, 91st Cong., 2nd Sess., 90 (1970) (Bonneville ratepayer liability for Washington Public Power Supply System costs); Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838g (ratesetting), § 838i(a) (single Bonneville fund), § 838k(b) (priority of payments); *Bonneville Power Administration Financing, Hearing on S. 3362 before the Subcomm. on Water and Power Resources of the Committee on Interior and Insular Affairs*, 93rd Congress, 2d Sess., on S. 3362, at 95-96 (June 6, 1974) (Statement of C. King Mallory, Acting Assistant Sec., Energy and Minerals, Department of the Interior: "Complete cost recovery has been an overriding principle of the Federal power program in the Pacific

inter-related nature of generation and transmission is recognized throughout Bonneville's organic statutes when it comes to finance, cash management, and cost recovery requirements."[25] Concomitantly, the Commission is charged with assuring that Bonneville's rates "are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs."[26]

Bonneville is also directed in its organic statutes to make transmission available to third parties on a fair and nondiscriminatory basis. Before it does so, however, given Bonneville's original charter to serve as the government's marketing agent for the power output of the Federal hydro projects, the historical evolution of the Bonneville transmission system, the massive Federal investment in the power and transmission system, and other factors, Congress directed that Bonneville make transmission available to third parties on a fair and nondiscriminatory basis but only if the Bonneville transmission capacity:

- is in "excess of the capacity required to transmit electric power generated or acquired by the United States;"[27] (the priority is "to the needs of the Government";[28]

Northwest and it will continue to be an inviolate rule of conduct after enactment of the proposed Federal Columbia River Transmission System Act."); *id*. at 108, 122, 148 (Statement of Donald Hodel); *id*. at 1 (Statement of Henry M. Jackson, U.S. Senator from the State of Washington); Cong. Rec. H. 9984 (Oct. 7, 1974)(Statement of Rep. Meeds).

[25] *See, e.g*., Federal Columbia River Transmission System Act, 16 U.S.C. § 838(a); 16 U.S.C. §§ 838i(a), 838i(b)(12); *id.*, § 838k(b), *as amended*, Pub. L. 96-501, § 8(c), (d), 94 Stat. 2728 (1980); *Bonneville Power Administration Financing, 1974: Hearings on S. 3362 Before the Subcomm. on Water and Power Resources*, 93rd Cong., 2d Sess. 121-22 (1974).

[26] 16 U.S.C. § 839e(a)(2)(A) (2009).

[27] Section 6 of the Transmission System Act of 1974, 16 U.S.C. § 838d, provides, "The Administrator shall make available to all utilities on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which he determines to be in excess of the capacity required to transmit electric power generated or acquired by the United States."

[28] H. R. Rep. No. 93-1375, at 16 (1974).

- "is not required for the transmission of Federal energy";[29]

- is made available subject to "(1) any contractual obligations of the Administrator; (2) any other obligations under existing law; and (3) the availability of capacity in the Federal transmission system";[30]

and the transmission service:

- "is not in conflict with the Administrator's other marketing obligations and the policies of [the Northwest Power Act] and other applicable laws";[31] and

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[29] Section 6 of the Regional Preference Act, 16 U.S.C. § 837e (2009), provides in full:

> Any capacity in Federal transmission lines connecting, either by themselves or with non-Federal lines, a generating plant in the Pacific Northwest or Canada with the other area or with any other area outside the Pacific Northwest, which is not required for the transmission of Federal energy or the energy described in section 837h of this title, shall be made available as a carrier for transmission of other electric energy between such areas. The transmission of other electric energy shall be at equitable rates determined by the Secretary, but such rates shall be subject to equitable adjustment at appropriate intervals not less frequently than once in every five years as agreed to by the parties. No contract for the transmission of non-Federal energy on a firm basis shall be affected by any increase, subsequent to the execution of such contract, in the requirements for transmission of Federal energy, the energy described in section 837h of this title, or other electric energy.

The energy described in section 837h refers to the Canyon Ferry project and downstream power benefits to which Canada is entitled under the treaty between Canada and the United States relating to the cooperative development of the water resources of the Columbia River Basin, signed at Washington, July 17, 1961, and energy or capacity disposed of to Canada in any exchange pursuant to paragraph 1 or 2 of article VIII thereof. 16 U.S.C. § 837h (2009).

[30] Section 9(d) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839f(d) (2006), provides:

> No restrictions contained in subsection (c) of this section shall limit or interfere with the sale, exchange or other disposition of any power by any utility or group thereof from any existing or new non-Federal resource if such sale, exchange or disposition does not increase the amount of firm power the Administrator would be obligated to provide to any customer. In addition to the directives contained in subsections (i)(1)(B) and (i)(3) and subject to:
>
> (1) any contractual obligations of the Administrator,
>
> (2) any other obligations under existing law, and
>
> (3) the availability of capacity in the Federal transmission system,
>
> the Administrator shall provide transmission access, load factoring, storage and other services normally attendant thereto to such utilities and shall not discriminate against any utility or group thereof on the basis of independent development of such resource in providing such services.

[31] Section 9(i)(1) of the Northwest Power Act, 16 U.S.C. § 839f(i)(1) (2009), referenced above, provides:

> At the request and expense of any customer or group of customers of the Administrator within the Pacific Northwest, the Administrator shall, to the extent practicable—
>
> (A) acquire any electric power required by (i) any customer or group of customers to enable them to replace resources determined to serve firm load under section 839c(b) of this title, or (ii) direct service industrial customers to replace electric power that is or may be curtailed or interrupted by the Administrator (other than power the Administrator is obligated to replace), with the cost of such replacement power to be distributed among the direct service industrial customers requesting

- can be provided "without substantial interference with his power marketing program, applicable operating limitations or existing contractual obligations."[32]

The United States Court of Appeals for the Ninth Circuit has determined that Bonneville has authority to protect fish and wildlife by imposing restrictions on transmission access:

> In addition to these somewhat conflicting responsibilities to maintain low rates, repay the federal treasury, and provide transmission access for other utilities, Bonneville must also "protect, mitigate, and enhance fish and wildlife" affected by the operation of the federal hydroelectric system. 16 U.S.C. § 839b(h)(10).[33]

Once the Bonneville Administrator has made the requisite statutory determinations and made the transmission available by contract, the contract is binding in accordance with its terms on Bonneville.[34] Consequently, Bonneville is careful to ensure the contract will not run afoul of Bonneville's statutory mandates.

Complainants ask the Commission to order Bonneville to file an open access tariff for Commission approval. In 1996, Bonneville determined that it could offer transmission pursuant to an open access transmission tariff consistent with Bonneville's

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such power; and
(B) dispose of, or assist in the disposal of, any electric power that a customer or group of customers proposes to sell within or without the region at rates and upon terms specified by such customer or group of customers, if such disposition is not in conflict with the Administrator's other marketing obligations and the policies of this chapter and other applicable laws.

[32] Section 9(i)(3) of the Northwest Power Act, 16 U.S.C. § 839f(i)(3) (2009), referenced above, provides:
The Administrator shall furnish services including transmission, storage, and load factoring unless he determines such services cannot be furnished without substantial interference with his power marketing program, applicable operating limitations or existing contractual obligations. The Administrator shall, to the extent practicable, give priority in making such services available for the marketing, within and without the Pacific Northwest, of capability from projects under construction on December 5, 1980, if such capability has been offered for sale at cost, including a reasonable rate of return, to the Administrator pursuant to this chapter and such offer is not accepted within one year.

[33] *Cal. Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1303 (9th Cir. 1990), *cert denied*, 500 U.S. 904 (1991); *see also Cal. Energy Res. Conservation and Dev. Comm'n v. Bonneville Power Admin.*, 831 F.2d 1467, 1477-78 (9th Cir. 1987), *cert denied*, 488 U.S. 818 (1988).

[34] *See* Regional Preference Act, 16 U.S.C. § 837e.

statutory responsibilities. However, Bonneville must continue to assure itself that any new transmission service it offers is consistent with these responsibilities.

As detailed below, the Administrator's statutory responsibilities were not changed or repealed by provisions of the Energy Policy Act of 1992. Neither were they changed or repealed by later-enacted provisions of the Energy Policy Act of 2005. They continue to be applicable.

V. BONNEVILLE HAS STRONGLY SUPPORTED WIND GENERATION

Four years ago, a Pacific Northwest regional task force on wind integration believed that connecting 3,000 megawatts of wind to the existing 500 MW on the Bonneville system could be achieved over a 20-year planning horizon.[35] But rather than the gradual increase predicted by the regional task force, wind generation beat the forecast by 16 years.[36] Today, over 3500 MW of wind power are connected to the Bonneville system and represent about 30 percent of total Bonneville balancing authority generation. An additional 3,700 MW of wind generation are expected to connect to the Bonneville system over the next three to four years. With a peak balancing authority load of 10,500 MW and a minimum light load of 4,000 MW, the wind penetration in the Bonneville balancing authority is among the highest in the nation.[37]

Bonneville's technical, policy and financial innovations to spur wind power, and its willingness not to insist on resolving all issues prior to interconnecting wind generation

[35] *Northwest Power and Conservation Council, WIF Document 2007-01, The Northwest Wind Integration Plan* 28, Deston Nokes, March 2007.
[36] *See* ROD at 8, graph.
[37] Bonneville Power Admin., *How BPA Supports Northwest Wind Power* 1 (May 26, 2011), *available at* http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/How%20BPA%20supports%20wind%20-%20May%202011.pdf; Comments of the Bonneville Power Administration, FERC Docket No. RM10-11-000, at 1 (Apr. 12, 2010); ROD at 8-9.

so as not to slow integration of wind projects, are a significant reason for the large amount of wind power on the Bonneville system. Bonneville has:

- Developed and offered Conditional Firm Service which has provided more transmission capacity primarily for wind generators.
- Stretched the Federal hydroelectric system to supply reserves to back up wind generation.
- Developed Dispatcher Standing Order (DSO) 216 ("operational fail safe") to allow more wind to interconnect with the Bonneville system even as the system approached the limits of its ability to provide reserves.
- Developed world-class wind forecasting tools.
- Developed enhanced generation visibility tools for Bonneville power dispatchers.
- Developed a generation imbalance reserves self-supply program.
- Developed an intra-hour transmission scheduling program.[38]

Bonneville is working with the California Independent System Operator on a joint pilot project to meld its market approach with Bonneville's intra-hour scheduling to provide a partial market solution to generation schedule deviations. It is also collaborating with ColumbiaGrid and the Joint Initiative on potential new approaches to providing generation imbalance services among utilities.[39]

In 2008 Bonneville launched its Network Open Season (NOS) approach to managing its queue of transmission requests and identifying the transmission infrastructure needed to provide service requested by customers. This approach has resulted in significant amounts of additional transmission capacity made available for requests associated with wind projects. Since initiating its first NOS, Bonneville has

[38] Bonneville Power Admin., *How BPA Supports Northwest Wind Power* at 1-4.
[39] *Id.* at 4.

offered over 400 megawatts of new transmission service for wind projects without the need for new construction and has studied approximately 7,000 megawatts of additional wind-related requests to identify the facilities that would be necessary to provide service. Through these studies, Bonneville has identified four new 500-kilovolt transmission projects which together will add more than 225 miles of high-voltage transmission capacity and 3,700 megawatts of transfer capability, including 2,800 megawatts contracted to customers with wind projects. Two of these projects are in the construction phase, whereas the other two are still in the environmental review process required by the National Environmental Policy Act (NEPA) for all Federal agencies. Related to interconnection of renewable generation, Bonneville has built eight new substations, expanded three others and constructed six new tap lines to physically integrate 37 wind projects, with total generation capacity of 3,522 megawatts. More integration projects are in the planning or construction phase.[40]

VI. ENVIRONMENTAL REDISPATCH POLICY

A. Background

1. Management of the Federal Columbia River Power System (FCRPS)

The FCRPS is a vast hydroelectric system operated jointly by the Corps of Engineers, the Bureau of Reclamation, and Bonneville to serve multiple purposes, including flood control, navigation, irrigation, and power generation. In its roles as balancing authority, power marketer and hydro operator, Bonneville must coordinate closely with the Corps of Engineers and Bureau of Reclamation to ensure that these purposes are met during all operating conditions. At the same time, the Federal entities

[40] *Id.* at 1.

that manage the river system must adhere to various constraints because of the need to protect fish and wildlife and maintain the reliability of the interconnected transmission system.[41]

The FCRPS generates electric power at Federally owned hydroelectric plants and one nuclear plant in the Columbia River Basin. A few projects, such as those on the Willamette River in Oregon, operate more or less independently, but the majority of the generating capability is part of an interconnected fuel supply that must be coordinated in order meet the multiple purposes. These generators are located on the main stem of the Columbia and Snake rivers. Some of these projects, such as Grand Coulee, Hungry Horse, Libby and Dworshak, are storage projects where the storage space is managed for flood control (reserving enough storage space to capture potential floods) and for the biological benefit of Federal ESA-listed species (filling storage space to later provide water when it is helpful to the species). Regular adjustments to storage and river flows out of these projects are needed to respond to weather-driven changes in the water supply. Other projects have little ability to store water over time and are largely operated to pass the flows coming from the upstream dam or dams. These are called run-of-the-river projects.[42]

Not all of the water is used to produce electricity. The lower Columbia and Snake River projects also pass water through the spillways to aid the migration of endangered salmon each spring and summer. The levels of spill are tailored to the unique conditions at each of these projects to benefit Federal ESA-listed species in an effort to achieve the

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[41] ROD at 2, 5-8; Attachment B, Sweet Affidavit at P 5, 10-12; Attachment C, Connolly Affidavit at P 2, 5-6; Attachment D, Spain Affidavit at P 4.
[42] Attachment C, Connolly Affidavit at P 2, 5-6, 10-11, 50-52; Attachment D, Spain Affidavit at P 4-5; ROD at 5-7.

dam survival performance standards in the 2010 FCRPS Supplemental BiOp. In order to maintain reliability, a number of the projects also hold turbine capacity aside (reserves) to respond to events on the electric system or to respond to variations in generation and load elsewhere in the electric grid. System planners and operators locate these reserves on different projects at different times in order to arrive at an overall operation that meets the multiple purposes of the system and maintains the reliability of the electric grid.[43]

2. Operations Under the Clean Water Act, Endangered Species Act, and Court Order

Environmental Redispatch is designed to ensure that Bonneville takes all reasonable actions to meet its legal responsibilities under the Clean Water Act (CWA)[44] and Endangered Species Act (ESA),[45] as well as under its authorizing legislation. As stated above, the FCRPS hydroelectric projects are operated for multiple public purposes, including flood control, irrigation, power production, navigation, recreation, and municipal water supply. The system is also operated to protect the river's aquatic life, including salmon, steelhead, sturgeon, bull trout, and other species listed under the Federal ESA as well as non-listed species.[46]

Flow objectives at FCRPS dams (which aid migrating fish and are discussed further below) have been established to protect Federal ESA-listed species and have dramatically changed the way the reservoirs are managed. In general, the flexibility to store water in FCRPS reservoirs has been reduced, leaving less flexibility to manage

[43] ROD at 6-8, 9; Bonneville Power Admin., DOE/BP-4203, *Columbia River High-Water Operations* 2-5 (Sept. 2010), *available at* http://www.bpa.gov/corporate/pubs/final-report-columbia-river-high-water-operations.pdf; Attachment B, Sweet Affidavit at P 11; Attachment C, Connolly Affidavit at P 20, 39-41.
[44] Federal Water Pollution Control Act, 33 U.S.C. §§ 1251-1387 (2009).
[45] Endangered Species Act of 1973, 16 U.S.C. §§ 1531-1544 (2009).
[46] ROD at 1-2, 5-8; Bonneville Power Admin., *Columbia River High Water Operations* at 1; Attachment B, Sweet Affidavit at P 5, 10-11; Attachment C, Connolly Affidavit at P 5-6, 10-15, 20.

water flows for power production. With less ability to store spring runoff (water flow caused by rain, snowmelt and other sources), high-water events can create conditions that are harmful to aquatic life.[47]

If water cannot be stored, additional power must be generated with the water or the water must be spilled through the dams' spillways (channels to permit the release of excess water). As explained below, spilling water can aid fish migration and increase survival rates. However, too much spill can harm fish when water spilled from a dam traps air as it plunges to the base of the dam, increasing gas levels in the water (known as supersaturation). The momentum of the fall carries the water to great depths where, under increased hydrostatic pressure, the gases dissolve into the water. Thus, high amounts of spill can lead to excessive Total Dissolved Gas (TDG), which threatens the health of aquatic life, including salmonids (fish of the salmon and trout families). TDG produces physiological problems known as gas bubble trauma (GBT), in which small bubbles develop within the tissue of the fish, blocking blood flow and causing physical tissue damage that is especially noticeable in the fins. In extreme cases the bubbles can be fatal. The severity of GBT is related to the level of TDG, frequency and length of exposure, and the depth of the water that the fish is swimming in.[48]

As shown in the following chart, as levels of total dissolved gas increase, levels of gas bubble trauma also increase; the horizontal axis shows the level of total dissolved gas

[47] ROD at 6-8, 9; Bonneville Power Admin., *Columbia River High Water Operations* at 4; Attachment B, Sweet Affidavit at P 11, 22; Attachment C, Connolly Affidavit at P 22-23, 26; Attachment D, Spain Affidavit at P 5.

[48] ROD at 5-7, 9; Bonneville Power Admin., *Columbia River High Water Operations* at 4-5; Attachment B, Sweet Affidavit at P 5-9.

by percentage and the vertical axis shows the percentage of fish with gas bubble trauma.[49]

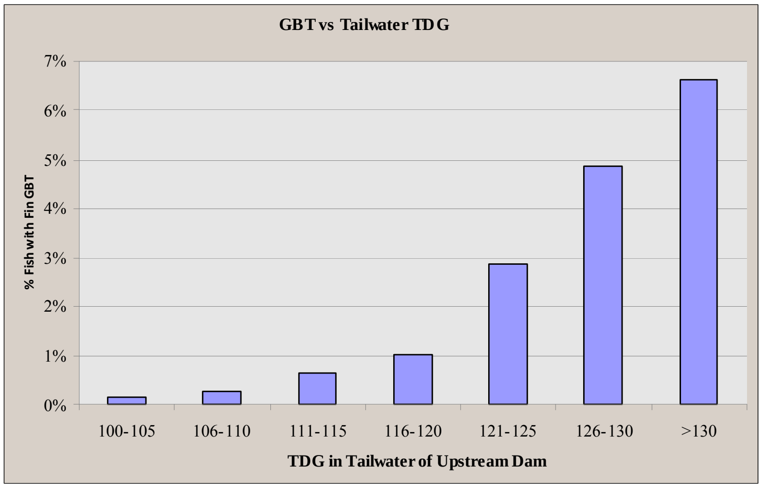

Figure 1. Gas Bubble Trauma increases related to TDG exposure. (From Washington DOE and Oregon DEQ Joint Adaptive Management Team report 2009).

An example of how spill increases TDG levels occurred on May 24, 2011, after transformer failures disabled all turbines at Little Goose Dam and water had to be diverted over the spillways. TDG levels increased significantly, from 130% on May 23 to 134% on May 25 and 136% on May 27.[50] These flows caused gas bubble trauma at the next dam down river, Lower Monumental, to jump from 5.5% on May 25 to 30% on May 28, as the fish exposed to the higher TDG levels at Little Goose began to arrive.[51] Under normal operating circumstances, GBT levels like those observed downstream at Lower Monumental would have triggered the region's "action criteria," which require spill levels to be reduced if more than 15% of fish in the sample show evidence of GBT, or more than 5% of fish show evidence of severe GBT. Even though the peak of the

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[49] ROD at 6; Attachment B, Sweet Affidavit at P 7, 10.
[50] Attachment B, Sweet Affidavit, Figure 3, Columbia River DART, School of Aquatic & Fishery Sciences, Univ. of Wash., *available at* http://www.cbr.washington.edu/dart/dart.html.
[51] Attachment B, Sweet Affidavit, Figure 4. Gas Bubble Trauma monitoring results at Lower Monumental Dam from May 25th to June 1st 2011. Data from the Fish Passage Center.

spring Chinook and steelhead runs had passed by May 24, fish were still passing in large numbers. On the last day a fish passage count was available for Little Goose (May 22), the daily passage estimate was nearly 80,000 juvenile salmonids. Based on upstream counts, the fish passage rates at Little Goose are estimated to have remained at similar levels each day over the duration of the outage.[52]

TDG levels would likely have been even higher without two recent innovations: first, flow deflectors (which redirect water that is spilled over the dam to reduce the depth to which the water plunges and therefore reduce TDG levels) and other improvements at several dams; and second, the TDG Management Plan of the Water Management Plan (the plan issued by the Corps of Engineers to guide water management when the agency must spill).[53] Prescribed levels of spill can increase fish passage survival by diverting a higher percentage of fish through the dam spillways instead of through the turbines, where the mortality rate is generally higher.[54]

Thus spill is a double-edged sword: too much spill can kill fish by increasing total dissolved gas in the water to harmful levels, but insufficient spill results in more fish taking other routes past the dams with higher mortality. To aid fish passage survival, FCRPS Biological Opinions ("BiOps") have required spill at the dams at levels that cause Bonneville to exceed the 110% standard where consistent with state water quality standards, including TDG waivers. The level of spill established for each project is the level that is expected to meet performance standards for ESA-listed species established in the 2010 FCRPS Supplemental BiOp. (Biological Opinions are documents issued under

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[52] Attachment B, Sweet Affidavit at P 23-25.
[53] Attachment C, Connolly Affidavit at P 23.
[54] ROD at 6-7; Bonneville Power Admin., *Columbia River High Water Operations* at 5; Attachment B, Sweet Affidavit at P 11, 13, 22; Attachment C, Connolly Affidavit at P 20, 23-28.

the ESA that analyze whether a Federal agency's actions are threatening or endangering listed species, and if so requiring mitigating actions. They are issued by the agency with jurisdiction over the listed species, in this case the National Oceanic and Atmospheric Administration National Marine Fisheries Service ("NOAA Fisheries").)[55]

The states of Washington and Oregon set water quality standards, including a TDG standard at 110 percent of the normal level of gas in the water (called 110 percent supersaturation).[56] To balance the potential benefits and adverse effects of spill, Oregon and Washington have provided TDG waivers consistent with the BiOp spill requirements. The waivers allow up to 120 percent TDG supersaturation in the project tailrace (the portion of the reservoir immediately downstream of the dam) during fish migration season. Washington has an additional limit of 115 percent TDG supersaturation in the project forebays (the portion of the reservoir immediately upstream of the dam).[57] NOAA Fisheries incorporated spill levels for fish passage consistent with state water quality standards and criteria adjustments into the 2010 FCRPS Supplemental Biological Opinion.[58] The Corps of Engineers manages spill at the Lower Columbia and Snake River dams through a system-wide TDG Management Plan.[59]

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[55] ROD at 6; Bonneville Power Admin., *Columbia River High Water Operations* at 5; Attachment B, Sweet Affidavit at P 11; Attachment C, Connolly Affidavit at P 5, 22.

[56] Dissolved gas levels generally remain near equilibrium with the air surface (near 100% TDG), but can become supersaturated (above 100%). *See also* ROD at 5-6; Attachment B, Sweet affidavit at P 5. Due to the limited hydraulic capacity of most of the FCRPS dams, these standards do not apply above certain flow levels (the highest 7 day average over 10 years or the 7Q10 flow) because the ability to limit TDG through changes in hydro operations is limited. On the Snake River, the 7Q10 flow is 214 kcfs.

[57] The Corps of Engineers manages spill at the Lower Columbia and Snake River dams to the more stringent of the two. In addition, Washington's waiver allows a maximum daily one-hour TDG of 125%. Oregon's waiver allows a maximum TDG level of 125%.for any two-hours of the 12 highest TDG hours in a day.

[58] *See* Reasonable Prudent Alternative 29 of the 2008 FCRPS BiOp, incorporated into the 2010 FCRPS Supplemental Biological Opinion, which states, "The Corps and BPA will provide spill to improve juvenile fish passage while avoiding high TDG supersaturation levels or adult fallback problems. Specific spill levels will be provided for juvenile fish passage at each project, <u>not to exceed established TDG levels</u>

In a joint 2009 report supporting the waivers, Washington concluded that "the weight of all the evidence clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120 percent." Washington had received reports of severe gas bubble trauma and fish deaths at dissolved gas levels above 130 percent or in shallow water.[60]

Although it is difficult to tie the incidence of gas bubble trauma directly to fish mortality during migration through the hydro system, high mortality rates have been observed. In 1968, as construction of John Day Dam was underway, all of the flow was routed over the spillway since the turbines had not been installed.[61] Researchers observed that large numbers of dead adult sockeye and Chinook salmon were found downstream of the dam with signs of GBT.[62] They also observed a high incidence of GBT in the adult fish monitored in the fish ladders (structures that allow the fish to ascend a series of steps over the dams). In this instance, TDG levels ranged from 123%

(either 110 percent TDG standard, or as modified by State water quality waivers, currently up to 115 percent TDG in the dam forebay and up to 120 percent TDG in the project tailwater, or if spill to these levels would compromise the likelihood of meeting performance standards…." (emphasis added), *available at* http://www.salmonrecovery.gov/BiologicalOpinions/FCRPS/2008Biop.aspx. An RPA is an alternative plan endorsed by NOAA that avoids jeopardy under the ESA.

[59] ROD at 6; Bonneville Power Admin., *Columbia River High Water Operations* at 5; Attachment B, Sweet Affidavit at P 11-12; Attachment C, Connolly Affidavit at P 23. These TDG levels are translated into "spill caps," the amount of spill necessary for TDG levels to reach the gas cap ceiling. A TDG Management Plan is developed annually by the USACE and is included as Appendix 4 in the annual Water Management Plan. This TDG Management Plan provides detailed information addressing TDG management measures, the process for setting spill caps, TDG management policies, and the TDG monitoring program and modeling. *See* Attachment C, Connolly Affidavit at P 23-24.

[60] Adaptive Management Team Total Dissolved Gas in the Columbia and Snake Rivers, Evaluation of the 115 Percent Total Dissolved Gas Forebay Requirement, Washington State Department of Ecology and State of Oregon Department of Environmental Quality, Final January 2009 Publication No. 09-10-002; Attachment B, Sweet Affidavit at P 17.

The Washington 115/120 TDG standard was upheld in a May 20, 2011 oral decision by Judge Sutton in an action brought in Thurston County Superior Court. *NW Sportfishing Indus. Ass'n v. Wash. State Dep't of Ecology*, NO.10-2-01236-0, as transcribed at 24.

[61] Attachment B, Sweet Affidavit at P 20.

[62] *Id.*

to 143%.[63] One of the researchers also noted large numbers of GBT-related deaths of juvenile salmon in the Snake River in 1970 when dissolved gas levels averaged 120-146% over a prolonged period.[64] Fish in this study were placed in cages with access to water ranging from 0 – 4.3 meters in depth so that the test fish had access to water with low TDG levels (TDG levels generally being lower in deeper water).[65] Even with such access, the fish in this study suffered mortality rates from 45-68% between late May and early June.[66]

For spring and summer 2011, the spill levels for juvenile fish passage were included in the Fish Operations Plans that were adopted by order of the U.S. District Court for the District of Oregon. FCRPS operations, conducted by the Corps of Engineers, the Bureau of Reclamation, and Bonneville, have been subject to ongoing litigation since 2001, and FCRPS flow and spill operations have been subject to multiple court orders. On March 24 and June 14, 2011, the U.S. District Court for the District of Oregon issued orders requiring that 2011 spring and summer fish operations be conducted as set forth in the 2011 Spring and Summer Fish Operation Plans ("FOPs") and other operative documents, including the 2010 FCRPS Supplemental Biological Opinion.[67] The 2011 FOPs require that, to the extent practicable, from April through August, the Corps of Engineers manage spill levels for fish passage to avoid exceeding

[63] *Id.*
[64] *Id.*
[65] *Id.*
[66] *Id.*
[67] A ruling is pending from the U.S. District Court of Oregon regarding the validity of the 2010 FCRPS Supplemental Biological Opinion under the Endangered Species Act. *Natl. Wildlife Fed. v. Natl. Marine Fisheries Serv.*, No. CV 01-640-RE, Orders for 2011 Spring and Summer Operations, dated March 24 and June 14, 2011.

120 percent TDG in project tailraces and 115 percent in the forebay of the next project downstream, consistent with the State of Washington's current TDG waiver limits.[68]

During times of high flows, spill and consequent TDG levels can be reduced by additional generation, which sends water through the turbines instead of through the spillways. Because generation and load must always be balanced, however, Bonneville cannot increase generation unless it has sufficient load to absorb all the power. If Bonneville has insufficient load, it must curtail other sources of generation, including wind generation. Under the Environmental Redispatch policy, Bonneville can maximize Federal hydro generation during high-water events, thus reducing excess spill and minimizing TDG levels to the lowest practical levels.[69]

In the past, Bonneville has managed high-water events by marketing its excess FCRPS generation at low prices in the Pacific Northwest and California. This strategy has been successful because most thermal generators have been willing to be displaced by low-cost hydro generation to reduce operating costs. Today, however, with the combination of legally mandated spill requirements and the interconnection of a significant amount of wind generation on Bonneville's system (which does not voluntarily curtail when prices approach zero), Bonneville is unable to continue to

[68] ROD at 6-7; Attachment B, Sweet Affidavit at P 11. The waiver limits are modified in *Letter from Melissa Gildersleeve, Watershed Management Section manager, Washington Dep't of Ecology to David Ponganis, U.S. Army Corps of Engineers, NW Division*, dated June 30, 2010, and Oregon Environmental Quality Comm'n, *Order Approving USACE Request for Waiver to State's TDG Water Quality Standard*, dated June 24, 2009 (exhibits to Sweet Affidavit).
[69] ROD at 7.

manage high-water events and meet its environmental obligations without employing additional tools.[70]

3. BPA's Marketing of Hydropower

BPA's energy production varies by large amounts from year to year and season to season based primarily on water supply. Some years BPA has surplus energy not needed to serve its wholesale customer base, which it sells into the West Coast's bulk electricity marketplace. Usually BPA sells surplus power on a short-term basis (less than 12 months), but it also sells for longer periods as circumstances warrant.[71]

Other times BPA has insufficient generation and must purchase power in the market to meet its obligations. Several factors can cause the deficits, including changes in operational requirements for fish and the use of water for other purposes, such as navigation, flood control, and recreation.[72]

BPA's spring operation of the FCRPS is determined by the Corps of Engineers and Bureau of Reclamation, the agencies that own the dams and are responsible for their operation. During April, May, and June, BPA must market and transmit power from the FCRPS within strict parameters determined by the Corps of Engineers and Bureau of Reclamation, including drafting certain FCRPS reservoirs (the storage projects) to a flood control elevation in April (that is, lowering the water levels to make space for spring runoff) and refilling through May and June so that the reservoirs are full in early July.[73]

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[70] ROD at 7-8, 11; Bonneville Power Admin., *Columbia River High Water Operations* at 3-4; Attachment D, Spain Affidavit at P 28-29.
[71] Attachment D, Spain Affidavit at P 4.
[72] Attachment C, Connolly Affidavit at P 5; Attachment D, Spain Affidavit at P 5.
[73] Attachment D, Spain Affidavit at P 4.

In dry years BPA must purchase large amounts of spring power, rather than using water to generate, to ensure that the storage projects refill, while in wet years BPA must sell large amounts of energy to mitigate the rate of refill and minimize the need for lack-of-market spill (spill because of insufficient load) and consequent increases in TDG supersaturation. The magnitude of this spring uncertainty is tremendous. BPA can be either surplus or deficit by thousands of megawatts and can routinely be short up to 2,000 or 3,000 MW even during light load hours (10:00 p.m. to 6:00 a.m. Monday through Saturday and all day Sundays and holidays. Because loads are lower during light load hours, the excess generation problem is greater).[74]

B. June 2010 High Water Event

1. Hydro Conditions in 2010

Bonneville can face a high-water event any spring, depending on the snowpack in the Columbia River basin and the timing of the runoff. During June 2010, Bonneville experienced its first high-water event since a significant amount of wind generation interconnected to its system. River flows in 2010 were lower than normal until several large storm fronts brought several inches of precipitation to the Columbia River basin in early June. Snake River stream flows nearly tripled, and Columbia River stream flows nearly doubled. Hydro operation went from managing operations to support fish passage with required flows and spill to seeking any possible measures to limit TDG and protect fish from excess spill.[75]

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[74] *Id.* at P 5.
[75] Bonneville estimates that there is a one in three chance of having a high water event in any given year. *See* ROD at 10.

2. Bonneville's Management of Dissolved Gas Levels

Bonneville responded quickly on many fronts to limit excessive spill. One front was management of the Columbia Generating Station (CGS), the region's one nuclear plant. Like most nuclear facilities, CGS generally runs near maximum output. Bonneville has worked with Energy Northwest, the operator of CGS, to add equipment to the plant that allows for output reductions and cycling (raising and lowering output levels as needed). In 2010, Bonneville employed both of these practices and CGS was reduced to as little as 20 percent of normal output.[76]

Bonneville also worked with the Corps of Engineers to use flood control space to store water at John Day Dam (which, unlike other run-of-the-river dams, has some flood control space). As much as possible, it shifted Federal dams' generation into heavy load hours (6:00 a.m. to 10:00 p.m. Monday through Saturday, except holidays) to minimize the risk of excessive light load hour spill. Bonneville coordinated with BC Hydro a 5,000-cubic-feet-per-second reduction at Hugh Keenleyside Dam (often referred to as Arrow Dam) in British Columbia, Canada to reduce flows into Grand Coulee that would otherwise increase the risk of excessive spill. Bonneville reduced flows at Albeni Falls Dam as much as possible to further reduce flows into Grand Coulee (Albeni Falls Dam feeds into Grand Coulee). The agency reduced decremental wind balancing reserves available to wind (that is, reserves available to decrease generation if wind production increased) to reduce the risk of increased spill caused by use of the reserves. Finally, it

[76] *Id.*; Attachment C, Connolly Affidavit at P 53; Bonneville Power Admin., *Columbia River High Water Operations*.

offered free power to all generators that were connected to Bonneville's system or that could access the Bonneville system.[77]

Almost all thermal generators in Bonneville's balancing authority responded to Bonneville's offer of free power, and Bonneville sold over 73,000 MWh of power at a zero price for June. Bonneville's stated policy was to not pay negative prices. Although Bonneville was unable to find enough load to generate fully and had to spill up to the TDG limits at times, it did not exceed the limits and would not have had to implement Environmental Redispatch even had the policy already been in place.[78]

C. Events After June 2010

1. Public Process in Fall 2010

Because of production tax credits and renewable energy credits, some wind generators are not sufficiently incentivized to accept low-priced or free energy. After the June 2010 high-water event Bonneville recognized the need to develop even more alternatives before the next high-water event. Bonneville held three public workshops between October 2010 and February 2011 to discuss potential solutions. Participants suggested a number of ideas which Bonneville captured and responded to in a February 2011 letter to the region.[79]

Bonneville investigated all of these ideas and has pursued those that appeared feasible, including reducing incremental reserves (reserves held out to increase hydro generation to compensate for a reduction in wind generation) for wind in addition to the reductions in decremental reserve reductions utilized in 2010; exploring the potential to

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[77] ROD at 10-11; Bonneville Power Admin., *Columbia River High Water Operations*.
[78] ROD at 11.
[79] http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/Cover_letter_DEC_Meeting_Notes_Final_FEB_2011.doc; ROD at 12-13; Attachment E, Lynam Affidavit at P 3-4.

shift irrigation load into nighttime periods; engaging with thermal resource owners to craft non-standard displacement offers; and others. A number of the other ideas that were generated at the public workshops were impractical, because they were outside Bonneville's control or would not be available for the upcoming runoff season.[80]

At these workshops Bonneville described the potential for Environmental Redispatch. Bonneville issued a Draft Record of Decision on its Environmental Redispatch and Negative Pricing Policies on February 18, 2011. Bonneville received 41 comments on the Draft Record of Decision, and Bonneville responded to all of them in the final ROD, which was issued on May 13, 2011.[81]

Bonneville also held a public process to develop two business practices to implement its Environmental Redispatch policy.[82] BPA allowed a two-week period for public comments, beginning March 18, 2011, and received 23 sets of written comments. One of the business practices implements Environmental Redispatch and the other establishes the process by which non-Federal thermal generators submit minimum generation levels for reliability reasons. Variable energy resources (VERs), such as wind generators, do not submit minimum generation levels because such resources do not have operational characteristics or reliability obligations that would require the resource to continue running.[83]

2. Bonneville's Spring 2011 Marketing

The agency's spring 2011 marketing activity started cautiously in the summer of 2010 but, as the La Nina weather pattern (a weather pattern that signals a wet and cold

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[80] Attachment E, Lynam Affidavit at P 4.
[81] *See* ROD at 22; Attachment E, Lynam Affidavit at P 5-6.
[82] *See* Attachment F, Nulph Affidavit and Exhibit (Business Practices).
[83] *Id.*

winter in the Northwest with substantial snow in the mountains) strengthened through the fall of 2010, Bonneville increased the pace and magnitude of its efforts. Bonneville eventually discarded strategies based on sales price and instead focused on volume. Each week, regardless of May and June energy prices, Bonneville traders set weekly sales volume targets. They also began marketing a quarterly product (blocks of power for the entire second quarter, April through June) to combat liquidity concerns the agency was facing and to improve the speed and ease of selling May and June power. Hydro uncertainty makes it risky to sell a full quarterly product, and generally Bonneville does not like to do so. However, it is difficult in the fall to find buyers for the individual months of May and June. When sales are packaged with April energy, the number of buyers notably increases. Therefore, Bonneville consciously decided to take more risk in April to help mitigate any over-generation concerns it might find itself battling in May and June.[84]

In fact, this strategy has considerable risk. April is a particularly difficult month for Bonneville. The agency must enter April with the FCRPS full enough to support the beginning of fish passage season but not so full as to risk daily draft limitations and the possible failure of the FCRPS to achieve its end-of-April flood control target.[85]

Thus, the first few weeks of April can be a waiting game as Bonneville prepares the FCRPS for the spring fish passage season and Grand Coulee draft. Bonneville is never given more than a few days notice to draft Grand Coulee in support of fish passage. While the agency waits for notice from the Corps of Engineers, it must hold the hydro

[84] Attachment D, Spain Affidavit at P 6-7.
[85] *Id.* at P 7.

system steady, exposing the agency to considerable energy purchase risks if April temperatures start cold and electricity demand is high. Once Bonneville gets the notice to draft, the risk of needing additional purchases is replaced by the need to make more sales to increase generation and stream flows.[86]

In the fall of 2010, Bonneville also explored the options market for May and June LLH energy puts. A put option establishes the right to sell energy to the other party at a predetermined price. Puts are options, not obligations, to deliver energy and appeared to be a good insurance vehicle to protect Bonneville from having to spill in May and June because of insufficient load, without increasing its risk in the event of a dry year. However, the market for these hedging tools proved disappointing, and Bonneville was able to negotiate only 100 MW of LLH daily puts for May and June.[87]

In January and February, it was clear that there was a strong La Nina weather pattern developing in the Pacific Northwest. However, the official Northwest River Forecast Center's January-through-July water supply forecast was for an average water year and Bonneville still faced a considerable amount of uncertainty as to the amount of water it would have in the spring. Nevertheless, in February Bonneville sent offers to the major northwest thermal generators and marketers to displace their generation with hydro power for May and June. Thermal owners could elect displacement periods of two to three weeks.[88]

Bonneville's economic displacement offer expired February 28. It sparked much discussion with thermal generation owners but no takers. Generators within Bonneville's

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[86] *Id.*
[87] *Id.* at P 8.
[88] *Id.* at P 10-11 and Exhibit (Letter to Thermal Generators).

balancing authority had already displaced through other market purchases, while those outside of the balancing authority refused the agency's offer.[89]

As the snowpack increased dramatically in March and Bonneville realized that it was facing the potential for a high-water event that could last months, not weeks, it adopted an even more aggressive marketing strategy. Bonneville began talking to any thermal generator that was willing to negotiate non-standard May/June sales that could help alleviate Bonneville's growing over-generation and lack-of-market concerns. (Non-standard sales include sales with, for example, variable start dates (established later by the seller and purchaser) or sales with different amounts of power in heavy and in light load hours.)[90]

Because of its aggressive winter outreach efforts, Bonneville was able to negotiate non-standard sales totaling 1,000,000 MWh for May through July. The energy deliveries associated with the deals were to begin in mid-May and extend through early June. In June, Bonneville renegotiated these sales to extend them into July.[91]

D. Implementation of Environmental Redispatch

1. Description of Environmental Redispatch

Under Environmental Redispatch, Bonneville will temporarily substitute renewable, carbon-free hydro power for other generation when necessary to ensure that FCRPS operations are consistent with Bonneville's environmental, statutory, and reliability responsibilities. It is employed only if Bonneville has unloaded turbines (that is, unused generation capacity) through which the agency can send water to avoid spill.

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[89] *Id.* at P 12-13.
[90] *Id.* at P 14-15.
[91] *Id.* at P 16, 27.

To assure that generation and load balances and maintain reliability, Bonneville must secure load to accept the generation. First, however, Bonneville will take all other reasonable actions to avoid the excess spill that can harm fish and other aquatic life.[92]

If these actions are insufficient to avoid harm, Bonneville will implement Environmental Redispatch. First, Bonneville will redispatch thermal generators to the minimum possible operating level without threatening reliability and serve their loads with free Federal hydro power. If Bonneville needs additional generation to reduce spill further, Bonneville will redispatch variable energy resources, such as wind generation, on a pro rata basis, and serve their loads as well with free Federal power. Bonneville will ensure generators' scheduled deliveries are met. Utilities and consumers that purchase energy from displaced generators will continue to receive their full energy deliveries.[93]

2. Description of the 2011 High-Water Event

Spring runoff in the Columbia River Basin (the area drained by the Columbia River and its tributaries) can vary widely each year in magnitude and duration. As evidenced by the events of June 2010, even during dry years the Federal hydro system is susceptible to sudden and unpredictable short-term weather phenomena that can swamp the system's flexibility (its ability to adjust as needed to serve its various purposes) and storage capacity. When spring stream flows are low, Bonneville must purchase large amounts of energy to ensure court-mandated summer refill at Grand Coulee by early July. When stream flows are high, the agency must sell power to mitigate the speed of refill and to minimize dissolved gases levels in the water.[94]

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[92] ROD at 14-15.
[93] *Id.*
[94] Attachment C, Connolly Affidavit at P 5; Attachment D, Spain Affidavit at P 5.

Predicting which condition will occur is very difficult. Bonneville may not know on which side of the spectrum the flows will fall until a high-water event (or a shortage) is imminent. Following the wrong marketing strategy − either over-selling or under-selling − can cause considerable risk to Bonneville's fish mitigation and flood control efforts.[95]

This year, snowpack was at average levels at the start of the winter in the United States, while snow accumulations lagged well below average in Canada. As noted above, normally a La Nina weather pattern signals a wet and cold winter in the Northwest with substantial snow in the mountains. However, the correlation is weak and a La Nina is not a sure guarantee of a wet winter and prolific spring runoff. Some La Nina winters can be quite dry, such as the 2001 winter when the Northwest experienced persistent winter drought conditions, and total flows at The Dalles (the standard area for measuring Columbia River flows) were only slightly above 50% of average.[96]

Through February 2011, the winter appeared to be heading toward an average water year at best. The Northwest River Forecast Center's forecast was near average until April 7, when it released a January-through-July forecast for 107% of average stream flows. Even before then, the hydrologic picture was not spread equally across the Columbia River Basin. Snowpack in the Canadian portion of the basin lagged below average until April, causing concern that forced purchases, not sales, would dominate Bonneville's spring 2011 marketing activities.[97]

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[95] Attachment D, Spain Affidavit at P 5.
[96] *Id.* at P 6, 10.
[97] *Id.* at P 15, 17.

That outcome did not materialize, however, as the 2011 La Nina spring turned out to be one of the coldest and wettest on record for the basin. The mountain snowmelt and runoff that normally begins in March and April did not begin until early May, when it went well above average. The runoff for January through June 2011 was 132% of average, the fourth highest since 1929. Columbia River flows were at or near flood stage for much of May and June.[98]

3. Hydro Operations Bonneville Took During the 2011 Event to Avoid Environmental Redispatch

a. Storage

Storage on the FCRPS is tightly managed. One of the requirements under the Biological Opinion is to provide some amount of flow augmentation through the spring and summer to aid juvenile salmon as they migrate downstream. Flow augmentation during migration improves salmon survival and is achieved through the planned storage of water in winter and early spring to be released in the later spring and in summer. The Federal hydro projects on the lower Columbia and Snake Rivers are not operated for seasonal storage because of limited storage capability at those facilities; therefore, flow augmentation is achieved at Grand Coulee and other upper basin projects.[99]

If not for flow augmentation for salmon, these projects could be drafted deeper in the winter to serve loads, leaving less flow in the spring and early summer and reducing the potential for excessive spill. With flow augmentation, however, the projects are

[98] Attachment C, Connolly Affidavit at P 7-9.
[99] Attachment B, Sweet Affidavit at P 12; Attachment C, Connolly Affidavit at P 10-11.

drafted so as to achieve flood control elevations while maintaining a high probability of fully refilling by early summer to provide water later in the summer for fish flow.[100]

To ensure sufficient flows for fish while providing flood control protection throughout the spring and summer, the Corps of Engineers sets specific reservoir elevation levels or targeted volumes of water storage and release for the storage projects. Managing the FCRPS through the spring and summer is a balancing act between ensuring there is enough flow to aid fish, but not so much that it harms fish and the other aquatic life in the river or conflicts with other non-power requirements such as flood control.[101]

In addition to jointly managing the hydro operations with the Corps of Engineers and the Bureau of Reclamation, Bonneville also coordinates with BC Hydro the Columbia River storage in Canada through the Columbia River Treaty between the United States and Canada. There are however, storage opportunities in Canada outside of Treaty operations, which Bonneville seeks to secure for multiple purposes, including flow augmentation. In 2011, Bonneville negotiated additional non-Treaty storage space. However, this storage is unavailable if its use would interfere with flood control, and the Canadian projects were operating for flood control through the high-flow period. Therefore, Bonneville was unable to use non-Treaty storage space in May or June 2011.[102]

b. Spill Strategy to Manage Total Dissolved Gas Levels

The reservoirs have only so much storage capacity. When they are full, or projected to be too full to manage flood control risk, the project operators must dispose of

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[100] Attachment D, Spain Affidavit at P 4.
[101] Attachment C, Connolly Affidavit at P 5.
[102] *Id.* at P 16-19.

the excess water. If all hydro projects are generating at full capacity, or if there is insufficient load, water must be spilled.[103]

Once it was recognized that 2011 would be a high-runoff year, Bonneville and its Federal partners began managing the hydro projects to minimize TDG caused by excessive spill. One aspect of TDG management is the distribution of spill across the system to minimize extreme spill at any given project.[104]

To implement spill, the Corps of Engineers develops and updates spill caps at each of the hydro projects on the Columbia and Snake Rivers. Spill caps are the amount of spill that will result in a given TDG level. If Bonneville is spilling up to the first spill cap without exceeding the TDG limits, it can alter operations and spill up to the next cap. In addition, to maximize allowable spill, Bonneville and the Corps of Engineers work to refine spill caps to make them as flexible as possible while remaining consistent with the state waivers and the Court order in the BiOp litigation.[105]

From mid-May to mid-June flows were so high that all the Columbia and Snake River projects except Chief Joseph were already spilling above the second spill cap because of high flows, leaving Chief Joseph as the primary tool to mitigate Environmental Redispatch when Bonneville had insufficient load for maximum generation. On occasion during this period, spill at the first spill cap at Chief Joseph was producing TDG measurements below the waiver limits. In order to minimize Environmental Redispatch on those occasions Bonneville spilled up to the second spill cap at Chief Joseph for brief periods while monitoring TDG levels to ensure they would

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[103] Attachment C, Connolly Affidavit at P 20.
[104] *Id.* at P 23.
[105] *Id.* at P 25-29.

not exceed the waiver limits. This action further reduced the need for Environmental Redispatch in some hours and eliminated the need in others.[106]

By June 18 river flows had receded to the point that some lower Columbia and Snake River projects were no longer spilling through the first spill cap but actual TDG measurements at those projects were at or in excess of the waiver levels. Because the Corps of Engineers issues a spill priority list requiring spill increases in a specific project-by-project order, increasing spill at Chief Joseph to level 2 was no longer an option and Bonneville returned to spilling through the first spill cap with hydro generation at less than maximum capacity. Throughout the period of high flow Bonneville managed spill so that Environmental Redispatch was called upon only when absolutely necessary to reduce the level of TDG in the rivers. Bonneville used Environmental Redispatch primarily during light load hours on nights and weekends when it could not otherwise find enough load.[107]

c. Operation of Columbia Generating Station

In 2011 CGS was scheduled to be off-line for refueling and maintenance beginning in early April. In late March 2011, Bonneville and Energy Northwest decided to take CGS off-line a week earlier than scheduled and instead generate additional hydro power to address the increasingly higher river flows and minimize the potential of high spill. CGS has been off-line during the 2011 high-water event.[108]

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[106] *Id.* at P 28.
[107] *Id.* at P 29.
[108] *Id.* at P 53.

d. Spill Exchange Arrangements

Bonneville was able to arrange spill swaps with the five mid-Columbia non-Federal hydro operators under an existing agreement by adjusting spill at Chief Joseph dam, the Federal project immediately upstream from the mid-Columbia projects. When reductions in spill at Chief Joseph and increases in spill at the mid-Columbia projects would be neutral or beneficial to fish, the non-Federal operators would spill and Bonneville would provide free power in exchange. From late May to mid-June, Bonneville delivered 13,200 MWh of spill exchange, reducing the need for Environmental Redispatch by the same amount.[109]

e. Minimizing Light Load Hour (LLH) Generation

As noted above, spill problems are most severe during LLH when Bonneville does not have enough load to generate at maximum capacity. Several dams—Libby, Dworshak, and Hungry Horse, the Willamette projects, and certain other Federal projects—operate independently from the mainstem Columbia and Snake River projects. Therefore, Bonneville can shift spill between these projects and the Columbia River projects as needed. Bonneville moved as much generation as possible out of light load hours at these FCRPS projects to free up load for projects that manage system spill. Bonneville asked that all these projects spill up to their own TDG limits during light load hours rather than generate in order to further lower generation during light load hours.[110]

f. Reductions of Balancing Reserve Capacity Limits

Bonneville uses the FCRPS projects on the Columbia and Snake Rivers to provide balancing reserves; that is, to instantaneously or on very short notice increase or decrease

[109] *Id.* at P 37-38.
[110] *Id.* at P 51-52.

generation to match load when the amount of load or other generation changes. Because changes in wind generation are less predictable than changes in load or thermal generation, it is the most significant user of reserves. With the extensive increase in wind generation on the Bonneville system, Bonneville has had to significantly increase its reserve capacity.[111]

Holding additional reserve capacity, however, means less generation is produced, which means more spill and higher TDG levels. Bonneville must maintain some level of reserve capacity to ensure reliability, but reducing the amount of reserves by generating more energy during heavy load hours (HLH) reduces the amount of excess water during light load hours. Bonneville has established Dispatcher Standing Order (DSO) 216 to ensure that the need for reserves to balance wind generation does not exceed the amount of reserves set aside for this purpose. If the usage of reserves exceeds the DSO 216 limits, wind generators that are the furthest off their schedules are ordered to reduce generation in an over-generation event or have their schedules reduced to actual generation in an under-generation event. Under normal operations, Bonneville holds 798 MW of incremental reserves and 975 MW of decremental reserves. During the 2011 high-water event Bonneville reduced its balancing reserve capacity to 400 MW of incremental reserves and 300 MW of decremental reserves. This reduction significantly lowered the amount of spill throughout the event and resulted in less TDG and less use of Environmental Redispatch.[112]

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[111] *Id.* at 39-40.
[112] *Id.* at 40-48.

g. Banks Lake Operations

Banks Lake is a storage facility in central Washington that stores water for irrigation. Banks Lake is supplied by pumping water out of Roosevelt Lake above Grand Coulee Dam. The pump load takes 600 MW of Federal power when operating at full capacity. For the pumps to achieve full capacity, however, Roosevelt Lake must be at a certain elevation, which was not achieved until June 9 because the lake must have space available for impending runoff coming down from Canada. During the entire high-water event Bonneville ran the Banks Lake pump load as much as possible, creating load for FCRPS generators and removing a substantial amount of water that otherwise would have been spilled. These operations also lowered TDG levels and reduced the need for Environmental Redispatch.[113]

4. Marketing Strategy Bonneville Adopted to Avoid Environmental Redispatch

Facing a Northwest LLH market that was trading negative from May 12 through June, Bonneville shifted its attention to mitigating its immediate LLH load needs and began to aggressively market LLH energy into California and the Southwest. Bonneville also began to exercise its May LLH put options and began deliveries on its non-standard flexible contracts. These actions provided over 1,000 MW of LLH load, but stream flows were such that the agency needed an additional 2,000 to 3,000 MW of daily LLH load to avoid spill, dangerous gas levels, and Environmental Redispatch orders.[114]

Before and during the 2011 high-water event, Bonneville contacted thermal generators, utilities, and marketers to discuss both standard and creative solutions to its

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[113] *Id.* at 49-50.
[114] Attachment D, Spain Affidavit at P 24.

spring 2011 over-generation concerns. Bonneville discussed spill-swaps, under which non-Federal hydro generators would spill in exchange for free FCRPS power (these generators are off the mainstem of the Columbia River). Bonneville discussed energy swaps under which it would deliver spring energy in exchange for taking delivery of an equal amount of energy in the summer and fall. The agency discussed shifting its irrigation and direct service industry loads from HLH to LLH to increase its LLH loads. Bonneville purchased put options to the regional trading hubs. Bonneville purchased reserves from its major direct service industrial customer (ALCOA Aluminum) to free-up FCRPS HLH generation and reduce LLH spill.[115]

Bonneville also continued to contact regional thermal generators in attempts to sell them more LLH power. Most of the Northwest thermal generators were already operating at minimum generation levels during LLH and were unwilling to shut their units down unless Bonneville could offer them HLH energy, capacity, and ancillary services to meet their energy and reliability requirements. The FCRPS was already generating at maximum capacity across the HLH hours and could not meet these demands unless Bonneville purchased HLH energy from other thermal generators. Furthermore, the displacement prices the generators requested reflected their marginal cost, which was considerably below the prevailing market prices and largely explained why they continued to operate. As long as market prices exceeded their marginal costs across light load hours and heavy load hours together, they were profitable and were not interested in displacing their generation.[116]

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[115] *Id.* at P 25-27, 43.
[116] *Id.* at P 25-26, 37-42.

Throughout the spring Bonneville continued to discuss non-standard solutions to its over-generation predicament with thermal generators and marketers. It extended a few non-standard sales into July, negotiated a few additional non-standard transactions, and offered free power to all buyers when Environmental Redispatch appeared imminent. No solution was too small, as evidenced by the agency's coordination of an 8-MW spill swap with two small utilities that own the generation output of the non-Federal McNary fish spillway hydro generation facility. In exchange for reducing the facility's LLH generation and increasing spill, Bonneville delivered free FCRPS hydro power.[117]

5. Transmission Actions Bonneville Took to Minimize Environmental Redispatch

Bonneville maximized its ability to transmit power out of the region by delaying all non-essential transmission maintenance, which forces transmission lines out of service and reduces transmission capacity. Spring is generally the best time to remove lines from service and perform maintenance because demand is lower and weather is less volatile. Nevertheless, Bonneville reviewed all scheduled maintenance to determine which outages would have the most impact on transmission capacity and rescheduled nine outages on Bonneville's system. Bonneville also coordinated with the owners of neighboring transmission systems to modify their outage schedules to maximize transmission capacity.[118]

Because of these actions, Bonneville had ample non-firm transmission capacity available for export. Because other regions, such as California, were experiencing their

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[117] *Id.* at P 27, 29-30.
[118] Attachment G, Ellison Declaration at P 2-7.

own over-generation problems, even when transmission was available it was not always utilized because of an absence of load at any price at or above zero.[119]

Bonneville also agreed to waive in-kind loss return obligations during an Environmental Redispatch event (that is, Bonneville did not require transmission customers to return energy to Bonneville to make up for losses associated with transmission). The waivers reduced the amount of power Bonneville had to market, allowed it to generate more, and reduced the need for Environmental Redispatch. The waiver of in-kind loss return obligations was added to the Environmental Redispatch Business Practice on June 16, 2011.[120]

6. Results of Environmental Redispatch During the 2011 High-Water Event

Environmental Redispatch has been an effective tool in managing overall system total dissolved gas. By displacing thermal and variable generation and using hydro power to serve the loads, lack-of-demand spill and TDG were reduced. Bonneville began using Environmental Redispatch on May 18, 2011, during LLH. The amount of Environmental Redispatch in any hour has depended on Bonneville's capacity to generate additional power, the generation levels necessary to avoid spill above the spill caps, the amount of thermal generation operating above its minimum generation levels, and the amount of actual wind generation. During LLH throughout the high-water event, only about 100 to 250 MW of thermal generation has been operating; that is, 1.5 to 3.5 percent of the 7,000 MW of thermal generation located in the BPA balancing authority area. During Environmental Redispatch events the thermal generators that were still operating

[119] Attachment D, Spain Affidavit at P 35-36.
[120] Attachment F, Nulph Affidavit at P 9.

were ordered to reduce their generation to their predetermined minimum generation levels.[121]

To date, approximately 97,000 MWh of wind generation (5.4% of the 1,760,905 MWh of wind generation that was produced between May 18 and July 18, 2011) have been redispatched during the 2011 high-water event. Over the same period, Bonneville has sold over 750,000 MWh of energy for less than the cost of the associated transmission. Of this amount approximately 250,000 MWh were sold at a price of zero, and BPA has spilled an estimated 12,400,000 MWh worth of water in addition to the normal spill for fish.[122]

This year's high flows resulted in extensive periods when spill levels were in excess of 120% supersaturation due to lack of turbines or lack of demand. High flows between May 18 and June 30 resulted in TDG levels that exceeded 120% TDG in project tailraces or 115% in the downstream forebay at all projects on the FCRPS almost every day. As shown in the chart below, without Environmental Redispatch, spill levels would have been higher. On May 21, the spill at Little Goose dam was approximately 80 kcfs (thousand cubic feet per second) which results in TDG of around 125% in the tailwater. These levels were typical of operations and TDG levels at most of the lower Snake and lower Columbia projects between May 18 and June 30. If Environmental Redispatch had not been available on that day as a means of acquiring load, additional lack-of-demand spill would have been required and spill would have increased to just under 140 kcfs, resulting in higher TDG levels.[123]

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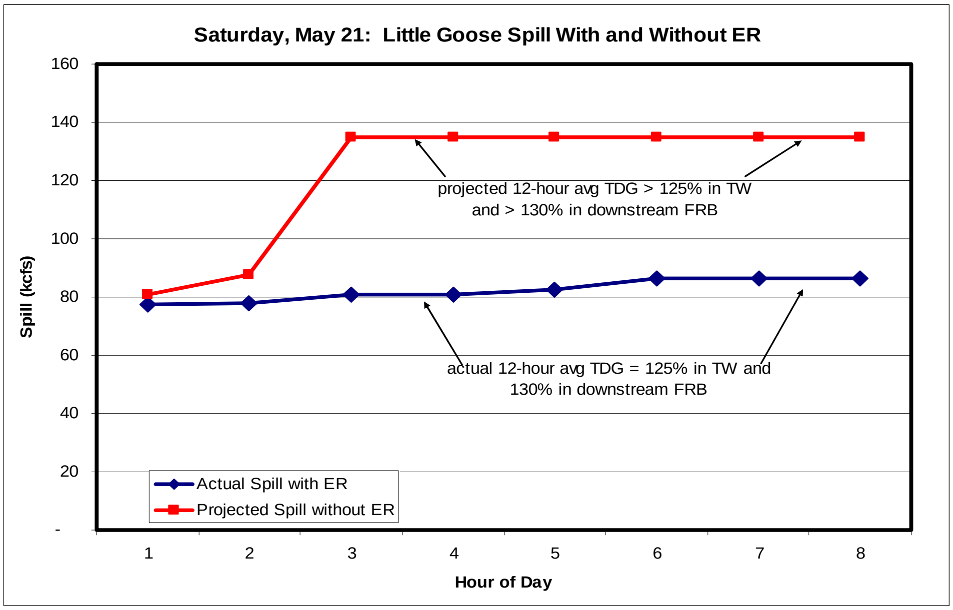
[121] Attachment C, Connolly Affidavit at P 61.
[122] *Id.*; Attachment D, Spain Affidavit at P 29.
[123] *See* Attachment C, Connolly Affidavit at P 32, 62.



As noted above, 2011 was the fourth highest water year on record with associated very high flows and very high levels of spill. Under these conditions elevated TDG levels expose listed species of salmon, steelhead, and other aquatic life to sub-lethal and lethal effects.[124] As the graph above demonstrates Environmental Redispatch has been effective in reducing spill levels. The projects affected and the level of relief varied with the conditions on the system and the amount of Environmental Redispatch available. There have been over 200 hours during the high-flow period where Environmental Redispatch has been used to reduce TDG significantly.[125]

VII. CHALLENGES TO THE ROD ARE WITHIN THE EXCLUSIVE JURISDICTION OF THE U.S. COURT OF APPEALS FOR THE NINTH CIRCUIT

A. Northwest Power Act Section 9(e)

Section 9(e)(5) of the NWPA vests the Court of Appeals for the Ninth Circuit with original jurisdiction to review challenges to final actions and decisions, or the

[124] *See* Attachment B, Sweet Affidavit at P 8, 17, 19, 23, 28-29, 33-34.
[125] Attachment C, Connolly Affidavit at P 62.

implementation of such final actions or decisions, taken by Bonneville pursuant to statutory authority. [126] The Ninth Circuit has consistently held that its jurisdiction over such final actions is broad and exclusive.[127] To determine whether a case involves a challenge to a final action or decision within the scope of the Ninth Circuit's exclusive jurisdiction, the Court determines whether Bonneville has taken a final action, and if so, whether the final action was taken pursuant to statutory authority. As demonstrated below, the ROD adopting the Policies is a final action under section 9(e)(3) of the NWPA, and the final action was taken pursuant to Bonneville's authority under multiple statutes.

B. The ROD Is a Final Action Under Section 9(e)(3) of the NWPA

Section 9(e)(1) of the NWPA contains a list of specifically enumerated final actions subject to the exclusive jurisdiction of the Ninth Circuit.[128] Section 9(e)(3) of the Act provides that "[n]othing in this section shall be construed to preclude judicial review of other final actions and decisions by the Council or Administrator."[129] The Ninth Circuit determined more than 25 years ago that, based on section 9(e)(3) of the NWPA,

[126] 16 U.S.C. § 839f(e)(5). These statutes include, but are not limited to, Bonneville's organic statutes such as the Northwest Power Act, the Federal Columbia River Transmission Systems Act, the Pacific Northwest Preference Act, and the Bonneville Project Act, as well as other statutes of more general application such as the Endangered Species Act and the National Environmental Protection Act ("NEPA"). *See generally Ass'n of Pub. Agency Customers, et al. v. Bonneville Power Admin*., 126 F.3d 1158, 1164-65 (9th Cir. 1997) ("APAC"); *NW Env'l Defense Ctr. v. Bonneville Power Admin*., 117 F.3d 1520 (9th Cir. 1997); *NW Resource Info. Ctr. v. Nat'l Marine Fisheries Serv.*, 25 F.3d 872, 874 (9th Cir. 1994). In addition, the Ninth Circuit has reviewed (and rejected) claims of undue discrimination against Bonneville as violating the Federal Power Act. *APAC*, 126 F.3d at 1172.

[127] *Transmission Agency of N. Cal. v. Sierra Pac. Power Co.,* 295 F.3d 918, 925-26 (9th Cir. 2002) ("*TANC*"), *cert. denied*, 539 U.S. 914 (2003); *Kaiser Aluminum & Chem. Corp. v. Bonneville Power Admin*., 261 F.3rd 843, 852 (9th Cir. 2001); *CP Nat'l Corp. v. Jura*, 876 F.2d 745, 747-78 (9th Cir. 1989); *Cent. Mont. Electric Coop., Inc. v. Bonneville Power Admin.*, 840 F.2d 1472, 1476 (9th Cir.1988) (*Central Montana)*.

[128] 16 U.S.C. § 839f(e)(1) (2006).

[129] 16 U.S.C. § 839f(e)(3) (2006).

the list of final actions identified in section 9(e)(1) of the Act is not exclusive.[130] As a result, section 9(e)(3) of the NWPA is regarded as a "catch-all" provision for the Ninth Circuit's jurisdiction under the NWPA.[131]

In *Industrial Customers, supra,* the Ninth Circuit found that the NWPA "does not delineate what constitutes a 'final action' under" section 9(e)(3).[132] Therefore, to determine whether an action taken by Bonneville is a final action, the Ninth Circuit turns to the general doctrine of finality in administrative law, and in particular, the finality test articulated in *Bennett v. Spear*, 520 U.S. 154 (1997).[133] The *Bennett v. Spear* test holds that an agency action is final when two conditions are met: (1) the action must mark the "'consummation' of the agency's decisionmaking process," and (2) the action must be one by which "'rights or obligations have been determined or from which legal consequences will flow."[134] Further, in applying the test, the Supreme Court explained that an important indicia of finality is "whether the action has a direct and immediate effect on the day-to-day operations of the party seeking review, and whether immediate compliance with the terms is expected."[135]

Applying this test to the instant case, there is no doubt that the ROD is a final action. In *Snohomish County, supra,* petitioners challenged certain contract amendments Bonneville had adopted.[136] The Court found that the challenged action satisfied the first

[130] *Cent. People's Util. Dist. v. Johnson*, 735 F.2d 1101, 1109 (9th Cir. 1984).
[131] *Pub. Util. Dist. No. 1 of Snohomish Cnty. Wash., v. Bonneville Power Admin*., 506 F.3d 1145, 1151-52 (9th Cir. 2007); *Indust. Customers of NW Utils. v. Bonneville Power Admin.*, 408 F.3d 638, 645 (9th Cir. 2005).
[132] *Indus. Customers*, *supra* n.128, 408 F.3d at 645 (citing *Puget Sound Energy, Inc. v. U.S.*, 310 F.3d 613, 624 (9th Cir. 2002).
[133] *Id.* at 646.
[134] *Industrial Customers*, 408 F.3d at 645-46.
[135] *Pub. Util. No. 1 of Snohomish Cnty.*, 506 F.3d at 1152.
[136] *Id.* at 1147.

prong of the finality test because, “after holding the standard notice and comment period, Bonneville announced its adoption of 2004 Amendments in a Record of Decision” which “was the consummation of Bonneville’s decision making process and expression of Bonneville’s final decision on the issue.”[137] The same is true in the instant case: the ROD was adopted following a regional notice and comment procedure, marked the end of the decision-making process, and is Bonneville’s final decision on its Interim Environmental Redispatch and Negative Pricing Policies. Upon issuing the ROD, Bonneville immediately began implementing its decisions in the ROD.[138]

The ROD also satisfies the second prong of the finality test – it fixes specific rights from which legal consequences flow. Indeed, it is because of these legal consequences that Complainants have filed their Complaint. Based on the decisions contained in the ROD, Bonneville redispatched thermal generation and then wind generation to maintain system stability and meet legal obligations.[139] In addition, Bonneville decided in the ROD that it would not pay negative prices to exercise Environmental Redispatch, which is the sole source of Complainants alleged injury.[140]

Further, in *Snohomish County*, the Ninth Circuit noted that it has interpreted its jurisdiction under the section 9(e)(3) “catch-all” “to extend only to actions based on the record developed before the agency, and expressly to exclude any causes of action arising from actions divorced from and unrelated to an administrative record.”[141] In the instant

[137] *Id*. at 1152.
[138] ROD at 15-16.
[139] ROD at 1-13.
[140] ROD at 12.
[141] 506 F.3d at 1151.

case, the action under review, that is, the ROD, is based exclusively on the administrative record developed before Bonneville.

Complainants may contend that the ROD is not a final action because it is an "interim" policy and will only remain in place until March 30, 2012.[142] However, the fact that the policy is designated "interim" and may be replaced sometime in the future does not preclude the ROD from being a final action. Indeed, the Ninth Circuit recently reviewed as a final action a Bonneville contract amendment with a term of only nine months that was intended to function as an interim short-term response to an adverse decision from the Court.[143] The important point is that the ROD is a final action because, as demonstrated, it satisfies the *Bennett v. Spears* finality test.

C. The ROD Is a Final Action Taken Pursuant to Statutory Authority

To determine whether an action is within the scope of the Ninth Circuit's exclusive jurisdiction, the Court applies the "true nature" test: "We determine whether we have jurisdiction over an action against Bonneville by looking to the nature of the conduct challenged rather than the label given the cause of action."[144] The Court originally articulated the "true nature" test in 1986, and followed it ever since.[145]

There have been numerous cases where litigants have attempted to avoid the exclusive jurisdiction of the Ninth Circuit by framing their claims as contract challenges or challenges to something other than a final action pursuant to statutory authority.[146] In

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[142] ROD at 1.
[143] *Pac. NW. Generating Coop. v. Bonneville Power Admin.*, 596 F.3d 1065 (9th Cir. 2010).
[144] *M-S-R Pub. Power Agency v. Bonneville Power Admin.*, 297 F.3d 833, 840 (9th Cir. 2002).
[145] *See Pac. Power & Light v. Bonneville Power Admin.*, 795 F.2d 810, 816 (9th Cir. 1986); *Puget Sound Energy, Inc. v. Bonneville Power Admin.*, 310 F.3d 613, 621 (9th Cir. 2002).
[146] *See e.g.*, *TANC,* 295 F.3d at 925-26 (characterizing statutory claim as contract and constitutional challenge); *Kaiser Aluminum & Chem. Corp. v. Bonneville Power Admin.*, 261 F.3d 843, 852 (9th Cir. 2001) (characterizing claim as contract challenge); *CP Nat'l Corp. v. Jura*, 876 F.2d 745, 747-78 (9th Cir.

each of these cases, the Ninth Circuit has held that the true nature of the action under review was a challenge to a Bonneville final action within its exclusive jurisdiction, regardless of a party's characterization of the claim as something else.

In the instant case, Complainants challenge Bonneville's decisions contained in the ROD, including Bonneville's Environmental Redispatch Protocol.[147] However, the ROD is a Bonneville final action taken pursuant to statutory authority under multiple statutes. In the ROD, Bonneville explained that:

> Environmental Redispatch is designed to ensure BPA is taking all reasonable efforts to meet its legal responsibilities under the Clean Water Act ('CWA'), Endangered Species Act ('ESA'), and court order (collectively, 'environmental responsibilities), as well as BPA's legal obligations under its authorizing legislation, such as the [Northwest Power Act, the Federal Columbia River Transmission System Act (the 'Transmission System Act'), the Pacific Northwest Power Preference Act ('Preference Act'), and the Bonneville Project Act (collectively, 'statutory responsibilities'), under specific hydro and load conditions, and after all reasonably practicable mitigating measures have been implemented. In addition, Environmental Redispatch will help provide options for BPA to maintain system reliability by balancing loads and resources within BPA's Balancing Authority Area while meeting BPA's environmental and statutory responsibilities.[148]

In *TANC, supra*, petitioners challenged the decisions of Bonneville and certain private utilities related to the construction and interconnection of the Alturas Intertie. Petitioners raised various legal arguments, including the breach of an interconnection agreement which allegedly resulted in the loss of intertie capacity. Petitioners argued that

1989) (characterizing challenge to Bonneville rates as contract claim); *City of Seattle v. Johnson,* 813 F.2d 1364, 1368 (9th Cir.1987) (same); *Atl. Richfield Co. v. Bonneville Power Admin.,* 818 F.2d 701, 705 (9th Cir.1987) (same); *PacifiCorp v. FERC,* 795 F.2d 816, 818-20 (9th Cir.1986) (characterizing challenge to administrative decision as contract claim).

[147] Complaint at 3.

[148] ROD at 1.

their breach of contract claim fell outside the scope of the Ninth Circuit's exclusive jurisdiction. The Court disagreed and explained that:

> TANC's particular legal theories about breach of contract and inverse condemnation are not controlling. *It matters not that the plaintiffs base their theory of recovery in part outside of the Northwest Power Planning Act*. In examining the nature of the agency action being challenged, our focus is 'on the agency being attacked and whether the factual basis for the attack is an agency action authorized by the Act.'[149]

With respect to the factual basis for the attack, the Court found that TANC's contract claims "*cannot be separated out* from the BPA's final administrative decision. . . . The *root cause* of the alleged inverse condemnation and breach of contract was the BPA's decision to join the Northwest AC Intertie to the Alturas Intertie, a final decision under section 9(e)(5) of the Northwest Power Planning Act. We alone have original jurisdiction over a challenge to that decision."[150]

In the instant case, as in *TANC*, Complainants' claims "cannot be separated out from the BPA's final administrative decision" contained in the ROD. Indeed, there is no question that the ROD is the "[t]he root cause of" the Complainants' grievance. Accordingly, jurisdiction over this case rests exclusively in the Ninth Circuit.

Moreover, in the instant case, Complainants' alleged injury stems solely from Bonneville's decision in the ROD not to pay them negative prices. However, that

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[149] 295 F.3d at 925 (citations omitted) (emphasis added).

[150] *Id*. at 926-27 (emphasis added). *See also Cent. Mont. Elec. Power Coop., Inc. v. Adm'r,* 840 F.2d 1472, 1475 (9th Cir. 1988), which was cited in *TANC*, in which petitioners challenged Bonneville's decision to deny their request for an allocation of electric power. The Ninth Circuit held that it had exclusive jurisdiction over the petition because "[t]he nature of the agency action being challenged by the Cooperatives [was] the Administrator's final action as to the marketing and allocation of electric power, a function that is governed extensively by the Northwest Power Planning Act," and "the effect of their action is to challenge the Bonneville's power-marketing decision." *Id.* at 1476 (emphasis added) (citations omitted).

decision is based on Bonneville's interpretation of its multiple and competing statutory responsibilities. As Bonneville explained in the ROD:

> Payment of negative prices to sell Federal hydropower is inconsistent with BPA's obligations under the Northwest Power Act. The Northwest Power Act provides that transmission access and services are to be provided subject to any existing legal obligations and without substantial interference with the Administrator's power marketing program. 16 U.S.C. § 839f(d)(2) & (3). While one purpose of the Northwest Power Act is to encourage the development of renewable power in the Pacific Northwest through BPA's acquisition authority, that is one purpose among many that BPA must meet, including assuring the Northwest has an economical power supply, providing environmental quality, continuing to repay the U.S. Treasury on a current basis, and protecting, mitigating and enhancing fish and wildlife of the Columbia River and its tributaries. 16 U.S.C. § 839. [151]

Further, Bonneville explained that:

> The payment of negative prices would shift the cost burdens associated with the PTC and REC to BPA's customers, jeopardize BPA's cost recovery objectives, and also hinder the ability of BPA to manage TDG levels. BPA, however, has the statutory requirements to carry out its marketing obligations, including keeping rates as low as possible consistent with sound business principles, recovering its costs, and protecting fish and wildlife affected by operation of the FCRPS. 16 U.S.C. § 839f(i)(1)(B); 16 U.S.C. § 839f(i)(3); 16 U.S.C. § 839b(h)(10)(A); 16 U.S.C. § 839e(a)(1). Such outcomes would be inconsistent with these statutory principles. The twin goals of protecting, mitigating, and enhancing fish and wildlife affected by the development, operation, and management of hydropower facilities while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply will be put at an unreasonable risk if BPA is forced to pay negative prices as a consequence of providing transmission to VERs.[152]

As such, Complainants' grievance regarding Bonneville's alleged undue discrimination and the payment of negative prices is completely intertwined with and inseparable from Bonneville's interpretation of its statutory obligations as set forth in the ROD. Under

[151] ROD at 12.
[152] ROD at 20-21.

TANC and other well established case precedent described above, the Ninth Circuit has exclusive jurisdiction to review this action.

Complainants may contend that *TANC* and some of the other cases involving the exclusive jurisdiction of the Ninth Circuit are distinguishable because they involve a question of whether jurisdiction rested with the Ninth Circuit as opposed to the Federal district court (or the Court of Federal Claims), whereas the instant case involves the jurisdiction of the Ninth Circuit as opposed to the jurisdiction of the Commission under the Federal Power Act. However, the point of these cases is that the jurisdiction of the Ninth Circuit to review challenges to Bonneville final actions taken pursuant to statutory authority is exclusive. The fact that the alternative forum may have been the district court or the U.S. Court of Federal Claims -- or that it may be the Commission -- makes no difference.

For instance, in *Kaiser Aluminum, supra*, petitioner Kaiser challenged a Bonneville decision regarding the appropriate rate for the sale of power.[153] Kaiser argued that Bonneville's decision breached its power sales contract and violated various provisions of Bonneville's organic statutes that were incorporated into the contract. As a result, Kaiser argued that its dispute was subject to arbitration under the arbitration provision of its contract and was outside the scope of the jurisdiction of the Ninth Circuit.[154] The Court disagreed and held that:

> Kaiser admits that it is primarily challenging action taken by the BPA pursuant to the Preference Act and the Northwest Power Act. *Because Kaiser is challenging a BPA action taken under those Acts, Congress has expressly bestowed exclusive jurisdiction to resolve the matter on us.* We

[153] *Kaiser Aluminum*, 261 F.3d at 845.
[154] *Id.* at 851-52.

> cannot relinquish that jurisdiction to an arbiter despite Kaiser's characterization of its claim as one for breach of contract. [155]

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To be clear, Bonneville is not arguing or suggesting that the Ninth Circuit has jurisdiction in every case filed against Bonneville under sections 210 or 211(A) of the FPA. On the contrary, statutory provisions must always be harmonized and reconciled to the extent possible.[156] However, the Ninth Circuit has broadly defined the scope of its jurisdiction over Bonneville and determined unequivocally and repeatedly that final actions taken by Bonneville pursuant to statutory authority can only be reviewed in that Court. In contrast, as explained below, the jurisdiction of the Commission over Bonneville is limited.[157] In accordance with the true nature test, the determination regarding whether a challenge to a Bonneville decision falls within the scope of the Ninth Circuit's exclusive jurisdiction must be made on a case-by-case basis.[158]

As demonstrated above, in this case, Complainants challenge a Bonneville final action taken pursuant to statutory authority. In the ROD, Bonneville made decisions regarding Bonneville's environmental and other responsibilities based on an administrative record and Bonneville's interpretation of multiple statutes, including the Clean Water Act, Endangered Species Act, and Bonneville's organic statutes, including

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[155] *Id*. at 852 (emphasis added). It should be noted that, prior to filing a petition in the Ninth Circuit, Kaiser initiated arbitration proceedings against Bonneville. The Ninth Circuit enjoined the arbitration proceedings from moving forward pending its disposition of the petition for review and resolution of the jurisdictional issue. A similar dispute over jurisdiction between an arbiter and the Ninth Circuit arose in NW Requirements Utils v. Bonneville Power Admin., Nos. 03-73849, 03-74179. Again, the Ninth Circuit enjoined the arbitration proceedings pending resolution of jurisdictional issue and petition for review. In these instances, the Ninth Circuit essentially determined that the scope of its jurisdiction can only be resolved dispositively by the Ninth Circuit itself.
[156] *See generally Ariz. Cattle Growers' Ass'n v. U.S. Fish and Wildlife,* 273 F.3d 1229, 1241 (9th Cir.2001).
[157] *See infra* sections XI and XII.
[158] *See generally NW Environmental Defense Center v. Bonneville Power Admin*., 117 F.3d 1520, 1528 (9th Cir. 2001) ("[t]he original jurisdiction granted this court by ... 16 U.S.C. § 839f(e)(5), raises procedural problems that will have to be resolved on a case-by-case basis.").

the Northwest Power Act, Transmission System Act, and Bonneville Project Act. The root cause of Complainants' grievance is the decision made by Bonneville in the ROD to comply with these statutes. Complainants cannot divest the Ninth Circuit of its exclusive jurisdiction to review this final action by filing their grievance with the Commission. Any relief the Commission might provide would have the effect of directly affecting and potentially interfering with Bonneville's decisions and its compliance with its many competing statutory obligations. Because the action challenged in this docket is a Bonneville final action taken pursuant to statutory authority, this case falls squarely within the scope of the exclusive jurisdiction of the Ninth Circuit.[159]

VIII. NEGATIVE PRICING POLICY

A. Paying Negative Prices Would Inappropriately Transfer Costs to Bonneville's Ratepayers and Entail an Open-Ended and Uncertain Financial Obligation for Bonneville That Would Jeopardize Its Ability to Fulfill Its Statutory Obligations

Complainants suggest that Bonneville can resolve its lack-of-load problem by paying negative prices; that is, by selling its generation into the electricity markets when they were negatively priced, or by paying wind generators not to generate. They assert that Bonneville refuses to do so because paying negative prices would create costs for Bonneville's preference customers.[160]

Bonneville is concerned with creating additional costs for any of its customer classes, particularly if a customer class has not caused the cost. Complainants assert that it would be appropriate for Bonneville's preference customers to bear the costs of

[159] Section 9(e)(5) of the Northwest Power Act provides that suits challenging a Bonneville final action must be filed within 90 days of the date of the final action. In this case, the date of the final action is May 13, 2011, when the Final ROD was issued. Therefore, Complainants have ample opportunity to file a timely petition for review in the Ninth Circuit, which must be filed by August 11, 2011.
[160] Complaint at 16.

negative prices, even though almost all of the wind power is exported out of Bonneville's balancing authority.[161]

The real issue in this case, however, is not the allocation of costs among Bonneville's various customer classes. The real issue is whether Bonneville or any of its ratepayers should bear the cost of the production tax credits (PTCs) and renewable energy credits (RECs) that the Federal and state governments have established for wind generators. They should not bear these costs.

Bonneville has multiple statutory responsibilities, which include assuring the Northwest an economical power supply, protecting the environment, repaying the U.S. Treasury for the Federal investment in the FCRPS, and protecting, mitigating, and enhancing fish and wildlife of the Columbia River and its tributaries.[162] At the same time Bonneville has an obligation to provide power at the lowest possible rates consistent with sound business principles.[163] Meeting these various responsibilities entails an intricate

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[161] *Id.* at 45-46. Complainants assert that section 7(g) of the Northwest Power Act prohibits the allocation of fish and wildlife costs to power rates and that Bonneville is effectively allocating such costs to Complainants. BPA disagrees.

Section 7(g) states that "the Administrator shall equitably allocate to power rates in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under [section 7]." 16 U.S.C § 839e(g). Section 7 authorizes the Administrator to set transmission rates to recover all costs of transmission. Id. § 839e. Even assuming that Bonneville is allocating costs as Complainants suggest, in this case such costs are a cost of the generation needed to maintain the reliability and stability of the transmission system.

Moreover section 7(g) says that the Administrator shall "equitably allocate" certain costs to power rates, not "solely allocate," and that the allocation shall be in accordance with generally accepted ratemaking principles.

Finally, BPA is directed to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 838h; 16 U.S.C. § 839e(a)(2)(C). Because fish and wildlife is a cost of ancillary and control area services necessary to support the stability and reliability of the transmission system, it is equitable to allocate such costs to the rates for these services.

The Ninth Circuit Court of Appeals has consequently determined that the Administrator has authority to protect fish and wildlife by imposing restrictions on transmission access. *California Energy Res. Conservation and Dev. Comm'n v. Bonneville Power Admin.*, 831 F.2d 1467, 1477-78 (9th Cir. 1987), *cert denied*, 488 U.S. 818 (1988).

[162] 16 U.S.C. § 839.

[163] 16 U.S.C. § 825s.

balancing act among competing objectives and multiple constituencies with different economic interests. Not all actions will satisfy everyone; the question for the Administrator is how to exercise the discretion Congress has granted him to resolve the various conflicts and satisfy all of his obligations.

Bonneville has been able to meet its various statutory objectives. Bonneville believes it can continue to meet these objectives even during high-water events by providing low-cost or free Bonneville hydro power to displace non-Federal generation and by employing Environmental Redispatch as necessary. However, fulfillment of Bonneville's statutory responsibilities and achievement of the Northwest Power Act's objectives would be at risk if Bonneville paid negative prices in order to ensure compliance with its environmental responsibilities.

The risk arises from the high and, as explained further below, uncertain cost of a negative pricing policy. Because Complainants are paid their incentives from the state and Federal governments only when generating, to induce them to shut down during periods of over-generation Bonneville would likely have to pay negative prices at least sufficient to replace these incentives. Currently the incentives are paid by the taxpayers (in the case of the PTCs) and by the consumers of wind power (in the case of the RECs). With almost all the wind generation in Bonneville's balancing authority being exported, however, paying negative prices would transfer the cost of the incentives to ratepayers who do not benefit from them. As noted above, this would be inconsistent with traditional principles of cost causation. The costs of Federal and state production incentives should be borne by the taxpayers and ratepayers that Congress and state governments intended would pay for them.

Moreover, if Bonneville adopted a policy of paying negative prices it would create opportunities to distort the market. Marketers and non-Federal thermal generators could refuse Bonneville offers of low-priced or even free power and wait until Bonneville was forced to either offer its power at negative prices or violate its legal obligations through excessive spill. The Northwest has an abundance of publicly available data regarding hydro generation, stream flow, and water storage. Although Bonneville must prepare for the possibility of both high and low water, thermal generators can analyze these data and judge that a high-water year is likely and that hydro flexibility may be tight. They can expect negative pricing and refuse offers until the price goes negative, forcing Bonneville to pay entities to accept its power. Unlike Bonneville, they can afford to be wrong without violating myriad legal responsibilities. Bonneville could be forced to regularly offer negative prices, at least during spring runoff.

A policy of paying negative prices could lead to the converse of the 2000-2001 California dysfunctional market crisis, when some generators held back power until the California Independent System Operator (CAISO) was forced to offer sky-high prices to keep the lights on. Northwest generators and energy traders could take the opposite approach, continuing to generate or to withhold purchasing until the price went negative even if, based on their costs, they could have profited when prices were positive. Just as the ISO purchased power at any price to avoid blackouts, Bonneville could be forced to pay any negative price to avoid spill.

When a generator or load-serving entity is facing a forced purchase or sale, and the market knows the distressed entity must pay what the market demands, the consequences can be dire. In Bonneville's case, for example, there is simply no way to know how low prices might have to get in this situation, particularly in a high water year or in the spring when runoff overwhelms the FCRPS's storage capability and forces BPA to generate. Bonneville could be faced with extreme market uncertainty and unknown cost exposure. This prospect would create undue pressures on Bonneville's budget and significant economic risk to Bonneville and its ratepayers.

Currently, Bonneville's fish and wildlife budget exceeds $750 million per year (over $440 million in direct expenditures and over $300 million in foregone revenues). Bonneville is already absorbing significant financial impact and risk by spilling significant quantities of water and providing low-cost and free power during over-generation events. Payment of negative prices to protect fish and wildlife and compensate wind generators for their PTCs and RECs would impose an additional burden on Bonneville's already prodigious fish and wildlife program costs, compromise Bonneville's cost recovery objectives, and endanger the obligation to maintain an economical power supply.

Based on a peer-reviewed analysis conducted by Bonneville, the cost of paying the value of lost PTCs and RECs alone could be as much as $50 million during 2012 if it proves to be a year of high water and heavy wind conditions.[164] Moreover, this study did not consider the possibility that thermal generators would hold out for negative prices, which could substantially increase the cost. The twin goals of protecting, mitigating, and enhancing fish and wildlife affected by the development, operation, and management of hydro power facilities while assuring the Pacific Northwest an adequate, efficient,

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[164] *Northwest Overgeneration: An Assessment of Potential Magnitude and Cost* 13, http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/BPA_Overgeneration_Analysis.pdf.

economical, and reliable power supply will be put at an unreasonable risk if Bonneville is forced to pay negative prices as a consequence of interconnecting wind generation.

B. Paying Negative Prices Is Unlikely to Succeed in the Northwest or to Achieve Bonneville's or the Commission's Public Policy Objectives

Complainants assert that Bonneville need only offer "some degree" or "some amount" of negative pricing to induce wind and other generators to curtail and create new markets for Federal power, including markets outside the region.[165] Bonneville's experience during this year's high-water event calls this unsupported assertion into question. Bonneville was able to induce almost all thermal generation in its balancing authority to displace by offering low-cost and free power. The higher-cost generators outside of Bonneville's balancing authority also voluntarily displaced. However, the lower-cost generators appeared uninterested in displacement regardless of price. Even when the market was trading negative during light load hours, these thermal generators continued to generate power, because the profits they earned during heavy load hours more than compensated for any losses during light load hours.[166]

Bonneville could not feasibly meet their demands. Although Bonneville's over-generation problem occurs mostly during light load hours, these generators wanted low-cost or free power for 24 hours − both heavy load hours and light load hours − for 15 to 30 days, together with the hourly capacity and ancillary services that those resources otherwise provide. In most cases, Bonneville did not have either the energy or the

[165] Complaint at 15, 41.
[166] Attachment D, Spain Affidavit at P 28, 44.

capacity in heavy load hours to meet their request. Some resources were inaccessible because transmission for the replacement Federal power was unavailable.[167]

Despite Complainants' assertion, therefore, Bonneville has little reason to believe that additional markets will suddenly appear if Bonneville adopts negative pricing. Instead, Bonneville expects that the low-priced sales Bonneville makes now to displace thermal generation would simply become negatively priced sales for the same load as thermal generators waited for Bonneville to pay them to take its energy. Moreover, under Bonneville's current policy of selling power down to a price of zero, Bonneville knows when it has attained all possible load. If Bonneville decides to pay negative prices, at what point does it stop? If negative $50/MWh doesn't garner enough load, does Bonneville go to negative $100? Negative $500? The costs are potentially enormous.

Complainants paint negative pricing as a normal component of a well-functioning market. They cite several articles from energy dailies that document instances of negative pricing in energy markets.[168] In all cases with which Bonneville is familiar, however, the economic impact is contained because the negative prices last for a few hours, or at most a few days. In addition, the over-generation situations are usually unexpected and therefore it is not practical for generators to predict when they will occur and plan to hold out for negative prices. In the Northwest, however, a high-water event can last for much longer periods of time and, as shown above, the spring runoff in the Northwest allows generators to predict at least generally when over-generation will occur. Finally, unlike the case with most other markets, energy markets in the Northwest

[167] *Id.* at P 38-41.
[168] Complaint at 43 nn.116-117.

include substantial hydro power that must run for reliability and environmental reasons, exacerbating the oversupply situation.

Thus, for example, one of the articles Complainants cite (but do not quote or discuss), from April 2009, notes that balancing energy prices in the West zone of ERCOT fell below zero around 2:00 a.m. one day and stayed below zero until about 9:00 a.m. on the same day.[169] This article quoted the independent market monitor for ERCOT saying that although negative prices are not completely unusual, it is uncommon to see such low levels for a prolonged time.[170] He called the situation an "anomaly" and added that, "You might be okay with taking negative prices for an hour or so, but when you're taking those prices for several hours, it'll make you take another look at how you're responding."[171] Taking a different look at how to respond is exactly what Bonneville has done.

In an article concerning an energy trader conference, Complainants quote a senior economist for PJM saying that PJM tries "not to favor or disadvantage wind," and that PJM has recently allowed wind to bid at a negative price if its cost is in fact negative.[172] The next sentence of the article, not quoted by Complainants, says that "[t]his has provided a certain advantage to wind generators, who unlike traditional generators receive tax benefits and can afford to bid below zero."[173] Negative prices apparently failed to achieve the desired result of not favoring wind.

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[169] Leticia Vasquez, *ERCOT System Prices Fall Below $0/MWh*, Megawatt Daily, vol. 14, issue 77 (Apr. 23, 2009).
[170] *Id*.
[171] *Id*.
[172] Milena Yordanove-Kline, *Power Price, Reliability Take Back Seat: Panelists*, Energy Trader, Nov. 12, 2009.
[173] *Id*.

The point of the article was to note that the participants at the conference agreed that the major concerns for regulators in today's energy industry do not include such traditional issues as price, but instead concern "issues like the smart grid and the penetration of wind and solar generation," and that "the environment is now the major issue in the industry."[174] These are exactly the issues Bonneville has been struggling with and has addressed in its Environmental Redispatch policy. Given Bonneville's significant statutory responsibilities toward the environment, they present even bigger issues for Bonneville than for most utilities, and even more of a struggle.

Finally, Complainants reproduced a passage from an article without attribution. In concluding their argument that negative prices should be considered a normal market phenomenon, they note that "[i]t can be economically rational for operators of less responsive generation units to offer negative prices in order to avoid the costs of shutting down for a short period of time and then starting up again when load increases. Prices that are near zero or negative typically occur when energy load is very low."[175] This unattributed statement (and the three sentences that immediately precede it) were lifted virtually word-for-word from a 2008 article on knowledgeproblem.com. The passage Complainants copied distorts the real author's point. To understand the author's point, one must read the parts of the article that Complainants omitted.

The article concerns the payment of negative power prices in the West region of ERCOT. After making the above statement (regarding the rationality of less responsive units offering negative prices in some cases), the author said that this was not what was

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[174] *Id.*
[175] Complaint at 43.

happening in the case of ERCOT: "That isn't the case in West Texas. Instead, the negative prices appear to be the result of the large installed capacity of wind generation."[176] The same is true in the Northwest. By appropriating the author's statement without the context, Complainants paint a false picture of the problem the author identified and the potential solution.

This becomes even clearer as one reads on. The author also states that negative prices "are a big anti-conservation incentive" − since a consumer can install equipment that uses substantial energy and then get paid by generators to operate it (the author's example is a giant toaster).[177] As to a balancing authority's ability to pay "some amount" of negative pricing, the author has this to say: "It is economically rational for wind power producers to operate as long as the subsidy [PTCs and RECs] exceeds their operating costs plus the negative price they have to pay the market. **Even if the market value of the power is zero or negative, the subsidies encourage wind power producers to keep churning the megawatts out.**"[178]

This is hardly a normally functioning market, where power has no value but continues to be produced. In the Pacific Northwest, before the interconnection of over 3,500 MW of wind generation negative pricing was relatively rare even during high flow periods. Negative pricing was much more common this year, particularly on light load hours when generation exceeded loads. This phenomenon has also occurred in other

[176] Michael Giberson, *Frequent negative power prices in the West region of ERCOT result from wasteful renewable power subsidies* (Nov. 20, 2008), *available at* http://knowledgeproblem.com/2008/11/20/frequent_negati/ at 1 (last visited July 12, 2011).
[177] *Id*.
[178] *Id*. (bolded in original).

balancing authority areas with a high penetration of wind generation.[179] Since no energy or capacity products can be produced at a negative cost, negative prices do not reflect actual production costs. It is reasonable to conclude that negative pricing should be avoided or minimized, and that it would be infrequent in a properly functioning market.

Finally, under Bonneville's Environmental Redispatch policy, curtailed wind power is replaced by hydro power and not, for example, by carbon-emitting coal. Our author addressed a similar issue in Texas. Noting that the incentives for wind projects may encourage environmentally friendly power, he added that "in this case the link between the payments and the possible reduced emissions effect is tenuous. In Texas the PTC is probably offsetting natural gas generation most of the time."[180] Similarly, if Bonneville had to abandon its Environmental Redispatch policy, wind power would be offsetting hydro power, and carbon emissions would not be reduced. Instead, negative prices would represent an unnecessary transfer of value between two carbon-free generation resources. Wind production incentives are intended to encourage carbon-free energy to displace carbon-based energy, not other carbon-free energy.

IX. THE COMPLAINT FAILS TO STATE A CLAIM OF DISCRIMINATION

Complainants raise claims of both undue discrimination and lack of comparability claims. Rule 206 requires that a complaint "[e]xplain how the action or inaction violates applicable statutory standards or regulatory requirements."[181] With respect to their undue discrimination claim, Complainants compare the impacts of the Policies on thermal

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[179] Attachment D, Spain Affidavit at P 28.

[180] Michael Giberson, *Frequent negative power prices in the West region of ERCOT result from wasteful renewable power subsidies* at 2.

[181] 18 C.F.R. § 385.206(a)(2) (2011).

generators[182] and "offtakers of thermal power"[183] to the impacts on wind generators, but never explain how or why Bonneville's actions satisfy any legal criteria for undue discrimination. Complainants do not even bother to define the term, let alone analyze relevant Commission precedent. Rather, they proffer conclusory statements that the Policies and Bonneville's Dispatcher Standing Order 216 (issued in 2009) constitute undue discrimination. FERC has consistently "admonished parties that rather than bald allegations, complaining parties must make an adequate proffer of evidence including pertinent information and analysis to support its claims."[184] When a pleading provides no basis in fact or law, FERC "is not obligated to address a position in a pleading."[185] This the Complainants have not done.

X. ARGUMENTS BASED ON BONNEVILLE'S LACK OF RECIPROCITY ARE IRRELEVANT

To gain the Commission's sympathy, Complainants construct a story of a "rogue" Bonneville thumbing its nose at reciprocity and Commission approval of tariff changes. Their tale is neither true nor relevant to the issues in this proceeding and lacks evidentiary support.

Complainants' allegations that Bonneville is "drift[ing] away from transmission service that comports with the Commission's terms and conditions for non-discriminatory open access service"[186] and that Bonneville is reconsidering whether to seek reciprocity

[182] Complaint at 37 n.103.
[183] Complaint at 42.
[184] *Californians for Renewable Energy, Inc. v. Cal. Pub. Util. Comm'n*, 129 FERC ¶ 61,075, P 13 (2009) (internal citations and quotations omitted).
[185] *S. Cal. Edison Co.*, 113 FERC ¶ 61,143, P 21 (2005).
[186] Complaint at 30.

through the Commission's "safe harbor" option[187] are irrelevant to this proceeding. Seeking reciprocity status is entirely voluntary for non-public utilities. This Commission has said that it "recognize[s] the voluntary nature of Bonneville's [safe harbor OATT] filing."[188] The Commission has approved all but a few of the provisions of Bonneville's OATT. The Commission elected not to grant reciprocity status to Bonneville because four deviations that Bonneville proposed in its Order 890 OATT filing did not meet the "substantially conforms or superior to" reciprocity test. A decision not to seek reciprocity status, or the failure to obtain it, is not a violation of any statute or regulation or Commission policy.

Complainants make further efforts to paint Bonneville as a rogue agency by charging that Bonneville has considered eliminating the requirement in its OATT that the Commission approve tariff changes.[189] This charge is also irrelevant to this proceeding. The Commission does not require a non-public utility OATT to contain such a provision. Bonneville has found no other non-public utility tariff that includes such a provision.

Finally, Complainants charge that Bonneville has been inappropriately modifying its OATT through the issuance of business practices.[190] Other than bare citations to four Bonneville business practices and cryptic references to a Bonneville public communications piece, they provide no support for their claim. And even if their assertions were true, they too are irrelevant to this proceeding. Bonneville is not a public

[187] Complaint at 23.
[188] *Bonneville Power Admin.*, 135 FERC ¶ 61,023, P 4 (2011).
[189] Complaint at 26-27.
[190] Complaint at 26.

utility subject to Federal Power Act Sections 205 and 206, nor is it subject to the "rule of reason" policy as Complainants imply.[191]

XI. THE COMMISSION HAS LIMITED JURISDICTION AND AUTHORITY OVER BONNEVILLE

A. The Commission Lacks Authority to Remedy Bonneville's Alleged Statutory Violations

Complainants do not explicitly request the Commission to determine whether Bonneville is in compliance with its statutory responsibilities. Nevertheless, Complainants incorporate references to Bonneville's statutory provisions and imply that Bonneville is violating them.[192] Complainants request remedies that would override Bonneville's determinations of what its statutory responsibilities require in this emergency situation.

Congress has granted the Commission only very limited authority with respect to reviewing Bonneville's compliance with its statutes. Congress directed the Commission to determine whether Bonneville's proposed rates comply with specified statutory standards.[193] But Congress has not granted jurisdiction to the Commission to determine whether Bonneville is in compliance with any of its other statutory responsibilities. As the Commission itself has acknowledged with respect to one of Bonneville's governing statutes:

> We . . . affirm . . . that we lack jurisdiction over the question of whether Bonneville has violated any aspect of the Preference Act[.][194]

[191] Complaint at 29.
[192] *See* Complaint at 16–19, 45.
[193] *See generally* 16 U.S.C. §839e(a).
[194] *Sierra Pac. Power Co*.. 86 FERC ¶ 61,198, P 14 (1999).

The Complaint in this case challenges a Bonneville decision regarding compliance with a broad range of statutory responsibilities over which the Commission has no jurisdiction.

B. The Commission Has No Authority to Adjudicate or Order Compliance with Bonneville's Contracts

1. The Commission Has No Authority to Adjudicate or Order Compliance with Bonneville's Contracts Under Federal Power Act Sections 205 and 206

The Commission may act only within the confines of its jurisdictional authorities.[195] As a Federal power marketing administration, Bonneville is not subject to the Commission's authorities under Sections 205 and 206 of the Federal Power Act (FPA).[196]

2. The Commission Has No Authority to Adjudicate or Order Compliance with Bonneville's Contracts Under Federal Power Act Sections 210 and 211

The Commission has authority under FPA section 212i(1)(B)(i), 16 U.S.C §824k(i), to order Bonneville to interconnect eligible entities to its transmission system under FPA section 210, 16 U.S.C. §824i, and to provide transmission services to eligible entities under section 211, 16 U.S.C. §824j. However, those authorities do not provide the Commission with authority to adjudicate contract disputes between Bonneville and its customers as Complainants have requested. Indeed, section 201(b) of the FPA provides that compliance with an order to interconnect under section 210 does not otherwise

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[195] *See Bonneville Power Admin. v. FERC* , 422 F.3d 908 (9th Cir. 2005) (Commission cannot exercise jurisdiction or authority unless authorized by statute).

[196] *United States Dept. of Energy -- Bonneville Power Admin*, 114 FERC ¶ 61,237, P 2 (2006) (**"**BPA is not a public utility within the Commission's jurisdiction under sections 205 and 206 of the Federal Power Act."); *see also Emerald People's Util. Dist. v. Bonneville Power Admin*., 85 FERC ¶ 61,229, P 2 (1998).

subject an entity to Commission regulation.[197] As the Ninth Circuit Court of Appeals has stated:

> Congress was mindful . . . to establish that the regulatory authority over governmental entities contained in these provisions of the FPA should not be construed to subject such electric utilities to the general jurisdiction of FERC:
>
>> "The provisions of sections [210, 211 and 212] shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order of the Commission under the provisions of section [210 or 211], *shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence."*
>
> FPA § 201(b)(2) (16 U.S.C. §824(b)(2)).[198]

The Commission itself has determined that it may not adjudicate Bonneville's contracts:

> Bonneville acknowledges that the Commission can require it to provide transmission services under sections 211 and 212. However, it contends that we may not examine a Bonneville transmission contract, and may examine its power sales contracts only for the limited purpose of responding to a section 211 application.
>
> * * * * *
>
> The majority of these agreements are not subject to our jurisdiction; those that are subject to our limited review under the Northwest Power Act.[199]

3. The Commission Has No Authority to Adjudicate or Order Compliance with Bonneville's Contracts Under Federal Power Act Section 211A

The Commission's authority under FPA section 211A, 16 U.S.C. §824j-1, does not authorize the Commission to adjudicate Bonneville's contracts. This section

[197] 16 U.S.C. § 824(b)(2) (2009).
[198] *Bonneville Power Admin. v. FERC.*, 422 F.3d 908, 916 (9th Cir. 2005) (emphasis in original).
[199] *Idaho Power Co.*, 82 FERC ¶ 61,002, P 4 (1998); *see also United States Dept. of Energy - Bonneville Power Admin.*, 100 FERC ¶ 61,102, P 12 (2002) ("Similarly, PNGC's argument concerning current contracts between PNGC and Bonneville is not subject to Commission jurisdiction.").

authorizes the Commission, by rule or order, to require unregulated utilities to provide transmission services "on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides itself and that are not unduly discriminatory or preferential." Nothing in this language suggests that the Commission can rule on alleged breaches of contract by non-jurisdictional entities.

Complainants have asked the Commission to issue an order to Bonneville under FPA section 211A requiring the agency to revise its curtailment practices and to file an OATT for Commission approval.[200] If, despite the jurisdictional argument above, the Commission elects to entertain Complainants' request, its authority to provide these remedies with respect to Bonneville is limited.

XII. THE COMMISSION'S AUTHORITY UNDER SECTION 211A IS LIMITED

A. The Commission's Authority Under Section 211A Must Be Applied Consistent with the Laws Applicable to Bonneville

In FPA section 211A, added by the Energy Policy Act of 2005, Congress authorized the Commission to order an "unregulated transmitting utility" to provide transmission services

> (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and
> (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.[201]

Bonneville is included in the definition of "unregulated transmitting utility." As applied to Bonneville, however, implementation of the Commission's authority under this section

[200] Complaint at 7-8.
[201] 16 U.S.C. §824j-1 (2009).

must take into account Bonneville's existing statutory rights, authorities and responsibilities.

Nowhere in Complainants' discussion of the FPA do they even reference the central requirement imposed by Congress on the Commission's use of its ordering authority with respect to Bonneville. Section 212(i) of the FPA requires that orders issued to Bonneville under sections 210 and 211 are subject to "the provisions of otherwise applicable Federal laws [which] shall continue in full force and effect and shall continue to be applicable to the [Federal] system."[202] These provisions include, but are not limited to, Congressional directives that Bonneville recover its costs. repay the Treasury,[203] set its rates "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles,"[204] and protect, mitigate, and enhance fish and wildlife resources.[205]

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[202] 16 U.S.C. §824k(i)(1)(B)(i) (2009). Congress also incorporated into the legislative history of the 1992 Energy Policy Act a directive that prohibits FERC from ordering transmission service if it would result in uncompensated spill of water from Federal reservoirs:

> The FERC shall not issue any order for transmission services under section 211 which is likely to cause the uncompensated spill of water from Federal . . . reservoirs which otherwise could be used to generate electric energy, because of the displacement from a transmission system by energy transmitted under such an order. Such spill shall be deemed contrary to the public interest unless full compensation is provided to those entities suffering such spill.

House Conf. Rep. No. 102-1018, Joint Explanatory Statement of the Committee of Conference at 2480 (page 389). This directive clearly indicates Congress's intent to restrict the Commission's authority when addressing transmission services that would affect water spills at Federal hydroelectric projects. This is an area Congress reserved to the Bonneville Administrator.

[203] 16 U.S.C. §§ 832f and 839e(a)(1) (2009).

[204] 16 U.S.C. § 838g (2009).

[205] 16 U.S.C. § 839b(h)(11)(A)(i) Section 212i(4) of the FPA also recognizes that other federal statutes qualify the Commission's authority:

> (4) To the extent the Administrator of the Bonneville Power Administration cannot be required under section 824j of this title, as a result of the Administrator's other statutory mandates, either to (A) provide transmission service to an applicant which the Commission would otherwise order, or (B) provide such service under rates, terms, and conditions which the Commission would otherwise require, the applicant shall not be required to provide similar transmission services to the Administrator or to provide such services under similar rates, terms, and conditions.

16 U.S.C. §824k(i)(4).

Section 211A does not explicitly include this requirement. However, nothing in section 211A or any other section of the Energy Policy Act of 2005 suggests that these laws were diminished in any way. To the contrary, in construing a statute,

> [i]t is assumed that whenever the legislature enacts a provision it has in mind previous statutes relating to the same subject matter. In the absence of any express repeal or amendment, the new provision is presumed in accord with the legislative policy embodied in those prior statutes.[206]

Nothing in the Energy Policy Act of 2005 expressly repeals or amends any provision of Bonneville's organic statutes. Implied repeal is strongly disfavored:

> We have repeatedly stated . . . that absent a clearly expressed congressional intention, repeals by implication are not favored. An implied repeal will only be found where provisions in two statutes are in irreconcilable conflict, or where the latter Act covers the whole subject of the earlier one and is clearly intended as a substitute.[207]

There is no irreconcilable conflict between section 211A, section 212(i), and Bonneville's statutes.

Moreover, in this case the later-enacted statute (section 211A) covers every unregulated transmitting utility in the country and broadly prohibits discriminatory actions (once the Commission implements the statute), whereas Bonneville's statutes were enacted to govern a single Federal entity and are tailored quite specifically to govern that entity's operations. In such a case there is no implied repeal: "[A] statute dealing with a narrow, precise, and specific subject is not submerged by a later enacted statute covering a more generalized spectrum."[208] In fact it seems obvious that the Northwest Power Act and other statutes that govern Bonneville remain in effect; and if

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[206] Normal J. Singer & Shambie Singer, Sutherland Statutes and Statutory Const. §51.02 (5th ed. 2011).
[207] *Branch v. Smith*, 538 U.S 270, 273 (2003) (internal quotation marks and citations omitted).
[208] *Nat'l Assoc. of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 663 (2007) (quoting *Radzanower v. Touche Ross & Co*., 426 U.S. 148, 153 (1976)).

they do, the Commission has no authority to issue orders requiring Bonneville to take actions that will violate them.

A 2003 Senate Conference Report that addressed language that was identical in all material respects[209] to the section 211A language eventually enacted in the Energy Policy Act of 2005 specifically states that meeting Bonneville's statutory responsibilities continues to be paramount:

> Section 1132 authorizes FERC to require that unregulated transmitting utilities provide open access to their transmission systems at rates that are comparable to those they charge themselves and on comparable terms and conditions that are not unduly discriminatory . . . The limited authority provided FERC to ensure access at comparable rates and terms that are not unduly discriminatory neither alters nor affects the specific prescriptions applicable to the Bonneville Power Administration, nor precludes the Bonneville Power Administration from establishing prices, terms, and conditions in accordance with its enabling statutes. *Those statutes, and their implementation by the Bonneville Power Administration, are unaffected.* Specifically, the Committee notes that the Bonneville Power Administration will continue to establish its cost-based rates in accordance with existing law and the rates, as well as terms and conditions, shall not be considered unduly discriminatory.[210]

This report evidences a recognition that actions Bonneville takes in compliance with its existing statutory responsibilities should not be viewed as discriminatory.

Thus, if the Commission does issue an order to Bonneville in this proceeding under any of its authorities, it must ensure that its order is consistent with Bonneville's organic statutes. Those laws entirely justify the Administrator's adoption of the Policies.

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[209] Section 211A(a) of Section 1132 of S. 1005 provided:

> SEC. 211A. (a) Subject to section 212(h), the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services--
> (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and
> (2) on terms and conditions (not relating to rates) that are comparable to those under which <u>such</u> unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.

The final version uses "the" instead of "such" in 211A(2).

[210] S. Rep. No. 108-43, at 164-165 (2003) (added space) (emphasis added).

B. Section 211A Does Not Authorize the Commission to Order Unregulated Transmitting Utilities to Adopt the *Pro Forma* Tariff

1. The Language of Section 211A Does Not Give the Commission Such Authority

Complainants suggest that section 211A gives the Commission the authority to regulate Bonneville – an "unregulated transmitting utility"[211] – as if it were a public utility. They urge the Commission to invoke this authority because Bonneville is "drift[ing] away from transmission service that comports with the Commission's terms and conditions for non-discriminatory open access service."[212] They argue that the Commission should not permit Bonneville to take an action "[i]f the Commission would not permit a public utility" to do so.[213] Specifically, they ask the Commission to order Bonneville to file an open access transmission tariff for Commission approval.

Even aside from the question of the Commission's authority, such a remedy would be far too broad for the action Complainants are challenging. The tariff includes myriad provisions unrelated to curtailment or to Environmental Redispatch. For example, significant portions of the tariff cover requests for new service and studies to be performed when transmission capacity is limited. A remedy requiring Commission approval of all of these provisions bears no relationship to the alleged wrong in this case. By painting Bonneville as a renegade, Complainants hope to provoke the Commission to

[211] 16 U.S.C. § 824j-1 (2009).
[212] Complaint at 30. Bonneville does not currently have safe-harbor reciprocity OATT status. In July 2009, the Commission determined that certain deviations in Bonneville's 890 tariff did not meet safe harbor reciprocity requirements. Bonneville has conducted, and continues to conduct, a series of public processes to seek customer and stakeholder input on the issues the Commission raised in the July 2009 order and other issues.
[213] *Id*. at 34.

overreach in its response and eviscerate the line between public utilities and unregulated utilities.

In enacting section 211A, however, Congress created a statutory framework for unregulated transmitting utilities that is far less expansive than the one that applies to public utilities. Section 211A authorizes the Commission to require an unregulated transmitting utility to provide transmission services

> (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and
>
> (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.[214]

This language applies no substantive standard comparable to the FPA's just and reasonable standard, which governs public utility rates and terms and conditions. It does not authorize the Commission to fix the terms and conditions of transmission service offered by unregulated transmitting utilities. Section 211A's minimalist language contrasts starkly with section 206 of the FPA, which provides the Commission plenary authority over public utilities:

> Whenever the Commission . . . shall find that any rate, charge, or classification demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.[215]

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[214] 16 U.S.C. § 824j-1.
[215] *Id*. § 824e(a).

Similarly, section 207 of the FPA, which also has no counterpart in section 211A, provides that if the Commission finds that any interstate service of any public utility is "inadequate or insufficient," it shall "determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation."[216] In contrast, the only remedial authority explicitly included in section 211A is the authority to order comparable and non-discriminatory service and to remand rates. When Congress includes particular language in one section of the statute but omits it from another section of the same act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.[217]

2. The Authority on Which the Commission Relied for Adopting the *Pro Forma* Tariff Is Not Included in Section 211A

In requiring public utilities to adopt the *pro forma* tariff, the Commission relied on sections 205 and 206 of the FPA. The Commission had previously adopted open access for the natural gas industry, and in Order No. 888 it relied heavily on *Associated Gas Distributors v. FERC*[218] which upheld the gas industry order. The *AGD* court said that "the primary authority invoked by the Commission" for its order was section 5 of the Natural Gas Act (NGA), which "directs the Commission to adopt corrective measures" when it finds that a rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential.[219] Section 5 of the NGA is the natural gas counterpart to section 206 of the FPA.

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[216] *Id*. § 824f.
[217] *KP Permanent Make-Up v. Lasting Impression I, Inc.*, 543 U.S. 111, 118 (2004).
[218] 824 F.2d 981 (D.C. Cir. 1987) ("AGD").
[219] *Id.* at 998.

The Commission also relied on *Gulf States Utilities Co. v. FPC*, 411 U.S. 747 (1973), quoting it to the effect that the Commission's power under the FPA "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to [FPA] sections 202 and 203, and under like directives contained in sections 205, 206, and 207."[220] Other than the undue discrimination standard of section 206, no part of these statutes has a counterpart in section 211A.

Turning to the electric industry, the Commission concluded that "based on the mandates of sections 205 and 206 of the FPA . . . we have ample legal authority . . . under section 206 of the FPA to order the filing of non-discriminatory open access transmission tariffs if we find such order necessary as a remedy for undue discrimination or anticompetitive effects."[221] As noted above, section 206, titled "Fixing Rates and Charges," authorizes the Commission to fix the terms of service to be offered by a public utility.

Replying to commenters who argued that the Commission lacked the authority to mandate the *pro forma* tariff, the Commission said that "[u]nder [sections 205 and 206] we must determine whether *any* rule, regulation, practice, or contract affecting rates for . . . transmission or sale for resale is unduly discriminatory or preferential, and we must disapprove those contracts and practices that do not meet this standard."[222] In Order No. 888-A, in response to arguments on rehearing, the Commission said that "the essential

[220] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs. ¶ 31,036, 31,669 (1996) (Order No. 888) (quoting *Gulf States*, 411 U.S. at 758-59).
[221] *Id.* at 31,669.
[222] *Id*. at 31,676 (emphasis in original).

question of the Commission's legal authority to impose the requirements of Order No. 888 turns on the flexibility of the Commission's remedial authority under sections 205 and 206 of the FPA to remedy undue discrimination."[223]

In upholding Order No. 888, the Court of Appeals also quoted both the anti-discrimination standard in section 205 and the extensive remedial authority of section 206, and stated the issue as "whether *these provisions* give FERC the authority to order involuntary wheeling as a generic remedy."[224] The absence of any explicit remedial authority in section 211A (with the exception of the Commission's authority to remand rates), which contrasts starkly with section 206, suggests that Congress did not intend for the Commission to have the same authority over governmental utilities that it has over public utilities.

3. The Legislative History of Section 211A Demonstrates That Congress Did Not Intend to Authorize the Commission to Order Unregulated Transmitting Utilities to Adopt the *Pro Forma* Tariff

A review of the legislative proposals that preceded the enactment of section 211A shows that Congress did not intend to authorize the Commission to order unregulated utilities to adopt the *pro forma* tariff. Congress rejected proposed bills offered by the Clinton administration,[225] Senator Frank Murkowski,[226] and Representative Joe Barton[227] during the 106th Congress, all of which would have given the Commission jurisdiction

[223] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC Stats. & Regs. ¶ 31,048, 30,203 (1997) ("Order No. 888-A").
[224] *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 685 (D.C. Cir. 2000) (emphasis added).
[225] *See* Comprehensive Electricity Competition Act, S. 1047, 106th Cong. § 301 (1999) (introduced by Sen. Frank Murkowski and Sen. Jeff Bingaman, by request); Comprehensive Electricity Competition Act, H.R. 1828, 106th Cong. § 301 (1999) (introduced by Rep. Tom Bliley and Rep. John Dingell, by request).
[226] Electric Power Market Competition and Reliability Act, S. 2098, 106th Congress (2000).
[227] Electric Competition and Reliability Act, H.R. 2944, 106th Congress (1999).

over unregulated transmitting utilities under sections 205 and 206 of the FPA. For example, the Clinton administration bill provided that "[t]he Commission has jurisdiction over the rates, terms, and conditions for transmission services provided by a transmitting utility that is not a public utility . . ." and that the Commission "may require . . . a transmitting utility that is not a public utility . . . to provide open access transmission services."[228]

Senator Murkowski's bill would have gone even further, redefining "public utility" to include transmitting utilities, specifically including, among others, "Federal power marketing administration[s] [and] a State or any political subdivision of a state."[229] Although even this bill would not have given the Commission authority over transmitting utilities equal to its authority over public utilities, the authority the bill would have conveyed included "determining, fixing, and otherwise regulating the rates, terms, and conditions for the transmission of electric energy in interstate commerce."[230] Representative Barton's bill would have given the Commission the same additional authority over transmitting utilities, except that it did not apply to Federal power marketing administrations (which includes Bonneville) or the Tennessee Valley Authority.[231]

All of these bills would have authorized the Commission to order transmitting utilities (either all or most such utilities, depending on the bill) to adopt the *pro forma* tariff. None were enacted.

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228 S. 1047, 106th Cong. § 301(c)(2)(A) (1999).
229 S. 2098, 106th Cong. § 101(e)(2) (2000).
230 *Id.*
231 H.R. 2944, 106th Cong. § 102(b) (1999).

In the 107th Congress, Senator Tom Daschle introduced a bill that would have required unregulated transmitting utilities to provide transmission service "on terms and conditions (not relating to rates) that are *comparable to those under Commission rules that require public utilities to offer open access transmission services* and that are not unduly discriminatory or preferential."[232] This bill was narrower than those introduced in the 106th Congress. It did not redefine "public utility" to include transmitting utilities and did not authorize the Commission to fix the rates of transmitting utilities. However, it did authorize the Commission to order unregulated utilities to adopt the same (or comparable) terms and conditions as required of public utilities. This narrower bill also was not enacted.

The 108th Congress removed the Commission's authority to order unregulated transmitting utilities to offer transmission service that is comparable to that required of public utilities. In its place, Congress added language that restricted the Commission's authority to ordering an unregulated transmitting utility to provide transmission service "on terms and conditions. . . . that are comparable to those under which such unregulated transmitting utility provides itself and that are not unduly discriminatory or preferential."[233] This bill also was not enacted. But nearly identical language passed the 109th Congress as part of the Energy Policy Act of 2005 and became section 211A.

This provision was the weakest language included in any of the bills introduced in Congress. It does not make transmitting utilities public utilities for any purpose; it does not authorize the Commission to "determine" or "fix" the terms and conditions of

[232] S. 1766, 107th Cong. § 206 (2001) (emphasis added).
[233] Energy Policy Act of 2003, H.R. 1644, 108th Cong. § 7021 (2003).

transmission service provided by transmitting utilities; it does not authorize the Commission to require transmitting utilities to adopt terms and conditions comparable to those required of public utilities. Congress rejected all of these versions of the bill in favor of a version authorizing the Commission only to require transmitting utilities to treat others as they treat themselves, and to provide service that is not unduly discriminatory or preferential. The legislative history demonstrates that Congress considered but rejected various proposals to grant the Commission broad authority to regulate the transmission services of non-jurisdictional entities on a par with the regulation of public utilities. Section 211A does not authorize the Commission to require unregulated utilities to adopt the *pro forma* tariff.

4. The Legislative History Cited by Complainants Does Not Challenge This Conclusion

The meager legislative history Complainants cite does not challenge the above conclusion. Complainants cite part of a sentence from the Senate report on the bill, which states that section 211 authorized the Commission "'to require unregulated transmitting utilities to provide open access to their transmission systems.'"[234] The rest of the sentence, which Complainants omitted, reads that the Commission may require transmitting utilities to provide open access to their transmission systems "at rates that are comparable to those that the unregulated transmitting utility charges itself and on terms and conditions that are comparable to those the utility charges itself [and] that are not unduly discriminatory or preferential."[235]

[234] Complaint at 19 n.43 (quoting S. Rep. No. 109-78, at 49 (2005)).
[235] *Id.*

This language merely repeats section 211A. Complainants would have the mention of the phrase “open access” in a committee report (the phrase does not appear in section 211A itself) perform the herculean task of restoring the authority that Congress removed from the legislation. In any case, Complainants simply assume that by “open access” the committee must have meant “the *pro forma* tariff.” Nothing in the sentence suggests as much. Instead, when the sentence is read in its entirety, it suggests that by “open access” the committee meant that all customers would have comparable access to transmission service. The multiple versions of the legislation Congress considered and rejected shows that Congress knew how to authorize the Commission to mandate the *pro forma* tariff had Congress wanted to.

Complainants next quote a statement of Senator Kyl to the effect that the energy bill expands jurisdiction over entities previously unregulated by the Commission and addresses the Commission’s efforts to provide open access over all transmission facilities in the United States.[236] Again Complainants vest this phrase with unwarranted significance; moreover, oral testimony of individual Congressmen “unless very precisely directed to the intended meaning of particular words in a statute, can seldom be expected to be as precise as the enacted language itself.”[237] And while Complainants have Senator Kyl saying that the bill “strikes the right balance,” again they omit what immediately follows: “It requires FERC to ensure that transmission owners . . . deliver power at terms that are not discriminatory or preferential. However, this provision is limited and does not give FERC the ability to begin regulating the rate-setting activities of these

[236] Complaint at 19 n.43.
[237] *Regan v. Wald*, 468 U.S. 222, 237 (1984).

organizations. FERC-lite does not confer further authority over public power systems."'[238]

Thus, Senator Kyl also simply repeated the statutory language and did not assert that the bill authorized FERC to fix the terms and conditions of transmission service. His only statement regarding the substantive authority the bill conveyed was one of limitation: FERC cannot set the rates of unregulated transmitting utilities.

Complainants next quote a written answer provided by Cynthia A. Marlette, the Commission's then-General Counsel, to questions on the bill posed by the House Subcommittee on Energy and Air Quality regarding the provision on unregulated utilities. However, the individual opinions of witnesses at hearings "'are of dubious value in interpretation of legislation.'"[239] Moreover, once more Complainants truncate the quotation. They reproduce Ms. Marlette's response that these provisions "'would provide helpful authority to ensure that non-public utilities provide non-discriminatory access to their transmission systems similar to the requirements currently imposed on public utilities,'"[240] but they omit the immediately following sentence, in which Ms. Marlette wrote that "[t]he provisions on rates, terms and conditions are adequate to ensure that customers receive service comparable to the service the utilities provide themselves" − not to the service public utilities provide.[241]

Complainants also omit the questions the committee posed, which asked generally for the Commission's position on the open access provisions of the bill and asked

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[238] 151 Cong. Rec. S7465 (daily ed. June 28, 2005) (statement of Sen. Kyl).
[239] *March v. U.S.*, 506 F.2d 1306, 1314 n.30 (DC Cir. 1974) (quoting *Potomac Passengers Ass'n v. Chesapeake & Ohio Ry. Co.*, 475 F.2d 325, 336 (DC Cir. 1973)).
[240] *The Energy Policy Act of 2005: Hearing Before the Subcomm. on Energy and Air Quality*, H.R. Ser. No. 109-1, 226 (2005).
[241] *Id*.

specifically "[h]ow, if at all, may this language be changed to ensure open access over interstate transmission facilities at comparable rates?"[242] − comparable rates, not rates that meet the test applicable to public utilities.

Even the minimal part of Ms. Marlette's answer that Complainants quote is not as definitive as Complainants would have it. Instead of claiming that the bill would authorize FERC to fix rates (or terms and conditions), she answered that it would be "helpful" to ensure non-discriminatory access − a reference to a result rather than to authority, and one that has largely obtained with respect to non-jurisdictional utilities since the Commission adopted the *pro forma* tariff, even without Commission authority to fix the terms and conditions of their tariffs.[243]

A final point regarding Ms. Marlette's answer: in response to the committee's question regarding how the language might be changed, Ms. Marlette said that "[t]he Commission could be given the authority to modify the rates where necessary, to prevent any delay in the establishment of rates in compliance with this section."[244] Congress rejected Ms. Marlette's suggestion and left the language unchanged. It declined to expand the Commission's authority.

Finally, Complainants quote a recommendation by the General Accounting Office (GAO) (now known as the Government Accountability Office) that Congress expand the Commission's jurisdiction to authorize it to require unregulated transmitting utilities to provide open access (apparently using the term in the broader sense of *pro forma* terms

[242] *Id*.
[243] *Id*.
[244] *Id*.

and conditions), implying that Congress adopted the recommendation.[245] But as the GAO also noted, "there have been several legislative proposals in the 107th Congress to address FERC's limited jurisdiction, though none has been enacted."[246] Exactly. The proposals introduced in the 107th Congress − when the GAO report was issued − would have authorized the Commission to order unregulated utilities to adopt the *pro forma* tariff. They were not enacted. A much weaker proposal was enacted during the 109th Congress. The GAO recommendation was rejected.

XIII. THE COMMISSION SHOULD NOT ISSUE A SECTION 211A ORDER

A. Environmental Redispatch Does Not Affect Transmission Service

Section 211A authorizes the Commission to require an unregulated transmitting utility to:

> provide transmission services . . . on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides itself and that are not unduly discriminatory or preferential.[247]

The Commission's authority under section 211A does not apply to Environmental Redispatch. Complainants incorrectly characterize Environmental Redispatch as a transmission action where Bonneville takes a Transmission Customer's transmission rights for its own use.[248] But Bonneville does not curtail a Transmission Customer's transmission schedules under Environmental Redispatch. Bonneville's actions are

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[245] Complaint at 19 n.43.
[246] U.S. Gen. Accounting Office, GAO-03-271, *Lessons Learned from Electricity Restructuring: Transition to Competitive Markets Underway, but Full Benefits Will Take Time and Effort to Achieve* 48 (2002).
[247] 16 U.S.C. §824j (emphasis added).
[248] Complaint at 38. The LGIA is clear that interconnection service is separate and distinct from transmission service. Article 4.4 of the LGIA provides:

> **No Transmission Delivery Service.** The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

similar to a Transmission Provider's assuring delivery of a schedule by providing its own power when a customer's generator is not performing as expected.

B. Environmental Redispatch Does Not Violate Comparability and Is Not Unduly Discriminatory

Complainants argue that Environmental Redispatch is not comparable to the service Bonneville provides itself and is unduly discriminatory. Although Complainants regularly conflate these two issues, it is important to recognize the distinctions. The Commission's test for comparability is "whether the transmission owner treats affiliated and non-affiliated generators on a comparable basis."[249] Thus, comparability involves an examination of how a utility treats others compared to how it treats itself. On the other hand, a policy is unduly discriminatory if there is "a difference in rates or services among similarly situated customers that is not justified by some legitimate factor."[250] Thus, undue discrimination involves differences in treatment between customers.

Complainants' scattered arguments reduce to two points: First, Bonneville is not providing comparable service (or is discriminating) because it is allegedly using Complainants' transmission for itself. Second, Bonneville is discriminating because, although the Policies apply to all customers, they have a greater impact on wind generators. Bonneville's actions satisfy the standard for comparability and are not unduly discriminatory or preferential

1. Bonneville Is Providing Comparable Service

As explained above, section XIII.A, Bonneville is not taking Complainants' transmission for its own use. The hydro power that Bonneville substitutes for wind

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[249] *Bonneville Power Admin. v. Puget Sound Energy*, 125 FERC ¶ 61,273, P 13 (2008).
[250] *El Paso Natural Gas Co.*, 104 FERC ¶ 61,045, P 115 (2003).

generation when Bonneville invokes Environmental Redispatch serves Complainants' loads (and other non-Federal loads). It does not serve Federal loads. Bonneville's affiliate (its power business) does not make any additional sales because of Environmental Redispatch. The Policies are intended to assure that Bonneville fulfills its environmental and reliability responsibilities.

Replacement of non-Federal generation with Federal hydro power under Environmental Redispatch is not the result of favoritism. Before implementing Environmental Redispatch this year, Bonneville reduced generation of the Columbia Generating Station nuclear plant to the lowest level possible without risking the plant's ability to return to full power − the same actions Bonneville takes with respect to non-Federal thermal plants.[251] In addition, Bonneville is itself a significant purchaser of wind power and is affected to the same extent as other purchasers of wind generation.

The fact that Complainants may lose some of their PTCs and RECs does not make Bonneville's policy non-comparable. The Commission has held that the economic effects of a term and condition of transmission service are not relevant to comparability, as long as the term and condition is applied equally to affiliated and non-affiliated generators. As explained below, the Commission applied this policy in a Bonneville case concerning reactive power.

The Commission's policy with respect to reactive power is that a transmission provider must compensate non-affiliates for reactive power inside the deadband if it compensates its own or affiliated generators. In *BPA v. Puget Sound Energy*,[252]

[251] ROD at 10.
[252] 125 FERC ¶ 61,273 (2008).

Bonneville ceased compensating all generators, affiliated and non-affiliated, for reactive power inside the deadband. Several non-affiliated generators argued that Bonneville had to continue compensating them, even though it had ceased compensating its affiliate, because Bonneville's affiliate would be able to recover the same revenue through power sales rates while the unaffiliated generators would likely be unable to do so. The Commission denied their claim, holding that this difference did not create a comparability issue because "there was no difference in treatment between affiliated and non-affiliated generators. . . . [T]he relevant inquiry for purposes of the Commission's comparability policy is whether the transmission owner treats affiliated and non-affiliated generators on a comparable basis."[253] Differences in impact because of the groups' different economic circumstances did not matter.

2. Environmental Redispatch Is Not Unduly Discriminatory

The Commission has found undue discrimination when there is "a difference in rates or services among similarly situated customers that is not justified by some legitimate factor."[254] Because Environmental Redispatch applies equally to all of Bonneville's customers, there is no undue discrimination against Complainants. If anything, because Bonneville displaces wind generators only after it displaces all thermal generators, the Environmental Redispatch Policy treats wind more favorably than thermal generation.

Complainants argue, however, that the Policies discriminate against them because thermal generators have an economic incentive to take free Federal power but wind

[253] *Id.* at P 13.
[254] *El Paso Natural Gas Co.*, 104 FERC ¶ 61,045, P 115 (2003).

generators do not.[255] Thus, they concede that Bonneville provides the same service to all customers, but argue that Bonneville is unduly discriminating because of the differences in impact. In a case with significant similarities to the current situation the Commission rejected differences in impact as being discriminatory. In *"Complex" Consolidated Edison Co. of New York, Inc. v. FERC* ("*Complex Con. Ed.*"), [256] the Tennessee Gas Pipeline Company required all customers to take uniform hourly quantities of gas "as nearly as practicable." Because of the gas transportation system's operational design, Tennessee had to place flow control meters on some customers' systems but not on others' systems. The customers without flow control devices could take more gas in a given hour than those with the devices. Tennessee applied the same rate to all customers.

Con Ed (which had a flow control device on its system) argued that, if it had the same hourly flexibility as other customers, it could have contracted for 31% less gas at an annual savings of $4 million. Con Ed argued that it should receive the same hourly flexibility as other customers and, if that was not feasible, a lower rate.[257]

The Commission concluded that Tennessee's policy and rate were not unduly discriminatory, and the court affirmed. The Commission found that the difference in hourly flexibility "was the result of operational constraints rather than preferential treatment" and that Tennessee "permitted all customers subject to the tariff to vary their hourly takes if operationally feasible, and . . . applied the same operational standard to all of its customers."[258] The Commission added that if "consistent application of the operational standard resulted in differing degrees of hourly flexibility for [different]

[255] Complaint at 42 & 37 n.103.
[256] *"Complex" Consol. Edison of N.Y. v. FERC*, 165 F.3d 992 (D.C. Cir. 1999).
[257] *Id.* at 1010.
[258] *Id.* at 1011.

customers . . . it was due to the physical design of the system."[259] Finally, the Commission noted that if Con Ed could take gas off the system in excess of the uniform hourly requirement, "Con Ed could potentially deplete the availability of service in the area, adversely affecting other Tennessee customers."[260]

Thus, the Commission found that a policy that was applied uniformly was not unduly discriminatory because it had different impacts on different customers' systems. Moreover, the Commission recognized the paramount responsibility of a utility to meet its operational responsibilities and assure reliable service to its customers. Like Tennessee's policy, Bonneville's policy is based on the physical nature of its system and on operational constraints rather than preferential treatment. As Bonneville has done here, the Commission, and the court, took into account operational realities in assessing the alleged discriminatory effect of a policy.

Complainants' argument here goes even further than Con Ed's. In *"Complex Con Ed,"* the utility itself placed the flow meters on some customers' systems but not on others'. Here, Complainants argue that Bonneville is responsible for state and Federal incentives that Bonneville had nothing to do with.

If anything, the effects of Bonneville's policy are more charitable to wind generators than the curtailment regime in the open access tariff. The Commission requires pro rata curtailments under the OATT, regardless of the generation type and the differing economic impacts of the curtailments. Thus, under the OATT wind generators are subject to the same transmission curtailments as all other transmission customers even

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[259] *Id*.
[260] *Id*. at 1013.

though the economic impact will be greater on them. Indeed, customers will all differ in their economic situation. Complainants argue that Bonneville is discriminating not because it is treating customers differently but because it is treating all alike. It would be impossible for a transmission provider to operate if it had to account for all of the differences in customers' systems and try to assure not that its policies were uniformly applied but that they had uniform effects.

Complainants do make one other claim of undue discrimination, alleging that the Policies favor Bonneville's preference customers.[261] This argument begs the question: it assumes that the cost of the lost PTCs and RECs is appropriately borne by these customers. Bonneville addressed this issue in Section VIII.A.

C. Issuance of a 211A Order Would Interfere with Bonneville's Implementation of Applicable Federal Law

The legislative history of section 211A clearly indicates that Congress intended for the Commission to avoid conflicts with Bonneville's statutory obligations:

> The limited authority provided FERC to ensure access at comparable rates and terms that are not unduly discriminatory neither alters nor affects the specific prescriptions applicable to the Bonneville Power Administration, nor precludes the Bonneville Power Administration from establishing prices, terms, and conditions in accordance with its enabling statutes. *Those statutes, and their implementation by the Bonneville Power Administration, are unaffected.*[262]

The Commission has a responsibility not to hinder Bonneville's implementation of its organic statutes and applicable environmental laws such as the Clean Water Act and the Endangered Species Act. The Bonneville Administrator has determined that the Policies

[261] Complaint at 45.
[262] S. Rep. No. 108-43, 164-65 (2003). This quote is taken from the 108th Congress. While the 109th Congress passed the Energy Policy Act of 2005 (including section 211A), the text of what became section 211A did not change in any material respect from the 108th Congress to the 109th Congress.

are necessary to balance the multiple statutory responsibilities imposed on him, and the Commission should provide substantial deference to the Administrator's determination.

D. Issuance of a Section 211A Order Is Not in the Public Interest

Complainants have not shown that it is in the "public interest" for the Commission to grant their first requested remedy, an order requiring Bonneville to revise its Environmental Redispatch practices.

If the Commission provides the Complainants' requested relief, it could cause excess spill of water from Federal reservoirs. Bonneville is not in full control of its other options to avoid spill limitations in high water – low load situations. Try as it might, it cannot guarantee that sufficient additional load or storage capability will be available. Bonneville cannot guarantee that negotiations over negative pricing would persuade sufficient numbers of generators or buyers to take additional amounts of Federal hydroelectric power. Bonneville invokes Environmental Redispatch only when other reasonable options have been exhausted. The only tool over which Bonneville has full control is its Environmental Redispatch tool. Elimination of Environmental Redispatch would open the door to possible violations of the TDG restrictions in the Federal court order.

Finally, the Commission should not grant Complainants' requested relief if it would unreasonably impair the continued reliability of electric systems affected by the order.[263] Environmental Redispatch is necessary to balance the loads and resources on Bonneville's transmission system during high water/low load situations when other

[263] *See* 16 U.S.C. §824j-1(e).

available alternatives do not alleviate the imbalance.[264] Without Environmental Redispatch, Bonneville may have to either (1) abdicate its environmental or statutory responsibilities, or (2) potentially allow over-generation to upset its load/resource balance, which would seriously compromise reliability. The Commission should not force Bonneville to choose between its responsibilities under environmental law and its own statutes, and reliability.

XIV. THE COMMISSION MAY NOT ISSUE A SECTION 210 ORDER

Complainants request that the Commission direct Bonneville to abandon its interim Environmental Redispatch Policy in order to provide Complainants with "effective and nondiscriminatory interconnection service" under FPA sections 210 and 212.[265] As explained below, Complainants' interpretation of these statutes conflicts with both the plain language and Commission decisions in previous cases. The Commission lacks the authority under sections 210 and 212 to grant the relief Complainants request, and its previous orders reflect the limits of the Commission's authority. Even if the Commission agrees with Complainants' interpretation, however, it should deny Complainants' requests for relief.

FPA section 210(a)(1) states that, upon application by an "electric utility,"[266] the Commission may issue an order requiring:

> (A) the physical connection of . . . the transmission facilities of any electric utility, with the facilities of such applicant,

[264] ROD at 14.
[265] Complaint at 32, 57.
[266] Although FPA section 210 provides for applications by persons other than an "electric utility," the Complaint does not allege that any Complainant meets the definition of any entity other than an "electric utility" under the statute. Complaint at 57.

> (B) such action as may be necessary to make effective any physical connection described in subparagraph (A), which physical connection is ineffective for any reason, such as inadequate size, poor maintenance, or physical unreliability,[267]

Despite the emphasis on "physical connection" of facilities under these subsections, Complainants urge the Commission to rely on its section 210 authority to assert jurisdiction over the terms and conditions of existing Bonneville interconnection agreements. Complainants' interpretation is at odds with the plain language of section 210 and the Commission's interpretation of the section.

A. The Plain Language of Subsections 210(a)(1)(A) and (B) Restricts the Commission's Authority to Ordering Physical Interconnections

The plain meaning of subsections 210(a)(1)(A) and (B) unambiguously conveys Congress's intent to authorize FERC to order the actual physical interconnection of facilities, and the Commission need not look any further than the statute under these circumstances.[268] "Physical" means something "material," "connect" means to "join, fasten, or link together," and "facilities" means something "built . . . to perform some particular function."[269] In other words, the plain language authorizes the Commission to order linking of items built to perform the function of creating an interconnection and to take other actions necessary to make that link effective. This language does not authorize the Commission to exercise ongoing jurisdiction over terms of service of utilities'

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[267] 16 U.S.C. § 824i(a)(1). Complainants request relief under FPA section 210(a)(1) and do not allege that any other provisions of the section apply. FPA section 210(b) requires the Commission to issue notice of the application, provide an opportunity for a hearing, and make the determinations in subsection (c), which requires specific findings in order to grant a request under section 210(a). 16 U.S.C. § 824i(b).
[268] 16 U.S.C. § 824i(a)(1).
[269] *Webster's Third New Int'l Dictionary* (unabridged) 1706, 480-81, 813 (1976). "Connection" means the "state of being connected or linked." *Id.* at 481.

interconnection agreements. If Congress's intent is clear on the face of the statute, the Commission must give it effect.[270]

Complainants ground their argument in section 210(a)(1)(B), which authorizes the Commission to issue orders to "make effective [a] physical interconnection."[271] The examples in the statute of such orders all relate to physical interconnections: they refer to a "physical connection" that is inadequate because of inadequate size, poor maintenance, or physical unreliability. This section does not contemplate broader relief regarding terms and conditions of an interconnection.

B. The Commission Has Limited Its Application of Subsections 210(a)(1)(A) and (B) to Ordering and Making Effective Physical Interconnections

Complainants' arguments also ignore a substantial body of Commission decisions limiting the application of subsections 210(a)(1)(A) and (B) to physical interconnections. The Commission has explicitly concluded that "Section 210 of the FPA refers to the Commission ordering a physical interconnection,"[272] and it has denied multiple section 210 applications that it found were effectively challenging agreements or terms and conditions of service rather than seeking physical interconnection.[273] In a 2004 order denying a section 210 application that challenged the terms of an existing agreement

[270] *Chevron v. Natural Res. Def. Council*, 467 U.S. 837, 842-43 (1984) ("If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress.") The legislative history of section 210 confirms the intent that Congress conveyed unambiguously in section 210. The legislative record includes discussions of ordering the "physical interconnection of transmission facilities" and reflects the emphasis on promoting efficient use of resources through authorizing the Commission to order interconnection of "facilities" that might not otherwise be interconnected. 123 Cong. Rec. 31,194 (1977); 123 Cong. Rec. 32,397-32,398 (1977); 124 Cong. Rec. 34,770 (1978). Bonneville found no legislative history indicating that Congress intended to establish broad authority for the Commission to oversee or regulate terms and conditions of existing interconnections. In fact, the record indicates that Congress developed a "narrow provision on interconnection" that the Commission could apply only upon request and that would not extend Commission regulation over other actions of non-jurisdictional entities. 123 Cong. Rec. 32,397 (1977).

[271] Complaint at 57.

[272] *N. Hartland, LLC*, 105 FERC ¶ 61,192, P 21 (2003).

[273] *Id.; Mirant Las Vegas, LLC*, 109 FERC ¶ 61,045, P 21 (2004).

related to the interconnection facilities, the Commission explicitly noted that its "section 210 orders have *all* involved the physical interconnection of facilities."[274] Bonneville has found no Commission order that applies section 210 in a different manner or suggests that applying the statute as Complainants request would be appropriate or consistent with Congress's intent.

Complainants effectively request that the Commission modify Complainants' existing interconnection agreements. Section 210, however, does not provide the Commission authority to order modification of Bonneville's existing interconnection agreements.

C. Complainants Have Not Satisfied the Other Elements of Section 210

Even if the Commission concludes that section 210 provides it with authority over the terms of existing interconnection agreements to address issues not related to physical interconnections, it should deny the Complaint. While Complainants address whether a section 210 order is in the public interest, they wholly fail to address the other requirements of section 210(c).

Section 210(c) provides as follows:

> No order may be issued by the Commission under subsection (a) of this section unless the Commission determines that such order—
> **(1)** is in the public interest,
> **(2)** would—
> **(A)** encourage overall conservation of energy or capital,

[274] *Mirant Las Vegas, LLC*, 109 FERC ¶ 61,045, at 61,207 n.12 (2004) (emphasis added) (citing *City of Corona, Cal. v. So. Cal. Edison Co.*, 101 FERC ¶ 61,240 (2002) (order directing physical interconnection); *Kiowa Power Partners, et al.*, 99 FERC ¶ 61,251, P 1 (2002) (same); *Sierra Pac. Power Co.*, 89 FERC ¶ 61,234 at 61,691-93 (1999) (same); *Ill. Mun. Electric Agency v. Ill. Power Co.*, 86 FERC ¶ 61,045, 61,174, 61,177 (1999) (same); *Laguna Irrigation Dist.*, 84 FERC ¶ 61,226, 62,086-89 (1998), reh'g dismissed, 85 FERC ¶ 61,220 (1999) final order sub nom, *Pac. Gas and Electric Co.*, 88 FERC ¶ 61,164 (same), order on reh'g, 91 FERC ¶ 61,340 (2000), order denying rehearing and granting and denying clarification, 95 FERC ¶ 61,305 (2001) (*Laguna*) (same). *See also Pac. Gas and Electric Co. and Fresno Irrigation Dist.*, 88 FERC ¶ 61,231, 61,761-63 (1999) (same)).

(B) optimize the efficiency of use of facilities and resources, or
(C) improve the reliability of any electric utility system or Federal power marketing agency to which the order applies, and
(3) meets the requirements of section 824k of this title.[275]

The requirements of paragraphs 1, 2, and 3 all must be satisfied if the Commission is to issue an order under subsection (a). For the reasons next indicated, none of the standards would be met in this case.

1. Granting the Requested Relief Would Be Contrary to the Public Interest

Complainants maintain that granting the requested relief satisfies the "public interest" standard in section 210, because the Commission has found that "availability of transmission and interconnection service, 'as a general matter, enhances competition in power markets by increasing power supply options of buyers and power sales options of sellers and leads to lower costs to consumers.'"[276] But the issue in this proceeding is not the availability of interconnection service; Complainants already have such service. Therefore, upholding the Complaint will not increase the availability of interconnection service. The Commission's findings in the cases cited by Complainants are not relevant to this proceeding. These cases found a public interest in the additional options and lower costs when more generators interconnect. But granting the Complainants' requested relief will not create additional interconnections. Complainants are already interconnected.

Moreover, the Complainants' argument that Environmental Redispatch increases wholesale power prices fails to recognize that the focus of the Commission's findings is

[275] 16 U.S.C. §824j-1.
[276] Complaint at 58 (*quoting Ill. Mun. Electric Agency v. Ill. Power Co.*, 86 FERC ¶ 61,045 (1999)).

reducing costs for end-use consumers, not for generators.[277] Complainants have not demonstrated or even argued that Bonneville's Environmental Redispatch and Negative Pricing Policies will increase costs to consumers. The Environmental Redispatch protocols are temporary measures applied for limited time periods primarily during light load hours, and Bonneville provides replacement hydro power at no cost.

Complainants also fail to mention that the Commission has articulated a more specific standard to assess the public interest for section 210 requests: "as long as the interconnecting utility is fully and fairly compensated for the costs it incurs in connection with the requested interconnection, and there is no unreasonable impairment of reliability, requiring the interconnecting utility to establish a physical interconnection is in the public interest."[278] In the context of the interim Environmental Redispatch Policy, Bonneville would not be fully and fairly compensated if the Commission granted Complainants' requested relief and Bonneville were required to pay negative prices to meet its environmental responsibilities.

Furthermore, one of the primary purposes of implementing Environmental Redispatch is to preserve reliability, and an order directing Bonneville to abandon the assurance it provides threatens reliability or compliance with environmental requirements. Granting complainants' requested relief is contrary to the Commission's own public interest standards under these circumstances.

Finally, Bonneville's Environmental Redispatch Policies were adopted only on an interim basis and carefully calculated to allow Bonneville to comply with its

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[277] *Ill. Mun. Electric Agency*, 86 FERC at 61,176.
[278] *East Kentucky Power Coop., Inc.*, 86 FERC ¶ 61,045, at 61,176 (1999).

environmental and other statutory authorities.[279] Until such time as better alternatives are developed, the Policies ensure that Bonneville can continue to interconnect renewable resources.[280] The public interest in compliance with these standards and law outweighs the inaccurate claim that the interim Environmental Redispatch policy is anti-competitive and the unsupported allegations that the policy increases wholesale power prices to the detriment of end use consumers.

2. Granting the Requested Relief Would Discourage Conservation of Energy and Capital and Efficient Use of Facilities and Resources

Complainants cite an order finding that physical interconnection of a wind generator would encourage conservation and enhance efficiency.[281] The Commission's findings in the context of physical connection of generators are inapplicable to the novel relief that Complainants request in this proceeding. Granting Complainants' requests will not result in new interconnections, and it will not encourage efficient use of capital or existing resources. It will result in Bonneville paying potentially unlimited negative prices to meet its environmental responsibilities. Bonneville believes this is an inefficient outcome that Congress prohibited under section 210.

As to (B), the order sought would de-optimize the efficiency of use of facilities and resources, since it would incent thermal generation to hold out for the payment of negative prices in the face of Bonneville's critical need to meet its environmental responsibilities,. Further, as to (C), Bonneville has established that its policy is necessary to meet reliability standards. Complainants' request for relief is in no way calculated to improve reliability.

[279] ROD at 29.
[280] *See supra* section I.
[281] Complaint at 59.

3. Granting the Requested Relief Would Be Inconsistent with the Requirements of Section 212

Section 210(c)(3) requires that the order meet "the requirements of section 824k of this title."[282] Section 824k(i)(1)(B)(i) requires that "the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the [Bonneville] system; . . ."[283] As demonstrated in depth earlier, Bonneville's Policies are fully grounded in, and warranted by, the otherwise applicable Federal laws. As noted above, the Commission should give substantial deference to the Administrator's decisions.

XV. ENVIRONMENTAL REDISPATCH IS AUTHORIZED BY THE LARGE GENERATOR INTERCONNECTION AGREEMENTS

As demonstrated above, the Commission has no authority to adjudicate disputes over the transmission contracts of non-jurisdictional transmission providers. Nevertheless, Bonneville here provides a description of its views on various provisions of the LGIA to help the Commission to more fully understand Bonneville's decision to implement Environmental Redispatch. The Bonneville Administrator is not acting in derogation of his contractual obligations. To the contrary, throughout the 87 page ROD he issued after taking comment on Bonneville's proposed policy, the Administrator analyzed his statutory responsibilities and contractual rights and obligations, and proceeded with a view to ensuring he honored both.

Multiple provisions of the LGIA give Bonneville the contractual authority to implement Environmental Redispatch. First, Article 9.7.2 gives Bonneville the right to interrupt or reduce an Interconnection Customer's deliveries of electricity in order to

[282] 16 U.S.C. § 824i(c)(3).
[283] 16 U.S.C. § 824k(i)(1)(B)(i).

maintain system reliability. Second, even if this is not a reliability issue, Article 4.3 gives Bonneville the right to interrupt or reduce deliveries of electricity in order to comply with its environmental and statutory responsibilities. Third, Article 16.1.2 excuses any breach of the LGIA caused by Environmental Redispatch because Bonneville's statutory and environmental responsibilities are beyond its control. All of these provisions of the LGIA give Bonneville the authority to implement Environmental Redispatch. To remove any doubt, Bonneville unilaterally amended Appendix C of the LGIA of all Interconnection Customers to clarify its authority. The Commission's orders clarify that Bonneville has the authority to unilaterally amend Appendix C of the LGIA to include operational requirements.

A. Article 9.7.2 of the LGIA Authorizes Bonneville to Interrupt or Reduce Deliveries of Electricity to Maintain System Reliability

Article 9.7.2 of the LGIA gives Bonneville the authority to interrupt or reduce deliveries of electricity from generating facilities in order to maintain system reliability. Article 9.7.2 provides:

> **9.7.2 Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System.

As explained in section VI, Bonneville must generate electricity at FCRPS projects in order to minimize spill in accordance with Bonneville's environmental responsibilities.[284] Bonneville, however, will not pay negative prices to dispose of the energy, as to do so would burden environmental compliance program costs, which are already substantial,

[284] *Supra* section VI.

and threaten Bonneville's statutory obligations to recover its costs, keep rates low consistent with sound business principles, and to repay its Treasury debt. As a result, Bonneville must displace non-Federal generation in its Balancing Authority Area to maintain balance between resources and loads. Because Environmental Redispatch is required to maintain system reliability under these circumstances, Article 9.7.2 specifically authorizes Bonneville to interrupt or reduce deliveries of electricity from Complainants' generating facilities.

Article 9.7.2 lists other requirements that Bonneville must comply with in order to interrupt or reduce deliveries of electricity. Bonneville has complied with all of them.

First, Article 9.7.2.1 provides that "[t]he interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice." Bonneville limits generation under Environmental Redispatch only when necessary to avoid spill and alleviate excess generation in Bonneville's Balancing Authority Area.[285]

Second, Article 9.7.2.2 requires that the "interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System." Bonneville understands that Environmental Redispatch has economic consequences for Complainants that do not exist with thermal generators. Therefore, Bonneville first limits generation from thermal generators. However, most thermal generators will already be offline before Bonneville implements Environmental Redispatch because they have accepted Bonneville's offers of low or no cost federal hydro power. Bonneville then redispatches Complainants' facilities and other wind generators (and any remaining thermal generators that do not have to run for

[285] *Id*.

reliability reasons) on a pro rata basis. Redispatching wind resources as a last resort is equitable, and redispatching all wind generators pro rata is non-discriminatory.[286]

Third, Article 9.7.2.3 requires that the interruption or reduction be made with advance notice, or that Bonneville notify the Interconnection Customer by telephone as soon as practicable afterwards. Bonneville has given Complainants ample advance notice of Environmental Redispatch.[287]

B. Article 4.3 of the LGIA Authorizes Bonneville to Implement Environmental Redispatch

Under Article 4.3 of the LGIA, displacement of a customer's energy with FCRPS energy to assure Bonneville meets its environmental responsibilities is not a breach of the LGIA. Article 4.3 of the LGIA provides:

> **4.3 Performance Standards.** Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is *required or prevented or limited* in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith.

(Emphasis added.) "Applicable Laws and Regulations" is defined as "all duly promulgated applicable federal, state and local laws, regulations, rules . . . or judicial and administrative orders, permits and other duly authorized actions of any Governmental Authority."[288] Bonneville implements Environmental Redispatch to meet its environmental and reliability responsibilities under the ESA, the CWA, the NWPA, and the U.S. District Court order in the BiOp litigation.

[286] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 118 FERC ¶ 61,119, P 1138 (2007).
[287] Attachment E, Lynam Affidavit at P 3-6; Attachment F, Nulph Affidavit at P 3-11 and Exhibit (Environmental Redispatch Business Practices).
[288] LGIA, Article I.

Complainants argue that Article 4.3 does not authorize Environmental Redispatch because Bonneville is not required by a regulation or standard to implement it. Complainants cite several actions that Bonneville could take to avoid Environmental Redispatch, and also argue that economics, and not Bonneville's environmental, statutory, and reliability obligations, are behind Bonneville's decision to implement its policy.[289]

First, as explained in the ROD and affidavits, Bonneville has taken all actions available to avoid Environmental Redispatch. Second, as explained previously, the payment of negative prices would put at risk Bonneville's fulfillment of its statutory obligations to recover its costs, keep rates low consistent with sound business principles, and to ensure repayment of the Federal Treasury. Because the payment of negative prices is not a reasonable option, Bonneville is required to implement Environmental Redispatch in order to operate the FCRPS consistent with its environmental responsibilities and system reliability.

Complainants focus on the term "required," when Article 4.3 excuses breaches if a party is "prevented or limited" in taking an action. Although "prevented" may add little to "required," "limited" means something less, and is not as absolute as "required" or "prevented." The dictionary definition of "limited" is "to confine within limits."[290] In turn, "limit" is defined as "something that bounds, constrains, or confines."[291] During conditions of high stream flows and low loads, Bonneville is, at the least, "limited" in its

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[289] Complaint at 47.
[290] *Webster's Third New Int'l Dictionary* at 1312 (1976).
[291] *Id*.

ability to allow Complainants to generate, for if Bonneville allowed unlimited generation it would either compromise reliability or violate its environmental obligations.

C. Environmental Redispatch Constitutes a Force Majeure Under Article 16 of the LGIA

Complainants also argue that Environmental Redispatch does not constitute a Force Majeure under Article 16 of the LGIA. "Force Majeure" is defined under Article 1 of the LGIA as "any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control." This includes environmental law and requirements, as ordered by the U.S. District Court. Complainants argue that Environmental Redispatch is based on an "economic hardship" and, pursuant to section 16.1.1 of the LGIA, does not qualify as a Force Majeure event.[292] The Force Majeure event, however, is the existence of high water, low loads, continuing non-Federal generation, and the need to comply with the U.S. District Court's order. These phenomena are what require Bonneville to generate more hydro power and non-Federal generation to back down. Bonneville's policy not to pay negative prices to induce non-Federal generation to reduce generation is grounded in the limits of Bonneville's statutory authority, and its Environmental Redispatch policy is necessary to meet environmental responsibilities and preserve reliability. It is not simply an economic decision, as Complainants try to characterize it. Under these circumstances, the events necessitating Environmental Redispatch constitute a Force Majeure.

Here, a court order has been imposed. Further, Bonneville has fully complied with the provisions for declaring a Force Majeure set forth in Article 16.1.2. Bonneville

[292] Section 16.1.1 states that "economic hardship is not considered a Force Majeure event."

has given all Interconnection Customers, including Complainants, written notice that Bonneville is declaring a Force Majeure, with full particulars, and the timeframe when the Force Majeure is reasonably expected to end.

D. Bonneville Has the Unilateral Right Under Article 9.3 to Amend Appendix C of the LGIA to Include Operational Requirements

Article 9.3 of the LGIA states:

> Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

Complainants argue that Bonneville does not have the right to unilaterally amend Appendix C under any circumstances. Not only is Complainants' position based on a tortured reading of Commission precedent, but would be unworkable in practice.

Bonneville acted here on the basis of a prior Commission order. When Bonneville filed its LGIA for reciprocity approval, among the deviations for which it sought approval was a change to Article 9.4 of the LGIA to clarify that the Transmission Provider had the unilateral right to modify its reliability requirements and incorporate them in Appendix C to the LGIA.[293] The Commission rejected Bonneville's request as unnecessary, reasoning that Article 9.3 already gives the Transmission Provider "the responsibility for establishing the Interconnection Customer's operating instructions and operating protocols and procedures."

[293] *Bonneville Power Admin.*, 112 FERC ¶ 61,195, P 19 (2005).

> Because these instructions, protocols, and procedures will include reliability requirements, article 9.3 already gives the Transmission Provider responsibility for modifications to Appendix C. The same provisions give the Interconnection Customer the right to propose changes for the Transmission Provider to consider, but not the right to make unilateral changes. In light of this provision, we conclude that BPA's proposed change is *unnecessary*. . . .[294]

Bonneville's request to amend Article 9.4 to clarify that the transmission provider had the unilateral right to amend Appendix C could be "unnecessary" only if the transmission provider already had that right. Moreover, transmission providers could not function if they needed customer consent for revising operating instructions, protocols, and procedures or to implement changes in reliability standards. For example, what if even one or merely a few interconnection customers refused consent? The transmission provider would either be prevented from making necessary amendments to its operations or would have to establish different operating procedures for different customers − either one an unworkable situation.

Complainants also argue that Article 30.10 requires mutual agreement to amend the Appendices, including Appendix C. Article 30.10 states:

> The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

It is a general canon of contract interpretation that specific terms control over general terms.[295] While Article 30.10 does state that the Parties may amend the Appendices by mutual agreement, the Commission was clear in its order that Article 9.3 gives the Transmission Provider the authority to unilaterally amend Appendix C to include

[294] *Id*. at P 20.
[295] *See Hills Materials Co. v. Rice*, 982 F.2d 514, 517 (1992) ("Where specific and general terms in a contract are in conflict, those which relate to a particular matter control over the more general language.")

operating instructions, protocols, and procedures. In light of this authority, Article 9.3 controls over Article 30.10. Bonneville cannot amend Appendix C to the LGIA for any reason whatsoever, but is limited to establishing operational requirements. That is what it has done here.

Complainants also argue that the Commission has a well-established policy not to make retroactive changes to interconnection agreements that are already in effect.[296] This argument misleadingly suggests that the Commission frowns on parties changing existing agreements. The orders Complainants cite are rulemakings in which the Commission adopted new tariff provisions for wind generation but declined to *require* retroactive changes to existing agreements.[297] These orders have no application to the situation here where the contract gives BPA the right to make the changes.

XVI. THE COMMISSION MAY HAVE TO CONSULT UNDER THE ENDANGERED SPECIES ACT PRIOR TO ISSUING AN ORDER

The Endangered Species Act (ESA) requires Federal agencies to consult with NOAA Fisheries and the U.S. Fish and Wildlife Service to ensure that their actions are not likely to jeopardize listed species or destroy or adversely modify designated critical habitat. ESA § 7(a)(2). The ESA also requires any person, including federal agencies and private entities, to avoid illegal take of listed species.[298] Federal agencies can be exempt from section 9 illegal take by consulting with the consultation Services and complying

[296] Complaint at 54.
[297] *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, P 64 (2010); *Interconnection for Wind Energy, Order No. 661*, FERC Stats. & Regs. ¶ 31,186, P 116 (2005).
[298] ESA § 9, 16 U.S.C. § 1538(a)(1)(B) (2009).

with the terms and conditions of an incidental take statement issued in connection with the BiOp.[299]

To avoid jeopardy to thirteen threatened and endangered salmon and steelhead species listed under the ESA and the adverse modification of their critical habitat, Bonneville, the Corps of Engineers, and the U. S. Bureau of Reclamation completed consultations with NOAA Fisheries, which issued a comprehensive FCRPS Supplemental BiOp in 2010. These action agencies then committed to implement the Reasonable and Prudent Alternative (RPA) formulated by NOAA to avoid jeopardy and adverse modification, and to follow the requirements specified in the 2010 FCRPS Supplemental BiOp.

One RPA, Measure No. 29, places limits on the amount of spill to improve juvenile fish passage, while avoiding high TDG supersaturation levels or adult fallback problems. Fish passage spill levels are required to be managed to the maximum extent practical to avoid exceeding state TDG water quality standards and applicable criteria adjustments, including waivers.[300] Excess TDG harms fish, and exceeding the state water quality standards and applicable criteria adjustments, including waivers, for voluntary spill for fish passage is inconsistent with the RPA that incorporates those limits.[301]

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[299] *Id.* § 1536.

[300] *See* Attachment C, Connolly Affidavit at P 23-30; 2008 FCRPS BiOp, Reasonable and Prudent Alternative Table, at 32 (Measure No. 29). RPA 29 states, "The Corps and BPA will provide spill to improve juvenile fish passage while avoiding high TDG supersaturation levels or adult fallback problems. Specific spill levels will be provided for juvenile fish passage at each project, *not to exceed established TDG levels* (either 110 percent TDG standard, *or as modified by State water quality waivers*, currently up to 115 percent TDG in the dam forebay and up to 120 percent TDG in the project tailwater, or if spill to these levels would compromise the likelihood of meeting performance standards…." (Emphasis added.)

[301] 2008 FCRPS BiOp, Reinitiation of Consultation, p. 12-3. The 2008 FCRPS BiOp, incorporated into the 2010 FCRPS Supplemental BiOp, requires additional consultation on material departures from RPA

For spring and summer 2011, the spill levels for juvenile fish passage spill were included in the Fish Operation Plans that were adopted by court order. On March 24 and June 14, 2011 in Portland Oregon, Federal District Court Judge James Redden issued Court Orders in the on-going Biological Opinion litigation requiring that 2011 spring and summer fish operations be conducted consistent with the 2011 Spring and Summer Fish Operation Plans ("FOPs") and other operative documents including the 2010 FCRPS Supplemental Biological Opinion. The 2011 FOPs require that, to the extent practicable, from April through August, the Corps of Engineers manage spill levels for fish passage to avoid exceeding 120% TDG in project tailraces, and 115% in the forebay of the next project downstream, consistent with the current State of Washington TDG waiver limits.[302] The Corps of Engineers manages spill at the Lower Columbia and Snake River dams though a system-wide TDG management plan.[303]

Bonneville adopted its Environmental Redispatch policy, in part, to meet its environmental responsibilities and to ensure compliance with the Court Orders. If, as a result of a Commission order, Bonneville is unable to implement its Environmental

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measures, such as RPA 29, where such departure causes effects not previously considered by the agencies, *Consultation must be reinitiated* if the amount or extent of taking specified in the incidental take statement is exceeded or is expected to be exceeded; if new information reveals effects of the RPA that may affect listed species in a way not previously considered; *if the RPA is modified in a way that causes an effect on listed species that was not previously considered*; or if a new species is listed or critical habitat is designated that may be affected by the action (50 C.F.R. § 402.16).
2008 FCRPS BiOp, Reinitiation of Consultation, p. 12-3. (Emphasis added.)

[302] *See supra*, n.68. Due to the limited hydraulic capacity of most of the FCRPS dams, these standards do not apply above certain flow levels (the highest 7 day average over 10 years or the 7Q10 flow) because the ability to limit TDG through changes in hydro operations is limited. On the Snake River, the 7Q10 flow is 214 kcfs.

[303] These TDG levels are translated into "spill caps" the amount of spill necessary for TDG levels to reach the gas cap ceiling. A TDG Management Plan is developed annually by the Corps of Engineers (USACE) and is included as Appendix 4 in the annual Water Management Plan. This TDG Management Plan provides detailed information addressing TDG management measures, the process for setting spill caps, TDG management policies, and the TDG monitoring program and modeling. *See* Attachment C, Connolly Affidavit at P 24-29.

Redispatch Policy, it may be forced to pay negative prices to address high water/low Federal load events. But negotiations on negative prices may fail because the parties are unable to reach a middle ground. In that situation and in the absence of any other satisfactory alternative to Environmental Redispatch, Bonneville must be able to implement its Environmental Redispatch tool to facilitate compliance with its environmental obligations; otherwise, it risks being held hostage by market counterparties who know Bonneville is short of alternatives to paying exorbitant negative prices.

At a minimum, the potential impact of a Commission order invalidating the Environmental Redispatch and Negative Pricing policy raises the question of whether the Commission must consult under the ESA prior to issuing such an order because it may have an effect on listed species. Because Endangered Species Act regulations on interagency cooperation require federal agencies to consult on actions that "may affect" listed species, the Commission's action of invalidating the Environmental Redispatch Policy may require consultation with NOAA prior to issuing its order.[304]

The Commission's order may also require consultation to avoid illegal take of listed species.[305] Federal agencies avoid illegal take by consulting with NOAA Fisheries and complying with the terms and conditions of an incidental take statement issued in connection with the BiOp.[306] The Commission's consultation and compliance with a BiOp on its order would meet this requirement.

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[304] 50 C.F.R. § 402.14(a); *see also Bennett v. Spear,* 520 U.S. 154, 158 (1997) ("If an agency determines that action it proposes to take may adversely affect a listed species, it must engage in formal consultation. . . .").
[305] ESA § 9(a)(1)(B).
[306] ESA § 7(o).

XVII. CONCLUSION

Faced with a difficult situation and the need to balance a myriad of statutory responsibilities, Bonneville explored a variety of options and ultimately adopted its Environmental Redispatch policy. This policy has effectively maintained the reliability of the transmission system and reduced the harm to endangered species. The Commission should not take action that could remove this critical tool from the agency as it continues its efforts to integrate wind generation into its system while meeting its statutory obligations consistent with its contractual rights and responsibilities. The Complaint should be dismissed.

DATED this 19th day of July, 2011.

Respectfully submitted,

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ATTACHMENT A

BPA's Interim Environmental Redispatch and Negative Pricing Policies
Final Record of Decision (ROD), May 2011

BPA's Interim Environmental Redispatch and Negative Pricing Policies

Administrator's Final Record of Decision

May 2011

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ADMINISTRATOR'S FINAL RECORD OF DECISION ON BPA'S INTERIM ENVIRONMENTAL REDISPATCH AND NEGATIVE PRICING POLICIES

I. INTRODUCTION

This Final Record of Decision ("ROD") documents the Bonneville Power Administration ("BPA") Administrator's decision to adopt, after consideration of public comments, the Environmental Redispatch and Negative Pricing Policies described in this document, on an interim basis, to ensure BPA can meet its legal responsibilities while BPA explores alternative solutions with stakeholders. The policies set forth in this Final ROD will take effect upon the Administrator's execution of this ROD and remain in place until March 30, 2012.

Environmental Redispatch is designed to ensure BPA is taking all reasonable efforts to meet its legal responsibilities under the Clean Water Act ("CWA"), Endangered Species Act ("ESA"), and court order (collectively, "environmental responsibilities), as well as BPA's legal obligations under its authorizing legislation, such as the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act"), the Federal Columbia River Transmission System Act ("Transmission System Act"), the Pacific Northwest Power Preference Act ("Preference Act"), and the Bonneville Project Act (collectively, "statutory responsibilities"), under specific hydro and load conditions, and after all reasonably practicable mitigating measures have been implemented. In addition, Environmental Redispatch will help provide options for BPA to maintain system reliability by balancing loads and resources within BPA's Balancing Authority Area while meeting BPA's environmental and statutory responsibilities.
When system conditions trigger Environmental Redispatch, BPA will replace scheduled generation in BPA's Balancing Authority Area with Federal hydropower at no cost. However, BPA will not pay negative energy prices under these conditions.

II. BACKGROUND

BPA issued a Draft ROD on February 18, 2011, detailing its proposed Environmental Redispatch and Negative Pricing policies, and requested public comment on the Draft ROD. BPA received 41 comments on the Draft ROD both in support of and against BPA's proposals. After consideration of public comments, BPA is adopting the policies set forth in this Final ROD on an interim basis.

The following sections describe factors that affect BPA's ability to manage high flows for system reliability and to meet its environmental and statutory responsibilities. These sections will detail the evolution of the Federal Columbia River Power System ("FCRPS"), the operation of the FCRPS, and how BPA responded to the overgeneration events of June 2010.

A. Evolution of the Federal Columbia River Power System and Federal Columbia River Transmission System

BPA was established pursuant to the Bonneville Project Act of 1937[1] to dispose of electric energy generated in the operation of the Bonneville Project located in the States of Washington and Oregon. The project was constructed and is operated by the U.S. Army Corps of Engineers ("Corps"). The BPA Administrator's authority to market power was expanded over the years as other Federal dams were built throughout the Pacific Northwest by the Corps and Bureau of Reclamation ("Bureau").[2] These facilities, and the transmission lines built by BPA to move the power generated, generally became known as the Federal Columbia River Power System (FCRPS).[3]

With the passage of the 1974 Transmission System Act,[4] the Administrator was, with minor exceptions, "designated as the marketing agent for all electric power generated by Federal generating plants in the Pacific Northwest" constructed by the Corps and the Bureau.[5] Many of the generating plants comprising the FCRPS are part of multiple purpose projects that are operated for many public purposes, including flood control, fish and wildlife protection, irrigation, power production, navigation, recreation, municipal water supply, and other purposes.[6] The Transmission System Act placed BPA on a "self-financing" basis, which removed BPA from the Congressional appropriations process for

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[1] 16 U.S.C. § 832 (2009).
[2] See, e.g., The Flood Control Act of 1944, 16 U.S.C. § 825s; Executive Order 8526, 5 Fed. Reg. 3390 (1940); see also Aluminum Co. of Am. v. Central Lincoln Peoples' Util. Dist., 467 U.S. 380, 386 n.5 (l984); U.S. Dep't of Energy, Bonneville Power Admin., 29 FERC ¶ 63,039, at 65,122 (Nov. 27, 1984).
[3] See, e.g., H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 2, at 26; 16 U.S.C. § 839a(10)(A).
[4] 16 U.S.C. § 838-838k (2009).
[5] Id. § 838f.
[6] See, e.g., Bonneville Project Act, 16 U.S.C. § 832 (2009); 43 U.S.C. § 485h(a)-(b) (2009); Federal Water Project Recreation Act, 16 U.S.C. §§ 460l-12, 460l-13, 460l-18 (2009); Flood Control Act of 1962, Pub. L. No. 87-874, § 203, 76 Stat. 1180 (1962); Flood Control Act of 1950, Pub. L. No. 81-516, § 204, 64 Stat. 170 (1950); Rivers and Harbors, Improvements Act, Pub. L. No. 79-14, 59 Stat. 10 (1945); Columbia Basin Project Act, 16 U.S.C. § 835l; H.R. Rep. No. 80-1507, at 2 (1948).

financing. As such, BPA funds its operations through revenues and borrowing authority granted to it under the Transmission System Act and subsequent acts. Today, BPA markets power generated at 30 Federal hydroelectric projects in the Pacific Northwest, and several non-Federal projects.[7]

The Federal Columbia River Transmission System (FCRTS) was developed simultaneously with hydroelectric development. BPA transmission lines were originally built to interconnect Federal generating resources and move the generation to the load areas. Over time, BPA transmission lines were also used to transmit power generated by non-Federal resources. The capability of the transmission system is tied to generation levels, especially at the critical hydroelectric projects along the Lower Columbia and Lower Snake Rivers.

Integrated operation of the Federal power and transmission facilities is reflected in the various statutory directions to the Administrator, which state that transmission service is to be made available to third parties if BPA transmission:

- "is not required for the transmission of Federal energy;"[8]
- is in "excess of the capacity required to transmit electric power generated or acquired by the United States;"[9]
- "is not in conflict with the Administrator's other marketing obligations;"[10] and
- can be provided "without substantial interference with his power marketing program."[11]

The inter-related nature of generation and transmission is recognized throughout BPA's organic statutes when it comes to finance, cash management, and cost recovery requirements.[12]

As indicated earlier, the Administrator is to make available transmission service to third parties once BPA's needs have been met. The Federal Energy Regulatory Commission ("Commission"), starting in 1996, has issued several major orders designed to encourage competition and discourage public utilities that own, operate or control interstate transmission facilities from using them in a manner that favors the transmission provider's power merchant function over other power suppliers.[13] A key feature of this

[7] See Ass'n of Pub. Agency Customers v. Bonneville Power Admin., 126 F.3d 1158, 1163 (9th Cir. 1997) [hereinafter APAC].
[8] 16 U.S.C. § 837e. The priority is "to the needs of the Government." H. R. Rep. No. 93-1375 at 56 (Sept. 25 1974).
[9] 16 U.S.C. § 838d.
[10] Id. § 839f(i)(1)(B).
[11] Id. § 839f(i)(3).
[12] See, e.g., Federal Columbia River Transmission System Act, 16 U.S.C. § 838(a); 16 U.S.C. §§ 838i(a), 838i(b)(12); Id. § 838k(b), as amended , Pub. L. 96-501, § 8(c), (d), 94 Stat. 2728 (1980); Bonneville Power Administration Financing, 1974: Hearings on S. 3362 Before the Subcomm. on Water and Power Resources, 93rd Cong., 2d Sess. 121-122 (1974).
[13] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. [Regs. Preambles 1991-1996] ¶ 31,036 (1996), Order No. 888-A, on reh'g, III FERC

initiative has been the establishment of Open Access Transmission Tariffs ("OATT") providing for transmission services that meet the Federal Power Act's just and reasonable, and not unduly discriminatory standard applicable to public utilities.[14] BPA has historically provided transmission access to others and is not a public utility under the Federal Power Act. However, as a matter of policy, in 1996, BPA adopted an OATT hewing closely to the Commission's OATT, with changes designed to meet BPA's and the region's needs and practices.[15] At the time that BPA first adopted the OATT, and for some time thereafter, wind resources were practically non-existent in the Pacific Northwest.

Stats. & Regs. [Regs. Preambles] ¶ 31,048 (1997), Order No. 888-B, on reh'g, 81 FERC ¶ 61,248 (1997), Order No. 888-C, on reh'g, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom., Transmission Access Policy Study Group, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), cert. denied, Board of Water, Light & Sinking Fund Comm'rs v. FERC, 121 S.Ct. 1188, cert. granted, New York v. FERC, , cert. granted, Enron Power Mktg., Inc. v. FERC, 69 U.S.L.W. 3574, 2001 D.A.R. 1983 (U.S. Feb. 26, 2001): Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct**,** Order No. 889, FERC Stats. & Regs. [Regs. Preamble 1991–1996] ¶ 31,035 (1996), order clarified, 76 FERC ¶ 61,009 (1996), order aff'd in part, remanded in part, Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C.Cir. 2000), cert. granted in part , New York v. FERC, 69 U.S.L.W. 3281 (U.S. Feb. 26, 2001), cert. granted, Enron Power Marketing, Inc. v. FERC., 69 U.S.L.W. 3382 (U.S.Dist.Col. Feb. 26, 2001), cert. denied, Board of Water, Light and Sinking Fund Comm'rs of the City of Dalton, Georgia v. FERC, 69 U.S.L.W. 3382 (U.S. Feb 26, 2001): Regional Transmission Organizations, Order No. 2000, FERC Stats. & Regs. [Regs. Preamble] ¶ 31,089 (2000), on reh'g, FERC Stats. and Regs. ¶ 31,092, 90 FERC ¶61,201 (2000), cert. denied, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001); Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007) , order on reh'g, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g, Order No. 890-C, 126 FERC ¶ 61,228, order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[14] See, e.g., Federal Power Act, 16 USC 824e(a).

[15] These tariffs apply transmission terms and conditions to all transmission users on a comparable, non-discriminatory basis. As noted in the 1996 Final Transmission Terms and Conditions Proposal, Administrator's Record of Decision, at 5:

> Similarly, the Public Generating Pool (PGP) stated
>
> > Comparability is a critical issue for all BPA customers who purchase transmission services from BPA. Much of the transmission terms and conditions testimony by PGP and others has focused on whether BPA's proposal meets comparability requirements. . . . The proposed NT and PTP tariffs, as modified by the settlement, are a realistic approach to the needs of BPA in operating the Federal Transmission System while maximizing the customers' ability to use the system. PGP believes that the proposed tariffs contain terms and conditions which are generally consistent with FERC's pro forma tariffs. They appropriately balance the obligation to substantially conform to the pro forma tariffs with the specific needs of BPA's customers in the Northwest. PGP believes that NT and PTP tariffs under the Settlement Agreements are equal to or better than the FERC pro forma tariffs when considered in light of the particularities of the Northwest hydro system and the historical usage of the Federal Transmission System.
>
> PGP Brief, WP-96-B-PG-01/TC-96-B-PG-01, at 5-6.

There has been a dramatic surge of wind generation in the Pacific Northwest in recent years, and the amount of wind generation is expected to double in the next several years. This has occurred as a consequence of a number of factors, including BPA's decision to adopt an OATT and other related policy decisions that have aided the development of wind generation in BPA's Balancing Authority Area. Recent events and the expected growth in wind generation have revealed the need for BPA to take action in order to ensure FCRPS operations remain reliable and consistent with BPA's environmental and statutory responsibilities.

B. Operation of the FCRPS Projects

BPA's marketing directives are diverse and often competing. BPA is, for example, required to establish rates to assure timely repayment to the U.S. Treasury, while keeping rates as low as possible consistent with sound business principles.[16] At the same time, BPA must act to protect, mitigate, and enhance fish and wildlife, including spawning grounds and habitat, of the Columbia River and its tributaries.[17]

The Administrator and other Federal agencies responsible for managing, operating, or regulating hydroelectric projects on the Columbia River and its tributaries must exercise their responsibilities "in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are managed and operated."[18] The Administrator must act "consistent with" the Pacific Northwest Electric Power Planning and Conservation Council's ("Council") Fish and Wildlife Program ("the program").[19] The Administrator and Federal water managers must take the program "into account . . . to the fullest extent practicable" at each relevant stage of decision making.[20]

High flows create specific fish-protection needs. When water is spilled over a spillway at a dam, it creates bubbles of air in the water. As the water plunges into the deep pool at the base of the dam, the air bubbles carried to a certain depth are subjected to hydrostatic pressure that forces them to dissolve into the water. The amount of Total Dissolved Gas ("TDG") generated varies with water temperature, spill volumes, and spillway plunge depth.

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[16] See, e.g., 16 U.S.C. § 838g.
[17] 16 U.S.C. § 839(6).
[18] Id. § 839b(h)(11)(A)(i). BPA provides equitable treatment to fish and wildlife by undertaking mitigation measures on a system-wide basis as described in greater detail in Northwest Environmental Defense Center v. Bonneville Power Admin., 117 F. 3d 1520, 1532-34 (9th Cir. 1997). In other contexts, the Ninth Circuit Court of Appeals has determined that BPA has authority to protect fish and wildlife by imposing restrictions on transmission access. California Energy Res. Conservation and Dev. Comm'n v. Bonneville Power Admin., 831 F.2d 1467, 1477-78 (9th Cir. 1987), cert denied, 488 U.S. 818 (1988).
[19] The program, by statute, consists of "measures to protect, mitigate, and enhance fish and wildlife affected by the development, operation, and management of [hydroelectric facilities on the Columbia River and its tributaries] while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply." 16 U.S.C. § 839b(h)(5). Congress directed the Council to include in the program measures that would "provide flows of sufficient quality and quantity between [the dams] to improve production, migration, and survival of such fish. . . ." Id. § 839b(h)(6)(E)(ii).
[20] Id. § 839b(h)(11)(A)(ii).

TDG is a serious concern in the Columbia River because excessive TDG levels threaten the health of the aquatic ecosystem, and salmonids in particular. Excessive TDG produces physiological problems known as gas bubble trauma that in extreme cases can be fatal to fish. The states of Washington and Oregon have delegated authority to set TDG levels under the CWA. Currently, the water quality standard for TDG levels is 110% for both states based on biological considerations.

The water management offices of the Corps, Bureau, and BPA plan and operate the hydroelectric facilities. These agencies determine the volume and pathway (generator, spillway, removable spillway weir, etc.) of water released at hydroelectric projects, with the goal of operating FCRPS projects consistent with state TDG standards.

For a number of years, the FCRPS Biological Opinions ("BiOps") have included flow augmentation and spill operations for fish passage to benefit ESA listed fish at the Corps' mainstem Columbia and Snake River projects. The spill operations can sometimes generate TDG levels in excess of the 110% TDG level. Consequently, Oregon and Washington provide "waivers" with criteria for generating TDG for a 12 hour average up to 120% at the project tailrace.[21] Washington has an additional limit of 115% at the project forebay when conducting operations to benefit ESA listed fish during the months of April to August. These waiver levels are designed to allow some spill flexibility for fish passage while limiting biological harm. TDG constraints remain at 110% outside the fish migration period.

In considering the ecological objectives of the ESA and CWA, operations are planned to comply with the ESA Biological Opinions ("BiOps") [22] and applicable state and tribal water quality standards, to the extent practicable.[23] For Spring 2011, these spill and water quality constraints have also been adopted by court order. On March 24, 2011, Judge James A. Redden issued a Court Order in the on-going BiOp litigation mandating that 2011 spring fish operations be conducted as set forth in the 2011 Spring Fish

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[21] Washington's waiver allows a maximum TDG one hour average of 125%. Oregon's waiver allows a maximum TDG two hour level of 125%.

[22] In Natl. Wildlife Federation v Natl. Marine Fisheries Serv., Judge Redden states, "BPA's choice, however, 'to operate certain turbines outside the 1% peak efficiency requirement' standard set out in the 2000 and 2004 FCRPS BiOps, and sacrifice the biological needs of listed species to satisfy its sales commitments to customers was wrong. This was not a system emergency. It was a marketing error, and ESA-listed salmon and steelhead paid the price. This, the law does not permit. Under the circumstances here, threatened and endangered species must come before power generation." No. CV 01-640-RE, 2007 WL 1541730 at 2 (D. Or. May 23, 2007)

[23] In the NOAA 2008 BiOp, NOAA's Reasonable and Prudent Alternative action ("RPA") provides: "The Corps and BPA will provide spill to improve juvenile fish passage while avoiding high TDG supersaturation levels or adult fallback problems. Specific spill levels will be provided for juvenile fish passage at each project, not to exceed established TDG levels (either 110 percent TDG standard, or as modified by State water quality waivers, currently up to 115 percent TDG in the dam forebay and up to 120 percent TDG in the project tailwater, or if spill to these levels would compromise the likelihood of meeting performance standards…." NOAA FCRPS 2008 BiOp, Appendix, Reasonable and Prudent Alternative Table, RPA Action 29 at 32 (May 5, 2008) (available at https://pcts.nmfs.noaa.gov/pls/pcts-pub/pcts_upload.summary
_list_biop?p_id=27149).

Operation Plan ("FOP").[24] The 2011 Spring FOP states that, from April to August, the Corps will manage spill levels for fish passage to avoid exceeding 120% TDG in project tailraces, and 115% in the forebay of the next project downstream consistent with the current State of Washington TDG upper limits. BPA anticipates that a summer FOP will be adopted in the near future.

Many structural changes have been made at FCRPS dams to lower the TDG levels created by spill. These changes consist of spillway flow deflectors[25] at every lower Snake and mainstem Columbia River FCRPS project included in the FCRPS BiOp, with the exception of The Dalles Dam.[26] Based upon preliminary information, the United States Army Corps of Engineers ("Corps") and BPA have collectively spent over $100 million on the design, construction, and operation for spillway flow deflectors on the Snake River and mainstem Columbia River projects to help alleviate TDG conditions in the rivers.

Releasing water through generators produces less TDG compared to releases through the spillway and other structures. However, water cannot be released through generators unless there is load for the energy produced to serve. Therefore, during periods of excess spill, avaliable federal hydroelectric turbines need to be run for environmental reasons, as keeping the generators loaded minimizes TDG.

BPA, as the Balancing Authority, must ensure that there is balance between loads and resources in order to maintain transmission system reliability. Because the FCRPS projects need to be run for environmental reasons, BPA must reduce other generation in its Balancing Authority Area to maintain balance and comply with mandatory Reliability Standards developed by the North American Reliability Corporation ("NERC") and approved by the Commission.[27]

Since the 1970s, BPA and other Northwest hydro producers have routinely sold surplus power produced during times of high flows at very low prices to utilities in the Northwest and California to encourage operators of coal, oil, natural gas, and other power plants to reduce the output of their plants and replace it with surplus hydropower when available.[28] Over the years, however, a number of factors have made it increasingly difficult to manage TDG levels due to high flows. In the 1990s, the wholesale power market was deregulated. In this environment, load and resource balance is no longer managed by

[24] <u>Natl. Wildlife Federation v. Natl. Marine Fisheries Serv.</u>, No. CV 01-640-RE, Order for 2011 Spring Operations (Mar. 29, 2011).

[25] Flow deflectors are structural devices that redirect water as it comes over the spillway of a dam in a manner that reduces the depth the water plunges into the pool below, helping to reduce the TDG levels.

[26] At the Dalles, flow deflectors were not considered effective due to existing spillway design. Other structural modifications, however, including a fish training wall, have been constructed to help improve juvenile fish survival.

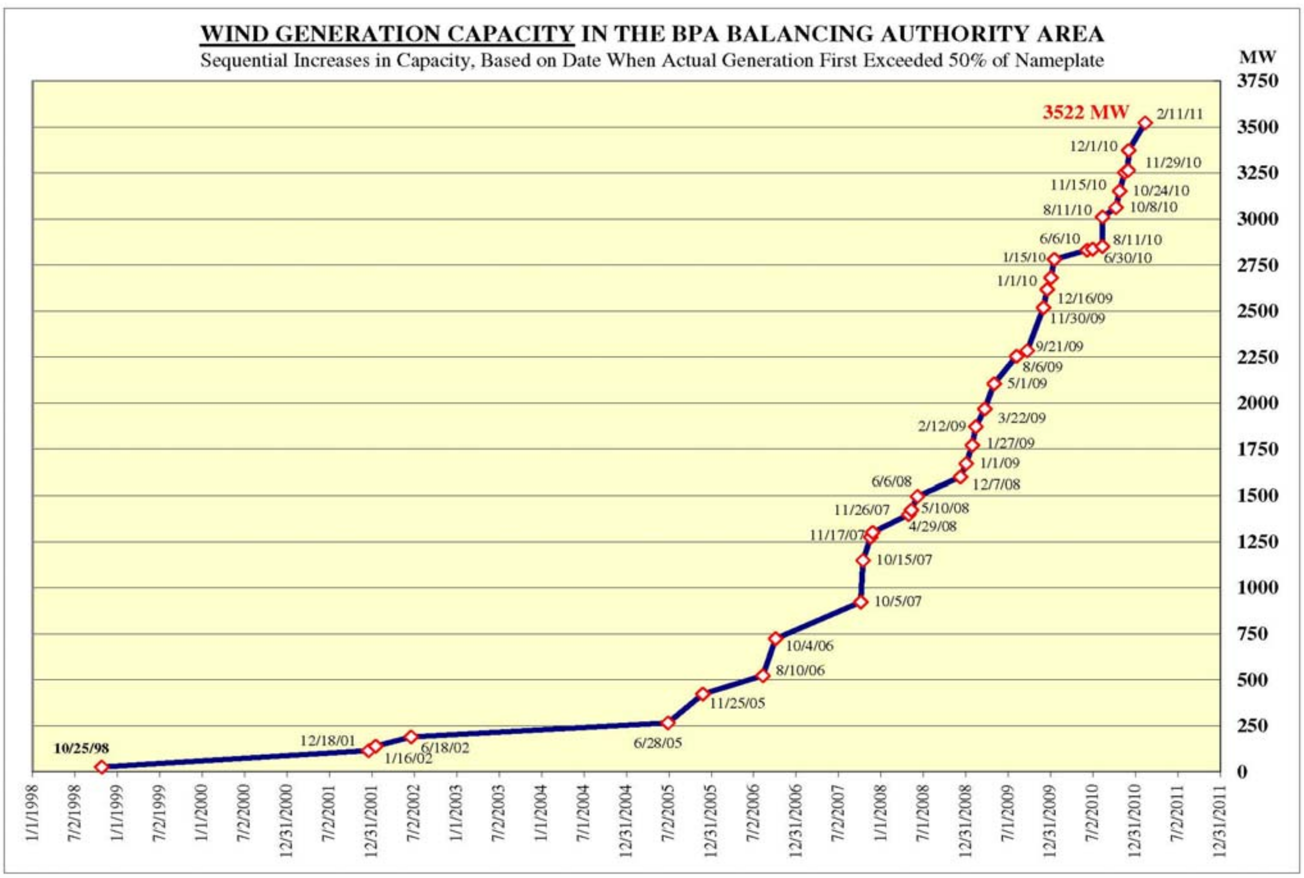
[27] For example, NERC Reliability Standard BAL-001-0.1a requires Balancing Authorities to "maintain Interconnection steady-state frequency by real power demand and supply in real-time."

[28] However, when river flow cannot be physically stored and power houses are fully loaded, so-called "involuntary" spill can still result in excess of TDG limits. Some involuntary spill occurs in almost all years.

utilities alone. Rather, generation has increasingly been developed by private parties independent of load requirements and sold outside the balancing authority area where the generation resides. The source balancing authority is left to deal with balancing loads and resources using the resources available to the balancing authority, such as the FCRPS. In addition, as previously explained, BiOp requirements have resulted in higher flows during fish migration season. Despite these complexities, the system has been managed consistent with all environmental and statutory responsibilities, and system reliability has been maintained.

C. The Growth of Wind Generation

In recent years, nearly 3,400 megawatts of wind power capacity has connected to the FCRTS, adding variable renewable generation to the hydro base of the Columbia River system. The amount of wind generation interconnected to BPA's transmission grid is expected to double in the next few years. The majority of this wind generation is exported out of BPA's Balancing Authority Area and the wind generation operates independently of load demand, increasing the likelihood of overgeneration conditions. The following graph illustrates the recent growth of wind generation in BPA's Balancing Authority Area:



WIND_InstalledCapacity_current.xls 3/15/2011

The rapid increase in wind power in the Northwest has increased the Northwest power system's maximum generation output significantly. It also requires balancing reserve capacity to compensate for within-hour movement and forecast error. Providing this capacity now consumes a significant portion of the operating flexibility of the FCRPS. Maintaining balancing reserve capacity through overgeneration conditions reduces BPA's ability to manage such conditions.

The provision of balancing reserves is necessary to maintain system reliability in BPA's Balancing Authority Area. BPA must use the FCRPS as a backstop for variations in the amount of generation and load that occur during an operating hour compared to the hourly schedule generators and load serving entities provide prior to each operating hour. Almost all loads and generators have some amount of variation between their actual hourly energy used or provided and the amount scheduled. As the Balancing Authority, BPA is responsible for maintaining the balance between overall generation and load required to maintain a reliable system.

The actual output of wind generation varies from the scheduled amount more frequently and in greater magnitude than loads or traditional thermal generators. BPA has had to significantly increase the amount of capacity it maintains for meeting its reliability obligations as the amount of wind generation interconnected to the system has increased.

This capacity is provided in the form of either incremental (inc) balancing reserves or decremental (dec) balancing reserves. To provide inc balancing reserves, BPA must ensure that enough flows are available to increase FCRPS generation to counterbalance output of the wind generation fleet below the submitted hourly schedule. When providing dec balancing reserves, BPA must ensure that water can be spilled or stored in order to decrease FCRPS generation if power produced by the wind generation fleet increases above the submitted hourly schedule. Failing to address the need for this reservation of capacity could affect BPA's ability to reliably operate the FCRPS.

The amount of reserves that BPA holds is partially a function of the hourly scheduling timeframe. BPA is participating in regional efforts to expand intra-hour scheduling and has a number of internal initiatives underway to allow for more flexible means for scheduling energy. To the extent these efforts successfully help accommodate the variability of wind generation, BPA hopes to be able to partially reduce reserve amounts. Continued growth of wind generation, however, will require BPA to increase the amount of reserves it must carry. As a result, while intra-hour scheduling may help reduce reserves in the near term, it will not solve the overgeneration condition itself since the region will still face more on-line generation than there is load to absorb it.

D. The June 2010 Events

High flows in the Columbia River system can create conditions where water can no longer be stored or spilled and need to be run through FCRPS generators in order to operate consistent with BPA's environmental responsibilities. In June 2010, the BPA Balancing Authority Area faced a potential oversupply of generation due to surging spring runoff and high generation levels from wind generators. The generation levels in the BPA Balancing Authority Area would have exceeded load and export commitments if generation was not reduced. BPA at all times maintained system reliability; however, excess generation in relation to loads and exports creates high frequency, which, if unmitigated, could negatively impact system reliability. These conditions also led to a lack of demand for Federal hydropower even at zero cost and threatened to create adverse water conditions in the Columbia River system.

High flows in the Columbia River system are not rare; there is a one-in-three chance of flows at least as high as those of early June 2010 occurring in any year and lasting for one month or more. High flows are more likely to occur in spring runoff periods, when the winter snow begins to melt, increasing river flows. Managing high flow events consistent with BPA's environmental responsibilities can require operation of FCRPS power generation to avoid certain levels of spilled water over the dams.

The events of early June 2010 illustrate how the increase in wind generation has influenced the ability to manage high flows on the Columbia River.[29] After a dry winter, spring 2010 river flows were expected to stay fairly low. Throughout April and May, FCRPS operation focused on providing enough river flow and spill to meet objectives designed to protect ESA listed juvenile salmon migrating to the Pacific and on refilling reservoirs in Idaho, Montana and Washington by July. In early June, however, a strong Pacific jet stream brought storm systems with heavy precipitation and runoff. Snake River streamflows nearly tripled, and Columbia River streamflows nearly doubled. The resulting flows exceeded those needed to meet flow and spill objectives for fish passage. Federal water management staff focus shifted to developing strategies and modifying operations to reduce excess spill and minimize excessive TDG production to the extent practicable.

BPA worked with the Corps, Bureau, and Northwest and California utilities to reduce spill in excess of the required levels in the BiOp and shift spill away from the fish passage routes on the Columbia and Snake rivers. To reduce excess spill, system operators:

- Reduced generation of the Columbia Generating Station nuclear plant to the lowest level possible without risking its ability to return to full power.
- Cancelled or delayed non-essential generating unit outages and transmission control maintenance.
- Arranged to use 2 feet of flood control space at John Day Dam to reduce involuntary spill and prevent lower Columbia flooding.
- Shaped Hungry Horse and Dworshak dams' generation as much as possible into heavy load hours.
- Coordinated a 5 kcfs reduction at Arrow Dam with B.C. Hydro.
- Reduced flows at Albeni Falls Dam as much as possible.

[29] BPA released a report detailing the events that occurred in June 2010 and the steps BPA took to mitigate the situation. The report is available at: http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmt/.

- Reduced decremental wind balancing reserves.
- Coordinated to move generation around the system to minimize capacity reduction on intertie lines to California while maintaining transmission reliability.
- Disposed of over 73,000 MWh of BPA power at zero sales price for the month of June.

After all these steps were taken, TDG levels were managed consistent with BPA's environmental responsibilities. Operationally, there was very little else that could have been done to reduce excess spill and manage system TDG levels. Because BPA was not able to find sufficient load for turbines to avoid involuntary spill, spill volumes were incurred up to the TDG standards equivalent to 745,000 megawatt-hours or about 1,000 average megawatts for lack of load in June.

During this time, most Northwest thermal generation shut down or reduced to minimum operating levels. These generation owners obtained low-cost or free Federal hydropower to replace thermal generation. Thermal generation normally finds it economical to displace their fuel with lower-cost hydropower since they can store or conserve their fuel while they receive hydropower.

However, due to differing economic considerations, the roughly 3,000 megawatts of wind power projects located in BPA's Balancing Authority Area did not respond to the availability of free Federal hydropower. Wind power projects cannot store their fuel and are generally eligible to receive Federal Production Tax Credits (PTC) and/or state Renewable Energy Credits (REC). Wind power output ranged from zero to nearly full output, depending on wind conditions.

To help ensure BPA could meet its environmental obligations, BPA reduced dec balancing reserve capacity because water storage capacity was at its maximum, and spilling additional amounts of water would have exacerbated TDG levels. With reduced dec balancing reserves, wind generators that are generating more than scheduled are more likely to be required to reduce generation in order to stay closer to the scheduled amount of generation. Even with this reduction in dec balancing reserves, BPA delivered all wind power that was scheduled and produced and operated consistent with its environmental responsibilities. As the amount of wind generation in BPA's Balancing Authority Area continues to grow, however, the steps taken by BPA to reduce spill in 2010 will likely be insufficient to continue to produce such results.

Unlike thermal operators, wind operators have an economic incentive to operate as much as possible, regardless of system conditions. The PTC is currently $21 per megawatt-hour ("MWh") and state RECs are generally in the $8 to $20 per MWh range, so this incentive is significant. While all wind power projects are eligible to receive RECs for production, most new wind power projects have opted not to take the PTC and instead opted for the Investment Tax Credit ("ITC") or other grants that provide up-front financial benefits tied to the cost of the project and not actual production. Wind power projects that opt for the ITC or other grants receive the full financial benefit of these incentives regardless of project output.

E. Negative Prices

Up until now, BPA anticipated that it could meet, and has met, its various statutory objectives under an open access transmission regime. Under current circumstances, BPA believes it can continue to meet these various objectives by providing no-cost BPA hydropower when necessary to displace non-Federal generation in order to satisfy BPA's environmental obligations, while at the same time ensuring load service. However, BPA believes that its statutory responsibilities and the objectives of the Northwest Power Act would be frustrated if BPA were required to pay negative prices in order to ensure compliance with BPA's environmental responsibilities.

Payment of negative prices to sell Federal hydropower is inconsistent with BPA's obligations under the Northwest Power Act. The Northwest Power Act provides that transmission access and services are to be provided subject to any existing legal obligations and without substantial interference with the Administrator's power marketing program.[30] While one purpose of the Northwest Power Act is to encourage the development of renewable power in the Pacific Northwest through BPA's acquisition authority, that is one purpose among many that BPA must meet, including assuring the Northwest has an economical power supply, providing environmental quality, continuing to repay the U.S. Treasury on a current basis, and protecting, mitigating and enhancing fish and wildlife of the Columbia River and its tributaries.[31] In that last regard, the Northwest Power Act directs that,

> [t]he Administrator shall use the [BPA] Fund and the authorities available to the Administrator . . . to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries in a manner consistent with [the Council's power plan and fish and wildlife program], and the purposes of th[e] [Northwest Power Act].[32]

In addition, paying negative prices to displace renewable generation to ensure BPA's environmental responsibilities are met is neither socially optimal nor consistent with traditional principles of cost causation. BPA's statutory preference customers would end up paying the costs of displacing renewable generation that is currently almost entirely serving the loads of utilities outside of the BPA Balancing Authority Area. The costs of Federal and state production incentives should be borne by a broad group of taxpayers and ratepayers receiving the wind power, not concentrated on smaller subsets of consumers with limited economic interest or benefits from the renewable generation.

F. Additional Mitigation Measures

BPA continues to work with the region to identify additional steps it could take in future years when similar overgeneration events occur. After receiving input at public

[30] 16 U.S.C. § 839f(d)(2) & (i)(3).
[31] 16 U.S.C. § 839.
[32] 16 U.S.C. § 839b(h)(10)(A).

workshops on October 12 and December 3, 2010, BPA is actively exploring the following additional tools that could assist managing TDG levels during overgeneration events:

- BPA is working actively with multiple counterparties to ensure that the thermal displacement market is as active and liquid as possible. BPA is committed to trying to maximize displacement of the region's thermal resources prior to implementing Environmental Redispatch.
- Discussions are taking place with multiple utilities for possible 2011 implementation of time-shifted irrigation pump load. While this likely will start small, the hope is that the concept can be grown in future years.
- BPA initiated conversations with the Bureau of Reclamation and Idaho Department of Water Resources to increase diversions to replenish irrigation aquifers. While there is very little potential for 2011 implementation due to limited infrastructure, the longer-term potential may be on the order of 5 kcfs.
- Through an effort known as the Transmission Utilization Group (TUG), BPA has been working with Northwest and California utilities to explore and mitigate potential barriers to maximizing utilization of the interties to California. A draft report of this group is expected to be released sometime this spring.
- BPA may reduce inc reserves as well as dec reserves as a step to manage TDG levels. Reducing inc reserves allows for the potential to increase on-peak FCRPS generation, which decreases the need for additional spill in off-peak hours.

BPA has assigned teams of subject matter experts to actively pursue these options and will continue efforts to find solutions to avoid overgeneration events. However, with as much as 3,000 MW of additional wind generation expected to come on line in the next few years, these steps may be insufficient to ensure consistency with BPA's environmental and statutory responsibilities. The use of traditional market mechanisms involving the sale of zero price hydropower does not appear to be a viable strategy for displacing renewable generation that faces the loss of Federal and state production incentives when not producing power.

As a result, given its statutory obligations and legal authorities, BPA will implement Environmental Redispatch on an interim basis this spring and provide no-cost Federal hydropower as necessary to displace non-Federal generation in BPA's Balancing Authority Area under the conditions described in this Final ROD. BPA will continue to explore alternative solutions with stakeholders before deciding whether to continue these policies in the future. These conditions and additional details of the rationale for BPA's Environmental Redispatch and Negative Pricing Policies are discussed in more detail below.

III. ENVIRONMENTAL REDISPATCH

Under Environmental Redispatch, BPA will temporarily substitute renewable, carbon-free hydropower for other generation when necessary to ensure FCRPS operations are consistent with BPA's environmental, statutory, and reliability responsibilities. During an Environmental Redispatch, utilities and consumers who purchase wind power or other energy would continue to receive the full energy deliveries associated with their transmission schedules, but the energy would originate from the FCRPS instead of other resources.

As explained in the previous section, during times of high flows, all reasonably practicable actions must be taken to operate the FCRPS consistent with BPA's environmental responsibilities. During the June 2010 events, in order to match this generation with load, BPA offered free hydropower to generators within BPA's Balancing Authority Area, resulting in most of the thermal generators in the Northwest shutting down. With another 3,000 MW of wind generation expected to interconnect to the BPA transmission system over the next few years, and with the potential for even higher flows than those experienced in June 2010, the proposed Environmental Redispatch protocol is now necessary to ensure consistency with BPA's environmental, statutory, and reliability responsibilities.

BPA would perform Environmental Redispatch only as a last resort to avoid harm to listed salmon and other aquatic species during high water periods that result in overgeneration in the BPA Balancing Authority Area and dangerous TDG levels in the Columbia River system, and to provide options to reduce generation in BPA's Balancing Authority Area in order to maintain system reliability, while meeting its environmental and statutory responsibilities.

A. Conditions for Environmental Redispatch

Before implementing Environmental Redispatch, BPA will take all reasonable actions to reduce excess spill, including:

- Sales through bilateral marketing, including offering to sell at zero cost;
- Cutting prescheduled Pacific Northwest Coordination Agreement storage;
- Deferring scheduled generation maintenance activities;
- Deferring scheduled transmission maintenance activities;
- Increased pumping into Banks Lake at Grand Coulee;
- Seeking flow reductions with BC Hydro;
- Seeking additional load under hourly coordination with Mid-Columbia Hydro Projects;
- Seeking access to additional reservoir storage space at Federal Projects;
- Generation Reductions at Columbia Generating Station;
- Requesting adjustments to mutually agreeable transactions;

- Operating hydro projects inefficiently and at speed-no-load, within BiOp parameters;
- Implementing additional spill at FCRPS projects per the Corps' spill priority list within prevailing water quality standards; and
- Reducing available balancing reserves to maximize turbine flows.

This is a list of known actions that are typically available and effective to relieve excess spill conditions. BPA is continually evaluating additional measures to add to this list.

In the event that BPA determines that these actions collectively will be insufficient to manage spill past unloaded turbines, BPA will implement Environmental Redispatch if: (1) high flow conditions at hydroelectric projects risk spill in excess of spill required for fish passage set in the BiOp resulting in TDG levels above prevailing water quality standards; (2) there is unloaded turbine capacity at those projects to potentially relieve spill; and (3) there is online generation that can be displaced with Federal power without compromising system reliability.

B. Environmental Redispatch Implementation

1. Environmental Redispatch Priority

BPA will first redispatch thermal generators, who can avoid fuel costs and do not receive economic incentives such as RECs and PTCs. BPA will redispatch thermal generators to as low of a generating level as possible without threatening reliability.[33] Most thermal generation, however, will likely have accepted low-cost or free FCRPS generation and should already be offline. Second, if BPA determines that additional generation relief is needed after redispatching thermal generators that do not have reliability requirements, BPA will redispatch variable energy resources ("VERs"),[34] such as wind generation, on a pro rata basis. VERs will include all generators that are characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, biomass, or process steam generating facilities. VERs will be redispatched to achieve the necessary relief, which may result in such generators being moved completely offline.

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[33] The reduction in output of some thermal generators may have negative impacts to system reliability. Examples include generation that supports the reactive stability of the transmission system, minimum generation to provide capacity for ancillary service obligations, or minimum generation to meet future peak load.

[34] In the future, VERs other than wind, such as solar energy, may be developed within BPA's Balancing Authority Area.

2. Environmental Redispatch Protocols

BPA has developed and received comments on the Environmental Redispatch Business Practices ("Business Practices") BPA will use to implement Environmental Redispatch for this year.[35] The Business Practices detail the generators that will be subject to Environmental Redispatch and the communication mechanisms for notification that an Environmental Redispatch event is imminent, when an event is declared, and when an event is over. The Business Practices also detail how generation limits for redispatched generators will be communicated and the procedures for thermal and non-federal hydro generators to set minimum generation levels which they cannot be redispatched below for reliability reasons. Further, the Business Practices address how BPA will treat Generation and Energy Imbalance accounting to avoid adverse economic impacts to customers from Environmental Redispatch.

3. Expected Duration of Environmental Redispatch

The conditions that lead to an Environmental Redispatch are of greatest likelihood during spring runoff periods. During spring runoff periods, Environmental Redispatch is more likely to be triggered in nighttime and shoulder periods, as regional loads are lower and unloaded turbine spill is more prevalent. During peak daytime hours, turbines are more likely to be loaded to full capacity, which reduces the likelihood for Environmental Redispatch. BPA will match the period of redispatch with the expected duration of the conditions necessitating Environmental Redispatch. Depending on the conditions, Environmental Redispatch could last anywhere from a minimum of several hours up to several weeks. BPA has also released peer-reviewed analysis that identifies scenarios that illustrate the potential range in magnitude, duration and potential financial implications of Environmental Redispatch events. These materials are available on BPA's website.[36]

4. Contractual Authority and Amendments

All generators interconnected to the FCRTS or within BPA's Balancing Authority Area have the obligation to reduce generation when ordered to do so by BPA. All generators with an interconnection agreement with BPA, such as Large Generator Interconnection Agreements ("LGIAs"), Small Generator Interconnection Agreements, Balancing Authority Service Agreements, and other generation interconnection agreements, must follow BPA's Dispatch Orders. These interconnection agreements specifically provide that generators are required to follow all Dispatch Orders issued by BPA, such as an order to reduce generation during an Environmental Redispatch.[37] BPA's Dispatch Orders must be followed to maintain system reliability.

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[35] See http://transmission.bpa.gov/ts_business_practices/ at Comments and Redline, Comments and Redline Postings, Environmental Redispatch, V1.

[36] http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/.

[37] Failure to follow a dispatch order will subject the generator to a Failure to Comply Penalty Charge, as specified in BPA's Transmission Rate Schedules.

Specifically with respect to LGIAs, Article 9.7.2 gives BPA the specific authority to interrupt interconnection service for reliability reasons. The LGIA also conditions interconnection service on BPA's compliance with Applicable Laws and Regulations, such as the legal responsibilities described in this document.[38] Further, BPA believes that situations such as those described in this document qualify as Force Majeure events under all interconnection agreements, since the need to comply with BPA's environmental responsibilities constitutes an "order, regulation or restriction imposed by governmental … authorities[.]"[39]

For the sake of clarity, however, BPA will be unilaterally amending Appendix C of LGIAs to specifically reference Environmental Redispatch.[40] Because this Final ROD is being issued on an interim basis, these amendments will terminate on March 30, 2012, concurrent with the expiration of this Final ROD.

5. OATT Amendments

Environmental Redispatch does not affect a Transmission Customer's transmission rights, as all energy deliveries will be made. However, BPA will continue to explore in a separate process whether to amend its OATT to more specifically delineate the effect of BPA's environmental and related statutory obligations on Transmission Service in order to be absolutely clear regarding the terms and conditions of Transmission Service.

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[38] See BPA OATT, Attachment L, Article 4.3 of the Standard Large Generator Interconnection Agreement; BPA OATT Attachment N, Article 1.5.2 of the Small Generator Interconnection Agreement.
[39] See BPA OATT, Attachment L, Article 1 of the Standard Large Generator Interconnection Agreement.
[40] The Commission has ruled that Transmission Providers have the unilateral right to amend LGIAs to include operational requirements. See Bonneville Power Administration, 112 FERC ¶ 61,195, P20 (2005).

IV. NEGATIVE PRICING POLICY

The Northwest energy market is a bilateral market, with most of the trading done at the Mid-Columbia trading hub and the California Oregon border. Under certain conditions, typically when electricity loads are light and there is an over-abundance of generation, the Northwest electricity market can be susceptible to negative prices. Generally, the magnitude and duration of negative prices is influenced by a number of factors, which include:

- transmission constraints,
- volatile stream flows,
- the region's growing number of VERs that can operate economically at negative prices due to PTCs and RECs,
- reliability-driven must-run thermal generators, and
- maintaining operations consistent with environmental laws.

These factors make generation forecasts difficult, limit exports, and inundate the region's resource stack with must-run generators and power that is profitable at negative prices for those generators that receive Federal and state production incentives.

A. Negative Pricing Policy During Overgeneration Events

BPA will not pay negative prices during times when BPA needs to generate in order to comply with its environmental responsibilities. The payment of negative prices could result in opportunities to distort the market and presents an unreasonable cost shift from those generators that can operate profitably during times of negative prices to BPA's fish and wildlife program and/or to BPA ratepayers, and jeopardizes BPA's ability to comply with its statutory responsibilities, including cost recovery. To date, BPA has not been required to pay negative prices during these situations. Similarly, when purchasing energy, BPA will accept zero-priced energy rather than negatively-priced energy from a generator that is required to generate energy due to operational constraints, such as compliance with environmental laws. The only exception to this policy is when BPA is bidding into auction markets at zero or positive prices and is awarded energy at negative prices as a result of the auction.

As indicated earlier, BPA must act in a fashion that reasonably balances and accommodates the multiple purposes of the Northwest Power Act.[41] Currently, BPA's fish and wildlife budget exceeds $750 million each year (over $440 million in direct expenditures and over $300 million in foregone revenues). The difficulties BPA has in balancing FCRPS generation to protect, mitigate, and enhance fish and wildlife and

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[41] Section 4(h)(10)(A) of the Northwest Power Act obligates the Administrator to use his authorities to "protect, mitigate, and enhance fish and wildlife to the extent affected by . . . any hydroelectric project of the Columbia River and its tributaries," consistent with the Council's Power Plan, the purposes of the Northwest Power Act, and other provisions of law. See, e.g., Cal. Energy Comm'n v. Bonneville Power Admin., 909 F.2d 1298, 1315 (9th Cir. 1990)

maintaining an economical power supply are captured well in BPA's ROD adopting the 2008 BiOp.[42] BPA is already absorbing significant financial impact and risk by providing free power during overgeneration events through Environmental Redispatch. Payment of negative prices in order to protect fish and wildlife and to assure that the value of a wind generators' PTCs and/or RECs are not impacted could impose an additional and unnecessary burden on BPA's fish and wildlife program costs and compromise BPA's cost recovery objectives and the need to maintain an economical power supply. Environmental compliance is a fundamental part of BPA's operations and a major cost of doing business. Just like BPA's customers, all generators interconnecting to BPA's system must take the system as it is, complete with environmental responsibilities. Negative pricing would place a new financial burden on BPA's fish and wildlife program and BPA's preference customers in order to ensure VERs are kept whole, even though BPA's preference customers are not purchasing or receiving benefits from the VER generation.

Some parties may well argue that negative prices should not be viewed as a fish and wildlife cost, occasioned by environmental limits, but as a transmission cost, since the cause of the payment would be BPA's open access transmission regime, *i.e.*, but for open transmission access, BPA would not be paying negative prices to meet its environmental responsibilities. Were that the case, we would again be shifting the costs to BPA ratepayers, albeit transmission ratepayers, and creating the risk of unreasonably high transmission rates, a large percentage of which are paid by BPA's preference customers.

Moreover, if BPA's policy was to pay negative prices to meet its environmental responsibilities, marketers and non-Federal generators would be presented with opportunities to refuse BPA offers of low-priced or free power and wait until BPA was forced to offer its power at negative prices in order to comply with its environmental responsibilities. The fact that there is a large amount of publicly available hydro generation, stream flow, and water storage data makes the region aware of those times when hydro flexibility is tight and the potential of negative prices exists. If the region knew that BPA was approaching conditions where it needs to generate in order to meet its environmental responsibilities and BPA was willing to pay negative prices, there would be less incentive for resources to back down economically in isolation and a higher incentive to delay target purchases until prices went negative and approached the last dispatchable resource in the region – renewable generation receiving Federal and state production incentives. As a result, the marketplace is not an effective solution, as BPA would be forced to accept the demands of the buyer. This would not only create undue pressures on BPA's budget and significant economic risk to BPA and its ratepayers, but also reduce the ability to manage TDG levels in the river.

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[42] Bonneville Power Administration Record of Decision Following the May 2008, NOAA Fisheries FCRPS Biological Opinion on Operation of the Federal Columbia River Power System, 11 U.S. Bureau of Reclamation Projects in the Columbia Basin and ESA Section 10 Permit for Juvenile Fish Transportation Program, at 33-36 (Aug. 12, 2008), available at http://www.bpa.gov/corporate/pubs/rods/2008/BPA_ROD_to_Implement_2008_FCRPS_BiOp_RPA.pdf.

BPA must plan the operation of FCRPS generation to keep the interconnected system of projects within operational requirements, such as meeting load and ancillary service obligations, maintaining reliability, and meeting environmental obligations. Meeting BPA long-term preference customer load obligations forms the base of this operation, and BPA purchases or sells power in the marketplace to reshape the net load to meet operational requirements. These purchases and sales are made in differing timeframes based on available information and the need to maintain reliability. If non-Federal generators and marketers withheld offers to purchase FCRPS power until the market turned negative, BPA could be presented with excessive uncertainty in market depth that could result in additional spill due to the magnitude of sales exposure.

In addition, the sale of power at negative prices inappropriately shifts the cost burdens associated with the PTC and RECs to BPA ratepayers. The PTC and RECs were intended to facilitate carbon-free renewable energy production and are paid for by Federal taxpayers and consumers of the renewable generation. BPA marketing activities associated with balancing the system and meeting non-power constraints directly impact the rates of BPA's preference customers; thus, paying negative prices would be reflected in these customers' rates through future rate proceedings that would shift the cost burden of the PTC and RECs to BPA's preference customers. This represents an unnecessary transfer of value between two carbon free generation resources.

While VERs would be kept whole financially if the costs of paying negative prices were shifted to BPA's preference customers, this outcome could have a detrimental effect on the development of renewable resources in BPA's Balancing Authority Area. Because of the cost shifts presented by the payment of negative prices, strong opposition to efforts to further develop and integrate VERs in BPA's Balancing Authority Area could result.

Based on the peer-reviewed analysis conducted by BPA, the cost of paying the value of lost PTCs and RECs alone could cost up to $50 million during 2012, if it proved to be a year of high water and heavy wind conditions.[43] But these may not be the only costs that a wind generator will consider, and that figure could be much higher in certain conditions.[44] In addition, this study does not consider the potential for thermal generators to seek negative-priced payments that they have not received before, creating a new revenue stream for these generators. The payment of negative prices would shift the cost burdens associated with the PTC and REC to BPA's customers, jeopardize BPA's cost recovery objectives, and also hinder the ability of BPA to manage TDG levels. BPA, however, has the statutory requirements to carry out its marketing obligations, including keeping rates as low as possible consistent with sound business principles, recovering its costs, and protecting fish and wildlife affected by operation of the FCRPS.[45] Such outcomes would be inconsistent with these statutory principles. The twin goals of

[43] Northwest Overgeneration: An Assessment of Potential Magnitude and Cost, at 13 (available at http://www.bpa.gov/corporate/AgencyTopics/ColumbiaRiverHighWaterMgmnt/BPA_Overgeneration_Analysis.pdf).
[44] See Comments of enXco at 8; Comments of Horizon at 8.
[45] See 16 U.S.C. § 839f(i)(1)(B); 16 U.S.C. § 839f(i)(3); 16 U.S.C. § 839b(h)(10)(A); 16 U.S.C. § 839e(a)(1).

protecting, mitigating, and enhancing fish and wildlife affected by the development, operation, and management of hydropower facilities while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply will be put at an unreasonable risk if BPA is forced to pay negative prices as a consequence of providing transmission to VERs.[46]

B. Economic Impacts

Environmental Redispatch seeks to ensure generators are able to meet their power delivery obligations. Different resources, however, will face different secondary impacts from displacement under Environmental Redispatch. Thermal resources may face reduced efficiency due to a change in operating level. This will likely be compensated for by the fuel savings associated with the displacement, which explains why thermal resources have traditionally accepted offers of low-priced hydro power during past overgeneration events. As a result, there is expected to be only a very small amount of thermal generation subject to Environmental Redispatch.

Depending on their financing arrangements and age, some VER resources may face the loss of PTCs if they are displaced by FCRPS generation. VERs may also face the loss of state-authorized RECs, which are assets that are marketable to meet some state Renewable Portfolio Standards ("RPS"). BPA understands that these losses may fall to the generation owners or to investors, depending on the contractual arrangements. Consequently, BPA will only redispatch VERs to the extent necessary after thermal generators are redispatched.

C. Proposed Legislative Approaches to Mitigate for Environmental Redispatch

Because the economic impacts on VERs stem from the loss of RECs and PTCs, BPA has proposed to explore with VERs and other regional stakeholders legislative solutions that would allow those generators to remain eligible for PTCs and RECs when an Environmental Redispatch occurs. Legislative solutions would mitigate the potential economic impacts that Environmental Redispatch poses for VERs.

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[46] These principles were reaffirmed in BPA's ROD adopting the 2010 Supplemental BiOp. In evaluating the different approaches proposed by the various parties, the ROD stated: "To the extent that these alternative operations would further reduce the generation of the hydrosystem or restrict its flexibility in meeting load, they would escalate the costs and intensify the challenges of maintaining an adequate, effective, economical and reliable power supply." Bonneville Power Administration Record of Decision Following the May 20, 2010, NOAA Fisheries Supplemental Biological Opinion to the May 2008 FCRPS Biological Opinion for Operation of the Federal Columbia River Power System, 11 U.S. Bureau of Reclamation Projects in the Columbia Basin and ESA Section 10 Permit for Juvenile Fish Transportation Program, at 20 (June 11, 2010), available at http://www.bpa.gov/corporate/pubs/RODS/2010/.

V. RESPONSE TO PUBLIC COMMENTS

BPA received 41 comments on the Draft ROD, both supporting and in opposition to the proposals in the Draft ROD. This Final ROD incorporates changes based on public comments, and below is BPA's response to the specific issues raised by the public comments.

A. Statutory Authority

A1. Issue: Whether BPA's decision not to pay negative prices constitutes market manipulation prohibited under Section 222 of the Federal Power Act.[47]

Commenters' Positions:

BPA received multiple comments expressing concern that BPA's Negative Pricing Policy may constitute market manipulation prohibited under Section 222 of the Federal Power Act. Iberdrola Renewables, Inc. ("Iberdrola") commented that BPA's proposal "introduces a market distortion that can improperly influence prices in the Northwest" and that BPA "must consider the risk that its proposal might be found to be inconsistent with the Commission's market manipulation rules" pursuant to Section 222 of the Federal Power Act.[48] Similarly, Puget Sound Energy, Inc. ("PSE") states that "the Draft ROD fails to explain how the proposed Environmental Redispatch Protocol and Negative Pricing Policies complies with the spirit, if not the letter, of section 222 of the Federal Power Act" and that "BPA should explain how its proposed Environmental Redispatch Protocol and Negative Pricing Policy is consistent with [the] statutory prohibition" against market manipulation.[49] Portland General Electric Company ("PGE") also commented that it "is concerned that BPA's proposed policy consists of the employment of a device or artifice to manipulate market prices and will therefore cause BPA and its customers to violate [the Commission's] anti-market manipulation rules. PGE requests that BPA address this issue before approving the Draft ROD."[50] Finally, PacifiCorp commented that "BPA fails to show compliance with section 222 of the Federal Power Act," that "BPA has not shown how the proposed policies are consistent with the market manipulation prohibition," and that, consequently, BPA's proposed policy "contravene[s] multiple federal laws."[51]

Evaluation of Positions:

BPA disagrees that its decision not to pay negative prices implicates Section 222 of the Federal Power Act. None of the comments submitted specifically explain how BPA's decision implicates Section 222, but simply cite the statute. Section 222 of the Federal Power Act prohibits any entity engaged in a transaction that is subject to the FERC

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[47] 16 USC § 824v(a).
[48] Comments of Iberdrola at 12-13.
[49] Comments of PSE at 16.
[50] Comments of PGE at 4.
[51] Comments of PacifiCorp at 9.

jurisdiction, from the use of "any manipulative or deceptive device or contrivance." Section 222 provides:

> It shall be unlawful for any entity . . . , directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance . . . , in contravention of such rules and regulations as the Commission may prescribe as necessary or appropriate in the public interest or for the protection of electric ratepayers.

The parties' comments are misplaced and fail to recognize the application of section 222 to prevent manipulation of the market. In Order 670, the Commission adopted regulations for implementing Section 222.[52] FERC's regulations provide:

> (a) It shall be unlawful for any entity, directly or indirectly, in connection with the purchase of or sale of transmission services subject to the jurisdiction of the Commission,
>
> (1) To use or employ any device, scheme or artifice *to defraud*,
>
> (2) To *make any untrue statement of a material fact or to omit to state a material fact* necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or
>
> (3) To engage in any act, practice, or course of business that operates or would *operate as a fraud or deceit* upon any entity.[53]

In Blumenthal v. ISO New England, Inc., et al, the Commission defined "fraud" as "'any action, transaction, or conspiracy for the purpose of impairing, obstructing or defeating a well-functioning market.'"[54] The Commission further qualified the term "fraud" as requiring that the "actual facts . . . must have been purposefully concealed."[55] None of BPA's actions rise to the level of the required element of fraud or deception. BPA has been open and transparent with respect to what actions it will be taking and the reasons for those actions. BPA has held multiple public meetings to discuss its policy decision, and has allowed for stakeholders to submit written comments. Thus, BPA has no intent to conceal any information in order to manipulate the market.

Further, as part of its authority granted by statute, BPA has the discretion to "exercise control over the marketing of electricity generated in the Pacific Northwest" in order to meet its statutory obligations.[56] The Ninth Circuit Court of Appeals has upheld BPA's

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[52] 18 C.F.R. § 1c.2.
[53] Id. (emphasis added).
[54] 132 FERC ¶ 63,017 at P90 (2010) (quoting Order 670 at P50).
[55] Id.
[56] See, e.g., Dep't of Water and Power v. BPA, 759 F.2d 684, 685 (9th Cir. 1985) (upholding BPA's Intertie Access Policy).

policies favoring BPA's access to the Pacific Northwest-Pacific Southwest Intertie in order to avoid wasteful spilling of water at FCRPS projects due to a lack of market in the Northwest that would jeopardize BPA's ability to recover its costs.[57] In this case, not only are BPA's Environmental Redispatch and Negative Pricing Policies required to protect BPA's ability to recover its costs and to keep rates low consistent with sound business principles, but BPA must also avoid spill to operate consistent with environmental laws. Further, under Environmental Redispatch, BPA will be providing FCRPS power at zero cost to non-federal generators to meet the scheduled power delivery. BPA has been mindful of the effects of its proposed policy on competition and has sought to ensure that any arguable effects were warranted by BPA's other statutory obligations. In this situation, where BPA is providing Federal hydropower at no cost to displaced generators in order to operate consistent with its environmental and statutory responsibilities, BPA is exercising its responsibilities reasonably.

Decision:
BPA's decision not to pay negative prices does not constitute market manipulation prohibited under Section 222 of the Federal Power Act.

A2. Issue: Whether Environmental Redispatch violates Section 6 of the Preference Act.

Commenters' Positions:
Iberdrola believes that BPA will "'take' non-Federal transmission for Federal needs, and that it intended to use the firm transmission rights of existing wind generators to displace wind energy deliveries and instead deliver Federal hydropower to such generators' power purchasers under the Environmental Redispatch protocol."[58] Iberdrola argues that Environmental Redispatch "is inconsistent with Section 6 of the [Preference Act]," because "Section 6 of the Preference Act makes it clear that firm contracts for transmission of non-Federal energy shall not be affected by 'any increase, subsequent to the execution of such contract, in the requirements for transmission of Federal energy.'"[59]

Evaluation of Positions:
BPA disagrees that Environmental Redispatch violates Section 6 of the Preference Act. Section 6 of the Preference Act provides:

> Any capacity in Federal transmission lines connecting, either by themselves or with non-Federal lines, a generating plant in the Pacific Northwest or Canada with the other area or with any other area outside the Pacific Northwest, which is not required for the transmission of Federal energy . . . shall be made available as a carrier for transmission of other electric energy between such areas. The transmission of other electric energy shall be at equitable rates[.] No contract for the transmission of

[57] Id. at 687.
[58] Comments of Iberdrola at 5.
[59] Id. at 5-6.

> non-Federal energy on a firm basis shall be affected by any increase, subsequent to the execution of such contract, in the requirements for transmission of Federal energy[.]

Section 6 of the Preference Act establishes that BPA must use Federal transmission capacity first to serve BPA's needs, and second, to the extent transmission capacity is not required to serve BPA's needs, Federal transmission is to be made available to non-Federal users. Section 6 also establishes that, once BPA has sold Federal transmission capacity, it may not subsequently breach those contracts if BPA later determines it may need that transmission capacity.

Iberdrola's argument that Environmental Redispatch violates Section 6 of the Preference Act is based on the premise that BPA is taking back transmission capacity that it has already sold in breach of its transmission contracts.[60] Iberdrola's assertion is unpersuasive because Environmental Redispatch does not affect a customer's transmission contracts; rather, Environmental Redispatch is a limitation on the use of a generation interconnection contract. Environmental Redispatch is a tool that will help manage overgeneration and reliability in BPA's Balancing Authority Area and TDG levels in the river by limiting the amount of non-federal generation. This is a *limit on generation*, and is not a limitation on the use of a customer's transmission contract. Due to the limitation on a generator that may be associated with the transmission contract, BPA will be ensuring that the delivery of power is completed using FCRPS generation.

This action is not an infringement of transmission customers' rights under their respective transmission contracts.[61] Generation interconnection contracts and transmission contracts are separate and distinct contracts. BPA's OATT makes this clear. For example, Article 4.4 of BPA's standard LGIA provides that "execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery." Therefore, a limitation contained in a generator's interconnection agreement does not mean that transmission service from that generator is also affected. BPA has the obligation as the Balancing Authority to ensure that generation and load are balanced to maintain reliability. Environmental Redispatch will ensure that firm transmission rights are maintained by delivering the quantity of energy scheduled using those transmission rights and that BPA's Balancing Authority Area stays reliable.

Moreover, Environmental Redispatch is consistent with how the Federal transmission system is currently operated. Environmental Redispatch is similar to the provision of imbalance energy, which no party has ever stated is an infringement of transmission contract rights. BPA provides imbalance energy when a generator in BPA's Balancing Authority Area, for whatever reason, cannot meet the generation levels committed to in

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[60] Id.

[61] Even if the contract at issue were the generation interconnection contracts and not the transmission contract, Section 6 of the Preference Act would still not be implicated because, as explained in this Final ROD, BPA is not in breach of those contracts. Infra at §§ V.B.1-4.

the associated transmission schedule. BPA makes up the difference between the generation levels and the transmission schedule by increasing generation on the FCRPS. During Environmental Redispatch, non-Federal generators in BPA's Balancing Authority Area have their ability to generate limited, and BPA will make up the difference by meeting the scheduled amount with FCRPS energy.

Decision:
Environmental Redispatch does not violate Section 6 of the Preference Act.

A3. Issue: Whether BPA's Environmental Redispatch and Negative Pricing Policies conflict with BPA's statutory obligation to encourage the development of renewable resources.

Commenters' Positions:
Iberdrola argues that, by "targeting wind resources with its … Environmental Redispatch protocol, [BPA] violates one of the fundamental purposes of the Northwest Power Act," namely "encouraging renewable resource development."[62] Iberdrola believes, therefore, that the "Draft ROD proposals discourage the development of renewable resources in contravention to [BPA's] Northwest Power Act directives."[63] The Public Power Council ("PPC") generally supports BPA's statutory authority to implement the Environmental Redispatch and Negative Pricing policies, as does the Western Public Agencies Group ("WPAG") and Pacific Northwest Generating Cooperative ("PNGC").

Evaluation of Positions:
BPA disagrees that BPA's policies adopted in this Final ROD conflicts with Section 2 of the Northwest Power Act. First, BPA's Environmental Redispatch proposal does not only apply to wind resources. Rather, BPA has made a commitment to take all steps reasonably available to avoid Environmental Redispatch, and when Environmental Redispatch is triggered, BPA will first attempt to solve the overgeneration issue by redispatching thermal resources. As a result, BPA's Environmental Redispatch policy goes to great lengths to ensure wind generation is not affected.

Second, encouraging the development of renewable resources cannot be viewed in isolation as the sole purpose of the Northwest Power Act.[64] Section 2 of the Northwest Power Act specifies the Congressional Declaration of Purpose of the Northwest Power Act. While "encouraging" the development of renewable resources is one listed purpose, Section 2 of the Northwest Power Act also provides that the Northwest Power Act was intended to "*assure* the Pacific Northwest of an adequate, efficient, economical and reliable power supply."[65] Moreover, Section 2 of the Northwest Power Act requires that the purposes be "construed in a manner consistent with applicable environmental laws."

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[62] Comments of Iberdrola at 8.
[63] Id.
[64] See Dep't of Water and Power v. BPA, 759 F.2d. at 685 (BPA's policy decisions "involve[] a complex web of four federal statutes and a complex factual background.")
[65] 16 USC § 839(2) (emphasis added).

Therefore, the language in Section 2 of the Northwest Power Act should be read as putting compliance with environmental laws and assuring an adequate, efficient, economical and reliable power supply as affirmative purposes of the Northwest Power Act, while encouraging renewable resources should be read as a goal.

Third, the Northwest Power Act and BPA's other governing statutes require it to establish "the lowest possible rates to consumers consistent with sound business principles,"[66] to provide "equitable treatment for [] fish and wildlife . . . .,"[67] and to recover its costs.[68] BPA believes that its Environmental Redispatch and Negative Pricing Policies strike the appropriate balance between these competing statutory obligations. The payment of negative prices when BPA is forced to generate energy in order to reduce spill would have enormous financial consequences for BPA, and may threaten BPA's ability to recover its costs.[69] As earlier stated, BPA embarked on its open access transmission regime with a view that Federal needs could be met. The policy here assures that this continues to be the case. Payment of negative prices does not. Further, BPA's decision not to pay negative prices keeps power and transmission rates low consistent with sound business principles, and BPA's decision to implement Environmental Redispatch gives BPA the tools necessary to continue the development of wind in the Pacific Northwest while ensuring the protection of fish and wildlife.

Further, it is unclear whether the payment of negative prices would actually encourage the development of renewable resources, as the parties suggest. Paying negative prices and shifting those costs to BPA's preference customers could draw significant opposition to the development of any more renewable resources in the Pacific Northwest, as further development of renewable resources would lead to increased overgeneration events and increased costs to BPA's preference customers. BPA's preference customers would likely oppose any further integration of VERs.

As a result, BPA does not view Environmental Redispatch as unduly discouraging the development of renewable resources. As explained previously, BPA's decision to adopt an OATT and related policies have encouraged the development of wind generation in the Pacific Northwest. Specifically, wind generators have interconnected in BPA's Balancing Authority Area far beyond the expectations and targets contemplated in regional power plans promulgated by the Council. For example, in the Council's 2005 Fifth Power Plan, it forecast up to 6,000 MW of installed wind capacity in the Pacific Northwest during the next 20 years.[70] The Pacific Northwest has already reached 6,000 MW of installed wind capacity, with over 3,000 MW in BPA's Balancing Authority Area. BPA cannot, however, allow the unfettered development of wind within its Balancing Authority Area if to do so would hinder BPA's ability to comply with its environmental, statutory, and reliability responsibilities.

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[66] 16 USC § 838g.
[67] 16 USC § 839b(h)(11)(A)(i).
[68] 16 USC § 838g.
[69] Supra § IV.A.
[70] Fifth Northwest Electric Power and Conservation Plan at 50 (available at http://www.nwcouncil.org/energy/powerplan/5/).

Decision:
BPA's Environmental Redispatch and Negative Pricing Policies do not discourage the development of renewable resources, but are necessary to continue to interconnect more wind resources in the region.

A4. Issue: Whether BPA's policy not to pay negative prices ensures the lowest possible rates to consumers as required by the Northwest Power Act and Transmission System Act.

Commenters' Positions:
PSE argues that BPA's Environmental Redispatch and Negative Pricing Policies will keep rates lower for power customers but increase costs for transmission customers. PSE states that the Northwest Power Act and Transmission System Act mandates that BPA's policies establish "the lowest possible rates for consumers," and that such mandate applies both to Power and Transmission rates.[71] PSE also implies that BPA has no obligation to protect Power rates, as preference customers do not have a "preference to price."[72] PPC supports BPA's proposal to not pay negative prices, stating it "protects powers customers from unreasonable costs," as well as "unreasonable costs to its fish and wildlife program and its cost recovery obligations." In addition, PPC commented that BPA should not "guarantee [generators'] receipt of state and federal payments" for RECs and PTCs.[73] PNGC also supports BPA's decision not to pay negative prices in order to keep electricity costs "reasonable and affordable."

Evaluation of Positions:
The fact that some VERs receive additional financial benefits from PTCs and RECs that may be affected by BPA's policies does not mean that BPA's actions do not ensure the lowest possible rates for all consumers. PSE's argument suggests that BPA's Environmental Redispatch policy will impact the rates paid by BPA's transmission customers. This is simply not the case. The decision to not pay negative prices when selling FCRPS power to any entity during a high water event may impact the ability of some parties to receive RECs and PTCs, but this does not implicate transmission rates. BPA's Environmental Redispatch and Negative Pricing Policies are simply not ratemaking and thus do not affect rates, as these policies do "not impose any charge at all or define any formula for computing charges."[74] As PPC and PNGC point out, the payment of negative prices when selling FCRPS power under the situations described in this Final ROD would result in unreasonable costs to BPA, and, ultimately, result in increased rates to BPA's customers. As indicated earlier, BPA would expect arguments to be made that the payments are caused by TDG limits to protect fish and should be borne by Power customers, while others would argue that they are necessitated by BPA's open access transmission policies and should therefore be allocated to Transmission customers. In either case, rates would be needlessly burdened. Thus, the policies in this

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[71] Comments of PSE at 10.
[72] Id.
[73] Comments of PPC at 3.
[74] Cal. Energy Res. Conservation and Dev. Comm'n v. BPA, 831 F.2d 1467, 1472 (9th Cir. 1987).

Final ROD do ensure the lowest possible rates for both Power and Transmission customers.

Moreover, BPA's obligation to establish the lowest possible rates to consumers must be consistent with "sound business principles." [75] As stated in this Final ROD, peer-reviewed studies conducted by BPA estimate the possible cost of paying negative pricing to be up to $50 million, based on an estimated combined value of RECs and PTCs of $38 MWh. As pointed out by enXco and Horizon Wind, however, the cost could potentially be up to $121 MWh, making it possible that the payment of negative prices may be much more costly to BPA.[76] Further, the peer-reviewed study did not account for the potential for thermal generators to also hold out for negative-priced power because BPA needs to generate at any cost to meet its environmental responsibilities. Because of the potential financial impact the payment of negative prices could have on BPA's rates and BPA's ability to recover its costs, and the unreasonableness of shifting the costs of RECs and PTCs to BPA's power customers, BPA does not believe that paying negative prices in order for BPA to meet its environmental obligations is consistent with sound business principles.[77]

Finally, BPA must consider the overall regional impacts. As parties have noted, the Pacific Northwest has always experienced periodic episodes of overgeneration. The addition of significant quantities of generation that is non-responsive to overgeneration events will cause such events to be more frequent and increase the risk that FCRPS operations will be inconsistent with BPA's environmental obligations. Shifting the costs that arise from this situation away from the parties that are causing the incremental impact would not only inappropriately transfer costs, but also ignore the operational realities of the Pacific Northwest load/resource dynamics in the development of new resources.

Decision:
BPA's policy not to pay negative prices does not violate BPA's statutory directive under the NWPA and Transmission System Act to establish the lowest possible rates for customers.

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[75] 16 USC 838g.
[76] Comments of EnXco at 7-8; Comments of Horizon Wind at 7-8,
[77] See Public Power Council v. BPA, 442 F.3d 1204, 1210-11 (9th Cir. 2006) (deferring to BPA's determination that it is acting according to "sound business principles" where "'the agency is responding to unprecedented changes in the market.'" (quoting Ass'n of Pub. Agency Customers v. BPA, 126 F.3d 1158, 1171 (9th Cir. 1997)).

A5. Issue: Whether BPA's Environmental Redispatch and Negative Pricing policies violate Section 7(g) of the Northwest Power Act.

Commenters' Positions:
Iberdrola asserts that any "costs associated with payment of negative prices should be treated like other fish and wildlife costs and allocated to power rates pursuant to Northwest Power Act Section 7(g)," because "these costs … are caused by the fish and wildlife requirements of the generating facilities whose output [BPA] markets."[78]

Evaluation of Positions:
Section 7(g) of the Northwest Power Act provides, in part:

> [T]he Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves . . . and the sale of or inability to sell excess electric power.[79]

Iberdrola characterizes BPA's Environmental Redispatch and Negative Pricing Policies as implicating only fish and wildlife concerns, and thus arguing that the costs should be allocated to power rates. As explained above, however, BPA's decision not to pay negative prices aims to balance multiple statutory obligations, including protecting fish and wildlife, keeping rates low consistent with sound business principles, and ensuring cost recovery. In addition, reasonable arguments might well be raised that but for BPA's provision of open access transmission, negative prices would not be paid and, as such, they should be viewed as a transmission cost, not a fish and wildlife cost. The payment of negative prices to guarantee the profits of wind generators is an unreasonable cost that should not be borne by BPA's customers. The costs of lost RECs and PTCs should be borne by the consumers of such energy and federal taxpayers, and not by BPA's customers.

Further, under Environmental Redispatch, BPA provides free FCRPS generation to meet the energy obligations of all generators within BPA's Balancing Authority Area. The cost of foregone power revenues incurred by spilling water and providing free power in order to comply with environmental obligations will already be reflected in power rates, absent rate case arguments leading to a different result. While BPA's policy may have an economic impact on some VERs, such impacts are not common to all generators and are due to policies beyond BPA's control, such as RPS and the PTC. Compensating generators for these lost profits would inappropriately shift the burden of these costs to BPA customers, and should be borne by the consumers and taxpayers that benefit from the renewable generation and the generator itself, since the generator contributes to the overgeneration problem.

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78 Comments of Iberdrola at 8-9.
79 16 U.S.C. § 839e(g).

Decision:
BPA's Environmental Redispatch and Negative Pricing policies do not violate Section 7(g) of the Northwest Power Act.

A6. Issue: Whether Environmental Redispatch violates Section 6 of the Transmission System Act.

Commenters' Positions:
Iberdrola and PSE argue that Environmental Redispatch would violate Section 6 of the Transmission System Act because of perceived discrimination in the allocation of transmission capacity. Iberdrola asserts that Section 6 of the Transmission System Act obligates BPA to "make available on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which [is] in excess of the capacity required to transmit electric power generated or acquired by [BPA]."[80] PSE argues that "the proposal would require BPA's transmission customers to bear costs of generation compliance with environmental restrictions," resulting in a shifting of costs to non-Federal transmission customers from power customers, which is "unduly discriminatory and preferential and is not fair and nondiscriminatory."[81]

Evaluation of Positions:
Iberdrola's argument appears to be based on the premise that BPA is discriminating against wind generation by taking back firm transmission rights. However, Environmental Redispatch is intended to solve an overgeneration issue by limiting a generator's ability to generate. Generation interconnection agreements and transmission contracts are separate and distinct. Restrictions on a generator under a generation interconnection agreement do not affect a transmission customer's transmission rights. Under Environmental Redispatch, BPA is ensuring that the energy delivery associated with transmission rights is being fulfilled. Thus, there is no discrimination with respect to the allocation of transmission capacity.

In addition, BPA disagrees that Environmental Redispatch unfairly shifts costs to non-federal generators, as PSE asserts. BPA is ensuring that all energy deliveries are met at no cost to the generator or transmission customer. The fact that some generators, such as wind generators, receive other economic benefits for the production of energy beyond BPA's control does not constitute an unfair or discriminatory cost shift. BPA should not be the guarantor of economic benefits beyond the physical delivery of energy.

Finally, as noted earlier, the Administrator is obligated to use all his authorities, power and transmission, to assure equitable treatment of fish and wildlife. At the same time, the ESA applies to BPA, not just its Power function. In this situation, where the provision of open access contributes to the problem we are addressing here, it is unreasonable to expect that BPA should do even more than it has proposed here, which is the offering of

[80] Comments of Iberdrola at 10; 16 USC § 838d.
[81] Id.

free Federal hydropower as a temporary substitute for other generation when necessary to avoid exceeding TDG limits.

Decision:
Environmental Redispatch does not violate Section 6 of the Transmission System Act.

A7. Issue: Whether Environmental Redispatch violates Section 2 of the Preference Act.

Commenters' Positions:
Charles Pace, PhD, comments that all energy generated from the FCRPS that is "delivered for sale/use outside the region . . . including power provided for peaking or for purposes of "balancing" wind generation, must be limited to surplus peaking capacity and surplus energy as required by 16 U.S.C. § 837a."[82] Mr. Pace also asserts that "30 days prior to executing any contract for the sale, delivery or exchange of such energy,"[83] BPA must give customers "written notice that such contracts are pending and make them available upon request."[84]

Evaluation of Positions:
According to Mr. Pace, because the vast majority of the wind power developed in recent years moves over BPA's high-voltage transmission system, and is delivered for sale/use outside the region, any energy that is generated at federal hydroelectric plants, including power provided for peaking or for purposes of balancing wind generation, must be limited to surplus peaking capacity and surplus energy pursuant to 16 U.S.C. § 837a. Mr. Pace also asserts that "section 837a requires at least 30 days prior to executing any contract for the sale, delivery or exchange of such energy with extra-regional entities, the Administrator must provide Bonneville's existing customers written notice that such contracts are pending and make them available upon request."[85]
Mr. Pace's comments focus on BPA's provision of balancing services to wind generators, rather than BPA's Environmental Redispatch proposal. This Final ROD, however, is narrowly focused on a solution to the overgeneration issues in the Pacific Northwest. Issues regarding the provision of balancing reserve capacity for wind balancing services are beyond the scope of this Final ROD. BPA also respectfully disagrees with Mr. Pace to the extent he implies that the replacement of non-federal energy with federal hydro-based energy during an Environmental Redispatch event constitutes a sale of surplus energy or surplus peaking capacity.

With regard to sales of surplus energy and surplus peaking capacity, section 837a of the Pacific Northwest Power Preference Act ("Preference Act") states:

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[82] Comments of Charles Pace at 2.
[83] Id.
[84] Id.
[85] Id. at 2.

> Subject to the provisions of this chapter, the sale, delivery, and exchange of electric energy generated at, and peaking capacity of, Federal hydroelectric plants in the Pacific Northwest for use outside the Pacific Northwest shall be limited to surplus energy and surplus peaking capacity. At least 30 days prior to the *execution of any contract* for the sale, delivery, or exchange of surplus energy or surplus peaking capacity for use outside the Pacific Northwest, the Secretary shall give the then customers of the Bonneville Power Administration written notice that negotiations for such a contract are pending, and thereafter, at any customer's request, make available for its inspection current drafts of the *proposed contract*.[86]

Section 837a of the Preference Act is clear that a contract is necessary to trigger the notice requirements for sale, delivery, or exchange of electric energy generated at the Federal hydroelectric plants in the Pacific Northwest. Environmental Redispatch, however, does not involve a contract for sale, delivery or exchange of energy from BPA; therefore, the requirements of the Preference Act are not triggered. It occurs only when BPA has not found additional buyers of Federal power and must instead displace other generation to avoid excessive TDG levels. If BPA replaces non-federal generation with federal hydro generation during an Environmental Redispatch event, BPA is providing free renewable hydropower to redispatch non-federal generators in the Pacific Northwest. Furthermore, the act of redispatching non-federal generators with federal hydropower is not a sale or exchange of surplus energy for use outside the region within the meaning of the Preference Act. Simply stated, BPA is not selling surplus energy or peaking capacity during an Environmental Redispatch event.

Mr. Pace also discusses 16 U.S.C. § 837b in relation to BPA's provision of balancing services to wind generators. As discussed above, BPA's decision to provide balancing reserve capacity for general wind balancing service is beyond the scope of this Final ROD. Nevertheless, section 837b(a) also relates to a "contract for the sale or exchange of surplus energy for use outside the Pacific Northwest, or as replacement, directly or indirectly, within the Pacific Northwest for hydroelectric energy delivered for use outside that region by a non-Federal utility . . ."[87] Since BPA is not engaging in a contract for the sale or exchange of surplus energy or peaking capacity for use outside the Pacific Northwest or replacement of energy delivered for use outside the region by a non-Federal utility, section 837b of the Preference Act simply does not apply to the issues at hand.

Decision

BPA's Environmental Redispatch policy is consistent with sections 837a and 837b of the Preference Act.

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[86] 16 U.S.C. § 837a (emphasis added).

[87] 16 U.S.C. § 837b(a).

B. Interconnection Contracts

B1. Issue: Whether Article 4.3 of the LGIA gives BPA the authority to implement Environmental Redispatch.

Commenters' Positions:
BPA received numerous comments disputing BPA's ability to implement Environmental Redispatch. PSE argues that the "Draft ROD erroneously asserts that BPA currently has the contractual right to implement the proposed Environmental Redispatch Protocol" pursuant to Article 4.3 of existing LGIAs because "[n]o law or regulation requires BPA to unilaterally replace scheduled generation in BPA's Balancing Authority Area with federal hydropower to comply with CWA and ESA obligations," and "to the extent that negative power prices are available to BPA to achieve such compliance, the Applicable Law provisions do not authorize the proposed Environmental Redispatch Protocol."[88]

PGE states that "no law or regulation requires BPA to unilaterally replace scheduled generation in BPA's Balancing Authority Area with federal hydropower to comply with [CWA] and [ESA] obligations" and that "to the extent that negative power prices are available to BPA to achieve such compliance, the Applicable Law provisions do not authorize the proposed Environmental Redispatch policy."[89]

PacifiCorp argues that "nothing in the [LGIAs and SGIAs] suggests that BPA is entitled to redispatch scheduled generation and replace it with Federal hydropower in order to comply with the CWA or ESA."[90] PacifiCorp states that "BPA may still comply with both the CWA and ESA without invoking any sort of redispatch, and BPA still has the option of paying negative power prices to comply with both the CWA and the ESA."[91]

Horizon Wind Energy, LLC ("Horizon") and enXco Development Corporation ("enXco") argue that BPA's reliance on compliance with "Applicable Laws and Regulations" in Article 4.3 of the LGIA is a "red herring," as BPA "can comply with the CWA and ESA whether or not this policy is adopted."[92] Horizon and enXco state that the purpose of BPA's proposed policy "is to limit [BPA's] costs in disposing of excess federal energy."[93]

Iberdrola argues that BPA has not "provided support for the argument that [BPA] is *required* to implement the Environmental Redispatch protocol in order to comply with its environmental compliance requirements."[94] To the extent that BPA can pay negative prices (or use other options proposed by Iberdrola), Iberdrola believes that "Article 4.3 does not authorize implementation of the proposed Environmental Redispatch

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[88] Comments of PSE at 11.
[89] Comments of PGE at 3.
[90] Comments of PacifiCorp at 6.
[91] Id.
[92] Comments of Horizon at 5; Comments of enXco at 5.
[93] Id.
[94] Comments of Iberdrola at 14-15 (emphasis in original).

protocol."[95] Iberdrola also states that Article 4.3 "does not state – or even imply – that the provisions of the LGIA can be modified unilaterally under the auspices of compliance with statutory requirements."[96] In addition, Iberdrola believes that "the Draft ROD makes it clear that economics are driving the proposed protocol, not reliability or statutory compliance."[97]

Evaluation of Positions:
All generators with an LGIA are required by Appendix C of the LGIA to follow all BPA Dispatch Orders, such as the redispatch of generation under Environmental Redispatch. Thus, Environmental Redispatch is not a breach of the LGIA, as generators are required to follow Dispatch Orders. However, assuming for the sake of argument that Environmental Redispatch orders are not proper Dispatch Orders under Appendix C of the LGIA, BPA would still not be in breach under Article 4.3 of the LGIA.

Article 4.3 of the LGIA provides that a "Party shall not be deemed to be in Breach of this LGIA" if it is "required or prevented or limited in taking any action" by Applicable Laws and Regulations. Article 1 of the LGIA defines "Applicable Laws and Regulations" as "all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority." Both BPA's responsibilities under environmental laws and its statutes fall within the scope of this definition. As a result, if BPA is prevented from continuing to provide interconnection service to a generator in order to meet its environmental and statutory responsibilities, Article 4.3 provides that such actions are not a breach of the LGIA.

In order to operate consistent with its environmental responsibilities, flows need to be run through the turbines at the Federal hydro projects and electricity must be generated. When BPA is in such a must-run condition, parties know that BPA is in a situation where it must dispose of the energy.[98] If BPA were to pay any price to dispose of the energy, it would provide opportunities for parties to hold BPA hostage by holding out until the price reached levels that would allow parties to reap a significant profit. As explained in this Final ROD, such a result would threaten BPA's ability to keep rates low consistent with sound business principles and to recover its costs, as mandated under BPA's authorizing legislation. Thus, the payment of negative prices so that generators will voluntarily reduce generation is not an option that BPA can take to meet its environmental responsibilities. As a result, when BPA is in a must-run situation due to environmental laws, BPA cannot allow non-federal generators to continue to generate in order to balance loads and resources. Thus, BPA must limit the ability of generators within BPA's Balancing Authority Area to operate in order to be able to comply with "Applicable Laws and Regulations," as specified in Article 4.3 of the LGIA. BPA is not unilaterally amending the LGIA under Article 4.3 to allow for Environmental Redispatch, as Iberdrola asserts. Rather, Article 4.3 deems actions taken that are necessary to comply

[95] Id. at 15.
[96] Id.
[97] Id.
[98] Supra at § IV.A.

with Applicable Laws and Regulations are not a breach of the LGIA. As will be discussed later, BPA will unilaterally amend LGIAs pursuant to Article 9.3.[99]

Decision:
Article 4.3 of the LGIA gives BPA the authority to implement Environmental Redispatch.

B2. Issue: Whether Environmental Redispatch constitutes a Force Majeure event under Article 16.1.1. of the LGIA.

Commenters' Positions:
PSE states that "to the extent that the proposed Environmental Redispatch Protocol reflects a BPA response to the costs of complying with environmental laws, the Force Majeure provisions of the LGIA do not authorize such policies," because "compliance with environmental obligations does not require BPA to utilize Environmental Redispatch, and the ability of BPA to comply with its CWA and ESA obligations is wholly within its control."[100]

PGE states that "to the extent that the proposed Environmental Redispatch policy reflects a BPA response to the costs of complying with environmental laws, the Force Majeure provisions of the LGIA do not authorize such policies" because "Section 16.1.1 of the LGIA specifically provides that '[e]conomic hardship is not considered a Force Majeure event.'"[101]

PacifiCorp argues that "BPA incorrectly determines that the Force Majeure provisions can be invoked to allow for establishing the Environmental Redispatch Protocol or the Negative Pricing Policy."[102] PacifiCorp states that "[s]ince BPA is attempting to implement the proposed protocol and policy to alleviate the high cost of complying with its environmental obligations" and the LGIA states that "[e]conomic hardship is not considered a Force Majeure event," it follows that "the Force Majeure clause cannot be used as support for unilaterally implementing Environmental Redispatch or avoiding Negative Pricing."[103]

Horizon and enXco argue that "under the circumstances under which [BPA] would assert" its rationale for the proposed policies, "it would be 'economic force majeure,' which is not permitted under [BPA's] LGIA," because BPA's "policy decision is based on cost-avoidance and [BPA] has not stated that compliance with the CWA or ESA are outside of [BPA's] control, absent this policy."[104]

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[99] <u>Infra</u> § V.B.3.
[100] Comments of PSE at 11-12.
[101] Comments of PGE at 3.
[102] Comments of PacifiCorp at 6.
[103] <u>Id.</u>
[104] Comments of Horizon at 5; Comments of enXco at 5.

Iberdrola asserts that “the issue of whether compliance with environmental requirements qualifies as a Force Majeure event under the LGIA and SGIA is irrelevant here, as [BPA’s] proposed Environmental Redispatch protocol is not in fact required by statute or regulation, but rather driven by economics.”[105] In addition, Iberdrola argues that since Section 16.1.1 excludes economic hardship from the definition of Force Majeure and BPA’s proposed approach “reflects [BPA’s] response to the costs of complying with environmental laws, the Force Majeure provisions of the LGIA do not authorize such policies.”[106]

TransAlta states that “BPA has not explained how [CWA and ESA] environmental requirements compel BPA to displace non-Federal generation without compensation for the economic and operational impacts arising from such displacement.”[107] TransAlta states that, while it “might be a Force Majeure event” if “BPA has no alternative but unilateral displacement of non-Federal generation,” this is not the case because “the Draft ROD identifies, but rejects, a market solution that would avoid unilateral displacement.”[108]

Evaluation of Positions:

Under Article 16.1.1 of the LGIA, neither party to the LGIA will be considered to be in Default of the LGIA due to a Force Majeure event. Force Majeure is defined as “any order, regulation or restriction imposed by governmental . . . authorities, or any other cause beyond a party’s control.” BPA’s statutory and environmental responsibilities fall within the scope of this language. In addition, the trigger for Environmental Redispatch is a combination of high flows and high winds, acts of nature that are beyond BPA’s control.

As explained in the previous section, Environmental Redispatch is not merely an economic choice. The payment of negative prices is not an option for BPA to meet its environmental responsibilities, as to do so would present a conflict between BPA’s competing statutory obligations. As a result, in order for BPA to operate the FCRPS consistent with its environmental and statutory responsibilities, BPA must implement Environmental Redispatch.

Decision:

Environmental Redispatch constitutes a Force Majeure event under Article 16.1.1. of the LGIA.

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105 Comments of Iberdrola at 15.
106 Id. at 15-16.
107 Comments of TransAlta at 7.
108 Id.

B3. Issue: Whether BPA has the unilateral right to amend Appendix C of the LGIA to include Environmental Redispatch.

Commenters' Positions:

BPA received several comments disagreeing with BPA's position that it has the unilateral right to amend Appendix C of the LGIA to specifically reference Environmental Redispatch. PGE disagrees with the BPA's interpretation of the Commission order cited as evidencing BPA's right to unilaterally amend Appendix C of the LGIA. PGE states that "[t]he Order cited merely indicates that the 'Transmission Provider has the responsibility for establishing the Interconnection Customer's operating instructions and operating protocols and procedures'" and that "[n]othing in the Order provides BPA with the right to unilaterally amend an existing LGIA."[109]

PacifiCorp argues that the "order does not provide BPA with the unilateral ability to amend Appendix C for reasons that do not involve reliability criteria or operating instructions, protocols or procedures" and that, therefore, "BPA does not have the authority to unilaterally amend Appendix C of the LGIA in order to adopt Environmental Redispatch or the Negative Pricing Policy."[110]

PSE states that the "Draft ROD erroneously asserts that transmission providers have 'the unilateral right to amend interconnection agreements to include control area requirements.'"[111] PSE argues that nothing in the cited part of the order "provides to BPA a right to amend Appendix C to the LGIA unilaterally, particularly when an amendment to implement the proposed Environmental Redispatch Protocol would not concern either operating instructions or operating protocols or procedures."[112]

Iberdrola argues that BPA "drastically overstates the application of this order and ignores both the well-settled Commission policy against making retroactive changes to LGIAs or SGIAs already in effect and the language of the LGIA itself, which requires mutual consent to modify terms."[113] Iberdrola believes that "nothing in the [order] grants any party the right to amend Appendix C to the LGIA unilaterally."[114]

Evaluation of Positions:

BPA disagrees with the commenters' position that the Commission's order does not interpret Article 9.3 of the LGIA as giving the Transmission Provider the unilateral right to amend Appendix C to include control area requirements.[115] On February 4, 2005, BPA filed with the Commission for approval certain changes to the *pro forma* LGIA. Included in those changes was specific language in Article 9.3 that clarified that BPA has the unilateral right to modify Appendix C in order to avoid arguments with the Interconnection Customer that agreement must be obtained in order to change Control

[109] Comments of PGE at 4.
[110] Comments of PacifiCorp at 7.
[111] Comments of PSE at 12.
[112] Id. at 13.
[113] Comments of Iberdrola at 18.
[114] Id. at 19.
[115] Bonneville Power Admin., 112 FERC ¶ 61,195, P 20 (2005).

Area reliability requirements.[116] While rejecting BPA's proposed change to Article 9.3, the Commission stated:

> While the Interconnection Customer does have the right to agree to modifications to the agreement, the LGIA should be read as granting the Transmission Provider the right to determine the applicable reliability criteria. Moreover, under LGIA article 9.3 (Transmission Provider Obligations), the *Transmission Provider has the responsibility for establishing the Interconnection Customer's operating instructions and operating protocols and procedures*. Because these instructions, protocols, and procedures will include reliability requirements, *article 9.3 already gives the Transmission Provider responsibility for modifications to Appendix C*. The same provision gives the Interconnection Customer the right to propose changes for the Transmission Provider to consider, but not the right to make unilateral changes. *In light of this provision, we conclude that BPA's proposed change is unnecessary* . . . .[117]

The Commission's order is clear and unambiguous. If BPA were required to obtain mutual agreement to update Appendix C to include operational requirements, as some commenters suggest, a customer could pick and choose which requirements it wishes to follow by simply refusing to amend Appendix C. This would make the provisions of Article 9.3 meaningless and could potentially jeopardize reliability, which is contrary to the Commission's policies.

While Article 30.10 does provide that mutual agreement is required to amend the Appendices to the LGIA, as the Commission recognized, the Commission has specifically ruled that Article 9.3 gives BPA the right to unilaterally amend Appendix C to specify operational requirements. Not only was the Commission clear on this point, it is a general canon of contract interpretation that specific terms control over general terms.[118] Thus, the specific terms of Article 9.4 that allow BPA to unilaterally amend Appendix C control over the terms of Article 30.10.

Comments were also submitted stating that, even if BPA does have the unilateral right to amend Appendix C, Environmental Redispatch is not within the scope of that right.[119] These comments are misplaced, as Environmental Redispatch is intended to maintain reliability and ensure BPA's environmental and statutory responsibilities are met. First, there is no question Environmental Redispatch is an operational protocol. Environmental Redispatch limits a generator's operation when the FCRPS hydro projects need to generate due to environmental constraints and other generation in BPA's Balancing Authority Area must be limited in order to maintain balance between loads and resources.

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[116] Id. at P19.
[117] Id. at P20 (emphasis added).
[118] See Hills Materials Co. v. Rice, 982 F.2d 514, 517 (1992) ("Where specific and general terms in a contract are in conflict, those which relate to a particular matter control over the more general language.")
[119] Comments of PSE at 13.

Second, Article 9.3 contemplates statutory requirements that may affect operations. Article 9, in general, is intended to address operational issues. Article 9.1, titled "General," provides:

> Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party *all information that may reasonably be required by the other party to comply with Applicable Laws and Regulations and Applicable Reliability Standards*.[120]

Read together with Article 9.3, the correct conclusion is that Article 9.3 was intended to address any issues that may affect operations, such as reliability and compliance with Applicable Laws and Regulations.

Further, Appendix C in most of the LGIAs already contains a contractual commitment from the interconnection customer to follow all Dispatch Orders, such as orders to reduce generation pursuant to Environmental Redispatch, so that BPA can maintain load resource balance and reliable operations. The purpose of unilateral changes to Appendix C to specifically reference Environmental Redispatch is to make absolutely clear to the interconnection customer that it must follow BPA's Environmental Redispatch orders.

Decision:
BPA has the unilateral right to amend Appendix C of the LGIA to include Environmental Redispatch.

B4. Issue: Whether Article 9.7.2 allows BPA to interrupt interconnection service for environmental reasons.

Commenters' Positions:
PSE cites to the LGIA Article 9.7.2, which addresses interruption of service to an Interconnection Customer, and states that, "[t]o the extent that the proposed Environmental [Red]ispatch Protocol would allow BPA to interrupt or reduce service for only non-federal generators for purposes other than to maintain the reliability of BPA's transmission system and a system directly or indirectly interconnected with such system, the proposal would directly conflict with the requirement in that interruptions be 'necessary to safely and reliably operate and maintain the Transmission System.'"[121]

PacifiCorp cites to LGIA Article 9.7.2 and argues that "BPA's proposed policies fail to address Good Utility Practice in the LGIA (LGIA section 9.7.2.1)" and that "BPA should also discuss the time periods for interruption and the standard used to evaluate if the interruptions are necessary."[122]

[120] Emphasis added.
[121] Comments of PSE at 14.
[122] Comments of PacifiCorp at 7.

Iberdrola cites to Article 9.7.2 and argues that BPA's "Environmental Redispatch protocol would violate … LGIA curtailment and interruption provisions, because … interconnection service would be interrupted in a discriminatory manner (only for wind generators) and for reasons unrelated to reliability.[123]

Evaluation of Positions:

Environmental Redispatch is consistent with Article 9.7.2 of the LGIA. As many parties point out, under Article 9.7.2, BPA may interrupt interconnection service if such service could "adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System." Environmental Redispatch is implemented in order to avoid effects on reliability, as excess generation in relation to loads and exports creates high frequency, which, if unmitigated, could negatively impact reliability. Because the FCRPS needs to generate electricity for environmental reasons, BPA must turn off other generation in its Balancing Authority Area in order to maintain balance between loads and resources. This is BPA's duty as a Balancing Authority. As a result, Article 9.7.2 gives BPA the authority to implement Environmental Redispatch.

PacifiCorp comments that Environmental Redispatch fails to comply with Good Utility Practice, as required by Article 9.7.2. Article 1 of the LGIA defines Good Utility Practice as:

> [A]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

PacifiCorp does not specify how Environmental Redispatch fails to meet the definition of Good Utility Practice. The definition of Good Utility Practice is broad, and it is hard to make a case that Environmental Redispatch does not meet this standard, as it is designed to allow BPA to comply with both its statutory and environmental responsibilities. Further, Environmental Redispatch is necessary to maintain system reliability, while not violating environmental and statutory responsibilities, and without unfairly shifting the cost of renewable energy and open transmission access to BPA's power customers. Thus, BPA does not agree that Environmental Redispatch does not meet the standard of Good Utility Practice.

PacifiCorp also asserts that BPA does not discuss the time periods required for Environmental Redispatch and the standard for triggering Environmental Redispatch.

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[123] Comments of Iberdrola at 22.

BPA cannot specify the time periods that will be required for Environmental Redispatch, as water conditions and the amount of wind generation will determine if and how long an Environmental Redispatch will be triggered. The development of the associated Business Practice addresses the specific details around notifications and their timelines. Also, this Final ROD specifically discusses the circumstances under which Environmental Redispatch will be triggered. BPA will take all reasonable actions to avoid triggering Environmental Redispatch, including marketing power at no cost.[124] Despite such actions, if BPA is still in danger of exceeding TDG levels at FCRPS projects, BPA will implement Environmental Redispatch in order to meet its environmental and statutory responsibilities and to provide the needed option to maintain system load resource balance. If it would be helpful, BPA will work with customers to quantify the limited circumstances under which Environmental Redispatch will apply.

Iberdrola's assertion that Environmental Redispatch is inconsistent with Article 9.7.2 because it only targets wind generators is unfounded. Environmental Redispatch applies to all non-federal generators, and, in fact, BPA will redispatch thermal generators first to try and avoid the need to redispatch wind generators. Thus, Environmental Redispatch does not unfairly target wind generation.

Decision:
BPA has authority under Article 9.7.2 to interrupt interconnection service under Environmental Redispatch to maintain system reliability.

C. OATT Issues

C1. Issue: Whether Environmental Redispatch is an improper curtailment under the OATT.

Commenters' Positions:
PSE argues that "BPA's proposal is inconsistent with its [OATT]", which defines "the specific parameters within which BPA can deviate from its service obligations, and the proposed Environmental Redispatch Protocol exceeds these defined parameters in seeking to broaden BPA's authority to curtail transmission … for non-federal generation to comply with ESA and CWA obligations."[125]

PacifiCorp states that BPA's OATT "outline[s] instances where BPA can curtail service" and that "[c]compliance with the CWA and ESA by instituting Environmental Redispatch Protocol and the Negative Pricing Policy does not qualify as one of those instances."[126]

Iberdrola argues that BPA's "Environmental Redispatch protocol would violate [OATT curtailment provisions], because transmission … service would be interrupted in a

[124] Supra, Section III.A.
[125] Comments of PSE at 13.
[126] Comments of PacifiCorp at 7.

discriminatory manner (only for wind generators) and for reasons unrelated to reliability."[127]

Evaluation of Positions:
BPA disagrees that Environmental Redispatch violates BPA's OATT. All the parties' arguments on this point rely on the assertion that BPA is curtailing transmission service under the OATT. As explained previously, Environmental Redispatch is not a curtailment of transmission service. Environmental Redispatch is a limitation on the ability of a generator interconnected to the FCRTS to generate, and does not affect a transmission customer's transmission rights. If BPA curtailed transmission service, the transmission customer would not receive the energy that was curtailed. For example, if a 100 MW transmission schedule were curtailed to 50 MW, the load to which the transmission schedule is sinking would be 50 MW short of its needs and would be required to find another 50 MW of energy elsewhere. Under Environmental Redispatch, BPA is not curtailing a transmission schedule. BPA is substituting Federal hydropower to ensure that all transmission schedules are met.

Environmental Redispatch is no different than if a generator was forced to shutdown or generated less than its full transmission schedule; the full transmission schedule would be met by available reserves from the FCRPS. These situations do not constitute curtailments under the OATT.

Decision:
Environmental Redispatch is not a curtailment under the OATT.

C2. Issue: Whether BPA is in violation of its OATT obligations by granting interconnection and transmission service requests despite a lack of sufficient transmission capacity.

Commenters' Positions:
Iberdrola argues that BPA "is obligated to properly plan and expand its transmission system to appropriately integrate generation," and if BPA "has violated its OATT obligations and granted interconnection and transmission service requests despite a lack of sufficient transmission capacity, [BPA] cannot engage in blatantly discriminatory practices by simply forcing the resulting costs incurred during overgeneration events upon the last generators to interconnect …, the last transmission customers to request service …, [or] upon wind generators as a class."[128]

Evaluation of Positions:
Environmental Redispatch is intended to solve an overgeneration problem, not designed to solve a transmission capacity issue. When the FCRPS needs to generate due to environmental reasons, other generators must be limited in order to maintain system reliability.

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[127] Comments of Iberdrola at 22.
[128] Comments of Iberdrola at 16-17.

If anything, the overgeneration problem is attributable to the continued development of generating resources irrespective of load needs, not due to a lack of transmission capacity. Wind generation in BPA's Balancing Authority Area provides clean, renewable energy to the Pacific Northwest and California and should be encouraged. However, unfettered development of generation without consideration for whether more generation is needed to meet load and where it should be located, will inevitably lead to such overgeneration events. To maintain system reliability, generation will need to be turned off. In most overgeneration circumstances, FCRPS generation is being limited to maintain system balance. But when the FCRPS needs to generate due to environmental conditions, other generation in BPA's Balancing Authority Area must take its turn to ensure system reliability.

Decision:
BPA has not violated its OATT obligations, because Environmental Redispatch is not needed to address a transmission capacity issue.

C3. Issue: Whether BPA is unlawfully taking customers' transmission service without just compensation.

Commenters' Positions:
Iberdrola asserts that BPA's "proposal constitutes an unauthorized taking of customers' firm transmission rights without just compensation."[129]

Evaluation of Positions:
As explained previously, Environmental Redispatch does not affect a transmission customer's transmission rights. Environmental Redispatch limits a generators' ability to generate due to overgeneration in BPA's Balancing Authority Area. All transmission schedules will continue to be met with FCRPS energy, so all transmission customers will receive full energy deliveries.

Decision:
BPA is not taking customers' firm transmission rights.

C4. Issue: Whether Environmental Redispatch is consistent with Attachment M of the OATT.

Commenters' Positions:
PSE commented that "BPA has not explained how its proposed Environmental Redispatch Protocol would be consistent with Attachment M to the OATT."[130]

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[129] Comments of Iberdrola at 24.
[130] Comments of PSE at 14.

PacifiCorp states that "BPA's proposed policies … fail to address … parameters for redispatch of Federal hydropower in Attachment M of the OATT" and that "BPA should discuss how the proposed Environmental Redispatch Protocol is consistent with Attachment M."[131]

Evaluation of Positions:
Attachment M of the OATT is not implicated by Environmental Redispatch. Attachment M of the OATT provides for redispatch of the FCRPS to maintain reliability due to transmission congestion and avoid the curtailment of transmission schedules. Environmental Redispatch is not within the scope of Attachment M, as Environmental Redispatch is not intended to solve a transmission congestion issue or to avoid transmission curtailments. Rather, Environmental Redispatch is intended to allow BPA to operate the FCRPS consistent with its environmental obligations and to maintain system reliability. As a result, Attachment M of the OATT is not applicable to the issues that Environmental Redispatch is intended to address.

Decision:
Environmental Redispatch is not within the scope of Attachment M of BPA's OATT.

C5. Issue: Whether Environmental Redispatch is inconsistent with FERC's open access policies, including Section 211A of the FPA.

Commenters' Positions:
PSE states that "BPA has not shown that the proposed Environmental Redispatch Protocol and Negative Pricing Policy is consistent with the policies underlying section 211A of the [FPA] and the policies articulated in Order 888, Order 890, and related orders of the [Commission]."[132] PSE argues that "the proposed Environmental Redispatch Protocol would allow BPA to provide transmission services to itself on terms and conditions that are not comparable to those under which BPA provides service to its transmission customers" and that it would create a cost shift benefiting BPA power customers that "is unduly discriminatory and preferential and is not fair and nondiscriminatory."[133]

Evaluation of Positions:
BPA has adopted an OATT to provide for non-discriminatory access to transmission services.[134] Further, Section 211A of the Federal Power Act grants FERC the authority to order unregulated transmitting utilities to provide transmission services at rates, terms, and conditions comparable to those which the unregulated transmitting utility provides to itself.[135] PSE's assertions are unfounded, because during an Environmental Redispatch event, BPA is ensuring energy deliveries related to transmission schedules are being met.

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131 Comments of PacifiCorp at 7-8.
132 Comments of PSE at 15.
133 Id.
134 See Final ROD at 5-6.
135 16 USC § 824j-1.

As explained previously, Environmental Redispatch does not affect a customer's transmission rights, but places operational limits on generators interconnected to the FCRTS so that BPA may operate the FCRPS in accordance with its environmental and statutory responsibilities, and maintain system reliability. Through Environmental Redispatch, BPA is ensuring that energy deliveries associated with transmission schedules are being served. Thus, BPA is not favoring its merchant function over other transmission customers, as the purpose of transmission service is being met in all cases. In addition, Section 211A does not repeal BPA's other statutory responsibilities, environmental or otherwise. BPA's proposal here is a reasonably balanced response to its myriad responsibilities.

Decision:
Environmental Redispatch is consistent with FERC's open access policies, including Section 211A of the Federal Power Act.

D. Negative Pricing

D1. Issue: Whether BPA should pay negative prices and allocate the costs according to cost causation principles.

Commenters' Positions:
Tacoma Power would prefer "for BPA to pay the market price and assign the costs of any negative prices, using cost causation principles, to the entities with the financial incentives that are supporting the negative price markets."[136] PPC and WPAG support BPA's policy to not pay negative prices.[137]

Evaluation of Positions:
Tacoma's comments recognize that the negative price problem arises during high water events because of the lack of generation response by some VERs during periods of regional overgeneration and this is caused by "perverse financial incentives for VERs to continue to operate even when the electricity produced exacerbates an excess supply of electricity."[138] Tacoma then recommends that BPA pay negative prices, and assign the costs to the entities that are causing the negative prices. Tacoma qualifies its recommend approach, however, with the phrase "if it is easily implemented."[139] One problem with Tacoma's recommendation is the uncertainty of the exposure to negative prices. If BPA is willing to pay VERs negative prices to shut down generation, there is no reason to assume that other generators, such as thermals, that know a high water event is imminent would not wait to shut down until BPA pays negative prices to dispose of excess Federal power, even if the economics of their generator indicated that they should respond to a low price or a price of zero. The marketplace is not an effective solution under high

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136 Comments of Tacoma at 2.
137 Comments of PPC at 3; Comments of WPAG at 5.
138 Comments of Tacoma at 2.
139 Id.

water situations, as BPA does not have the option of not paying due to environmental constraints, and must accept demands from the buyer. WPAG recognized in its comments that paying negative prices in these circumstances may lead to market distortion.[140]

Another uncertainty of Tacoma's proposal is the outcome of the BPA rate case process that would be necessary to assign negative price costs to the generators causing the negative prices. Attempting to forecast the amount of negative prices would be very difficult and wind generators would strongly oppose the inclusion of these costs in a wind balancing rate. There would be significant debate whether the payments should be allocated to power or transmission for reasons previously stated. While many, like Tacoma, may believe BPA's equitable allocation ratemaking standard would permit allocation of negative pricing payments to transmission, that is an issue likely to generate substantial controversy. Only when FERC has reviewed the issue and judicial review has been exhausted can we be certain of the outcome. Given the significant amounts that would potentially be incurred were negative prices to be paid, the absence of a full factual and legal rate case record on the issues and our need to prudently balance our multiple competing statutory directives, BPA believes at this time it should not pay negative prices based on an untested legal assumption.

As explained previously, BPA's decision not to pay negative prices in order to meet its immediate environmental responsibilities represents a reasonable balance of BPA's statutory responsibilities. BPA should not be the guarantor of economic incentives received by only a subset of generators within BPA's Balancing Authority Area. This approach will eliminate the uncertainty that is inherent in Tacoma's preferred approach. Furthermore, BPA sees no efficiency gains or monetary benefits in aggregating the costs of paying negative prices only to disaggregate those costs later through rate proceedings.

Decision:
Rather than incur the cost of negative prices on the uncertain assumption that we can assign those costs to those who are charging us the negative prices, BPA will not pay negative prices. This best assures its environmental and statutory responsibilities are met.

D2: Issue: Whether negative pricing is an intended outcome of state and Federal policies.

Commenters' Positions:
PSE comments that the policies behind RECs and PTCs intentionally reduce the operating cost of variable energy resources to negative levels. PSE states that these policies are actually intended to encourage investment in such resources and BPA's Environmental Redispatch and not paying negative prices policies would distort price

[140] Comments of WPAG at 5; See also comments of PPC at 3.

signals, generated, in part, by Federal and state policies and could hinder the development of VERs in the Pacific Northwest and West Coast.[141]

Evaluation of Positions:

PSE rationalizes that the intent of providing PTCs and RECs to incentivize the development of renewable resources should be reflected in the markets in which those resources participate. BPA disagrees with PSE's assertions. BPA is unaware of any legislative history indicating that lawmakers considered negative pricing and the operational difficulties when adopting these policies, especially with respect to the effects such policies would have on a system that is dependent on hydro resources. As PSE acknowledges, RPS and PTCs were intended to incentivize the development of renewable resources. But these policies should not also be construed as guaranteeing profits for these generators under any conditions.

As PSE points out, the fuel for wind generation is free, so wind generation is already a very low cost resource to operate. From a pure marketing perspective generators should be expected to stop operations when the market price is equal to their operating cost. Thus if PTCs and RECs are taken out of the equation, having wind generation shut down when prices reach zero is the appropriate market signal.

BPA understands that Environmental Redispatch may affect a utility's ability to meet RPS requirements, as RECs will not be produced during an Environmental Redispatch. RPS policies, however, were likely not intended to guarantee the production of RECs under any and all circumstances. Further, it is not BPA's responsibility to guarantee the region that all RPS requirements are met under any circumstances. It is the utility's responsibility to ensure that it has the ability to comply with RPS requirements.

In addition, the PTC was developed to provide assistance in financing renewable resource projects. While the operating costs of renewable resources are typically low, the capital costs are often very high. The earliest programs were grants, but the PTC was later adopted to encourage ongoing O&M in the projects. Currently, new projects can either receive ITCs or PTCs.

BPA's concern with negative pricing is that such a policy would encourage a willful ignorance of the operational realities of the electric grid. Negative pricing due to RECs, PTCs or other externalities ignores the need to maintain balance of loads and resources and pushes the system into a condition where both electric reliability and environmental compliance are threatened. BPA's Environmental Redispatch and Negative Pricing policies are intended to mitigate this situation, and BPA does not find credible claims that existing incentives are insufficient for the continued development of renewable resources. Further, the payment of negative prices to keep VERs whole financially and the shift of those costs to BPA's preference customers would likely lead to opposition of any further development of VERs in BPA's Balancing Authority Area. There is no compelling evidence that Environmental Redispatch will have any greater impact on the development of renewable resources than would the payment of negative prices.

[141] Comments of PSE at 6.

Decision:
There is no evidence that negative prices during overgeneration events are an intended outcome of state REC and Federal PTC policies.

E. Effects to Thermals

E1. Issue: Whether BPA's Environmental Redispatch policy properly considers minimum generation levels of generators.

Commenters' Positions:
TransAlta expresses concern about "dispatching non-Federal generators below minimum stable generation and related market power problems."[142]

PGE states that "BPA's proposal does not ensure that minimum generation levels on each of the non-federal generators will be maintained."[143]

Evaluation of Positions:
TransAlta asserts that BPA has not considered the minimum stable generation or minimum generating requirements of non-federal thermal generating resources.[144] According to TransAlta, BPA must choose between two options: (1) guarantee that non-federal generation will not be dispatched below minimum stable generation, like the Columbia Generating Station, or (2) account for and provide to displaced generators the true costs of restarting, including replacement power for the entire period during which a generator is returning to full service, as well as restart costs.[145]

Similarly, PGE argues that BPA's Environmental Redispatch proposal does not ensure minimum generation levels for non-federal generators.[146] PGE states that BPA's position could force generators in the region to either run their generators in a non-efficient manner or endure unacceptable generation disruption without regard to economics or environmental impacts.[147]

BPA agrees with TransAlta and PGE that the Environmental Redispatch policy should not impact the minimum generation levels of non-Federal generators. BPA will allow each non-federal thermal generator within the BPA balancing authority area to specify its minimum generation level (*i.e.*, minimum stable generation level). A non-federal generator's minimum generation level must be based on the specific reliability requirements of the generator, as opposed to economic or discretionary reasons. During an Environmental Redispatch event, BPA will not redispatch a non-federal generator below its stated minimum generation level. If a non-federal generator does not submit a

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142 Comments of TransAlta at 2.
143 Comments of PGE at 2-3.
144 Comments of TransAlta at 2.
145 Id.
146 Comments of PGE at 2-3.
147 Id. at 3.

minimum generation level to BPA, BPA will assume the minimum generation level to be zero. The process for a non-federal generator to specify its minimum generation level will be addressed in the Business Practices.

Accordingly, since BPA will take the minimum generation levels of non-federal generation into account during an Environmental Redispatch event, TransAlta's and PGE's broad concerns associated with the operation of a generator below its minimum generation level should now be moot.

Decision:
BPA will modify its Environmental Redispatch Business Practice to allow each non-federal generator in BPA's Balancing Authority Area to specify its minimum generation level based on the specific reliability requirements of the generator. BPA's Environmental Redispatch policy will not redispatch a non-federal generator below its stated minimum generation level.

E2. Issue: Whether thermal generators will hold out of the forward market to obtain free power for displacement.

Commenter's Position:
The Public Power Council (PPC) indicated they are concerned "for the potential of thermal generation to hold out of the forward market in order to obtain free power for displacement, rather than at a price greater than zero that is still below its avoided costs."[148] PPC goes on to suggest that this problem may become more prevalent as more VER generation is added and some thermal generators are required to continue operating to maintain reserves and meet peak loads. PPC suggests that BPA maintain a registry in which thermal generators can indicate their status for displacement.

Evaluation of Positions:
Thermal generators will continue to be able to make displacement decisions in a west coast market. Prior to an Environmental Redispatch event, BPA will be actively working to capture much of the available thermal generation at low prices. From the perspective of non-Federal thermal generators, as BPA approaches a high water event there will most likely be little certainty as to whether BPA will implement an Environmental Redispatch, and if so, the duration of the event. Some thermal generators may decide to gamble on the possibility of an Environmental Redispatch with zero priced displacement power. In most cases the thermal generators will be served better by the certainty of shutting down and accepting Federal power at a price at or slightly below their operating costs for a known duration of time.

As to PPC's additional comments regarding the increased need for some thermal generators to continue to run due to reserve and peaking obligations, these issues are addressed in the Business Practices and may be refined as BPA gains more experience with Environmental Redispatch.

[148] Comments of PPC at 3.

Decision:
While there is a risk that thermal generators will hold out until they receive zero priced power, that is a risk we already face; BPA's Environmental Redispatch policy does not increase the risk. Market forces along with the uncertainty regarding whether BPA will implement an Environmental Redispatch and its duration will hopefully keep thermal generators from anticipating receiving zero priced power from BPA.

E3. Issue: Whether cogeneration facilities that are tied to production operations should be excluded from Environmental Redispatch or have the lowest redispatch priority.

Commenter's Position:
Weyerhaeuser states that its cogeneration facilities are not "dispatchable" in the traditional sense because its production system is tied to steam output and generation, and any reduction in generation must be made in a slow, planned process.[149] Weyerhaeuser agrees with prioritizing redispatch on a least-cost basis, but maintains that BPA does not appear to have considered the specific economic issues associated with thermal cogeneration facilities.

Evaluation of Positions:
BPA appreciates the unique operational issues presented by generators with cogeneration facilities that are tied to production operations. Weyerhaeuser points out that redispatch of its cogeneration facilities could create risk of safety incidents or environmental concerns. BPA does not want Environmental Redispatch and Negative Pricing Policies to create the risk of those types of incidents or concerns for generators. As specified in the Business Practices, BPA is asking generators to specify minimum generation levels and ramp rate limitations associated with particular facilities. BPA urges Weyerhaeuser and all other generators to provide information in that process that will ensure safety and environmental compliance are not at risk.

Weyerhaeuser cites "lower avoided costs" and "green fuel sources" as the specific economic circumstances of thermal cogeneration facilities that BPA should account for in establishing Environmental Redispatch priority. Weyerhaeuser does not expand on these comments or provide information to demonstrate the specific issues it asks BPA to consider. Without additional information regarding Weyerhaeuser's comments, BPA is not in a position to establish a redispatch priority that distinguishes thermal cogeneration facilities for other thermal facilities. As described in this Final ROD, BPA is adopting an Environmental Redispatch priority under which thermal generators will be asked to reduce generation and take free FCRPS generation before wind generators. BPA is not further distinguishing specific types of facilities within those categories based on an individual generator's (or types of generators) particular characteristics. BPA expects to have more regional discussions regarding long-term solutions for overgeneration events in the future, and BPA encourages Weyerhaeuser and other cogeneration operators to

[149] Comments of Weyerhaeuser at 1.

provide information to evaluate the specific circumstances of individual facilities as part of those discussions.

Decision:
BPA's Environmental Redispatch policy will not recognize priority distinctions within the thermal class of generators. However, the Environmental Redispatch Business Practice provides cogeneration facilities with the opportunity to establish their minimum generation levels and associated ramp rates consistent with the particular operating characteristics of these generators.

F. Discrimination

F1. Issue: Whether BPA should distinguish between VERs based on whether the generator output qualifies for PTCs.

Commenters' Positions:
Multiple commenters indicated that BPA's proposal to establish the Environmental Redispatch priority for VERs based on whether the VER output qualifies for PTCs is inequitable, and certain commenters suggested that BPA should redispatch VERs on a pro-rata basis.[150] Cowlitz PUD specifically supported redispatching generators that do not receive PTCs first to "minimize economic harm to the group as a whole."[151]

Evaluation of Positions:
As specified in the Business Practices, BPA will redispatch VERs on a pro-rata basis rather than distinguishing between VERs based on whether particular resources are receiving PTCs. BPA received many comments expressing concern that some wind facilities would be redispatched more than others under BPA's proposal and that there are economic considerations other than PTCs and RECs that the proposal did not consider.[152] Because the Environmental Redispatch policy is an interim policy, BPA will redispatch VERs on a pro-rata basis and may revisit this redispatch priority in the future should BPA continue with Environmental Redispatch in the future.

Decision:
BPA will not distinguish between VERs that receive PTCs or RECs and those that do not for purposes or Environmental Redispatch priority. BPA is open to gathering additional information on this issue and potentially making changes in the future.

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[150] Comments of Tacoma at 3, Comments of PSE at 19, Comments of Snohomish at 2, Comments of WPAG at 4.
[151] Comments of Cowlitz PUD at 1.
[152] Comments of enXco at 8; Comments of Horizon at 8.

F2. Issue: Whether BPA should explore making a distinction between VERs receiving PTCs where the output is being used to serve load within BPA's Balancing Authority Area rather than marketed outside of the Balancing Authority Area.

Commenter's Position:
NRU recommends that BPA explore making a distinction between VERs with PTCs serving load in the BPA Balancing Authority Area and VERs exporting power out of the BPA Balancing Authority Area for purposes of implementing an Environmental Redispatch.[153] NRU goes on to state that they see a difference between NRU members that are developing their own resources to serve load and huge wind farms being built in BPA's Balancing Authority Area for export to the Southwest. However NRU realizes these details may not be implemented before spring runoff.

Evaluation of Position:
The majority of the VERs interconnected to BPA's transmission system are currently exported to serve load in other balancing authority areas. However, there is a sizable amount of VER resources serving preference customer loads in the BPA Balancing Authority Area and BPA anticipates that these types of arrangements will continue to grow as preference customers develop or purchase more non-Federal resources.

In the Draft ROD, BPA requested input on the issue of whether BPA should distinguish between VERs with PTCs and VERs without PTCs when an Environmental Redispatch is implemented.[154] As discussed previously, BPA will not be making a distinction between VERs with or without PTCs and plans to redispatch VERs on a pro rata basis up to the amount needed.[155]

Even if BPA was planning on distinguishing between VERs based on their PTC status, it would not make sense to treat VERs that are exported differently from VERs serving load in the BPA Balancing Authority Area, because the need for Environmental Redispatch is driven by the overgeneration conditions that exist at the time and the redispatch should apply to any resources that can be redispatched without causing a reliability problem. The amount of VERs that is not being exported is large enough to help relieve the problem and the inclusion of more resources in the pool that can be called upon during an Environmental Redispatch event means that the amount of generation reduction per individual generator will be less.

Decision:
BPA will not distinguish between VER resources during an Environmental Redispatch event based on whether they are exporting power or serving load in the BPA Balancing Authority Area.

[153] Comments of NRU at 3-4.
[154] Draft ROD at 22-23.
[155] See infra § F6.

F3. Issue: Whether BPA excludes Federal generation from Environmental Redispatch.

Commenters' Positions:
PSE states that BPA has not demonstrated that non-Federal generators in BPA's Balancing Authority Area are the cause of overgeneration.[156] PSE also states that the Environmental Redispatch policy excludes Federal generation, shifting the costs of compliance with environmental laws to non-Federal generators in BPA's balancing authority area and forcing only those generators to forgo generation and revenue.[157]

Evaluation of Positions:
BPA disagrees that it has not demonstrated that non-Federal generators in its Balancing Authority Area are the primary cause of the overgeneration events that the Environmental Redispatch policy is intended to address. The June 2010 events are an example of the type of circumstances that BPA seeks to address. During those events, BPA reduced Federal generation and made other operational adjustments to limit Federal generation at projects that were not facing TDG issues. BPA also offered the remaining Federal generation at no cost to encourage non-Federal generators to reduce generation to minimum operating levels, and most non-Federal thermal generators responded. Although these types of actions historically had been sufficient to address many overgeneration events in BPA's Balancing Authority Area, excess generation conditions persisted during the June 2010 events primarily due to non-federal VER generation. Non-Federal VER generators continued to generate up to full output during the June 2010 events, depending on wind conditions. As the Final ROD explains, economic policies beyond BPA's control create incentives for VERs to generate regardless of system conditions. The Environmental Redispatch policy is intended to address excess generation by non-Federal generators in these circumstances.

BPA also disagrees that Federal generation is excluded from the Environmental Redispatch policy. The policy specifically contemplates that BPA will take all reasonable actions, including measures that affect Federal generation, before redispatching any non-Federal generator in BPA's Balancing Authority Area. These actions include reducing Columbia Generating Station generation to minimum levels and spilling Federal hydro generation across the system in excess of any required spill for fish wherever feasible. Although the reductions in Federal generation associated with actions that BPA takes before redispatching non-federal generators will vary based on system configuration and operating conditions at the time, BPA estimates that such actions could result in a maximum reduction of Federal generation of approximately 3,000 – 4,000 MWs.

Decision:
Evidence demonstrates that non-Federal generators contribute to the overgeneration events that the Environmental Redispatch policy addresses, and the policy includes

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[156] Comments of PSE at 7.
[157] Id.

limitations and operational adjustments to Federal generation during overgeneration events prior to implementing any Environmental Redispatch of non-Federal generation.

F4. Issue: Whether all generating entities are properly notified of Environmental Redispatch events.

Commenters' Positions:
Snohomish suggests that "BPA notify all transmission customers when an Environmental Redispatch event is imminent and when an event begins and ends."[158]

Evaluation of Positions:
BPA's Business Practices will specify the procedures for notices regarding Environmental Redispatch. Initially, BPA intends to post notices to inform all customers, including transmission customers, that an Environmental Redispatch is imminent. The notice procedures primarily focus on the information and instructions provided to generators that are subject to Environmental Redispatch. Should BPA continue its Environmental Redispatch policy beyond the interim period, BPA anticipates that it will continue to make improvements as necessary.

Decision:
BPA will post notice that an Environmental Redispatch event is imminent but BPA will not otherwise provide specific notices to transmission customers regarding the beginning and end of such events.

F5: Issue: Whether BPA should notify all generators of Environmental Redispatch events via telephone.

Commenters' Positions:
PSE argues that all generators should be notified via telephone of Environmental Redispatch events to ensure adequate notice.[159]

Evaluation of Positions:
Due to the interim nature of the Environmental Redispatch policy, BPA intends to utilize telephone instructions for thermal projects, primarily because BPA currently lacks the ability to communicate with these generators via electronic signal. BPA does not believe, however, that telephone notification is the most efficient or effective method to inform thermal generators of Environmental Redispatch events on an ongoing basis. BPA will explore the development of systems to notify thermal generators via electronic signal should BPA continue its Environmental Redispatch policy past the interim period.

BPA currently has the ability to communicate electronically with wind generators. BPA believes that this system of electronic signals has proven effective at providing

[158] Comments of Snohomish at 3.
[159] Comments of PSE at 22.

notifications to wind generators and providing operational instructions, but since BPA does not currently have the infrastructure or systems in place to notify thermal generators via electronic signal, BPA will notify thermal generators of Environmental Redispatch events via telephone and will notify VER generators via electronic signal. BPA will explore systems to provide the ability to notify all generators via electronic signal in the future.

Decision:
BPA will notify thermal generators of Environmental Redispatch events by telephone, but BPA will explore establishing systems to provide electronic notifications to all generators if Environmental Redispatch is extended beyond the interim period.

F6. Issue: Whether Environmental Redispatch should be resource agnostic.

Commenters' Positions:
Springfield Utility Board states that Environmental Redispatch should be resource agnostic and that there is too much focus on taking steps to not curtail wind.[160]

Evaluation of Positions:
BPA continues to be interested in implementing Environmental Redispatch in a manner that is least cost to the Region. However, due to the lack of consensus on the appropriate way to measure cost and the additional complexity entailed for this initial implementation, BPA will implement Environmental Redispatch in two groups. Thermal resources that must be redispatched manually will be dispatched first and resources with automated communications equipment in place will be redispatched second, such as VERs. The automated redispatches will be allocated on a pro rata basis. Not only is this the only technologically feasible way to conduct Environmental Redispatch for this year, but it will help to ensure the least cost redispatch to the region.

Decision:
Implementation of Environmental Redispatch will be prioritized between thermal and VER resources.

G. Environmental Responsibilities

G1. Issue: Whether BPA should refrain from implementing Environmental Redispatch because TDG levels are likely to change and allow additional spill.

Commenters' Positions:
Multiple commenters believe that BPA should address TDG constraints directly, as allowing additional spill (and higher TDG levels) would be beneficial for ESA listed fish and further BPA's obligations to meet its environmental responsibilities. They also

[160] Comments of Springfield Utility Board at 2.

believe it is unwise to rely upon TDG water quality standards that are likely to change due to ongoing litigation.[161]

Evaluation of Positions:
Under the CWA, the states of Oregon and Washington established state water quality standards to protect the waters within their borders, and the U. S. Environmental Protection Agency reviewed and approved those standards. It is BPA's responsibility to operate consistent with existing state water quality standards for TDG. BPA, however, does not support any change that increases the risk to endangered species. In any event, this Environmental Redispatch proposal is not the proper forum to resolve the ongoing TDG water quality debate. BPA's Environmental Redispatch proposal is not dependent on any particular TDG criteria and could be adapted to account for any revised TDG standard or waiver, should they be changed due to ongoing litigation.

Decision:
The Environmental Redispatch proposal is not dependent on particular TDG criteria and can be adjusted for different spill levels if TDG criteria change.

G2: Issue: Whether BPA should adopt an Environmental Redispatch trigger based on metrics such as TDG related to ESA and CWA constraints, not negative prices.

Commenters' Positions:
PSE argues that "if BPA proceeds with Environmental Redispatch Protocol based on BPA's need to comply with ESA and CWA requirements, such a protocol should be triggered based on metrics such as TDG related to ESA and CWA constraints…"[162]

Evaluation of Positions:
Environmental Redispatch is not triggered by negative prices, as PSE suggests, but rather is triggered by a combination of factors, such as expected runoff, weather forecast, energy forecast, fish migration patterns, and TDG levels. Environmental Redispatch will only be triggered when all other reasonable actions outlined in this Final ROD have been taken to reduce excess spill in the FCRPS power system. Once all reasonable actions have been taken, Environmental Redispatch will be implemented if: 1) high flow conditions at hydroelectric projects risk excessive spill and TDG levels; 2) there is unloaded turbine capacity at those projects to potentially relieve spill; and 3) there is online generation that can be displaced with Federal power without compromising system reliability. These actions constitute operational responses and are not triggered by negative prices, and Environmental Redispatch achieves the goal of lowering TDG.

Decision:

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[161] Comments of Northwest Energy Coalition at 7, Comments of Save Our Wild Salmon at 3, Comments of Renewable Northwest Project at 2-3.
[162] Comments of PSE at 19.

The Environmental Redispatch protocol is not triggered by negative prices but by TDG levels. The displacement of non-Federal generation is one additional step in the protocol that is implemented after the protocol initially triggers and all other available remedies are exhausted.

G3: Issue: Whether BPA is clear on how it intends to meet its environmental obligations through Environmental Redispatch.

Commenters' Positions:
Angus Duncan indicates that the ROD does not clarify how BPA intends to fulfill its legal obligations, including its legal obligations to meet its CWA, ESA, and river operations requirements outlined in the BiOp. The proposal should describe and set priorities for specific terms and conditions of implementation of Environmental Redispatch to see if it will actually accomplish the environmental objectives and improve conditions for ESA listed fish populations.[163]

Evaluation of Positions:
As far as addressing how BPA intends to meet the river operations in the BiOp, that issue, like TDG, has been the subject of an ongoing debate for years and, as pointed out in several comment letters, is the subject of ongoing litigation. While we agree the BiOp is an extremely important issue to the region, we do not believe that this is the proper forum to resolve those issues. As far as describing the terms and conditions for implementation of the Environmental Redispatch, BPA's Business Practice describes how we are setting our priorities, and explains the steps BPA will take to implement Environmental Redispatch. Responding to how Environmental Redispatch would address whether the environmental objectives are achieved, BPA believes, as evidenced by BPA's analysis of the June 2010 spill event, that there is already substantial monitoring and modeling capabilities currently available to undertake a reasonable analysis of biological effectiveness. BPA would anticipate that the current level of monitoring and modeling would continue.

Further, the problems detailed in this Final ROD amount to an excess of clean, renewable energy. BPA will continue to explore solutions to maximize the use of this energy, without threatening BPA's environmental and statutory responsibilities.

Decision:
The Environmental Redispatch protocol's ability to achieve environmental objectives will be monitored and modeled within the much larger context of BPA's environmental obligations, which are properly addressed in other forums. In addition, BPA will continue to explore solutions to maximize the use of the clean, renewable energy available in the Pacific Northwest.

[163] Comments of Angus Duncan at 1.

G4. Issue: Whether extreme ramping rates, particularly at Bonneville dam, resulted in serious impacts on spawning chum salmon.

Commenters' Positions:
Charles Pace submitted comments expressing concerns about the impact of extremely high flows on spawning lower chum salmon.

Evaluation of Position:
As addressed below, we view the proposed Environmental Redispatch as an approach to better comply with our environmental responsibilities, and we believe that, by initiating this proposal, we are avoiding adverse impacts to listed species. BPA believes that Environmental Redispatch is consistent with the BiOp, and within the limitations of our proposed action and operating requirements.

Decision:
There is no decision to make regarding this comment.

G5. Issue: Whether BPA's marketing and transmission activities, including the integration of wind power, trigger a responsibility to initiate consultation with the National Oceanic and Atmospheric Administration ("NOAA") under section 7 of the ESA.

Commenters' Positions:
Charles Pace stated that BPA's "marketing and transmission activities, including but not limited to the integration of wind power, adversely impacts other survival/recovery and the designated critical habitat of several threatened and endangered species of Pacific salmonids, as well as numerous other listed species of plants and animals. Section 1536(a)(2) of Title 16, Chapter 35, United States Code, requires that Bonneville, […] to insure that all of the actions the agency authorizes, funds, or carries out—including though not limited to Bonneville's proposed environmental redispatch and negative pricing policy are unlikely to jeopardize the continued existence of any species of plants or animals listed as threatened or endangered or result in the destruction or adverse modification of such species' habitat(s), which have been determined by the Secretaries, to be critical."[164]

Evaluation of Positions:
BPA believes Mr. Pace is misconstruing the factual context for the Environmental Redispatch and Negative Pricing Policies. Contrary to Mr. Pace's account of BPA's legal obligations, BPA is acting proactively to take a discretionary action that ensures that if future conditions of overgeneration and high flows do arise, BPA will be in a position to take an action to redispatch non-FCRPS generating sources and replace them with FCRPS generation, as one part of BPA's efforts to protect listed species and water quality. As such, Environmental Redispatch is consistent with our current environmental responsibilities.

[164] Comments of Charles Pace at 6.

Decision:
Environmental Redispatch will not result in any additional impacts that have not been previously considered; therefore, consultation with NOAA is not necessary.

G6. Issue: Whether BPA must comply with the new guidelines proposed by the EPA and Army Corps of Engineers that may expand the reach of Federal jurisdiction over wetlands and other "isolated" waters.

Commenters' Positions:
Mr. Pace asserts in his comments that "selective compliance on the part of Bonneville with the CWA provisions that limit spill while ignoring the full range of protections that the CWA provides for navigable waters, interstate water, adjacent wetlands, non-navigable tributaries that are subject to seasonal flows, and wetlands that abut non-navigable wetlands, is not in accord with law. Bonneville …must comply fully with the statute. With respect to the implementation of such [CWA] regulations, I want to bring to your attention new guidelines that have been drafted by the Environmental Protection Agency ("EPA") and the Army Corps of Engineers, which may significantly expand the reach of Federal jurisdiction over wetlands and other 'isolated' waters. My understanding is that EPA and the Army Corps provided these new guidelines sometime during the last month to the Office of Management and Budget ("OMB") for its review and consideration."[165]

Evaluation of Positions:
In the first part of the quoted comment, Mr. Pace states that BPA must comply fully with the CWA. However, he does not describe any specific incidents or events of non-compliance. Without such specific examples, BPA cannot respond to this aspect of his comments. As to the issue of having to comply with the new CWA guidance, BPA notes that the new guidance is only Draft Guidance and does not have the force of law. As the Guidance goes through the review process, it is likely to be modified, and may even be withdrawn. If the guidance is codified and becomes a final rule, to the extent that it is applicable to BPA activities, BPA will comply with its requirements.

Decision:
There is no need to make a decision regarding the Draft Guidance at this time.

H. Relation to Balancing Reserves

H1. Issue: Whether BPA should relax generation imbalance and deviation charges coming out of an Environmental Redispatch event.

Commenters' Positions:
PSE states that recent output plays a significant component in the forecasting practices of VERs and suggests that, because such data is not available during an Environmental

[165] Comments of Charles Pace at 8-9.

Redispatch event, generation "[i]mbalance and deviation charges and penalties should be relaxed when a wind generator is resuming generation" after an Environmental Redispatch event.[166]

Evaluation of Positions:
Generation imbalance and persistent deviation penalties will not be applied while an Environmental Redispatch event is in place, but VERs that are subject to an Environmental Redispatch event will be expected to continue to submit reasonably accurate schedules during the event. Thus VER operators or scheduling coordinators should continue to monitor current and expected wind speeds and weather forecasts at the generators. The schedules submitted during the Environmental Redispatch event should track what actual output would have been at the generators and wind schedulers should be able to combine these schedules with the actual wind speed information from the previous hour to determine an accurate schedule regardless of whether the generator is shut down or limited by an Environmental Redispatch event.

BPA will be managing Environmental Redispatch events to the shortest duration required to operate consistent with BPA's environmental responsibilities. After the end of an Environmental Redispatch event, the Federal projects will likely be operating at full capacity, less amounts required to support contingency reserves and balancing reserves required for system reliability. Under these conditions, it will be even more important than usual that parties submit schedules that are as accurate as possible to avoid reductions in balancing reserve quantities or the implementation of another Environmental Redispatch event. Relaxation of charges and penalties after an Environmental Redispatch event would not encourage that accuracy. At the same time, BPA will remain open to discussions whether the Environmental Redispatch is somehow causing unanticipated problems when a wind generator resumes generation.

Decision:
BPA will not waive generation imbalance charges and persistent deviation penalties directly following an Environmental Redispatch event due to the increased need for scheduling accuracy and the VER schedulers' ability to continue to provide reasonable schedules during and after an event. In the event, however, that it can be shown that the Environmental Redispatch event is causing an inability to provide reasonable schedules, we will discuss waiving the otherwise resulting generation imbalance charges.

H2. Issue: Whether BPA will ensure that VERs do not submit inflated schedules during an Environmental Redispatch event.

Commenters' Positions:
Tacoma raised a technical concern. Since BPA is offering to replace the redispatched resources' schedules with free BPA power, there will be an incentive for the resources owners/operators to over schedule the future hourly production in order to take advantage of accessing the free hydro and selling a higher volume at the contracts' sales price to

[166] Comments of PSE at 9.

parties buying the resource output. Tacoma asks that BPA adopt procedures to prevent this outcome.[167]

Evaluation of Positions:
During an Environmental Redispatch event generators that are redispatched will continue to submit hourly schedules. Tacoma is correct that there may be an opportunity for generators with certain types of power purchase agreements ("PPAs") to inflate their schedules to take more zero cost Federal power to loads than their own generators would have produced. However, BPA expects generators to continue to provide reasonable schedules, because the Business Practices will implement Environmental Redispatch on an hour-by-hour basis, and thus, when the event ends, the generator will be expected to return to normal operation in the next hour. Generators could be subject to all charges and penalties associated with schedule error in the first hour after the Environmental Redispatch event, although stated previously, BPA will be evaluating the ability of generators to meet their next-hour schedules after Environmental Redispatch ends. Not knowing when the event will end should incentivize generators to schedule accurately during the event. As such, BPA believes that its approach appropriately considers Tacoma's concern.

Decision:
Existing scheduling incentives that will be applied to the hour following an Environmental Redispatch event should provide the necessary incentive to prevent generators from submitting inflated schedules during the event.

I. Impact to VERs

I1. Issue: Whether BPA's Environmental Redispatch policy will discourage the development of renewable energy in the Pacific Northwest.

Commenters' Positions:
Several parties argue that BPA's proposed Environmental Redispatch policy will discourage the development of renewable resources in the Pacific Northwest.[168] In general, these parties also argue that Environmental Redispatch will make it difficult for developers to secure financing, which will lead to a decrease in new renewable energy projects and economic development in rural communities.

Evaluation of Positions:
Community Renewable Energy Association ("CREA"), Renewable Northwest Project, Horizon, PGE, and Iberdrola argue that Environmental Redispatch will have significant and negative consequences for the future development and investment in renewable resources in the Pacific Northwest. These parties also argue that Environmental

[167] Comments of Tacoma at 4.
[168] Comments of Community Renewable Energy Association at 1; Comments of Renewable Northwest Project at 3; Comments of Horizon at 3-4; Comments of PGE at 3; Comments of Iberdrola at 12.

Redispatch would make it difficult, if not impossible, to obtain new financing for new wind and solar energy projects.[169]

While BPA acknowledges that Environmental Redispatch will have economic impacts on certain VER projects, BPA is not convinced that Environmental Redispatch will discourage the development of new wind and solar projects in the Pacific Northwest. BPA believes that Environmental Redispatch strikes a middle ground that enables the continued development of VERs in the Pacific Northwest, while preserving load and resource balance and compliance with environmental and statutory responsibilities. Without such policies in place, the risks associated with overgeneration events during high run-offs would create a substantial roadblock to the development of any new resources in the BPA Balancing Authority Area. Further, it is unclear whether Environmental Redispatch will have any greater effect on the development of renewable resources than paying negative prices, as the costs shifts created by paying negative prices would likely garner strong public opposition to the further development of VERs in the Pacific Northwest.

In addition, as stated throughout this Final ROD, BPA must balance its environmental, statutory, and reliability responsibilities with its policies supporting the development of renewable resources in the BPA Balancing Authority Area. Several parties argue that Environmental Redispatch will jeopardize renewable energy project financing. BPA does not presume to know the details of a wind or solar developer's financing arrangements, and therefore, cannot opine on the specific reasons that may inform an investor's tolerance for risk. BPA acknowledges that Environmental Redispatch will have an economic impact on VERs. However, to date, BPA has not observed any evidence to support the parties' claims that investment in renewable energy will stall as a result of BPA's efforts to maintain load and resource balance and compliance with its environmental and statutory responsibilities. Indeed, despite experiencing the worst financial downturn in decades, wind developers have continued to receive financing for their projects, as evidenced by the continued growth of wind development in the BPA Balancing Authority Area. This demonstrates that the wind industry has the ability to manage a variety of market conditions and risks. As discussed in this Final ROD, the rapid and sustained success in variable energy resource development is heavily influenced by state RPS and Federal tax incentives. These incentives are expected to continue to drive investment in and development of renewable resources in the region.

In addition, there appears to be situations in other parts of the country where wind generation is curtailed to protect endangered species. For example, Iberdrola has implemented, on a voluntary basis, an Avian and Bat Protection Plan that considers limitations on its wind generators if high avian or bat mortality is experienced.[170] In addition, Iberdrola has installed an avian radar system on some of its projects located in Texas for the purpose of shutting down the wind turbines when major bird migration

[169] Horizon Comments at 4; RNP Comments at 3.
[170] Avian and Bat Protection Plan at § 4.1 (Dec. 2008), available at http://www.iberdrolarenewables.us/pdf/Signed_ABPP_10-28-08.pdf.

activity is detected.[171] Under these circumstances, these wind projects will also likely not receive PTCs or RECs when shut down for bird migration. It does not appear, however, that such conditions will threaten the development of renewable energy.

Further, BPA has a proven track record of supporting VER integration and is undertaking a variety of initiatives to facilitate the integration of new wind and solar resources into the BPA transmission system. As of April 2011, there was 3,522 MW of wind power in operation, with the number forecasted to reach 6,492 MW by the end of 2013. BPA continues to invest significant resources in transmission infrastructure and system upgrades to accommodate this growth. Thus, when combining BPA's efforts with state and Federal policies and incentives, BPA believes that Environmental Redispatch will not significantly affect the demand for renewable energy projects in the Pacific Northwest.

Decision:
Environmental Redispatch is a solution to an overgeneration event that arises for a limited amount of time in some years. During this event there is a surplus of carbon free electricity, including wind that receives PTCs and RECs from generating. In this situation, it has been proposed by commenters that BPA either pay wind operators to reduce output or curtail wind operations without providing payment beyond the provision to them of free Federal hydropower. Either policy results in a cost being borne by different customers, as well as some negative impact on future renewable resource investment. If BPA pays wind operators to reduce output, that will result in a cost to BPA that must be allocated to and borne by either BPA's power or transmission customers. That would raise BPA's rates to customers who for the most part are not currently buying much of the wind operating on BPA's system. This will ultimately make it more difficult to accomplish the siting of new wind resources and transmission lines needed to integrate renewable resources within BPA's Balancing Authority Area. Alternatively, if BPA temporarily reduces wind generation and does not pay them for the reduction, that could result in a negative economic impact due to the loss of PTCs and RECs . There is no way to know definitively which approach will have the bigger impact on future renewable resource investment. BPA has concluded that reducing wind generation without payment is more consistent with our environmental and statutory responsibilities and provides system reliability.

I2. Issue: Whether Environmental Redispatch will adversely affect the ability of entities to meet their RPS requirements.

Commenters' Positions:
PSE states that the "proposed Environmental Redispatch Protocol would jeopardize existing strategies for meeting RPS requirements and could impede the ability of affected utilities to satisfy their RPS obligations."[172]

[171] "Newest Texas Wind Farm Cause for Community Celebration, Brings Energy Industry Leaders Kenedy County on the Gulf Coast" (April 17, 2009), available at http://www.iberdrolarenewables.us/rel_09.04.17.html.
[172] Comments of PSE at 9.

PacifiCorp states that implementing BPA's proposed policy "denies PacifiCorp retail customers the rightful benefit of the value of [PTCs] and [RECs] they would otherwise have received, as well as puts at risk PacifiCorp's and other Northwest renewable resource owners' ability to comply with the law in meeting [RPS]."[173]

Seattle City Light commented that it "does not believe its ability to comply with the State of Washington's [RPS] will be materially impacted" by BPA's proposed policies.[174]

Evaluation of Positions:
As indicated earlier, the substantial growth of wind power in the Pacific Northwest and more specifically in BPA's Balancing Authority Area is evidence of BPA's commitment to supporting RPS in both Northwest states and California. BPA has and will continue to look for opportunities to work with states, utilities and the wind community to develop protocols and RPS accounting practices that would enable the wind that could have been generated, if not for Environmental Redispatch, to continue to qualify as contributing to RPS requirements. However, BPA's primary responsibility is to ensure that BPA is able to meet its environmental and statutory responsibilities, not to ensure that the region is able to meet state RPS policies that are beyond BPA's control. BPA will be taking all reasonable actions to avoid having to implement Environmental Redispatch. In addition, when Environmental Redispatch is implemented, resources that receive RECs needed for state RPS compliance will be the last resources to be redispatched. Thus, BPA is taking all reasonable steps to ensure that RECs and PTCs are protected.

Further, it is not clear that the payment of negative prices will have a different outcome. Because of the cost shift to BPA's preference customers that is created by the payment of negative prices, there may be significant opposition to the development of new VERs within BPA's Balancing Authority Area. Should the payment of negative prices hinder the development of VERs, utilities may also find it difficult to meet state RPS requirements.

Decision:
BPA will work to minimize the impact of Environmental Redispatch on entities' abilities to meet RPS requirements; however, BPA's priority is meeting its statutory and environmental obligations.

I3. Issue: Whether BPA provides a clear definition of VERs in this ROD.

Commenters' Positions:
Snohomish included the definition of VER from the FERC NOPR and questioned whether BPA was relying on this definition as one was not provided in the Draft ROD.[175] Additionally, Snohomish questioned whether BPA would "seek to re-dispatch all types of

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[173] Comments of PacifiCorp at 1-2.
[174] Comments of Seattle City Light at 2.
[175] Comments of Snohomish at 1-2.

resources – both thermal and non-thermal – throughout its Balancing area" and if "resources that are located behind a customer's meter" would also be subject to redispatch.[176]

Evaluation of Positions:
The Commission's recent VER NOPR defines a VER as an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[177] BPA will generally use this definition to determine what resources are considered VERs in determining Environmental Redispatch priority. To be more specific, BPA will consider as VERs wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. The definition of VERs does not include, however, hydroelectric, biomass, or process steam generating facilities.

Decision:
BPA will generally adopt FERC's definition of VERs.

I4. Issue: Whether BPA's analysis underestimates the true economic impact of the proposed policy.

Commenters Positions:
EnXco and Horizon comment that BPA has understated the economic impact of Environmental Redispatch. BPA's study estimated up to a $50,000,000 annual impact based on the projected value of RECs and PTCs. EnXco and Horizon state, however, that BPA's study "does not consider that wind energy producers may not be paid for energy under their PPAs if [BPA] substitutes federal excess energy for wind energy."[178] In addition, enXco and Horizon state that "the wind energy producer could also potentially be exposed to liquidated damages or even contract default, depending on the terms of the particular PPA[,]" and may also may be exposed to "potential costs or fines to which a utility may be subject if it fails to meet RPS targets."

Iberdrola raises the same concerns, stating that "not only would Bonneville's 'replacement policy' impact revenues associated with RECs and any generation-based tax credits, the entire power purchase price would arguably be forfeited."[179]

Evaluation of Positions:
BPA understands that Environmental Redispatch may have potential economic consequences for wind generators. As stated previously, however, BPA should not be the guarantor of a generator's profits due to circumstances beyond its control, such as state RPS policies and PPAs. Even if there are other costs beyond just the value of RECs and PTCs, these costs should still not be shifted to BPA's Preference Customers. Further, the fact that the estimated costs could be greater means that the payment of negative prices

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[176] Id. at 2.
[177] *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, at P 64 (2010).
[178] Comments of enXco at 8; Comments of Horizon at 8.
[179] Comments of Iberdrola at 23.

would have an even greater impact on BPA's preference customers and BPA's ability to recover its costs.

There are numerous forms of PPAs and different RPS for different states. BPA is not a party to these agreements, and has no control over these agreements or state RPS policies. BPA cannot ensure that all contractual arrangements or state policies are met. Even Iberdrola acknowledges that it "has many forms of [PPAs.]" BPA has received differing comments about the effect that Environmental Redispatch will have on PPAs and RPS requirements. For example, Tacoma Power comments that revenues are tied to the delivery of power under most PPAs, and the substitution of FCRPS energy "could potentially increase the revenues [VERs] receive from their buyer(s) by overstating their scheduled output."[180] This appears at odds with enXco, Horizon, and Iberdrola's position that they will not be paid for the delivery of energy if it is not wind energy. In addition, SCL has stated that it "does not believe that its ability to comply with the state of Washington's [RPS] will be materially impacted by BPA's potential actions[.]"

Decision:
BPA understands that its Environmental Redispatch and Negative Pricing Policies will have economic impacts on some generators, but BPA cannot ensure that the terms of contracts and policies that are beyond its control are met.

I5. Issue: Whether the mismatch between the source listed on the e-Tag and the actual source may create REC accounting compliance issues.

Commenters' Positions:
PSE states that "the potential mismatch between the source listed on the e-Tag and the actual source of the generation may also create compliance problems with REC accounting policies and standards in place for compliance with RPS obligations and Western Renewable Energy Generation Information System [WREGIS] reporting requirements."[181]

Seattle City Light indicated they "do not believe its ability to comply with the state of Washington's Renewable Portfolio Standard will be materially impacted by BPA's potential actions…"[182]

Evaluation of Positions:
PSE provides insufficient information for BPA to evaluate its concern. BPA understands that REC accounting is at the meter, not based on the e-Tag. For example, the WREGIS Operating Rules specifically provide that "[f]or each renewable energy resource, total MWhs of generation shall be measured at the point of interconnection to the transmission

[180] Comments of Tacoma Power at 4.
[181] Comments of PSE at 22.
[182] Comments of Seattle at 2.

or distribution company's system . . . ."[183] Thus, based on WREGIS rules, it does not appear that the e-Tag will have any impact on REC accounting or reporting requirements.

Further, currently, at any time, a wind generator receives FCRPS energy through generation imbalance when the generator is not able to meet the scheduled amount specified in the e-Tag. BPA has never received feedback on this situation creating REC accounting difficulties. Seattle City Light, who is subject to the same RPS as PSE, states that its ability to comply will not be materially affected by Environmental Redispatch.

Decision:
BPA does not believe that Environmental Redispatch will impact REC accounting standards.

J. Contractual Impacts

J1. Issue: Whether BPA's proposed Environmental Redispatch policy compromises wind owners' ability to satisfy forward contracts for the purchase or sale of RECs.

Commenters' Positions:
PSE states that the "proposed Environmental Redispatch Protocol would improperly displace generation from resources in BPA's Balancing Authority Area that generate RECs. The proposed Environmental Redispatch protocol would jeopardize existing strategies for meeting Renewable Portfolio Standard requirements and could impede the ability of affected utilities to satisfy Renewable Portfolio Standard obligations."[184] PSE goes on to state that "the proposed Environmental Redispatch Protocol could compromise the utilities' ability to satisfy obligations entered into under forward contracts for the purchase or sale of RECs."[185]

Evaluation of Positions:
The issue of overgeneration supply of combined wind and hydro resources in the BPA Balancing Authority Area during spring high water run-off periods is an issue that BPA has discussed with Pacific Northwest market participants since late 2008. All parties buying and selling power in the Pacific Northwest understand that Pacific Northwest hydro resources alone have periodically overwhelmed the amount of load and intertie export capability in the region. So it should be no surprise that when a substantial amount of new wind resources were added over the past five years, these non-dispatchable VERs would only add to this problem. The way that thermal resources respond to this issue is through rational economic displacement of their energy with lower cost surplus power. Due to production subsidies and RECs tied to specific resource production, VERs do not respond similarly.

[183] WREGIS Operating Rules at Section 9.3 (Dec. 2010) (available at http://www.wregis.org/uploads/files/854/WREGIS%20Operating%20Rules%20v%2012%209%2010.pdf).
[184] Comments of PSE at 9.
[185] Id.

BPA understands that VERs will not produce RECs during an Environmental Redispatch event. In order to minimize this risk, BPA will first redispatch thermal generation, and only redispatch VERs if additional relief is needed. Further, BPA is willing to work with Pacific Northwest VERs, REC purchasers, and surrounding States to enact legislation that would allow the continued ability to "count" or credit VERs' planned production when it is displaced by a host balancing authority attempting to operate consistent with environmental standards such as the CWA or ESA. BPA's proposed approach allows REC value and RPS standards to be unaffected while also allowing the balancing authority to meet applicable environmental criteria.

If legislative changes are not supported, then VERs interconnected with the BPA Balancing Authority will need to recognize and share some of the burden of interconnecting to an environmentally constrained run-of-the river hydro system. BPA cannot be the guarantor of state and Federal subsidies and contractual arrangements that are beyond BPA's control. Utilities that must meet RPS standards will have to evaluate the risk of potential shortfalls caused by BPA's Environmental Redispatch policy and hedge their REC strategy accordingly. As indicated previously, we will continue to work with parties in an effort to better quantify the likelihood of Environmental Redispatch.

Decision:
BPA will take all reasonable actions to avoid redispatching VERs, and will continue to support efforts at legislative changes.

J2: Issue: Whether existing PPAs do not allow for substitution of energy.

Commenters' Positions:
Iberdrola states that BPA's Environmental Redispatch policy is inconsistent with its PPAs that require "a time-based true-up of metered energy at a specific wind generator versus the delivered energy to the customer."[186] According to Iberdrola, purchasers under its contracts, including contracts between BPA and Iberdrola, pay for wind generation as measured at the generator's meter, and BPA's proposal to "replace" the energy from Iberdrola facilities will create "a disconnect between deliveries and metered output."[187] Iberdrola maintains that "not only would Bonneville's 'replacement policy' impact revenues associated with RECs and generation-based tax credits, the entire power purchase price arguably would be forfeited."[188]

Horizon states that "[m]ost renewable energy PPAs are facility-specific and do not allow sellers to substitute energy from a different resource. Federal hydropower likely would not be an acceptable substitute for PPA offtakers because the power would not come

[186] Comments of Iberdrola at 22.
[187] Id. at 23.
[188] Id.

from the same facility, and federal hydropower does not meet the requirements of applicable state [RPS]."[189] EnXco makes the same statement.[190]

Evaluation of Positions:
BPA is offering free energy to redispatched resources during Environmental Redispatch events to allow those resources to meet their commercial delivery obligations. BPA has no control over the specific contractual arrangements of generators in its Balancing Authority Area, and BPA is not the guarantor of those contractual arrangements. Nevertheless, the replacement of wind generators' scheduled energy with power from the FCRPS occurs frequently through generation imbalance when a wind generator cannot produce the amount of energy scheduled, and those generators have not made BPA aware that this replacement of energy required a seller to forfeit the "entire power purchase price" of an agreement.

Although BPA generally has no knowledge of the terms of the Iberdrola PPAs to which BPA is not a party, Iberdrola states that BPA purchases power from Iberdrola under agreements that provide for payment for wind generation as measured at the generator's meter. BPA understands that Environmental Redispatch may affect these contracts, but BPA cannot guarantee that the revenues from all contracts can be met at all times.

Finally, we would observe that Force Majeure provisions are standard in commercial contracts. Typically as well, just as with our interconnection and transmission contracts, they excuse performance on account of an order or restriction imposed by the government. BPA is part of the government and its orders resulting from this policy are to protect fish. Under the circumstances, we would surmise that curtailed generators may have a good basis to avoid contractual penalties or the like for nonperformance.

Decision:
BPA cannot comment on the terms of PPAs of which it has no knowledge or guarantee the results under those agreements. BPA has decided to apply Environmental Redispatch on a pro rata basis across all generators.

K. Reliability Issues

K1. Issue: Whether Environmental Redispatch complies with Western Electricity Coordinating Council ("WECC") and NERC e-tagging requirements.

Commenter's' Positions:
PSE comments that "BPA should modify e-Tags to identify accurately the generation source and contract path of the energy delivered during the environmental redispatch."[191] PSE lists five NERC Reliability Standards that it believes may be violated by

[189] Comments of Horizon at 8.
[190] Comments of enXco at 8.
[191] Comments of PSE at 20.

Environmental Redispatch: 1) INT-006-3, R1.2; 2) INT-001-WECC-CRT-2; 3) INT-003-2; 4) INT-004-2; and 5) INT-005-3. PSE believes that "[t]he potential mismatch between the source listed on the e-Tag and the actual source of the generation may create compliance problems with certain [NERC] and [WECC] reliability standards" and requests that BPA explain how Environmental Redispatch complies with these standards, without explaining itself how Environmental Redispatch would violate these standards.[192]

Powerex also raises issues with e-tagging requirements, stating that it "believes e-tags must be adjusted to appropriately show the source generation, consistent with NERC/WECC e-tagging requirements."[193]

Evaluation of Positions:
As will be specified in BPA's Business Practices, Environmental Redispatch will be an hour to hour evaluation, and Environmental Redispatch will only be triggered within the hour. All generators in BPA's Balancing Authority Area must submit schedules for next hour operations, as the conditions triggering Environmental Redispatch may be alleviated for the next hour and the generator will be required to meet its transmission schedules. Environmental Redispatch will be conducted similar to any other redispatch on BPA's system. Currently, under BPA's Redispatch and Curtailment Procedures Business Practice, BPA specifies that "Redispatch will not result in changes to the original e-Tags." BPA is unaware of any other practice that requires tags to be modified within the operating hour in order to redispatch generating resources to preserve reliability. In fact, to do so would be infeasible, as BPA is not the tag author and does not have the time or capability to modify the generating source. If BPA were required to modify all e-tags when redispatching generating resources, it would not have the ability to react in time to preserve the reliability of the system. All generation displaced before the next operating hour will be appropriately tagged and specify the FCRPS as the source.

Environmental Redispatch will comply with the NERC Reliability Standards cited by PSE. All of the standards cited by PSE involve transactions that involve one or more balancing authorities, generally referred to as an Interchange Transaction. [194] Generally, transactions between balancing authorities only need ensure that reliability is maintained and that flows between balancing authorities accurately reflect the transmission schedules, and do not concern the source of the generation. For example, an "Interchange Schedule" only requires specification of "[t]ransaction size (megawatts), start and end time, beginning and ending ramp times and rates, and type required for delivery and receipt of power and energy between the source and sink Balancing Authorities involved in the transaction." [195]

The first standard cited by PSE is INT-006-3, R1.2. This standard requires that each Transmission Service Provider "confirm that the transmission service arrangements

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[192] Id. at 20-21.
[193] Comments of Powerex at 2.
[194] The NERC Glossary defines an "Interchange Transaction" as an "agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries." NERC Glossary at 23.
[195] NERC Glossary at 23.

associated with the Arranged Interchange have adjacent Transmission Service Provider connectivity, are valid and prevailing transmission system limits will not be violated." The purpose of INT-006-3 is to "ensure that each Arranged Interchange is checked for reliability before it is implemented."[196] The standard requires "review of [of] proposed interchange transactions to ensure that transmission service is available and that system limits are not violated[.]"[197] When the tags are initially submitted by the generator, BPA ensures that transmission service is available and that system limits will not be violated. When Environmental Redispatch is triggered and BPA completes the interchange transaction with FCRPS energy, BPA is not reducing use of the underlying transmission service, but only limiting the generator associated with the transmission service. If Environmental Redispatch creates congestion issues within the hour, BPA will take all actions available to it to ensure that system limits will not be violated.

PSE next cites INT-001-WECC-CRT-2, which requires Transmission Providers to use e-Tags as the primary tool to communicate curtailments. BPA understands PSE as implying BPA is not alerting other parties to a curtailment because it is leaving the original e-Tag in place during Environmental Redispatch. Environmental Redispatch complies with this standard, however, because, again, BPA is not curtailing transmission service. BPA is ensuring that the transmission schedule is met by FCRPS energy.

Third, PSE cites to INT-003-2. The purpose of this standard is to "ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Area (ACE) equations." BPA reads PSE's concern as to whether the Interchange Schedule must properly reflect the source of the power. However, the definition of "Interchange Schedule," cited to above, makes no mention of source of the generation. Environmental Redispatch will not affect any other attributes of the schedule. For example, the substitution of FCPRS energy will ensure that the transaction size will remain the same.

Fourth, PSE cites to INT-004-2. This Reliability Standard requires that Dynamic Transfers be adequately tagged to determine their reliability impacts. Environmental Redispatch does not implicate this Reliability Standard. There are two requirements to this Standard. Requirement 1 concerns curtailments and reloading of dynamic schedules. As explained previously, Environmental Redispatch does not involve curtailments, so Requirement 1 is not applicable. Requirement 2 is a requirement for the Purchasing-Selling Entity to ensure tag accuracy. Since Environmental Redispatch will be an hour to hour assessment, BPA expects all entities to correctly tag their Dynamic Interchange Schedules according to this standard for the "next available scheduling hour and future hours[.]"

Finally, PSE cites to INT-005-3. The purpose statement of this Reliability Standard provides that "the implementation of Interchange between Source and Sink Balancing

[196] "Arranged Interchange" is defined by the NERC Glossary as "[t]he state where the Interchange Authority has received the interchange information (initial or revised)." NERC Glossary at 5.
[197] Revised Reliability Standards for Interchange Scheduling and Coordination, 129 FERC ¶ 61,223, P 17 (2009).

Authorities is distributed by an Interchange Authority such that Interchange information is available for reliability assessments." INT-005-3 applies only to Interchange Authorities. BPA is not an Interchange Authority, so BPA has no obligation to distribute Interchange information under this Reliability Standard.

Decision:
BPA will comply with the applicable NERC and WECC standards.

K2. Issue: Whether Environmental Redispatch would exacerbate voltage and stability.

Commenters' Positions:
PSE asserts that BPA's proposal creates system reliability issues in that the resulting "dramatic swings in generation (and the accompanying changes in points of delivery and receipt) could threaten the reliability of the transmission system and the ability to meet load."[198] Further, PSE questions "how dramatic swings in generation due to the proposed Environmental Redispatch Protocol and Negative Pricing Policy would exacerbate voltage and stability conditions on BPA's system and lead to further complications with ATC and DTC issues."[199]

PacifiCorp generally asserts that "BPA has not provided evidence that Environmental [R]edispatch will not adversely affect the reliability of the transmission system."[200]

Evaluation of Positions:
The magnitude of the change in generation patterns created by Environmental Redispatch is nothing new for BPA. BPA has experienced and accommodated ramps in the positive direction of wind in the magnitudes of 1580MW in 60 minutes, 1120MW in 30 minutes, 756MW in 10 minutes, and 492MW in 5 minutes. BPA has experienced and accommodated negative ramps of the wind in the magnitudes of -1161MW in 60 minutes, -937MW in 30 minutes, -734MW in 10 minutes, and -724MW in 5 minutes. BPA has routine morning pick-up ramps that exceed 2000MW. BPA has not experienced any reliability concerns with these variations in the wind and BPA's generation. Environmental Redispatch is expected to be near these levels, and BPA has the infrastructure to accommodate these changes in generation patterns.

In addition, BPA's Dispatchers will be constantly monitoring the Environmental Redispatch process. If a determination is made that Environmental Redispatch is creating safety or system reliability issues, BPA Dispatch has the authority and is required by Reliability Standards to take necessary actions to ensure system reliability. Environmental Redispatch does not supplement the requirement to maintain a safe and reliable power system. Dispatch will not require plant operators to make sudden changes which could impact the integrity of the project. The project operators will be allowed to

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[198] Comments of PSE at 8.
[199] Id.
[200] Comments of PacifiCorp at 4.

move the generation output to required levels using plant ramping capabilities as determined by the plant operator. BPA will be proactive in identifying environmental concerns in advance to minimize any in-hour Environmental Redispatch needs. BPA's Automatic Generation Control system will automatically balance generation to load thus maintaining reliable Interconnection Frequency. For voltage collapse concerns, BPA Dispatchers continuously monitor voltage levels and reactive reserve requirements. BPA will work with neighboring Transmission Operators if voltage concerns are experienced. System reliability is paramount and BPA will not enact Environmental Redispatch if a determination is made that there will be negative impacts to reliability.

Decision:
Environmental Redispatch is not expected to create reliability issues. BPA will monitor the effects on the system of Environmental Redispatch actions and will modify or terminate the proposed protocol if there are negative impacts to system reliability.

K3. Issue: Whether Environmental Redispatch will create transmission congestion.

Commenters' Positions:
Snohomish County PUD is concerned that "transmission congestion could be created as generating patterns change when Environmental Re-Dispatch is implemented."[201]

PGE asserts that "transmission curtailments are also likely if the use of replacement generation causes energy to flow over constrained paths."[202]
Powerex made similar comments, stating that "large scale redispatch may cause congestion and result in the inappropriate curtailment of schedules flowing through BPA's [Balancing Authority Area]."[203]

Evaluation of Positions:
As stated previously, the magnitude of the changes in generation patterns that could be created by Environmental Redispatch is nothing new for BPA. BPA has experienced such changes in generation patterns in the past, and has not run into significant issues with transmission congestion.

Further, BPA's Dispatchers will be constantly monitoring the Environmental Redispatch process. In a declared Environmental Redispatch event, BPA dispatchers will monitor any increased transmission congestion to paths/flowgates internal and external to the FCRTS. If Environmental Redispatch will create transmission path congestion, BPA will take all necessary actions to ensure system reliability, including excluding certain generators, whether thermal, hydro, or VER, from Environmental Redispatch because of the location of the generator. Reduction in the output of generators in real time could cause a violation of System Operating Limits ("SOL") or create system stability issues,

[201] Comments of Snohomish at 2.
[202] Comments of PGE at 1.
[203] Comments of Powerex at 2.

such as voltage collapse, because the reduction in output could lead to increased flows in the negative direction of the path or flowgate based on the generator's location, regardless of generation type. In addition, if transmission path congestion occurs that leads to a SOL exceedance, BPA will take all necessary actions to reduce generation affecting the path, Federal or non-federal, in order to ensure flows are within SOLs.

Decision:
Environmental Redispatch is not expected to create transmission congestion issues. If Environmental Redispatch actions create or could create transmission congestion issues, BPA will use established processes and modify or suspend the Environmental Redispatch protocol to address these issues.

L. National Environmental Policy Act ("NEPA") Issues

L1. Issue: Whether BPA's Environmental Redispatch policy and the accompanying Business Practices trigger the need to complete an environmental impact statement or environmental assessment to comply with NEPA.

Commenters' Positions:

Charles Pace, Ph.d, appears to suggest that integrating wind projects into the grid and Environmental Redispatch make "irreversible and irretrievable commitments of its power marketing and transmission assets."[204] He also claims that "excessive generation and spill in November and December of 2010 was devastating for [listed chum salmon] spawning downstream from the Bonneville Project." Mr. Pace's last concern was that those operations affected other species "includ[ing] listed species of Pacific salmonids and white sturgeon."[205] Overall, Mr. Pace believes that BPA's proposal constitutes a major federal action and requires preparation of an Environmental Impact Statement ("EIS"). Iberdrola notes that it "considers the Draft ROD to be a cost issue, and not an environmental issue," and that "if Bonneville does in fact believe its proposal is an environmental issue, it should conduct the required NEPA review."[206]

Evaluation of Positions:
In implementing the policy and business principles, BPA will manage the FCRPS within existing operating constraints. The following documents explain those parameters:

- NOAA Fisheries' 2008 FCRPS BiOp[207] and its 2010 supplemental BiOp[208]

[204] Comments of Charles Pace at 7.
[205] *Id.* at 6 note 6.
[206] Comments of Iberdrola at 24.
[207] https://pcts.nmfs.noaa.gov/pls/pcts-pub/pcts_upload.summary_list_biop?p_id=27149
[208] https://pcts.nmfs.noaa.gov/pls/pcts-pub/sxn7.pcts_upload.download?p_file=F25013/201002096_FCRPS Supplemental_2010_05-20.pdf BPA also has coverage in the Adaptive Management Implementation Plan that was incorporated into the supplemental BiOp.
http://www.salmonrecovery.gov/Files/BiologicalOpinions/AMIP_09%2010%2009.pdf

- BPA's RODs adopting the 2008 BiOp[209] and 2010 supplemental BiOp[210]
- Columbia River System Operations EIS (Nov. 1995) and Record of Decision (Feb. 21, 1997)

In the NEPA discussion contained in this Final ROD and the Categorical Exclusion attached to it, BPA has shown that the redispatch policy would not change current status quo hydrosystem operations within existing constraints and in compliance with existing NEPA records of decision, ESA biological opinions, and CWA water quality standards.[211]

BPA has examined the environmental effects of integrating wind projects into the transmission grid in the following NEPA documents:

- Whistling Ridge Environmental Impact Statement[212]
- Leaning Juniper II - Jones Canyon Substation Expansion Wind Interconnection Project Record of Decision[213]
- Electrical Interconnection of the Golden Hills Wind Project Record of Decision[214]
- Electrical Interconnection of the Kittitas Valley Wind Farm Record of Decision[215]
- Lower Snake River Wind Energy Project Record of Decision [216]
- Juniper Canyon I Wind Project Record of Decision[217]

These NEPA documents have already discussed the reasonably foreseeable high wind/high water effects on fish and water quality, as well as measures—such as instructing wind projects to reduce their generation to specified levels for ESA and CWA compliance—that BPA is taking to reduce or avoid the cumulative impact of wind project overgeneration on hydrosystem operations for fish. When the potential for high water/high wind events was understood, BPA considered and reconsidered the site specific and cumulative effects of wind integration and the system operations needed to integrate the new generators. Consistent with this NEPA analysis, Environmental Redispatch is now necessary to ensure compliance with BPA's environmental responsibilities.

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209 http://www.bpa.gov/corporate/pubs/RODS/2008/BPA_ROD_to_Implement_2008_FCRPS_BiOp_RPA.pdf

210 http://www.salmonrecovery.gov/Files/2010%20BPA%20ROD%20following%20the%202010%20Supplemental%20BIOp.pdf

211 Infra at § VI.

212 http://efw.bpa.gov/environmental_services/Document_Library/Whistling_Ridge/WR_DEIS_Chapter3.pdf at pages 3-276 to 3-278 (2008)

213 http://efw.bpa.gov/environmental_services/Document_Library/Leaning_Juniper/FinalLeaningJuniperIITieredROD2.pdf at 24-26 (April 9, 2009)

214 http://www.bpa.gov/corporate/pubs/RODS/2009/Golden_Hills_Wind_ROD.pdf at 21-23 (Aug. 13, 2009)

215 http://www.bpa.gov/corporate/pubs/RODS/2009/KittitasValleyWindFinalROD090409.pdf at 24-26 (Sept. 4, 2009)

216 http://efw.bpa.gov/environmental_services/Document_Library/Central_Ferry_Substation_Project/CFS_LowerSnakeRiverWindEnergyROD.pdf at 26-28 (January 28, 2010)

217 http://www.bpa.gov/corporate/pubs/RODS/2010/JuniperCanyon_I_WindEnergyROD-5-10-2010.pdf at 20-22 (May 10, 2010)

Regarding Mr. Pace's comments about the effects of high water on fish, NOAA Fisheries' chum salmon spawning survey crews did not report any damage to chum redds or other fish or fish habitat during high water events in late 2010.[218] A BPA fish biologist who accompanied the survey team noted that "there were no unusual impacts. Flows were only in the 200 kcfs range in a stretch of the river that probably needs 800 kcfs or greater to see any bed movement."[219] Beyond his observations on chum salmon, the statements that Mr. Pace made about adverse effects to other kinds of fish lacked enough detail to evaluate. These facts neither substantiate Mr. Pace's personal observations regarding potential new information or changed circumstances nor his conclusions concerning the effects of high water and hydrosystem operations on Columbia River salmon.

Turning to Iberdrola's statement about the nature of BPA's decision, this policy and Business Practices simply explain how BPA will operate the FCRPS within existing FCRPS operating parameters to protect fish. This policy and Business Practices do not propose operational changes that may adversely effect the environment, and so Iberdrola appears correct insofar as it argues that the economic effects of BPA's decision do not trigger the need for further NEPA review.

Finally, a review of the actions to be taken under BPA's Environmental Redispatch policy and practices shows that they either do not trigger NEPA compliance or have already been reviewed in previous NEPA documents. The policy and business practices have three main components.

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- An operational component—to protect fish by complying with the BiOp and current CWA water quality standards and ramping down wind as a last resort.
- A financial component—the decision to not pay negative pricing.
- A contractual component—the decision to unilaterally amend the LGIAs to clarify BPA's authority to implement environmental redispatch.

The first component and its potential cumulative fish impacts have been addressed in NEPA documents for previous wind interconnections, as discussed above. The second component identifies an administrative action related to finances that does not have environmental effects, and thus does not require NEPA compliance. The third component is an administrative, contractual clarification action that does not by itself have any environmental effects; and to the extent that this action suggests cumulative fish impacts, BPA considered those already.

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[218] Columbia River Regional Forum Technical Management Team, conference call notes (Dec. 22, 2010) ("A December 17 survey documented the effects of higher flows and runoff below Bonneville. In response to unexpected precipitation and high flows, there was a decision to maintain an around-the-clock operation of 18.5 feet for 48 hours or longer, while acknowledging the risk that chum might spawn at higher elevations during that time. The December 17 survey, however, found no evidence that spawning occurred at high elevations.") http://www.nwd-wc.usace.army.mil/tmt/agendas/2010/1222_Minutes.pdf

[219] Email from Scott Bettin, BPA biologist, to Philip Key, BPA attorney (Apr. 5, 2011) on file at BPA.

Decision:
None of the comments received identified a single potentially significant environmental effect from the proposal. BPA believes that this proposal fits within one of the classes of actions that are categorically excluded from further NEPA compliance.[220] *BPA has documented this consideration in a Categorical Exclusion under NEPA that accompanies this decision. Adopting the Environmental Redispatch Policy and Business Practices does not trigger the need for an environmental assessment or EIS.*

L2. Issue: Whether BPA's Environmental Redispatch Policy decision increases hydrosystem operations that expose Native American gravesites, funerary objects, and other sacred objects.

Commenter's Position:
Donald Kieffer notes that Grand Coulee is a wind balancing resource and those operations expose gravesites, funerary objects, sacred objects, etc.[221] He states that wind integration has severe impacts on Native Americans in and around Grand Coulee and adverse effects on fish, water quality, and shoreline vegetation. Therefore, he requests consultation regarding the proper disposition of human remains, and other materials, as appropriate.

Evaluation of Positions:
Under the policy BPA would continue managing the FCRPS with the Bureau of Reclamation and the Army Corps of Engineers within existing operating constraints which have been examined for environmental effects to Native Americans already.[222] BPA will continue to comply with the System Operation Review EIS and ROD, including funding and participating in the FCRPS Cultural Resources Program to properly address human remains and artifacts as provided in federal statutes.

Decision:
BPA will continue to fund the Spokane Tribe, the Confederated Colville Tribes, as well as many others to help implement the FCRPS Cultural Resource program and Columbia River Fish and Wildlife Program to appropriately address these important tribal resources.

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[220] 10 CFR 1021.410, Appendix B to Subpart D, B4.1.
[221] Comments of Donald G. Kieffer at 1.
[222] *See generally*, Columbia River System Operations EIS (Nov. 1995), Appendix D Cultural Resources, and Record of Decision (Feb. 21, 1997).

M. Public Process

M1. Issue: Whether BPA should establish an on-going process for reviewing Overgeneration occurrences and current and past practices, and maintaining regional coordination.

Commenters' Position:
WPAG indicates that BPA should include "a commitment to a yearly meeting with its customers to discuss the environmental redispatch policy and associated protocols."[223]

Evaluation of Positions:
BPA agrees that regional coordination is needed on an on-going basis as overgeneration conditions and possible Environmental Redispatch issues are being confronted. BPA is in the process of developing a regular series of meetings to review recent system conditions including loads, export capability, and the full spectrum of resource types operating in the region.

Decision:
BPA will host a regional forum for reviewing potential and actual Overgeneration and Environmental Redispatch events. Additional meetings will be held on an as-needed basis.

M2. Issue: Whether BPA should postpone issuing the currently proposed policy and convene a regional forum.

Commenters' Position:
Save Our Wild Salmon "urges BPA to withdraw this misguided proposal and focus on real solutions to the problem."[224]

Community Renewable Energy Association urges "BPA to abandon their proposed discriminatory policy and convene a series of regional workshops to reach a conclusion where all generators in the Northwest share proportional reductions…"[225]

Nextera Energy and Vestas Americas "encourage[] the BPA to postpone finalizing the ROD..."[226]

EnXco states that "[g]iven the large number of practical and cost-effective alternatives to Bonneville's proposal, enXco believes that Bonneville must do more to work with the region to develop an equitable and durable framework…"[227]

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[223] Comments of WPAG at 6.
[224] Comments of Save Our Wild Salmon at 4.
[225] Comments of Community Renewable Energy Association at 1.
[226] Comments of NextEra Energy at 1; Comments of Vestas Americas at 1.
[227] Comments of enXco at 12.

The Northwest Energy Coalition "urges BPA to abandon formal adoption of the Draft ROD and instead seek clarity by committing to a cooperative regional effort…"[228]

Evaluation of Positions:
BPA agrees that it will be necessary to continue to work with regional stakeholders on long-term solutions to overgeneration events in the Pacific Northwest, but BPA believes that an Environmental Redispatch Policy is necessary at this time to establish protocols to deal with overgeneration events that may occur this spring. BPA intends to initiate regional discussions on issues related to the Environmental Redispatch Policy, and BPA looks forward to working with stakeholders in that forum.

Decision:
BPA is moving forward with the Environmental Redispatch and Negative Pricing Policies in this Final ROD on an interim basis, but BPA agrees that an ongoing regional forum is needed and will be defining and implementing that process immediately.

N. Actions Taken Prior to Triggering Environmental Redispatch

N1. Issue: Whether BPA should defer some "reasonable actions" and go straight to Environmental Redispatch to avoid the costs of actions taken to avoid Environmental Redispatch.

Commenters' Position:
PPC states that that BPA should pursue the options for avoiding Environmental Redispatch "as time and conditions allow but 'reasonable' actions should balance effectiveness and cost in taking an option."[229]

WPAG proposes that BPA should assess the costs or losses associated with BPA actions to forestall or eliminate the need for Environmental Redispatch within the next twelve months and balance the costs of BPA preemptive actions against any financial exposure to non-federal generation that is redispatched in accordance with the Environmental Redispatch policy.[230]

Evaluation of Positions:
Although WPAG and PPC do not define the cost or losses relative to BPA actions addressed in their comments, BPA does not expect that actions taken to avoid Environmental Redispatch will result in unreasonable net costs to the Agency. WPAG's primary concern appears to be the financial impacts on Agency revenues from more frequent conditions where the value of energy is low or zero.

[228] Comments of the Northwest Energy Coalition at 2.
[229] Comments of PPC at 2.
[230] Comments of WPAG at 3.

In the marketplace there are various resource types, each with their own operational characteristics and variable operating costs. As long as resources have the flexibility to operate or not operate they can be willing buyers and sellers of energy and that may result in a lower market price for energy or FCRPS spill consistent with BPA non-power operations. BPA's Environmental Redispatch and Negative Pricing Policies are directed more narrowly at periods when FCRPS generation does not have the flexibility to cease generating electricity. Under those conditions, the marketplace is not an effective solution because BPA would be compelled to accept the demands of the buyer since BPA cannot reliably generate in excess of load. However, when there is available load that could be served with FCRPS generation, BPA is expected to operate consistent with its environmental responsibilities.

Decision:
BPA does not believe that its actions to avoid Environmental Redispatch expose the agency to unreasonable costs and will only take those actions that are reasonable under the specific circumstances.

N2. Issue: Whether BPA should consider the facts and conditions known at the time to determine the reasonable actions to take prior to implementing Environmental Redispatch.

Commenters' Position:
WPAG suggests that BPA should evaluate the actions that it would take to avoid Environmental Redispatch based on the conditions at the time and only implement those actions that are reasonable for the conditions.[231] Springfield Utility Board also offers that the actions BPA proposes to avoid Environmental Redispatch should be non-exclusive and non-prescriptive.[232] PPC states that options to manage TDG prior to Environmental Redispatch should be pursued as time and conditions allow, but effectiveness should be considered.[233]

Evaluation of Positions:
BPA's objective with respect to the actions it proposes to take before implementing Environmental Redispatch is to manage TDG levels consistent with the Clean Water Act when those actions can be reasonably implemented. BPA takes this objective seriously, and this objective existed prior to the policies in this ROD. BPA agrees that it should consider conditions at the time when implementing actions to avoid Environmental Redispatch. BPA may encounter conditions that make certain actions ineffective or even counterproductive to achieving the objective described above. There are often considerable uncertainties in the operation of the FCRPS where an action can be helpful under one potential outcome and harmful under another. BPA must often make decisions based on a large range of potential outcomes and attempt to balance multiple risks to the operation. Certain actions could conflict with electric reliability or non-power objectives

231 Comments of WPAG at 3.
232 Comments of the Springfield Utility Board at 5.
233 Comments of PPC at 2.

unrelated to TDG management under certain circumstances. BPA must evaluate all these risks in implementing an action. BPA does not view the actions it proposes to take prior to implementing Environmental Redispatch as mandatory.

Decision:
BPA will consider the facts and conditions known at the time when implementing actions prior to implementing Environmental Redispatch.

O. Miscellaneous Issues

O1. Issue: Does the Environmental Redispatch policy have unintended consequences on the long-term Regional Dialogue contracts?

Commenters' Position:
PPC states that "BPA should ensure there are no unintended consequences to requirements customers from the interaction between this policy and long-term Regional Dialogue contracts."[234]

Evaluation of Position:
Under the Regional Dialogue contracts between BPA and its preference customers, the customers may choose to procure power either from BPA or procure the power from non-federal resources to serve load growth. It is probable that some of the non-Federal generation resources that preference customers choose to develop or contract with will be impacted by Environmental Redispatch. This should have no effect on the requirements and obligations in the Regional Dialogue contract. During the Environmental Redispatch the preference customer's non-Federal resource will be replaced by zero cost Federal power and for purposes of the Regional Dialogue contract the power will be treated as if it were generated by the preference customer's non-Federal resource.

Decision:
BPA does not believe the Environmental Redispatch and Negative Pricing ROD will have any impact on BPA's Long-Term Regional Dialogue contracts.

O2. Issue: How BPA should document the reasons for and the steps taken prior to an Environmental Redispatch event.

Commenter's Position:
PNGC suggests that BPA should explain in detail the list of steps it will take before each Environmental Redispatch, and carefully document the reasons for and the steps taken prior to each individual Environmental Redispatch event. PNGC believes these steps will better protect the agency from after-the-fact challenges from third party generators or from others following an Environmental Redispatch event.[235]

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[234] Comments of PPC at 2.
[235] Comments of PNGC at 5; See also Comments of NRU at 3.

Evaluation of Position:
In the policy section of this Final ROD, BPA has described the conditions that would lead to an Environmental Redispatch event and steps that BPA will take prior to implementing Environmental Redispatch.[236] In the Business Practices, BPA has detailed the process for implementing an Environmental Redispatch.[237]
Following the June 2010 high water event, BPA developed a comprehensive report on the conditions that BPA faced and the steps that were taken by BPA during the event.[238] This report was used to kick off the process that led to this ROD. Based on the experience of last June and the development of the comprehensive report associated with that event, BPA anticipates that it will carefully document the conditions and steps taken prior to and during an Environmental Redispatch event.

Decision:
BPA expects to document the conditions and operational steps prior to and during an Environmental Redispatch event. BPA agrees with PNGC's comment.

O3. Issue: Whether BPA should consider Sea Breeze's Juan de Fuca project as a solution for an overgeneration events.

Commenters' Position:
Sea Breeze Pacific Regional Transmission Systems Inc. ("Sea Breeze") suggests that BPA's final ROD include "efforts to increase intertie capacity to Canada, also, for the reasons that it is the least costly near-term solution and British Columbia is in an overall energy supply deficit situation…"[239]

Evaluation of Position:
Transmission infrastructure improvements, like those suggested by Sea Breeze, are likely to have significant costs and lead times. As a result, such improvements are unlikely to resolve the overgeneration issues that BPA must confront in the short-term. Nevertheless, BPA will continue to consider such long-term opportunities to address or prevent occurrences of overgeneration.

Decision
BPA will continue to consider long-term solutions to overgeneration situations in BPA's Balancing Authority Area.

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[236] Supra, Section III.A.
[237] Environmental Redispatch Business Practice, Version 1 (Mar. 18, 2011) (available at http://transmission.bpa.gov/ts_business_practices/Content/PDF_files/Env_Redispatch_V1_4.pdf).
[238] Columbia River High Water Operations [June 1-14, 2010] (Sept. 2010) (available at http://www.bpa.gov/corporate/pubs/final-report-columbia-river-high-water-operations.pdf).
[239] Comments of Sea Breeze at 2.

O4. Issue: Whether energy storage capacity can address overgeneration issues.

Commenters' Positions:
Wild River Consulting/Symbiotics proposed "an alternative strategy for incorporating renewable energy when it exceeds the capacity of the current system." They indicate they are "in the licensing process for two large closed-loop pumped storage (CLPS) hydroelectric projects… with the potential to aid wind integration in the [western interconnection], support BPA, and reduce curtailment."[240]

David Galle, a Mason County PUD #1 customer, states that "our real issue is not overgeneration, but instead the lack of capability to store energy."[241]

Mark Crossler supported the use of a "battery back-up system" to absorb excess power.[242]

Evaluation of Positions:
Energy storage is outside the scope of this policy; however, it is a technology that BPA and others in the region are evaluating. As the region continues to adjust the resource mix to meet future needs and accommodate policy objectives storage may be necessary to address overgeneration and to provide the dispatch flexibility necessary to respond to increased operational uncertainty. Some of these technologies are available today and some are at the demonstration stage. However, they are not options for addressing overgeneration at this time given the necessary lead time for these technologies and the cost of development and implementation.

Decision:
Energy storage is outside the scope of this policy; however, BPA will continue to explore new solutions to this problem.

O5. Issue: Whether BPA will apply penalties for failure to comply with Environmental Redispatch orders.

Commenters' Positions:
Springfield Utility Board comments that "BPA must impose a financial penalty for those resource operators that fail to curtail during an Environmental Redispatch directive from BPA."[243]

Evaluation of Positions:
As specified in the Business Practices, an order to reduce generation under Environmental Redispatch will be a Dispatch Order that is subject to BPA's Failure to Comply Penalty Charge (FTC) under Section II.B of BPA's Transmission Services General Rate Schedule Provisions. Under the FTC, the "[f]ailure of a generator in the

[240] Comments of Symbiotics at 1.
[241] Comments of Galle at 1.
[242] Comments of Crossler at 1.
[243] Comments of SUB at 6.

BPA [Balancing Authority Area] or which directly interconnects to the FCRTS to change or limit generation levels" will be subject to the FTC. Currently, the FTC is 1000 mills per kilowatthour ($1000 MWh), and is calculated based on the amount of kilowatthours that were not redispatched pursuant to the Dispatch Order.

Decision:

BPA will apply the FTC to generators that fail to comply with BPA's Dispatch Orders to limit generation for Environmental Redispatch.

VI. ENVIRONMENTAL EFFECTS

BPA is proposing to implement an interim policy and Business Practice focusing on Environmental Redispatch and Negative Pricing. The proposal describes the methods that the agency will use during times of high water to protect natural resources and comply with the CWA and the ESA while meeting BPA's fiscal, statutory, and contractual obligations. As described elsewhere in this Final ROD, the contractual amendments that BPA will be implementing simply clarify existing contractual rights, the operational procedures to be implemented are intended to avoid environmental effects, and the decision to not pay negative energy prices is primarily a financial and administrative decision. After closely examining these and other aspects of the proposal, BPA has determined that there are no direct environmental effects associated with the proposal; to the extent that any potential indirect environmental effects arguably can be traced to the proposal, these effects have already been previously considered by BPA.[244] Furthermore, the proposal falls within a class of actions categorically excluded from further NEPA review pursuant to applicable NEPA regulations. Accordingly, BPA has prepared an Environmental Clearance Memorandum for the interim policy and Business Practice that considers environmental implications of the proposal and documents the categorical exclusion of the proposal from further NEPA review.[245]

[244] BPA has observed that during periods of high water and excess generation there is a risk that total dissolved gases may exceed allowable levels safe for fish listed under the Endangered Species Act. BPA has previously discussed the environmental impacts of these conditions – conditions which have existed prior to the implementation of the policies in this ROD. See, for example, Record of Decision for the Electrical Interconnection of the Juniper Canyon I Wind Project, May 2010, p. 20 (and other RODs related to the interconnection of wind projects).

[245] This memorandum is at http://efw.bpa.gov/environmental_services/categoricalexclusions.aspx. BPA has addressed NEPA-related and other environmental issues related to this proposal that were raised during the public comment period in its response to comments on the draft policy and principles.

VII. CONCLUSION

After consideration of all public comments, BPA will adopt the Environmental Redispatch and Negative Pricing Policies described in this Final ROD on an interim basis in order to meet BPA's environmental and legal responsibilities, and to provide needed options to maintain system reliability. This Final ROD will take effect upon execution by the Administrator and remain in effect until March 30, 2012. BPA has multiple competing environmental, statutory, and reliability responsibilities, and the Final ROD strikes a reasonable balance between those responsibilities while BPA explores alternative solutions to this problem.

Issued in Portland, Oregon.

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Stephen J. Wright Bonneville Power Administration Administrator and Chief Executive Officer	Date

BONNEVILLE POWER ADMINISTRATION

DOE/BP-4288 ▪ May 2011

ATTACHMENT B

Affidavit of Jason C. Sweet

EXHIBITS TO SWEET AFFIDAVIT

Order Approving U.S. Army Corps of Engineer's Request for Waiver to the State's TDG Water Quality Standard, June 24, 2009

Waiver Letter from Washington DOE to U.S. Army Corps of Engineer's, June 30, 2010

Order for 2011 Spring Operations

Order for 2011 Summer Operations

Joint Oregon and Washington AMT Total Dissolved Gas Report in the Columbia and Snake Rivers, January 2009

Verbatim Report of Proceedings,
Washington Superior Court No. 10-2-01236-0, May 20, 2011

Findings of Fact, Conclusion of Law, and Order Denying Relief,
Washington Superior Court, June 13, 2011, No. 10-2-01236-0

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.;	)	
	)	
PacifiCorp;	)	
	)	
NextEra Energy Resources, LLC;	)	
	)	
Invenergy Wind North America LLC;	)	
and	)	Docket No. EL11-44-000
Horizon Wind Energy LLC,	)	
	)	
Petitioners,	)	
	)	
v.	)	
	)	
Bonneville Power Administration,	)	
	)	
Respondent.	)	
	)	

AFFIDAVIT OF JASON C. SWEET IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

1. My name is Jason C. Sweet. My business address is 905 N.E. 11th Avenue – KEWR-4, P.O. Box 3621, Portland, OR 97208-3621. I am a Fishery Biologist for the Bonneville Power Administration ("BPA"), currently serving as a Policy Analyst and Technical Lead on fish-passage related issues on the Federal Columbia River Power System ("FCRPS") as part of BPA's Division of Environment, Fish, and Wildlife. I have been in this position since December 21, 2008. My primary duties include providing technical as well as strategic guidance and direction to projects, directed at improving dam and reservoir survival of fish in an effort to allow BPA and its fellow federal action agencies to meet the requirements laid out in the 2008/2010 FCRPS Biological Opinion. Prior to the promotion to my current position, I served as a fish biologist in the same division at BPA from October 31, 2005 through December 2008 working primarily on mainstem Columbia River and Snake River fish passage issues. As such, I

have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's Answer.

2. Previously I worked for a private consulting company (Hydroacoustic Technology Inc.) as a Fishery Biologist. Among other projects, my primary duties were as a team leader tasked with measuring salmon and steelhead survival past Chelan County Public Utility Districts' two Federal Energy Regulatory Commission ("FERC") licensed projects, Rocky Reach and Rock Island Dams on the Columbia River in north-central Washington State. As part of a team along with the project manager and other biologists, I was responsible for the installation and removal of our research equipment, collecting and analyzing data, as well as assisting with the reporting of results. I was also responsible for supervising the day-to-day activities and performance of a crew of twenty (20) seasonal research technicians.

3. Between August 2000, and January 2003, I worked as a research technician at the Univerisity of Washington- School of Aquatics and Fisheries Science's Fisheries Acoustics Laboratory. My primary duty in this role involved assisting various research projects to determine the effect of a fish's swimbladder size and shape on its acoustic signature. The intent of this research was to develop a method that would allow a fish to be intentified at species level (e.g. salmon vs. bass) based on sound alone.

4. I earned a Bachelor of Science in Fisheries degree, with a minor in Wildlife Science, from the University of Washington in Seattle, Washington in 1999.

Overview of Total Dissolved Gas

5. BPA is required to protect, mitigate, and enhance fish and wildlife, including spawning grounds and habitat, of the Columbia River and its tributaries (16 U.S.C. § 839(6)). Total Dissolved Gas ("TDG") supersaturation is a known source of both lethal, and sub-lethal effects on not only Endangered Species Act ("ESA") listed salmon and steelhead but a wide variety of other aquatic life as well (e.g. amphibians such as frogs and their tadpoles, freshwater mollusks,

crustaceans such as crayfish, aquatic insects, zooplankton, and phytoplankton). Dissolved gas levels (primarily oxygen, nitrogen, carbon dioxide, argon, and other trace elements) generally remain near equilibrium with the air surface (near 100% TDG), but can sometimes become supersaturated, even in unmodified streams and rivers. Examples of natural sources of elevated TDG include waterfalls, large rapids, or even warming water temperatures during the spring. In modified systems such as the Columbia and Snake Rivers with their large hydropower dams, water passing over the spillways into the tailrace is the largest source of TDG on the river.

6. When TDG levels exceed equilibrium and become supersaturated, the potential for aquatic organisms to develop gas bubble disease ("GBD") or gas bubble trauma ("GBT") increases. GBD and GBT are used synonymously in the total dissolved gas literature even though clinically, "disease" and "trauma" have different connotations. The term GBT has seemed to gain regional preference lately, so this declaration will use that notation.

7. As the term suggests, GBT occurs when small bubbles develop within the tissue of an organism. These bubbles can form in a wide variety of organs and tissues, but are most commonly observed in the fins, eyes, and gills, and lateral lines of fish. These bubbles can block the flow of blood if they occur in small capillaries and can also cause physical tissue damage, especially noticeable in the fins. Gas bubbles in the lateral lines can cause disorientation in the fish which could lead to an inability to sense and avoid predators. Gas bubble trauma can cause chronic, but sub-lethal responses, or the effects can be lethal depending on TDG levels and the severity of the resulting GBT. While GBT is not always fatal, and the observation of bubbles in a fish does not imply that death is imminent, GBT is a sign that water quality in the river is poor due to elevated total dissolved gas levels. Even though the occurrence of GBT does not always cause 100% mortality, fish can succumb to the effects of GBT even when bubbles are not observed in the fins, lateral lines, or eyes (gas bubbles in the gills are nearly always fatal). As the levels of TDG increase, the incidence and severity of GBT also increase (see Figure 1).

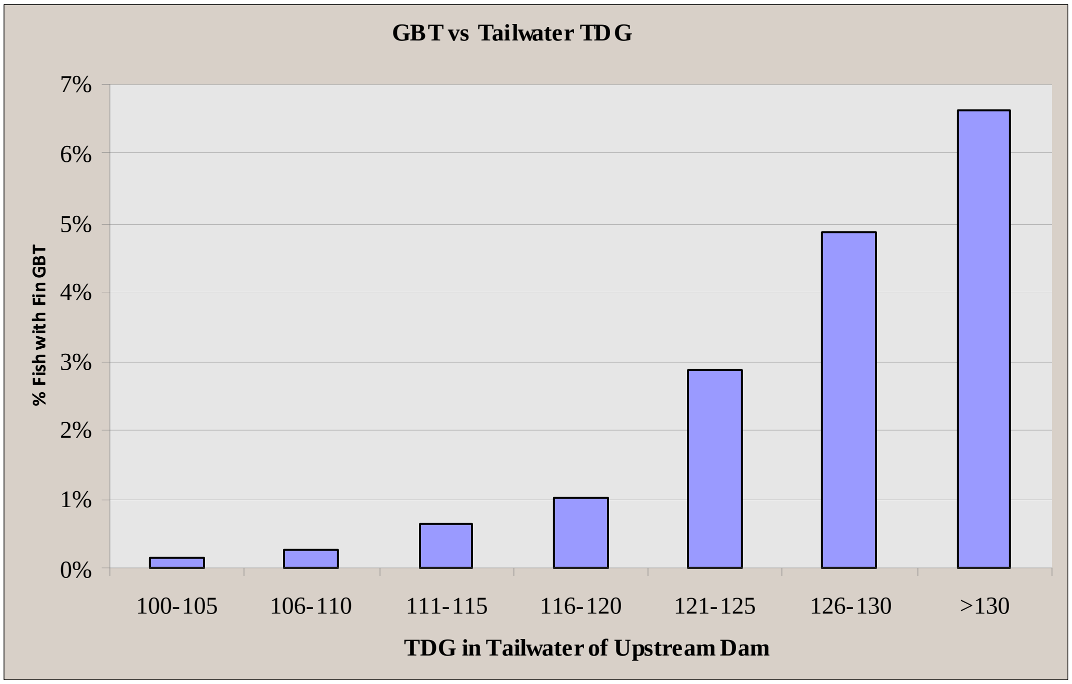

Figure 1. Gas Bubble Trauma increases related to TDG exposure. (From Washington DOE and Oregon DEQ Joint Adaptive Management Team report 2009).

8. The severity of GBT is related to the length of exposure, but even more important is the depth of the water that the fish is swimming in. The effects of TDG and the resulting GBT are greatly reduced if the fish has access to deep water. This effect is known as depth compensation (see Figure 2). For each meter (3.3 ft) of depth above the fish, the effects of TDG are reduced by 10%. In other words, if TDG levels are 120% at the surface and a fish is swimming one meter (1m) deep, the TDG is effectively 110% and similarly, if the fish is two meters (2m) deep, the effects of the TDG levels would be 100%. As shown in figure 2, this relationship is linear and would continue through deeper waters, so that even if gas levels were at 130% or 140%, as long as suitable depth is available and the fish are present at that depth, then the effects of the TDG would be reduced.

9. Although the effects of TDG are reduced as depth increases, the ability for aquatic animals to sense high TDG levels and actively move into deeper water, or to seek other areas

with lower TDG concentrations is limited (Weitkamp, 2008)[1]. That is, if a fish moves throughout different parts of the water column as part of its natural movement like a salmon smolt, then some level of depth compensation is likely afforded, at least for part of the day. But if an animal has a preferred depth or a narrow range of suitable habitat, it is unlikely that the animal would move to a deeper depth or different part of the river solely in response to high TDG levels.

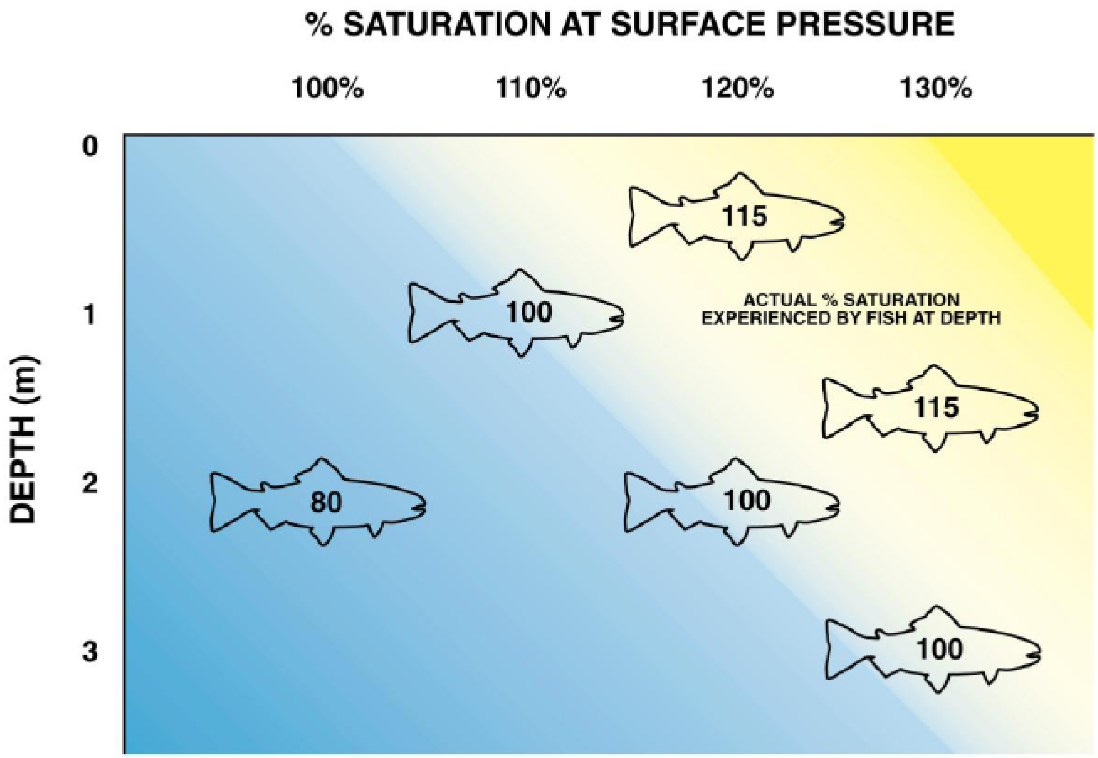

Figure 2. Example of Depth Compensation. (Weitkamp et al., 2003)[2]

10. The federal agencies in charge with managing the dams on the FCRPS operate the system taking reasonable actions available to keep TDG levels consistent with state water quality standards set forth by the State of Washington and the State of Oregon. In all rivers in Washington, Idaho, and Oregon, the current allowable standard for TDG is 110%. The 110%

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[1] Weitkamp, D.E. 2008. Total Dissolved Gas Supersaturation Biological Effects, Review of Literature 1980-2007 Prepared for WDOE and OR DEQ Adaptive Management Team. Available at: http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html

[2] Weitkamp, D.E., R.D. Sullivan, T. Swant, and J. DosSantos. 2003. Behavior of Resident Fish Relative to TDG Supersaturation in the Lower Clark Fork River. Transactions of the American Fisheries Society 132:856-864.

criterion was developed in the 1970's by the EPA during the development of the Clean Water Act and applies nationwide except as modified by any waiver in force at the time issued by states or entities with delegated authority. The state of Oregon also has a shallow water criterion that limits TDG to 105% in hatchery receiving waters and other water of less than two feet in depth. Similarly, British Columbia has a shallow water criterion of 103%.

11. The State of Oregon has provided a waiver, and the State of Washington has provided an exemption specific to the Columbia and Snake Rivers that allow the federal agencies to spill water up to 120% TDG in the tailrace of the dams during the period of juvenile salmon and steelhead migration through the rivers (April 1-August 31). The State of Washington's exemption has an additional restriction that limits TDG to 115% in the water arriving in the forebays of the Snake and Columbia River Dams. When these exceptions were provided, the intent was to allow more voluntary spill to occur, which is generally beneficial to juvenile migrating salmon by providing a safer route of passage than through turbines. These exemptions were approved with the acknowledgement that a trade-off was being made between the potential well-being of other aquatic organisms that live in the river and improved passage conditions for ESA listed salmon and steelhead. The initial spill volumes that were called for by NOAA Fisheries under RPA 29 of the 2008 FCRPS Biological Opinion acknowledge the waivers and exemptions that allow spill up to the 120% tailrace and 115% forebay levels. The spill volumes in RPA 29 would exceed 110% TDG under most conditions.[3]

12. The two states have slightly different methods for determining the average twelve (12) hour TDG levels which are compared to either the 120% standard in the tailrace and in Washington's case to the 115% forebay standard. The state of Washington has a single hour

[3] Order Approving the U.S. Army Corps of Engineer's Request for a Waiver to the State's Total Dissolved Gas Water Quality Standard (OR. Dep't of Env't Quality June 24, 2009); Letter approving U.S. Army Corps of Engineer's Total Dissolved Gas Abatement Plan for the Columbia and Lower Snake River Corps Projects (Wash. Dep't of Ecology June 30, 2010). The US District Court of Oregon issued Orders requiring that the 2011 Spring and Summer Fish Operation Plans be conducted as set forth in the March 24 and June 14, 2011 Orders. *Natl. Wildlife Fed. v. Natl. Marine Fisheries Serv., No. CV 01-640-RE.*

maximum TDG level of 125% and Oregon's waiver states that spill must be reduced if TDG exceeds 125% in any two of the highest twelve (12) hours measured in a calendar day. When hydraulic conditions allow, spill is reduced if any of the 115/120/125% criteria are met. These TDG standards do not apply when stream flows exceed the 7Q10 flow; defined as the average peak annual flow for seven (7) consecutive days that has a recurrence interval of ten (10) years.

13. When water is spilled from a dam it entrains air as it plunges to the stilling basin or plunge pool at the base of the dam. The momentum of the fall carries the water and entrained gases to great depths in the pool and under increased hydrostatic pressure, the entrained gases are driven into solution causing supersaturation of dissolved gases. The spillways of most[4] dams have flow deflectors that can greatly reduce the amount of gas generated by the spillways. But dissolved gas is still generated and cannot be completely removed before the water enters the slower, deeper main channel of the river downstream of the dam where TDG levels tend to stabilize. The TDG levels of water that passes through the turbines does not generally increase like water in the spillway, but instead tends to remain at same level as the water that arrived from upstream. TDG levels are measured for compliance with the state's tailrace standards in the waters downstream of the spillway, in locations that are logistically accessible, but that also give a realistic snapshot of the high levels of gas downstream. The forebay monitors just upstream of the dam measure TDG in the mixed flows from both the turbines and spillway from the upstream dam.

Impacts of Gas Bubble Trauma on Aquatic life

14. Since the initial TDG standards were set at 110% in the 1970's, a great deal of research has been performed to determine the effects of elevated TDG levels and resulting GBT on

[4] The dams that do not have flow deflectors generally have unique configurations which negate the need, e.g. The Dalles Dam which sits on a long and shallow rock shelf which acts as a giant natural flow deflector.

aquatic organisms. Recently, the state of Oregon's Department of Environmental Quality (DEQ) and the state of Washington's Department of Ecology (WDOE) jointly convened a technical workgroup (the Adaptive Management Team, or AMT) comprised of diverse stakeholders[5] to investigate the recent literature in an effort to make a determination if the current TDG waivers were appropriate or if they were too conservative. Specifically, the AMT was tasked with determining whether the 115% forebay criterion was too restrictive given the potential benefits of spill on downstream migrating salmonids.[6]

15. While the two state agencies reached different conclusions, impacts from elevated TDG levels were clearly documented to both salmonids as well as other aquatic organisms. While DEQ found that the risk of elevated TDG levels did not outweigh the potential direct survival benefits to salmon and steelhead, WDOE did not reach the same conclusion. In the final 2009 AMT report, WDOE found that "[t]he weight of all the evidence from available scientific studies clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120%. The detrimental effects ranged from behavior changes to high levels of mortality after a few days." *Id.*

16. Because the two states differed in their conclusions, the State of Washington has been petitioned to change their determination three separate times by parties who would like to see spill levels increased to aid in the juvenile migration. All three times WDOE has declined to modify their TDG criteria which led to a recent challenge in state court. In the end, the Court ruled in support of Ecology's determination "that the current 115/120/125 percent criterion adjustments achieved …'[t]he best balance between increased spill for salmon migration and the

[5] In addition to the co-chairs of Oregon DEQ and Washington DOE, AMT representatives included: federal agencies such as the US Army Corps of Engineers, NOAA Fisheries, and the US Fish and Wildlife Service, environmental and industry advocacy representatives such as Save our Wild Salmon and NW River Partners, tribal representation from the Colville Indian Tribe and the Columbia River Inter-Tribal Fish Commission (CRITFC), and mid-Columbia PUD representatives from Grant County PUD.

[6] Washington State Department of Ecology and Oregon Department of Environmental Quality. 2009. Adaptive Management Team Total Dissolved Gas in the Columbia and Snake Rivers. Evaluation of the 115 Percent Total Dissolved Gas Forebay Requirement. Final Report. Publication no 09-10-002.

protection of aquatic life that have shown lethal and sublethal affects due to prolonged exposure to TDG supersaturation.'"[7]

17. As part of the AMT[8] workgroup review on TDG, three (3) separate literature reviews (a private and public utility funded review by Dr. Don Weitkamp, WDOE review by Chris Maynard, and NOAA Fisheries review by Dr. Mark Schneider) were performed and hundreds of research publications were summarized. The three reviews each had a slightly different scope. Dr Weitkamp's review was limited to literature since 1980 as he had performed a similar review in 1979 that focused on the earlier studies up to that point. The DOE review limited their search by focusing on studies that monitored gas levels greater than 103% but lower than 120% because in their words "[r]esearch shows that exposure to TDG levels greater than 120 percent harms aquatic organisms consistently enough to omit review of higher concentrations" and "[s]hallow-dwelling organisms are susceptible to harm from long periods of TDG exposure at 103% TDG and greater" (Maynard, 2008)[9]. The NOAA Fisheries review was focused primarily on resident (non-migratory) species such as sturgeon, northern pikeminnow, etc.

Impacts to Salmon and Steelhead

18. As noted earlier, elevated levels of TDG and the associated instances of GBT are not always fatal to migrating salmon and steelhead, primarily because they have the ability to swim deeper in the water thereby reducing their TDG exposure due to depth compensation. The length of exposure to elevated dissolved gas levels is also an important factor in determining the effects of TDG. Although the effects of GBT are not always fatal, there is a very deep base of literature, primarily from lab studies, but also from field studies, on the effects of TDG on salmon and steelhead.

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[7] Verbatim Report of Proceedings at 24, Northwest Sportfishing v. Washington State Dep't of Ecology (Wash. Super. Ct., May 20, 2011) (No. 10-2-01236-0); Findings of Fact, Conclusion of Law, and Order Denying Relief, Northwest Sportfishing v. Washington State Dep't of Ecology (Wash. Super. Ct., June 13, 2011) (No. 10-2-01236-0).
[8] Adaptive Management Team Report cited in footnote 6 above; Weitkamp, 2008 Report cited in footnote 1 above.
[9] Maynard, C. 2008. Evaluation of Total Dissolved Gas Criteria (TDG) Biological Effects Research: A literature review. Washington State Department of Ecology Publication no 08-10-059.

19. A summary of the findings of the three (3) AMT literature reviews shows that in most instances, fish or other aquatic organisms that are one to two meters (1m-2m) deep should not have any substantial signs of GBT if TDG levels are at, or below 120%. If TDG levels rise above 120%, or if the fish do not have (or do not use) suitable deeper water habitats, then the effects of GBT will be more severe. These effects will vary from species to species (e.g. Chinook salmon are less susceptible than sockeye or steelhead) and may vary from year to year.

20. It is very difficult to tie the incidence of GBT directly to mortality, and in most cases, even when GBT is observed in salmonids migrating through the hydrosystem; high mortality rates are rarely directly observed. There are several instances however, where high TDG levels have led to high GBT and large fish kills. In 1968, as construction of John Day Dam was underway, all of the flow was routed through the spillway since the turbines had not been installed. Beiningen and Ebel observed that large numbers of dead adult sockeye and Chinook salmon were found downstream of the dam with signs of GBT (Beiningen and Ebel, 1970)[10]. There was also a high incidence of GBT observed in the adults monitored in the fish ladders. In this instance, dissolved nitrogen levels ranged from 123% to 143% (Ebel et al., 1974)[11]. Ebel also noted large numbers of GBT related mortalities of juvenile salmon in the Snake River in 1970 when TDG levels averaged 120-146% over a prolonged period (Ebel, 1971)[12]. Fish in Ebel's study were placed in cages with access to water ranging from 0 – 4.3m depth so that the test fish had access to low TDG levels through depth compensation. Even with access to deep water, salmon in Ebel's study suffered mortality rates from 45-68% between late May and early June. Although net pet studies of the effects of TDG exposure on fish are not likely to be entirely representative of the run-at-large, studies such as these provide valuable insight into the

[10] Beiningen, K.T., and W.J. Ebel. 1970. Effect of John Day Dam on dissolved nitrogen concentrations and salmon in the Columbia River, 1968. Transactions of the American Fisheries Society 99:664-671.

[11] Ebel, W. J., H. L. Raymond, G. E. Monan, W. E. Farr, G. K. Tanonaka. 1974. Effect of Atmospheric Gas Supersaturation Caused by Dams on Salmon and Steelhead Trout of the Snake and Columbia Rivers. National Marine Fisheries Service, Seattle, Washington, 117 p.

[12] Ebel, W. J. 1971. Dissolved Nitrogen Concentrations in the Columbia and Snake Rivers in 1970 and their Effect on Chinook Salmon and Steelhead Trout. U.S. Dept. of Commerce, NOAA Tech. Memo., NMFS-SSRF-646, 13 p.

effects of elevated TDG levels on salmonids.

21. As noted, instances of observed salmonid mortality at Snake and Columbia River dams directly attributable to GBT are rare but have been noted in many laboratory studies. Current field monitoring involves the sampling of juvenile salmonids at a subset of FCRPS and PUD dams one- to two- days a week throughout the migration season. This monitoring is part of the Smolt Monitoring Program, but this program only can sample and monitor fish that arrive at the dam alive and able to pass into the juvenile bypass system. Adult salmon and steelhead are no longer monitored for GBT on a regular basis.

A Case Study of How High Spill Volumes Can Effect TDG Levels and Associated GBT Levels

22. The current configuration of most of the dams in the FCRPS is very different than in the 1960's and 1970's, and many modifications have been made to reduce the amount of TDG generated by the spillways under normal conditions. But even with the modifications to the dams, unusually high river flow levels and mechanical and/or operational emergencies can lead to conditions which result in elevated TDG levels.

Little Goose Dam Transformer Failure in 2011

23. After a transformer failure coupled with an ongoing transformer outage at Little Goose Dam took all of its turbines off line, on May 24, 2011, water that had been going through the Little Goose turbines needed to go over the spillways instead and TDG levels increased significantly from 130% on May 23rd to 134% on May 25th. TDG levels reached as high as 136% on May 27th (see Figure 3).

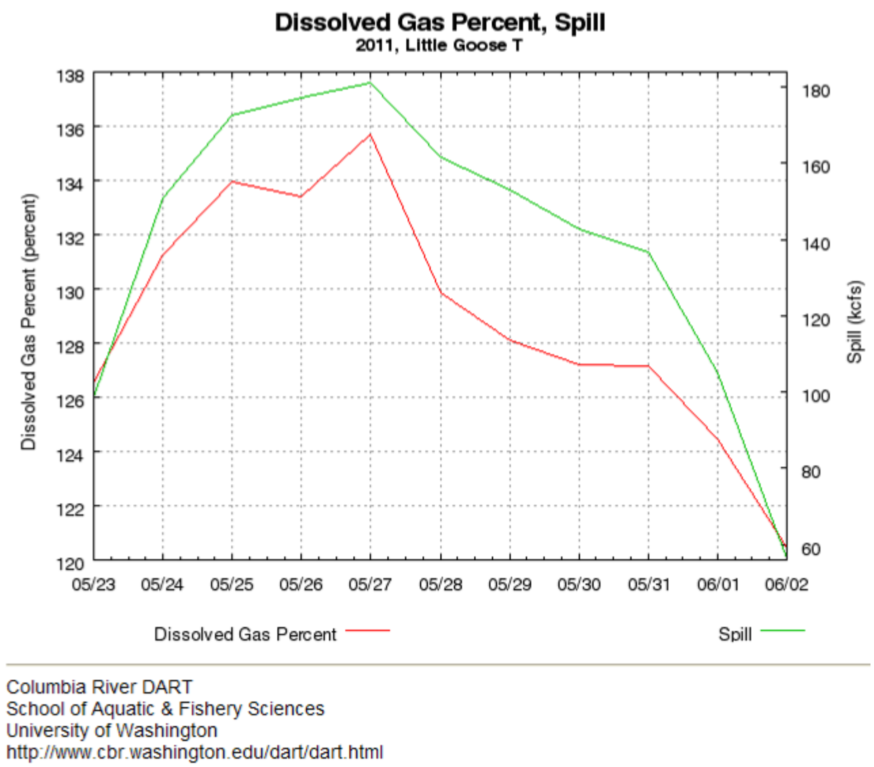

Figure 3. Total Dissolved Gas Levels and associated Spill Volumes in the tailrace of Little Goose Dam.

24. As a result of spill levels that were nearly 100% of the incoming river flow, gas bubble trauma at the next dam down river, Lower Monumental, jumped from 5.5% on May 25th to 30% on May 28th as the fish exposed to the higher level TDG began to arrive (see Figure 4). GBT had dropped back down to 4% after the powerhouse was restored on June 1st. Those percentages are based on sample rates of ninety-four (94) fish that were pulled from the juvenile bypass system on May 25th and one-hundred (100) fish on May 28th and June 1st. Under normal operating circumstances, GBT levels like those observed downstream at Lower Monumental would have triggered the region's "action criteria" which require spill levels to be reduced if GBT observations increase above 15% of the sample or severe GBT observations increase above 5% of the sample.

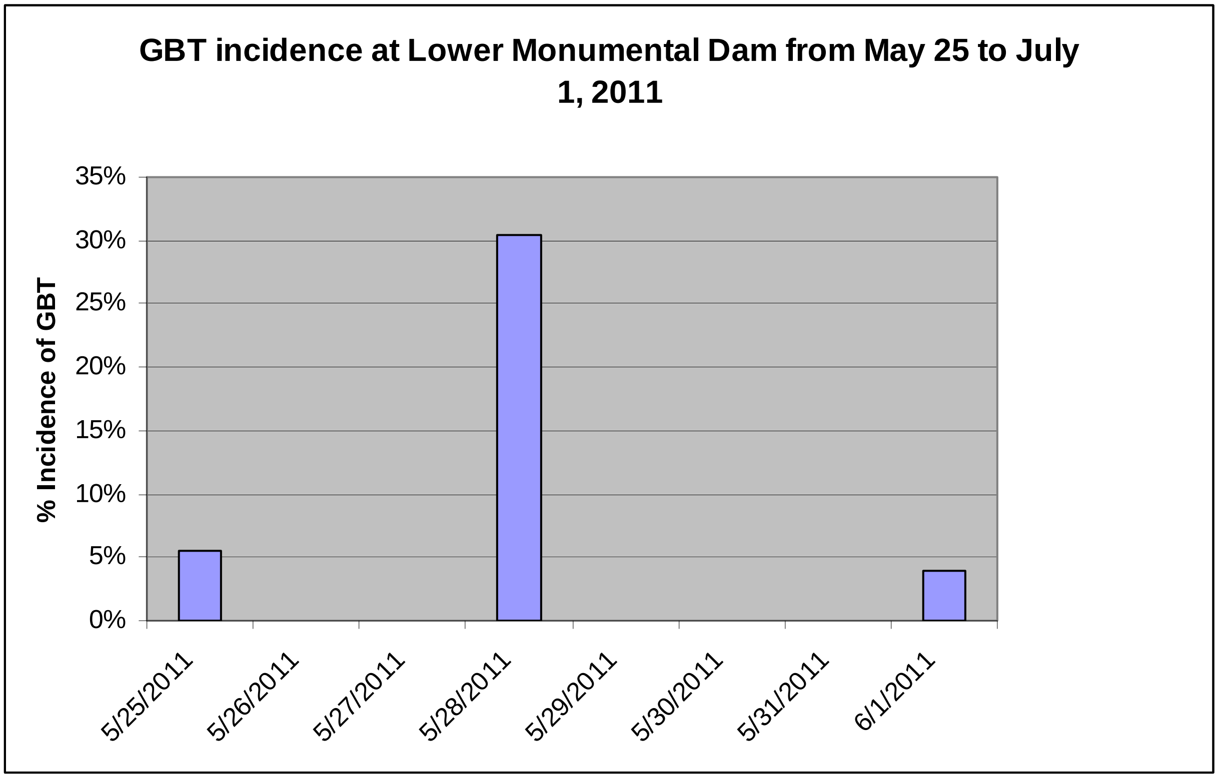

Figure 4. Gas Bubble Trauma monitoring results at Lower Monumental Dam from May 25th to June 1st 2011. Data from the Fish Passage Center.

25. Even though the peak of the spring Chinook and steelhead runs had past by May 24th fish were still passing in large numbers. On the last day a fish passage index was available for Little Goose (May 22nd), the daily passage estimate was nearly 80,000 juvenile salmonids. Based on upstream indices, the fish passage rates at Little Goose are estimated to have remained at similar levels each day over the duration of the powerhouse outage.

26. Juvenile salmon weren't the only fish that were subjected to high TDG levels. After the transformer was restored at Little Goose Dam and powerhouse flows were restored on the afternoon of June 1st, a large pulse of adult Chinook which had been delayed by the confusing tailrace conditions created by the high spill levels were able to find the fish ladder and pass. Adult counts that had averaged seven-hundred twenty-four (724) per day between May 26th and May 31st jumped to 4,393 on June 1st and 2,743 on June 2nd. While thankfully a large scale mortality event did not occur with the adult Chinook as a result of being delayed in high TDG

waters, as evidenced by prior experience at John Day Dam in the 1960's and at other dams on the Snake River, the potential was there.

Impacts to Aquatic Life in Shallow Water

27. It is the aquatic life in shallow waters (salmon and steelhead as well as non-ESA listed species) that appears to be most negatively affected by elevated TDG levels. Indeed, in the Finding of Fact, Conclusions of Law and Order from the recent Washington State Court ruling[13] that upheld WDOE's 115% forebay waiver requirement, the Court found that "…Ecology's literature review identified an impact to aquatic species near the surface, less than one meter deep, that should not be considered negligible. But review found that there was a detrimental effect on aquatic life at less than one meter depth and that some aquatic life may be residing near the surface for long enough to suffer the detrimental effects of gas bubble trauma."[14]

28. In the wide range of studies reviewed as part of the AMT's literature review, mortality rates due to GBT in laboratory studies (shallow water) increased from few effects when TDG was between 110 and 115% to rates that ranged from: 20% in one day, 50% in 3 or 4 days, 20% in 6 days, 42% in 9 days, 10% in 11 days, 32% in 12 days, 50% in 22 days, and 20% in 23 days once TDG levels were raised to 120% (see table 14, pg 46 of AMT report for study details). These variable rates that were observed in different studies over different years also serve to illustrate how dynamic the relationship of TDG and GBT can be. The studies referenced above incorporated a wide variety of organisms including juvenile and adult salmon, steelhead, rainbow trout, and northern pikeminnow.[15]

29. This concludes my Affidavit.

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[13] Verbatim Report of Proceedings at 24, Northwest Sportfishing v. Washington State Dep't of Ecology (Wash. Super. Ct., May 20, 2011) (No. 10-2-01236-0);); Findings of Fact, Conclusion of Law, and Order Denying Relief, Northwest Sportfishing v. Washington State Dep't of Ecology (Wash. Super. Ct., June 13, 2011) (No. 10-2-01236-0).
[14] Adaptive Management Team Report cited in footnote 6 above.
[15] Adaptive Management Team Report cited in footnote 6 above.

AFFIDAVIT

State of Oregon
County of Multnomah

NOW BEFORE ME, the undersigned authority, personally came and appeared, Jason C. Sweet, who after being duly sworn by me, did depose and say:

That the above and foregoing is true to the best of his knowledge, information, and belief.

Jason C Sweet

Jason C. Sweet

SIGNED AND SWORN TO BEFORE ME ON THIS 18th Day of July, 2011

OFFICIAL SEAL
BARBARA M WILLARD
NOTARY PUBLIC - OREGON
COMMISSION NO 438867
MY COMMISSION EXPIRES APR. 28, 2013

Barbara M. Willard

NOTARY PUBLIC, STATE OF OREGON

Order Approving the U.S Army Corps of Engineer's Request for a Waiver to the State's Total Dissolved Gas Water Quality Standard

BEFORE THE ENVIRONMENTAL QUALITY COMMISSION

In the matter of the U.S. Army Corps of Engineers' request to spill water to assist out-migrating threatened and endangered salmon smolts	))))	FINDINGS and ORDER

Findings

1. The Department of Environmental Quality received a request from the U.S. Army Corps of Engineers dated January 09, 2009, to adjust the 110 percent t total dissolved gas water quality standard as necessary to spill water over McNary, John Day, The Dalles and Bonneville dams on the Lower Columbia River to assist out-migrating threatened and endangered salmon smolts during the fish passage season of Apr. 1 to Aug. 31. The application sought approval for five years. The public was notified of the request on Feb. 19, 2009 and given the opportunity to provide written comments until 5:00 p.m. on Mar. 23, 2009.

2. Acting under **OAR 340-041-0104(3)** the commission finds that:

   (a) *Failure to act would result in greater harm to salmonid stock survival through in-river migration than would occur by increased spill:*

   Biological assessments and opinions have concluded that providing project spill for fish passage at levels that result in exceeding the 110 percent total dissolved gas water quality standard is necessary to assure adequate passage conditions for Endangered Species Act listed fish species. The National Marine Fisheries Service Federal Columbia River Power System Biological Opinion concluded that the risk associated with a managed fish passage spill program to a 120 percent total dissolved gas level is warranted by the projected 4 percent to 6 percent increase in system survival of juvenile salmonids. The opinion estimated mortality from fish passing through turbines between 7 and 14 percent, and mortality due to fish passage spill between 0 to 2 percent. Barge and truck transport are alternative modes of fish transport to voluntary spill. The mortality associated with truck and barge transport is difficult to estimate due to the potential for latent mortality. However, the US Fish and Wildlife Service studied the transport of fall Chinook salmon directly from Spring Creek Hatchery by barge to a release site below Bonneville Dam. A high percentage of the adult returns from the barged groups strayed to other hatcheries, and the return rates to Spring Creek Hatchery were significantly lower for the barge test groups than for the voluntary spill control group. The US Fish and Wildlife Service also evaluated the possibility of raising and releasing additional fish to make up for those fish that would be lost to turbines or other causes during passage at Bonneville Dam in the absence of spill. The USFWS concluded that it would not be possible to raise additional fish because rearing space, water supply, and waste treatment capability are limited. It would also not be feasible to release fish at a later date because of limited hatchery capacity since these fish would continue to grow and exceed hatchery capacity.

(b) The modified total dissolved gas criteria associated with the increased spill provides a reasonable balance of the risk of impairment due to elevated total dissolved gas to both resident biological communities and other migrating fish and to migrating adult and juvenile salmonids when compared to other options for in-river migration of salmon:

The Fish Passage Center estimates a 1.4 percent incidence of gas bubble trauma in salmon smolts in the Columbia River when total dissolved gas levels are managed to 120 percent in the tailrace. This estimate is based on smolt monitoring information collected between 1995 and 2007.

When the in-river total dissolved gas levels are below 120 percent, few adult fish (in some cases none) display signs of gas bubble trauma. Investigators have observed adult tolerance to total dissolved gas and hypothesized that it was attributable to the migration depth of adult salmonids. Depth-sensitive radio tags used in adult migration studies confirmed that adults migrate at depths up to 4 meters and find depth compensation protection from gas bubble trauma. For every meter below the surface water, a reduction of 10 percent total dissolved gas is measured in the water column. Resident fish and aquatic invertebrates in the Columbia River downstream of Bonneville Dam have been monitored by National Marine Fisheries Service for signs of gas bubble disease from 1993 to 1998. There were no signs of gas bubble disease observed in the aquatic invertebrates examined. There was a low incidence of gas bubble disease (less than one percent) in resident fish examined in 1993 and 1995 while in 1994, 1997 and 1998 none of the fish observed had signs of gas bubble disease. Signs of gas bubble disease were prevalent in 1996 but this was a high flow year with large volumes of involuntary spill and total dissolved gas levels above 120 percent in the tail races of dams. Given the past monitoring of gas bubble disease, the levels requested in this petition strike a reasonable balance between increased survival due to reduced turbine mortality and the risk of mortality from gas bubble disease.

c) Adequate data will exist to determine compliance with the standards:

Physical in-river total dissolved gas monitoring will be conducted at the tailraces of McNary, John Day, The Dalles, and Bonneville Dams. Hourly data will be available on the Corps' website. The Corps has submitted a physical monitoring plan. The physical monitoring plan of action is available at:
http://www.nwdwc.usace.army.mil/tmt/wq/tdg_monitoring/2010-14_final.pdf
Implementation of the physical monitoring plan will ensure that data will exist to determine compliance with the standards for the voluntary spill program identified in this Order. The Corps will report each year's physical monitoring results to DEQ.

d) Biological monitoring is occurring to document that the migratory salmonid and resident biological communities are being protected:

The corps has submitted a biological monitoring plan. Biological monitoring will occur according to the "Fish Passage Center Gas Bubble Trauma Monitoring Program Protocol for Juvenile Salmonids" document, available at: ftp://ftp.fpc.org/gbtprogram/ . Juvenile salmonids will be collected at Bonneville and McNary Dams and examined and evaluated for incidence of gas bubble trauma, and will be assigned ranks based on severity of their symptoms. The corps will report each year's biological monitoring results to the DEQ.

Order

1. The Environmental Quality Commission approves a modification to the 110 percent total dissolved gas water quality standard for voluntary fish passage spill at McNary, John Day, The Dalles and Bonneville Dams on the Lower Columbia River, subject to the following conditions:

   (i) A modified total dissolved gas standard for the Columbia River applies:

      a) during the voluntary spill period from midnight on Apr. 1 to midnight on Aug. 31 for the purpose of fish passage; and

      b) during any period of voluntary spill that occurs outside the periods specified in 1(i)(a) above, if the spill is for the purpose of Spring Creek Hatchery fish release, maintenance activities and/or biological or physical studies of spillway structures and prototype fish passage devices, then the U.S. Army Corps of Engineers must have approval from the Department prior to such spill. The corps must notify the DEQ in writing describing the action, the purpose of the action and dates of action at least one week prior to the voluntary spill for the purpose of informing DEQ and having the DEQ make a final determination of approval. The U.S. Army Corps of Engineers will conduct physical and biological monitoring during these periods of voluntary spill.

   (ii) The modified total dissolved gas criteria will apply for five-years, 2010, 2011, 2012, 2013 and 2014.

   (iii) Spill must be reduced when the average total dissolved gas concentration of the 12 highest hourly measurements per calendar day exceeds 120 percent of saturation in the tailraces of McNary, John Day, The Dalles, and Bonneville Dams monitoring stations.

   (iv) Spill must be reduced when instantaneous total dissolved gas levels exceed 125 percent of saturation for any 2 hours during the 12 highest hourly measurements per calendar day in the tailraces of McNary, John Day, The Dalles, and Bonneville Dams monitoring stations.

(v) If either 15 percent of the fish examined show signs of gas bubble disease in their non-paired fins, or five percent of the fish examined show signs of gas bubble trauma in their non-paired fins where more than 25 percent of the surface area of the fin is occluded by gas bubbles, the DEQ director will halt the spill program.

(vi) The Corps must provide written notice to DEQ within 24 hours of any violations of the conditions in the modification as it relates to voluntary spill. Such notice must include actions proposed to reduce total dissolved gas levels or the reason(s) for no action.

(vii) No later than Dec. 31 for each year of this waiver, the corps must provide an annual written report to DEQ detailing the following:

a) flow and runoff descriptions for the spill season;
b) spill quantities and durations;
c) quantities of water spilled for fish versus spill for other reasons for each project;
d) data results from the physical and biological monitoring programs, including incidences of gas bubble trauma;
e) description and results of any biological or physical studies of spillway structures and prototype fish passage devices to test spill at operational levels; and
f) progress on implementing the gas abatement measures contained in the 2002 Lower Columbia River total dissolved gas total maximum daily load and other gas abatement activities identified through adaptive management.

(viii) If requested, the corps must report to the commission on any of the above matters or other matters relevant to this order.

(ix) The commission reserves the right to terminate or modify this modification at any time.

Adaptive Management

The process for reviewing the implementation of the 2002 Lower Columbia River total dissolved gas total maximum daily load will continue. The Washington State Department of Ecology will convene an advisory group with representatives from Oregon DEQ, tribes, federal and state agencies to evaluate appropriate points of compliance for this total maximum daily load. Based on these findings, further studies may be needed, and structural and operational gas abatement activities will be redirected or accelerated if needed.

Dated: 6-24-09

ON BEHALF OF THE COMMISSION

Dick Pedersen

Director

Chad copy

STATE OF WASHINGTON

DEPARTMENT OF ECOLOGY

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June 30, 2010

Mr. David Ponganis
U.S. Army Corps of Engineers
Northwestern Division
P.O. Box 2870
Portland, OR 97208-2870

Dear Mr. Ponganis:

The U.S. Army Corps of Engineers (Corps) requested an adjustment of the total dissolved gas (TDG) criteria to aid fish passage over the Corps-operated dams on the Columbia and Snake Rivers. The requested adjustment is provided under Washington Administrative Code (WAC) 173-201A-200(1)(f)(ii). The criteria adjustment is contingent on the approval of a TDG abatement plan for the Corps dams.

In accordance with the conditions detailed in the Department of Ecology (Ecology) criteria adjustment approval letter dated February 8, 2008, the Corps submitted a TDG abatement plan prior to the 2010 spill season, (*The Total Dissolved Gas Abatement Plan for the Columbia and Lower Snake River Corps Projects, March 2010).* To allow time for Ecology to review this plan, we issued an extension to the February 2008 TDG criteria adjustment in a letter to the Corps on March 29, 2010. Ecology is issuing the following findings and conditions as a result of final review of the TDG abatement plan.

A. **The Washington State Department of Ecology approves the gas abatement plan based on the following findings:**

   1. Limiting the allowable spill based on the 110 percent TDG criteria will result in more fish passing through turbines. Mortality is generally higher when fish pass through turbines than when fish passage is available through spill pathways at the Corps dams.
   2. Increasing the TDG criteria threshold above 110 percent significantly decreases the mortality of juvenile fish migrating downstream.
   3. Monitoring of gas bubble trauma (GBT) by the Fish Passage Center continues to show limited incidence of GBT in salmonids during spill season when the Corps dams are operating under the adjusted TDG criteria.
   4. The Corps met the conditions detailed in Ecology's February 2008 criteria adjustment approval letter.
   5. The Corps' gas abatement plan details the continuing structural and operational improvements occurring in the Columbia and lower Snake River projects.

B. **This approval is subject to the following conditions:**

1. This approval shall extend through the end of February 2015 and apply to Corps dams on the Columbia and Snake Rivers in Washington State.
2. This approval allows spill to increase the dissolved gas levels above 110 percent of saturation to aid fish passage, but not to exceed 125 percent of saturation as a one-hour average. Gas saturation may not exceed 120 percent in the tailrace and 115 percent in the forebay of the next downstream dam as measured by the highest twelve-hour, consecutively-averaged value in any one day.
3. The Corps shall provide Ecology with an annual dissolved-gas monitoring report each year for the period of this criteria adjustment. The annual report shall include updated gas bubble trauma monitoring results and an update of the Corps TDG total maximum daily load (TMDL) implementation actions.
4. In the event of a rule revision to WAC 173-201A that is applicable to TDG criteria, conditions of this approval may be subject to change based on the revised criteria.

Application of the conditions of this approval by the Corps constitutes a large part of the implementation of Washington's Lower Columbia River TDG TMDL, the Mid-Columbia River TDG TMDL, and the Snake River TDG TMDL. As Phase II of the TMDLs gets underway, beginning in 2011 and proceeding through 2020, Ecology anticipates that the Corps will be actively involved in the process of reviewing the status of implementation of the TMDLs along with other key representatives involved in the Columbia and Snake River fish spill efforts.

Please contact me at (360) 407-6461 or Chad Brown of my staff at (360) 407-6128 if you have questions about this approval.

Sincerely,

Melissa Gildersleeve
Watershed Management Section Manager

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, NORTHWESTERN DIVISION
PO BOX 2870
PORTLAND OR 97208-2870

S: 1 April 2011

CENWD-PDD 28 March 2011

MEMORANDUM FOR

Commander, Portland District (CENWP-DE)
Commander, Seattle District (CENWS-DE)
Commander, Walla Walla District (CENWW-DE)
CENWD-PDS (Rux)
CENWD-PDW (Barton)

SUBJECT: Court Order for 2011 Spring Project Operations for Fish

1. References:

a. 2011 Spring Fish Operations Plan (Spring FOP), 22 March 2011 (Encl 1).

b. U.S. District Court of Oregon Order on 2011 Spring Operations, 24 March 2011 (Encl 2).

2. This memorandum provides guidance for the 2011 Spring Project Operations for Fish.

3. The Corps' Federal Columbia River Power System (FCRPS) projects are operating in accordance with the National Oceanic and Atmospheric Administration (NOAA) Fisheries 2010 Supplemental Biological Opinion (BiOp)[1]. The legal adequacy of the BiOp has been challenged in the U.S. District Court of Oregon. While the litigation is in process, the Federal Defendants (U.S. Army Corps of Engineers (Corps), Bureau of Reclamation, and NOAA Fisheries) will implement the project operations contained and referenced in the enclosed 2011 Spring FOP (reference 1.a.). The 2011 Spring FOP specifically identifies spring 2011 project operations for spill for fish passage, juvenile fish transportation, related research, and operational considerations for low flow and other special conditions. To the extent hydro-operations are not specified in the 2011 Spring FOP, the Corps' projects will be operated consistent with the 2010 Supplemental BiOp and/or other operative documents necessary to implement that BiOp. These operative documents include the Corps' current Water Management Plan (WMP), including seasonal updates, and the Fish Passage Plan (FPP).

4. The 2011 Spring FOP was submitted to the U.S. District Court of Oregon on 22 March 2011. The Court issued an Order on 24 March 2011 adopting the 2011 Spring FOP (reference 1.b.). With the issuance of the 24 March Order, it is imperative that all Corps personnel strictly adhere

[1] The 2010 Supplemental BiOp incorporates the 2008 BiOp

to the operations described in the 2011 Spring FOP and that there are no deviations unless properly coordinated and communicated. Recognizing that emergencies or unforeseen circumstances may occur, please immediately contact the following staff concerning any operations that may conflict with the 24 March Order.

- NWD Reservoir Control Center (CENWD-PDW-R), Steve Barton, 503-808-3945
- NWD Fish Policy (CENWD-PDD)
    - Rock Peters, 503-808-3723
    - Dan Feil, 503-808-3727
- NWD Legal Counsel (CECC-NWD), Gayle Lear, 503-808-3764

In addition, please identify and provide a District point of contact to CENWD-PDD and CECC-NWD (phone numbers listed above) by **1 April 2011** to facilitate communication with NWD in the event there are concerns about a conflict with the 24 March Order. Generally, if an issue arises concerning conformance with the 24 March Order and a change in operations is desired, the objective is to obtain consensus among all participating sovereigns on any proposed changes. These changes must be discussed through the appropriate regional forum coordination group (e.g., Technical Management Team, Fish Passage Operations and Maintenance Coordination Team, Fish Facility Design Review Work Group, or Studies Review Work Group), with complete and accurate record keeping of the sovereigns' positions.

5. It is imperative that we have a successful and flawless implementation of 2011 spring project and system operations. Please take appropriate action to notify all district and project staff who are involved in Corps FCRPS project operations, including flood risk management, navigation, fish operations, and research.

6. Thank you for your hard work and support. If you have questions or need additional information concerning our internal processes for addressing the 2011 Spring FOP, please feel free to contact David Ponganis, at 503-808-3828, or Rock Peters, at 503-808-3723.

FOR THE COMMANDER:

W. T. Anderson

2 Encls

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Director, Programs

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Attorneys for Defendants

UNITED STATES DISTRICT COURT
DISTRICT OF OREGON

NATIONAL WILDLIFE FEDERATION, *et al.*

Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, *et al.*

Defendants.

Civil No. 01-640-RE

[~~PROPOSED~~] ORDER FOR 2011 SPRING OPERATIONS

Federal Defendants submit the following (Proposed) Order for 2011 spring fish operations for the Federal Columbia River Power System ("FCRPS").

In 2005, this Court granted in part, and denied in part, Plaintiffs' motion for preliminary injunctive relief seeking to alter FCRPS operations during the spring and summer of 2006. See Doc. 1221. The Court adopted the Federal Defendants' proposals for the amount and timing of spring and summer spill at FCRPS dams with two exceptions. Id. at 11. After commencement of spill, Federal Defendants were directed to provide the court with a monthly written report describing the implementation and progress of the spill program. Id.

Similar spring and summer operations were implemented in 2007 pursuant to an agreement between the Bonneville Power Administration (BPA), the Confederated Tribes of the Warm Springs Reservation, the Nez Perce Tribe, Confederated Tribes of the Umatilla Indian Reservation, Confederated Tribes and Bands of the Yakama Nation, and Confederated Tribes of the Colville Indian Reservation. See Doc. 1347 at 3. On May 23, 2007, the Court adopted the 2007 operations agreement as an order of the Court. See Opinion and Order (May 23, 2007).

At a December 12, 2007 status conference, Federal Defendants offered to continue the 2007 spring and summer operations if Plaintiffs would agree to not seek a preliminary injunction until after issuance of the 2008 BiOp. In agreeing to work toward this goal, Plaintiffs' recognized that any agreement for 2008 operations "would essentially continue - subject to discussion of limited changes necessary to accommodate new structures and perform essential research - the court-ordered operations from 2007." See Plaintiffs' January 11, 2008 Letter. The 2008 Fish Operations Plan, incorporated into the Court's Order on 2008 Operation, recognized the operational adjustments necessary to perform this research and accommodate structural changes. See Doc. 1409, Attachment 1. On February 25, 2008, this Court entered the joint proposed order for 2008 spring and summer operations. Doc. 1423.

In a February 18, 2009 letter to counsel, the Court asked Federal Defendants to agree to "continue recent court-ordered spill operations for Spring 2009." See Doc. 1682 at 2. At the March 6, 2009 hearing, counsel represented that Federal Defendants would abide by the Court's request to continue court-ordered spring spill operations subject to modifications necessary to accommodate new structures and perform essential research. See Tr. at 167. On April 10, 2009, the Court entered an order adopting the parties proposed order. See Doc. 1694.

On February 19, 2010, the Court entered an order granting Federal Defendants' request for a limited, voluntary remand and directed Federal Defendants to complete this remand within three months. In the interests of maintaining the three-month remand schedule, Federal Defendants submitted a nearly identical proposed order for 2010 spring operations as they did in 2009, and the Court entered that order on April 21, 2010. See Doc. 1760. Consistent with past practices and in the interests of resolving the merits of this litigation, Federal Defendants have attached a proposed order for 2011 spring fish operations.

THEREFORE, in light of this prior history and in the interests of avoiding further litigation, the undersigned parties stipulate as follows:

1. Scope: The Court's entry of the proposed order on spring 2011 fish operations shall not be construed as a concession or preliminary assessment of the merits of any parties' claim concerning the 2008 Biological Opinion, Adaptive

Implementation Management Plan (AMIP), Action Agencies' Records of Decision and Amended Records of Decision, and the 2010 Biological Opinion as set forth in the parties' pending cross-motions for summary judgment and supplemental cross-motions for summary judgment.

2. Operations: FCRPS spring 2011 fish operations shall be conducted as set forth in the 2011 Spring Fish Operations Plan, incorporated herein by reference. To the extent hydro-power operations are not specified in the 2011 Spring Fish Operations Plan, Federal Defendants shall operate the FCRPS consistent with the 2010 Biological Opinion, and/or other operative documents necessary to implement that Biological Opinion, unless otherwise specified herein.

3. Timing: This Order applies to spring spill operations for 2011 only and shall continue until the transition date from spring spill operations as set forth in the 2011 Spring Fish Operations Plan, unless this Court issues an opinion on the pending cross-motions for summary judgment prior to that transition date. If the Court issues an opinion granting, in whole or in part, the plaintiffs' pending motions for summary judgment, this Order shall remain in effect until replaced by a further order of the Court. If the Court issues an opinion granting the federal defendants' pending cross-motions for summary judgment, this Order shall terminate on the date the Court issues such a ruling without prejudice to the right of any party to seek emergency or other appropriate relief in any forum.

4. In-Season Adjustments: As set forth in the 2011 Spring Fish Operations Plan, Federal Defendants will utilize the existing Regional Forum committees to make in-season adjustments.

5. Standard Reporting Requirement: Federal Defendants shall provide the court with a written report describing the implementation of the 2011 Spring Fish Operations Plan, beginning May 17, 2011, and monthly intervals thereafter until satisfaction of the earlier of the conditions in Paragraph 3. Should the agencies encounter a situation similar to that which occurred on April 3, 2007, which the Court characterized as "placing power needs before the needs of listed species", Federal Defendants shall notify the Court and the other parties promptly and shall propose mitigation measures, if any, that may be appropriate as soon as practicable.

6. Emergency Reporting Requirements: Federal Defendants shall take all reasonable and practicable steps to notify the Court and the parties prior to any declared system emergency. If unforeseen circumstances arise that preclude Federal Defendants from notifying the Court and the parties prior to a declared system emergency, they shall report those actions directly to the court as soon as practicable.

Dated this 24 day of MARCH ,2011.

James A. Redden
United States District Judge

RESPECTFULLY SUBMITTED,

IGNACIA S. MORENO
Assistant Attorney General
United States Department of Justice
Environment and Natural Resources Division
SETH M. BARSKY
Section Chief

/s/ Coby Howell
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CENWD-PDD March 2011

2011 Spring Fish Operations Plan

INTRODUCTION

The 2011 Spring Fish Operations Plan (FOP) describes the U.S. Army Corps of Engineers' (Corps) planned operations for fish passage at its mainstem Federal Columbia River Power System (FCRPS) dams during the 2011 spring fish migration season; generally April through June. The 2011 Spring FOP is consistent with the 2010 Court ordered spring spill operations and the adaptive management provisions in the 2010 NOAA Fisheries FCRPS Supplemental Biological Opinion (2010 Supplemental BiOp)[1] and the Corps' Record of Consultation and Statement of Decision (ROCASOD) adopting the project operations contained in the 2010 Supplemental BiOp and Columbia Basin Fish Accords (Accords).

As in 2010, the 2011 Spring FOP incorporates planned project operational adjustments necessary to conduct essential research to evaluate fish passage features during the 2011 spring migration season. Other FCRPS water management actions and project operations not specifically addressed in this document shall be consistent with the 2010 Supplemental BiOp and other guiding operative documents including the 2011 Water Management Plan (WMP), seasonal WMP updates, and the 2011 Fish Passage Plan (FPP). Operations described herein may be adjusted to address in-season developments through discussion and coordination with regional sovereigns.

The following sections describe factors that influence management of fish operations during various runoff conditions, including: total dissolved gas (TDG) management, spillway operations, minimum generation requirements, operations under low flow conditions, navigation safety, juvenile fish transportation operations, specified spring operations for fish at each mainstem project, protocols for fish protection measures related to operational emergencies, coordination with regional entities, and monthly reporting.

GENERAL CONSIDERATIONS FOR FISH OPERATIONS

For planning purposes, the Corps' 2011 Spring FOP assumes average runoff conditions. As actual runoff conditions vary in timing and shape and may be higher or lower than average in any given year, adjustments in fish transportation and/or spill operations (kcfs discharge levels, spill percentages, or spill caps) will be adaptively managed in-season. These in-season changes will be coordinated through the Technical Management Team (TMT) and other appropriate regional forums, to avoid or minimize poor juvenile or adult fish passage conditions, navigation safety concerns, or to accommodate powerhouse and/or transmission system constraints. Actual spill levels may be adaptively managed to

[1] The 2010 Supplemental BiOp incorporates the 2008 NOAA BiOp

accommodate fish research or other conditions and will be coordinated through the TMT and other appropriate regional forums.

TDG Management During Spill for Fish Passage

The Corps will manage spill levels for fish passage to avoid exceeding 120% TDG in project tailraces, and 115% TDG in the forebay of the next project downstream consistent with the current State of Washington TDG saturation upper limits.[2] These limits are referred to as gas caps. The project maximum spill discharge level that meets, but does not exceed the gas cap, is referred to as the spill cap. Gas caps are constant, whereas spill caps may vary daily depending on flow, spill pattern, temperature, and other environmental conditions.

As noted above, the spill levels presented below in Table 2 are planned spill operations and assume average runoff conditions; however, adjustments to these spill rates may be necessary. Reasons for these adjustments may include:

1. Low runoff conditions that may require adjustments in spill level while still meeting project minimum generation requirements.
2. High runoff conditions where flows exceed the powerhouse hydraulic capacity with the specified spill rates.
3. Navigation safety concerns.
4. Generation unit outages that reduce powerhouse capacity.
5. Power system or other emergencies that reduces powerhouse discharge.
6. Lack of power demand resulting in an increase of spill level.

The Corps' Reservoir Control Center (RCC) is responsible for daily management of spill operations responsive to changing TDG conditions. In order to manage gas cap spill levels consistent with the states' TDG saturation limits, the RCC establishes the spill caps for the lower Columbia and Snake River projects on a daily basis throughout the fish passage season so that resultant TDG percent saturation levels are not expected to exceed the 120%/115% TDG limits measured as the average of the highest 12 hourly readings each day.

Within any given day, some hours of measured TDG levels may be higher or lower than the gas caps due to changing environmental conditions (wind, air temperature, etc.). The process of establishing daily spill caps entails reviewing existing hourly data at each dam (including flow, spill, temperature, and TDG levels) and taking into consideration a number of forecast conditions (including total river discharge, powerhouse discharge, wind and temperature forecast, etc.). These data are used as input variables into the System TDG (SYSTDG) model. The SYSTDG model estimates TDG levels expected several days into the future and is a tool integral to daily decision-making when establishing spill caps at individual dams. Spill caps set by RCC and contained in the

[2] In February 2009, the State of Oregon modified its 5-year waiver to remove the 115% forebay TDG limit. However, the Corps will continue to manage to 120% and 115% (the Washington TDG standard) consistent with the 2010 spring court ordered operation in 2011.

daily spill priority list will be met at the projects using the individual project spill pattern(s) contained in the FPP Sections 2 through 9, which most closely correspond to the specified spill level (i.e. may be slightly over or under the specified spill discharge or percent value). During the spring freshet, when river discharge may be greater than project powerhouse hydraulic capacity given the specified Spring FOP spill level, or a lack of power load results in an increase in the spill level, the Corps will attempt to minimize TDG on a system-wide basis. In this case, spill caps are also developed for 125%, 130%, or 135% saturation as a means of minimizing TDG throughout the system.

The Corps will initiate spill at 0001 hours, or shortly after midnight, at each of the projects on the start dates specified in the project sections below. Spill caps will be established at the specified levels and will continue unless conditions require changing to maintain TDG within the upper limits of 120% in the tailwater of a dam and 115% in the forebay of the next project downstream (and at Camas/Washougal). Spill will transition to summer levels at 0001 hours, or shortly before midnight, at each project on the end dates specified. Operations to manage TDG will continue to be coordinated through the TMT.

Spillway Operations

The Action Agencies will meet the specified spill levels to the extent feasible; however, actual hourly spill levels at each dam may be slightly more or less than those specified in Table 2 below. Actual spill levels vary depending on the precision of spill gate settings, flow variations in real time, varying project head (the elevation difference between a project's forebay and tailwater), automatic load following, and other factors.

Operations Considerations:

- Spill discharge levels: Project spill levels listed in Table 2 coincide with specific gate settings in the FPP project spill pattern tables. Due to limits in the precision of spill gates and control devices, short term flow variations, and head changes, it is not always possible to discharge the exact spill levels stated in Table 2, or as stated in RCC spill requests (teletypes) to projects that call for discrete spill discharges. Therefore, spillway gates are opened to the gate settings identified in the FPP project spill pattern tables to provide spill discharge levels that are the closest to the prescribed spill discharge levels.

- Spill percentages: Spill percentages are considered target spill levels. The project control room operator and BPA duty scheduler calculate spill levels to attempt to be within ±1% of the target percentage for the following hour (or more than ±1% at The Dalles and Little Goose dams as specified in FPP Sections 3 and 8 spill pattern tables). Prescribed or specified percentages in Table 2 may not always be attained due to low discharge conditions, periods of minimum generation, spill cap limitations, temporary spill curtailment for navigation safety, and other unavoidable circumstances. Operators and schedulers review the percentages achieved during the day and adjust spill levels in later hours, with the objective of ending the day with a daily average spill percentage that achieves the specified spill percentage.

Minimum Generation

The Corps has identified minimum generation flow values derived from actual generation records when turbines were operating within ±1% of best efficiency (Table 1). Values stated in Table 1 are approximations that account for varying head or other small adjustments in turbine unit operation that may result in variations from the reported minimum generation flow and spill amount. Conditions that may result in minor variations include:

1. Varying pool elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor "dead band": the governor controls the number of megawatts the unit should generate, but cannot precisely control a unit discharge; variations may be 1-2% of generation.
3. System disturbances: once a generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase discharge and generation slightly within an hour. Individual units operate differently from each other and often have unit specific constraints.
4. Generation control systems regulate megawatt (MW) generation only; not discharge through individual turbine units.

All of the lower Snake River powerhouses may be required to keep one generating unit on line at all times for power system reliability under low river discharge conditions, which may result in a reduction of spill at that project. These projects have two "families" of turbines with slightly different capacities – small and large. In most cases during low flow conditions, one of the smaller turbine units (with reduced generation and flow capabilities) will be online. The smaller turbine units are generally numbered 1–3 and are the first priority for operation during the fish passage season. If smaller turbine units are unavailable, larger units may be used. Turbine unit 1 at Little Goose Dam is the first priority unit during fish passage and typically operates at the upper end of the ±1% of best efficiency range for the purpose of providing tailrace conditions that are favorable for juvenile and adult fish passage.

During low river discharge events, the operating unit generally runs at the lower end of the ±1% of best efficiency range. At Lower Monumental Dam however, turbine unit 1 (the first priority unit during fish passage), cannot operate at the low end of the design range because it has welded blades. Ice Harbor turbine units cannot be operated at the lower end of the ±1% of best efficiency range because these units experience cavitation which damages the turbine runner and can be detrimental to fish. Therefore, Ice Harbor turbine units will operate at their lower cavitation limits. Minimum generation flow ranges at McNary, John Day, and The Dalles dams are 50-60 kcfs; and 30-40 kcfs at Bonneville as shown in Table 1.

Table 1.— Minimum generation ranges for turbine units at the four lower Snake and four lower Columbia River dams.

Project	Turbine Units	Minimum Generation (kcfs)
Lower Granite	1-3	11.3-13.1
	4-6	13.5-14.5
Little Goose	1-3	11.3-13.1
	4-6	13.5-14.5
Lower Monumental	1	16.5-19.5
	2-3	11.3-13.1
	4-6	13.5-14.5
Ice Harbor	1, 3-6	8.5-10.3
	2	11.3-13.1
McNary	N/A	50-60
John Day	N/A	50-60
The Dalles	N/A	50-60
Bonneville	N/A	30-40

Low Flow Operations

Low flow operations at lower Snake River projects are triggered when inflow is not sufficient to meet both minimum generation requirements and planned FOP spill levels in Table 2. In these situations, Snake River projects will operate one turbine unit at minimum generation and spill the remainder of flow coming into the project. Columbia River projects will also operate at minimum generation and pass remaining inflow as spill down to minimum spill levels. As flows transition from higher flows to low flows, there may be situations when maintaining minimum generation and the target spill may not be possible on every hour since these projects have limited flexibility. During the transition phase, flows may recede at a higher rate than forecasted and inflows provided by non-Federal projects upstream are often variable and uncertain. The combination of these factors may result in instances where unanticipated changes to inflow cause forebay elevations to go outside of recommended BiOp operating ranges.

Low flow conditions occurring when the navigation lock is being emptied at some projects may temporarily result in the spill percentage falling below the target. While the total spill volume remains constant, the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total flow than when river flows are higher.

At Little Goose Dam, when daily average flows in the lower Snake River are $\leq$32 kcfs, achieving 30% spill requires switching turbine operations between operating 2 units at the low end of the $\pm$1% of best efficiency range to operating one unit at the high end of the $\pm$1% of best efficiency range. This operation is incompatible with the more constant discharge upstream at Lower Granite Dam. It is also often difficult to achieve the FOP prescribed spill level downstream at Lower Monumental Dam and maintain MOP operations. In 2010, through coordination with TMT during low flow periods, Little Goose spill operations changed from 30% to a constant spill level of approximately 7-11 kcfs to smooth out Little Goose discharges, meet Lower Monumental spill levels, and maintain the MOP operating range at Little Goose. A similar operation will be implemented in spring 2011 if necessary, depending on river flow.

Operations during Rapid Load Changes

Project operations during hours in which load and/or intermittent generation changes rapidly may result in not meeting planned hourly spill level because projects must be available to respond to within-hour load variability to satisfy North American Electric Reliability Council (NERC) reserve requirements ("on response"). This usually occurs at McNary, John Day and The Dalles dams. In addition to within-hour load variability, projects on response must be able to respond to within hour changes that result from intermittent generation (such as wind generation). During periods of rapidly changing loads and intermittent generation, projects on response may have significant changes in turbine discharge within the hour while the spill quantity remains the same within the hour. Under normal conditions, within-hour load changes occur mostly on hours immediately preceding and after the peak load hours, however, within-hour changes in intermittent generation can occur at any hour of the day. Due to the high variability of within-hour load and intermittent generation, these load swing hours may have a greater instance of reporting actual spill percentages that vary more than the ±1% requirement than other hours.

Turbine Unit Testing around Maintenance Outages

Turbine units may be operationally tested for up to 30 minutes by running the unit at speed no load and various loads within the 1% of best efficiency range to allow pre-maintenance measurements and testing, and to allow all fish to move through the unit. Units may be operationally tested after maintenance or repair efforts but before a unit comes out of a maintenance or forced outage status. Operational testing may consist of running the unit for up to 30 minutes before it is returned to operational status. Operational testing of a unit under maintenance is in addition to a unit in run status (e.g. minimum generation) required for power plant reliability. Operational testing may deviate from unit operating priorities and may use water that would otherwise be used for spill if the running unit for reliability is at the bottom of the ±1% of best efficiency range. Water will be used from the powerhouse allocation if possible, and water diverted from spill for operational testing will be minimized. The Corps will coordinate this testing with the region through the FPOM.

Navigation Safety

Short-term adjustments in spill may be required for navigation safety, primarily at the lower Snake projects, but may also be necessary at the lower Columbia projects. This may include changes in spill patterns, reductions in spill discharge rates, or short-term spill stoppages. In addition, unsteady flow at Little Goose due to switching between operating one and two units during low flow conditions may impact that project's reservoir elevation and cause inadequate navigation depths at the downstream entrance to the Lower Granite navigation lock. Therefore, adjustments to pool elevation in the Little Goose pool of up to 1.0 ft. above the MOP operating range may be necessary to accommodate safe entrance to the navigation lock at Lower Granite Dam during periods of low flow (approximately 50 kcfs or less) and will be coordinated in TMT. These adjustments may be necessary for both commercial tows and fish barges.

JUVENILE FISH TRANSPORTATION PROGRAM OPERATIONS

As noted above, the Corps' planned spill operations assume average runoff conditions. In previous years, the FOP provided that spill for fish passage would occur under all flow conditions.[3] To improve survival of juvenile migrants, the 2010 Supplemental BiOp calls for an annual review of the previous year's fish survival information and discussion with the Regional Implementation Oversight Group (RIOG) to inform transport/spill operations for the subsequent year. After considering the best available information and taking into account input from regional sovereigns, the Corps has made the determination to continue juvenile fish transportation program operations implemented in 2010 at the Snake River collector projects in 2011. These operations will continue spill specified in Table 2 during the spring regardless of flow conditions. River flow and fish condition will be monitored, and if regional sovereigns recommend adjustments in spill and/or transportation operations that differ from those stated herein, the Corps will use the regional coordination process to make a determination on recommended operational changes.

The following describes the proposed transportation operations for the lower Snake River projects. Detailed descriptions of project and transport facility operations to implement the juvenile fish transportation program are contained in the FPP Appendix B.

Lower Snake River Dams - Operation and Timing

Transportation will be initiated at Lower Granite Dam no earlier than April 20 and no later than May 1. Transportation will start up to 4 days and up to 7 days after the Lower Granite Dam start date at Little Goose and Lower Monumental dams, respectively. The actual start date for Lower Granite, Little Goose, and Lower Monumental dams will be determined through coordination with TMT as informed by the in-season river condition (e.g. river flow and temperature) and the status of the juvenile Chinook and steelhead runs (e.g. percentage of runs having passed the project).

The collection of fish at lower Snake River projects for transportation will commence at 0700 hours on the agreed to start dates. Barging of fish will begin the following day and collected juvenile fish will be barged from each facility on a daily or every-other-day basis (depending on the number of fish) throughout the spring. Transportation operations will be carried out at each project in accordance with all relevant FPP operating criteria.

[3] The 2009 FOP provided: "In exceptionally low water years, when the projected seasonal average flow is less that 70 kcfs, the Corps will begin transportation on April 20 at all three Snake collector projects. Spill for fish passage will occur under all flow conditions."

Transportation and spill operations may be adjusted due to research, conditions at fish collection facilities such as overcrowding or temperature extremes, through the adaptive management process with FPOM and/or TMT to better match juvenile outmigration timing or achieve/maintain performance standards.

SPRING SPILL OPERATIONS

Lower Snake River Projects

Spring spill will begin on April 3 at Lower Granite, Little Goose, Lower Monumental, and Ice Harbor dams. Spring spill operations will continue through June 20. However, fish run timing and research schedules may require an earlier transition date to summer operations to assure that research occurs during the bulk of the migration. Such changes will be coordinated through TMT. Spring spill levels for Snake River dams are shown in Table 2.

Lower Columbia River Projects

Spring spill will begin April 10 at McNary, John Day, The Dalles, and Bonneville dams. Spring spill operations will continue through June 30 at John Day, and The Dalles dams, through June 19 at McNary Dam, and through June 20 at Bonneville Dam. However, fish run timing and research schedules may require earlier transition dates to summer spill operations to assure that research occurs during the bulk of the migration. Such changes if necessary will be coordinated through the TMT. Spring spill operations are shown in Table 2.

PROJECT BY PROJECT SPRING OPERATIONS

The following sections describe 2011 spring spill operations for each project. Included in the descriptions are planned research activities identified in the 2010 Supplemental BiOp. The Corps, regional fishery agencies, and Tribes are interested in the continuation of project research studies under the Corps' Anadromous Fish Evaluation Program (AFEP). These studies have been evaluated through the annual AFEP review process with the regional fishery agencies and Tribes, with the study designs being finalized prior to initiation in 2011. The studies are intended to provide further information on project survival that will help inform the region in making decisions on future operation and configuration actions to improve fish passage and survival and meet BiOp performance standards at the lower Snake and Columbia River dams.

Table 2.— Summary of 2011 spring spill levels at lower Snake and Columbia River projects.[4]

Project	Planned 2011 Spring Spill Operations (Day/Night)	Comments
Lower Granite	20 kcfs/20 kcfs	Same as 2010
Little Goose	30%/30%	Same as 2010
Lower Monumental	Gas Cap/Gas Cap (approximate Gas Cap range: 20-29 kcfs)	Same as 2010
Ice Harbor	**April 3-April 28:** 45 kcfs/Gas Cap **April 28-June 20:** 30%/30% vs. 45 kcfs/Gas Cap (approximate Gas Cap range: 75-95 kcfs)	Same as 2010
McNary	40%/40%	Same as 2010
John Day	**Pre-test:** 30%/30% **Testing:** 30%/30% and 40%/40%	Same as 2010
The Dalles	40%/40%	Same as 2010
Bonneville	100 kcfs/100 kcfs	Same as 2010

Lower Granite

Spring Spill Operations April 3 through June 20: 20 kcfs 24 hours per day.

Changes in Operations for Research Purposes:

- Spring research operations: There are no special spill operations for research planned in 2011. Established spill patterns as described in FPP Section 9 will be used.

Operational Considerations:

- Lack of power load or unexpected unit outages could cause involuntary spill at higher total river discharges that could result in exceeding the gas cap limits.
- During periods of high spring runoff when involuntary spill occurs, there may be periods where spill levels create unsafe hydraulic conditions for commercial, non-commercial, and fish transportation barges entering and exiting the tailrace and/or while moored at the fish loading facility. If such runoff conditions occur, spill may

[4] Table 2 displays in summary form planned spring spill operations, however, more specific detail governing project operations is in the section entitled "Spring Fish Operations By Project."

be reduced temporarily when fish transport barges approach or leave the barge docking area or are moored at loading facilities. If conditions warrant a spill reduction for any navigational passage, Lower Granite pool MOP elevation restrictions may be temporarily exceeded until the barge/vessel exits the tailrace safely and spill resumes.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Maintenance dates are subject to change.

Little Goose

Spring Spill Operations April 3 through June 20: 30% spill 24 hours per day with the spillway weir in service by April 4.

Changes in Operations for Research Purposes:

- Spring research operations: There are no special spill operations for research planned in 2011. Established spill patterns as described in FPP Section 8 will be used.

Operational Considerations:

- Daily average flows in the lower Snake River of $\leq$32 kcfs can result in incompatible operations with Lower Monumental Dam and cause spill quantity fluctuations. Alternative Little Goose operations to resolve this issue are described in the Low Flow Operations section above and will be coordinated through the TMT.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Maintenance dates are subject to change.
- Turbine Unit 1 Operation: Operating range will be set within the GDACS program for Little Goose Dam to restrict Turbine Unit 1 operation to approximately the upper 25% of the 1% of best efficiency range (about 16-17.5 kcfs). This will ensure a strong current along the south shore to counter the strong eddy that forms in the tailrace during certain spill conditions. A strong south shore current in the tailrace is important for both adult fish passage and juvenile fish egress. If low flow conditions occur in the spring, the full ±1% of best efficiency range will be restored to minimize impacts on spill levels.

Lower Monumental

Spring Spill Operations April 3 through approximately June 20: Spill to the 115/120% TDG spill cap 24 hours per day.

Changes in Operations for Research Purposes:

- Spring research operations: There are no special spill operations for research planned in 2011. The "bulk" spill pattern as described in FPP Section 7 will be used. Based on previous years' study results, dam survival is higher using the "bulk" spill pattern compared to the "uniform" spill pattern.

Operational Considerations:

- Daily average flows of ≤32 kcfs can result in incompatible operations with Little Goose Dam and may cause spill quantity fluctuations.
- Transit of the juvenile fish barge across the Lower Monumental tailrace, then docking at and departing from the fish collection facility, may require spill level to be reduced due to safety concerns. The towboat captain may request that spill level be reduced or eliminated during transit. During juvenile fish loading operations, spill is typically reduced to 15 kcfs, but can be reduced further if necessary for safety reasons. Barge loading duration can be up to 3.5 hours. Because of the time needed to complete loading at Lower Monumental, the Little Goose Project personnel will notify the Lower Monumental personnel when the fish barge departs from Little Goose. This ensures that BPA scheduling is provided advance notice for spill control at Lower Monumental Dam. Reducing spill may cause the Lower Monumental pool to briefly operate outside of MOP conditions.
- Operating units within the 1% of best efficiency range translates to as much as 19 kcfs discharge for each of the 6 turbine units, for a maximum hydraulic capacity of approximately 114 kcfs. The expected spill cap is roughly 27 kcfs (but varies depending on total river discharge). Therefore, if total river discharge is greater than 141 kcfs the gas cap will be exceeded. Either lack of power load or unit outages can also cause forced spill above spill cap limits at higher total river discharges.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Maintenance dates are subject to change.

<u>Ice Harbor</u>

Spring Spill Operations April 3 through June 20: Spill will begin at 45 kcfs day/spill cap night on April 3 and continue until April 28. On April 28, spill will alternate between 45 kcfs day/spill cap night and 30% /30% with the SW operating and continue through the spring season. Nighttime spill hours are 1800–0500.

Changes in Operations for Research Purposes:

- <u>Spring research operations</u>: There are no special spill operations for research planned in 2011. Spill patterns as described in FPP Section 6 will be used.

Operational Considerations:

- Spill operation treatments may be rearranged within a week throughout the season. If rearrangement of treatments occurs, the total number of each spill level treatment for the spring season will not change. The flexibility to rearrange treatments during periods of higher power demand may alleviate the need to declare a power emergency.
- Powerhouse capacity at Ice Harbor is approximately 94 kcfs with all 6 units operating within the 1% of best efficiency range, while spill cap rates are about 100 kcfs. If

total river flows exceed about 194 kcfs, TDG levels may exceed the water quality standards set by the States of Oregon and Washington.

- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.
- Submersible Traveling Screens (STSs) will be installed by April 1. The normal juvenile bypass operation will be to route fish through the full flow bypass pipe, which has interrogation capability to monitor for PIT tags. From April 1 through July 31, juvenile fish will be sampled every 3 to 5 days to monitor fish condition and then bypassed to the river. Sampling activity may be terminated early should juvenile bypass fish numbers drop to the point where valid sampling is no longer feasible (100 fish of the most dominant species present are needed to properly assess fish condition). Sampling may also cease if the cumulative number of fish sampled for the season reach the permitted maximum.

McNary

Spring Spill Operations April 10 – approximately June 19: 40% spill 24 hours per day with the two spillway weirs operating. A spillway weir will be operated in both spillbay 19 and spillbay 20 for the period April 10 thru June 6. Both spillbay weirs will be removed from service by June 6 for the benefit of subyearling Chinook. This operational change will be coordinated through FFDRWG, FPOM, the Tribes, and NOAA. Temporary spill pattern changes to allow removal of the spillway weirs will occur, however spill will continue at 40% during the spillway weir removal process. Following removal of the spillway weirs, the spill pattern contained in Table MCN-10 in FPP section 5 will be used for the remainder of the spring.

Changes in Operations for Research Purposes:

- Spring research operations: There are no special spill operations for research planned in 2011. Spill patterns as described in FPP Section 5 will be used.

Operational Considerations:

- Juvenile fish collected at McNary during the spring FOP implementation period will be bypassed to the river. The normal operation will be to bypass fish through the full flow bypass pipe, which has interrogation capability to monitor for PIT tags. Every other day, however, in order to sample fish for the Smolt Monitoring Program, fish will be routed through the separator, interrogated for PIT tags, and then bypassed to the river.
- All extended-length submersible bar screens (ESBSs) at McNary will be installed by April 15 as agreed to in consultation with FPOM, the Tribes, and NOAA. This is part of the Corps' consideration of lifting (or waiting to install) some turbine intake screens during periods of significant juvenile lamprey passage. Effects to both salmon and lamprey have been considered. Although there are some adverse impacts to migrating salmon from this delay in screen installation, regional sovereigns have considered this acceptable in balancing the needs of multiple species.

- During the periods when total river discharge exceeds approximately 320 kcfs, involuntary spill in excess of the States' TDG limits for fish passage may occur.
- In addition, low power demand may also necessitate involuntary spill at total river discharge of less than 320 kcfs.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

John Day

Spring Spill Operations April 10 – June 30: 30% spill 24 hours per day prior to testing, then 30% spill and 40% spill 24 hours per day during the test. Spill levels will alternate in a random 4-day block with two-day treatments. Spill level changes will occur at 0600 hours.

Changes in Operations for Research Purposes:

- Spill duration for performance standard testing: Testing in late April through early June. The dates of testing will be dependent on the size of fish, fish availability, and the number of treatments needed for testing. Final dates for testing will be coordinated through the SRWG.
- Spring research operations: Performance standard testing at 30% and 40% spill will occur in spring 2011 at John Day Dam.
- Objectives of the biological test: The objectives of the test are to assess passage distribution and efficiency metrics, forebay retention and tailrace egress times, and dam survival for yearling Chinook, and juvenile steelhead to determine if juvenile dam survival at 30% and/or 40% spill under the current project configuration meets or exceeds the juvenile dam survival performance standard for spring migrants (96%) specified in the 2010 Supplemental BiOp.
- Spill pattern during biological test: Spill patterns as described in FPP section 4 will be used.

Operational Considerations:

- Unit outages will occur for required maintenance activities. The outage schedule for the project is shown in the FPP. Dates are subject to change.
- Unit outages and spillway outages may be required to repair hydrophones and other research equipment. These will be coordinated through FPOM and TMT as needed.

The Dalles

Spring Spill Operations April 10 – June 30: 40% spill 24 hours per day.

Changes in Operations for Research Purposes:

- Spring research operations: Performance standard testing at 40% spill will occur in spring 2011 at The Dalles Dam.

- Objectives of the biological test: The objectives of the test are to assess passage distribution and efficiency metrics, forebay retention and tailrace egress times, and dam survival for yearling Chinook, and juvenile steelhead to determine if juvenile dam survival at 40% spill under the current project configuration meets the juvenile dam survival performance standard for spring migrants (96%) specified in the 2010 Supplemental BiOp.
- Spill pattern during the biological test: Spill patterns developed for use with the new spillwall and included in FPP section 3 will be used.

Operational Considerations:

- If total river discharge is between 90 and 150 kcfs, the spill percentage could range from 38.6 to 41.4 percent due to the new spill patterns developed for use with the newly completed spillwall.
- If the total river discharge is between 150 and 300 kcfs, the spill percentage could range from 38.9 to 41.2 percent due to the new spill patterns developed for use with the newly completed spillwall.
- If the total river discharge is between 300 and 420 kcfs, the spill percentage could range from 38.4 to 41.0.
- At no time is spill recommended on the south side of the spillway (Bays 14-22) as this creates a poor tailrace egress condition for spillway-passed fish.
- Spill bays 10, 11, 13, 16, 18, 19, and 23 are not operational due to wire rope, structural and concrete erosion concerns.
- The spill pattern in the FPP is based on a nominal Bonneville forebay elevation of 74 feet.
- Unit outages will occur for required maintenance activities. The outage schedule for the project is shown in the FPP. Dates are subject to change.

Bonneville

Spring Spill Operations April 10 – June 20: 100 kcfs spill 24 hours per day.

Changes in Operations for Research Purposes:

- Spring research operations: Performance standard testing at 100 kcfs spill will occur in spring 2011 at Bonneville Dam.
- Objectives of the biological test: The objectives of the test are to assess passage distribution and efficiency metrics, forebay retention and tailrace egress times, and dam survival for yearling Chinook, and juvenile steelhead to determine if juvenile dam survival at 100 kcfs spill under the current project configuration meets the juvenile dam survival performance standard for spring migrants (96%) specified in the 2010 Supplemental BiOp.
- Spill pattern during biological test: Spill patterns for 100 kcfs as described in FPP section 2 will be used.

Operational Considerations:

- Minimum spill discharge rate is 50 kcfs however, under extreme low flow conditions lower spill levels may be considered and coordinated through the TMT. This is to provide acceptable juvenile fish egress conditions in the tailrace.
- At total spring flows less than about 135 kcfs, spill will be less than 100 kcfs to maintain minimum powerhouse generation of 30 kcfs plus fish ladder and facility spill (e.g. second powerhouse corner collector, first powerhouse sluiceway).
- The TMT will consider the possible effects of TDG on emerging chum salmon downstream of Bonneville Dam. The TMT may request special operations such as flow increases or spill reductions to protect ESA-listed fish.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Maintenance dates are subject to change.
- Actual spill levels at Bonneville Dam may range from 1 to 3 kcfs lower or higher than specified in Table 2. A number of factors influence this including hydraulic efficiency, exact gate opening calibration, spillway gate hoist cable stretch due to temperature changes, and forebay elevation (a higher forebay results in a greater volume of spill since more water can pass under the spill gate).
- The second powerhouse Corner Collector (5 kcfs discharge) will operate from the morning of April 10 through the remainder of the spring season as coordinated through the FPOM.

TRANSPORT, LATENT MORTALITY, AND AVIAN RESEARCH

Seasonal Effects of Transport

A study will be conducted to determine seasonal effects of transporting fish from the Snake River to optimize a transportation strategy. At Lower Granite, fish will be collected for this study starting on April 4, with marking beginning on April 5. Depending on the number of fish available, fish will be collected 1-2 days with tagging occurring on the day following collection. A barge will leave each Thursday morning with all fish collected during the previous 1-3 days. By barging all fish (minus the in-river group) during 1 to 3 days of collection, barge densities will be maintained at a level similar to what would occur under normal transport operations that time of year. This pattern will occur in the weeks preceding general transportation and will be incorporated into general transportation once that operation begins. The desired transported sample size is 6,000 wild Chinook and 4,000 - 6,000 wild steelhead weekly for approximately eight weeks.

Latent Mortality

A study will be conducted to evaluate latent mortality associated with passage through Snake River dams. The goal of this study is to determine whether migration through Snake River dams and reservoirs causes extra mortality in Snake River yearling (spring/summer) Chinook salmon smolts. Specifically, the study will determine if life-cycle survival downstream from McNary Dam is significantly higher for yearling hatchery Chinook salmon released into the Ice Harbor Dam tailrace than for counterparts which must pass three additional dams and reservoirs after release into the Lower Granite Dam tailrace. Fish will be collected at Lower Granite Dam beginning approximately April 20, with the goal of tagging approximately 74,000 smolts of which 45,000 will be released into the tailrace of Lower Granite Dam, and 29,000 transported by truck and released in the tailrace of Ice Harbor Dam.

EMERGENCY PROTOCOLS

The Corps and the Bureau of Reclamation will operate the projects in emergency situations in accordance with the WMP Emergency Protocol (WMP Appendix 1). This protocol identifies the process the Action Agencies will use in the event of an emergency concerning the operation of FCRPS that impacts planned fish protection measures. The most recent version of the Emergency Protocols is located at: http://www.nwd-wc.usace.army.mil/tmt/documents/wmp/2010/final/emerproto

COORDINATION

To make adjustments in response to changes in conditions, the Corps will utilize the existing regional coordination committees. Changes in spill rates when flow conditions are higher or lower than anticipated will be coordinated through the TMT. This could include potential issues and adjustments to the juvenile fish transportation program. Spill patterns and biological testing protocols that have not been coordinated to date will be finalized through the Corps' AFEP subcommittees, which include the SRWG, FFDRWG, and FPOM.

REPORTING

The Corps will provide periodic in-season updates to TMT members on the implementation of 2011 fish passage operations. The updates will include the following information:

- the hourly flow through the powerhouse;
- the hourly flow over the spillway compared to the spill target for that hour; and,
- the resultant 12-hour average TDG for the tailwater at each project and for the next project's forebay downstream.

The updates will also provide information on substantial issues that arise as a result of the spill program (e.g. Little Goose adult passage issues in 2005 and 2007), and will address any emergency situations that arise.

The Corps will continue to provide the following data to the public regarding project flow, spill rate, TDG level, and water temperature.

- Flow and spill quantity data for the lower Snake and Columbia River dams are posted to the following website every hour: http://www.nwd-wc.usace.army.mil/report/projdata.htm

- Water Quality: TDG and water temperature data are posted to the following website every hour: http://www.nwd-wc.usace.army.mil/report/total.html. These data are received via satellite from fixed monitoring sites in the Columbia and Snake rivers every hour, and placed on a Corps public website upon receipt. Using the hourly TDG readings for each station in the lower Snake and Columbia rivers, the Corps will calculate both the highest and highest consecutive 12-hour average TDG levels daily for each station. These averages are reported at:
  http://www.nwd-wc.usace.army.mil/ftppub/water_quality/12hr/wa/

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UNITED STATES DISTRICT COURT
DISTRICT OF OREGON
PORTLAND DIVISION

NATIONAL WILDLIFE FEDERATION, *et al.*

Plaintiffs,

v.

NATIONAL MARINE FISHERIES SERVICE, *et al.*

Defendants.

Civil No. 01-640-RE

~~[PROPOSED]~~ ORDER FOR 2011 SUMMER OPERATIONS

Federal Defendants submit the following (Proposed) Order for 2011 summer fish operations for the Federal Columbia River Power System ("FCRPS").

In 2005, this Court granted in part, and denied in part, Plaintiffs' motion for preliminary injunctive relief seeking to alter FCRPS operations during the spring and summer of 2006. See Doc. 1221. The Court adopted the Federal Defendants' proposals for the amount and timing of spring and summer spill at FCRPS dams with two exceptions. Id. at 11. After commencement of spill, Federal Defendants were directed to provide the court with a monthly written report describing the implementation and progress of the spill program. Id.

Similar spring and summer operations were implemented in 2007 pursuant to an agreement between the Bonneville Power Administration (BPA), the Confederated Tribes of the Warm Springs Reservation, the Nez Perce Tribe, Confederated Tribes of the Umatilla Indian Reservation, Confederated Tribes and Bands of the Yakama Nation, and Confederated Tribes of the Colville Indian Reservation. See Doc. 1347 at 3. On May 23, 2007, the Court adopted the 2007 operations agreement as an order of the Court. See Opinion and Order (May 23, 2007).

At a December 12, 2007 status conference, Federal Defendants offered to continue the 2007 spring and summer operations if Plaintiffs would agree to not seek a preliminary injunction until after issuance of the 2008 BiOp. In agreeing to work toward this goal, Plaintiffs' recognized that any agreement for 2008 operations "would essentially continue - subject to discussion of limited changes necessary to accommodate new structures and perform essential research - the court-ordered operations from 2007." See Plaintiffs' January 11, 2008 Letter. The 2008 Fish Operations Plan, incorporated into the Court's Order on 2008 Operation, recognized the operational adjustments necessary to perform this research and accommodate structural changes. See Doc. 1409, Attachment 1. On February 25, 2008, this Court entered the joint proposed order for 2008 spring and summer operations. Doc. 1423.

In a February 18, 2009 letter to counsel, the Court asked Federal Defendants to agree to "continue recent court-ordered spill operations for Spring 2009." See Doc. 1682 at 2. At the March 6, 2009 hearing, counsel represented that Federal Defendants would abide by the Court's request to continue court-ordered spring spill operations subject to modifications necessary to accommodate new structures and perform essential research. See Tr. at 167. On April 10, 2009, the Court entered an order adopting the parties proposed order. See Doc. 1694.

On February 19, 2010, the Court entered an order granting Federal Defendants' request for a limited, voluntary remand and directed Federal Defendants to complete this remand within three months. On May 20, 2010, Federal Defendants submitted a notice of completion of remand and on June 9, 2010, the Court entered a litigation scheduling order for review of the Supplemental Biological Opinion. Doc. 1766. In the interests of maintaining this litigation schedule, Federal Defendants submitted a nearly identical proposed order for 2010 summer operations as they did in 2009, and the Court entered that order on June 14, 2010. See Doc. 1768. Consistent with past practices and in the interests of resolving the merits of this litigation, Federal Defendants have attached a proposed order for 2011 summer fish operations.

THEREFORE, in light of this prior history and in the interests of avoiding further litigation, the undersigned parties stipulate as follows:

1. Scope: The Court's entry of the proposed order on summer 2011 fish operations shall not be construed as a concession or preliminary assessment of the merits of any parties' claim concerning the 2010 Supplemental Biological Opinion, Action Agencies' Amended Records of Decision, 2008 Biological Opinion, Adaptive Management Implementation Plan (AMIP), or Action Agencies' 2008 Records of Decision as set forth in the parties' pending cross-motions for summary judgment and supplemental cross-motions for summary judgment.

2. Operations: FCRPS summer 2011 fish operations shall be conducted as set forth in the 2011 Summer Fish Operations Plan, incorporated herein by reference. To the extent hydro-power operations are not specified in the 2011 Summer Fish Operations Plan, Federal Defendants shall operate the FCRPS consistent with the Supplemental Biological Opinion, 2008 Biological Opinion, and/or other operative documents necessary to implement that Biological Opinion, unless otherwise specified herein.

3. Timing: This Order applies to summer spill operations for 2011 only and shall continue until August 31, 2011, unless this Court issues an opinion on the pending cross-motions and supplemental cross-motions for summary judgment prior to that transition date. If the Court issues an opinion granting, in whole or in part, the plaintiffs' pending motions for summary judgment, this Order shall remain in effect until replaced by a further order of the Court or August 31, 2011. If the Court issues an opinion granting the federal defendants' pending cross-motion for summary judgment, this

Order shall terminate on the date the Court issues such a ruling without prejudice to the right of any party to seek emergency or other appropriate relief in any forum.

4. In-Season Adjustments: As set forth in the 2011 Summer Fish Operations Plan, Federal Defendants will utilize the existing Regional Forum committees to make in-season adjustments.

5. Standard Reporting Requirement: Federal Defendants shall provide the court with a written report describing the implementation of the 2011 Summer Fish Operations Plan, beginning July 15, 2011, and monthly intervals thereafter until satisfaction of the earlier of the conditions in Paragraph 3. Should the agencies encounter a situation similar to that which occurred on April 3, 2007, which the Court characterized as "placing power needs before the needs of listed species", Federal Defendants shall notify the Court and the other parties promptly and shall propose mitigation measures, if any, that may be appropriate as soon as practicable.

6. Emergency Reporting Requirements: Federal Defendants shall take all reasonable and practicable steps to notify the Court and the parties prior to any declared system emergency. If unforeseen circumstances arise that preclude Federal Defendants from notifying the Court and the parties prior to a declared system emergency, they shall report those actions directly to the court as soon as practicable.

Dated this 14th day of JUNE, 2011.

James A. Redden
United States District Judge

RESPECTFULLY SUBMITTED,

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CERTIFICATE OF SERVICE

Pursuant to Local Rule Civil 100.13(c), and F.R. Civ. P. 5(d), I certify that on June 13, 2011, the foregoing will be electronically filed with the Court's electronic court filing system, which will generate automatic service upon on all Parties enrolled to receive such notice. The following will be manually served by overnight mail:

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June 2011

2011 Summer Fish Operations Plan

INTRODUCTION

The 2011 Summer Fish Operations Plan (FOP) describes the U.S. Army Corps of Engineers' (Corps) planned operations for fish passage at its mainstem Federal Columbia River Power System (FCRPS) dams during the 2011 summer fish migration season, generally June through August. The Action Agencies are committed to the summer spill measures and achieving mainstem FCPRS project hydro performance standards contained in the 2010 NOAA Fisheries Supplemental Biological Opinion (2010 Supplemental BiOp)[1] as supported by the BiOp analyses. The Action Agencies are also interested in expeditious resolution of the case challenging these opinions; therefore, for summer 2011, the agencies support adoption of the project operations contained in the Order for 2010 Summer Spill Operations. The 2011 Summer FOP adopts project operations in the Order for 2010 Summer Spill Operations.

The 2011 Summer FOP provides for adaptive management and is consistent with the 2010 Supplemental BiOp and the Corps' Record of Consultation and Statement of Decision Document (ROCASOD) adopting the project operations contained in the 2010 Supplemental BiOp. As in the 2010 Summer FOP, operations described herein may be adjusted to address in-season developments through discussion and coordination with regional sovereigns. Other FCRPS water management actions and project operations not specifically addressed in this document shall be consistent with the 2010 Supplemental BiOp and other guiding operative documents including the 2011 Water Management Plan (WMP), seasonal WMP updates, and the 2011 Fish Passage Plan (FPP).

The following sections describe factors that influence management of fish operations during various runoff conditions, including: total dissolved gas (TDG) management, spillway operations, minimum generation requirements, operations under low flow conditions, navigation safety, juvenile fish transportation operations, specified summer operations for fish at each mainstem project, protocols for fish protection measures related to operational emergencies, coordination with regional entities, and monthly reporting.

GENERAL CONSIDERATIONS FOR FISH OPERATIONS

For planning purposes, the Corps' 2011 Summer FOP assumes above average runoff conditions. As a result of above average runoff, performance standard testing at Bonneville, The Dalles, and John Day dams has been canceled due to a likely inability to

[1] The 2010 Supplemental BiOp incorporates the NOAA 2008 BiOp

maintain target spill levels during the test period. However, because actual runoff conditions vary in timing and shape and may be higher or lower than average, adjustments in fish transportation and/or spill operations (kcfs discharge levels, spill percentages, or spill caps) will be adaptively managed in-season. These in-season changes will be coordinated through the Technical Management Team (TMT) and other appropriate regional forums, to avoid or minimize poor juvenile or adult fish passage conditions, navigation safety concerns, or to accommodate powerhouse and/or transmission system constraints.

Management of Spill for Fish Passage

The Corps will manage spill for fish passage to avoid exceeding 120% TDG in project tailraces, and 115% TDG in the forebay of the next project downstream.[2] These levels are referred to as "gas caps." The project maximum spill discharge level that meets, but does not exceed the gas cap, is referred to as the spill cap. Gas caps are constant, whereas spill caps may vary daily depending on flow, spill pattern, temperature, and other environmental conditions.

As noted above, the spill levels presented below in Table 2 are planned spill operations and assume average runoff conditions; however, adjustments to these spill rates may be necessary. Reasons for these adjustments may include:

1. Low runoff conditions that may require adjustments in spill level while still meeting project minimum generation requirements.
2. High runoff conditions where flows exceed the powerhouse hydraulic capacity with the specified spill rates.
3. Navigation safety concerns.
4. Generation unit outages that reduce powerhouse capacity.
5. Power system or other emergencies that reduces powerhouse discharge.
6. Lack of power demand resulting in an increase of spill level.

The Corps' Reservoir Control Center (RCC) is responsible for daily management of spill operations responsive to changing TDG conditions. In order to manage gas cap spill levels consistent with the states' TDG saturation limits, the RCC establishes the spill caps for each project on the lower Columbia and Snake rivers on a daily basis throughout the fish passage season. These spill caps are set so that resultant TDG percent saturation levels are not expected to exceed the 120%/115% TDG limits measured as the average of the highest 12 hourly readings each day.

Within any given day, some hours of measured TDG levels may be higher or lower than the gas caps due to changing environmental conditions (wind, air temperature, etc.). The process of establishing daily spill caps entails reviewing existing hourly data at each dam (including flow, spill, temperature, and TDG levels) and taking into consideration a number of forecast conditions (including total river discharge, powerhouse discharge,

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[2] For 2011 summer operations, the Corps will continue to manage TDG to 120% in the tailwater and 115% in the forebay of each mainstem project, consistent with summer 2010 court ordered operations.

wind and temperature forecast, etc.). These data are used as input variables into the System TDG (SYSTDG) model. The SYSTDG model estimates TDG levels expected several days into the future and is a tool integral to daily decision-making when establishing spill caps at individual dams. Spill caps set by RCC and contained in the daily TDG production curves will be met at the projects using the individual project spill pattern(s) contained in the FPP Sections 2 through 9, which most closely correspond to the specified spill level (i.e. may be slightly over or under the specified spill discharge or percent value). During periods when river discharge is greater than project powerhouse hydraulic capacity or a lack of power demand results in an increase in the spill level, the Corps will attempt to minimize TDG on a system-wide basis. In this case, spill caps are also developed for 122%, 125%, 127%, 130%, or 135% saturation as a means of minimizing TDG throughout the system.

The Corps will transition to summer spill operations at 0001 hours, or shortly after midnight, at each of the projects on the start dates specified in the project sections below. Spill caps will be established at the specified levels and will continue unless conditions require changing to maintain TDG within the upper limits of 120% in the tailwater of a dam and 115% in the forebay of the next project downstream (and at Camas/Washougal from July 21 – August 31, following the alternating spill operation at Bonneville Dam). Operations to manage TDG will continue to be coordinated through the TMT.

Spillway Operations

The Action Agencies will meet the specified spill levels to the extent feasible; however, actual hourly spill quantities at dams will be slightly greater or less than specified in Table 2 below. Actual spill levels depend on the precision of spill gate settings, flow variations in real time, varying project head (the elevation difference between a project's forebay and tailwater), automatic load following, and other factors.

Operational Considerations:

- Spill discharge levels: Project spill levels listed in Table 2 coincide with specific gate settings in the FPP project spill pattern tables. Due to limits in the precision of spill gates and control devices, short term flow variations, and head changes, it is not always possible to discharge the exact spill levels stated in Table 2, or as stated in RCC spill requests (teletypes) to projects that call for discrete spill discharges. Therefore, spillway gates are opened to the gate settings identified in the FPP project spill pattern tables to provide spill discharge levels that are the closest to the prescribed spill discharge levels.

- Spill percentages: Spill percentages are considered target spill levels. The project control room operator and BPA duty scheduler calculate spill levels to attempt to be within ±1% of the target percentage for the following hour (or more than ±1% at The Dalles and Little Goose dams as specified in FPP Sections 3 and 8 spill pattern tables). Prescribed or specified percentages in Table 2 may not always be attained due to low discharge conditions, periods of minimum generation, spill cap limitations, temporary spill curtailment for navigation safety, and other unavoidable circumstances. Operators and schedulers review the percentages achieved during the day and will attempt to adjust spill rates in later hours if necessary, with the objective of ending the day with a daily average spill percentage that achieves the specified spill percentage.

Minimum Generation

The Corps has identified minimum generation flow values derived from actual generation records when turbines were operating within ±1% of best efficiency (Table 1). Values stated in Table 1 are approximations that account for varying head or other small adjustments in turbine unit operation that may result in variations from the reported minimum generation flow and spill amount. Conditions that may result in minor variations include:

1. Varying pool elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor "dead band": the governor controls the number of megawatts the unit should generate, but cannot precisely control a unit discharge; variations may be 1-2% of generation.
3. System disturbances: once a generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase discharge and generation slightly within an hour. Individual units operate differently from each other and often have unit specific constraints.
4. Generation control systems regulate megawatt (MW) generation only; not discharge through individual turbine units.

All of the lower Snake River powerhouses may be required to keep one generating unit on line at all times for power system reliability under low river discharge conditions, which may result in a reduction of spill at that project. All of the Snake River projects have two “families” of turbines with slightly different capacities – small and large. In most cases during low flow conditions, one of the smaller turbine units (with reduced generation and flow capabilities) will be online. The smaller turbine units are generally numbered 1–3 and are the first priority for operation during the fish passage season. If smaller turbine units are unavailable, larger units may be used instead. At Little Goose, turbine unit 1, the first priority unit during fish passage, typically operates near the upper end of the ±1% of best efficiency range for the purpose of providing tailrace conditions that are favorable for juvenile and adult fish passage.

During low river discharge events, generally the operating unit runs at the lower end of the ±1% of best efficiency range. However, at Lower Monumental, turbine unit 1, which is the first priority unit during fish passage, has welded blades and consequently cannot operate at the low end of the design range. Ice Harbor turbine units cannot be operated at the lower end of the ±1% of best efficiency range. At generation levels near the lower end of the ±1% of best efficiency range, excessive cavitation occurs, which can damage the turbine runner and also be detrimental to fish. Therefore, Ice Harbor turbine units will operate at a generation level somewhat higher than the lower ±1% limit. Additionally, Ice Harbor unit 2 has welded blades affecting minimum generation for that unit. Minimum generation flow ranges at McNary, John Day, and The Dalles are 50-60 kcfs; and 30-40 kcfs at Bonneville as shown in Table 1.

Table 1.— Minimum generation ranges for turbine units at the four lower Snake and four lower Columbia River dams.

Project	Turbine Units	Minimum Generation (kcfs)
Lower Granite	1-3	11.3-13.1
	4-6	13.5-14.5
Little Goose	1-3	11.3-13.1
	4-6	13.5-14.5
Lower Monumental	1	16.5-19.5
	2-3	11.3-13.1
	4-6	13.5-14.5
Ice Harbor	1, 3-6	8.5-10.3
	2	11.3-13.1
McNary	N/A	50-60
John Day	N/A	50-60
The Dalles	N/A	50-60
Bonneville	N/A	30-40

Low Flow Operations

Low flow operations at lower Snake River projects are triggered when inflow is not sufficient to meet both minimum generation requirements and planned spill levels in Table 2. In these situations, Snake River projects will operate one turbine unit at minimum generation and spill the remainder of flow coming into the project. Columbia River projects will also operate at minimum generation and pass remaining inflow as spill down to minimum spill levels under low flow conditions. As flows transition from higher flows to low flows, there may be situations when flows recede at a higher rate than forecasted. In addition, inflows provided by non-Federal projects upstream are often variable and uncertain. The combination of these factors may result in instances where unanticipated changes to inflow result in forebay elevations dropping to the low end of the Minimum Operating Pool (MOP). Consequently, maintaining minimum generation and the target spill may not be possible on every hour since these projects have limited operating flexibility.

During low flow conditions when the navigation lock is being emptied at some projects, the total spill volume remains constant, but the spill reported as a percent of total flow may be temporarily reduced below the target spill percentage. This occurs because the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total flow than when river flows are higher.

At Little Goose Dam, when daily average flows in the lower Snake River are ≤32 kcfs, achieving 30% spill requires switching turbine operations between operating 2 units at the low end of the ±1% of best efficiency range to operating one unit at the high end of the ±1% of best efficiency range. This operation is incompatible with the more constant discharge upstream at Lower Granite Dam. It is also often difficult to achieve the FOP prescribed spill level downstream at Lower Monumental Dam and maintain MOP operations. In 2010, through coordination with TMT during low flow periods, Little Goose spill operations changed from 30% to a flat spill level of approximately 7-11 kcfs to smooth out Little Goose discharges, meet Lower Monumental spill levels, and maintain the MOP operating range at Little Goose. In accordance with the 2011 FPP Section 8 spill pattern tables, when daily average discharge drops below 35 kcfs in the summer while the spillway weir (SW) is installed at the high crest position and flow is forecast to remain below 35 kcfs for at least three days, the SW will be closed for the remainder of the spill season. Spillway weir removal allows allow finer control of spill discharge during periods of low river discharge. If necessary in 2011, additional operational adjustments at Little Goose may be implemented during low flow periods after coordination with FPOM/TMT.

Operations during Rapid Load Changes

Project operations during hours in which load and/or intermittent generation changes rapidly may result in not meeting planned hourly spill level because projects must be available to respond to within-hour load variability to satisfy North American Electric Reliability Council (NERC) reserve requirements ("on response"). This usually occurs at McNary, John Day and The Dalles dams. In addition to within-hour load variability, projects on response must be able to respond to within hour changes that result from intermittent generation (such as wind generation). During periods of rapidly changing loads and intermittent generation, projects on response may have significant changes in turbine discharge within the hour while the spill quantity remains the same within the hour. Under normal conditions, within-hour load changes occur mostly on hours immediately preceding and after the peak load hours, however, within-hour changes in intermittent generation can occur at any hour of the day. Due to the high variability of within-hour load and intermittent generation, these load swing hours may have a greater instance of reporting actual spill percentages that vary more than the ±1% requirement than other hours.

Turbine Unit Testing around Maintenance Outages

Turbine units may be operationally tested for up to 30 minutes by running the unit at speed no load and various loads within the ±1% of best efficiency range to allow pre-maintenance measurements and testing and to allow all fish to move through the unit. Units may be operationally tested after maintenance or repair efforts but before a unit comes out of a maintenance or forced outage status. Operational testing may consist of running the unit for up to 30 minutes before it is returned to operational status. Operational testing of a unit under maintenance is in addition to a unit in run status (e.g. minimum generation) required for power plant reliability. Operational testing may deviate from unit operating priorities and may use water that would otherwise be used for spill if the running unit for reliability is at the bottom of the ±1% of best efficiency range. Water will be used from the powerhouse allocation if possible, and water diverted from spill for operational testing will be minimized. The Corps will coordinate this testing with the region through the FPOM.

Navigation Safety

Short-term adjustments in spill may be required for navigation safety, primarily at the lower Snake projects, but may also be necessary at the lower Columbia projects. This may include changes in spill patterns, reductions in spill discharge rates, or short-term spill stoppages. In addition, unsteady flow at Little Goose and Ice Harbor dams during low flow conditions may impact those projects' reservoir elevation and cause inadequate navigation depths at the downstream entrances to the Lower Granite and Lower Monumental navigation locks. Therefore, adjustments to pool elevation in the Little Goose pool and Ice Harbor pool, of up to 1.0 ft. above the MOP operating range may be necessary to accommodate safe entrance to the navigation locks at Lower Granite and Lower Monumental dams during periods of low flow (approximately 50 kcfs or less) and will be coordinated in TMT. These adjustments may be necessary for both commercial tows and fish barges. Additionally, to accommodate safe navigation, the Lower Granite pool will be operated up to MOP+2 ft. depending on river flow. This operation was requested through System Operational Request (SOR) 2011-01 during implementation of the 2011 Spring FOP, and coordinated through the TMT on March 31, 2011 available here: http://www.nwd-wc.usace.army.mil/tmt/sor/2011/

This operation will continue through the remainder of MOP operations in 2011.

JUVENILE FISH TRANSPORTATION PROGRAM OPERATIONS

The following describes the juvenile fish transportation program under all runoff conditions and is consistent with the 2010 Summer FOP transport operations. The lower Snake River projects are described first, followed by McNary project operations. Detailed descriptions of project and transport facility operations, including the transition from barges to trucks when fish numbers decrease in the summer, are contained in FPP Appendix B.

Lower Snake River Dams - Operation and Timing

The 2011 Spring FOP provides information about the initiation of transport at the lower Snake River collector projects. Summer transport operations at the lower Snake River collector projects will continue as specified in the Order for 2010 Summer Spill Operations. Starting on or about August 15, fish will be transported by truck, dependant on numbers of subyearling Chinook collected. Transport operations will be carried out concurrent with FOP spill operations at each project and in accordance with all relevant FPP operating criteria. Fish transportation operations for the lower Snake River collector projects are described in FPP Appendix B.

Fish transportation operations are expected to continue through approximately October 31 at Lower Granite and Little Goose dams, and through September 30 at Lower Monumental Dam. Transportation operations may be adjusted due to research, conditions at the collection facilities, or through the adaptive management process to better match juvenile outmigration timing or achieve/maintain performance standards.

McNary Dam - Operation and Timing

Transportation will be initiated at McNary Dam between July 15–30 per the 2010 Supplemental BiOp (RPA 30, Table 4) and in coordination with NOAA Fisheries and the TMT. Fish will be transported from McNary Dam by barge through August 16, then transported by truck every other day. All fish collected will be transported except those marked for in-river studies. Fish are expected to be transported through September 30. The presence of factors such as excess shad, algae or bryozoans that can clog screens and flumes may result in discontinuing transport operations at McNary Dam before September 30. Detailed criteria for McNary transport are contained in the FPP, Appendix B.

Transportation operations may be adjusted for research purposes, due to conditions at the collection facilities, or as a result of the adaptive management process (to better match juvenile outmigration timing and/or to achieve or maintain performance standards). If new information indicates that modifying (or eliminating) transportation operations at McNary Dam is warranted, adaptive management will be used to make appropriate adjustments through coordination with the FPOM/TMT.

SUMMER SPILL OPERATIONS

Lower Snake River Projects

Summer spill will begin on June 21 at Lower Granite, Little Goose, Lower Monumental and Ice Harbor dams and continue through August 31 at all four Snake River projects. Summer spill levels are shown in Table 2.

Lower Columbia River Projects

Summer spill will begin June 16 at Bonneville Dam, June 20 at McNary Dam, and July 1 at John Day and The Dalles dams and continue through August 31 at all four Columbia River projects. Summer spill levels are shown in Table 2.

PROJECT SUMMER OPERATIONS

The following sections describe 2011 summer spill operations for each project. The Corps, regional fishery agencies, and Tribes are interested in the continuation of project research studies under the Corps' Anadromous Fish Evaluation Program (AFEP). These studies have been evaluated through the annual AFEP review process with the regional fishery agencies and Tribes, with the study designs being finalized prior to initiation in

2011. The studies are intended to provide further information on project survival that will help inform the region in making decisions on future operation and configuration actions to improve fish passage and survival and meet BiOp performance standards at the lower Snake and Columbia River dams. The current river flow forecast indicates much higher than normal river flow conditions will likely limit the ability to conduct all research as planned. In the event that actual river flow conditions change, the Action Agencies, in collaboration with regional sovereigns, will consider whether continuing any planned research is warranted.

Table 2.— Summary of 2011 summer spill levels at lower Snake and Columbia River projects.[3]

Project	**Planned 2011 Summer Spill Operations (Day/Night)**	**Comments**
Lower Granite	18 kcfs/18 kcfs	Same as 2010
Little Goose	30%/30%	Same as 2010
Lower Monumental	17 kcfs/17 kcfs	Same as 2010
Ice Harbor	**June 21-July 13:** 30%/30% vs. 45 kcfs/Gas Cap **July 13-August 31:** 45 kcfs/Gas Cap (approximate Gas Cap range: 75-95 kcfs)	Same as 2010
McNary	50%/50%	Same as 2010
John Day	**July 1-July 20:** 30%/30% and 40%/40% **July 20-August 31:** 30%/30%	Same as 2010
The Dalles	40%/40%	Same as 2010
Bonneville	**June 16-July 20:** 85 kcfs/121 kcfs and 95 kcfs/95 kcfs **July 21-August 31:** 75 kcfs/Gas Cap	Same as 2010

Lower Granite

Summer Spill Operations June 21 – August 31: 18 kcfs 24 hours per day. Spill patterns as described in FPP Section 9 will be used in 2011.

Changes in Operations for Research Purposes:

- Summer research operations: There will be no special spill operations for research in 2011.

[3] Table 2 displays in summary form the planned summer spill operations. More specific detail governing project operations is included in project specific sections.

Operational Considerations:

- Lack of power load or unexpected unit outages could cause involuntary spill at higher total river discharges that could result in exceeding the gas cap limits.
- During periods when involuntary spill occurs, there may be instances when certain spill levels create hydraulic conditions that are unsafe for fish barges crossing the tailrace and/or while moored at fish loading facilities. If such conditions occur, spill may be reduced temporarily when fish transport barges approach or leave the barge dock or are moored at loading facilities. If conditions warrant a spill reduction, the MOP elevation range at Lower Granite will be exceeded temporarily to enable the barge to exit the tailrace safely.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

Little Goose

Summer Spill Operations June 21 – August 31: 30% spill 24 hours per day. Spill patterns as described in FPP Section 8 will be used in 2011.

Changes in Operations for Research Purposes:

- Summer research operations: There will be no special spill operations for research in 2011.

Operational Considerations:

- Daily average flows in the lower Snake River of $\leq$32 kcfs can result in discharge rates from Little Goose Dam that are incompatible with operations and may cause spill quantity fluctuations at Lower Monumental Dam. Alternative Little Goose operations to resolve this issue are described in the Low Flow Operations section above and will be coordinated through the FPOM/TMT.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.
- Turbine Unit 1 Operation: In 2011, operating range will be set within the GDACS program for Little Goose Dam to restrict Turbine Unit 1 operation to approximately the upper 25% of the 1% of best efficiency range (about 16-17.5 kcfs). If low flow conditions occur in the summer, the full ±1% of best efficiency range may be restored to minimize impact on spill levels.

Lower Monumental

Summer Spill Operations Approximately June 21 – August 31: 17 kcfs 24 hours per day. Spill patterns as described in FPP Section 7 will be used in 2011.

Changes in Operations for Research Purposes:

- Summer research operations: There will be no special spill operations for research in 2011.

Operational Considerations:

- Consistent with adjustments made in 2011 spring operations, when total river flow is likely to exceed turbine capacity and spill over the 120% TDG spill cap (occurs at a total river flow of ~140 kcfs) for three or more days, the project will use the uniform spill pattern. This may also occur if spill over the 120% TDG spill cap is required due to "lack of demand" spill at any river flow level. See Corps' Summary of Decision on SOR 2011-02 at: http://www.nwd-wc.usace.army.mil/tmt/agendas/2011/0511_Agenda.html
- Daily average flows of $\leq$32 kcfs can result in incompatible operations with Little Goose Dam and may cause spill quantity fluctuations.
- Transit of the juvenile fish barge across the Lower Monumental tailrace, then docking at and departing from the fish collection facility, may require spill level to be reduced due to safety concerns. The towboat captain may request that spill level be reduced or eliminated during transit. During juvenile fish loading operations, spill is typically reduced to 15 kcfs, but can be reduced further if necessary for safety reasons. Barge loading duration can be up to 3.5 hours. Because of the time needed to complete loading at Lower Monumental, the Little Goose Project personnel will notify the Lower Monumental personnel when the fish barge departs from Little Goose. This ensures that BPA scheduling is provided advance notice for spill control at Lower Monumental Dam. Reducing spill may cause the Lower Monumental pool to briefly operate outside of MOP conditions.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

Ice Harbor

Summer Spill Operations June 21 – August 31: Spill operations will continue from spring at 30% 24 hours per day vs. 45 kcfs day/Gas Cap night until July 13 at 0500 hours, then 45 kcfs day/Gas Cap night through August 31. Spill patterns as described in FPP Section 6 will be used in 2011.

Changes in Operations for Research Purposes:

- Summer research operations: There will be no special spill operations for research in 2011.

Operational Considerations:

- Spill operation treatments may be rearranged within a week throughout the season. If rearrangement of treatment occurs, the total number of each spill level treatment for the spring season will not change. The flexibility to rearrange treatments during periods of higher power demand may alleviate the need to declare a power emergency.

- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

McNary

Summer Spill Operations June 20 – August 31: 50% spill 24 hours per day without spillway weirs, using the spill patterns contained in Table MCN-10 in FPP section 5.

Changes in Operations for Research Purposes:

Summer research operations: There will be no special spill operations for research in 2011. Nighttime velocity reduction testing on adult lamprey may be initiated in mid-June in the Oregon shore ladder to test entrance and passage success.

Operational Considerations:

- Spill will be curtailed as needed to allow safe operation of fish transportation barges near collection facilities downstream of the project.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

John Day

Summer Spill Operations July 1 – August 31: Spill operations will continue from spring at 30% and 40% spill 24 hours per day and continue through approximately July 20. Spill levels will alternate in a four-day block with two-day treatments (30% or 40% spill). Spill treatment changes will occur at 0600 hours. Once the alternating spill treatment schedule concludes, 30% spill 24 hours per day will continue July 20 through August 31. Spill patterns contained in FPP section 4 will be used during summer.

Changes in Operations for Research Purposes:

- Summer research operations: Performance standard testing at 30% and 40% spill planned for summer 2011 at John Day Dam has been canceled due to expected high river flow.

Operational Considerations:

- Spill operation treatments may be rearranged within a week throughout the season. If rearrangement of treatment occurs, the total number of each spill level treatment for the spring season will not change. The flexibility to rearrange treatments during periods of higher power demand may alleviate the need to declare a power emergency

- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

The Dalles

Summer Spill Operations July 1 – August 31: 40% spill 24 hours per day. Spill patterns developed for use with the new spillwall and included in FPP section 3 will be used.

Changes in Operations for Research Purposes:

- Summer research operations: Performance standard testing at 40% spill during summer 2011 at The Dalles Dam has been canceled due to expected high river flow.

Operational Considerations:

- At no time is spill recommended on the south side of the spillway (Bays 14-22) as this creates a poor tailrace egress condition for spillway-passed fish.
- Spill bays 10, 11, 13, 16, 18, 19, and 23 are not operational due to wire rope, structural and concrete erosion concerns.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.

Bonneville

Summer Spill Operations June 16 – August 31: Summer spill operations will alternate every two days between 85 kcfs/121 kcfs and 95 kcfs 24 hours per day. The alternating operation will begin at 0430 hours approximately June 16 and continue through July 20. Spill changes will occur according the daytime spill schedule contained in Table BON-5 in FPP section 2. Following the alternating spill operation, a 75 kcfs/Gas Cap operation will begin on July 21 and continue through August 31. Spill patterns in FPP section 2 will be used.

Changes in Operations for Research Purposes:

- Summer research operations: Performance standard testing during summer 2011 at Bonneville Dam has been canceled due to expected high river flow.
- Spill duration for alternating spill operation: Approximately June 16 – July 20. Spill at 85 kcfs/121 kcfs and/or 95kcfs/95 kcfs will be unconstrained by the Camas/Washougal fixed monitoring TDG station.

Operational Considerations:

- The current minimum spill level is 50 kcfs per prior Fish Operations Plans and Fish Passage Plans. In view of the best biological information, alternative minimum spill operations are currently being examined. If an alternative minimum spill operation is developed, changes will be coordinated through regional processes.

- Actual kcfs spill levels at Bonneville Dam may range up to 3 kcfs lower or higher than levels specified in Table 2. A number of factors influence this including hydraulic efficiency, exact gate opening calibration, spillway gate hoist cable stretch due to temperature changes, and forebay elevation (a higher forebay results in a greater volume of spill since more water can pass under the spill gate).
- The second powerhouse corner collector (5 kcfs discharge) will operate until the afternoon of August 31.
- Unit outages may occur for required or emergency unscheduled maintenance activities described in FPP Appendix A. Dates are subject to change.
- High river flow and excessive debris load at the second powerhouse may require removal of submersible traveling screens (STSs) and vertical barrier screens (VBSs) according to criteria described in FPP Section 2 in coordination with the FPOM.
- Pending further coordination with regional sovereigns, implement an extended turbine operation range at powerhouse one (from 7.3-9.8 kcfs to 7.5-11.5 kfcs). This expands the current operating range of powerhouse one turbine units to a "best geometry" configuration which may be beneficial for juvenile salmonids passing powerhouse one.

COORDINATION

To make adjustments in response to changes in conditions, the Corps will utilize the existing regional coordination committees. Changes in spill rates when flow conditions are higher or lower than anticipated will be coordinated through the TMT. This could include potential issues and adjustments to the juvenile fish transportation program. Spill patterns and biological testing protocols that have not been coordinated to date will be finalized through the Corps' AFEP subcommittees, which include the SRWG, FPOM, and FFDRWG.

REPORTING

The Corps will provide periodic in-season updates to TMT members on the implementation of 2011 fish passage operations. The updates will include the following information:

- the hourly flow through the powerhouse
- the hourly flow over the spillway compared to the spill target for that hour
- the resultant 12-hour average TDG for the tailwater at each project and for the next project's forebay downstream

The updates will also provide information on substantial issues that arise as a result of the spill program (e.g. Little Goose adult passage issues in 2005 and 2007), and will address any emergency situations that arise. The Corps will continue to provide the following data to the public regarding project flow, spill rate, TDG level, and water temperature.

- Flow and spill quantity data for the lower Snake and Columbia River dams are posted to the following website every hour: http://www.nwd-wc.usace.army.mil/report/projdata.htm
- Water Quality: TDG and water temperature data are posted to the following website every hour: http://www.nwd-wc.usace.army.mil/report/total.html. These data are received via satellite from fixed monitoring sites in the Columbia and Snake rivers every hour, and placed on a Corps public website upon receipt. Using the hourly TDG readings for each station in the lower Snake and Columbia rivers, the Corps will calculate both the twelve highest hourly (OR method) and highest consecutive twelve-hour average (WA method) TDG levels daily for each station. These averages are reported at:

  http://www.nwd-wc.usace.army.mil/ftppub/water_quality/12hr/wa/

DEPARTMENT OF ECOLOGY
State of Washington

State of Oregon
Department of Environmental Quality

Adaptive Management Team Total Dissolved Gas in the Columbia and Snake Rivers

Evaluation of the 115 Percent Total Dissolved Gas Forebay Requirement

Washington State Department of Ecology and
State of Oregon Department of Environmental Quality

Final

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Adaptive Management Team
Total Dissolved Gas in the Columbia and Snake Rivers

Evaluation of the 115 Percent Total Dissolved Gas Forebay Requirement

Washington State Department of Ecology and
State of Oregon Department of Environmental Quality

Final

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Executive Summary

The Oregon Department of Environmental Quality (ODEQ) and the Washington Department of Ecology (Ecology) are making a decision on the need for the 115% forebay total dissolved gas (TDG) requirement to regulate spill during fish passage spill on the Columbia River and Lower Snake River dams. Oregon and Washington both have 110% TDG criteria that are modified for fish passage in the Columbia and Snake Rivers. The requirements for the Columbia and Snake Rivers include a 115% TDG requirement in the forebays and 120% in the tailraces.

This document provides technical decision-making information on forebay total dissolved gas issues, an overview of the regulatory history and requirements as described in the Columbia River and Lower Snake River Total Dissolved Gas Total Maximum Daily Loads, and summarizes and evaluates the technical information presented at the total dissolved gas Adaptive Management Team (AMT) meetings.

Policy and management issues such as setting fish passage spill volumes, fish transport options, and bypass routes are not addressed in this paper. This paper addresses only the 115% forebay TDG requirement. This paper focuses primarily on the Lower Snake River and Lower Columbia River dams, but includes a discussion on the dams from Priest Rapids to Chief Joseph.

All referenced documents are available on the AMT website at http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html. The document tracking number is included in this document for reference.

Ecology and ODEQ received many comments on the analyses submitted at the AMT meetings. Ecology and ODEQ read each comment and frequently requested additional information from either the entity that did the analysis or the commenter. Because the purpose of this document is to provide a digestible synthesis of the information, a discussion of the comments received during the AMT meeting on each presentation is not included. Ecology and ODEQ understand the issues in the comment letters received regarding each AMT presentation, and the comments helped inform the agencies' decisions. The comments and the responses received on each AMT presentation are all available on the AMT website.

A draft of this document (website tracking #803) was presented to the Adaptive Management Team on September 4, 2008 for a 30-day AMT comment period. ODEQ and Ecology made the appropriate changes to the document based on the comments they received. Ecology and ODEQ responded to each comment from the 30-day AMT comment period. The response to comments summary document (#902) is available on the AMT website. Ecology and ODEQ used the information submitted and all of the comments received to develop the agencies' decisions.

If the 115% requirement was removed, the amount of fish passage spill could be increased, especially at Lower Monumental Dam on the Lower Snake River. The total amount of additional water that could be spilled in the near-term is estimated to be between 1-2%. Due to the expected increased power use in the region, reductions in overgeneration spill are likely. If overgeneration spill is reduced, the 115% forebay requirement limits voluntary spill more frequently. If both the Biological Opinion (BiOp) spill requirements and overgeneration spill volumes change significantly over time, removal of the 115% forebay requirement has the possibility of affecting spill even more significantly (up to a theoretical maximum of 60% more spill in some years).

There is no way to know the exact impacts on fish survival due to the increase in spill. ODEQ and Ecology used four methods provided by resource management agencies to estimate fish survival due to increased spill. Each method has a high level of uncertainty and controversy. With an increased spill of 1-2%, each analysis found that there is likely a small, positive effect on Chinook survival percentage (greater than zero but less than 1%). Some analyses found the potential for much greater survival (4-9%) at the higher spill estimates. One analysis found there might also be small negative effects on Snake River steelhead.

Likewise, there is no way to know the exact impacts on aquatic life from increases in TDG due to the increase in spill. With increases in spill of 1-2%, TDG would likely increase by about 0.3% in the forebays and 0.1% in the tailraces. In some forebays in some situations, TDG could increase by as much as 4% (the maximum TDG is estimated at 120% at Ice Harbor Dam forebay on the Lower Snake River). Results from the gas bubble trauma (GBT) monitoring program predict a small increase (less than 1%) in overall GBT in salmon if the 115% requirement was eliminated. (At 116-120% TDG in the forebays, about 1.4% of fish exhibit signs of GBT; in Oregon's TDG waiver, fish passage spill is terminated if 15% of the fish exhibit signs of GBT.) Two literature reviews argue that any negative effect would be negligible ("negligible" is defined as so unimportant as to be safely disregarded). The third literature review identifies that with depth compensation, aquatic life at one meter or deeper would not be affected if TDG increased to 120%. However, the same review identifies a potential impact that, while probably small, is not negligible for species at depths between the surface and one meter.

Ecology decided not to change its 115% TDG forebay water quality criterion for the Columbia and Snake Rivers. Ecology determined that there would be a potential for a small benefit to salmon related to fish spill if the 115% forebay criterion was eliminated, but there would also be the potential for a small increase in harm from increased gas bubble trauma. The weight of all the evidence from available scientific studies clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120%. Based on the information in this document, Ecology does not believe the overall benefits of additional spill versus additional risk of gas bubble trauma are clear and are sufficient for a rule revision.

ODEQ decided to remove the forebay monitoring requirement. ODEQ finds that removal of the forebay monitoring requirement will not cause excessive harm to the beneficial use - aquatic species in the Columbia River - during fish passage spill. On June 22, 2007, the Environmental Quality Commission acting under the authority of OAR 340-041-0104(3) modified the total dissolved gas standard for the main stem Columbia River during specified periods in 2008 and 2009. Paragraph 3(vi) of the Environmental Quality Commission's Order gives the ODEQ authority to approve changes to the location and use of forebay monitors.

ODEQ and Ecology reached different conclusions regarding the 115% forebay requirement. ODEQ and Ecology do not disagree on the fundamental technical findings in this report. There are important differences in the TDG requirements in the two states; ODEQ issues a waiver with 115% forebay requirements while Ecology's forebay requirements are part of the water quality standards. Changing water quality standards is more difficult than changing a waiver. Further, ODEQ has a 105% shallow water TDG criterion while Ecology does not. Ecology's 115% requirements apply to dams on the Lower Columbia, Middle Columbia, and Lower Snake Rivers while ODEQ's requirement applies only to the Lower Columbia River.

Background

Oregon TDG requirements for the Columbia River

The state of Oregon total dissolved gas (TDG) water quality standard, found in OAR 340-041-0031 (2), states:

> Except when stream flow exceeds the ten-year, seven-day average flood, the concentration of total dissolved gas relative to atmospheric pressure at the point of sample collection may not exceed 110% of saturation. However, in hatchery-receiving waters and other waters of less than two feet in depth, the concentration of total dissolved gas relative to atmospheric pressure at the point of sample collection may not exceed 105% of saturation.

The Oregon Department of Environmental Quality (ODEQ), with approval from the Environmental Quality Commission (EQC), issues "waivers" to the U.S. Army Corps of Engineers (USACE) to allow for TDG levels above the state standard of 110%. According to OAR 340-041-0104 (3) the EQC may modify the total dissolved gas standard in the Columbia River for the purpose of allowing increased spill for salmonid migration. The commission must find that:

a. Failure to act would result in greater harm to salmonid stock survival through in-river migration than would occur by increased spill.
b. The modified total dissolved gas criteria associated with the increased spill provides a reasonable balance of the risk of impairment due to elevated total dissolved gas to both resident biological communities and other migrating fish and to migrating adult and juvenile salmonids when compared to other options for in-river migration of salmon.
c. Adequate data will exist to determine compliance with the standards.
d. Biological monitoring is occurring to document that the migratory salmonid and resident biological communities are being protected.
e. The commission will give public notice and notify all known interested parties and will make provision for opportunity to be heard and comment on the evidence presented by others, except that the Director may modify the total dissolved gas criteria for emergencies for a period not exceeding 48 hours.
f. The commission may, at its discretion, consider alternative modes of migration.

Oregon first issued a TDG waiver in 1994. The current TDG waiver is available on ODEQ's website: http://www.deq.state.or.us/WQ/TMDLs/columbia.htm.

The TDG waiver allows for total dissolved gas levels of:

- 120% of saturation in the tailrace.
- 115% of saturation in the forebay.
- TDG may not exceed 125% of saturation for more than two hours in every 24 hours in the forebay and tailrace.

ODEQ measures the TDG average as the highest 12 hours in one calendar day. Biological monitoring is required during voluntary spill to determine the incidence of GBT to juvenile salmonids.

Washington TDG requirements for the Columbia and Snake Rivers

The Washington Department of Ecology (Ecology) last modified the TDG requirements in the water quality standards in 2003. The standards, found in WAC 173-201A 200(1)(f), state that the TDG criteria may be adjusted to aid fish passage over hydroelectric dams when consistent with a department-approved gas abatement plan. This plan must be accompanied by fisheries management and physical and biological monitoring plans. The elevated TDG levels are intended to allow increased fish passage without causing more harm to fish populations than caused by turbine fish passage. The following special fish passage exemptions for the Snake and Columbia Rivers apply when spilling water at dams is necessary to aid fish passage:

- TDG must not exceed an average of 115% as measured in the forebays of the next downstream dams and must not exceed an average of 120% as measured in the tailraces of each dam (these averages are measured as an average of the twelve highest consecutive hourly readings in any one day, relative to atmospheric pressure).
- A maximum TDG one hour average of 125% must not be exceeded during spillage for fish passage.

When reviewing the appropriateness of revising a water quality standard, Ecology must carefully consider whether the criteria will adequately protect the designated uses for that water. Designated uses are those water uses (e.g., fishing, boating, aquatic life, water supply) that are specified in the water quality standards for protection in a water body. All designated uses and even the most sensitive use must be fully protected. Sometimes the most sensitive use is not an Endangered Species Act (ESA) listed threatened or endangered species. If Ecology adopts criteria that are less stringent for pollutants, such as TDG, than those published by EPA, Ecology must justify the less restrictive criteria.

Under section 303(c) of the Act, EPA is required to review and to approve or disapprove state-adopted water quality standards. This review involves a determination of whether:

- The state adopted criteria that protect the designated water uses.
- The state followed its legal procedures revising or adopting standards.

EPA reviews any changes Ecology makes to its water quality standards to ensure that the standards meet the requirements of the Clean Water Act. EPA would disapprove the water quality standards and may promulgate federal standards under section 303(c)(4) of the Clean Water Act if state-adopted standards are not consistent with the factors listed above.

Overview of TDG Production

TDG levels can be increased above the water quality criteria by spilling water over spillways of dams on the Columbia River. There is a variety of other ways that TDG may be elevated: passage of water through turbines, fishways, or locks, and natural processes such as low barometric pressure, high water temperatures, or high levels of biological productivity. However, the vast majority of the high TDG levels found in the Columbia River are caused by spills from dams.

Natural processes may have a significant effect on TDG. TDG exchange rates increase as wind speeds rise, which produces degassing. If conditions are still and TDG levels are constant, the percent saturation of TDG can increase if the water temperature increases or barometric pressure drops. Also, primary productivity (periods of algal growth) can increase dissolved oxygen levels, which results in a higher TDG percent saturation. However, because oxygen is metabolized by the aquatic life its physical effects are minor compared to nitrogen.

TDG levels above the water quality standard can cause gas bubble trauma (GBT) in fish. GBT is caused by the formation of gas bubbles in the cardiovascular system of aquatic species. These bubbles block the flow of blood and respiratory gas exchange. GBT can cause chronic or acutely lethal effects, depending on TDG levels. Fish are protected from fatal pressures in deeper waters by compensation from hydrostatic pressures, which reduces absolute TDG approximately 10% for every one meter below the surface.

Spill at dams occurs for several reasons:

- "Involuntary spill" to bypass water that exceeds the available hydraulic capacity of the powerhouse due to:
    - High river flows.
    - Lack of power market.
    - Maintenance, break-down, or other reasons.
- "Voluntary spill" to enhance downstream fish passage (to meet "Performance Standards" for fish survival under the Endangered Species Act).

Involuntary spill occurs during periods of very high river flows. The quantity of water exceeds the capacity of a dam to either temporarily store the water upstream of the dam or pass the water through its turbines. In these circumstances, water is released over the spillway because there is nowhere else for it to go. The Columbia and Snake River hydropower dams contain very little storage potential relative to the quantity of spring runoff. At times of rapid runoff, the dams cannot constrain the quantity of water, and it is spilled with high TDG levels. Often, dissolved gas levels from involuntary spill exceed those experienced during periods of spill for fish. However, high river flows under these circumstances are often in excess of the 7Q10 high flow, in which case the TDG standard would not apply.

Spills for fish passage typically occur during the spring and summer months, April 1 to August 31. During periods of fish passage spills, deviations of ambient conditions from the water quality standard are frequent but usually small. This is because spill quantities are managed to meet the current TDG levels for fish passage: 115% in the forebay and 120% in the tailrace.

The highest TDG levels, and therefore the area most likely to exceed standards, are directly below the spillway. In this area, the plunging and air entrainment of the spill (aerated zone) generates high levels of TDG, but then quickly degasses while the water remains turbulent and full of bubbles. However, as this water moves from the stilling basin into the tailrace, degassing slows and the TDG levels stabilize.

The TDG exchange in spill is an equilibrium process where the time history of entrained air below the spillway will determine the resultant TDG pressure exiting the vicinity of the dam. TDG exchange in spillway flow is the high rate of mass exchange that occurs below a spillway. The large volume of air entrained into spillway releases initiates the TDG exchange in spill. The resultant TDG pressure generated during a spill is almost entirely determined by physical conditions that develop below the spillway and is effectively independent from the initial TDG content of this water in the forebay. The TDG exchange in spill is not a cumulative process where higher forebay TDG pressures will generate yet higher TDG pressures downstream in spillway flow.

TMDL Overview

A total maximum daily load (TMDL), as identified in the federal Clean Water Act, determines the quantity (load) of a pollutant that can enter a water body and the water body still meet water quality standards. The TDG TMDLs for the Columbia River and Lower Snake River are available for review at:

Oregon: http://www.deq.state.or.us/wq/TMDLs/columbia.htm#tdg
Washington: Lower Columbia TDG TMDL: http://www.ecy.wa.gov/biblio/0203004.html
Mid Columbia TDG TMDL: http://www.ecy.wa.gov/biblio/0403002.html
Snake River TDG TMDL: http://www.ecy.wa.gov/biblio/0303020.html

The TMDLs address TDG in the mainstem Columbia and Snake Rivers. The states of Oregon and Washington listed multiple reaches of the Columbia and Snake rivers on their federal Clean Water Act 303(d) impaired waters lists due to TDG levels exceeding the states' water quality standards.

The TDG TMDL for the Lower Snake River addresses the 110%, 115% forebay, and 120% tailrace criteria. The Columbia River TDG TMDLs address only the ultimate attainment of the 110% criteria, because the 115% and 120% limits were temporary and annually renewed. The Columbia River TDG TMDLs implementation plans allow compliance with the 115% and 120% limits as an interim allowance for compliance with the TMDL in the short-term. The expectation of the Clean Water Act is that the 110% water quality criteria will be attained in a limited amount of time.

Biological Opinion for the Federal Columbia River Power System

As required by the Endangered Species Act, the Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) requires that the action agencies (U.S. Army Corps of Engineers, Bonneville Power Administration, and the U.S. Bureau of Reclamation) meet specific hydropower system biological performance standards for both adult and juvenile salmon. The purpose of these standards is to help reverse the downward trend in listed salmon populations and therefore, ensure viable salmon resources in the Columbia River Basin.

The current 2008 Endangered Species Act Section 7(a)(2) Consultation Biological Opinion and Magnuson-Stevens Fishery Conservation and Management Act Essential Fish Habitat Consultation, dated May 5, 2008, states that the voluntary spill program is not to exceed established TDG levels by the state water quality agencies (Table 1). The Biological Opinion does not recommend or identify a numeric TDG threshold for state water quality agencies to include in their TDG standard or waiver for voluntary spill purposes, but rather relies on ODEQ and Ecology to make that determination.

Table 1. 2008 Biological Opinion Reasonable and Prudent Alternative Action Description for Total Dissolved Gas.*

RPA No.	Action Description	Implementation Plans, Annual Progress Reporting and Comprehensive RPA Evaluations
Hydropower Strategy 3—Implement Spill and Juvenile Transportation Improvements at Columbia River and Snake River Dams		
29	**Spill Operations to Improve Juvenile Passage** The Corps and BPA will provide spill to improve juvenile fish passage while avoiding high TDG supersaturation levels or adult fallback problems. Specific spill levels will be provided for juvenile fish passage at each project, not to exceed established TDG levels (either 110 percent TDG standard, or as modified by state water quality waivers, currently up to 115 percent TDG in the dam forebay and up to 120 percent TDG in the project tailwater, or if spill to these levels would compromise the likelihood of meeting performance standards (see RPA Table, RM&E Strategy 2). The dates and levels for spill may be modified through the implementation planning process and adaptive management decisions. The initial levels and dates for spill operations are identified in Table 2 [in the BiOp]. Future Water Management Plans will contain the annual work plans for these operations and spill programs, and will be coordinated through the TMT. The Corps and BPA will continue to evaluate and optimize spill passage survival to meet both the hydro system performance standards and the requirements of the Clean Water Act (CWA).	***Implementation Plans*** • The initial spill operation for juveniles is described in the proposed RPA. The spill operation will be updated annually and reported in the FPP. ***Annual Progress Report*** • Spill operations are reported annually. ***2013 and 2016 Comprehensive RPA Evaluation Reports*** • This information is the same as will be reported for each mainstem dam in hydro actions 14-21.

*Reasonable and Prudent Alternative Table, pg 32 of 98, https://pcts.nmfs.noaa.gov/pls/pcts-pub/pcts_upload.summary_list_BiOp?p_id=27149

The provisions of both the Clean Water Act and the Endangered Species Act (ESA) must be met. Notwithstanding that, it is not the purpose of the Clean Water Act to assume functions properly undertaken based on the Endangered Species Act. On the contrary, the Endangered Species Act contains provisions that encourage EPA to consult with National Marine Fisheries Service (NMFS) prior to approval of a TMDL that affects ESA-listed species. This ensures that the TMDL is consistent with species recovery goals. The BiOp issued under the Endangered Species Act requires attainment of certain fish passage performance standards. One way of meeting these is through spilling water over hydroelectric dam spillways (fish passage spill). This action results in elevated TDG. Control of TDG is the purpose of the Columbia and Snake Rivers TMDLs. The Clean Water Act does not suggest trade-offs of fish passage for TDG. Rather, it requires attainment of water quality standards. This is one of the significant challenges posed by the TDG TMDLs.

TMDL Implementation

Meeting the load allocations in the TDG TMDLs fall into two phases. Phase I short-term actions involve improving water quality while ensuring that salmonid passage is fully protected in accordance with the BiOp. Phase II long-term actions will involve structural and operational changes to dams to achieve the water quality standard for TDG.

The short-term actions in Phase I focus on meeting the fish passage performance standards as outlined in the BiOp through spill levels that generate gas no greater than the “waiver” levels of the water quality TDG standards. Water quality standards are measured at existing fixed monitoring stations managed by the U.S. Army Corps of Engineers and U.S. Geological Survey. This phase will also include short-term structural modifications at the dams to achieve TDG reductions during periods of spill, while ensuring that the fish passage requirements of the BiOp are met.

Short-term compliance and the effectiveness of operational implementation actions are monitored at existing fixed monitoring station sites. The current TDG fixed monitoring station system consists of tailrace and forebay monitoring stations at each mainstem lower Snake and Columbia River dam. While most of these stations do a credible job of reporting meaningful data, some stations may be affected by environmental variables.

The Phase II long-term actions will be determined after evaluating the success of the short-term actions. The second phase will also move toward further structural modifications and reductions in fish passage spill after the BiOp-specified performance standards are met and adequate survival is provided for non-listed species. Actions taken in the previous phase will be reviewed for their effectiveness, both in improving TDG levels and for protecting salmonid passage. The BiOp survival goals may be met through fish passage actions other than spilling water. The final goal is meeting the Oregon and Washington water quality standard for TDG as measured at the end of the aerated zone below each dam. As part of Phase II, a detailed implementation plan or equivalent will be developed by the designated action agencies.

Long-term compliance with load allocations for dam spills will be at the downstream end of the aerated zone below each spillway in the tailrace. The TDG TMDLs specify distances for the compliance location at each dam. As a result, the load allocation must be met at each dam individually at a specified compliance location, with allowance made for degassing in the tailrace below the spillway.

Need for Adaptive Management

ODEQ was directed to evaluate the need for the 115% forebay TDG monitoring requirement during fish passage spill by the Oregon Environmental Quality Commission (EQC) on June 21, 2007. At this EQC meeting, the 2007 TDG waiver was approved with the condition that the Adaptive Management Team (AMT) evaluates the need for the 115% TDG forebay limit during fish passage spill as stated:

> 3(vi) The Department may approve changes in the location of forebay and tailrace monitors, use of forebay monitors, and may approve changes to the method for calculating total dissolved gas. Before approving any changes, the Department must consult with the Adaptive Management Team or the Federal Columbia River Power System (FCRPS) Water Quality Team or both. The Department is directed to begin this process for consultation immediately and to evaluate and, if appropriate, approve such changes as soon as possible.

Additionally, the TDG waiver outlined the adaptive management process, as per the TDG TMDLs:

> The process for reviewing the implementation status of the 2002 Lower Columbia River Total Dissolved Gas TMDL will begin no later than January 1, 2011. The Washington State Department of Ecology will convene an advisory group comprising representatives of Oregon Department of Environmental Quality, tribes, and federal and state agencies to evaluate appropriate points of compliance for this TMDL. Based on these findings, further studies may be needed and structural and operational gas abatement activities will be redirected or accelerated if needed. After 2010, the location of total dissolved gas monitors will be consistent with the adaptive management implementation strategy for the 2002 Lower Columbia River Total Dissolved Gas TMDL, may no longer require forebay monitors, and may require only tailrace monitors as TMDL implementation transitions from short-term to long-term strategies.

On June 27, 2007, Ecology received a letter from Save Our Wild Salmon (SOWS) regarding total dissolved gas and the Adaptive Management Team. SOWS stated itsr concern regarding the use of forebay monitors, specifically “monitoring for the forebays at the dams on the river are not working to protect water quality and salmon as they should.” SOWS requested that Ecology convene the Adaptive Management Team as soon as possible.

The geographic scope of the AMT is the mainstem Columbia River as specified by the 2002 and 2004 TDG TMDLs (Bonneville, The Dalles, John Day, McNary, Priest Rapids, Wanapum, Rock Island, Rocky Reach, Wells, and Chief Joseph dams), and the lower Snake River in Washington as specified by the 2003 TDG TMDL (Ice Harbor, Lower Monumental Little Goose, and Lower Granite dams), Figure 1.

Figure 1. The Columbia River Basin. This paper addresses the eight Lower Columbia River and Snake River dams: Lower Granite (LGR), Little Goose (LGS), Lower Monumental (LMN), Ice Harbor (IHR), McNary (MCN), John Day (JDA), The Dalles (TDA), and is Bonneville (BON).

The AMT is a technical group. Policy and management issues, such as setting fish passage spill volumes, fish transport options, and bypass routes are not addressed at the AMT meeting. These topics are discussed at the FCRPS Implementation Team, Technical Management Team or other forums, with representation from Oregon and Washington departments of fish and wildlife.

The Adaptive Management Team

The AMT consisted of 11 member organizations, including the states of Oregon and Washington represented by their respective water quality agencies. The AMT membership was limited to 11 member organizations to expedite technical review and decision making while still allowing for input from the multiple viewpoints.

The role of the AMT members was to share and provide technical information to the group and advise Washington and Oregon on TDG. The role of Washington and Oregon was to make decisions using the technical input and follow state and federal laws and regulations. The Washington Department of Fish and Wildlife (WDFW) and Oregon Department of Fish and Wildlife (ODFW) advised Ecology and ODEQ on the adaptive management process.

The AMT held meetings about monthly from November 2007 through September 2008. At the meetings, different facets and impacts of the 115% forebay requirement were discussed. Complete meeting summaries, agendas, presentations, and papers are all available on the AMT website: http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html.

AMT members:

- State of Washington (Ecology co-chair)
- State of Oregon (ODEQ co-chair)
- NOAA Fisheries
- U.S. Army Corps of Engineers (USACE)
- Save our Wild Salmon
- Confederated Tribes of the Colville Reservation
- Columbia River Inter Tribal Fish Commission
- Grant County Public Utility District (PUD)
- U. S. Environmental Protection Agency (EPA)
- NW River Partners
- U.S. Fish and Wildlife Service (USFWS)

All AMT meetings were open to the public. Regular attendees, in addition to the 11 AMT members, included Bonneville Power Administration (BPA), D. Rohr and Associates, Fish Passage Center (FPC), and Douglas PUD.

Issue for the Adaptive Management Team

The technical issue evaluated by the AMT and described in this document is the need for the 115% forebay TDG requirement during fish passage spill.

A determination that there is no longer a need for the 115% forebay TDG requirement during fish passage spill would result in removing the requirement from the states' water quality standards and waiver, and managing fish passage spill to the tailrace TDG limit of 120%. Currently, fish passage spill is managed to both the forebay and tailrace TDG limits, and would continue to be managed to these limits if the 115% forebay TDG limit is determined to be necessary.

Forebay Gauge History

Currently, there is no research being conducted to assess the representativeness of the forebay monitors as they relate to fish passage spill. However, several past studies evaluated the application and use of the forebay monitors as they relate to fish passage spill.

USACE operates the forebay gauges to accurately represent the TDG levels in the dominant aquatic habitat of each dam. USACE performed 28 TDG exchange research studies on forebay and tailwater gages on the Lower Columbia and Snake Rivers over an 11-year period, 1996 to 2007. The results of these studies reflect that the high TDG levels are generated from the spillway, and forebay TDG levels are carried through the powerhouse so that TDG levels can be different at different points in the tailrace. The TDG gauges are calibrated every three weeks to a primary and secondary standard, and the USGS and USACE perform data quality reviews daily. The TDG data exceeds the 95% data completeness standard. For more information on USACE's

TDG monitoring program history, please see “History of the Total Dissolved Gas Monitoring System” (#812) on the AMT website.

In 2000, National Marine Fisheries Service (NMFS) asked the USACE to address concerns regarding forebay monitor representativeness by including language in its Biological Opinion Reasonable and Prudent Alternatives (RPA) 132 to complete a systematic review and evaluation of the TDG fixed monitoring stations in the forebays. The study was conducted during the 2003 and 2004 fish passage spill season at McNary Dam and the four Lower Snake River projects: Ice Harbor Dam, Lower Monumental Dam, Little Goose Dam, and Lower Granite Dam.

Each of the study project forebay stations experienced “thermally-induced TDG pressure spikes during the test periods.” The study resulted in two recommendations. The first was to permanently relocate each forebay gauge to an area just upstream of the project in a location not affected by down-welling surface waters, such as the navigation lock guide wall. Additionally, the study recommended each instrument be positioned at a depth of 12-15 meters to avoid thermal responses in the TDG pressure readings. The findings and full report are available on-line:

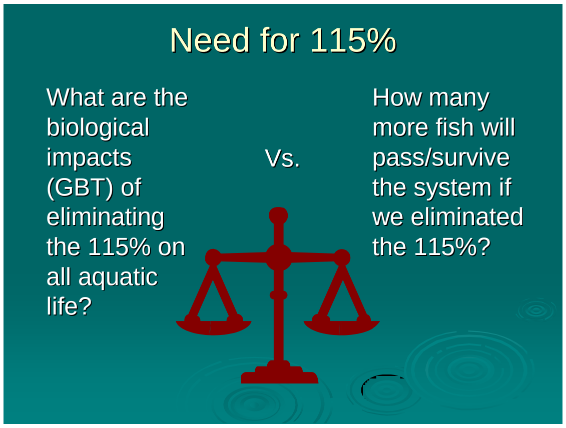
> BiOp Measure 132 Final Report, December, 2004: "Total Dissolved Gas Forebay Fixed Monitoring Station Review and Evaluation for Lower Snake River Projects and McNary Dam, 2003-2004,"
> http://www.nwd-wc.usace.army.mil/tmt/wq/studies/rpa132_20041230.pdf

In 2001, the USGS identified representativeness issues with the Camas-Washougal forebay gauge. Specifically, the USGS found that daily variations of TDG were “probably due to the production of oxygen by aquatic plants and to water-temperature variations on warm, sunny days” (Water-Resources Investigations Report 01-4273, page 11 and Figure 13 on page 12, http://or.water.usgs.gov/pubs_dir/WRIR01-4273/index.html). This USGS report led to a 2004 follow-up isotope study of TDG at Camas-Washougal. These data were never published, but the data indicated that the increased afternoon dissolved oxygen at Camas-Washougal forebay gauge was due to photosynthesis rather than Bonneville Dam spill (email communication with Dwight Tanner, USGS, June 24, 2008).

On September 29, 2006, the Fish Passage Center (FPC) sent a memo to the Fish Passage Advisory Committee regarding Spring Spill 2006 (FPC document 136-06.pdf). In that memo, FPC evaluated the “efficacy of forebay monitoring” and discussed the question of “did the USACE’s relocation in 2004 and 2005 lead to more accurate monitoring?” in the forebay. The FPC memo concluded that the forebay monitors “do not represent the measurements of TDG in mixed waters as was originally intended.” Although the forebay monitors were relocated and lowered deeper into the water column in 2004 and 2005, questions regarding their representativeness of fish passage spill still exist.

Information the AMT Considered

In evaluating the need for the 115% TDG forebay limit during fish passage spill season, the AMT considered how removal of the 115% TDG forebay limit would affect fish and other aquatic life. ODEQ and Ecology framed the technical evaluation by asking the AMT the following two questions:



Question 1: What are the biological impacts (gas bubble trauma) of eliminating the 115% TDG forebay limit on all aquatic life?

Question 2: How many more fish will survive the system if we eliminated the 115% limit?

Removing the 115% forebay TDG limit has the potential to increase spill volumes at the Columbia and Snake River dams. Increased spill volumes may result from managing fish passage spill only to the 120% tailrace TDG limit. Additional spill has the potential to increase fish passage and survival past each dam. However, increasing fish passage spill may also increase the TDG levels that may increase the incidence of gas bubble trauma and potentially affect aquatic species.

The AMT presented the following data and analytical results to the states to evaluate the need for the 115% TDG forebay limit:

- FPC analysis of spill volume.
- USACE analysis (SYSTDG) of spill volumes.
- BPA analysis (HYDSIM) of spill volumes.
- FPC Analysis of Juvenile Hydro-system Survivals Smolt to Adult Returns (SARs).
- Comparative Survival Study (CSS).
- Comprehensive Passage Model (COMPASS).
- Adult Passage and Survival.
- Smolt Monitoring Program Results on Gas Bubble Trauma Incidence.
- NOAA Fisheries Resident Fish Literature Review.
- Ecology Literature Review.
- Parametrix Literature Review.

All presentations and reports were open for comment. Comments were shared with presenters giving them a chance to respond. All presentations, comments, and responses are available on the TDG AMT website:

http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html

ODEQ and Ecology used all the information presented at the AMT to form the technical basis of their decision.

Spill Volume Considerations

Setting or limiting fish passage spill volumes are considered a management issue for discussion at the Federal Columbia River Power System (FCRPS) forum or other forums. Spill management will not be set or negotiated at the AMT, but will be discussed in the context of TDG and impacts to aquatic species.

Fish passage spill volumes are determined by several factors:

- Spill operations (as defined by the BiOp.)
- Spill caps (as defined by TDG water quality limits in the forebay and tailrace set by state water quality agencies.)
- Involuntary spill (when the river flow exceeds the hydraulic capacity of the dam.)
- Minimum generation (the amount of flow necessary to generate the minimum amount of electricity to keep the regional electrical grid stable, and the remainder is used for fish passage.)
- Overgeneration spill (spill that must occur when the amount of flow in the river system would otherwise produce more energy, if passed through turbines, than there are accessible energy markets available.)
- Other fish passage spill determinations may exist, such as physical limitations due to erosion in tailrace basins or navigational concerns.

Spill Volume Analysis: With and Without the 115 Percent TDG Limit

The Fish Passage Center (FPC), USACE, and Bonneville Power Administration (BPA) each conducted an analysis of how much more fish passage spill volume would be possible if the 115% was eliminated. The amount of spill varies greatly depending on the fish passage spill volume factors being implemented (described previously) and how much water is in the river. The amount of water in the river varies by year, season, and day. The variations in volume are caused by amount of snow pack, rainfall, water withdrawal, and upstream dam operations.

The three entities analyzed the potential changes in spill volume using different approaches and assumptions. The differences observed among the analyses were due to the flow years used, the assumptions of spill operations, treatment of excess generation spill, and other limitations on spill. The FPC analysis considered past years' empirical data for flow, spill, and TDG and projected what spill would have occurred if the 115% forebay requirement was removed in four different spill scenarios. The USACE and BPA analysis assumed that the 2008 Biological Opinion spill levels were implemented. Their analyses used one spill scenario. The BPA analysis included overgeneration spill and conducted simulations for the 70-year flow record.

One must be careful when directly comparing the spill volumes from the different analyses, given the differences in assumptions for each analysis. Table 2 summarizes the assumptions made for spill program amounts implemented in each of the analyses.

Table 2. Spill Volume Analysis Summary

Author	Report Title	Years Analyzed	Simulation	Data Set
FPC	*Volume Changes with Use of Tailrace Monitors.* (#303), see page 2	**Low - Moderate water years**: 2003, 2005, 2007 **High water year**: 2006	**Base Scenario:** The year's actual spill volume, which accounts for excess generation spill. **Scenario B**: The spill that would have occurred during that year if all projects spilled to the 120% cap on days when spill was restricted by the 115% downstream forebay, but not the 120% tailrace. **Scenario C**: The spill that would have occurred in that year if all projects spilled to the 120% cap. This scenario was limited by planned operations. **Scenario D**: The spill that would have occurred in that year if all projects spilled to the 120% cap, but this spill analysis was not limited by planned operations.	FPC used a statistical analysis of the empirical data set for each year and modeled the estimated changes in spill volumes. The analysis does not include overgeneration or other involuntary spill.
USACE	*Report on the SYSTDG Modeling for AMT: With and without 115 percent TDG standard.* (#710), see page 10.	**Low water year**: 2007 **Moderate water year:** 2002 **High water year**: 1999	Hourly average of spill volume and spill cap with and without the 115% TDG forebay limit for each project and each year.	The ACOE SYSTDG hourly time-step model was used to model the flow assumptions from each year using the 2008 FCRPS BiOp spill operations, including overgeneration and other involuntary spill.
BPA	*HYDSIM Use in Analysis of Removing 115 percent TDG Forebay Gauge Requirements BPA Report to the Adaptive Management Team.* (#710), see page 10, and (#605)	70 years, averaged (1929 - 1999)	70-year average spill with and without the 115% TDG forebay limit for each project.	The BPA HYDSIM monthly time-step model used the SYSTDG hourly calculated spill caps, which were averaged into monthly spill caps for input into HYDSIM using the 2008 FCRPS BiOp spill operations and involuntary spill. HYDSIM modeled 70 years of historical runoff data, including overgeneration spill, to generate monthly average flows and spill volumes at each dam.

FPC Analysis

The FPC's analysis, *Spill Volume Changes with Use of Tailrace Monitors* (#303), is available on the AMT website. BPA and USACE provided comments on the FPC analysis, and FPC responded to the comments. These documents are available on the AMT website.

The FPC analyzed the low to moderate water years of 2003, 2005, and 2007 and the high water year of 2006; see Figures 2 through 5. The FPC ran scenarios with differences in planned operations ranging from the base case (what was actually implemented in that year) to what would occur if there was no spill management except for the 120% TDG requirement (meaning projects were not managed to a specific spill program but spilled the full volume of water to the 120 % TDG). They defined the scenarios as:

Scenario B: Spill that would have occurred if all projects spilled to the 120% cap on days when spill was restricted by the 115% downstream forebay (but not the 120% tailrace).

Scenario C: Spill that would have occurred in that year if all projects spilled to the 120% cap (limited by planned operations).

Scenario D: Spill that would have occurred in that year if all projects spilled to the 120% cap (not limited by planned operations).

The planned operations were different among years, dependent on the spill program implemented. For example, the 2003 spill program followed the 2000 BiOp and the 2005 spring spill followed the 2000 BiOp, whereas the 2005 summer spill followed the court-ordered spill. Years 2006 and 2007 followed the court order.

Depending on the year and the scenario used, removing the 115% forebay requirement would allow an additional 0.5 to 58.1 million acre feet of spill on the lower Columbia and Snake Rivers; see Table 3.

Table 3. FPC Statistical Analysis Additional Spill Volumes (Million Acre Feet) Under the Three Scenarios, Compared to the Base Case Volume (involuntary spill removed).

Water Year	Scenario B: FB Restricted	Scenario C: 120% Limited	Scenario D: 120%
2003	2.27	13.01	41.57
2005	0.52	11.06	43.06
2006	2.8	9.56	52.53
2007	1.45	5.98	58.07

According to the FPC analysis, if the 115% forebay requirement was removed then all the dams would experience an increase in fish passage spill. However, Little Goose and Lower Monument dams on the Snake River would experience the greatest increase in fish passage spill.

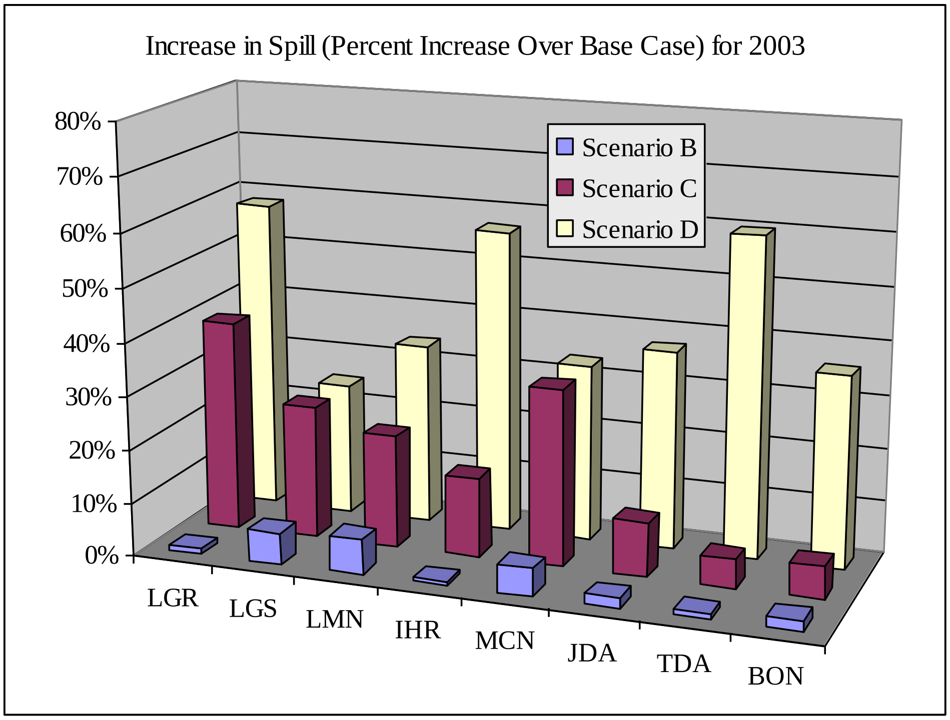


Figure 2. FPC Statistical Analysis of Increased Spill in 2003 (percent increase over base case). Lower Granite (LGR), Little Goose (LGS), Lower Monumental (LMN), Ice Harbor (IHR), McNary (MCN), John Day (JDA), The Dalles (TDA), and Bonneville (BON). The increase in spill (percent increase over base case) is calculated as:

$$\frac{Spill\ Volume\ (KAF)\ of\ Scenario\ B,\ \ C, or\ D - Spill\ Volume\ (KAF) of\ Base\ Case}{Spill\ Volumbe\ (KAF) of\ Base\ Case}$$

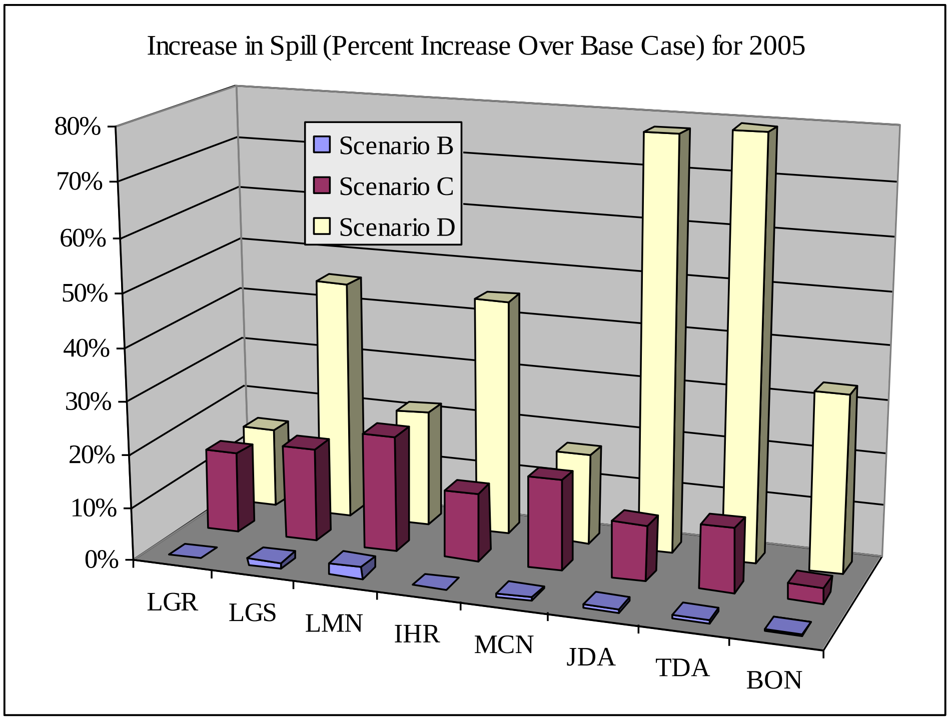


Figure 3. FPC Statistical Analysis of Increased Spill in 2005

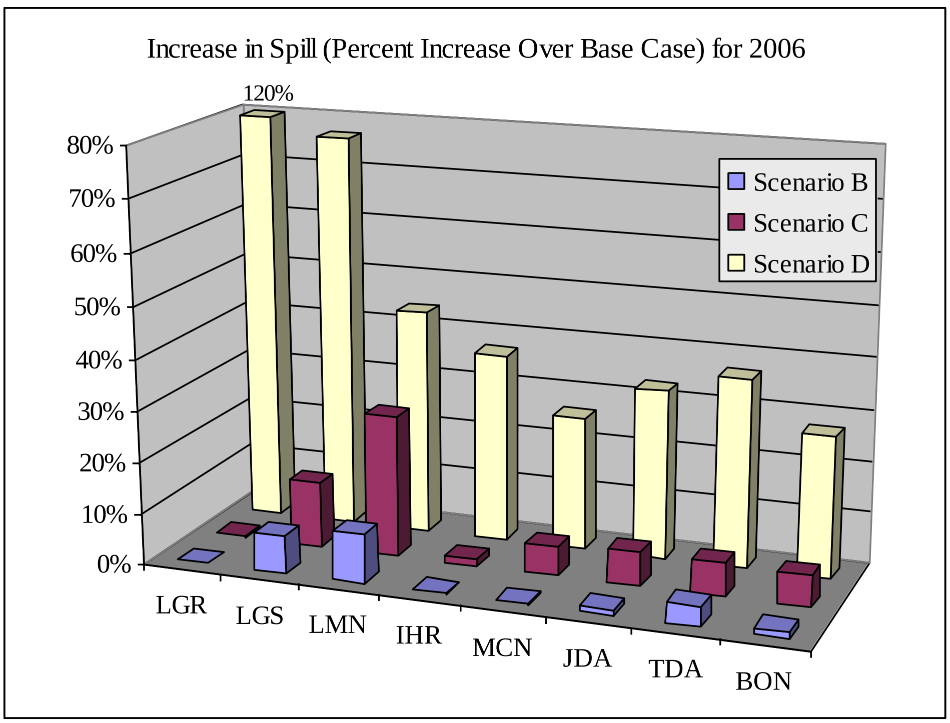


Figure 4. FPC Statistical Analysis of Increased Spill in 2006

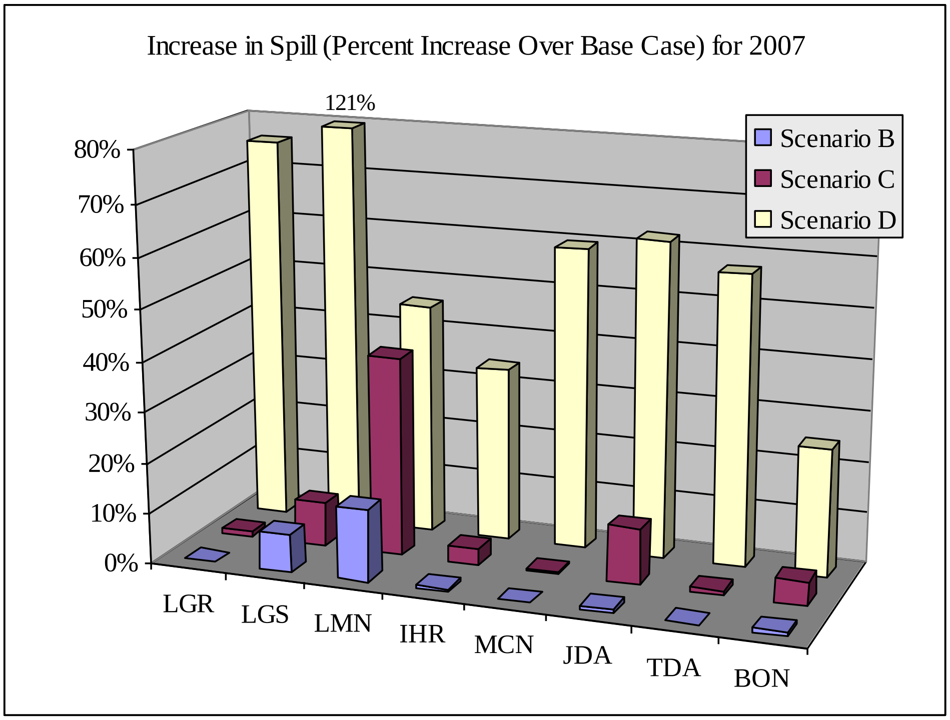


Figure 5. FPC Statistical Analysis of Increased Spill in 2007

USACE Analysis (SYSTDG)

The USACE's analysis, *Report on the SYSTDG Modeling for AMT: With and without 115 percent TDG standard* (#710), is available on the AMT website. Comments on this document are available on the AMT website.

The USACE analyzed the high water year of 1999, the moderate water year of 2002, and the low water year of 2007. The analysis used assumptions from 1999, 2002, and 2007 operations, and spill operations from the October 31, 2007 Columbia and Snake River FCRPS BiOp. See the report for details.

In the USACE analysis, multiple factors controlled spill on the Lower Columbia and Snake Rivers:

- BiOp spill operations (76% of the time).
- The 120/115% spill caps (12% of the time).
- Involuntary spill (8% of the time).
- Minimum generation (4% of the time).

According to the analysis:

- For the 1999 high water year, eliminating the 115% TDG requirement would result in an additional 5.9 Million Acre Feet (MAF) spill (a 4.0% increase).

- For the 2002 medium water year, eliminating the 115% TDG requirement would result in an additional 2.3 MAF spill (a 1.8% increase).
- For the 2007 low water year, eliminating the 115% TDG requirement would result in an additional 2.5 MAF spill (a 2.2% increase).

Most of the additional spill would come from Lower Monumental and Bonneville dams. In high water years, some would also come from John Day, The Dalles, and Little Goose dams. See Figure 6 (and Tables 11-13 of the USACE analysis, document 710) for details.

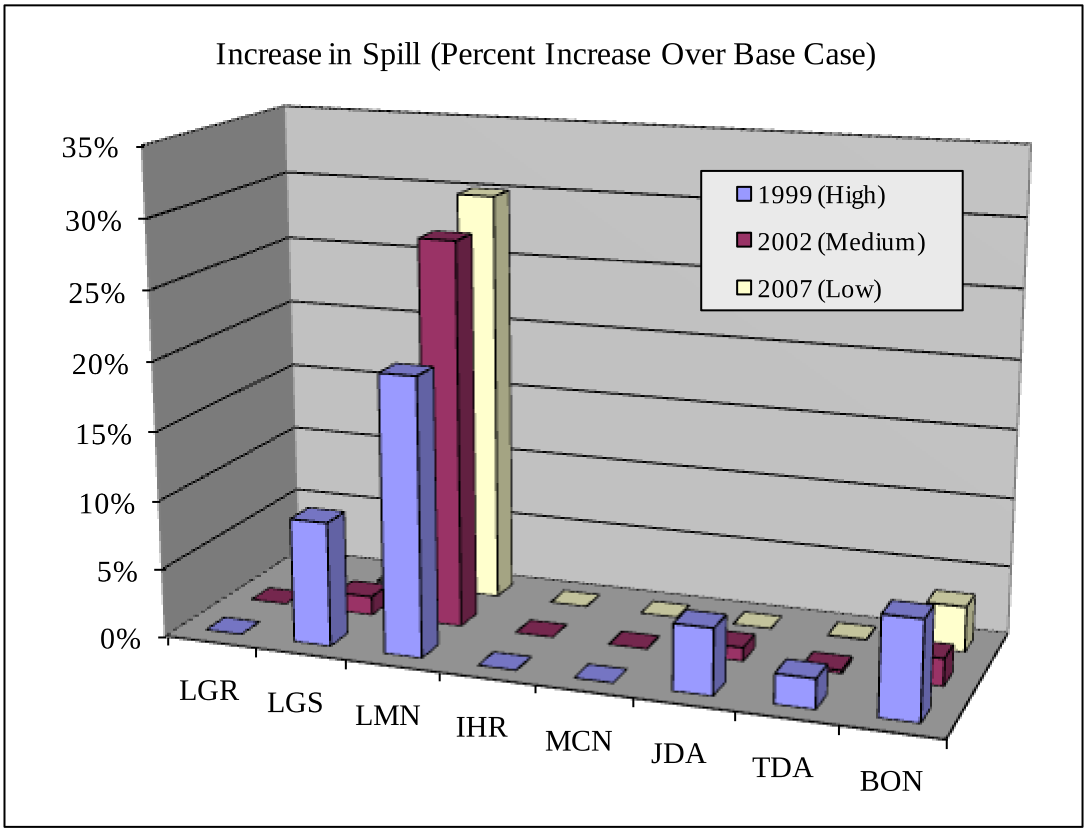


Figure 6. USACE SYSTDG Model Results of Analysis of Spill Volumes. SYSTDG analyzed how much spill would occur under the base case of the 115%/120% requirement and determined how much more spill would occur under a 120%-only scenario. The increase in spill (percent increase over base case) is calculated as:

$$\frac{\boldsymbol{Spill\ Volume}\ (\boldsymbol{KAF})\ \boldsymbol{of}\ \mathbf{120}\%\ \boldsymbol{only\ Scenario} - \boldsymbol{Spill\ Volume}\ (\boldsymbol{KAF})\boldsymbol{of}\ \mathbf{115}\ \&\ 120\ Base\ Case}{\boldsymbol{Spill\ Volume}\ (\boldsymbol{KAF})\boldsymbol{of}\ \mathbf{115}\ \&\ 120\ Base\ Case}$$

BPA Analysis (HYDSIM)

The BPA analysis, *HYDSIM Use in Analysis of Removing 115 percent TDG Forebay Gauge Requirements BPA Report to the Adaptive Management Team – May 2008* (#605) is available on the AMT website. No comments were received on this analysis.

The BPA analysis used spill caps provided by the USACE analysis. The spill caps were applied to 70 years of historical runoff data to generate monthly average flow and spill volumes at each dam. Overgeneration spill that occurred in excess of the planned spill program (the 2008 Biological Opinion) is included in the BPA base case.

According to BPA's analysis, eliminating the 115% requirement would result in more spill at Lower Monumental (13% increase), Bonneville (2.9% increase), and, to a much lesser extent, Little Goose (1.1%) and The Dalles (0.5% increase) dams. The increase in spill at these dams, and the resulting loss of power generation, means the other dams could generate more power and would have less overgeneration spill. Thus, eliminating the 115% requirement would result in slightly less spill at Lower Granite, Ice Harbor, McNary, and John Day by 0.1-0.2%. See Figure 7 for details.

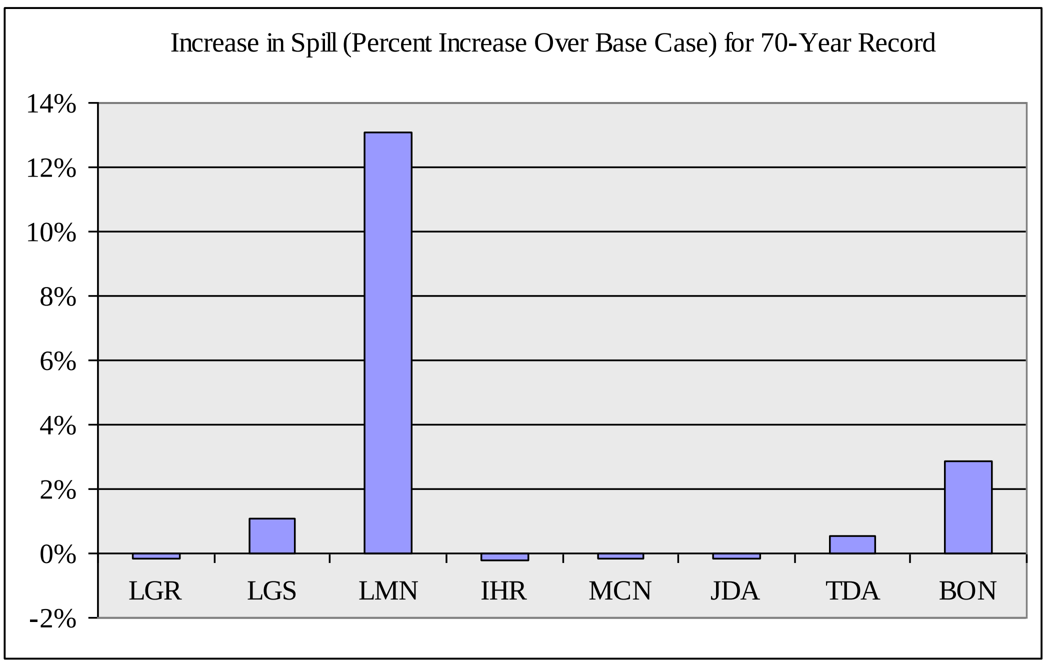


Figure 7. BPA HYDSIM Model Calculations of Spill Changes The increase in spill (percent increase over base case) is calculated as:

$$\frac{\boldsymbol{Spill\,Volume\,(KAF)\;of\;120\%\;only\;Scenario - Spill\,Volume\,(KAF)of\;115}\;\&\;120\;Base\;Case}{\boldsymbol{Spill\,Volume\,(KAF)of\;115}\;\&\;120\;Base\;Case}$$

Synthesis of FPC, USACE, and BPA Analyses of Spill Volumes

The three analyses reached similar conclusions on where the elimination of the 115% requirement would have the most significant difference.

Table 4. Dams Most Affected by Removal of the 115% Requirement

Analysis	Dams most affected by eliminating 115% requirement
FPC Analysis	Little Goose and Lower Monumental
BPA HYDSIM	Lower Monumental and Bonneville
USACE SYSTDG	Lower Monumental and Bonneville

The three analyses reached variable conclusions on the total amount of additional spill that would occur if the 115% requirement was eliminated.

Table 5. Increase in Spill. The increase in spill (percent increase over base case) is calculated as:

$$\frac{\boldsymbol{Spill\,Volume\;(KAF)\;of\;120\%\;only\;Scenario - Spill\,Volume\;(KAF)of\;115}\;\&\;120\;Base\;Case}{\boldsymbol{Spill\,Volume\;(KAF)of\;115}\;\&\;120\;Base\;Case}$$

Analysis	Increase in spill (percent increase over base case; per year; an average for all eight Lower Columbia and Snake River dams combined)
FPC Analysis	1% - 60% depending on the year and scenario
BPA HYDSIM	1.8% - 4.0% depending on the year
USACE SYSTDG	1.3% average over 70 water years

One must be careful when directly comparing the spill volumes analyses. While the three analyses presented are addressing the same topic, the assumptions made in each analysis vary. The differences between the FPC, USACE, and BPA analyses were the assumptions each analysis made on inclusion of 2008 BiOp spill operations, the treatment and inclusion of overgeneration spill, the years analyzed, and other limitations on spill programs. Since each analysis treated these important factors differently, the changes in spill volumes with and without the 115% TDG forebay limit range in value.

Fish Survival Impacts

The FPC, U.S. Fish and Wildlife Service (USFWS), National Oceanic and Atmospheric Administration (NOAA), and the Columbia River Inter-Tribal Fish Commission (CRITFC) each conducted an analysis on how anadromous fish passage and survival would be impacted if the 115% TDG limit was removed. The FPC provided an analysis of the importance of spill in juvenile hydro-system survivals and Smolt to Adult Returns (SARs), using empirical data and a multiple regression analysis. USFWS presented modeling results from the Comparative Survival Study (CSS) on juvenile salmonid survival. NOAA presented results from its Comprehensive Passage (COMPASS) model. Adult passage and survival impacts were summarized by CRITFC. These analyses addressed the eight Lower Columbia and Lower Snake River dams. Table 6 summarizes the assumptions made for each of the analyses.

Table 6. Fish Passage and Survival Impacts Analysis Summary

Author	Report Title	Years Analyzed	Simulation	Data Set
FPC	*Importance of spill in Juvenile Hydro-system survivals and SARs* (#306)	1998 - 2005	Statistical analysis for smolt reach survival analyses for yearling spring / summer Chinook, steelhead and fall Chinook; Relation between juvenile survival and adult return rates with and without the 115% TDG forebay limit.	Empirical data set for each year and species used in the analysis.
USFWS presen-tation	*Comparative Survival Study (CSS) Chapter 2* (#402a)	1998 - 2006	Statistical analysis for yearling Chinook and steelhead migrants' survival.	Empirical and modeled data set for each species analyzed for two reaches: Lower Granite to McNary and McNary to Bonneville. The analysis used weekly released cohort PIT-tagged fish, with median estimated fish travel time and survival rates. The analysis included temperature, turbidity, flow, water travel time, average percent spill, and seasonality for each year and reach modeled.
NOAA	*Explanation of COMPASS Analysis of TDG Alternatives* (#609)	70 years, averaged (1929 - 1999)	Statistical analysis of survival and Lower Granite to Lower Granite smolt-to-adult-return for Snake River spring / summer Chinook and steelhead, Upper Columbia spring Chinook and steelhead, and Mid	Empirical and modeled data set were used for this daily time step model. The HYDSIM monthly modeled mean 70 year average water record was translated into a daily time step for average flow and spill model input. The model includes transport, FCRPS

Author	Report Title	Years Analyzed	Simulation	Data Set
			Columbia steelhead with and without the 115% TDG forebay limit.	survival but not post Bonneville effects for the period starting April to end of June.
CRITFC	*Review of Adult Passage through Different Dam Passage Routes* (#709)	2008 ACOE Steelhead Kelt fish passage	Statistical analysis of four downstream adult passage routes: screen bypass system, spill, turbines, and surface bypass.	Empirical data set for the years analyzed and literature.

FPC Analysis of Juvenile Hydro-system Survivals and SARs

The FPC's analysis, *Importance of spill in Juvenile Hydro-system survivals and SARs* (#306), is available on the AMT website. BPA provided comments on the FPC analysis, and FPC responded to the comments. These documents are available on the AMT website.

The FPC presented statistical analysis for smolt reach survival analyses for yearling spring / summer Chinook, steelhead and fall Chinook, and a relation between juvenile survival and adult return rates for data collected between 1998 and 2005. The study showed a relationship between increased spill and increased reach survival for juvenile migrants. The analyses accounted for the effect of ocean conditions on adult survival and showed a relationship between juvenile reach survival and adult returns.

According to the FPC analysis, the increased benefit of spill occurs when average spill proportions increase above 40% for spring / summer Chinook and steelhead; see Figures 8 and 9. This is likely due to increased numbers of fish passing via spill as spill proportions increase.

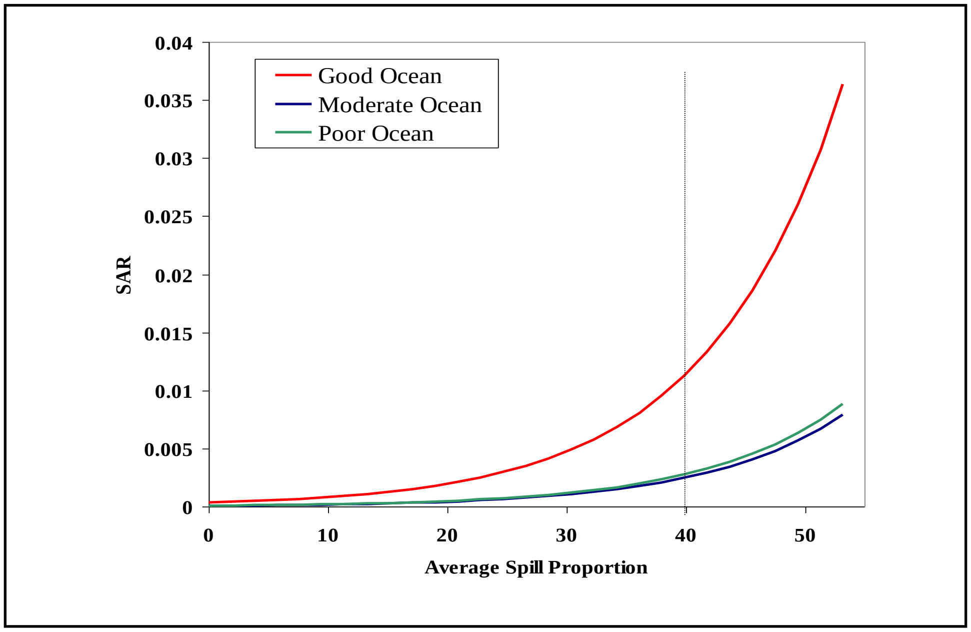


Figure 8. FPC Statistical Analysis Predicted response to increasing spill volumes of Smolt to Adult Returns (SARs) for spring/summer Chinook salmon under good, moderate and poor ocean productivity levels.

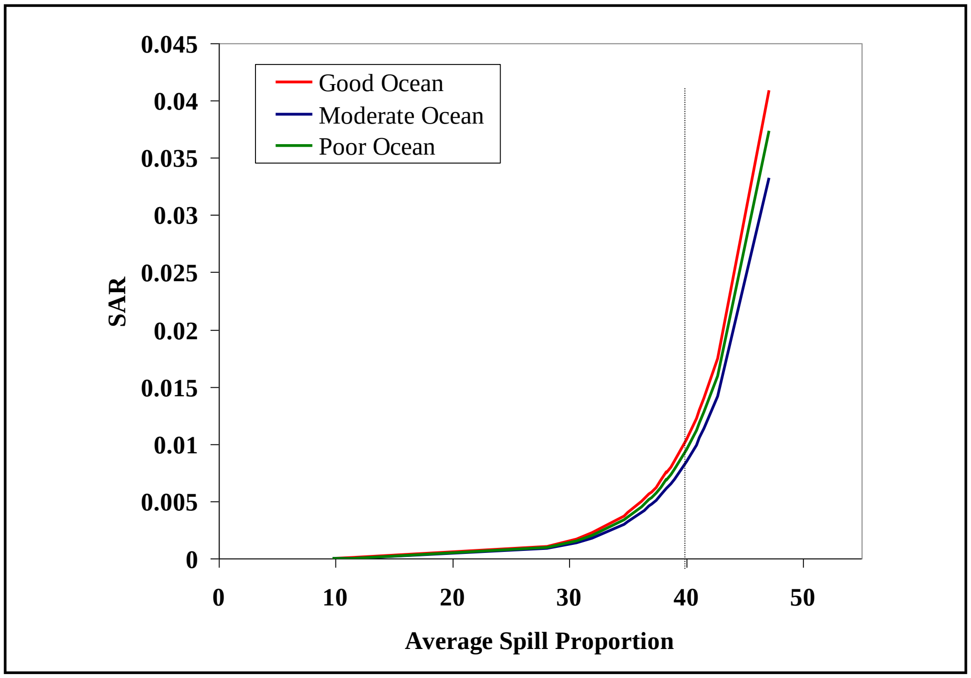


Figure 9. FPC Statistical Analysis Predicted response to increasing spill volumes of Smolt to Adult Returns (SARs) for steelhead under good, moderate and poor ocean productivity levels.

The FPC analysis identified a positive relationship between juvenile reach survival and average spill; see Figure 10.

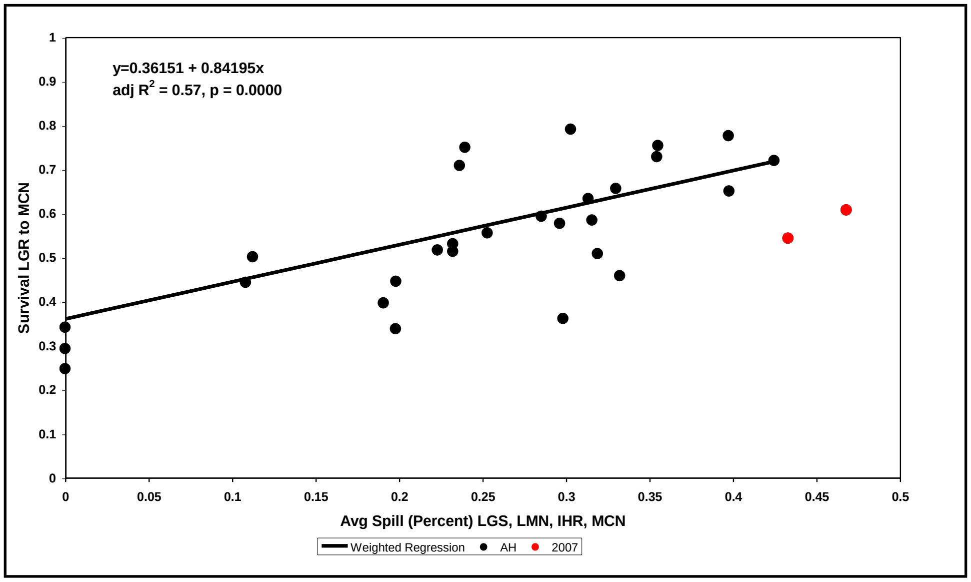


Figure 10. FPC Statistical Analysis x-y Plot of Sub-Yearling Chinook Survival from Lower Granite (LGR) to McNary (MCN) dams versus Average Spill Percent for Little Goose (LGS), Lower Monumental (LMN), Ice Harbor (IHR) and McNary (MCN) dams.

A similar approach showed that an increase in water travel time had a negative relationship with reach survival demonstrating that as water travel time decreases (i.e., flows increase) survival increases; see Figure 11.

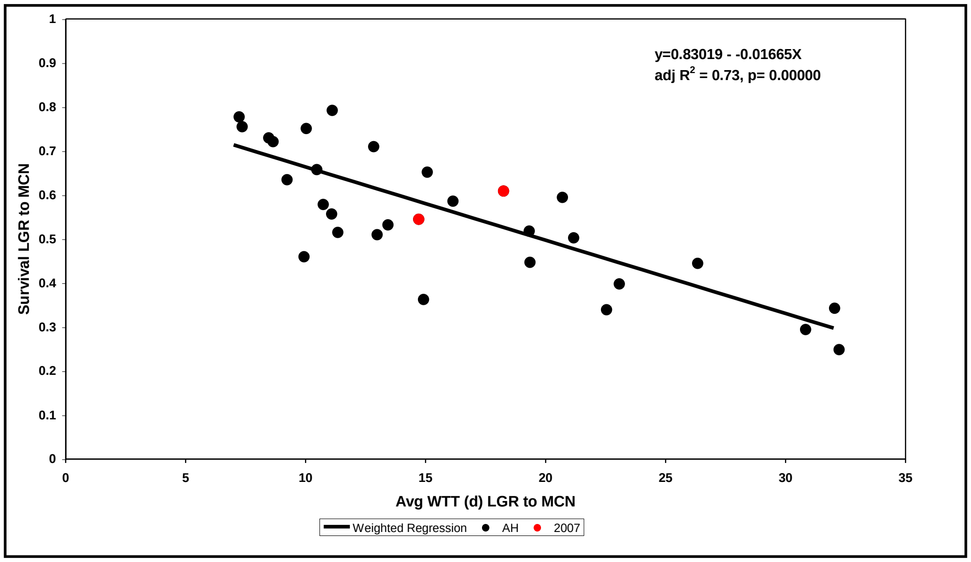


Figure 11. FPC Statistical Analysis x-y Plot of Hatchery Sub-Yearling Chinook Survival versus Water Travel Time (WTT) from Lower Granite (LGR) to McNary (MCN) dams.

CSS Study Presented by USFWS

The *Comparative Survival Study (CSS) Chapter 2* (#402a), presented by USFWS, is available on the AMT website along with comments on the analysis. BPA and Northwest River Partners provided comments on the CSS. Most of the comments received at the AMT were developed during the 2007 regional CSS review. USFWS and FPC responded to the comments received during the AMT process. These comments are available on the AMT website. The CSS is a joint project of FPC, USFWS, Idaho Department of Fish and Game, ODFW, WDFW, and CRITFC.

The CSS used the 1998 to 2006 data set to show that juvenile travel times, instantaneous mortality rates, and survival rates through the hydro system are strongly influenced by managed river conditions including flow, water travel time, and spill levels.

USFWS provided the expected juvenile survival under the different spill volume scenarios presented by the FPC analysis. The spill amounts for each year were further divided by date to match the different steelhead and chinook cohorts. The CSS determined that survival was based on when during the year the salmon migrated (Julian date is used in the formulas), the spill proportion, and either the flow (steelhead) or water transit time (Chinook). FTT is fish transit time and Z is instantaneous mortality.

For wild Chinook, survival from Lower Granite to McNary is:

$$Survival = e^{-Z \times FTT}$$

$$FTT = e^{9.175098 - 0.009814 \times Spill - 0.097455 \times Date + 0.030975 \times WTT + 0.000342 \times Date^2}$$

$$Z = -3.893879 - 0.214382 \times WTT + 0.00394 \times Date + 0.00204 \times Date \times WTT$$

Hatchery Chinook survival uses the same basic formula but different numeric constants.

For steelhead, survival from Lower Granit to McNary is:

$$Survival = e^{-Z \times FTT}$$

$$FTT = e^{2.143886 - 0.0053 \times Date - 0.00513 \times Spill + 0.093911 \times WTT}$$

$$Z = -0.17176 + 0.001806 \times Date - 0.00071 \times Spill + \frac{3.683971}{Flow}$$

The CSS analysis predicted that the absolute increase in juvenile yearling Chinook survival from Lower Granite Dam to McNary Dam would range from 0% to 4%, and 1% to 9% for steelhead; see Table 7. The McNary to Bonneville Dam absolute increase in juvenile yearling Chinook survival would range from 0% to 5%.

Table 7. Absolute Increase in Survival. No planned spill occurred at Lower Granite, Little Goose, and Lower Monument during the spring of 2005.The increase in survival uses the FPC spill volume analysis and is calculated as:

$$Percent\ Survival\ in\ FPC\ Scenario\ B, C, or\ D - Percent\ Survival\ in\ FPC\ Base\ Case$$

Year	Scenario B	Scenario C	Scenario D
Lower Granite to McNary – Steelhead			
2003	0%	3%	8%
2005	0%	2%	5%
2006	1%	2%	6%
2007	2%	4%	17%
Average	**1%**	**3%**	**9%**
Lower Granite to McNary – Wild Yearling Chinook			
2003	0%	1%	3%
2005	0%	1%	3%
2006	0%	1%	2%
2007	1%	2%	7%
Average	**0%**	**1%**	**4%**
Lower Granite to McNary – Hatchery Yearling Chinook			
2003	0%	1%	3%
2005	0%	1%	3%
2006	0%	1%	3%
2007	1%	2%	7%
Average	**0%**	**1%**	**4%**
McNary to Bonneville – Hatchery and Wild Yearling Chinook			
2003	0%	1%	5%
2005	0%	2%	7%
2006	0%	1%	2%
2007	0%	1%	4%
Average	**0%**	**1%**	**5%**

NOAA COMPASS Study

The NOAA analysis, *Explanation of COMPASS Analysis of TDG Alternatives* (#609), is available on the AMT website. ODFW provided comments on COMPASS, and BPA and NOAA responded to those comments. The Independent Scientific Advisory Board's review of COMPASS was also received. These documents are available on the AMT website.

The NOAA analysis incorporated results from three modeling efforts. USACE's SYSTDG model provided spill cap volumes. The SYSTDG model is run on an hourly time step and assumed 2008 FCRPS BiOp operations. The hourly time step spill caps were converted to a monthly average in order to be incorporated into BPA's HYDSIM model. The HYDSIM model incorporated overgeneration conditions and the 2008 electrical load capacity to a model simulation of over 70 years of monthly historical runoff averages. The HYDSIM model-derived monthly average flow and spill volumes were then converted to daily input for NOAA's COMPASS model. COMPASS calculated daily flows for the period of April to end of June and incorporated fish transport. The COMPASS model ran using the 2008 FCRPS BiOp operations. See the report for details.

COMPASS estimated the downstream passage survival of juvenile salmonids. Survival values were rounded up to one decimal space for relative difference, and to three decimal spaces for absolute difference, which resulted in several calculations of a zero survival difference between the current TDG management scenario and eliminating the 115% TDG forebay limit. However, NOAA states that if model results were carried out to the maximum precision then there would be a small positive difference between alternatives. Differences in survival presented at the AMT can be found in Tables 8 and 9.

Table 8. NOAA COMPASS Model Increase in Steelhead Reach Survivals. The increase in survival uses the USACE's SYSTDG spill volume analysis and is calculated as:

$$\boldsymbol{Percent\ Survival\ in\ 120\%\ Only\ Scenario - Percent\ Survival\ in\ 115}\ \&\ 120\ Base\ Case$$

Years	Scenario	Snake River	Columbia River
70-Year Average	120%-Only	66.0%	67.1%
	115/120%	65.9%	67.0%
	Survival Increase	**0.1%**	**0.1%**
Low Flows	120%-Only	49.8%	56.2%
	115/120%	49.7%	56.2%
	Survival Increase	0.1%	0.0%
Mid-Range Flows	120%-Only	70.3%	69.9%
	115/120%	70.2%	69.9%
	Survival Increase	0.1%	0.0%
High Flows	120%-Only	81.0%	76.3%
	115/120%	81.0%	76.2%
	Survival Increase	0.0%	0.1%

Table 9. NOAA COMPASS Model Increase in Spring Chinook Reach Survivals. The survival increase uses the USACE's SYSTDG spill volume analysis and is calculated as:

$$\boldsymbol{Percent\ Survival\ in\ 120\%\ Only\ Scenario - Percent\ Survival\ in\ 115}\ \&\ 120\ Base\ Case$$

Years	Scenario	Snake River	Columbia River
70-Year Average	120%-Only	85.5%	71.3%
	115/120%	85.3%	71.3%
	Survival Increase	**0.2%**	**0.0%**
Low Flows	120%-Only	81.8%	68.8%
	115/120%	81.7%	68.8%
	Survival Increase	0.1%	0.0%
Mid-Range Flows	120%-Only	86.7%	71.7%
	115/120%	86.5%	71.7%
	Survival Increase	0.2%	0.0%
High Flows	120%-Only	88.0%	73.4%
	115/120%	87.9%	73.4%
	Survival Increase	0.1%	0.0%

The COMPASS analysis concluded that "elimination of the forebay monitors, with resulting increasing spill rates, would provide a small, but positive effect on survival and adult returns of listed stocks", except for Snake River Steelhead. COMPASS model results showed a drop in estimated survival and SAR for Snake River Steelhead, Table 10. The NOAA analysis states that negative effects estimated for Snake River Steelhead could be reduced through "management actions, such as limiting spill, to increase collection for transportation at Lower Granite Dam." Transport is considered a management option by the states and is not considered in this technical evaluation.

Table 10. Summary of NOAA COMPASS Model Results for Smolt to Adult Returns (SARs).

Species	Measurement	115% and 120%	120% Only	Survival Increase (Relative[1])	Survival Increase (Absolute[2])
Snake River Spring / Summer Chinook	Whole population Lower Granite-Lower Granite SAR	0.915%	0.922%	0.8%	0.007%
Snake River Steelhead	Whole population Lower Granite-Lower Granite SAR	1.803%	1.783%	-1.1%	-0.02%
Upper Columbia River Chinook	Whole population Lower Granite-Lower Granite SAR (surrogate for Rocky Reach Dam to Rocky Reach Dam SAR)	0.768%	0.768%	0.0%	0.0%
Upper Columbia River Steelhead	Whole population Lower Granite-Lower Granite SAR (surrogate for Rocky Reach Dam to Rocky Reach Dam SAR)	0.716%	0.716%	0.0%	0.0%
Mid-Columbia River Steelhead	In-river survival	52.4-90.3%	52.5-90.3%	0.0% - 0.2%	0.0-0.1%

CRITFC Adult Passage Analysis

The CRITFC analysis, *Review of Adult Passage through Different Dam Passage Routes* (#709), is available on the AMT website. USACE and BPA provided comments on the CRITFC analysis. Their comments are available on the AMT website. No response to comments was received from CRITFC.

[1] Since SARs are such low numbers, the relative change in the survival appears much larger than the absolute change provided in the table. Relative change is defined as:

$$\frac{SAR\ percentage\ in\ the\ 120\%\ only\ Scenario - SAR\ percentage\ in\ the\ 115\ \&\ 120\%\ scenario}{SAR\ percentage\ in\ the\ 115\ \&\ 120\%\ scenario}$$

[2] The absolute survival increase uses the USACE's SYSTDG spill volume analysis and is calculated as:

$$Percent\ Survival\ in\ 120\%\ Only\ Scenario\ - Percent\ Survival\ in\ 115\ \&\ 120\ Base\ Case$$

Adult survival is important because of their imminent likelihood to spawn. The CRITFC study states that "the downstream route of adult passage is an important factor that contributes to survival and ultimate escapement to spawning areas and spawning success, reproductive fitness and genetic integrity." The study evaluates four downstream passage routes available to adults. They include the screen bypass system, spill, turbines, and surface bypass.

CRITFC evaluated each of the four adult downstream passage routes. The CRITFC analysis states that the screen bypass system exposes juvenile and adult salmon to increased water temperatures. These fish are held at temperatures that are significantly warmer than that found in the ambient river. Spill has been associated with increased fish passage efficiency, Table 11, and has been demonstrated to reduce travel and passage times. Turbine passage has an increased mortality because of the blade to fish size ratio. The CRITFC study identified surface bypass structures as an "emerging, promising adult downstream passage route" that reduces adult passage delays. The CRITFC review "indicates that spill and surface bypass and probably a combination of both provide the safest downstream passage route for adult migrants, whether they are fallbacks or steelhead kelts heading seaward." Fallbacks occur when adult salmon heading upriver go back downstream through or over a dam.

Table 11. Steelhead kelt fish passage efficiencies through Lower Columbia dams with and without spill (data from Corps 2008).

Dam	Percent Spill	Percent Fish Passage Efficiency
Bonneville	37%	84%
Bonneville	0%	68%
The Dalles	30%	99%

Synthesis of FPC, USFWS, NOAA and CRITFC Analyses

It is difficult to assess the precise impacts on fish passage and survival that would result from removing the 115% TDG limit forebay requirement. The analyses and data presented were based on both empirical and simulated data. The assumptions contained in the simulation analyses often ranged widely among studies.

The FPC analysis noted that increased spill would result in increased juvenile reach and adult survival, and that smolt survival had a strong relation to reach survival and spill.

The CSS report found that higher levels of spill during smolt migration years 1998 – 2006 were associated with:

- Reductions in fish travel time (faster migration rates) for both yearling Chinook and steelhead.
- Reductions in instantaneous mortality rates of steelhead.
- Increased survival rates for both yearling Chinook and steelhead.

The COMPASS model analysis found that most species experienced a small, positive effect on in-river survival (<1%) if the 115% TDG limit was removed due to increased spill. However, the COMPASS model estimated a decreased survival and SARs for Snake River steelhead. NOAA stated that this decreased estimate result was likely due to reduced collection for transport.

The CSS analyses predicted that the absolute increase in juvenile yearling Chinook survival from Lower Granite Dam to McNary Dam would range from 0% to 4%, dependent on the spill scenario chosen, and would range from 1% to 9% for steelhead. This contrasts with the 0.2% for yearling Chinook, and 0.1% for Steelhead, estimated by COMPASS. The CSS analyses also predicted an increase survival of 0% to 5% for yearling Chinook in the Lower Columbia in contrast to no increase simulated by COMPASS. These results illustrate that the benefits to juvenile and adult salmonid survival are mostly a function of the analysis' assumptions.

The CRITFC study review of four adult passage routes indicated that spill and surface bypass, and probably a combination of both, provide the safest downstream passage route for adult migrants when also evaluating turbine and screen bypass systems. CRITFC states that this route combination is an important factor in adult passage that contributes to survival and escapement to spawning areas and spawning success.

Gas Bubble Trauma Impacts

The USACE analyzed how much TDG would increase if the 115% requirement was removed. Four AMT studies provide gas bubble trauma (GBT) summary information on the possible impacts of eliminating the 115% requirement. The three TDG literature reviews presented to the AMT synthesized hundreds of previous field and laboratory studies. Each review had a slightly different focus. The FPC's report on the Smolt Monitoring Program examined GBT in salmon in the Columbia and Snake Rivers. This report is highlighted separately due to its high relevance to the 115% requirement.

USACE SYSTDG TDG Simulations

The USACE's analysis, *Report on the SYSTDG Modeling for AMT: With and without 115 percent TDG standard* (#710), analyzed the expected change in TDG in the forebays. The USACE analyzed the high water year of 1999, the moderate water year of 2002, and the low water year of 2007. In each case, the high 12-hour average TDG level is reported.

The simulations summarized the TDG levels for each water year, for each project, with and without the 115% TDG standard over the entire spill season (water year), from April through August.

Table 12 and Figure 12 summarize the TDG change in the forebays between the two scenarios, with and without the 115% forebay TDG limit. The values highlighted in gray show an increase in the high 12 hour average TDG levels if the 115% limit was removed.

Table 12. ACOE SYSTDG Modeled Seasonal Average Absolute TDG in the Forebays with and without the 115% Limit. The difference in TDG is calculated as:

$$\boldsymbol{TDG\ under\ the\ 120}\%\ \boldsymbol{only\ scenario} - \boldsymbol{TDG\ under\ the\ 115}\ \&\ 120\ base\ case\ scenario$$

Forebay High 12 Hour Average % TDG Levels

Water Years: Low = 2007; Medium = 2002; High = 1999

		Seasonal **Average** of the High 12 Hour Average TDG		
Year	**Project**	**With 115%**	**Without 115%**	**Difference**
2007	LWG forebay	101.9	101.9	0.0
2002	LWG forebay	101.7	101.7	0.0
1999	LWG forebay	106.1	106.1	0.0
2007	LGS forebay	106.8	106.8	0.0
2002	LGS forebay	106.1	106.1	0.0
1999	LGS forebay	109.2	109.2	0.0
2007	LMN forebay	109.8	109.8	0.0
2002	LMN forebay	110.7	110.7	0.0
1999	LMN forebay	113.3	113.7	0.5
2007	IHR forebay	110.8	111.7	0.9
2002	IHR forebay	110.8	111.3	0.5
1999	IHR forebay	112.2	115.2	3.0
2007	MCN forebay	109.5	109.5	0.0
2002	MCN forebay	109.0	109.0	0.0
1999	MCN forebay	109.4	109.4	0.0
2007	JDA forebay	107.6	107.6	0.0
2002	JDA forebay	106.9	106.9	0.0
1999	JDA forebay	108.1	108.1	0.0
2007	TDA forebay	109.8	109.8	0.0
2002	TDA forebay	108.8	108.8	0.0
1999	TDA forebay	110.4	110.6	0.2
2007	BON forebay	111.2	111.2	0.0
2002	BON forebay	110.1	110.1	0.0
1999	BON forebay	112.2	112.4	0.2
2007	Camas Forebay	113.3	113.8	0.5
2002	Camas Forebay	113.0	113.0	0.0
1999	Camas Forebay	113.9	115.2	1.3

Average % TDG Difference :	**0.3**

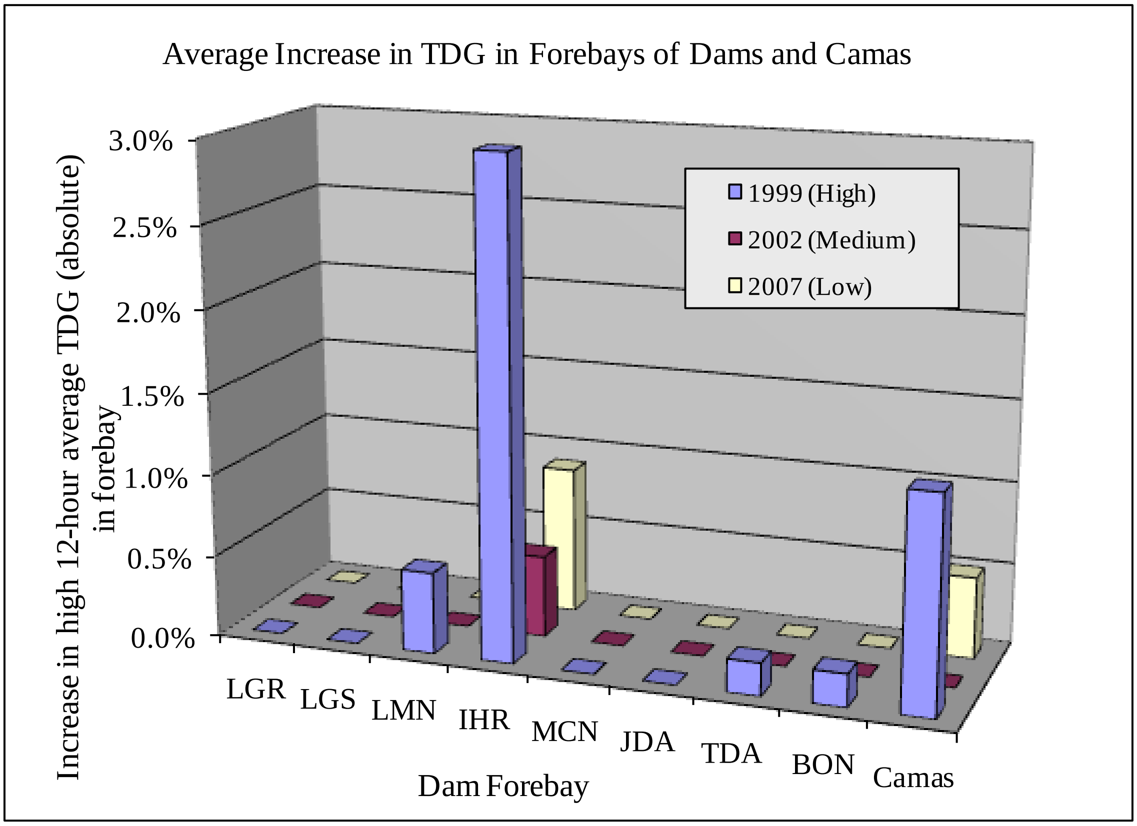


Figure 12. ACOE SYSTDG Modeled Seasonal Average Absolute Increase in Percent TDG in the Forebays without the 115% Forebay Requirement.
The difference in TDG is calculated as:

$$\boldsymbol{TDG\ under\ the\ 120\%\ only\ scenario - TDG\ under\ the\ 115}\ \&\ 120\ \textit{base case scenario}$$

Table 13 and Figure 13 summarize the TDG change in the tailraces between the two scenarios, with and without the 115% forebay TDG limit. The values highlighted in gray show an increase and the black highlighted values show a decrease in the high 12 hour average TDG levels if the 115% limit was removed.

Table 13. ACOE SYSTDG Modeled Seasonal Average Absolute TDG in the Tailraces with and without the 115% Limit. The difference in TDG is calculated as:

$$\boldsymbol{TDG\ under\ the\ 120}\%\ \boldsymbol{only\ scenario} - \boldsymbol{TDG\ under\ the\ 115}\ \&\ 120\ base\ case\ scenario$$

Tailrace High 12 Hour Average % TDG Levels

Water Years: Low = 2007; Medium = 2002; High = 1999

		Seasonal **Average** of the High 12 Hour Average TDG		
Year	**Project**	**With 115%**	**Without 115%**	**Difference**
2007	LWG Tailrace	108.5	108.5	0.0
2002	LWG Tailrace	108.8	108.8	0.0
1999	LWG Tailrace	112.2	112.2	0.0
2007	LGS Tailrace	113.8	113.8	0.0
2002	LGS Tailrace	114.6	114.6	0.0
1999	LGS Tailrace	116.0	116.2	0.1
2007	LMN Tailrace	113.2	114.1	0.9
2002	LMN Tailrace	113.1	113.1	0.0
1999	LMN Tailrace	114.4	115.2	0.8
2007	IHR Tailrace	113.4	113.4	0.0
2002	IHR Tailrace	113.9	113.9	0.0
1999	IHR Tailrace	115.1	115.1	0.0
2007	MCN Tailrace	114.7	114.7	0.0
2002	MCN Tailrace	116.0	116.0	0.0
1999	MCN Tailrace	116.5	116.5	0.0
2007	JDA Tailrace	117.5	117.5	0.0
2002	JDA Tailrace	118.2	118.2	0.0
1999	JDA Tailrace	118.9	119.2	0.3
2007	TDA Tailrace	115.1	115.1	0.0
2002	TDA Tailrace	115.0	115.0	0.0
1999	TDA Tailrace	115.7	115.2	-0.5
2007	BON Tailrace	117.1	117.6	0.5
2002	BON Tailrace	117.7	117.7	0.0
1999	BON Tailrace	119.6	120.8	1.2

Average % TDG Difference :	**0.1**

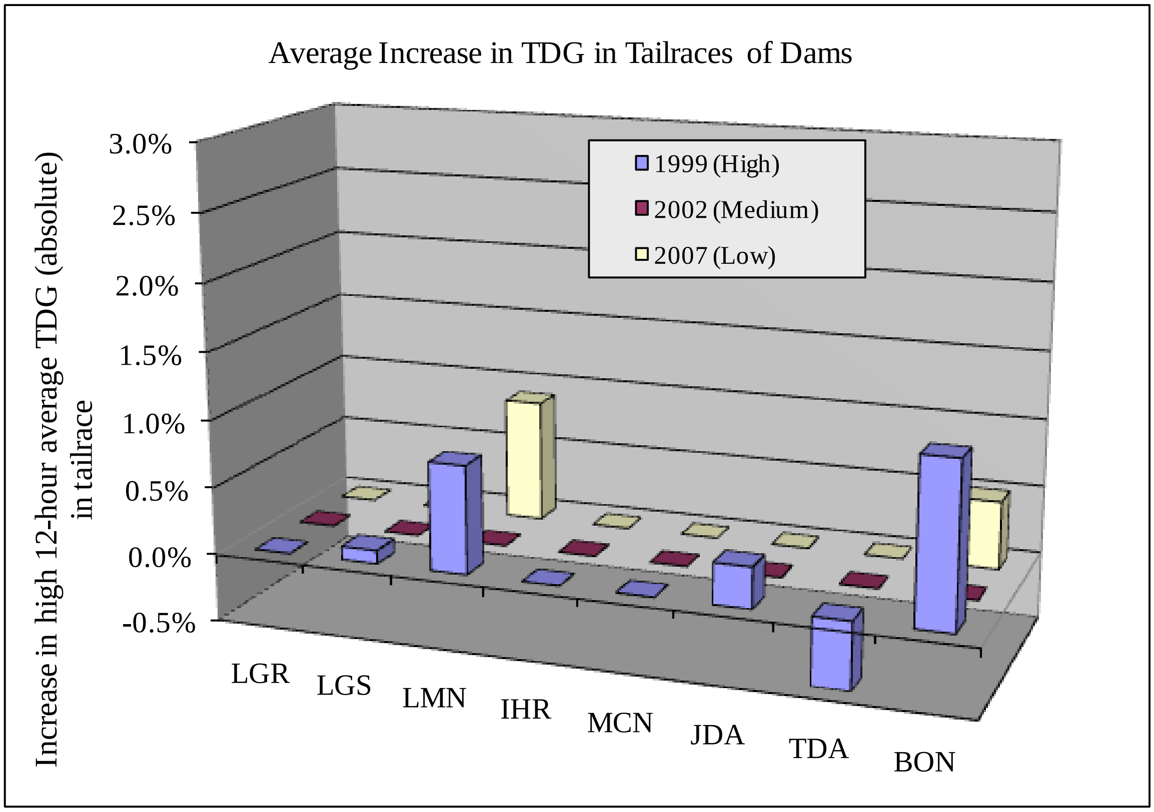


Figure 13. ACOE SYSTDG Modeled Seasonal Average Absolute Increase in Percent TDG in the Tailraces without the 115% Forebay Requirement.
The difference in TDG is calculated as:

$$\boldsymbol{TDG\ under\ the\ 120\%\ only\ scenario - TDG\ under\ the\ 115\ \&\ 120\ base\ case\ scenario}$$

It is expected that TDG in the forebay would not go above 120% because the tailraces are limited to 120% during fish passage spill. The USACE analysis shows that eliminating the 115% requirement would increase TDG by an average of 0.3% in the forebays and 0.1% in the tailraces. The maximum single day increase in forebay TDG values was predicted at Ice Harbor (downstream of Lower Monumental dam), a difference of 4.1% TDG in 2007. The analysis also found situations where TDG appeared to decrease when the 115% requirement was eliminated, but these are believed to be modeling artifacts.

Ecology Literature Review

The Department of Ecology completed a literature review to assess the appropriate water quality criteria for TDG. The review, *Evaluation of Total Dissolved Gas Criteria (TDG) Biological Effects Research* (#713) is available on the AMT website. No comments were received by the AMT regarding the Ecology literature review.

The review showed that, near the surface (less than one meter), increasing the TDG from 115% would have a detrimental effect on aquatic life. However, with depth compensation, aquatic life at one meter or deeper would not be affected if TDG is increased to 120%.

Impacts on aquatic life (in the top one meter):

A number of papers summarized in the literature review studied the impact of TDG on aquatic life near the surface. While some studies did not find any effects at 120% TDG, the weight of all the evidence clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120%. There were fewer effects on aquatic life at 115% TDG. The detrimental effects ranged from behavior changes to high levels of mortality after a few days. A summary of the findings presented in Table 14 are as follows (see Table 14 for details):

At 110% TDG or less, reported symptoms in shallow water included:

- Sub-lethal impacts.
- Mortality in insects and larval striped bass.
- No symptoms present.

At 115% TDG, reported symptoms in shallow water included:

- Sub-lethal impacts (tadpoles floating).
- Mortality in fish such as 20% in 8 days and 56% in 35 days.
- No symptoms present.

As TDG increases to 120%, reported symptoms in shallow water included:

- Sub-lethal impacts (frogs, sturgeon larvae).
- Increased mortality in fish such as 20% in one day, 50% in 3 or 4 days, 20% in 6 days, 42% in 9 days, 10% in 11 days, 32% in 12 days, 50% in 22 days, and 20% in 23 days.
- Some mortality in other aquatic life (daphnia).
- No symptoms present.

It is important to note that high mortalities are not found in the Columbia and Snake Rivers when TDG reaches these levels, presumably due to depth compensation. It is also important to include a significant margin of safety since high mortality is a very undesirable outcome.

Table 14. Summary of TDG Impacts in Shallow Water from Ecology Literature Review.

Author	Species	Percent TDG	Depth	Impact
Anticliffe et al (2003)	Juvenile rainbow trout	118%	0.1-0.25 m	3% had bubbles.
Anticliffe et al (2002)	Juvenile rainbow trout	116%	0.25 m	42% mortality after 9 days.
Bently et al (1981)	Pike minnow	117.2%	0.25 m	32% mortality after 12 days (also observed behavior changes).
Bouck et al (1976)	Various (salmonids and bass)	120%	1 m	No mortality after 12 days for bass. 50% mortality in 4 days for adult salmon.
Clay et al (1976)	Adult menhaden	110%	Very shallow (assumed)	Erratic swimming and death in 24 hours
Colt et al (1985)	Juvenile catfish	115%	Shallow (assumed)	56% mortality in 35 days

Author	Species	Percent TDG	Depth	Impact
Colt et al (1984a, 1984b, and 1987)	Bullfrogs and African clawed frog	116.5%	Shallow (assumed)	All frogs had bubbles in cardiovascular system and other impacts
		120%	Shallow (assumed)	Behavior changes
		114%	Shallow (assumed)	Tadpoles float to surface.
Cornacchia et al (1984)	Larval striped bass	106%	0.1 m	23% increase in mortality after 3 days.
Counihan et al (1998)	White sturgeon larvae	118%	0.25 m	No mortalities, but did have behavior changes.
Dawley et al (1975)	Juvenile rainbow trout, Coho, whitefish, and steelhead	120%	Shallow	50% mortality in 2.5-6 days depending on the species. (At 2.5 meters there were fewer deaths even with higher TDG.)
Dawley et al (1975)	Juvenile Chinook	116%	0.25 m	10% mortality in 11 days.
Dawley et al (1976)	Juvenile Chinook and steelhead	120%	0.25 m	50% mortality in 22 days (Chinook). 50% mortality in 30 hours (steelhead).
Gale et al (2004)	Adult Chinook	114 and 118%	0.5m	Some symptoms, including death. No effect on other some symptoms.
McInerny (1990)	Largemouth bass, bluegill and white bass	115-120%	up to 5-11 m	18-28% gas bubble signs depending on species.
Mesa et al (2000)	Juvenile Chinook and steelhead	113%-120%	0.27 m	60% fin bubble in 22 days and 20% mortality in 1.7-5 days at 120%. No mortalities in 22 days at 113%.
Mesa et al (1995)	Juvenile Chinook	120%	0.28 m	50% mortality in 60 hours. No mortalities in 22 days at 112%, but numerous other symptoms.
Mesa et al (1996)	Juvenile Chinook	120%	0.28 m	43% mortality in 75 hours. At 110%, numerous other symptoms.
Nebeker et al (1976)	Various insects	120%	0.25 m	Daphnia: 50% mortality in 93 hours (compared to 10% mortality in 170 hours at 110%). Crayfish: No deaths for 30 days. Larval Stoneflies: No deaths.

Author	Species	Percent TDG	Depth	Impact
Nebeker et al (1980)	Juvenile cutthroat trout	113-120%	0.6 m	Cutthroat trout: At 113%, 20% mortality in 185 hours and at 120%, 20% mortality was 20 hours (juveniles). At 118%, 20% mortality in 142 hours and at 121%, 20% mortality was 34 hours (adults).
	Juvenile speckled dace	119%	0.25 m	Speckled dace: At 119%, 20% mortality was 550 hours.
Nebeker et al (1976)	Adult sockeye	110-120%	0.7 m	At 110%, no signs. At 115%, first mortality in 21 days. At 120%, first mortality in 3 days.
Nebecker et al (1978)	Steelhead	126.7%	0.08 m	Eggs and embryos showed no signs of trauma for 20 days.
Newcolm (1974)	Juvenile steelhead	110%	0.23 m	46% had gas bubble signs. Blood chemistry changes at 105%.
Parametrix (2002)	Resident fish and macro-invertebrates	105-109% with spikes to 115%	0.5 and 3 m	Little signs of GBD.
Parametrix (2003)	Macro-invertebrates and resident fish	113-118%	3 m or less	Mayflies: 9% had GBD at 118%. Bristle worms: 0.05% had GBD at 113% at 3 m deep. Resident fish in 3 m or less showed signs of GBD.
Richter et al (2006)	Resident fish	120%	Unknown	No gas bubbles found in 20 species.
Schisler (1999)	Juvenile rainbow trout	105%	Shallow	Affected symptoms of whirling disease.
Weitcamp (1977)	Juvenile Chinook	120-128%	Up to 4 m	When fish had access to deeper water, no mortalities within 20 days.
Weitcamp et al (2003a)	Resident fish	<120%	<2 m	Only one fish found with gas bubbles.

Depth Distribution:

A number of papers summarized in the literature review studied the depth compensation of fish in the Columbia and Snake Rivers (see Table 15). While it is important to consider mean and average depth, the number of fish in the top one meter is particularly critical. Fish depth distribution varies between day and night. The mean depth was always deeper than one meter, and usually deeper than two meters. The amount of time spent at depths shallower than one meter was usually (but not always) less than the amount of time where significant detrimental effects were found.

Table 15. **Summary of Depth Distribution from Ecology Literature Review.**

Author	Species	Fish Observation	Depth
Abernathy et al (1997)	Juvenile Chinook and rainbow trout	Some observed	<1 m
		70% of fish	<3 m
Beeman et al (1997)	Juvenile steelhead	All fish	1.1-4.3 m
Beeman et al (2003)	Resident fish	Suckers (all)	0.3-16 m
		Some observed (all species)	<1 m
		Median (all species)	>= 2 m
Beeman et al (2006)	Juvenile steelhead	Mean	2-2.3 m
	Juvenile chinook	Mean	1.5-3.2
Dawley (1986)	Juvenile Chinook	8-22%	<3 m
Dawley et al (1975)	Juvenile Chinook	46%	<1.8 m
	Juvenile steelhead	29%	<1.8 m
Johnson et al (2007)	Adult chinook	4-12%	Shallow enough to be potentially affected by TDG
Johnson et al (2005)	Adult Chinook	1.3 hours (maximum time)	<1 m
		19 hours (maximum time)	<2 m
		Mean	>2 m
		3-9% of the time	<1m
Johnson et al (2005)	Adult steelhead	10% (Lower Monumental reservoir) 23% (Bonneville tailrace) 1.3% (McNary tailrace) 2.3% (Dalles reservoir)	<1 m
Johnson et al (2008)	Adult Chinook	28% (Dalles) 10% (Bonneville pool)	<2 m
		4.1 hours (maximum time)	<1 m
	Adult steelhead	14% (Lower Monumental reservoir) 2.9% (Dalles reservoir) 21% (Bonneville tailrace) 0.5% (Ice Harbor tailrace)	<1 m
		Some fish spent several days	<1 m
Parametrix (1999) [studied the Clark Fork River]	Brown trout	14%	<1 m
		Mean	3 m
Parametrix (1999) [studied the Clark Fork River]	Brown trout	20%	<1 m
	Rainbow trout	53%	<1 m
	Cutthroat trout	40%	<1 m
	Bull trout	Median	1.5-2 m
	Pikeminnow	1%	<1 m

Author	Species	Fish Observation	Depth
Parametrix (2000) [studied the Clark Fork River]	Brown trout	Median	1.7-5.5 m
	Bull trout	Range	0.9-3.8 m
	Cutthroat trout	Average	1.6 m
		Median hours depth	0.3-2.5 m
	Rainbow	Range	0.3-5.9 m
Smith (1974)	Juvenile Chinook and steelhead	28-46% (Lower Monumental reservoir)	<2m
Weitcamp et al (2003b) [studied Clark Fork River and Lake Pend Oreille]	Resident fish	Half the time (all species)	<2 m
		Median (rainbow trout)	1.3 m

The Ecology literature review also found that:

- Fish cannot quickly avoid high TDG, but some species seem to have some ability to avoid it.
- Fish can be negatively affected by TDG without showing evidence of gas bubbles.
- Susceptibility to gas bubble harm increases with activity, stress, and disease.
- Salmon usually migrate close to the shore where the TDG levels are usually less than in the thalweg (Johnson et al, 2007 and Schrank et al, 1998).
- Depth distribution of aquatic organisms and shallow water exposure is not well-known. There are recent studies on salmonids in the Columbia River, but there is little information on free-floating and surface dwelling organisms such as larvae of fish, crustaceans, and mollusks.

NOAA Fisheries Resident Fish Literature Review

Dr. Mark Schneider conducted a literature review of resident fish for NOAA Fisheries. The review, *Washington and Oregon State – Adaptive Management Team Resident Fish Literature Review* (#708) is available on the AMT website. USACE provided comments on Dr. Schneider's literature review, and Dr. Schneider provided a response to these comments. These documents are available on the AMT website.

This review concluded that there were negligible adverse effects from 120% TDG on resident fish and aquatic invertebrates. Further, with a 10% depth compensation for each meter below the surface, a TDG level of 120% at the surface would mean all aquatic life below one meter would have a depth compensated TDG equivalent to 110%. The report noted that the Columbia River has extensive amounts of deep water habitat available to aquatic life. It also concluded that salmon, resident fish, and invertebrates are similarly affected by TDG supersaturation.

In order to conclude from the report that removing the 115% requirement would be acceptable, two assumptions need to be made:

- "Negligible" adverse effects are acceptable (or are mitigated by the benefits).

- The availability of deep water in the Columbia and Snake Rivers will provide adequate protection even though not all aquatic life lives in that deep water.

Parametrix Literature Review

Dr. Don Weitkamp, Parametrix, conducted a literature review of TDG literature since 1980 on behalf of Avista Utilities, Tacoma Power, and Chelan, Douglas, and Grant County PUDs. The *Total Dissolved Gas Supersaturation Biological Effects, Review of Literature 1980-2007 (#704)* is available on the AMT website. Douglas County PUD commented on Dr. Weitkamp's literature review. The comments are available on the AMT website.

The literature review found:

- TDG supersaturation results in little or no GBT at levels up to 120% of saturation when compensating depths (two meters or more) are available.
- Fish have the capacity to rapidly recover from GBT when they reach compensating depths or TDG supersaturation is decreased.
- Most instances of GBT have reported low incidence and severity; however, there have been a few cases of substantial mortalities reported. The reported mortalities and severe cases of GBT are generally attributed to either TDG supersaturation in situations where available depths are shallow (about one meter or less) or the TDG levels are exceptionally high (greater than 130%).
- Field investigations have not demonstrated population effects resulting from TDG supersaturation.
- Generally the biological effects of TDG supersaturation appear to be influenced by the depth distribution of the fish or invertebrates resulting from their natural behavior, and there is limited evidence suggesting active avoidance of high TDG levels.

Similar to the NOAA Fisheries review, in order to conclude from the Parametrix report that removing the 115% requirement would therefore be acceptable, two assumptions need to be made:

- Negligible adverse effects are acceptable (or are mitigated by the benefits).
- The availability of deep water in the Columbia River will provide adequate protection even though not all aquatic life lives in that deep water.

GBT Monitoring Program

FPC summarized data from its Smolt Monitoring Program for GBT monitoring in salmon in the Columbia and Snake Rivers from 1995 to 2007. This information is available on the AMT website (#607), along with comments on the analysis.

FPC identified relatively low occurrences of fin GBT. The highest was 7%, which occurred when TDG exceeded 130% in the tailwater. The threshold for spill curtailment is a GBT incidence of 15% in the sampled population. However, during certain situations, such as the end of an abnormally slow steelhead migration in 2007, as high as 39% of the fish at Little Goose dam had signs of GBT. It is important to note that signs of GBT do not directly translate to mortality.

For salmon experiencing TDG of 116-120% in the tailwater of the upstream dam, GBT was found in 1.0% of the fish (compared to 0.6% of the fish when TDG was 111-115%). See Figure 14 for details.

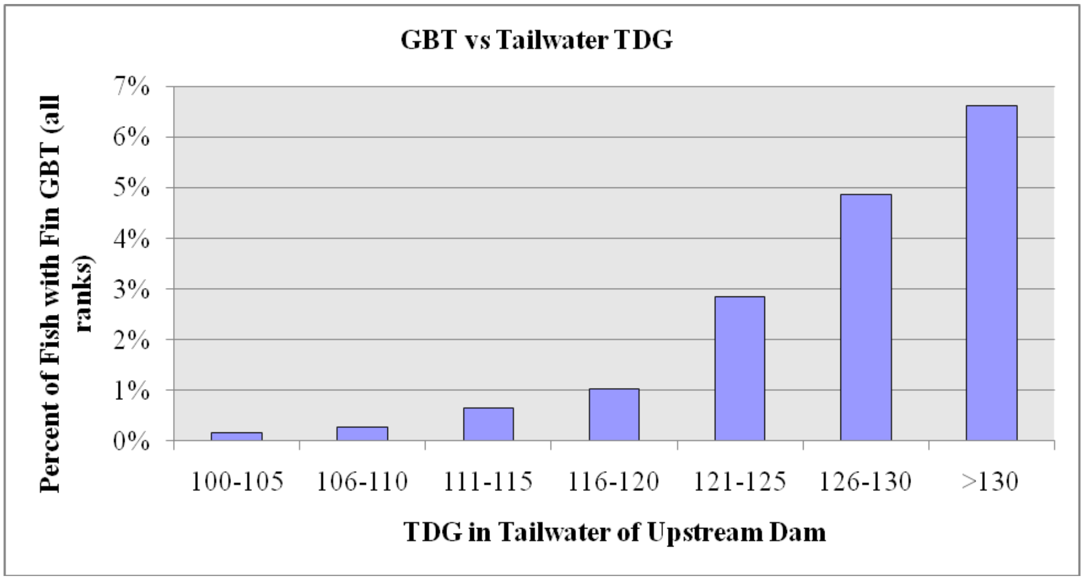


Figure 14. Total GBT at Varying TDG Levels in the Tailrace.

For salmon experiencing TDG of 116-120% in the forebay of the dam, GBT was found in 1.4% of the fish (compared to 0.4% of the fish when TDG was 111-115%). This is a 1% increase in GBT. The increase in GBT is calculated as:

$$Percent\ of\ Fish\ with\ GBT\ at\ 116\ to\ 120\%\ TDG - Percent\ of\ Fish\ with\ GBT\ at\ 111\ to\ 115\%\ TDG$$

See Figure 15 for details.

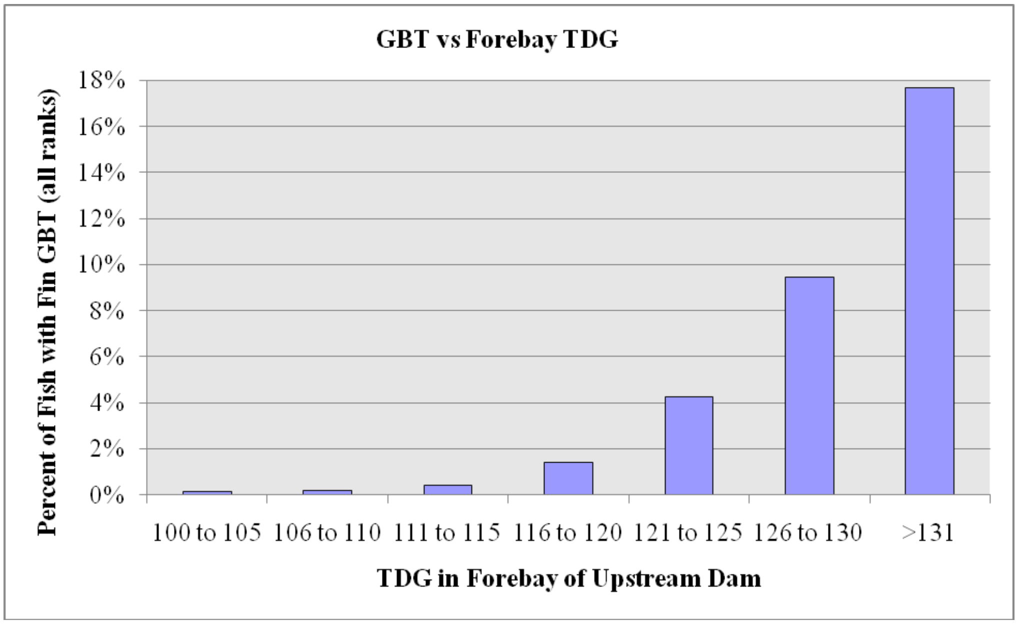


Figure 15. Total GBT at Varying TDG Levels in the Forebay.

Synthesis of Ecology, NOAA Fisheries, and Parametrix Literature Reviews and GBT Monitoring Program

It is expected that TDG in the forebay would not go above 120% because the tailraces are limited to 120%. The USACE analysis showed that eliminating the 115% requirement would increase TDG an average of 0.3% in the forebays and 0.1% in the tailraces. The Ecology, NOAA, and Parametrix literature reviews agree that a one meter or more depth compensation would protect aquatic species if TDG levels were at or below 120%. The three literature reviews and the GBT monitoring program results identify a minor increase in the incidence of GBT if the 115% requirement is removed. The NOAA Fisheries and Parametrix literature reviews both argue that any negative effect would be negligible. Results from the GBT monitoring program predict a 1% increase in GBT signs even if TDG increases from 111-115% to 116-120%. The Ecology literature review identifies an impact to aquatic species near the surface (less than one meter deep) that should not be considered negligible. The Ecology review found that there is a detrimental effect on aquatic life at less than one meter depths, and that some aquatic life may be residing near the surface for long enough to suffer the detrimental effects of GBT.

Chronic, long-term effects of exposure to high TDG are difficult to fully study. Some studies have been done on various aspects of chronic exposures, but few studies have been completed on high TDG exposures greater than one month.

Dams on the Middle Columbia River

There are six dams on the middle Columbia that are regulated by the 115% forebay requirement. Chief Joseph Dam, like the lower Snake River and Columbia River dams, is run by the USACE. Wells Dam is owned by Douglas County PUD, Rocky Reach and Rock Island Dams are owned by Chelan County PUD, and Wanapum and Priest Rapids Dams are owned by Grant County PUD.

There is far less information on the potential effects of eliminating the 115% forebay requirement on the mid-Columbia River dams compared to the other dams. Many of the mid-Columbia River dams recently completed or are planning structural changes to their dams. These recent changes make it difficult to analyze various spill scenarios based on TDG limits. Currently, these dams rarely manage their spill to the forebay requirement. The biological opinion for the FCRPS does not apply to the PUDs. Wells, Rocky Reach, and Rock Island are covered by a Habitat Conservation Plan (HCP). Wanapum and Priest Rapids are covered by separate biological opinions and incidental take statements. The Department of Ecology addresses water quality issues for PUD-owned dams in 401 water quality certifications. See http://www.ecy.wa.gov/programs/wq/ferc/ for details.

Chief Joseph (USACE)

Chief Joseph Dam recently installed new deflectors to reduce TDG. Spill testing is needed before fully knowing how much TDG will be reduced. This additional testing will also help determine how much of an effect the 115% forebay criterion has on Chief Joseph Dam.

Wells (Douglas County PUD)

During fish spill season at Wells Dam, water is diverted into a juvenile bypass system, a series of modified spill gates. Spill volumes are based on salmon survival criteria set in the HCP. Wells spills about 6-9% of the flow for fish passage as required by the HCP. This spill adds up to 2% TDG to the water Wells Dam receives. Douglas PUD is currently reviewing their ability to meet TDG standards as part of their dam relicensing process, which may result in lowered TDG in the tailrace, and hence, downstream forebay.

Over the past five years, using daily average TDG values (not the same as the water quality standards), Wells Dam had TDG exceedances in the downstream forebay 14% of the days. If the forebay criterion is eliminated and if Wells receives water with higher TDG in its forebay, it may be more difficult for Wells to meet the 120% tailrace standard. If the TDG criterion is changed, it may affect operations at Wells Dam.

Rocky Reach (Chelan County PUD)

Studies performed during relicensing of Rocky Reach Dam showed that the dam would probably meet the 115% downstream forebay levels. Spill volumes at Rocky Reach Dam are managed in accordance with an HCP and are set as a fixed percentage of flow. There are a few exceedances of the 115% forebay criterion due to fish spill operations. Rocky Reach spill rarely needs to be managed to the 115% forebay criterion.

Rock Island (Chelan County PUD)

Like Wells and Rocky Reach Dams, Rock Island operates in accordance with an HCP, where spill volumes during fish passage season are set as a fixed percentage of flow. These spills have included both 10% and 20% of flow. While the 10% would likely not lead to exceedances of the downstream 115% forebay criterion, the 20% level may occasionally cause exceedances.

Wanapum (Grant County PUD)

Wanapum Dam recently installed a new 20 kcfs bypass system, so historical information does not accurately reflect future conditions. As part of the relicensing process for Wanapum Dam, Grant PUD submitted information on proposed TDG improvements. According to these studies, Wanapum Dam would meet the 115% forebay criterion after the bypass and advanced turbines are installed, to be completed by year ten of the new license. For more information on Wanapum Dam, see the Water Quality Certification available at http://www.ecy.wa.gov/programs/wq/ferc/existingcerts/priestrapids/priest_rapids-final_cert040307.pdf.

Priest Rapids (Grant County PUD)

Spill volumes at Priest Rapids Dam for fish management are set on fixed percentages, currently at 61%. The forebay criterion downstream of Priest Rapids is in Pasco, a considerable distance from the Priest Rapids Dam. Priest Rapids has never reduced voluntary spill due to the 115% forebay criterion. As part of the relicensing process for Priest Rapids, Grant PUD submitted information on proposed TDG improvements. According to these studies, Priest Rapids currently (and after currently planned structural modifications) will meet the downstream 115% standard. For more information on Priest Rapids Dam, see the Water Quality Certification available at http://www.ecy.wa.gov/programs/wq/ferc/existingcerts/priestrapids/priest_rapids-final_cert040307.pdf.

Agencies' Decisions

Technical Information

The weight of evidence approach is the process of weighing measurable effects (*measurement endpoints*) against identified values (*assessment endpoints*) in order to evaluate whether a significant risk of harm or benefit is posed to the environment. This method is typically applied when reconciling or balancing multiple lines of evidence pertaining to an assessment endpoint.

Measurement endpoints are the lines of evidence used to evaluate the assessment endpoint. The TDG AMT measurement endpoints are:

- The negative biological impacts (gas bubble trauma) of eliminating the 115% TDG forebay limit on all aquatic life.
- The beneficial increase in anadromous fish that will survive the system if the 115% TDG forebay limit was removed.

Assessment endpoints are the explicit expressions of the actual environmental values that are to be protected. The TDG AMT assessment endpoint is:

- The protection of aquatic species, the most sensitive beneficial use, if the 115% total dissolved gas forebay requirement was removed.

The weight of evidence approach may be qualitative or quantitative. A simplified qualitative weight of evidence approach was used by Ecology and ODEQ in the decision making process. The typical qualitative approach allows the assessor to evaluate the outcome of each measurement endpoint with respect to indication of effect (harm, benefit, or neither); see Table 16.

Table 16: Weight of Evidence for the 115% Forebay TDG Requirement

Magnitude of Effect	Biological Impacts (gas bubble trauma) if the 115% forebay TDG requirement is removed	Fish Survival related to increased spill if the 115% forebay TDG requirement is removed
High Harm	None	None
Low Harm	• **Ecology Literature Review**: The review found potential impacts on aquatic life near the surface (less than one meter). • **GBT Monitoring**: If TDG increases by 5%, signs of GBT would be expected to increase by 1%. With a 1-2% increase in spill, TDG would only increase 0.3% on average, thus the expected increase in GBT would be much less than 1%.	• **NOAA COMPASS Study**: The study predicts that the smolt to adult return for Snake River Steelhead would decrease by 0.02%.
No Harm or Benefit	• **NOAA Fisheries Resident Fish Literature Review**: The review found that any negative effect would be negligible. • **Parametrix Literature Review**: The review found that any negative effect would be negligible. • **Ecology Literature Review**: With depth compensation, aquatic life deeper than one meter would not be affected if TDG increased to 120%.	• **NOAA COMPASS Study**: The study predicts that the smolt to adult return for Upper Columbia River Chinook and steelhead would not change.
Low Benefit	None	• **NOAA COMPASS Study**: The study predicts that the smolt to adult return for Snake River Chinook would increase by 0.007%. It also found that the in-river survival of Mid-Columbia steelhead would increase by up 0.1%. • **CSS Study presented by USFW**: The study predicts that river survival for Steelhead would increase by 1-3% and for Chinook would increase by 0-1% (under FPC spill scenario B and C). • **CRITFC Adult Passage Analysis**: The analysis found that spill and surface bypass provide the safest downstream passage route for adult migrants.
High Benefit	None	• **CSS Study Presented by USFW**: The study predicts that river survival of Chinook and steelhead for increase 4-9% (under FPC spill scenario D).

The AMT included a broad scope of members and attendees who have specific expertise, data, and analyses that contributed to the AMT process. Each presenting AMT member, attendee, and commenter provided evidence for and against each analysis and presented his or her view to the AMT either in person or in writing. The AMT participants each developed a set of overall conclusions and recommendations for each analysis summarized in this document, such as spill volume analysis, fish survival impacts, and gas bubble trauma impacts. Ecology and ODEQ kept record of the AMT discussions and information submitted for and against each analysis and read the evidence for and against each analysis as presented on the AMT website. The water quality agencies used all the information submitted during the AMT process to make an informed decision.

If the 115% requirement was removed, the amount of fish passage spill could be increased, especially at Lower Monumental Dam on the Lower Snake River. The total amount of additional water that could be spilled in the near-term is probably about 1-2%. Due to the expected increased power use in the region, reductions in overgeneration spill are likely. If overgeneration spill is reduced, the 115% forebay requirement limits voluntary spill more frequently. If both the BiOp spill requirements and overgeneration spill volumes change significantly over time, removal of the 115% forebay requirement has the possibility of affecting spill even more significantly (up to a theoretical maximum of 60% more spill in some years).

There is no way to know the exact impacts on fish survival due to the increase in spill. Each method of determining this impact has great uncertainty and controversy. With an increase in spill of 1-2%, each analysis found that there is likely a small, positive effect on Chinook survival percentage (greater than zero but less than 1%). Some analyses found the potential for much greater survival (4-9%) at the higher spill estimates. One analysis found there might also be small negative effects on Snake River steelhead.

Likewise, there is no way to know the exact impacts on aquatic life from increases in TDG due to the increase in spill. With increases in spill of 1-2%, TDG would likely increase by about 0.3% in the forebays and 0.1% in the tailraces. In some forebays in some situations, TDG could increase by as much as 4% (the maximum TDG is estimated at 120% at Ice Harbor Dam forebay on the Lower Snake River). Results from the GBT monitoring program would predict a small increase (less than 1%) in overall GBT in salmon if the 115% requirement was eliminated. Two literature reviews argue that any negative effect would be negligible ("negligible" is defined as so unimportant as to be safely disregarded). The third literature review concludes that with depth compensation, aquatic life at one meter or deeper would not be affected if TDG increased to 120%. However, the same review identifies a potential impact that, while probably small, is not negligible for species at depths between the surface and one meter.

Ecology Decision

Ecology decided not to change its 115% TDG forebay water quality criterion for the Columbia and Snake Rivers. This decision is based on the information provided in this document.

Spilling water over dams increases the level of total dissolved gas (TDG) in the river. Water plunging from a spill entrains air and carries it to a depth where the pressure forces the gas into solution. TDG levels above 110% of saturation can cause gas bubble trauma in fish. Gas bubble trauma is caused by gas bubbles forming in the cardiovascular system of aquatic species. These bubbles block the flow of blood and respiratory gas exchange.

Ecology's statewide total dissolved gas criterion in the water quality standards is 110%. This criterion is designed to fully protect salmon and all other aquatic life. In the 1990s, Ecology added a specific exemption for the Columbia and Snake Rivers for higher TDG levels to allow additional spill of water over the dams to aid salmon migration. Ecology allows TDG up to 120% in the tailrace immediately below the dam and 115% in the forebays behind the dams. While this level of gas is less protective than our statewide criterion, it does allow for additional spill that benefits salmon.

TDG levels in the tailrace are typically higher just after the water plunges over the dam. However, most aquatic life spends more of their time in the forebays. The 115% forebay criterion provides an additional margin of safety for chronic protection against gas bubble trauma in all aquatic life.

Ecology determined that there would be a potential for a small benefit to salmon related to fish spill if the 115% forebay criterion was eliminated, but there would also be the potential for a small increase in harm from increased gas bubble trauma.

The weight of all the evidence from available scientific studies clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120%. The detrimental effects ranged from behavior changes to high levels of mortality after a few days. There were fewer effects on aquatic life at 115% TDG. Ecology strongly encourages implementing actions that increase salmonid survival without further increasing total dissolved gas.

When reviewing the appropriateness of revising a water quality standard, Ecology must carefully consider whether the criteria will adequately protect the designated uses for that water. Designated uses are those water uses (e.g., fishing, boating, aquatic life, water supply) that are specified in water quality standards for protection in a water body. All designated uses and even the most sensitive use must be fully protected. Under section 303(c) of the Act, EPA is required to review and to approve or disapprove state-adopted water quality standards. This review involves a determination of whether (1) the state has adopted criteria that protect the designated water uses and (2) the state has followed its legal procedures revising or adopting standards. NOAA Fisheries and USFW would need to conduct an ESA consultation on any water quality standard EPA approves.

Changing the water quality criterion would trigger additional administrative procedure requirements. In Washington, rule changes must include a cost benefit analysis and a small business economic impact statement to determine the effects of rule changes on the public and businesses in the state. The benefits of the rule change must outweigh the costs in order to be adopted into rule. A State Environmental Policy Act (SEPA) determination would be needed. Based on that determination, there might be a requirement for an environmental impact statement if the proposed rule change was determined to significantly impact the environment. Based on the information in this document, Ecology does not believe the overall benefits of additional spill versus additional risk of gas bubble trauma are clear and are sufficient for a rule revision.

ODEQ Decision

The Oregon Department of Environmental Quality TDG waiver issued to the U.S. Army Corps of Engineers on June 22, 2007, allows for three key provisions for the purpose of addressing the TDG AMT question regarding the need for the forebay total dissolved gas (TDG) monitoring requirement to regulate spill during fish passage spill season on the Columbia River:

DEQ
State of Oregon
Department of Environmental Quality

- 3(iii): Spill must be reduced when the average total dissolved gas concentration of the 12 highest hourly measurements per calendar day exceeds 115% of saturation in the forebays of McNary, John Day, The Dalles, and Bonneville Dams monitoring stations.

- 3(vi): The Department may approve changes in the location of forebay and tailrace monitors, use of forebay monitors, and may approve changes to the method for calculating total dissolved gas. Before approving any changes, the Department must consult with the Adaptive Management Team or the Federal Columbia River Power System Water Quality Team or both. The Department is directed to begin this process for consultation immediately and to evaluate and, if appropriate, approve such changes as soon as possible.

- Adaptive Management: The process for reviewing the implementation status of the 2002 Lower Columbia River Total Dissolved Gas TMDL will begin no later than January 1, 2011. The Washington State Department of Ecology will convene an advisory group comprising representatives of Oregon Department of Environmental Quality, tribes, federal and state agencies to evaluate appropriate points of compliance for this TMDL. Based on these findings, further studies may be needed, and structural and operational gas abatement activities will be redirected or accelerated if needed. After 2010, the location of total dissolved gas monitors will be consistent with the Adaptive Management implementation strategy for the 2002 Lower Columbia River Total Dissolved Gas TMDL, and may no longer require forebay monitors and may only require tailrace monitors as TMDL implementation transitions from short-term to long-term strategies.

The TDG waiver is available on ODEQ's website:
http://www.deq.state.or.us/WQ/TMDLs/columbia.htm#tdg

Based on the information presented at the TDG AMT, the ODEQ finds that the removal of the forebay monitoring requirement will not cause excessive harm to the beneficial use, aquatic species in the Columbia River, during fish passage spill season. On June 22, 2007, the

Environmental Quality Commission acting under the authority of OAR 340-041-0104(3) modified the total dissolved gas standard for the main stem Columbia River during specified periods in 2008 and 2009. Paragraph 3(vi) of the Environmental Quality Commission's Order gives the Department authority to approve changes to the location and use of forebay monitors, after consultation with the Adaptive Management Team or the Federal Columbia River Power System Water Quality Team or both. The Department consulted with the Adaptive Management Team starting November 2007 until September 2008. Based on these consultations and the findings and conclusions described in this document, the Department proposes to remove the requirement for the use of forebay monitors in 2009. All other provisions of the Environmental Quality Commission's 2007 Order remain in effect.

Sufficient information has been provided to assess the need for the forebay TDG monitoring gauges. The ODEQ has assessed the relative importance of the information presented to the AMT describing the continued disagreement of the placement and representativeness of the TDG forebay monitoring gauges, the role of spill to fish survival, the impacts of TDG based on gas bubble trauma monitoring conducted over the past 14 years, and the expected spill volume changes and survival impacts based on the various modeling approaches.

The Ecology literature review found potential impacts on aquatic life near the surface (less than one meter). Through the successful implementation of ODEQ’s TDG shallow water criterion, 105% TDG at depths less than two feet in depth (0.6096 meters), aquatic life at shallow depths have been protected during fish passage spill season. Typically during the early spring, TDG must be reduced below Bonneville Dam to meet ODEQ’s shallow water criterion because salmonid redds are present at the Ives Island location at depths less than two feet.

Adult salmonids typically do not exhibit gas bubble trauma when entering shallower water habitat of Columbia River tributaries. Currently, there is no adult monitoring going on for the explicit reason of gas bubble trauma monitoring because handling is harmful to the adults and may cause mortality or stress. Based on the potential for harm and the data collected showing few to no signs of gas bubble trauma in adults under controlled fish passage spill conditions, DEQ has not required adult gas bubble trauma monitoring since 2000. This is likely due to depth compensation. For every meter below the surface water, a reduction of 10% TDG is measured in the water column. This is called “depth compensation”. A TDG level of 120% at the surface would mean all aquatic life below one meter would have a depth compensated TDG equivalent to 110%. The movement of the adult fish into tributaries, such as the Deschutes or Umatilla rivers, results in the fish slowly entering shallower water so that the fish continue to benefit from hydrostatic compensation as it also moves to lower TDG tributary waters. The TDG levels in the tributaries are less than the TDG levels in the mainstem Columbia River during fish passage spill, and meet the 110% TDG water quality standard. Even once within the tributary a fish could still be in relatively deep water, allowing for depth compensation, as it begins migration up stream to its spawning ground.

The information collected on the incidence of gas bubble trauma in salmon smolts in the Columbia River from 1995 to 2007 shows that an estimated 1.4% of the salmon smolts would experience gas bubble trauma if the forebay monitoring requirement is removed and if TDG levels were between 115% and 120% in the forebay. This is well below ODEQ’s TDG waiver threshold, in which if 15% of the sampled fish experience gas bubble trauma then fish passage spill is to be terminated. The TDG waiver states:

- 3(vii): If 15 percent or more of the juvenile fish examined show signs of gas bubble trauma in their non-paired fins where more than 25 percent of the surface area of the fin is occluded by gas bubbles or that contra-indicatory evidence suggests that fish are being harmed, the Director must terminate the modification.

The monitoring of gas bubble trauma in juvenile fish is implemented by the Fish Passage Center (FPC) under the Smolt Monitoring Program during the fish passage spill season. This program is overseen by the Fish Passage Advisory Committee (FPAC) which is made up of the Federal, State and Tribal fishery managers, including the Oregon Department of Fish and Wildlife. Historically, FPC notifies ODEQ if the incidence of gas bubble trauma in juvenile fish exceeds the TDG waiver threshold of 15% incidence of gas bubble trauma. In order to verify that the beneficial use is not experiencing excessive harm, ODEQ will continue to require gas bubble trauma monitoring during the fish passage spill season. Additionally, annual reporting of both physical and biological data during fish passage spill as identified in the TDG waiver will continue:

- 3(ix): No later than December 31 for each year of this waiver, the Corps must provide an annual written report to the Department detailing the following:
  - d) Data results from the physical and biological monitoring programs, including incidences of gas bubble trauma;
  - e) Description and results of any biological or physical studies of spillway structures and prototype fish passage devices to test spill at operational levels;

ODEQ's decision to remove the forebay monitoring requirement is in compliance with the Lower Columbia River TDG TMDL and is supportive of the long-term TMDL implementation strategy. Meeting the load allocations in the TMDL falls into two phases. Phase I, short-term implementation, involves improving water quality, while ensuring that salmon passage is fully protected and in accordance with the National Marine Fisheries Service's Federal Columbia River Power System Biological Opinion. The goal for the long-term TMDL compliance is to meet the Oregon DEQ TDG water quality standard of 110% at the specified TMDL tailrace load allocation locations at each dam. For short-term compliance, forebay and tailrace fixed monitoring stations can be used, or new fixed monitoring stations can be established. The fixed monitoring stations were selected by the Endangered Species Act forums and outside the development of the TMDL. Short-term implementation relies primarily on operational changes to be made at the dams to reduce TDG. Short-term compliance can remain adaptive and flexible, while long-term compliance remains fixed to firm goals. Through the adaptive management forum, the TMDL implementation is now transitioning into a long term implementation strategy. Long-term implementation will involve primarily structural and some operational changes to be made at the dams to achieve the water quality standard for TDG while protecting fish passage. Long-term compliance monitoring will occur at the tailrace loading capacity compliance location at each dam, as specified in the TMDL.

In order to implement the decision to remove the forebay TDG monitoring requirement, ODEQ will draft a proposed Departmental Order and allow for a 30-day public comment period, similar to the TDG waiver renewal process. Once public comments are received on the proposed Departmental Order and all appropriate changes made, the ODEQ Director will sign and issue the Departmental Order to the U.S. Army Corps of Engineers. The Departmental Order will likely be issued prior to the start of the 2009 fish passage spill season, April 1, 2009. Additionally at the June, 2009 EQC meeting, the U.S. Army Corps of Engineers will request a new multi-year TDG waiver for the Columbia River dams. The current TDG waiver expires on August 31, 2009. The June EQC hearing on the TDG waiver renewal will allow for issuance of a new TDG waiver prior to the expiration of the current waiver. For more information on this process, please contact: Agnes Lut, Columbia River Coordinator, Oregon Department of Environmental Quality at 503-229-5247, lut.agnes@deq.state.or.us, or 811 SW 6th Ave, Portland, OR 97204, or Fax: 503-229-6037.

References

The following referenced information is available on the AMT website at
http://www.ecy.wa.gov/programs/wq/tmdl/ColumbiaRvr/ColumbiaTDG.html

8th Meeting -- September 9, 2008

- *Agenda* (801) and Meeting Notes (811)
- Oregon and Washington Presentation (802)
- Ecology and ODEQ Evaluation of the 115% Total Dissolved Gas Forebay Requirement (803).
    - USACE Comments:
        - History of Gages. (812)
        - Synthesis Table. (813)
        - SYSTDG Spill. (814)
        - Overall Comments. (815)
            - FPC Response to Figures 13-15. (822)
    - FPC Comments (816)
        - FPC Calculation of Spill Variable. (822)
        - FPC Response to Scenarios. (825)
    - BPA Comments (817)
    - Northwest RiverPartners Comments (818)
    - CRITFC Comments:
        - Comments. (819)
        - Cited ISAB Snake River Spill-Transport Review. (820)
    - ODFW Comments (821)
- Additional background files for the Evaluation of the 115% (excel files used to make the charts and other summaries of information presented to the AMT).
    - FPC Spill Volume. (804)
    - SYSTDG Spill Volume. (805)
    - Importance of Spill. (806)
    - HYDSIM . (807)
    - COMPASS. (808)
    - GBT Monitoring. (809)
    - SYSTDG TDG Levels. (810)
    - FPC Fish Survival Calculations. (823)

July Reports and Comments

- Ecology literature review: Evaluation of Total Dissolved Gas Criteria Biological Effects Research (final) (713)

7th Meeting - June 23, 2008

- Agenda (701) and Meeting Notes. (702)
- Overview Presentation. (703)
- Don Weitkamp literature review:

- Total Dissolved Gas Supersaturation Biological Effects, Review of Literature 1980-2007. (704)
- Summary. (705)
- Presentation. (706)
- Total Dissolved Gas Literature 1980-2007, an Annotated Bibliography**.** (707)
- Douglas County PUD comments on Weitkamp literature review (712)

- CRITFC Review of Adult Passage through Different Dam Passage Routes. (709)
  - USACE Comments on CRITFC Review of Adult Passage (714)
  - BPA Comments on CRITFC Review of Adult Passage (715)

6th Meeting - May 13, 2008

- Agenda (601) and Meeting Notes. (602)
- Overview Presentation. (603)
- SYSTDG modeling results and presentation. (604)
- Revised SYSTDG Report. (710)
  - FPC Review of "Report on the SYSTDG Modeling for AMT: With and Without 115% TDG Standard (May 8, 2008)" (620)
- HYDSIM modeling presentation and report. (605)
- COMPASS modeling results. (606)
  - COMPASS report (609) and presentation. (610)
  - ISAB review of COMPASS, 2008 (630)
  - ODFW comments. (711)
  - BPA response to ODFW comments (716)
  - NOAA Fisheries response to ODFW comments (717)
- Gas Bubble Trauma Monitoring Program. (607)
  - Corps comments on FPC gas bubble trauma presentation. (613)
  - FPC response to COE comments on FPC's GBT Presentation (628)
- Resident Fish Literature Review. (608)
  - Corps comments on resident fish report. (614)
  - Updated Resident Fish Literature Review. (708)

5th Meeting - April 8, 2008

- Agenda (501) and Meeting Notes. (502)
- USACE Presentations:
  - Project Configuration and Operation for Fish Passage at Bonneville, the Dalles, and John Day Dams. (503)
  - Fish Passage and Survival at Lower Snake and McNary Dams. (504)
- SYSTDG presentation. (505)
- HYDSIM presentation. (506)
  - HYDSIM report (611) and presentation. (612)
- COMPASS presentation. (507)

4th Meeting - March 11, 2008

- Agenda and Meeting Notes. (401)
- Presentation on Comparable Survivability Study (CSS)
  - BPA comments on CSS Comment #1. (402)
  - USFWS response to previous BPA comments on CSS. (615)
  - Comments forwarded by Northwest RiverPartners:
    - NOAA NWFSC comments on CSS (621)
    - Anderson comments on CSS (622)
    - BPA comments on CSS (623)
    - NOAA comments on CSS (624)
  - FPC response to previous comments by Northwest RiverPartners on CSS. (618)
  - FPC response to CSS comments by Anderson (625)
  - FPC response to CSS comments by NOAA (626)
  - FPC response to CSS comments by BPA (627)
  - Comparative Survival Study of PIT-Tagged Spring/Summer Chinook and Steelhead in the Columbia River Basin: Ten-year Retrospective Analyses Report (629)
- Oregon DEQ and Washington Ecology Draft AMT Schedule. (403)

3rd Meeting - February 12, 2008

- Agenda (301) and Meeting Notes. (302)
- Fish Passage Center's analysis of spill volumes. (303)
- U.S. Army Corps of Engineers draft analysis of spill volumes. (304)
- Literature review for TDG (old draft). (305)
- Fish Passage Center's Importance of Spill presentation. (306)
  - BPA comments on FPS Importance of Spill presentation: Comment 1 and Comment 2.
  - FPC response to previous BPA comments on FPC's importance of spill presentation. (619)
- CRITFC's Weight of Evidence presentation. (307)
- Oregon DEQ and Washington Dept. of Ecology presentation. (308)

2nd Meeting - December 13, 2007

- Agenda (201) and Meeting Notes. (202)
- Ecology and ODEQ review and introduction presentation. (203)
  - No comments received.
- U.S. Army Corps of Engineers draft analysis of spill volumes. (204)
  - No comments received.
- Fish Passage Center's analysis of spill volumes. (205)
  - Comments on the FPC "analysis of spill volumes" and "importance of spill presentation" with Comment #1 (404) and Comment #2. (405)
  - FPC response to previous BPA comments on FPC spill analysis. (616)
  - FPC response to previous Corps comments on FPC spill analysis. (617)
- NOAA Fisheries Literature Review of Resident Fish and Invertebrates. (206)

1st Meeting - November 1, 2007

- Agenda (101) and Meeting notes. (102)
- Presentation. (103)

IN THE SUPERIOR COURT OF THE STATE OF WASHINGTON

IN AND FOR THE COUNTY OF THURSTON

NORTHWEST SPORTFISHING, et al., Petitioners,	
vs.	
WASHINGTON STATE DEPARTMENT OF ECOLOGY, et al., Respondents.	SUPERIOR COURT NO. 10-2-01236-0

VERBATIM REPORT OF PROCEEDINGS

BE IT REMEMBERED that on May 20th, 2011, the above-entitled and numbered cause came on for hearing before JUDGE LISA L. SUTTON, Thurston County Superior Court, Olympia, Washington.

Pamela R. Jones, Official Court Reporter
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A P P E A R A N C E S

ALL APPEARANCES VIA SPEAKERPHONE

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For the Respondent: Department of Ecology	JOAN MARCHIORO Assistant Attorney General Post Office Box Olympia, WA 98504
For the Respondent: Northwest River Partners	BETH GINSBERG Attorney at Law STOEL RIVES 600 University Street, Ste 3600 Seattle, WA 98101

May 20, 2011 Olympia, Washington

AFTERNOON SESSION

Department 8 Hon. Lisa L. Sutton, Presiding

APPEARANCES:

For the Petioners, Steve Mashuda and Amada Goodin, Attorneys at Law; for the Respondents, Joan Marchioro, Assistant Attorney General and and Beth Ginsberg, Attorney at Law

Pamela R. Jones, Official Reporter

* * * * *

THE COURT: Hi, this is Judge Sutton. Could you identify yourselves for the record.

MS. MARCHIORO: Joan Marchioro with the Attorney General's Office, and on the phone with me is my colleague, Steven North.

MS. GINSBERG: Beth Ginsberg and Jason Morgan on behalf of Northwest River Partners, and with us is Terry Flores, the executive director.

MR. MASHUDA: And you have Steve Mashuda and Amanda Goodin from Earth Justice representing the petitioners, Northwest Sportfishing Industry Association.

THE COURT: And we have the court reporter here, Pam, taking down what's said, and we also have the clerk assisting us today.

Thank you for participating by phone. I know this might be a little awkward, but we'll do the best we can, and hopefully those of you that are at a CLE can return promptly for your presentation.

Just so you know, since the last hearing where we heard oral argument in this matter, I have 20 pages of typed notes that I took, including footnotes, and I also reviewed my handwritten notes that I took during the oral presentations. I looked at the briefs again, as we discussed. I looked at the key material that was provided as part of the record, some of which I had in front of me at the hearing. I actually had the whole record back in chambers but I had some key provisions in front of me at the hearing.

I have in front of me the petition to amend the WAC 173-201A-200(1)(f)(ii) regarding the water quality standards, and so I'm just going to proceed, but first I want to again compliment the parties for their briefing and their oral presentation. I very much appreciated the timeliness by which the briefing was filed to allow me to prepare in advance, well in advance of the oral hearing, and also to allow me to review the materials again and take it under advisement. I appreciate that. And again, as I indicated earlier, I knew it was important for the parties that the Court issue a ruling promptly, and so I wanted to give you a date certain, today's date, by which I would rule.

As I indicated I have reviewed all the materials here. Oral arguments took place on May 13, 2011, with all parties present, and I have indicated all of the materials I have reviewed including the administrative record filed with the court.

The petitioners here include a coalition of sport and commercial fishing organizations and conservation groups. They are represented here by Mr. Steve Mashuda and Amanda Goodin. Respondents include the Washington State Department of Ecology, and they were represented by Senior Counsel Joan Marchioro and intervenor, Northwest River Partners.

The Washington State Department of Ecology is charged with protecting the quality of waters in the State of Washington, and their statutory authority is set forth in RCW 90.48.010. I should say that the Northwest River Partners, the intervenor, includes a group of electric customers, ports, business owners and farmers, and they are represented by Beth Ginsberg and Jason Morgan.

Judge Carol Murphy previously heard oral argument on the intervenor's motion to dismiss on the basis of collateral estoppel. That motion was denied on the basis that Ecology's denial of the petition, which is at issue here, to compel Ecology to initiate rulemaking, Judge Murphy ruled that that was a quasi-legislative rulemaking decision and therefore the doctrine of collateral estoppel did not apply. That order was entered on April 1st, 2011. We're here today because the petitioners have appealed the Department of Ecology's denial of their request that Ecology initiate rulemaking to modify or eliminate Washington's current water quality standards for total dissolved gas, or as referred to, TDG. Those current standards are set forth in WAC 173-201A(200)(1)(f)(ii).

The purpose of the current rule is to provide a special fish passage exemption for the Snake and Columbia Rivers to apply when spilling water at dams is necessary to aid fish passage over the hydroelectric dams when consistent with the Ecology's approved gas abatement plan. This plan is accompanied by fisheries management and physical and biological monitoring plans as well. The idea is to increase the fish passage without causing more harm to the fish population.

Here, there were two prior petitions that were filed by a subpart of the petitioner's group, and those were filed previously and denied by Ecology. The first petition, I believe, was filed in March '07. That was withdrawn. Excuse me, it was withdrawn so that the parties could enter into discussions, and subsequently in June 2007 the Adoptive Management Team, commonly referred to as AMT, was formed as part of a study group. The Save Our Wild Salmon was part of this study group, and they met for a period of time from roughly November '07 to September '08. And then on August 10th, '09, Ecology denied the June '09 petition.

Save Our Wild Salmon resubmitted another petition on March 8th, 2010. This was the third petition filed with Ecology to amend or remove the 115 percent forebay standard. Ecology denied that 2010 petition on May 7th 2010.

And just so the parties know, I'm going to summarize briefly Ecology's bases, and this again is a summary, for their denial decision. Ecology found that some of the aquatic organisms would experience adverse effects at TDG saturation levels approaching 120 percent, and Ecology contended that retaining the current 115 percent forebay limit was necessary to fully protect all species of aquatic life as they believe they're required to do under state and federal laws. And again, that's just a summary. Ecology's decision is set forth in the materials at Ecology 1840.62 and Ecology 1840.63, and I'm referring to by number the administrative record.

The petitioners here argue that Ecology's denial was arbitrary and capricious, contrary to sound science and outside the scope of Ecology's statutory authority for the following reasons. And again, I'm not going to repeat all of the petitioners' arguments because they argued very well to the court earlier in their oral presentation, but I will summarize for purposes of this ruling their arguments.

First, the petitioners felt that in so issuing its denial, Ecology had failed to consider all of the relevant studies which demonstrate that aquatic life, petitioners assert, would not be harmed by the removal or the amendment of the 115 percent forebay limit.

Secondly, that Ecology in conducting its risk-benefit analysis did not appropriately consider the benefits to salmon and all other aquatic life, such as the Pacific lamprey, from potential increases in spill resulting from the petition rule change. And they felt that based on the relevant evidence and new information, as well as the June 2009 petition that the petitioners had filed previously, that they felt that it was reasonable for Ecology to grant their petition as has the State of Oregon and remove the 115 percent forebay limit or, alternatively, that Ecology should increase that limit to 120 percent by initiating the rulemaking process to alter or eliminate the current standard, and again, I've cited the WAC that's at issue here.

This court has jurisdiction over this matter under RCW 34.05.570, and that statute authorizes judicial review of a state agency's action, including review of an agency's rule, review of a state agency's failure to perform a legally required duty, and review of the exercise of a state agency's discretion.

The pending matter here involves a rule challenge. Venue is proper in this county, and this action that's currently before the court was timely filed under RCW 34.05.542.

There was argument here about what the standard of review was, and again, I won't purport to resummarize what's in the briefing here, but an agency's denial of a petition for rulemaking is subject to judicial review under the Washington State Administrative Procedures Act. The case law is *Northwest Ecosystem*

Alliance vs. Forest Practices Board found at 149 Wn.2d 67, at page 74. That's a 2003 decision. A state agency's decision to deny a petition for review is other agency action reviewable under RCW, the APA, 34.05.57(4)(c) standards. Relief will only be granted if the court determines that the agency's decision to deny rulemaking is unconstitutional, outside the agency's statutory authority, arbitrary and capricious, or made by unauthorized persons. RCW 34.05.570(4)(c).

In making this determination, the court here will review the agency's record under RCW 34.05.558. And here there was supplemental information provided to the agency record which the court has as part of the administrative record below. The petitioners here, as the parties challenging the agency's actions, have the burden to demonstrate the invalidity of Ecology's actions under RCW 34.05.570(1).

Now here, the petitioners in their opening brief at pages 10 and 11 argued that Ecology's denial was arbitrary and capricious, and therefore this court should engage in a thorough, probing, in-depth review, and they cited the case of *Neah Bay Chamber of Commerce vs. Department of Fisheries,* which cited and quotes the *Citizens to Overton Park* decision.

The petitioners here felt that there was a broader standard of review that the court must engage in here that would allow the court to examine the relevant data and articulate a satisfactory explanation for its actions including a rational connection between the facts found and the choice made, and the petitioners have represented and argued to the court that they don't believe Ecology did so.

This court has reviewed the relevant standard of review in this matter, which standard of review is a question of law. There was citation by both parties to the *Rios* case here, and the court is finding here that where there is room for two opinions, an action taken after due consideration is not arbitrary and capricious, even though a reviewing court may believe it to be erroneous. And that's the *Hillis vs. Department of Ecology* case, 131 Wn.2d 373 at page 383. Agency action is arbitrary and capricious if it is willful and unreasoning and taken without regard to the attending facts or circumstances. That's the *Hillis* decision at page 383.

On matters involving complex factual issues, which are technical and within the agency's expertise, such as the matters presently before this court, the courts are highly deferential, citing the case of

Department of Ecology vs. PUD No. 1 of Jefferson County, 121 Wn.2d 179 at page 201.

The Department of Ecology is the state's water pollution control agency for all purposes under the federal Clean Water Act. State law requires that Ecology participate fully in the programs of the Clean Water Act and take all necessary action to secure to the state the benefits and to meet the requirements of this federal law. Washington has adopted certain regulations, and they're found in WAC 173-201A, and that those regulations contain three parts, based upon the designated uses of the body of waters in the State of Washington.

This first part of those regulations govern the classification of all surface waters based upon their designated beneficial uses; the second part of the regulations contain water quality criteria deemed necessary to support the specific identified beneficial use; and the third part of those regulations set forth the anti-degradation policy.

Washington conducts a triennial review of its water quality standards as required under the federal Clean Water Act. That includes public hearings, receiving public input and taking comments with respect to whether or not Ecology should modify or adopt new standards. If there is any modification or new standards, they are subject to review and approval by the federal Environment Protection Agency who must find, in part, that the standard to protect the designated water uses under federal regulations.

If the proposed water quality standards are likely to adversely impact listed species or designated critical habitat, federal EPA must formally consult with the Secretaries of Commerce and/or Interior Departments before EPA can approve the proposed state's water quality standards, and that's under federal law.

And in circumstances where formal consultation is required, the Secretary must issue a biological opinion which discusses the effects on the protected species and indicate whether the Secretary believes that jeopardy is likely to result from the state's proposed action.

If the Secretary determines that jeopardy will occur, he or she must specify reasonable and prudent alternatives that will avoid jeopardy and state whether such alternatives are available. If after this consultation the Secretary concludes no jeopardy will result from the proposed project, the Secretary shall provide the state agency an application, if any, with an incidental take statement, and that's a phrase that's used in federal law. Once formal consultation is done, EPA may act on the state's water quality standards.

All right. Here, TDG is defined as the measure of the sum total of all gas partial pressures, including water vapor, in water. That's found in the administrative record at Ecology 32.24. When water becomes supersaturated with gas, gas bubbles can form in the blood and tissues of aquatic organisms. And I'm referring again to the same part of the administrative record. The exposure of fish and other aquatic organisms to excess dissolved gas can produce physiological problems referred to by the parties as gas bubble disease or gas bubble trauma. The citation is Ecology 2150.1 and Ecology 2141.1 and 2141.2. Gas bubble trauma can, in turn, cause rapid acute mortality as well as increase long-term mortality in aquatic organisms. Ecology 32.24. The spilling of water over the spillways and dams is a major source of elevated TDG in the Snake and Columbia River system, and that's described in Ecology 2150.3.

So here generally, the rule statewide is that the TDG cannot exceed 110 percent saturation. But here, as we've indicated, Ecology amended the water quality standards back in 1997 to permit a relaxation of that standard not to exceed 125 percent in the tailraces of each dam for water being spilled for fish passage and in aid of fish passage in the Snake and Columbia Rivers. The rule then was reviewed as required in 2003 and Ecology proposed to make permanent the exemption which exists today.

And by way of background, here Oregon Department of Environmental Quality was directed by the Oregon Environment Quality Commission to evaluate the need here as to whether or not the 115 percent forebay TDG requirement for fish passage should be revised. And again, there was an Adaptive Management Team referred to as the AMT process that reviewed this matter and reviewed the literature associated with it. The parties in their materials point to various literature and studies that were reviewed as part of the AMT process in support of their various positions. I'm not going to go over that; it's well spelled out in the briefing and in the administrative record below.

It is true here that Oregon concluded that removal of the 115 percent forebay standard "will not cause excessive harm to the beneficial use, aquatic species in the Columbia River, during fish passage spill season." The record there is Ecology 1840.61. What's also true is that the intervenor, Northwest River Partners, noted that there were differences between Washington and Oregon's process, and that's described in their responsive brief at page 10, footnote 7. They claim here that Oregon's process for eliminating the standard is substantially simpler than Washington's. Oregon simply had to modify, and apparently they did, an existing order to establish a TDG waiver. And that's described in Ecology 001017-10. Unlike Oregon, Ecology here to alter or revise their 115 percent forebay TDG standard, would be required to undergo and initiate a new rulemaking process. Unlike Washington's TDG standard, Oregon's TDG standard includes a 105 percent shallow water TDG criteria to protect species including frogs, mollusks, other invertebrates and fish larva, that cannot dive to sufficient depths to avoid harmful levels of TDG.

In the administrative record starting at Ecology 1840.3 up to 1842.1, there was an evaluation of the 115 percent total dissolved gas forebay requirement by the Adoptive Management Team for the Columbia and Snake Rivers. Those materials also included comments by Ecology. That group of teams, AMT, included a broad scope of members and attendees, each of whom had specific expertise, data and analysis, all of whom contributed their input regarding spill volume analysis, fish survival impacts and gas bubble trauma impacts. The water qualities agencies used all of this information submitted during the AMT process to make an informed decision. And the document that states this specifically is Ecology 1840.61.

I would also note that Ecology's literature review identified an impact to aquatic species near the surface, less than one meter deep, that should not be considered negligible. But review found that there was a detrimental effect on aquatic life at less than one meter depth and that some aquatic life may be residing near the surface for long enough to suffer the detrimental effects of gas bubble trauma. The report then concluded that "Chronic long-term effects of exposure to high TDG are difficult to fully study. Some studies have been done on various aspects of chronic exposures, but few studies have been completed on high TDG exposures greater than one month." And the citation for that is, I believe it's at 1840.55. The AMT review noted the six dams on the middle Columbia river that are regulated by the 115 percent forebay requirements and the group specifically studied the potential impact at each dam, the administrative record at 1840.57 and the materials associated with those pages, also contained charts examining the different impacts at each dam, and the report noted that "There is no way to know the exact impacts on fish survival due to the increase in spill. Each method of determining this impact has great uncertainly and controversy." And I'm citing page Ecology 1840.57.

So for these reasons, and I have in front of me Ecology's denial that is on page 1840.62 and .63, as well as the reasons summarized in their denial letter that was attached to the petition, the petition to amend filed here starts at Ecology pages 1754 to 1. That is a letter and there is a -- excuse me. This was the letter, denial letter from Ecology, I apologize, it's not the petition, the denial letter was dated May 7th, 2010, and it starts on pages Ecology 1754.1, two-page letter ending at 1754.2. It had attachments. The court reviewed each of the attachments and outlined the issues associated with the petition and Ecology's response to the specific issues.

In sum and substance, Ecology declined to change the 115 percent TDG forebay water quality criteria for the Columbia River. Ecology concluded the small benefit to migrating salmon that would result from the proposed 120 percent TDG relaxation was insufficient to weaken the existing rule when weighed in light of increased risk of injury to aquatic species. Ecology's reasoning is stated as follows, and I'm citing Ecology 1017.62. Ecology determined that there would be a potential for a small benefit to salmon related to fish spill if the 115 percent forebay criterion was eliminated. But there would also be the potential for a small increase in harm from increased gas bubble trauma. The weight of all the evidence from available scientific studies clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120 percent. Based upon the information in the AMT report, Ecology does not believe that the overall benefits of additional spill verses additional risk of gas bubble trauma are clear and sufficient for rule revision.

Ecology also in its reasoning determined that changing the water quality criterion at this point would trigger additional administrative procedure requirements including a cost-benefit analysis and a small business impact statement that would be needed to determine the effects of rule changes on both the public and businesses in the State of Washington. And Ecology concluded that the benefits of that process -- the benefits from that process must outweigh the cost of any rule change to justify the rule's adoption. Ecology also determined that the state Environment Policy Act determination would be needed, and based upon what that determination would be, an environment impact statement may also be required. And that's found at Ecology 1840.62 and also point 63.

This factual and legal background is important to understand in light of the petitioners' matter before this court and the arguments advanced in support of the petitions' motion for summary judgment slash petition for judicial review. I've indicated that the petitioners have filed a second rulemaking petition back in June 2009 arguing that either the 115 percent TDG forebay rule should be raised to 120 percent or that monitoring forebay should be eliminated entirely. That's found at Ecology 1014.2.

For the same reasons stated earlier, Ecology chose not to revise the existing TDG rule and, thus, Ecology denied the second petition in August 2009, and when they did so, they cited the 2007/2009 AMT evaluation, review and process in support of its decision. And that's found at Ecology 1746.1.

At that time, petitioners did not seek judicial review of the denial the second petition but filed a third petition for a rulemaking request, and as the court has indicated, based on the paperwork that third petition was filed March 8, 2010, and it sought identical relief, and that third petition is found at Ecology 1453.1.

In the third petition, petitioners asserted Ecology, one, failed to consider the studies petitioners relied upon in support of their position; two, Ecology misrepresented other studies; three, Ecology inappropriately favored certain lab studies over field studies; and fourth, Ecology failed to properly consider the benefits of spill.

Some of the petitioning groups then sought review in superior court regarding Ecology's third denial, and that's the matter that we have presently before us. The petitioners here have dropped their second and third causes of action, and that's referred to in petitioners' brief, page 9 at footnote 9. The sole remaining claim before this court today is whether Ecology's denial of the third petition was arbitrary and capricious, contrary to Washington law, and/or exceeded the statutory authority of Ecology in violation of RCW 34.05.570(4)(c).

And so that you know, I did go back and I looked specifically at the petition, I looked specifically at the attachment to the petition and each of the petition issues that was raised by the petitioners to Ecology of which there were five.

Petitioner issue number one. It was asserted that spill is a vital salmon and steelhead protected measure. Ecology agreed that the use of spill was an important measure to decrease mortality in migrating salmon and steelhead. To aid fish in the passage over dams of the Snake and Columbia Rivers, Washington adopted an exemption already to the 110 percent TDG criterion. And that exemption allowed for increased fish passage in order to meet the Endangered Species Act by reducing fish passage mortality.

Now, petitioners claim that Ecology is required under state and federal laws to set the TDG limits that maximize salmon survival by balancing the benefits of spill with the risk of gas bubble trauma, but Ecology disagrees that the law requires them to do so. The court finds that Ecology is required under state regulations to maintain and protect all designated and existing uses in waters of Washington State under the WAC Rule 173-201A-310, which is also required under federal law under 40 CFR 131.12(a). The Snake and Columbia Rivers are designated uses which include key species uses of salmon spawning, rearing and migration and, the additional requirement. "It is required that all indigenous fish and nonfish aquatic species be protected in waters of the state in addition to key species described below." And that's set forth in Washington's Regulation 173-201A-200(1).

Now, petitioners took issue with Ecology's understanding of the state and federal obligations to include protecting aquatic organisms other than salmonids. The court, however, here does not find that Ecology acted arbitrarily and capriciously or outside its statutory authority in making its decision to deny the petitioners' third petition. And it was argued to the court that petitioners had not met their burden of proof, and the court so finds.

Ecology examined petition issues number two, the 115 percent forebay TDG criterion, as not grounded in science. The court went back and looked at the literature and the studies that were cited in the materials, both in the briefing and in the administrative record, and this issue the court understood was one of the most contested ones in this review given the assumptions that were made in the studies and the nature of the lab studies both reviewed and relied upon. Based on its review, Ecology concludes that the current 115 percent adjustment was not too restrictive because the data and studies show that there is only limited gas bubble trauma exhibited at that 115 percent level. Ecology has set most of the water quality standards to be more restrictive, that is more protective, and thus, Ecology had concluded here that the current 115/120/125 percent criterion adjustments achieved, and this is a quote, "The best balance between increased spill for salmon migration and the protection of aquatic life that have shown lethal and sublethal affects due to prolonged exposure to TDG supersaturation."

Ecology's denial letter to the third petition specifically addressed petitioners' concerns regarding the studies reviewed and relied upon. Ecology acknowledged that they could have clarified some of the result summaries, but they did not. They represented that they did not misrepresent the results of the studies. Some of the studies weren't accorded as much weight as petitioners would have liked. And Ecology's literature review, the petitioners' claim, also did not include the studies mentioned by petitioners, which they believe show detrimental effects to some aquatic organisms. And this specific issue is discussed in petition issue number four by Ecology in its denial letter. But Ecology gave weight to these other studies because the non-negligible impact on appropriate water quality standards Ecology believes it is required to maintain and protect for all aquatic life uses. Ecology also relied upon studies shown harmful effects to other indigenous species, and Ecology concluded that neither state nor federal law allow them to disregard aquatic life use requirements of some species over others; rather, Ecology concluded that they must consider all aquatic organism other than and including salmonids and the effects.

Petitioners here took issue with Ecology's reliance on experimental studies to reach its conclusion that the risk of gas bubble trauma to aquatic life was present. Ecology's counter set forth in the denial letter was that EPA routinely uses experimental studies as do other states in developing water quality standards. Based on all the information that the court reviewed, the court does not find that Ecology's reasoning as to this petition issue and its conclusion, the court does not find it to be arbitrary and capricious, exceeding its statutory authority, Ecology's statutory authority, even though petitioners would reach a different result or the court may reach a different result.

Petition issue number three discussed the forebay monitors do not provide credible data necessary for monitoring compliance with water quality standards. Petitioners noted the difficulty in collecting data for monitoring compliance with water quality standards. And Ecology concluded that, apparently, there are difficulties with monitoring compliance, but that wasn't a valid reason Ecology felt to either adjust or eliminate a criterion in water quality standards and they declined do so. Apparently, there's a group of stakeholders working on the issue to improve monitoring, and that process is an independent one from the water quality criterion themselves. The court does not find that as to petition issue number three that Ecology acted arbitrarily and capriciously in so concluding, or that they exceeded their statutory authority in so concluding.

Ecology also found that any change in conditions of the downstream reach that influenced TDG, such as change in barometric pressure, water temperature, degassing rates, incoming gas, total river flow, or tailwater elevation, may cause an increase in TDG above 120 percent, which Ecology did not find acceptable in light of the statutory duties under state and federal law. And again, the court does not find Ecology's reasoning to be arbitrary and capricious or that they exceeded their statutory authority as to petition issue number three.

Petition issue number four addressed the 115 percent forebay TDG limit, and it was asserted that that does not protect the most sensitive designated use of the Snake and Columbia Rivers, i.e., salmon habitat. This issue is perhaps at the heart. The heart of the matter is the matter of the protection of salmon and the petitioners did claim and argue that the salmonids' habitat is the most sensitive designated use on the Snake and Columbia Rivers. Petitioners did clarify that they acknowledge that other aquatic organisms need to be protected, but salmon are the most sensitive designated protection. Ecology believes it has a statutory duty to protect all aquatic organisms. I'm looking through my notes here.

Ecology's denial petition letter and attachment cited the AMT evaluation, *Spill Volume Analysis,* with and without the 115 percent TDG limit. In reviewing this information, Ecology agrees with the salmon distribution information provided by petitioners in their third petition, and Ecology also included 15 studies on aquatic life distribution in its literature review. Ecology did not agree that the fact that some organisms sense and avoid water quality limited areas should be used as the only basis to ensure protection which Ecology believes is required under the federal Clean Water Act. Ecology concluded that the fact that some aquatic organisms can not deter or otherwise avoid this water quality limited area should not be disregarded by Ecology. Again, the court does not find that Ecology in so concluding acted arbitrary and capriciously, or that they exceeded their statutory authority.

The final petition issue was petition issue number five, and that was the request that Ecology should amend WAC 173-210A-200(1)(f)(ii) in order to remedy violations of federal and state laws. Petitioners base this request by asserting that there is no aquatic risk near the surface when TDG approaches the 120 percent, but Ecology disagreed with this assertion, in large part basing its reliance on the evaluation by the AMT work group and the gas bubble trauma to aquatic life near the surface when TDG approaches the 120 percent bubble. Ecology's literature review found sublethal and lethal effects to aquatic life, not just salmon, at the 120 percent levels. The parties did disagree over the cost-benefit analysis and whether or not that should be a determining factor or not as to whether or not to begin rulemaking. Ecology concluded that the cost-benefit analysis and the small business economic statement were not determinative factors.

Petitioners did argue that the court should look at and Ecology should have looked at the fact that Oregon eliminated the 115 percent forebay monitoring requirement, and Ecology's refusal to do so here undermines the Oregon's efforts. Ecology does not agree that Oregon's removal of the 115 percent waiver is more protective of all aquatic organisms that ought to or were considered by Ecology. Ecology's denial also notes that both states have the same TDG criterion, and that is 120 percent of the saturation in the tailrace that limits spill at Bonneville Dam.

And then Ecology's denial letter also noted that because Little Goose and Lower Monumental Dams are within Washington's jurisdiction exclusively, Ecology's waiver does not affect them.

Finally, Ecology's 105 percent TDG criterion for shallow waters provides further protection for aquatic organisms above the TDG hydrostatic compensation depth is not directly comparable to Washington's, and I indicated earlier Washington does not currently have a criterion specific to the protection of a aquatic organisms in shallow water.

And so as I have indicated, I did review all of the bases for Ecology's decision making, and based upon the standard of review here in front of the court, each petition issue the court examined and the reasons set forth by Ecology for the denial of the request that Ecology engage in either a waiver or initiate rulemaking, and so the petitioners request to have this court order Ecology to initiate rulemaking to alter or eliminate the current 115 forebay criterion and revise WAC 173-201A-200(1)(f)(ii) is hereby denied. And I indicated previously that I did agree with the respondents' argument that the petitioners here had not met their burden of proof, and thus, the court will deny the relief requested by the petitioners here.

And I noticed I needed to put on the record, we did have someone joint us in the courtroom. Can you identify yourself, ma'am?

MS. GABRIEL: I am Kay Gabriel representing Northwest River Partners.

THE COURT: So during the court's ruling she did enter the courtroom. Everyone else is on the telephone, so I did want the parties to know that she was present.

Does anyone have any questions? Hello?

MS. MARCHIORO: No questions.

MS. GINSBERG: No questions, Your Honor.

MR. MASHUDA: No questions from petitioners, Your Honor.

THE COURT: All right. And I would have preferred to do this orally with you present, but I guess it wasn't possible today. So I appreciate your patience on the phone. Again, I indicated I took detailed notes and typed them up so that I guess, in essence, I've read my ruling to you, and I trust that someone will prepare an order that's consistent with the court's ruling and I will sign that order upon review.

MS. MARCHIORO: That will be taken care of.

THE COURT: Thank you very much.

MS. MARCHIORO: Thank you, Your Honor.

MS. GINSBERG: Thank you, Your Honor.

MR. MASHUDA: Thank you, Your Honor.

* * * * *

CERTIFICATE OF REPORTER

STATE OF WASHINGTON)
COUNTY OF THURSTON)

I, PAMELA R. JONES, RMR, Official Reporter of the Superior Court of the State of Washington, in and for the County of Thurston, do hereby certify:

That I was authorized to and did stenographically report the foregoing proceedings held in the above-entitled matter, as designated by counsel to be included in the transcript, and that the transcript is a true and complete record of my stenographic notes.

Dated this the 25th day of May, 2011.

PAMELA R. JONES, RMR
Official Court Reporter
Certificate No. 2154

☐ EXPEDITE
☒ No Hearing Set
☐ Hearing is Set
Date:
Time:
Judge Lisa Sutton

STATE OF WASHINGTON
THURSTON COUNTY SUPERIOR COURT

NORTHWEST SPORTFISHING INDUSTRY ASSOCIATON; ASSOCIATION OF NORTHWEST STEELHEADERS; PACIFIC COAST FEDERATION OF FISHERMEN'S ASSOCIATIONS; INSTITUTE FOR FISHERIES RESOURCES; and IDAHO RIVERS UNITED,

Petitioners,

v.

WASHINGTON DEPARTMENT OF ECOLOGY,

Respondent,

NORTHWEST RIVERPARTNERS,

Intervenor.

NO. 10-2-01236-0

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER DENYING RELIEF

Pursuant to Chapter 34.05 RCW, this administrative appeal came before the Court on May 13, 2011. Petitioners, Northwest Sportfishing Industry Association, Association of Northwest Steelheaders, Pacific Coast Federation of Fisherman's Associations, Institute for Fisheries Resources and Idaho Rivers United, appeared through their counsel Stephen D. Mashuda and Amanda W. Goodin of EarthJustice. Respondent Department of Ecology (Ecology), appeared through its counsel, Senior Counsel Joan M. Marchioro. Intervenor

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Northwest RiverPartners appeared through its counsel Beth Ginsberg and Jason T. Morgan of Stoel Rives LLP.

The Court reviewed all of the pleadings filed in this matter, the relevant portions of the agency's record, the supplemental materials added to the record, and heard oral arguments of the parties. Pursuant to RCW 34.05.570(1)(c) and .574(1), the Court enters the following Findings of Fact, Conclusions of Law, and Order.

I. FINDINGS OF FACT

1.1 On March 8, 2010, pursuant to RCW 34.05.330(1), Petitioners submitted to Ecology their third petition for rulemaking requesting amendment of WAC 173-201A-200(1)(f)(ii). The petition asked Ecology to either remove the 115 percent forebay total dissolved gas (TDG) standard in the rule or, in the alternative, to bring the forebay standard in line with the tailrace standard of 120 percent.

1.2 On May 7, 2010, Ecology denied the petition.

1.3 On June 2, 2010, Petitioners filed a Petition for Review and Declaratory and Injunctive Relief (Petition) in this Court. The Petition asserted three causes of action. Subsequently, Petitioners dropped their Second and Third Causes of Action. The sole claim before the Court was whether Ecology's denial of the third petition "was arbitrary and capricious, contrary to Washington law, and exceeds the statutory authority of the agency, in violation of RCW 34.05.570(4)(c)." Petition for Judicial Review and Declaratory and Injunctive Relief at 21, ¶ 58.

1.4 On May 13, 2011, the Court heard oral argument on the remaining issue in the Petition. On May 20, 2011, the Court issued its oral opinion. A transcript of the Court's oral opinion is attached as Attachment A and is incorporated by reference.

1.5 The statewide TDG rule is that the TDG cannot exceed 110 percent saturation, but Ecology has adopted an exemption to that water quality standard to aid fish passage in the Snake and Columbia Rivers. The rule embodying that exemption provides that TDG may not exceed 120 percent in the downstream tailraces of each dam or 115 percent in the upstream forebay of the next dam downriver when water is being spilled to aid fish passage in the Snake and Columbia Rivers. WAC 173-210A-200(1)(f)(ii). The purpose of the current rule is to provide a special fish passage exemption for the Snake and Columbia Rivers when spilling water at dams is necessary to aid fish passage over the hydroelectric dams, when consistent with Ecology's approved gas abatement plan. The rule seeks to increase fish passage without causing more harm to the fish population.

1.6 TDG is defined as the measure of the sum total of all gas partial pressures, including water vapor, in water. When water becomes supersaturated with gas, gas bubbles can form in the blood and tissues of aquatic organisms. The exposure of fish and other aquatic organisms to excess dissolved gas can produce physiological problems referred to as gas bubble disease or gas bubble trauma. Gas bubble trauma, can, in turn, cause rapid acute mortality as well as increase long-term mortality in aquatic organisms. The spilling of water over the spillways and dams is a major source of elevated TDG in the Snake and Columbia River system.

1.7 Petitioners assert five reasons why Ecology's denial of their third rulemaking petition was arbitrary and capricious. First, Petitioners asserted that spill is a vital salmon and steelhead protective measure. Ecology agreed that the use of spill was an important measure to decrease mortality in migrating salmon and steelhead. To aid fish in the passage over dams of the Snake and Columbia Rivers, Washington adopted an exemption to the 110 percent TDG criterion, and that exemption allowed for increased fish passage and reduced fish passage mortality. Petitioners claimed that Ecology is required under state and federal laws to set TDG limits that maximize salmon survival by balancing the benefits of spill with the risk of gas bubble trauma. Ecology disagreed with Petitioners' claim regarding the requirements of state and federal law. The Court found that Ecology is required under state regulations to maintain and protect all designated and existing uses in waters of Washington State under WAC 173-

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201A-310, which is also required under federal law under 40 C.F.R. 131.12(a). "It is required that all indigenous fish and nonfish aquatic species be protected in waters of the state in addition to key species described below." WAC 173-201A-200(1). The Court found that Ecology did not act arbitrarily and capriciously or outside its statutory authority in making its decision to deny the Petitioners' third petition. The Court also found that Petitioners did not meet their burden of proof on this issue.

1.8 Petitioners' issue number two asserted that the 115 percent forebay TDG criterion was not grounded in science. The Court reviewed the literature and the studies cited in the briefing and administrative record. Ecology's literature review identified an impact to aquatic species near the surface, less than one meter deep, that should not be considered negligible. Ecology found that there was a detrimental effect on aquatic life at less than one meter depth and that some aquatic life may be residing near the surface for long enough to suffer the detrimental effects of gas bubble trauma. Ecology concluded the small benefit to migrating salmon that would result from the proposed 120 percent TDG relaxation was insufficient to weaken the existing rule when weighed in light of increased risk of injury to aquatic species. Ecology determined that the weight of all the evidence from available scientific studies clearly points to detrimental effects on aquatic life near the surface when TDG approaches 120 percent. Ecology has set most of the water quality standards to be more restrictive, that is more protective, and thus, Ecology concluded here that the current 115/120/125 percent criterion adjustments achieved "[t]he best balance between increased spill for salmon migration and the protection of aquatic life that have shown lethal and sublethal affects due to prolonged exposure to TDG supersaturation."

1.9 Ecology's letter denying the third petition specifically addressed Petitioners' concerns regarding the studies reviewed and relied upon. Ecology gave weight to studies demonstrating impacts to some aquatic organisms and studies that showed harmful effects to other indigenous species. Ecology concluded that neither state nor federal law allowed the

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agency to disregard aquatic life use requirements of some species over others. Rather, Ecology concluded that it must consider all aquatic organisms other than and including salmonids and the effects on those organisms. Responding to Petitioners' criticism that it relied upon experimental studies, in its denial letter Ecology stated that EPA and other states routinely use experimental studies in developing water quality standards.

1.10 Based on all of the information that the Court reviewed, the Court does not find that Ecology's reasoning and its conclusion as to this petition issue to be arbitrary and capricious, or in excess of its statutory authority, even though Petitioners would reach a different result or the Court may reach a different result.

1.11 In petition issue number three, Petitioners asserted that the forebay monitors do not provide credible data necessary for monitoring compliance with water quality standards. Ecology concluded that there are difficulties with monitoring compliance, but that was not a valid reason for the agency to either adjust or eliminate a criterion in water quality standards and it declined do so. As to petition issue number three, the Court does not find that that Ecology acted arbitrarily and capriciously, or that the agency exceeded its statutory authority in so reaching its conclusion.

1.12 Ecology also found that any change in conditions of the downstream reach that influenced TDG, such as changes in barometric pressure, water temperature, degassing rates, incoming gas, total river flow, or tailwater elevation, may cause an increase in TDG above 120 percent, which Ecology did not find acceptable in light of the statutory duties under state and federal law. Again, the Court does not find Ecology's reasoning to be arbitrary and capricious or that the agency exceeded its statutory authority as to petition issue number three.

1.13 Petition issue number four addressed the 115 percent forebay TDG limit. Petitioners asserted that the limit does not protect the most sensitive designated use of the Snake and Columbia Rivers, i.e., salmon habitat. Petitioners clarified that they acknowledge that other aquatic organisms need to be protected, but they asserted that salmon are the most

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sensitive designated protection. Ecology responded that it has a statutory duty to protect all aquatic organisms.

1.14 Ecology's letter denying the petition and its attachment cited the Adaptive Management Team (AMT) evaluation, *Spill Volume Analysis,* who conducted a review with and without the 115 percent TDG limit. In reviewing this information, Ecology agrees with the salmon distribution information provided by Petitioners in their third petition, and Ecology also included 15 studies on aquatic life distribution in its literature review. Ecology did not agree that the fact that some organisms sense and avoid water quality limited areas should be used as the only basis to ensure protection which Ecology asserts is required under the federal Clean Water Act. Ecology concluded that the fact that some aquatic organisms cannot detect or otherwise avoid this water quality limited area should not be disregarded by the agency. Again, the Court does not find that Ecology in so concluding acted arbitrary and capriciously, or that they exceeded their statutory authority.

1.15 Petition issue number five asserted that Ecology should amend WAC 173-210A-200(1)(f)(ii) in order to remedy the violations of federal and state laws alleged by petitioners. Petitioners asserted that there is no aquatic risk near the surface when TDG approaches the 120 percent. Ecology disagreed with this assertion, in large part basing its reliance on the evaluation by the AMT and the gas bubble trauma to aquatic life near the surface when TDG approaches the 120 percent levels. Ecology's literature review found sublethal and lethal effects to aquatic life, not just salmon, at the 120 percent levels.

1.16 The Oregon Department of Environmental Quality was directed by the Oregon Environment Quality Commission to evaluate whether the 115 percent forebay TDG requirement for fish passage should be revised. Based on the literature and scientific studies considered in the AMT review process, Oregon concluded that removal of the 115 percent forebay standard "will not cause excessive harm to the beneficial use, aquatic species in the Columbia River, during fish passage spill season." ECY 1840.61. Petitioners argued that the

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Court should consider, and Ecology should have considered as well, the fact that Oregon eliminated its 115 percent forebay monitoring requirement. Petitioners asserted that Ecology's refusal to do so here undermines Oregon's efforts. Ecology does not agree that Oregon's removal of the 115 percent waiver is more protective of all aquatic organisms that ought to or were considered by the agency. Ecology's petition denial also notes that both states have the same TDG criterion—120 percent of the saturation in the tailrace that limits spill at Bonneville Dam. Ecology's petition denial letter further noted that because Little Goose and Lower Monumental Dams are within Washington's jurisdiction exclusively, Oregon's waiver does not affect them. Finally, Oregon's 105 percent TDG criterion for shallow waters, which provides further protection for aquatic organisms above the TDG hydrostatic compensation depth, is not directly comparable to Washington's water quality standard for TDG. Currently, Washington does not have a criterion specific to the protection of aquatic organisms in shallow water.

1.17 While Oregon simply had to modify an existing order to establish a TDG waiver, Ecology determined that changing the water quality criterion would trigger additional administrative procedural requirements, including a cost-benefit analysis and a small business impact statement in order to determine the effects of the rule change on both the public and businesses in the State of Washington. Ecology concluded that the benefits from that administrative process must outweigh the cost of any rule change to justify the rule's adoption. Ecology also determined that a State Environmental Policy Act determination would be needed, and an environmental impact statement may also be required. The parties disagreed over the cost-benefit analysis and whether or not that should be a determining factor in deciding whether to begin rulemaking. Ecology concluded that the cost-benefit analysis and the small business economic statement were not determinative factors in its decision.

1.18 The Court did not find that Ecology's response to issue number five was arbitrary or capricious, or contrary to law.

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II. CONCLUSIONS OF LAW

2.1 This Court has jurisdiction over this matter under the Administrative Procedure Act, Chapter 34.05 RCW. An agency's decision to deny a petition is "other agency action" reviewable under the standards in RCW 34.05.570(4)(c). Venue is proper in Thurston County and the action before the Court was timely filed under RCW 34.05.542.

2.2 Relief will only be granted if the Court determines the decision to forego rulemaking is unconstitutional, outside the agency's authority, arbitrary and capricious, or made by unauthorized persons. RCW 34.05.570(4)(c). In making that determination, the Court will review the agency record. RCW 34.05.558. The party challenging agency action bears the burden of demonstrating the invalidity of such action. RCW 34.05.570(1).

2.3 Where there is room for two opinions, and the agency acted honestly upon due consideration, the Court will not find that an action was arbitrary and capricious, even though the Court may believe it to be erroneous. *Hillis v. Dep't of Ecology,* 131 Wn.2d 373, 383, 932 P.2d 139 (1997). On matters involving complex factual issues, which are technical and within the agency's expertise, such as the matters presently before the Court, the courts are highly deferential to the administrative agency. *Dep't of Ecology v. PUD No. 1 of Jefferson Cy.*, 121 Wn.2d 179, 201, 849 P.2d 646 (1993), *aff'd*, 511 U.S. 700, 114 S. Ct. 1900, 128 L. Ed. 2d 716 (1994).

2.4 The Court reviewed all of the bases for Ecology's denial of the petition. Based upon the standard of review, the Court concludes that Ecology's denial was not arbitrary or capricious or contrary to law.

2.5 Petitioners' request to have this Court order Ecology to initiate rulemaking to alter or eliminate the current 115 percent forebay criterion and revise WAC 173-201A-200(1)(f)(ii) is hereby denied. The Court further concludes that Petitioners have not met their burden of proof, and thus, the Court denies the relief requested by Petitioners.

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III. ORDER

Based on the foregoing Findings of Fact and Conclusions of Law, the Court orders that the Petition for Review and Declaratory and Injunctive Relief is DENIED.

DONE IN OPEN COURT this 13th day of June, 2011.

Lisa L Sutton

JUDGE LISA SUTTON
LISA L. SUTTON

Presented by:

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ATTACHMENT C

Affidavit of Kieran P. Connolly

EXHIBITS TO CONNOLLY AFFIDAVIT

Witt Anderson Letter to Steve Oliver, February 11, 1011

2011 Water Management Plan, December 31, 2010

Appendix 4, 2011 Total Dissolved Gas Management Plan

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.; PacifiCorp; NextEra Energy Resources, LLC; Invenergy Wind North America LLC; and Horizon Wind Energy LLC, Petitioners, v. Bonneville Power Administration, Respondent.	)	Docket No. EL11-44-000

AFFIDAVIT OF KIERAN P. CONNOLLY IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

1. My name is Kieran P. Connolly. My business address is 905 N.E. 11th Avenue, Mail Stop: PF-6, Portland, OR 97208-3621.

2 I have been employed with the Bonneville Power Administration (BPA) since 1991. I am currently the Acting Manager of Power Policy and Rates in BPA's Power Services organization. From April 2007 until July 2011 I was the manager of Generation Scheduling in Power Services. Generation Scheduling responsibilities include short term planning and real time coordination of the operations of the Federal Columbia River Power System[1] (FCRPS) with our partners to meet power and non-power objectives. These operations are coordinated with and ultimately implemented by the US Army

[1] The FCRPS generates electric power at federally owned hydro electric dams and one nuclear plant in the Columbia Basin.

Corps of Engineers and the US Bureau of Reclamation for the respective hydro electric facilities they each own and operate. Nuclear operations at Columbia Generating Station are coordinated with and ultimately implemented by Energy Northwest. Generation Scheduling staff also coordinate the reliability services from the FCRPS with BPA's Transmission Services organization to support the operation of BPA transmission and the BPA Balancing Authority Area.

3. I hold a Masters in Business Administration from the University of Portland, undertook graduate work at the University of Notre Dame and have a Bachelor's of Science in Business Economics from Willamette University.

4. Having managed Generation Scheduling during the timeframe above, I have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's response.

FCRPS Operations in Spring and early Summer 2011

5. The Pacific Northwest garners a large fraction of its electricity from hydroelectric generation within the Columbia River Basin. The fuel supply for this generation varies significantly with the January through July water supply ranging from just over fifty million acre feet (Maf) to more than one hundred and fifty Maf. This large range makes water supply forecasts critical to determining the operation of the system to meet multiple purposes, particularly space requirement to manage the runoff for flood control with a high likelihood of refill and implementation of some obligations under the 2010 FCRPS Supplemental Biological Opinion for Federal ESA listed species. The operation, in turn, determines the power generation that the system is capable of at any given time. To ensure sufficient flows for fish while providing flood control protection throughout the

spring and summer, the Corps sets specific reservoir elevation levels or targeted volumes of water storage and release for the storage projects. Managing the FCRPS through the spring and summer is a balancing act between ensuring there is enough flow to aid fish, but not so much that it harms fish and the other aquatic life in the river or conflicts with other non-power requirements such as flood control.

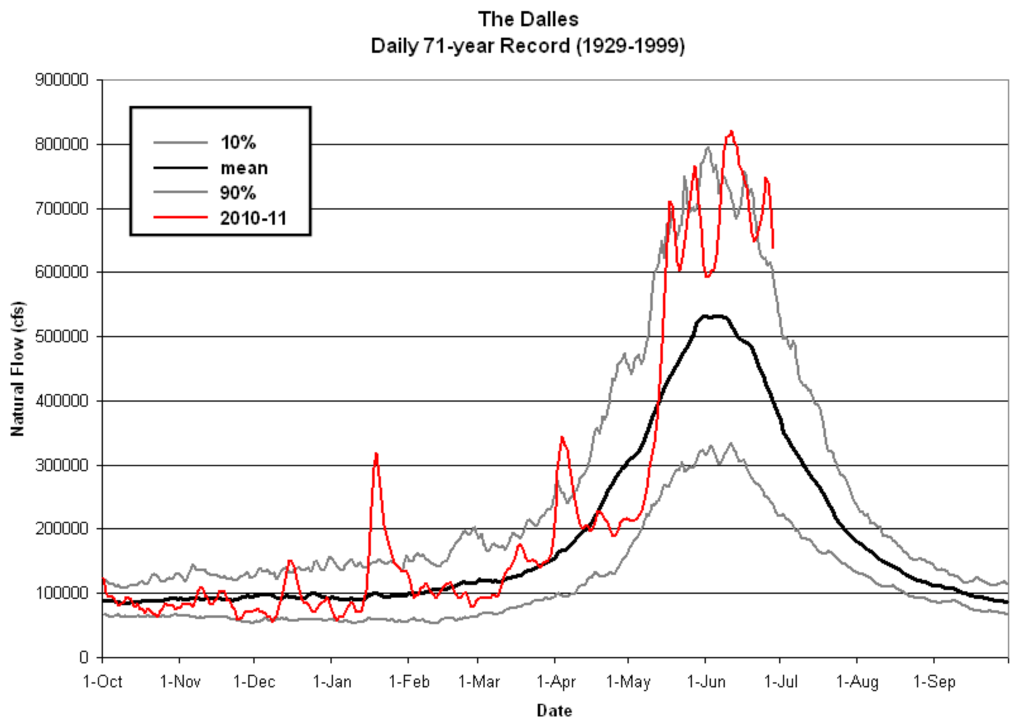
Water supply forecasts

6. The majority of the hydroelectric generating capacity is located on the main stem of the Snake and Columbia rivers, sharing an interconnected fuel supply. Headwater storage project operations are bounded by flood control drafts and refill/flow requirements under the Biological Opinions. The natural tension of these objectives leads to an operation that is sensitive to changes in volume runoff expectations and the timing of the runoff.

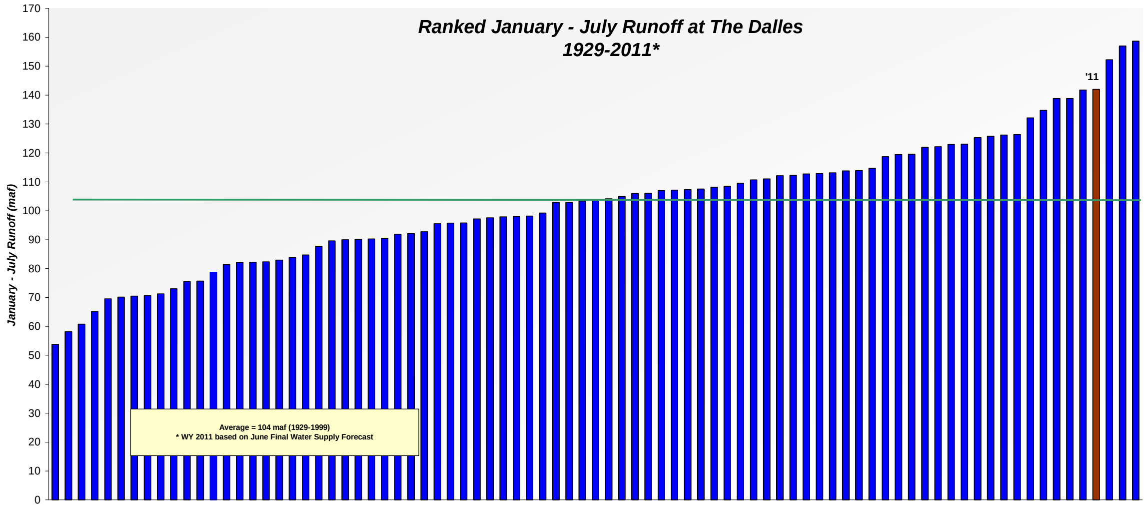
7. Volume runoff forecasts from the NOAA/NWS Northwest River Forecast Center (NWRFC) for the January-July runoff period increased only slightly through early March, before the unusually cold and wet spring east of the Cascades prompted rapid water supply forecast increases in the second half of March, April, May and June. One result of this changing forecast was that flood control objectives changed significantly during the season and required deeper drafts into the reservoirs. Flood control reservoirs operated with very little flexibility and remained drafted until they were released for refill between mid-May and early-June, which is much later than normal.

8. The timing of how the runoff occurs is as important as the volume of the runoff. The cold wet spring of 2011 led to a slow, drawn-out spring runoff. The unregulated peak flow estimated at The Dalles occurred around June 10, was about two weeks later

than usual. But the peak was embedded in a long period of high flows that rose above average in early May and have continued ever since. Below is a chart of observed natural flows, along with historical mean, low and high flows shown for comparison.



9. The NWRFC June mid-month forecast updated June 16 was for a total January-July volume of 142.0 Maf, or 132% of normal. If this holds, it will be the 4th highest runoff since 1929. The highest recorded was 158.6 Maf in 1997. The average is 107.3 Maf.



Federal Reservoir Operations

10. In order to provide system flood control protection, the headwater projects (Hungry Horse, Libby and Dworshak) were operated through the winter and spring for flood control and refill requirements. Dworshak Dam was able to provide some daily and weekly shaping of their turbine discharge to reduce light load hour generation during this period. Shaping generation away from evenings and weekends when demand for power tends to be low lessened the probability of high spill levels due to lack of demand and therefore lessened the risk of Environmental Redispatch.

11. Grand Coulee provides for a significant portion of the total system flood control space. Grand Coulee, in conjunction with Dworshak, is the US Army Corps of Engineers' (Corps) most direct tool for managing flow regulation on the lower Columbia River. In 2011, critical maintenance of Grand Coulee Dam's spillway drum gates required the reservoir to be operated at or below elevation 1255 feet March 15 through May 15 which is approximately in the middle of its full 1208-1290 feet operating range. Based on the NWRFC March Final Water supply forecast, the April 10 flood control elevation at Grand Coulee dam was above that required for drum gate maintenance. Since flood

control based on that forecast was met Grand Coulee operated to the elevation required for maintenance work.

12. Throughout March weather conditions across the basin contributed to an increased water supply forecast and subsequently deeper forecasted flood control elevations. The forecasted April 30 flood control elevation for Grand Coulee dam based on the March Mid-Month Water supply forecast dropped over 10 feet. The project was operated close to elevation 1250 feet at the end of March to minimize the rate of draft to meet April requirements.

13. The elevation of Grand Coulee on March 31st was 1250.5 feet. The April Early Bird water supply forecast received on March 31st increased further still and the subsequent forecasted flood control for the end of April was computed to be elevation 1221 feet. This left 30 days to draft the reservoir 30 feet which is difficult to accomplish and remain within the Bureau of Reclamation's (Reclamation) daily draft rate limits for Grand Coulee, which are set to minimize the potential for damage to the banks of Lake Roosevelt. Subsequent water supply forecasts in April lowered the April 30 flood control elevation to elevation 1220.2 feet.

14. As is typical after reaching the April 30 flood control elevation, Grand Coulee and other reservoirs held these elevations until released for refill by the Corps unless further draft was required to support flow objectives for salmon. With high flows through the period further draft was not required to meet flow objectives. In previous years, there was only a foot or two of operating flexibility allowed at Grand Coulee while waiting to be released for refill. But coordination with Reclamation and the Corps resulted in a small amount of additional operating flexibility compared to previous years which was

intended to be used to assist the FCRPS to meet non-power objectives in extreme situations. In this case, the use of the operating flexibility to manage non-power objectives also reduced the potential for overgeneration conditions. From April 30th to May 16th Grand Coulee operated within a 3 foot operating range which provided some room to shape flows over short periods.

15. From May 16th through June 20th the system flood control objective was to regulate releases from Bonneville Dam to no more than two feet above flood stage at Vancouver Washington. This allowed Grand Coulee to begin refill, but in a very controlled manner in order to move as much water as possible through the system while minimizing downstream flooding at that time and providing adequate space in Grand Coulee and other storage projects to manage the expected runoff in June and July. After June 20 Grand Coulee was operated to fill no higher than elevation 1285 feet by July 5th and not exceed 500 kcfs at Bonneville Dam. Managing to these targets required controlled fill throughout this period as well to avoid exhausting the space prior to July 5th.

Canadian Reservoirs

16. Canadian projects were operated through the winter and spring in accordance with flood control requirements established under the Columbia River Treaty (Treaty) Flood Control Operating Plan and the Treaty Detailed Operating Plans agreed to by the United States and Canadian Entities.

17. In addition to the magnitude and uncertainty of the spring runoff volume and shape, factors that affect outflows from Canadian Treaty projects into the U.S. system include Treaty supplemental operating agreements, agreements to coordinate use of

additional reservoir storage in Canada (non-Treaty storage) and BC Hydro's use of operating flexibility in Canada.

18. During the winter, BPA stored 1.0 Maf of flow augmentation (FA) water in Treaty space in accordance with the Non-Power Uses Supplemental Operating Agreement to meet NOAA Fisheries 2010 FCRPS Supplemental Biological Opinion objectives for Federal ESA listed fish. In January, when this water was stored, the water supply forecast was slightly less than average. BPA and BC Hydro also negotiated a short-term agreement to coordinate use of non-Treaty storage space (NTS) to provide additional flexibility in the fall and winter to store or release additional water and to shape flows in the spring/summer period for U.S. fisheries. This agreement was envisioned to be a tool to reduce flows from Canada when river flows became very high as long as flood control space was maintained. Under the NTS agreement, slightly more than 0.5 MAF of water was released during the winter which resulted in some Canadian projects being below flood control requirements at the end of March.

19. Throughout the spring and early summer, the Canadian projects were operated to meet flood control requirements as set out by the Corps. The additional space created by the 0.5 MAF of water released in the winter under the NTS agreement allowed flows to be slightly lower than otherwise (about 4 kcfs lower for May/June period), would have been without the release. Due to flood control requirements and increasing water supply forecasts there was no ability to reduce Arrow outflows further by storing additional water.

Spill due to lack-of-demand

20. The reservoirs have only so much storage capacity. When they are full, or projected to be too full to manage flood control risk, BPA must dispose of the excess water. If all hydro projects are generating at full capacity, or if there is insufficient load, BPA must spill water. Spill at any FCRPS project can occur for a variety of reasons, including:

- Fish Passage – spill at Lower Snake and Lower Columbia projects from April through August as a measure to increase survival of endangered salmon and steelhead as they pass the dams to assist their migration to the ocean.[2]
- Lack of turbine – spill at projects where all available turbines are fully loaded or are carrying required reserves.
- Lack of demand – spill at projects where there are available units that are not fully loaded due to insufficient demand for power.

21. The FCRPS actions consulted on in the 2010 FCRPS Supplemental Biological Opinion addressed conditions that resulted in all of these types of spill.

22. While spill for fish passage is beneficial to migrating fish, high spill levels can be dangerous, with symptoms ranging from minor injuries to death.[3] See, Sweet Affidavit, at 3-5, 7-13. Mr. Sweet also describes the 110% TDG state water quality standards, adjustments to the state standards, and the interaction of Oregon and Washington TDG standards for projects that border both states in his Affidavit, at 5-8.

23. A TDG Management Plan is developed annually by the Corps and is included as Appendix 4 in the annual Water Management Plan. This TDG Management Plan provides detailed information addressing TDG management measures, the process for setting spill levels, TDG management policies, and the TDG monitoring program and modeling. This plan is consistent with the 2000 U.S. Fish and Wildlife Service (USFWS)

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[2] See RPA-29 of the 2010 FCRPS Supplemental Bi-op.
[3] http://www.salmonrecovery.gov/Libraries/hemlock_doc_lib/High_flows_TDG_Effects05-27-11_2.sflb.ashx

Biological Opinion, and the NMFS 2008 Biological Opinion and NMFS 2010 FCRPS Supplemental Biological Opinion (2010 FCRPS Supplemental BiOp).[4]

24. In implementation the amount of spill necessary for TDG to reach a particular level is referred to as a "spill cap" and the TDG levels associated with state standards and adjustments are referred to as "gas caps". These terms will be used throughout the remainder of this section.

25. In preparing for operations this spring, BPA coordinated with the Corps on how Environmental Redispatch fit into the Corps' TDG Management Plan.[5] From these discussions BPA concluded that spill due to lack of demand up to the "gas cap" at all FCRPS projects referenced in the spill priority list is consistent with applicable state water quality standards and criteria. Spill at levels above the calculated gas caps for a brief time were consistent with the prevailing state water quality standards when 120 percent was not exceeded on the specified 12 hour average and TDG saturation did not exceed the specified 125 one hour Washington criteria adjustment.[6]

26. In February 2011, Steve Oliver, Vice President of Generation Asset Management gave a presentation on overgeneration conditions to the Technical Management Team (TMT) (a regional sovereign technical group responsible for making recommendations on dam and reservoir operations that affect fish). This briefing described how spill due to lack of demand could increase in high flow and high wind conditions and reinforced

[4] http://www.nwd-wc.usace.army.mil/tmt/wqnew/tdg_mgmt_plan/2011.pdf
[5] Letter from Witt Anderson, Director of Programs, Dept. of Army, Corps of Engineers, NW Division to Steve Oliver, V.P. of Generation Asset Management, BPA, dated February 11, 2011.
[6] Sweet Affidavit at 6-7

BPA's position to take all reasonable steps to ensure that TDG levels resulting from spill due to lack of demand would be kept with the prevailing state water quality standards.

27. This past spring, the Corps revised the spill priority list for involuntary spill to better manage system TDG. This new procedure, which was coordinated at TMT, added a spill level that equates to 122% TDG. In previous years, the spill management procedure moved from spill flows which equated to 120% TDG to spill flows which equated to 125% TDG. Including this additional "spill level" at 122% TDG allowed for a more refined management of system-wide TDG levels and provided an additional tool that could be used in circumstances to minimize the amount of overgeneration by spilling at this level for short periods of time if actual 12-hour TDG levels were running lower than 120%. An example of "spill levels" from Friday, June 17 is shown below.

Level 1 (120% in tailrace except where noted)	**Level 2 (122% in tailrace except where noted)**	**Level 3 (125% in tailrace except where noted)**
LMN at 49 kcfs	LMN at 55 kcfs	LMN at 75 kcfs
LGS at 52 kcfs	LGS at 56 kcfs	LGS at 75 kcfs
MCN at 190 kcfs	MCN at 235 kcfs	MCN at 280 kcfs
IHR at 79 kcfs	IHR at 90 kcfs	IHR at 105 kcfs
LWG at 50 kcfs	LWG at 61 kcfs	LWG at 76 kcfs
TDA at 146 kcfs	TDA at 220 kcfs	TDA at 269 kcfs
JDA at 144 kcfs	JDA at 177 kcfs	JDA at 190 kcfs
BON at 107 kcfs	BON at 120 kcfs	BON at 215 kcfs
DWR at 35% of flow (110%)	DWR at 35% of flow (110%)	DWR at 35% of flow (110%)
CHJ at 190 kcfs	CHJ at 210 kcfs	CHJ at 230 kcfs
GCL at 0 kcfs (110%)	GCL at 5 kcfs (115%)	GCL at 19 kcfs (120%)

28. BPA and the Corps routinely discussed the implementation of the spill priority list, which continued to evolve throughout the spring. The Corps provides BPA with the spill caps for each project and changes them as conditions warrant. From March through mid-May BPA was able to avoid use of Environmental Redispatch. Beginning on May

18, 2011, these actions no longer sufficed. Through the rest of May and the first half of June flows were so high that all the Columbia and Snake River projects except Chief Joseph were already spilling above the second spill cap, leaving Chief Joseph as the primary tool to mitigate Environmental Redispatch when BPA had insufficient load for maximum generation. On occasion during this period, spill at the first spill cap at Chief Joseph was producing TDG measurements below the waiver limits. In order to minimize Environmental Redispatch on those occasions Bonneville spilled up to the second spill cap for brief periods while monitoring TDG levels to ensure we did not exceed the waiver limits. This action further reduced the need for Environmental Redispatch in some hours and eliminated the need in others.

29. By June 18 river flows had receded to the point that some lower Columbia and Snake river projects were no longer spilling through the first spill cap and actual TDG measurements at those projects were at or in excess of the waiver levels. Because the spill priority list requires increases in spill in a specific project-by-project order, increasing spill at Chief Joseph to level 2 was no longer an option and BPA returned to spilling through the first spill cap with hydro generation at less than maximum capacity. Throughout the period of high flow Bonneville managed spill so that Environmental Redispatch was called upon only when absolutely necessary to reduce the level of TDG in the rivers. In late June the spill priority list was temporarily modified during the high flow period to address then current system spill issues and adult passage on the Snake river, this spill priority, illustrated below (from June 29) was also coordinated at TMT. As this change moved Chief Joseph to the top of the 120% level it was more likely that

the project would be accessible for spill consistent with the Washington rule adjustment with a commensurate reduction in the exposure to Environmental Redispatch.

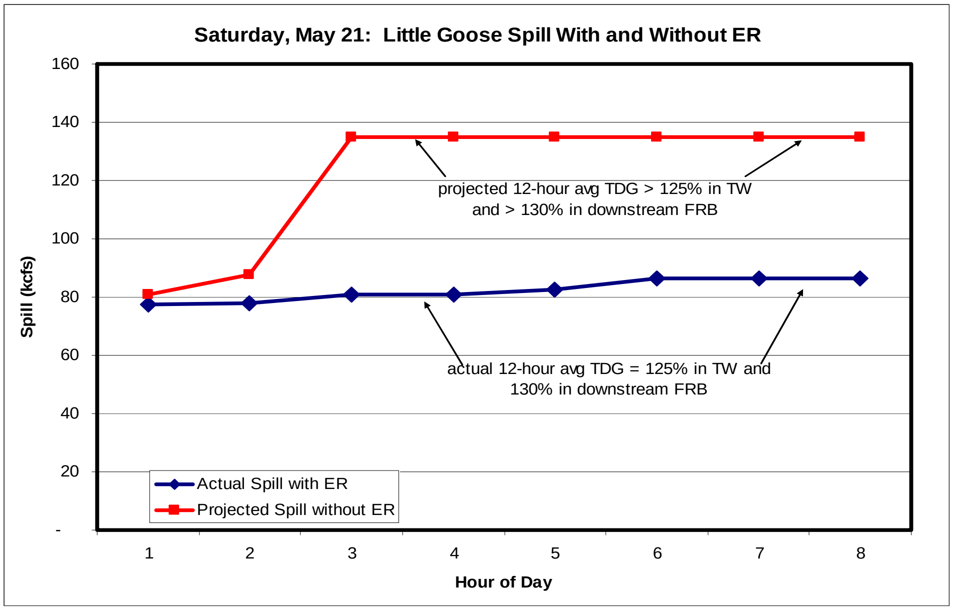
Level 1 (120% in tailrace/115% in downstream forebay except where noted)	**Level 2 (120% in tailrace except where noted)**	**Level 3 (122% in tailrace except where noted)**
LMN at 28 kcfs	CHJ at 189 kcfs	LMN at 55 kcfs
LGS at 40 kcfs	LMN at 40 kcfs	LGS at 59 kcfs
MCN at 190 kcfs	LGS at 52 kcfs	MCN at 235 kcfs
IHR at 79 kcfs	MCN at 190 kcfs	IHR at 85 kcfs
LWG at 41 kcfs	IHR at 75 kcfs	LWG at 52 kcfs
TDA at 135 kcfs	LWG at 45 kcfs	TDA at 140 kcfs
JDA at 135 kcfs	TDA at 135 kcfs	JDA at 177 kcfs
BON at 121 kcfs	JDA at 144 kcfs	BON at 120 kcfs
CHJ at 150 kcfs	BON at 107 kcfs	CHJ at 200 kcfs
	DWR at 37% of flow (110%)	DWR at 37% of flow (110%)
	GCL at 15 kcfs (115%)	GCL at 18 kcfs (120%)

30. During the Spring, BPA adhered to the principle of not implementing Environmental Redispatch (ER) until spill due to lack of demand resulted in TDG reaching levels specified in the Washington rule adjustment while following the procedures determined by the Corps after coordination with TMT.

31. Environmental Redispatch was an effective tool in managing overall system TDG. By displacing thermal and variable generation and using hydro power to serve the load, lack of demand spill and TDG were reduced.

32. This year's high flows resulted in extensive periods when spill levels were in excess of 120% due to lack of turbines or due to lack of demand. High flows between May 18th and June 30th resulted in TDG levels that exceeded 120% TDG in project tailraces or 115% in the downstream forebay at all projects on the FCRPS almost every day. Without ER, spill levels would have been higher as can be seen in the chart that follows. On May 21st the spill at Little Goose dam was approximately 80 kcfs which

results in TDG of around 125% in the tailwater. If Environmental Redispatch had not been available on that day as a means of acquiring load, additional lack of demand spill would have been required and spill would have increased to just under 140 kcfs which would have likely resulted in higher TDG levels.



33. Environmental Redispatch not only reduced the level of spill, it also reduced the frequency of spill. Looking at the FCRPS as a whole from May 18th through July 6th and focusing only on the hours in which ER occurred, the system as a whole was spilling due to lack of load and lack of turbine above 120% TDG approximately 75% of the time. During that same period it is estimated that without ER the system would have been spilling due to lack of load and lack of turbine above 120% TDG approximately 90% of the time.

Spill Exchanges

Historical Immediate Spill

34. As discussed previously, flow in excess of power demand has to be spilled in addition to fish passage spill. In the past delivery of Immediate Spill Energy to non-Federal hydro operators was a means of reducing spill due to lack of demand at Federal dams. When BPA experienced spill due to lack of demand and a non-Federal entity had the ability to spill, BPA would deliver free energy to the non-Federal project owner equivalent to the amount of lost generation due to spill at the non-Federal project. The additional load reduced spill on Federal projects and increased spill at, ideally, lower head dams or dams further downstream, which distributed TDG more evenly across the system. Although spilling projects off of the Columbia River system was a high priority to mitigate TDG levels on the mainstem, spill on non-mainstem projects was limited due to operating requirements at those projects. Mid-Columbia projects and British Columbia projects were the most common immediate spill counterparties. In addition, Columbia River tributary hydro projects owned by Washington Water Power and Montana Power Company also participated. Seattle City Light also participated in the spill exchange with their hydro resources, adding the Skagit River dams which are outside of the Columbia River system.

35. By the mid-1990’s most northwest hydro facilities had required spill, minimum generation, and minimum flows for downstream juvenile fish migration and closely monitored TDG levels. This reduced the maximum immediate spill delivered per hour and the total immediate spill that could be delivered dramatically. As a result of lack of

effectiveness, immediate spill deliveries fell out of use. Prior to 2011, the last year of immediate spill energy deliveries was 1999.

36. While immediate spill energy had fallen out of use due to the above mentioned constraints BPA prepared and offered new spill exchange agreements in 2011 in an effort to fully explore the potential to minimize the frequency and amount of Environmental Redispatch. BPA held conference calls with regional entities to explore the design of the agreements and to present the resulting drafts. Ultimately, parties preferred to retain any spill flexibility for their own system and risk management needs. BPA also explored the immediate spill concept with extra-regional hydro facilities in California and Montana, but was unable to enter into any agreements.

2011 Hourly Coordination Spill Exchange

37. Although no Immediate Spill counterparties were found, the Public Utility Districts operating the five non-Federal Mid-Columbia reservoirs were interested in an arrangement that would trade Mid-Columbia participant load for Chief Joseph spill under an existing coordination process known as Hourly Coordination. BPA and the Mid-Columbia projects worked together to identify periods where reducing spill at Chief Joseph would reduce the total dissolved gas entering the Mid-Columbia reservoirs and, with the low gas production characteristics of Mid Columbia spill, reduce system-wide total dissolved gas.

38. From late May to mid-June BPA had delivered the equivalent of 13,200 megawatt hours of Hourly Coordination Spill Exchange. This offset an equivalent amount of potential Environmental Redispatch during the period.

Reduction of DSO216 reserves

39. When loading turbines to minimize excess spill, there are electric reliability considerations that must be taken into account. All the available turbines across the FCRPS cannot be fully loaded because that would leave the system with insufficient reserves to respond to system needs. These reserves come in two basic forms, Contingency Reserves and Balancing Reserves. Contingency Reserves are the ability to increase power production (or reduce load) in response to specific qualifying events – most typically the unexpected loss of a generating unit. Balancing Reserves constitute matching capacity necessary to meet the regulation, load following and schedule imbalances that occur each hour.

40. Up until the mid 2000s BPA held on average 200-300 megawatts of capacity for balancing reserves to accommodate the loads at that time. With the increase in variable generation on the BPA system the need for balancing reserves increased to address the variability and scheduling error associated with those resources. BPA capped this capacity with a set of operational tools implemented under Dispatcher Standing Order 216 (DSO 216). DSO 216 ensures that the actual demands placed on the FCRPS are aligned with the planning expectations of variable generation scheduling accuracy. Outside that expectation, or if scheduling accuracy is less than expected, variable generation resources are instructed to reduce generation to be closer to schedule or schedules are reduced to be closer to actual output.

41. BPA strives to provide these reserves when possible, but there are operational conditions that make the provision of balancing reserves incompatible with other system operational obligations, such as those that result from legal and reliability requirements.

Under these conditions balancing reserves are reduced to resolve the conflict. If necessary, balancing reserve levels are reduced to be equivalent to those necessary for load service. BPA made it clear in the BPA rate case that it would potentially make these reductions (WP10 ROD, issue 10, page 262-3). Such reductions ensure that the growth in balancing reserves that has occurred due to BPA integration of new resources does not interfere with operations under the FCRPS Biological Opinion or conflict with operations consistent with Clean Water Act TDG standards and associated waivers.

42. In June 2010 during a high flow event, to help ensure BPA could meet its environmental obligations, BPA reduced balancing reserve capacity. Water storage capacity was at its maximum, and spilling additional water due to lack of demand would have exacerbated TDG levels. These reductions, which were predominantly in the decremental (DEC) reserve levels, occurred on June 5 and June 9-13 2010.

43. A lower DEC reserve level meant there was less chance that significant changes in generation level of the wind fleet would cause reductions in hydro generation that would result in additional spill. In short, to help meet fish protection requirements at the height of the high water event, BPA reduced balancing reserves that serve load and wind power projects to levels necessary to maintain reliability.

44. In 2011, an above average water year with a delayed runoff, resulted in high levels of flow which continued into July. Under these conditions DSO 216 balancing reserves for managing variable generation error were reduced from the planned amounts (798 MW INC and 976 MW DEC) in order to manage the hydraulic operation of the river system consistent with non-power requirements. For DEC reserves, BPA targeted to hold reserves of 300 MW as this amount of regulating margin that is needed for overall system

operations. As stated above, reducing the DEC reserves means there is less chance that wind generation above hourly schedules would cause reductions in hydro generation and potentially result in additional spill.

45. BPA reduced DSO 216 incremental (INC) reserves down to 400 MW. In order to provide INC balancing reserves, BPA must operate the FCRPS to ensure that enough turbines are available to run FCRPS generation to meet drops in the output of the wind generation below the hourly schedule. Reducing the INC reserves means that there is increased turbine capacity available to run water through the turbines rather than through the spillway (while always maintaining spill for fish passage) as a means of moving water through the system. By generating with the water rather than spilling, BPA is able to manage the TDG levels in the FCRPS to the water quality standards more effectively.

46. Under certain flow conditions, reducing INC reserves also allows BPA to shape flow into higher load periods where it can be used to generate power and out of low load periods where the water is typically spilled. During low load periods (typically at night) demand for power is low and as a result high levels of spill can occur in order to pass water through the system. To the extent that water can be moved into a high demand period and out of a low demand period, lack of demand spill and TDG levels can be reduced. Since Environmental Redispatch is implemented once spill levels on the system reach the prevailing state standards for TDG, by reducing the level of spill on the system, the probability of having to implement ER is reduced.

47. Further reductions in DSO 216 reserves are implemented when BPA projects that other management tools alone will be insufficient to avoid ER and to aid in the operational transition into ER for thermal and variable generation. DEC reserves are

eliminated for the purpose of wind balancing prior to implementing ER. This reduction ensures that all unscheduled generation is removed prior to implementation of ER, therefore minimizing the quantity of the ER instruction. Once an ER event has ended, the level of DSO 216 DEC reserve was restored to 300 MW.

48. INC reserve reductions to 400 MW have been implemented when the carrying of reserves would have otherwise resulted in spill above prevailing state standards for TDG. In time periods when ER is not necessary and generating capacity is not needed for TDG management INC reserves are restored as much as possible up to the full DSO 216 levels.

Minimizing LLH generation

49. Markets for power are limited during light load hours (LLH). When in overgeneration conditions, BPA made efforts to minimize hydro generation in the LLHs as much as possible. In effect, BPA pre-planned an Environmental Redispatch action on all FCRPS hydro generation with the flexibility to reduce in order to maximize the available load for the FCRPS generation being operated to manage system TDG.

50. These efforts included the following actions:

51. Shaping of headwater project generation. Limited flexibility exists at the headwater projects (Libby, Dworshak, Hungry Horse) to shape generation within the day. BPA coordinated with the Corps and Reclamation to shape as much generation as possible out of the LLH and into the heavy load hour (HLH) period.

52. Shaping of generation and spilling at the Willamette and other hydro independent projects (hydro independents are projects that operate independent of the coordinated Columbia River projects). BPA coordinated with the Corps and Reclamation to shape the generation at the Willamette Valley and other hydro independent projects out of the LLH

and into the HLH to the extent possible. In addition, where shaping of the flows out of the LLH period was not possible BPA requested the projects spill up to the prevailing state standards for TDG rather than pass the water through the turbines in an attempt to lower generation levels during the LLH period.

53. BPA limited generation at the Columbia Generating Station (CGS), the region's one nuclear plant. Like most nuclear facilities, CGS generally runs near maximum output. BPA has worked with Energy Northwest, the operator of CGS, to add equipment to the plant that allows for output reductions and cycling (raising and lowering output levels as needed). In 2010 BPA employed both of these practices and CGS was reduced to as little as 20 percent of normal output. In 2011 CGS was scheduled to be off-line for refueling and maintenance beginning in early April. In late March 2011 it was decided to take CGS off-line a week earlier than scheduled and instead generate additional hydro power to address the increasingly higher river flows and minimize the potential of high spill and Environmental Redispatch.

54. Unit Outage coordination. Under normal conditions BPA attempts to minimize outages in an effort to maximize HLH generation and reduce LLH generation. This process is emphasized in periods of potential high spill where reduced outages minimize the risk of lack of turbine spill. In addition, the more units that are available at the hydro projects, the more generation that can be shaped into the HLH period and out of the LLH period, reducing the likelihood of lack of demand spill.

55. As part of the annual outage planning process, BPA works with the Corps and Reclamation to minimize outages during the high runoff period. Ultimately, the Corps and Reclamation determine the outages based on a number of factors, including plant

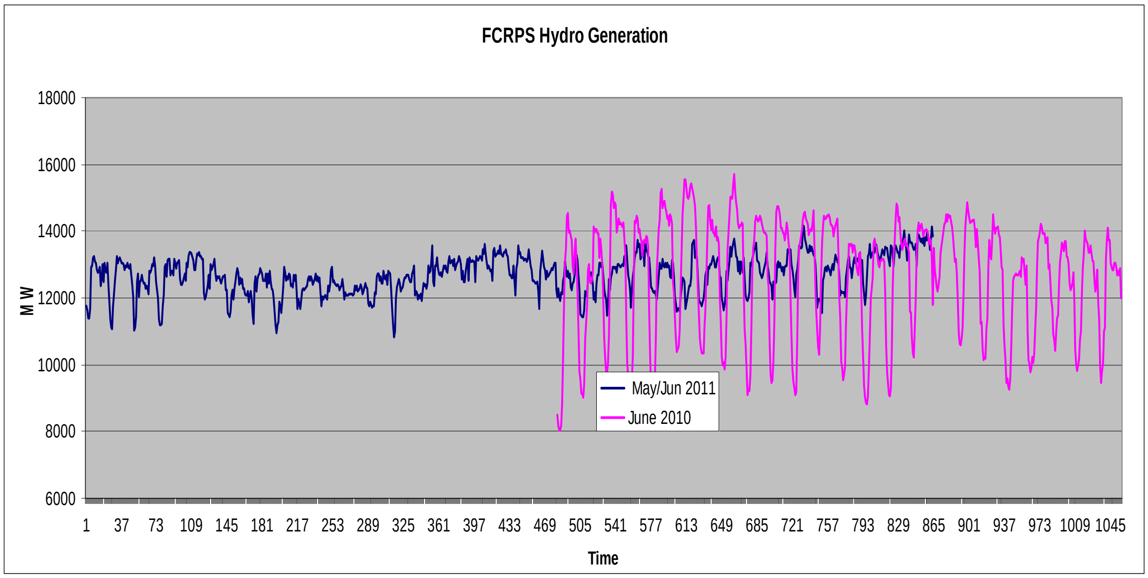
safety, condition of the equipment, operations for the Biological Opinion, power generation needs, transmission impacts, and the availability of the required staff.

56. Despite efforts to maximize HLH turbine availability, the FCRPS experienced a high number of unavoidable outages this year. These outages were due to a combination of factors, including forced outages and preparation for the overhaul of the 3rd powerhouse units at Grand Coulee (GCL) for critical rehabilitation work. As high flows approached a delay of an outage on a large unit (690 MW) scheduled for mid-May was explored but Reclamation determined that a delay would pose a significant risk to the 3rd powerhouse overhauls due to the recent performance of the unit and the critical path of the overhaul schedule.

57. The large number of outages this year, paired with the high flow conditions has lead to lack of turbine spill in some situations where lack of demand spill (and therefore Environmental Redispatch) would have otherwise occurred. This is because there is a point where flows are so high relative to turbine capacity that shaping from LLH to HLH is not possible. The FCRPS has to run relatively flat in order to pass the high flow and minimize TDG levels. In these situations having more units available would mean higher minimum LLH generation to achieve fully loaded turbines and a greater likelihood of lack of demand spill.

58. The below chart, which compares FCRPS generation during two high flow periods (May 18th - June 22nd 2011 and June 7th - 30th 2010), illustrates the impact of unit outages on the ability to shape flows. The blue line, which represents 2011 generation, is relatively flat compared to the pink line which represents last year's generation levels. During the June 2010 high flow event, the system was able to shape

much more generation into the HLH period and out of the LLH period as can be seen by how the pink line dips down near and below the 10,000 MW level and reaches between the 14,000 MW and 16,000 MW level. The dips in generation occurred during the LLH hours and the peaks occurred during the HLH. The hydro system had the ability to shape generation in this manner partly due to the lower flows that occurred in 2010 (325 kcfs at The Dalles on average for the June 2010 period vs. 475 kcfs at The Dalles on average for the May/June 2011 period) and partly due to the reduced number of unit outages.



Banks Lake

59. The John W. Keys III pumping plant pumps water from Lake Roosevelt to Banks Lake for Reclamation’s Columbia Basin Project. The John W. Keys III pumping facility is operated to meet a combination of non-power constraints and objectives including irrigation, recreation, some non-listed fisheries operations, as well as draft for flow augmentation on the lower Columbia River. Within the requirements imposed by the non-power objectives BPA has the flexibility to shape pumping and generation to meet power objectives.

60. The availability of the six pumps and the six pump-generators at Banks Lake is impacted by routine maintenance, unexpected outages, as well as Lake Roosevelt water levels. The pump load takes 600 MW when operating at full capacity. Throughout the spring and especially during high flow and over generation conditions BPA coordinated with Reclamation's Grand Coulee Power Office as well as Reclamation's Ephrata Field Office an operational strategy for Banks Lake that maximized pump load during light load hours to minimize spill and therefore the risk of Environmental Redispatch.

Conclusions

61. Throughout the 2011 high-water event BPA was able to find loads and keep all of its generators fully loaded through almost all heavy load hours. BPA used Environmental Redispatch primarily during light load hours on nights and weekends when it could not find enough load. BPA began using Environmental Redispatch on May 18, 2011, during LLH. The amount of Environmental Redispatch in any hour has depended on BPA's capacity to generate additional power, the generation levels necessary to avoid spill above the gas cap, the amount of thermal generation operating above its minimum generation levels, and the amount of actual wind generation. During LLH throughout the high water event only about 100 to 250 MWs of thermal generators were operating, that is 1.5 to 3.5 percent of the 7000 MWs of thermal generation located in the BPA balancing authority area. During Environmental Redispatch event the thermal generators that were operating were ordered to reduce their generation to their predetermined minimum generation levels. To date, approximately 97,000 MWh of wind generation (5.4% of the 1,760,905 MWh of wind generation that has been produced between May 18 and July 18, 2011) have been redispatched during the 2011 high-water event. During this period we

estimate that the FCRPS spilled 12,400,000 MWhrs worth of water in addition to the normal spill for fish. This includes spill due to lack of turbine and lack of demand.

62. This year's high flows resulted in extensive periods when spill levels were in excess of 120% due to lack of turbines or due to lack of demand. High flows between May 18th and June 30th resulted in TDG levels that exceeded 120% TDG in project tailraces or 115% in the downstream forebay at all projects on the FCRPS almost every day. Without ER, spill levels would have been higher. As discussed previously this was a very high water year with associated high flows and high levels of spill. Under these conditions elevated TDG levels expose listed species of salmon, steelhead, and other aquatic life to sub lethal and lethal effects.[7] Environmental Redispatch was effective in reducing spill levels. The projects and the level of relief varied with the conditions on the system and the amount of Environmental Redispatch available. There were over 200 hours during the high flow period where Environmental Redispatch was used to reduce TDG significantly.

63. This concludes my Affidavit.

[7] *See* Sweet Affidavit at P. 8; 17; 19; 23; 28-29; 33-34.

AFFIDAVIT

State of Oregon
County of Multnomah

NOW BEFORE ME, the undersigned authority, personally came and appeared, Kieran P. Connolly, who after being duly sworn by me, did depose and say:

That the above and foregoing is true to the best of his knowledge, information, and belief.

Kieran P Connolly

Kieran P. Connolly

SIGNED AND SWORN TO BEFORE ME ON THIS 18th Day of July, 2011

Barbara M Willard

NOTARY PUBLIC, STATE OF OREGON

OFFICIAL SEAL
BARBARA M WILLARD
NOTARY PUBLIC - OREGON
COMMISSION NO 438867
MY COMMISSION EXPIRES APR. 28, 2013

DEPARTMENT OF THE ARMY
CORPS OF ENGINEERS, NORTHWESTERN DIVISION
PO BOX 2870
PORTLAND OR 97208-2870

REPLY TO
ATTENTION OF

Programs Directorate

Mr. Steve Oliver
Vice President of Generation Asset Management
Bonneville Power Administration, PG-5
905 NE 11th Street
Portland, OR 97232

Dear Mr. Oliver:

This letter responds to your email requesting the Corps of Engineers (Corps) clarify its position on operations when the Federal Columbia River Power System (FCRPS) is in an over-generation condition due to lack of market or lack of load. The following discussion addresses the Corps' responsibilities under the Clean Water Act (CWA) as it applies to total dissolved gas (TDG) saturation levels under a lack of market condition.

The Corps understand when there is insufficient load or market to manage water through turbine discharge, Bonneville Power Administration (BPA) would take several steps to minimize excessive TDG levels by increasing load, decreasing inflow, deferring (unit or transmission) maintenance, aggressively marketing power, and taking other actions announced at BPA's "Public Workshop on Planning and Responding to Overgeneration Events" on December 3, 2010. To the extent an over-generation condition remains after taking these actions, current practice is for federal projects to incrementally spill according to the Corps' spill priority list. The spill priority list is designed to alleviate the over-generation condition by incrementally spilling projects in a manner that distributes TDG production evenly throughout the FCRPS to minimize impacts to aquatic species.

BPA stated in the December presentation, and as a part of this request, the intent to set a policy of Environmental Redispatch in order to displace wind and other generating resources within BPA's Balancing Authority Area (BAA), and maximize opportunities to operate the FCRPS within applicable water quality standards. BPA has indicated that this policy would be implemented after all other actions identified above were undertaken.

The Corps' policy is to consider respective ecological objectives of the Endangered Species Act (ESA) and the CWA in making operational decisions. This includes harmonizing operations to comply with both the ESA Biological Opinions and the applicable state and tribal water quality standards to the extent practicable. For a number of years, the FCRPS Biological Opinions have included flow augmentation and spill operations for fish passage at the Corps' mainstem Columbia and Snake River projects. The resulting spill operations generate TDG levels in excess of the current Oregon and Washington water quality standard for TDG, which is 110 percent. Consequently, Oregon and Washington provide "waivers," which generally provide criteria for generation of TDG up to 115 percent at the project forebay and 120 percent at the project tailrace when conducting operations to benefit ESA listed fish.[1]

Accordingly, the Corps makes good faith efforts to operate its projects consistent with these standards, criteria and waivers. This includes taking appropriate actions, to the extent practicable, to best manage TDG levels when conditions dictate spill that exceeds the applicable standards.

In over-generation conditions as described herein, the Corps endeavors to implement best management practices with respect to TDG management. Consequently, the Corps supports BPA's efforts to seek arrangements and develop policies to displace wind and other generation with federal hydropower to better manage system TDG levels consistent with applicable state and tribal water quality standards, criteria and waivers.

Sincerely,

Witt Anderson
Director, Programs

[1] The Corps' decision document adopting the most recent ESA Biological Opinion issued in June 2010, states: "Ultimately, in the proper exercise of its discretion, if there is a truly irresolvable conflict between an action the Corps believes that it must take to comply with the ESA on the one hand, and a state or tribal water quality standard on the other, and the Corps does not receive a variance from the appropriate state or tribal water quality agency, the Corps believes that the requirements imposed by the ESA override the water quality goals of the CWA. Should such a conflict exist, the Corps may decide to operate its reservoir projects in a manner inconsistent with state and tribal water quality standards and administrative process. We believe this is consistent with congressional intent as interpreted by the Supreme Court in the TVA v. Hill (437 U.S. 153; 98 S. Ct. 2279; 57 L. Ed. 2d 117; 1978). There, the Supreme Court indicated that Congress intended that preservation of endangered species be given the highest priority. In effect, Federal agencies must do all they can within their authorities, to conserve endangered species when undertaking authorized programs and activities."

2011 WATER MANAGEMENT PLAN

Bonneville Dam
(Photo courtesy of Dennis Schwartz)

Bonneville Power Administration
U.S. Bureau of Reclamation
U.S. Army Corps of Engineers

Table of Contents

1 Table of Contents

2011 Water Management Plan

2 Introduction

The Water Management Plan (WMP) describes the Action Agencies' annual plan for implementing specific operations identified in the NMFS 2008 Biological Opinion and NMFS 2010 Supplemental Biological Opinion (NMFS 2010 Supplemental BiOp), and the USFWS 2000 and 2006 BiOps on the operation of the FCRPS during the current water year (October 2010 – September 2011). The AAs are the final authorities on the content of 2011 WMP, although review, comment, and recommendations are solicited from the Technical Management Team (TMT) and NMFS for consideration during preparation of the WMP. Seasonal operation summary updates to the WMP (spring/summer & fall/winter updates) will be prepared by the AAs and distributed to the region through the TMT. The system operations contained herein may be adjusted according to water year conditions based on recommendations from the TMT and pending review and coordination with NMFS and/or USFWS, whichever is appropriate.

The U.S. Army Corps of Engineers (Corps), Bureau of Reclamation (Reclamation), and Bonneville Power Administration (BPA), collectively referred to as the Action Agencies (AAs), undergo Endangered Species Act (ESA) consultations on the effects of the operation of 14 Federal multi-purpose hydropower projects in the Federal Columbia River Power System (FCRPS)[1] on listed species[2] with the National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS). Biological opinions produced in response to these consultations contain operations that are addressed in this WMP. The applicable biological assessments and biological opinions are as follows:

- The AAs' 2007 FCRPS Biological Assessment (BA) and the Comprehensive Analysis of the FCRPS and Mainstem Effects of Upper Snake and Other Tributary Actions (Comprehensive Analysis) (USACE *et al.* 2007) (BA) were submitted to NMFS in August 2007 and can be found at: http://www.nwr.noaa.gov/Salmon-Hydropower/Columbia-Snake-Basin/final-BOs.cfm

- Reclamation's 2007 Upper Snake BA and BiOp
The BA can be found at:
http://www.usbr.gov/pn/programs/UpperSnake/.
The BiOp can be found at:
http://www.nwr.noaa.gov/Salmon-Hydropower/Columbia-Snake-Basin/final-BOs.cfm

[1] The FCRPS comprises 14 Federal multipurpose hydropower projects. The 12 projects operated and maintained by the Corps are: Bonneville, The Dalles, John Day, McNary, Chief Joseph, Albeni Falls, Libby, Ice Harbor, Lower Monumental, Little Goose, Lower Granite and Dworshak dams. Reclamation operates and maintains the following FCRPS projects: Hungry Horse Project and the Columbia Basin Project, which includes Grand Coulee Dam.
[2] Species listed as endangered or threatened under the Endangered Species Act (ESA).

- NMFS's 2008 FCRPS BiOp

The current WMP reflects provisions contained in the NMFS 2008 FCRPS BiOp (NMFS BiOp) issued May 5th, 2008, and titled "Consultation on Remand for Operation of the Federal Columbia River Power System, 11 Bureau of Reclamation Projects in the Columbia Basin and ESA Section 10(a)(1)(A) Permit for Juvenile Fish Transportation Program (Revised and reissued pursuant to court order, *NWF v. NMFS*, Civ. No. CV 01-640-RE (D. Oregon))." The Corps prepared a Record of Consultation and Statement of Decision (ROCASOD) relative to the NMFS BiOp on August 1, 2008, BPA signed a Record of Decision (ROD) on August 13, 2008 and Reclamation signed a Decision Document on September 3, 2008. The NMFS BiOp, the Upper Snake BiOp, the Corps' ROCASOD, and Reclamation's Decision Document can be found at: http://www.nwr.noaa.gov/Salmon-Hydropower/Columbia-Snake-Basin/Final-BOs.cfm

- NMFS 2010 Supplemental FCRPS Biological Opinion

After the Obama Administration reviewed the BiOp in 2009, NOAA and the Action Agencies jointly developed an Adaptive Management Implementation Plan (AMIP). In February 2010 , the federal agencies entered into a voluntary remand to formally integrate the AMIP developed during the fall of 2009 into the 2008 BiOp and its RPA.

In addition to consideration of new information, the 2010 Supplemental BiOp incorporated the 2008 BiOp and added the amended AMIP to the 2008 BiOp RPA. The Action Agencies amended their respective Records of Decision on June 11, 2010. The amended ROD's may be found at the following website:
http://www.bpa.gov/corporate/pubs/RODS/2010/

The Supplemental FCRPS BiOp may be found at the following website:
http://www.nwr.noaa.gov/Salmon-Hydropower/Columbia-Snake-Basin/final-BOs.cfm

- USFWS's 2000 FCRPS BiOp, the 2006 Libby Dam BiOp

The USFWS 2000 FCRPS BiOp, "Effects to Listed Species from Operation of the Federal Columbia River Power System" is operative for all the FCRPS projects except for Libby Dam and can be found at: http://www.fws.gov/pacific/finalbiop/BiOp.html.

The USFWS issued the 2006 Libby BiOp, which amended and supplemented the USFWS 2000 BiOp with respect to the effects of the operations of Libby Dam on the Kootenai sturgeon and the bull trout in the Kootenai River. That document can be found at: http://kootenaifwlibrary.org/PDFs/26S%20Final%20Libby%20Dam%20BiOp%202-18-06lr3.pdf

3 Additional Governing Documents

- Corps 2003 Columbia River Treaty Flood Control Operating Plan (FCOP)

The Columbia River Treaty between Canada and the United States of America provides that the powers and duties of the Canadian and United States Entities include the preparation of a flood control operation plan (FCOP) for the Canadian storage. The purpose of the FCOP for Canadian storage is to prescribe criteria and procedures by which the Canadian Entity will operate Mica, Duncan and Arrow Reservoirs to achieve desired flood control objectives in the United States and Canada. The purpose of including Libby Reservoir in the FCOP is to meet the Treaty requirement to coordinate its operation for flood control protection in Canada. Because Canadian storage is an integral part of the overall Columbia River reservoir system, the FCOP for this storage must be related to the flood control plan of the Columbia River as a whole. The principles of the Columbia River system operation are therefore contained in the FCOP. A copy of the FCOP may be found online at the following website: http://www.nwd-wc.usace.army.mil/cafe/forecast/FCOP/FCOP2003.pdf

4 WMP Implementation Process

- Technical Management Team

The TMT is an inter-agency technical group comprised of sovereign representatives responsible for making recommendations to the AA's on dam and reservoir operations in an effort to meet the expectations of the applicable BiOps (NMFS 2010 Supplemental; USFWS 2000 FCRPS, USFWS 2006 Libby; BOR 2007 Upper Snake). The Corps' representative is the TMT chair; and, the TMT consists of representatives from: NMFS, USFWS, BOR, Corps, BPA; the states of Oregon, Washington, Idaho, Montana; and, tribal sovereigns.

- Preparation of the WMP

Each fall, the AAs prepare an annual WMP (draft by October 1st and the final by January 1st). The AAs have prepared this WMP for the 2011 water year consistent with the NMFS 2010 Supplemental BiOp and the USFWS 2000 and 2006 BiOps. This WMP describes the planned operations of the FCRPS dams and reservoirs for the 2011 water year (October 1, 2010 through September 30, 2011)[3]. The operations are designed to:

- implement water management measures in a manner consistent with actions considered in their respective BiOps.
- assist in meeting the biological performance standards specified in the BiOps in combination with other actions or operations identified in the NMFS 2010 Supplemental BiOp.
- meet non-BiOp related requirements and purposes such as flood control, hydropower, irrigation, navigation, recreation, and fish and wildlife not listed under the ESA. For a detailed description of flood control see http://www.nwd-wc.usace.army.mil/report/colriverflood.htm.
- take into consideration recommendations contained in the applicable Northwest Power and Conservation Council Fish and Wildlife Program and amendments.

[3] When the draft WMP is prepared, very little information is available about the future year's water supply; therefore, the draft provides only a general description of how the FCRPS will be operated during the upcoming water year.

The WMP will also include any special operations (such as any special tests, required maintenance, construction activities, flood control procedures planned for the year, etc.) that are known at the time the WMP is developed. These action plans will take into account changes in the operations due to water supply or other factors. As the water supply forecasts become available, the AAs will develop more detailed in-season action plans for the proposed FCRPS project operations that describe planned hydro system fish operations for the upcoming fall and winter (draft by November 1 and final by January 1) and for the spring, and summer (draft by March 1 and final by May 15).

- The Corps also prepares a Fish Passage Plan (FPP) each year that provides detailed operating criteria for project fish passage facilities, powerhouses, and spillways to allow for the efficient passage of migratory fish. The FPP contains appendices that describe special operations for fish research studies, the juvenile fish transportation program, operation of units within 1% of best efficiency, spill for fish passage, total dissolved gas (TDG) monitoring, and dewatering procedures. The FPP is coordinated through the Fish Passage Operations and Maintenance Coordination Team (FPOM) and is available on the web at http://www.nwd-wc.usace.army.mil/tmt/ .

- NMFS 2010 Supplemental BiOp Strategies

This WMP addresses strategies to enhance juvenile and adult fish survival through a coordinated set of hydro project management actions to achieve performance standards, and to provide benefits to resident fish. The plan is structured to address water management actions associated with the following strategies and sub-strategies, as defined in the NMFS 2010 Supplemental BiOp.

- Hydropower Strategy 1—Operate the FCRPS to provide flows and water quality to improve juvenile and adult fish survival.
- Hydropower Strategy 2—Modify Columbia and Snake River dams to maximize juvenile and adult fish survival.
- Hydropower Strategy 3—Implement spill and juvenile transportation improvements at Columbia River and Snake River dams.
- Hydropower Strategy 4—Operate and maintain facilities at Corps mainstem projects to maintain biological performance.

4.1 Non ESA Operations

Each year the AAs implement water management actions that are not part of our ESA obligations, but are aimed at meeting other project requirements and purposes such as flood control, power generation, irrigation, navigation, recreation, and fish and wildlife not listed under the ESA. Table 1 includes fish and wildlife related non-ESA water management actions that may be implemented and the time of year such actions typically occur. These actions are further described below.

Table 1. Non-ESA listed species and period of impact.

Action	**Time of Year**
Keenleyside Dam (Arrow) mountain whitefish actions	December – January
Keenleyside Dam (Arrow) rainbow trout actions	April – June
Libby - burbot actions	October - February
Dworshak – flow increase for hatchery release	March
Grand Coulee – kokanee	September – Mid November
Hanford Reach Fall Chinook Protection Program Agreement	October – June
McNary - waterfowl nesting	March – May
McNary - waterfowl hunting enhancement	October – January
John Day - goose nesting	March – May
Bonneville - Tribal fishing	April – September
Bonneville - Spring Creek Hatchery release	April – May
Ice Harbor - waterfowl hunting enhancement	October – January
Little Goose – waterfowl hunting enhancement	October – January
Duncan - whitefish flows	March – May

4.2 Lamprey Passage

The Fish Accords signed in May 2008 address actions to protect Pacific lamprey. The goals of the Pacific lamprey passage program are to improve both juvenile and adult lamprey passage through the FCRPS. Guidance for project operations to improve passage conditions for adult and juvenile lamprey are addressed in FPOM and specific 2011 operations for juvenile and adult lamprey will be defined in the appropriate project sections of the 2011 FPP. In-season conflicts between operations for listed species and Pacific lamprey not covered in the FPP will be reviewed by TMT and TMT may provide management recommendations on these issues.

5 Hydro System Operation

- Priorities

The NMFS 2010 Supplemental BiOp and USFWS 2000 and 2006 BiOps list the following strategies for flow management:

- Provide minimum project flows in the fall and winter to support fisheries below the projects (e.g. Hungry Horse, Dworshak, and Libby).

- Limit the winter/spring drawdown of storage reservoirs to increase spring flows and the probability of reservoir refill.

- Draft from storage reservoirs in the summer to increase summer flows.

Provide minimum flows in the fall and winter to support mainstem chum spawning and incubation flow below Bonneville Dam. The Action Agencies have reviewed these strategies and other actions called for in the NMFS 2010 Supplemental BiOp, and USFWS 2000 and 2006 BiOps and developed the following priorities (in order) for flow management and individual reservoir operations after ensuring adequate flood damage reduction is provided:

1. Operate storage reservoirs (Hungry Horse and Libby) to meet minimum flow and ramp rate criteria for resident fish.

2. Refill the storage projects to provide summer flow augmentation. The timing and shape of the spring runoff may result in reservoir refill a few days before or after the target refill date. For example, a late snowmelt runoff may delay refill in order to avoid excessive spill.

    - Hungry Horse refill by about June 30 to provide summer flow augmentation.

    - Dworshak refill by about June 30 to provide summer flow augmentation.

    - Grand Coulee refill by about June 30 to provide summer flow augmentation.

    - Operate Libby Dam in accordance with VARQ Operating Procedures combined with the tiered sturgeon volume shaped as recommended in the USFWS 2006 BiOp, as clarified. These operating assumptions provide an approximate 12% probability of Libby refill to within one ft. of full by July 31.

3. Operate storage projects to be at their April 10 elevation objectives, if possible, to provide spring flow augmentation.

4. Provide flow augmentation, from the start of chum spawning in November through the end of chum emergence (approximately April), to maintain sufficient water surface to protect Ives/Pierce Island chum salmon spawning and incubation.

In addition to operations for anadromous fish, the AAs operate the FCRPS projects to benefit listed fish at or near each project or in its reservoir. Reservoirs operate to meet project minimum outflows, to avoid involuntary spill and resulting elevated TDG, to reduce outflow fluctuations to avoid stranding fish and degrading fish habitat and productivity, to reduce cross sectional area of run-of river mainstem projects to speed juvenile passage and reduce reservoir surface area to moderate temperatures, and to make specific temperature releases from storage projects to improve water temperatures for fish. These operations are generally the highest priority because of the direct linkage between a particular operation and impacts on fish near the dam.

As the operating year begins on October 1, the flow objectives are not encountered in the same order as the NMFS 2010 Supplemental BiOp flow priorities (e.g. decisions need to be made on chum spawning flows first despite the fact that they have a lower priority than spring or summer migration flows). However, the AAs will operate chronologically during the year while attempting to meet the flow priorities as they are outlined in the NMFS 2010 Supplemental BiOp. Objectives include:

- Operate the storage reservoirs (Dworshak, Hungry Horse, Libby, and Grand Coulee) to achieve the April 10 refill objectives with a high probability. These levels vary with the runoff forecast. The ability to reach these objectives is affected by how much water was released for flood control, changes in runoff volume forecasts, power generation, and fishery flows to support both lower Columbia chum and Hanford reach fall Chinook spawning, as well as minimum flow requirements below the projects.

- Refill the storage reservoirs by about June 30[4] while minimizing spill (except as needed to maintain flood control), in order to maximize available storage of water for the benefit of summer migrants. Although the June 30 refill objective generally has priority over spring flow (April, May, June) objectives, the AAs attempt to refill as well as meet the spring flow objectives and other fish needs.

- Manage the available storage to augment summer (July and August) flows in an attempt to meet flow objectives and to moderate water temperature. When

[4] Libby Dam refill probability is likely to be later into July as defined in the VARQ Flood Control Operating Procedures and supporting effects analysis. *See*, Upper Columbia Alternative Flood Control and Fish Operations (VARQ) Environmental Impact Statement. http:/www.usbr.gov/pn/programs/fcrps/varq/index.html

necessary for summer flow augmentation, Libby and Hungry Horse will be drafted to no lower than their specified draft limits by September 30, Grand Coulee and Banks Lake will be drafted to no lower than their specified draft limits by August 31. Dworshak will reach its summer draft limit in September to augment summer flows and to moderate river temperatures. Draft limits are a higher priority than the summer flow objectives in order to meet other project uses and reserve water in storage for the following year.

- These objectives are intended as general guidelines. The NMFS 2010 Supplemental BiOp and the USFWS 2000 and 2006 BiOps embrace the concept of adaptive management. Adaptive management is the concept that the operation of the system should be adjusted based on best available science and acquired knowledge about current conditions in the system and effects due to management actions, as opposed to following a rigid set of rules. Conditions that are continually changing include information on fish migration, stock status, biological requirements, biological effectiveness, and hydrologic and environmental conditions.

- Conflicts

System managers recognize that water supply conditions are variable and unpredictable and there is typically insufficient water to accomplish all the objectives addressed in the NMFS 2010 Supplemental BiOp, and USFWS 2000 and 2006 BiOps for the benefit of listed fish. This may be further complicated by responsibilities to provide for other authorized purposes such as flood protection, power system reliability, irrigation, recreation, and navigation needs. Management of water resources for any one fish species may conflict with the availability of water for other fish species or project purposes. The AAs, in coordination with regional parties through the TMT, consider the multiple uses of the system, while placing a high priority on measures to benefit listed species. Below are some of the typical conflicts that may occur.

5.1 Flood Control Draft versus Project Refill

The NMFS 2010 Supplemental BiOp, and USFWS 2000 and 2006 BiOps specify that the storage projects be as full as possible on April 10 to increase the likelihood of refill and to maximize both spring flow management and summer flow augmentation.

Flood control procedures specify the amount of storage needed to provide flood damage reduction. In furtherance of the flood damage reduction objective, storage space is provided to reduce the risk of forecast and runoff uncertainty. In an effort to reduce forecast error and to better anticipate the runoff timing or water supply the AAs and the River Forecast Center (RFC) use the best available science to compute water supply forecasts. An annual forecast review will occur each fall by the Columbia River Forecast Group (CRFG) to evaluate the performance of the current forecast procedures. The CRFG will evaluate new forecasting techniques for potential implementation.

5.2 Provision of Spring Flows versus Project Refill and Summer Flow Augmentation

Flood control elevations are determined based on water supply and runoff forecasts and can change significantly from one forecast to the next. Changes in forecasts throughout the flood control season can make it difficult to achieve both flow and project refill objectives.

5.3 Chum Tailwater Elevations versus Refill/Spring Flows

Providing a Bonneville Dam tailwater elevation level for chum spawning and incubation in the Ives Island complex typically requires flow augmentation from storage reservoirs when reliable flow forecast information is unavailable. Project refill and spring flows have priority over flow augmentation to provide chum tailwater elevations which have to be set in November/December. Although there is an early season Southern Oscillation Index (SOI) based forecast and other early season climate indices that can provide an indication of the upcoming year’s water supply, the more reliable water supply forecasts don’t start until January. If the tailwater elevation level selected during the spawning season is too high (requiring higher flows and requiring deeper reservoir drafts), there is a risk of drafting below the April 10 elevation objective thereby reducing spring flows if the higher flows are maintained throughout the incubation period. On the other hand, if the flows are reduced during the incubation period in order to refill, then there is the risk of dewatering chum redds. When this conflict arises, project refill and spring flows that benefit multiple ESUs have priority over maintaining the chum tailwater elevations set in December.

5.4 Sturgeon Pulse below Libby Dam versus Summer Flow Augmentation

Water released from Libby Dam for spring sturgeon spawning flows (pulse) during May and into July impact the project’s ability to refill, thus reducing the reservoir refill level, and consequently the amount of the water available for summer flow augmentation from Libby. Water released for sturgeon spawning flows will take a higher priority than refilling by early July to meet salmon summer flow targets.

5.5 Fish Operations versus Other Project Uses

In addition to flood control operation, there are other project purposes that may conflict with operations for the benefit of fish. For example; (1) a particular spill pattern at a project may impact the ability of commercial barges to access and enter navigation locks safely. Additionally, in some cases, spill must be curtailed temporarily to allow fish barges to safely moor and load fish at fish loading facilities; (2) spilling water for juvenile fish passage reduces the amount of power that can be generated to meet demand; and, (3) timing of releases for flow augmentation during fish migration periods may conflict with the shape or timing of power demand. In addition to power generation, operations for irrigation and reservoir recreation may conflict with releases of water for flow augmentation.

5.6 Conflicts and Priorities

The conflicts described above pose many challenges to the AAs in meeting the multiple uses of the hydrosystem. The priorities for flow management and individual reservoir operations outlined in section 4.1 will assist the AAs in their operational decision-making. Discussion of conflicts between operational requirements and alternatives for addressing such conflicts will occur in TMT.

- Emergencies

The WMP, the NMFS 2010 Supplemental BiOp, and the current FPP acknowledge that emergencies and other unexpected events occur and may cause interruptions or adjustments of fish protection measures. Such deviations may be short in duration, such as a response to an unexpected unit outage or power line failure, or a search and rescue operation, or longer in duration, such as what was experienced in 2001 in response to the low water conditions. Emergency operations will be managed in accordance with the TMT Emergency Protocols, the FPP and other appropriate AA emergency procedures. The TMT Emergency Protocols can be found Appendix 1: Emergency Protocols.

5.7 Operational Emergencies

The AAs will manage interruptions or adjustments in water management actions, which may occur due to unforeseen power system, flood control, navigation, dam safety, or other emergencies. Such emergency actions will be viewed by the AAs as a last resort and will only be used in place of operations outlined in the annual WMP, if necessary. Emergency operations will be managed in accordance with TMT Emergency Protocols, the FPP and other appropriate AA emergency procedures. The AAs will take all reasonable steps to limit the duration of any interruption in fish protection measures. Emergency Action Plans for generation and transmission emergencies are provided in the Attachments 1 and 2 of the TMT Emergency Protocols.

5.8 Fish Emergencies

The AAs will manage operations for fish passage and protection at FCRPS facilities. The intended operation may be modified for brief periods of time due to unexpected equipment failures or other conditions. These events can result in short periods when projects are operating outside normal specifications due to unexpected or emergency events. Where there are significant biological effects of more than short duration emergencies impacting fish, the AAs will develop (in coordination with the in-season management Regional Forum (see BA Appendix B.2.1) and implement appropriate adaptive management actions to address the situation. The AA's will take all reasonable steps to limit the duration of any fish emergency. The AA's will operate in accordance with the TMT Emergency Protocols identified in Appendix 1 of the WMP.

5.9 Emergency Operations for Non-ESA listed Fish

The AAs agree to take reasonable actions to aid non-listed fish during brief periods of time due to unexpected equipment failures or other conditions and when significant detrimental biological effects are demonstrated. When there is a conflict in such operations, operations for ESA-listed fish will take priority.

- Fish Research

Research studies sometimes require special operations that differ from routine operations otherwise described in the NMFS 2010 Supplemental BiOp, the USFWS 2000 and 2006 BiOps, and the current FPP. These studies are generally developed through technical workgroups of the Regional Forum (e.g., the Corps' Anadromous Fish Evaluation Program, Fish Facilities Design Review Work Group and Studies Review Work Group). Specific research operations are further described in the Corps' FPP (Appendix A) and the AAs' seasonal updates to the WMP. In most cases, operations associated with research entail relatively minor changes from routine operations and are coordinated in regional technical forums (e.g., TMT and FPOM). In some cases, the nature or magnitude of operational changes for research may require further coordination and review in policy forums [e.g., Hydro Coordination Team (HCT) or Regional Implementation and Oversight Group (RIOG)]. Generally, research planning and coordination occurs throughout the late fall and winter, with final research plans established by late winter/early spring. In the event extraordinary events occur, such as extreme low runoff conditions or a hydrosystem emergency, planned research may be modified prior to implementation to accommodate anticipated unique circumstances and/or to reallocate resources to obtain the greatest value given the circumstances.

- Flood Control Shifts

The AA will look for opportunities to shift system flood control requirements from Brownlee and Dworshak to Grand Coulee periodically between January 31 and April 15 to provide more water for flow augmentation in the lower Snake River during the spring migration. Consideration of these flood control shifts by the Corps will include an analysis of impacts to flood risk management and will not be implemented if flood control would be compromised. These shifts may be implemented after coordination with TMT to discuss tradeoffs and impacts.

6 Decision Points and Water Supply Forecasts

Table 2 below lists the key water management decisions/actions and when they need to be made. Some decision points, such as setting flow objectives, are clearly articulated in the NMFS 2010 Supplemental BiOp and the USFWS 2000 and 2006 BiOps. Other decision points, such as setting weekly flow augmentation levels, require thorough discussion and coordination. The decision points given below are spelled out in the BiOps, or are based on best professional judgment and expertise. These decisions are made by the AAs in consideration of actions called for in the BiOps, and input received through the Regional Forum (TMT, RIOG, and Regional Executives).

Table 2. Water Management Decision Points/Actions.

	September	Early October	November	Winter (December – March)	Early April	Early May	June	Early July
Operations	• Albeni Falls fall/winter minimum control elevation discussion to support kokanee spawning and incubation • Establish stable flows from Libby to protect bull trout and other resident fish while meeting end of September draft limit	• Assess potential tailwater elevations to support chum spawning below Bonneville Dam • Preliminary discussions of flood control/ project refill strategy • Support for Hanford Reach fall chinook protection operations begins.*(Non-Bi Op Action)* • Consider Kootenai burbot temperature operation	• Early season water supply forecast using SOI	• Determine winter/spring chum flow tailwater elevations below Bonneville Dam • Determine flood control and refill strategies, including any available flood control shifts • Determine final April 10 objective base on FCE's from March Final WSF. • Minimum flows from Hungry Horse Dam and minimum Columbia Falls flows are set by April-August	• Spring flow objectives are set by the April final volume forecasts • Determine spring flow manageme nt strategy including priority for refill • Determine Juvenile Fish Transport Operations for Lower Snake Projects and McNary • Determine start dates and levels by project for spring spill • Determine start date for Minimum	• Evaluate likely tier for sturgeon water volume • Determine refill start date based on streamflow forecast to exceed Initial Control Flow (ICF) at The Dalles (if this does not occur in April • Use May forecast to determine VARQ refill flows for Libby and Hungry Horse • Use May final forecast to calculate the appropriate	• Summer flow objective at Lower Granite determined by June final volume forecast • Use June forecast to determine VARQ refill flows for Libby and Hungry Horse • Regional technical team recommends shape and timing of Libby Dam sturgeon pulse • Determine summer flow augmentati on strategy (early June)	• Grand Coulee summer reservoir draft limit determined by July Final April – August volume forecast at The Dalles • Salmon Draft at Libby and Hungry Horse

	September	Early October	November	Winter (December – March)	Early April	Early May	June	Early July
				forecast • Begin discussing spring operations • Begin spring transport discussions • Hanford Reach operations *(non-BiOp action)* discussed, beginning in January • Perform analysis to determine amount of flexibility Dworshak has to operate above minimum flow and still reach spring refill targets • Prepare outlook for meeting flow objectives • Determine end of	Operating Pool (MOP) at Lower Snake River projects • Determine John Day forebay elevations • Determine refill start date based on streamflow forecast to exceed Initial Control Flow at The Dalles • If required, use April forecast to determine VARQ refill flows for Libby and Hungry Horse	volume of the bull trout flow release from Libby for after the sturgeon pulse through August • Use May final forecast to calculate the appropriate volume of the sturgeon tiered flow release from Libby • Regional technical team recommends shape and timing of Libby Dam sturgeon pulse • May 15 until sturgeon flow begins Libby minimum outflow is 6	• Complete Dworshak temperature modeling and determine release strategy • Decision on McNary juvenile fish transportation (late June)	

	September	Early October	November	Winter (December – March)	Early April	Early May	June	Early July
				December flood control elevation at Libby, using the Corps' December forecast		kcfs for bull trout.		
Plans		Develop fall/winter update to the annual WMP		Preliminary work on spring/summer update to the annual WMP	Start operational plans for Libby and Hungry Horse Dams	Libby and Hungry Horse operational plans due		
Forecasts				January, February, and March volume forecasts released by the NWRFC	April final forecast released by NWRFC	May final forecast released by NWRFC	June final forecast released by NWRFC	

6.1 Water Supply Forecasts

Water supply forecasts serve as a guide to how much water is available for fish and other operations. Flow projections are provided to the TMT regularly during the flow management season (April 3 – August 31).

The RFC, Corps Northwestern Division Hydrologic Engineering Branch, Reclamation, and others prepare water supply forecasts to manage the Columbia River. Table 3 below lists the forecasts used to implement actions referenced in the BiOps. Table 4 summarizes the major fish-related reservoir and flow operations by project. More detailed descriptions of each of these operations follow.

Table 3. Water Supply Forecasts Used to Implement BiOp Actions.

Forecast Point	Forecast period	Forecast	BiOp Actions to be Determined
Hungry Horse	April – August Provided by Reclamation	January, February, and March Final	Columbia Falls and Hungry Horse minimum flows
	May – September Provided by Reclamation	January, February and March Final	Sets VARQ flood control targets
		April Final	Sets VARQ flood control targets and VARQ refill flows
		May and June Final	VARQ refill flows
The Dalles	April – August Provided by NWRFC	April Final	Spring flow objective at McNary Dam Juvenile Fish Transport operations at McNary
		May Final	Libby Summer Draft Limit (2,449 ft. by the end of September except for the lowest 20 percent of years, then 2,439 ft. by the end of September). Hungry Horse Summer Draft Limit (3,550 ft. by the end of September except for the lowest 20 percent of years, then 3,540 ft. by the end of September).
		July Final	Summer draft elevation for Grand Coulee (August 31 elevation of 1,280 ft. or 1,278 ft.)
Lower Granite	April – July Provided by NWRFC	April Final	Spring flow objective at Lower Granite Juvenile Fish Transport operations at Lower Snake Projects
Lower Granite	April – July Provided by	June Final	Summer flow objective at Lower Granite

	NWRFC		
Libby	April – August Provided by Seattle District	December Final	Sets end of December variable draft target
		January, February and March Final	Sets VARQ flood control targets
		April Final	Sets VARQ flood control targets and VARQ refill flows
		May Final	Volume of water to provide for sturgeon and minimum bull trout flows to begin after sturgeon pulse through August. VARQ refill flows
		June Final	VARQ refill flows
Dworshak	April – August Provided by Walla Walla District	October to June	Draft for summer flow augmentation and water temperature reduction, not to exceed reservoir draft limit of 1,520 ft. in September

Table 4. Reservoir and Flow Operations for ESA-listed fish species.

Project	Flood Control & Refill	Sturgeon	Bull Trout	Spring Anadromous	Summer Anadromous	Chum
Libby	Winter: Operate to VARQ flood control rule curve and achieve appropriate elevation by April 10 if possible Spring: Adhere to VARQ Operating Procedures at Libby Dam, supply the appropriate tiered volume for sturgeon, supply appropriate minimum bull trout flow	May – July Provide USFWS sturgeon volume to augment flows at Bonners Ferry.	Year Round: Observe project ramping rates to minimize adverse affects of flow fluctuations May 15 – Sep 30: Operate to Bull Trout Minimum Flows and maintain a steady outflow if possible for July -– September while meeting end of September draft limit.	Operate to meet flow objectives and refill if possible without jeopardizing flood control	September Draft 10 ft. from full by the end of September (except in lowest 20th percentile water years, as measured by The Dalles May water supply forecast, when draft will increase to 20 ft. from full by end of September)	Fall/winter storage may be used to support chum flows
Hungry Horse	Winter: Operate to VARQ flood control rule curves with a 75% confidence of meeting the April 10 elevation objective Spring: Refill by about June 30 if possible without excessive spill and operate to help meet flow objectives		Year Round: Operate in order to maintain Columbia Falls and project minimum flow requirements. Operate using ramping rates to minimize adverse affects of flow fluctuations and maintain a steady outflow if possible for July -– September while meeting end of September draft limit.	Operate to meet flow objectives and June 30 refill if possible without exceeding TDG limits	September Draft 10 ft. from full (elevation 3,550 ft.) by the end of September except in lowest 20th percentile water years, as measured at The Dalles when draft will increase to 20 ft. from full (elevation 3,540 ft.) by the end of September	

Project	Flood Control & Refill	Sturgeon	Bull Trout	Spring Anadromous	Summer Anadromous	Chum
Albeni Falls	Winter: Operate to standard flood control criteria Spring: Refill by June 30 and operate to help meet flow objectives		Fall/Winter: Determine winter minimum control elevation after annual meeting with AAs, IDFG, NMFS, USFWS and interested parties. This year's winter minimum control elevation will be 2,055 ft. Reach 2,055 ft. msl by mid-November and maintain this elevation until the end of kokanee spawning as determined by IDFG survey. After the end of spawning, operate not to exceed flood control rule curve but not to fall below the winter control elevation.			Fall/winter storage may be used to support chum flows

Project	Flood Control & Refill	Sturgeon	Bull Trout	Spring Anadromous	Summer Anadromous	Chum
Grand Coulee	Winter: Operate to 85% confidence of meeting April 10 elevation objective Spring: Refill by about June 30 and operate to help meet flow objectives			Operate to 85% confidence of meeting April 10 elevation objectives to increase spring flows in the Lower Columbia river. Operate to help meet the Spring flow objective at Priest Rapids Dam	July-August: Draft to support salmon flow objectives, not to exceed reservoir draft limit of 1,280 ft (>= 92 MAF July Final forecast at The Dalles) or 1,278 ft. (<92 MAF forecast at The Dalles)[5] August: Operate Banks Lake to draft to elevation 1,565 ft. by August 31 to provide more water for summer flow augmentation	Fall/winter storage may be used to support chum flows
Dworshak	Winter: Operate to achieve April 10 refill objective Spring: Refill by about June 30 and operate to help meet flow objectives				Draft for summer flow augmentation and water temperature reduction, not to exceed reservoir draft limit of 1,520 ft. in September	Fall/winter storage may be used to support chum flows
Lower Granite				Flow objective of 85-100 kcfs Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency	Flow objective of 50-55 kcfs Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency	

[5] These draft limits will be modified as the Lake Roosevelt Incremental Storage Release Project is implemented (see Section 6.5.6).

Project	Flood Control & Refill	Sturgeon	Bull Trout	Spring Anadromous	Summer Anadromous	Chum
Little Goose				Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency Manually set Unit 1 lower operating limit	Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency Manually set Unit 1 lower operating limit	
Lower Monumental				Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency	Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency	
Ice Harbor				Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency	Operate within 1 ft. of MOP to reduce juvenile travel time Operate within 1% of best efficiency	
McNary				Flow objective of 220-260 kcfs Operate within 1% of best efficiency	Flow objective of 200 kcfs Operate within 1% of best efficiency	
John Day				Operate within 1.5 ft. of minimum level that provides irrigation pumping to reduce juvenile travel time Operate within 1% of best efficiency	Operate within 1% of best efficiency	
The Dalles				Operate within 1% of best efficiency	Operate within 1% of best efficiency	

Project	Flood Control & Refill	Sturgeon	Bull Trout	Spring Anadromous	Summer Anadromous	Chum
Bonneville				Operate within 1% of best efficiency	Operate within 1% of best efficiency	Provide support to chum if hydrologic conditions indicate system can likely maintain minimum project tailwater elevation (on Oregon shore 0.9 miles downstream of first powerhouse and 50 ft. upstream of Tanner Creek) during spawning and incubation

7 Project Operations

7.1 Hugh Keenlyside Dam (Arrow Canadian Project)

7.1.1 Mountain Whitefish

Spawning flow levels are set between 45-55 kcfs beginning the third week in December and continuing through mid-January. Egg protection flows are set 5-15 kcfs lower than the spawning flow from mid-January through the end of March.

7.1.2 Rainbow Trout

Rainbow trout spawning begins in April. Protection levels begin somewhere between 15 and 25 kcfs. The goal is to have stable flows or ever-increasing flows through June.

7.2 Hungry Horse Dam

Hungry Horse Dam is operated for multiple purposes including fish and wildlife, flood control, power, and recreation. Specific operations for flow management to aid anadromous and resident fish are listed in the following sections.

7.2.1 Winter/Spring Operations

Hungry Horse will be operated for flood control from January through April using the Storage Reservation Diagram (SRD) developed for VARQ flood control. Hungry Horse began operating using VARQ Flood Control rule curves on an interim basis starting January 1, 2001, based on an Environmental Assessment Finding of No Significant Impact. Reclamation in coordination with the Corps, completed the Upper Columbia EIS in 2006. A ROD was prepared and signed by Reclamation in September 2009.

Hungry Horse will be operated during the winter and early spring to achieve a 75% probability of reaching the April 10 elevation objective in order to provide more water for spring flows. This is achieved by operating between Upper Rule Curve (URC) as an upper limit and the Variable Draft Limits (VDL's) as a lower operating limit for the reservoir from January through March. A description of VDL's is provided in Section 7.5. In many years, typically dry years, the previous year's summer draft for flow augmentation and year-round required minimum discharges for resident fisheries will prevent Hungry Horse from reaching the April 10 elevation objective. Reclamation computes Hungry Horse Dam's April 10 elevation objective by linear interpolation between the March 31 and April 15 forecasted flood control elevations based on the Reclamation March Final May - September Water Supply Forecast (WSF).

Refill at Hungry Horse usually begins approximately ten days prior to when streamflow forecasts of unregulated flow is projected to exceed the ICF at The Dalles, Oregon. During refill, discharges from Hungry Horse are determined using inflow volume forecasts, streamflow forecasts, weather forecasts, and the VARQ Operating Procedures. Other factors such as local flood control are also considered when determining refill operations. During the latter part of the flood control season (April) and the refill season (typically May through June), Hungry Horse discharges may be reduced for local flood protection in the Flathead Valley. The official flood stage for the Flathead River at Columbia Falls, Montana is 14 ft. (an approximate flow of 51,000 cubic feet per second (cfs)). In order to prevent or minimize flooding on the Flathead River above Flathead Lake, Reclamation will adjust outflows from Hungry Horse Dam as necessary (down to a minimum discharge of 300 cfs) in order to maintain the Flathead River at Columbia Falls below 14 ft. if possible. Hungry Horse generally starts reducing discharges when the stage at Columbia Falls begins to exceed 13 ft. (approximately 44,000 cfs).

Often during the spring, changes in flood control, transmission limitations and generation unit availability will require adaptive management actions for real-time operations in order to control refill and to avoid spill.

7.2.2 Summer Operations

Hungry Horse will operate to refill by about June 30 to provide summer flow augmentation, except as specifically provided by the TMT. However, the timing and shape of the spring runoff may result in reservoir refill a few days before or after the June 30 target date. For example, a late snowmelt runoff may delay refill to sometime after June 30 in order to avoid excessive spill.

During the summer, Hungry Horse is drafted within the NOAA Fisheries BiOp's specified draft limits based on flow recommendations provided by TMT. TMT considers a number of factors when developing its flow recommendations, such as: the status of the migration, attainment of flow objectives, water quality, and the effects that reservoir operations will have on other listed and resident fish populations. Flows during the summer months should be even or gradually declining in order to minimize a double peak on the Flathead River. The summer reservoir draft limit at Hungry Horse is 3,550 ft. (10 ft. from full) by September 30 except in the lowest 20th percentile[6] of water years (The Dalles April-August <71.8 maf) when the draft limit is elevation 3,540 ft. (20 ft. from full) by September 30. If the project fails to refill, especially during drought years, minimum flow requirements (see Section 6.2.4) may draft the reservoir below these draft limits. Operations in September are primarily focused on benefiting listed resident bull trout and other fish species below the project. The intent is to maintain steady flows below the project. Inflows increasing above the planned operation could result in an elevation above the end of September draft limit.

7.2.3 Reporting

Reclamation will fulfill the USFWS Reasonable and Prudent Measure (RPM) from the 2000 USFWS BiOp for annual and monthly reporting by contributing to the annual WMP and presenting weekly and biweekly reports of Hungry Horse operations through the TMT process. Reclamation will also fulfill the USFWS RPM recommendation for reporting actual operations by making available pertinent historic elevations and flows as related to Hungry Horse Dam through its current website at: http://www.usbr.gov/pn/hydromet/esatea.html.

[6] The lowest 20th percentile as measured at The Dalles (RPA 4 in RPA Table, pg 6 of 98) based on RFC's statistical period, currently 1971-2000, using May final for The Dalles Apr-Aug (RPA 14 in RPA table, pg 15 of 98)

7.2.4 Minimum Flows and Ramp Rates

The following minimum flows and ramp rates help guide project operations to meet various purposes, including power production. Minimum flows and ramp rates were identified in the 2000 USFWS BiOp for Hungry Horse Dam to protect resident fish and their food organisms in the Flathead River.

There are two minimum flow requirements for Hungry Horse Dam. One is for Columbia Falls on the mainstem Flathead River located just downstream from the confluence of the South Fork with the mainstem. This flow requirement generally governs Hungry Horse outflows during the fall and winter. The second minimum flow requirement is for the South Fork Flathead River just below Hungry Horse Dam. This minimum flow typically comes into play during refill of the project in spring when the minimum flows at Columbia Falls are met by the North and Middle Fork flows. The minimum outflow for Hungry Horse Dam and the minimum flow for Columbia Falls will be determined monthly based on the Reclamation WSF for the inflows into Hungry Horse for the period April 1 to August 31. Both minimum flows are determined monthly starting with the January forecast, and then set for the remainder of the year based on the March final runoff forecast. Table 5 shows how the minimum flows are calculated[7]. Reclamation Water Supply Forecasts will be provided to the TMT.

Table 5. Minimum Flows at Hungry Horse and Columbia Falls.

April – August inflow forecast (KAF)	Hungry Horse min flow[8] (CFS)	Columbia Falls min flow (CFS)
<1190	400	3,200
1,790 > forecast > 1,190	Interpolate between 400 and 900	Interpolate between 3,200 and 3,500
>1,790	900	3,500

The maximum ramp up and ramp down rates are detailed in Table 6. The daily and hourly ramping rates may be exceeded during flood emergencies to protect health and public safety and in association with power or transmission emergencies (Note: The ramp rates will be followed except when they would cause a unit(s) to operate in a zone that could result in premature wear or failure of the units. In this case the project will utilize a ramp rate, which allows all units to operate outside the rough zone. The AAs will provide additional information to the USFWS describing operations outside the "rough zone."

[7] USFWS BiOp at Section 3.A.1 Page 6

[8] To prevent or minimize flooding on the Flathead River above Flathead Lake, Hungry Horse discharges can be reduced to a minimum flow of 300 cfs when the stage at Columbia Falls exceeds 13 ft.

Table 6. Hungry Horse Dam Ramping Rates.

Daily and Hourly Maximum Ramp Up Rates for Hungry Horse Dam (as measured by daily flows, not daily averages, restricted by hourly rates).		
Flow Range (measured at Columbia Falls)	**Ramp Up Unit (Daily max)**	**Ramp Up Unit (Hourly max)**
3,200 - 6,000 cfs	Limit ramp up 1,800 cfs per day	1,000 cfs/hour
>6,000 - 8,000 cfs	Limit ramp up 1,800 cfs per day	1,000 cfs/hour
>8,000 - 10,000 cfs	Limit ramp up 3,600 cfs per day	1,800 cfs/hour
>10,000 cfs	No limit	1,800 cfs/hour

Daily and Hourly Maximum Ramp Down Rates for Hungry Horse Dam (as measured by daily flows, not daily averages, restricted by hourly rates)		
Flow Range (measured at Columbia Falls)	**Ramp Down Unit (Daily max)**	**Ramp Down Unit (Hourly max)**
3,200 - 6,000 cfs	Limit ramp down to 600 cfs per day	600 cfs/hour
>6,000 - 8,000 cfs	Limit ramp down to 1,000 cfs per day	600 cfs/hour
>8,000 - 12,000 cfs	Limit ramp down to 2,000 cfs per day	1,000 cfs/hour
>12,000 cfs	Limit ramp down to 5,000 cfs per day	1,800 cfs/hour

7.2.5 Spill

Hungry Horse will be operated to avoid spill if practicable. Spill at Hungry Horse is defined as any release through the dam that does not pass through the power plant. Large amounts of spill can cause TDG levels in the South Fork of the Flathead River to exceed the state of Montana's standard of 110%. Empirical data and estimates show that limiting spill to a maximum of 15% of total outflow will help to avoid exceeding the Montana State TDG standard of 110%.

7.3 Albeni Falls Dam

7.3.1 Albeni Falls Dam Fall and Winter Coordination

The AAs, the USFWS, NOAA Fisheries, and IDFG will meet annually (per the 2000 USFWS BiOp and the USFWS letter of September 28, 2007 to the Corps and BPA on "Lake Pend Oreille Winter Lake Elevations."), along with the Kalispel Tribe and other interested parties, to evaluate Lake Pend Oreille female kokanee spawner numbers, the winter climate (precipitation) forecast, spawning and incubation success for threatened lower Columbia River chum salmon the previous winter, and recent history of winter elevations for Lake Pend Oreille (hereafter referred to as the "interagency meeting"). One of the purposes of this meeting is to recommend the winter minimum control elevation (MCE) to ensure winter lake operation addresses the needs of kokanee spawning and hence, threatened bull trout, which feed on kokanee, while also taking into consideration spawning and incubation needs for lower Columbia River chum salmon. A decision support tree has been developed by the parties to evaluate these factors in a stepwise decision process to provide recommendations on minimum winter lake elevations.

Generally, sufficient information is available in September to develop a sound recommendation. TMT members will consider recommendations made at the interagency meeting. If the decision support tree is sensitive to and there is likely volatility in specific parameters (e.g. November through January precipitation outlook) participants in the interagency meeting may elect to defer making a recommendation on the MCE until updated information is available in October and recommend interim operations until such data are available.

TMT members will review recommendations from the interagency meeting and develop a recommendation for the proposed Lake Pend Oreille fall and winter operations to the Action Agencies for final decision.

7.3.2 Flood Control Draft

Albeni Falls Dam will be operated during the winter season using standard flood control criteria.

7.3.3 Refill

During the spring, Albeni Falls Dam will be operated to fill Lake Pend Oreille in accordance with standard flood control criteria. The AAs will operate Albeni Falls Dam to meet the flow objectives and refill by approximately June 30.

7.3.4 Summer Operations

During the summer, Albeni Falls Dam will be operated to maintain Lake Pend Oreille elevation at Hope, Idaho, between elevation 2,062 ft. and 2,062.5 ft. The annual fall drawdown to the winter minimum control elevation begins soon after Labor Day.

7.4 Libby Dam

7.4.1 Libby Dam General Operations

Libby Dam flows will be regulated consistent with existing treaties, Libby Project authorization for public safety, other laws, and the 1938 International Joint Commission order on Kootenay Lake to achieve water volumes, water velocities, water depths, and water temperature at a time to maximize the probability of allowing significant sturgeon recruitment and to provide a year-round thermograph that approximates normative conditions, while also meeting flood damage reduction objectives. The year-round project minimum outflow is 4.0 kcfs.

7.4.1.1Coordination

The AAs will continue to coordinate Libby Dam BiOp operations at TMT.

7.4.1.2Burbot

Providing low temperatures, if possible, from Libby Dam to aid upstream migration of burbot to spawning areas in the Kootenai River in Idaho will occur each winter. These low temperatures may be called for over an extended period from October through February. Specific details of this operation for the current year will be developed and will be included in the fall/winter update. An interagency Memorandum of Agreement for this species was completed in June 2005. Use of VARQ flood control procedure and implementation of the variable end-of-December flood control target elevation may aid this operation in years with below average runoff forecasts.

7.4.1.3Ramp Rates and Daily Shaping

The purpose of the following actions is to provide better conditions for resident fish by limiting the flow fluctuations and setting minimum flow levels. In addition, ramping rates protect varial zone productivity by emulating a normative hydrograph. These ramp rates for Libby Dam were proposed in the BA supplement to minimize impacts to bull trout and are included in the USFWS 2006 BiOp. The following ramp rates will guide project operations to meet various purposes, including power production.

Table 8. Prescribed maximum ramp rates to protect resident fish and prey organisms in the Kootenai River in addition to minimizing levee erosion along the river. Rate of change may be less than stated limits.

		Summer (05/01 - 09/31)	
		Hourly	Daily
Ramp Up	4-6 kcfs	2500 cfs	1 unit
	6-9 kcfs	2500 cfs	1 unit
	9-16 kcfs	2500 cfs	2 units
	16-QPHC	5000 cfs	2 units
Ramp Down	4-6 kcfs	500 cfs	500 cfs
	6-9 kcfs	500 cfs	1000 cfs
	9-16 kcfs	1000 cfs	2000 cfs
	16-QPHC	3500 cfs	1 unit
		Winter (10/01 - 04/30)	
		Hourly	Daily
Ramp Up	4-6 kcfs	2000 cfs	1 unit
	6-9 kcfs	2000 cfs	1 unit
	9-16 kcfs	3500 cfs	2 units
	16-QPHC	7000 cfs	2 units
Ramp Down	4-6 kcfs	500 cfs	1000 cfs
	6-9 kcfs	500 cfs	2500 cfs
	9-16 kcfs	1000 cfs	1 unit
	16-QPHC	3500 cfs	1 unit

(USFWS 2006 BiOp at Description of the proposed action, page 7, Table 1.)

Daily and hourly ramping rates may be exceeded during flood emergencies to protect health and public safety and in association with power or transmission emergencies. Variances to these ramping rates during years when water supply forecasting errors overestimate actual runoff, or variances are necessary to provide augmentation water for other listed species or other purposes, will be coordinated through the TMT process. This is expected in only the lowest 20th percentile water years (Note: At the project, the ramp rates will be followed except when they would cause a unit(s) to operate in the rough zone, a zone of chaotic flow in which all parts of a unit are subject to increased vibration and cavitation that could result in premature wear or failure of the units. In this case the project will utilize a ramp rate which allows all units to operate outside the rough zone).

7.4.2 Flood Control

The Corps will continue to use its forecast procedure in December to determine the December 31 flood control elevation. In water years where the forecast for the period April through August is less than 5,900 KAF based on the Corps' forecast procedures, the end-of-December draft elevation will be higher than 2,411 ft. If the early forecast for

April-August is 5,500 KAF or less, the end-of-December target elevation would be 2,426.7 ft. The end-of-December elevation is a sliding scale between elevation 2,426.7 ft. and 2,411 ft. when the forecast is between 5,500 and 5,900 KAF.

Libby Dam will be operated during January through March to the VARQ flood control storage reservation diagram (SRD). During the refill period from about April through June, Libby Dam will release flow in accordance with VARQ Flood Control Operating Procedures at Libby Dam. Refill at Libby Dam will begin 10 days prior to when the forecasted unregulated flow at The Dalles is expected to exceed the ICF. Once refill begins, Libby Dam outflow will be no lower than the computed VARQ flow (or inflow, if that is lower than the VARQ flow), unless otherwise allowed by the VARQ Operating Procedures. For example, changes to reduce the VARQ flow can occur to protect human life and safety, during the final stages of refill, or through a deviation request.

The VARQ flow will be recalculated with each new Corps water supply forecast and outflows will be adjusted accordingly. If the VARQ operating procedures require discharges above powerhouse capacity, spill from Libby Dam may occur. The intent is to adjust Libby Dam discharge to maximize reservoir refill probability and minimize the potential for spill.

7.4.3 Spring Operations

The purpose of the following actions is to refill Libby Dam in order to provide the flow for Kootenai River white sturgeon, bull trout ramping rates, and anadromous fish flow augmentation water. Libby Dam will provide flows for sturgeon, bull trout, and salmon during spring; for salmon and bull trout during summer, and for bull trout and resident fish in September while attempting to minimize a double peak or large flow fluctuations in the June – September period. After adhering to the VARQ flood control guidance and providing salmon flow augmentation and the sturgeon flow operation, Libby Dam refill may happen by July 31. During the spring, the AAs will operate Libby Dam to meet its flow and refill objectives. If both these objectives cannot be achieved, VARQ and sturgeon flow operations are a higher priority over summer refill.

When not operating to minimum flows, the project will be operated to achieve a 75% chance of reaching the April 10 elevation objective (the exact date to be determined during in-season management) to increase flows for spring flow management.

7.4.3.1Bull Trout

From May 15 to June 30 and during the month of September, a minimum flow of 6,000 cfs will be provided and minimum flows of 4,000 cfs will be provided for the rest of the year. Volume to sustain the basal flow of 6,000 cfs from May 15 through May 31 will be accounted for with sturgeon volumes, and in the fall should be drawn from the autumn flood control draft.

Per the USFWS 2006 BiOp, the tiered bull trout minimum flow will be provided from 1 July through 31 August and the period between sturgeon and salmon flow augmentation beginning in September. The bull trout minimum flow may be from 6,000 cfs to 9,000 cfs. Table 7 shows how to determine the bull trout minimum flow during this period.

Table 7. Minimum bull trout releases from Libby Dam July 1 through 31 August, based on the May final Libby water supply forecast for the April-August period (May 15 – June 30 and all of September the minimum is 6 kcfs).

Forecast runoff Volume (MAF*) at Libby	Min bull trout flows between sturgeon and salmon flows
0.00 < forecast < 4.80	6 kcfs
4.80 < forecast < 6.00	7 kcfs
6.00 < forecast < 6.70	8 kcfs
6.70 < forecast < 8.10	9 kcfs
8.10 < forecast < 8.90	9 kcfs
8.90 < forecast	9 kcfs

**MAF = million acre-feet*

7.4.3.2Sturgeon Operation

The purpose of the actions below is to provide water for sturgeon spawning and egg incubation. Libby Dam will provide the tiered volume for sturgeon flows as described in the USFWS 2006 BiOp, the Clarified 2008 RPA from USFWS and as summarized in Figure 2. The outflow during sturgeon augmentation period will be equal to or greater than the VARQ flow. The release operation will be developed prior to commencement of the sturgeon tiered flow release. Water temperature profiles will be monitored near the dam starting in April and continue through July to provide information necessary for timing of sturgeon spawning/rearing flow augmentation. Also, water temperature profiles in the forebay are used to determine when warmer temperatures may be provided to assist sturgeon spawning. Reservoir temperature data collection is occurring and is intended to allow better planning for temperature management of water releases.

This sturgeon water will be in addition to needs for listed bull trout, salmon, and will be measured above the 4,000 cfs minimum releases from Libby Dam. Accounting for these total tiered volumes will begin when the USFWS determines benefits to conservation of sturgeon are most likely to occur or when additional flow is needed to sustain basal flow of 6,000 cfs from May 15 through May 31. Sturgeon flows will generally be initiated between mid-May and the end of June to augment lower basin runoff entering the Kootenai River below Libby Dam, consistent with the current version of the Kootenai River Ecosystem Function Restoration Flow Plan Implementation Protocol and USFWS 2006 BiOp and applicable clarifications.

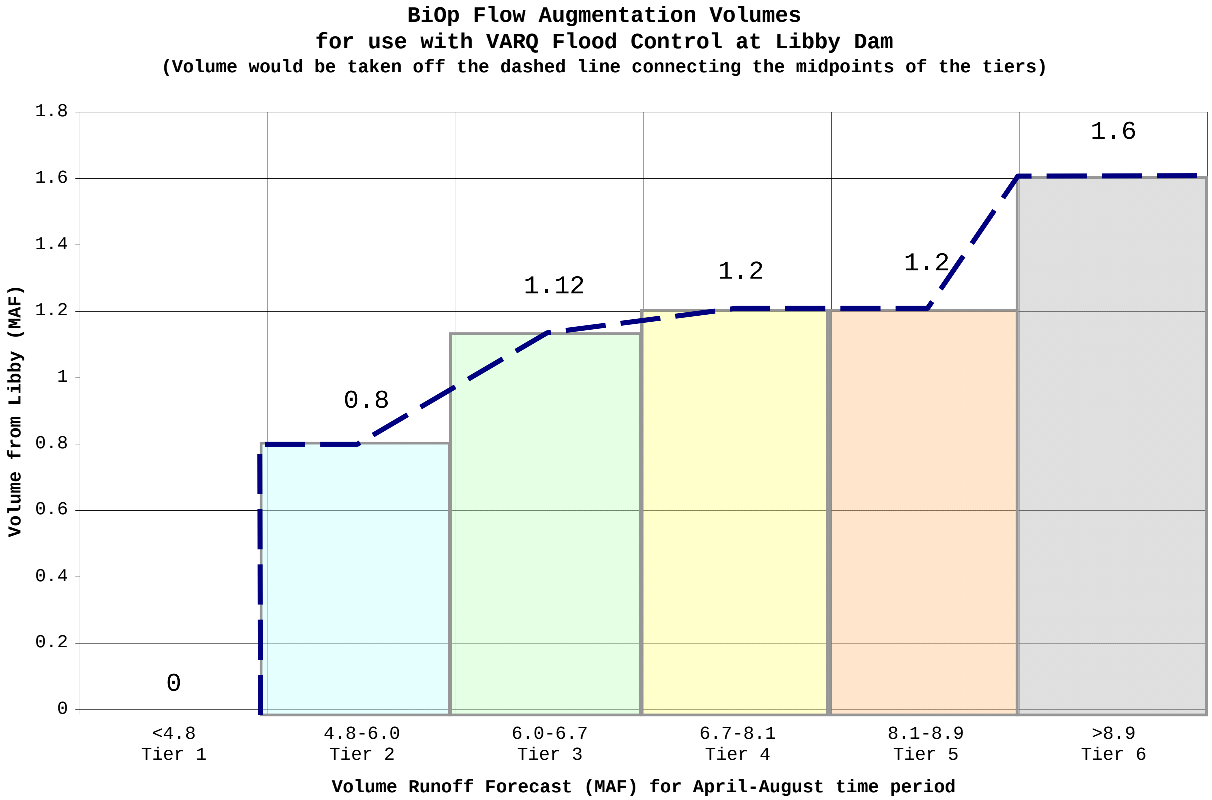


Figure 2. "Tiered" volumes of water for sturgeon flow enhancement to be released from Libby Dam according to the Libby May final forecast of April - August volume. Actual flow releases would be shaped according to seasonal requests from the USFWS and in-season management of water actually available.

7.4.3.3Spill

The 2006 USFWS Clarified RPA, calls for the Corps to perform a spill operation, if conditions permit (e.g if a tier 1 year, this operation would not take place), in conjunction with the sturgeon pulse in 2011 taking into account other operational requirements. Spill that induces TDG in excess of 110% is not to exceed 7 days, water temperatures are to be maintained at or above 8° C, and spill will range between 5,000 cfs and 10,000 cfs. TDG shall never exceed 123%.

The spill will occur sometime between late May and late June, depending on water supply forecast, runoff projections, water temperature and reservoir elevation. The Corps will coordinate the timing and other details with the State of Montana, the USFWS, the Kootenai Tribe of Idaho, BPA, and other regional interests, assuring that conditions remain safe during the spill.

Otherwise, the Corps is to limit voluntary spill to avoid exceeding Montana State TDG standard of 110%, when possible, and in a manner consistent with the AAs' responsibilities for ESA-listed resident fish and settlement agreement.

7.4.3.4Post Sturgeon Operation

After the sturgeon operation flows will be set to try and refill by July 31, if possible, while trying to minimize double peak. Summer operations will be coordinated through TMT in-season management. A double peak is assumed to be a flow increase and decrease of more than 5,000 cfs within one month. Libby Dam releases will follow ramp rates in the 2006 USFWS BiOp.

7.4.4 Summer Operations

During the summer, the AAs draft Libby Dam within the NMFS 2010 Supplemental BiOp and USFWS BiOp's specified draft limits based on flow recommendations provided by TMT. TMT considers a number of factors when developing its flow recommendations, such as: the impact of flow fluctuations on bull trout and other resident fish below the project, the status of juvenile salmon outmigration in the lower Columbia, attainment of flow objectives, water quality, and the effects that reservoir operations will have on other listed and resident fish populations.

During the summer (July and August), the AAs will operate Libby Dam to help meet the flow objectives for juvenile salmon out-migration in the Columbia River. The summer reservoir draft limit is 10 ft. from full by the end of September (except in lowest 20th percentile[9] water years (The Dalles April-August <71.8 maf), when draft will increase to 20 ft. from full by end of September). If the project fails to refill, then release inflows or operate to meet minimum bull trout flows through the summer months. Rationale for the experimental draft was adopted by the Northwest Power and Conservation Council (Council) and further details of the evaluation can be found in the FCRPS 2008 Biological Opinion from NMFS (Appendix B.2.1).

Arrangements for retention of July-September water in Lake Koocanusa are possible under a Libby-Canadian storage water exchange under the current Libby Coordination Agreement, which was signed February 16, 2000. However, this operation cannot be guaranteed in any given year because it must be mutually beneficial to the Canadian Entity and the U.S. Entity. Information needed for such a determination such as the volume of the water year, is not available until well into the migration season. This operation, if any, for a given water year is generally not finalized until June or July of that year. The exchange agreement reduces the draft of Lake Koocanusa and provides an equivalent amount of water from Canada.

For September, the Corps will use the best available forecast at the end of August to set a flow that will draft the remaining volume out of Libby. If this flow is greater than the bull trout minimum of 6 kcfs the discharge will be maintained until the draft target is met or the month ends, whichever comes first. Operating to this flow is consistent with Columbia River flow augmentation per the BiOp and a desire for stable flows immediately downstream of Libby.

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[9] The lowest 20th percentile as measured at The Dalles (RPA 4 in RPA Table, pg 6 of 98) based on RFC's statistical period, currently 1971-2000, using May final for The Dalles Apr-Aug (RPA 14 in RPA table, pg 15 of 98)

7.5 Grand Coulee Dam

Grand Coulee Dam is operated for multiple purposes including fish and wildlife, flood control, irrigation, power, and recreation. Specific operations for flow management to aid anadromous and resident fish are listed in the following sections.

7.5.1 Winter/Spring Operations

Grand Coulee will be operated for flood control from January through April using the NWRFC's forecast for unregulated runoff at The Dalles (adjusted for available storage capacity upstream of The Dalles other than at Grand Coulee Dam) and Grand Coulee's Flood Control SRD. Grand Coulee is also operated during this period to support chum operations (described in detail in Section 7.4) and to maintain an 85% probability of reaching the April 10 elevation objective.

The April 10 elevation objective purpose is to provide more water for spring flows and is achieved by operating between the URC as an upper elevation limit and the VDL as a lower elevation limit for the reservoir from January through March. A description of VDL is provided in Section 7.5.

Reclamation computes Grand Coulee Dam's April 10 elevation objective by linear interpolation between the March 31 and April 15 forecasted flood control elevations based on the NWRFC March Final April-August WSF at The Dalles. The March forecast is chosen for the calculation of the April 10 elevation objective in order to allow enough time to react and to plan Grand Coulee operations accordingly. The April final forecast is not released until the 5th business day of the month, after which the Corps calculates flood control elevations. This usually means that final April 15 and April 30 flood control elevations are not released until around April 8 at the earliest. It is notable that even modest changes in The Dalles water supply forecast can produce significant changes in the forecasted flood control elevations for Grand Coulee. In order to achieve final April flood control targets, actual Grand Coulee elevations on April 10 may be slightly below or above the April 10 objective depending on draft rates and water supply conditions. Grand Coulee operations will be discussed and coordinated at TMT.

Opportunities to shift system flood control requirements from Brownlee and Dworshak to Grand Coulee will also be considered. See section 4.5 on Flood Control Shifts for more details. The deepest reservoir draft typically occurs around April 30. Refill at Grand Coulee normally begins approximately one day prior to when streamflow forecasts of unregulated flow is projected to exceed the ICF at The Dalles, Oregon.

During the spring, the AAs will operate the FCRPS to help meet the flow objectives and to refill the projects. If both of these objectives cannot be achieved, the TMT will make an in-season recommendation, weighing considerations unique to each particular year and project.

7.5.2 Summer Operations

Grand Coulee will operate to refill by about June 30 to provide summer flow augmentation, except as specifically provided by the TMT. Grand Coulee will be operated during the summer (July and August) to help meet the flow objectives for juvenile salmon out-migration. Grand Coulee will be drafted to a minimum elevation of either 1,280 ft. or 1,278 ft. by the end of August depending on the July Final forecast for April through August runoff produced by the NWRFC. If the July Final April through August forecast for The Dalles is equal to or greater than 92 MAF then Lake Roosevelt's draft limit will be 1,280 ft. If the forecast is less than 92 MAF, the draft limit will be 1,278 ft. These draft limits will be modified to implement the Lake Roosevelt Incremental Storage Release Project (see Section 6.5.6).

7.5.3 Banks Lake Summer Operation

Normally Banks Lake is drafted to elevation 1,565 feet (5 feet from full) by the end of August as part of the Action agencies summer flow augmentation program. In 2011 Banks Lake may be drafted deeper than elevation 1565 by the end of August. Required maintenance activities in the fall and winter on the Main Canal Outlet Structure and on the Feeder Canal near North Dam will require it to be drafted down nearly 30 feet by the end of October. In order to accomplish the desired elevation, pumping into Banks Lake will most likely end in July and irrigation withdrawals or generation back through the pump generators will drawdown the lake. As a result Banks Lake may be as much as 10-15 feet from full by August 31. After the maintenance activities have been completed, refilling of Banks Lake will begin in the late winter to early spring of 2012. More discussion of this maintenance activity is provided in the FCRPS BA (Appendix B, page B.1-4-8).

7.5.4 Project Maintenance

Drum gate maintenance is planned to occur during April and May annually. The reservoir must be at or below elevation 1,255 ft. to accomplish this work. Typically the flood control elevations during this time of year provide the required elevations and sufficient time to accomplish this work. However, during dry years flood control operations will not draft Lake Roosevelt low enough for a long enough period of time to perform necessary maintenance on the drum gates. Drum gate maintenance may be deferred in some dry water years; however drum gate maintenance must occur at a minimum one time in a 3-year period, two times in a 5-year period, and three times in a 7-year period. The drum gates are extremely important dam safety features and must be maintained at a satisfactory level. Drum gate maintenance was deferred in 2009 and 2010 because of low water supply forecasts and high flood control elevations. Since maintenance has been deferred the last 2 years, drum gate maintenance will be performed in the spring of 2011 regardless of water supply conditions. Lake Roosevelt will be at or below elevation 1255 feet for a minimum of 8 weeks during the spring of 2011 in order to accomplish the necessary maintenance. Reclamation will coordinate this operation with TMT.

7.5.5 Kokanee

Every attempt is made to refill Lake Roosevelt to 1,283 ft. by September 30 (coordination with tribe will determine actual date) and maintain an elevation 1,283 to 1,285 ft. or greater through the middle of November to aide in kokanee brood stock collection, improve spawning access to tributaries, and to increase retention time during a critical period for zooplankton production.

7.5.6 The Lake Roosevelt Incremental Storage Release Project

The Lake Roosevelt Incremental Storage Release Project will not reduce flows during the salmon flow objective period (April to August). This project provides that Lake Roosevelt will be drafted by an additional 1.0 ft. in non-drought years and by about 1.8 ft. in drought years by the end of August. A third of this water will go to in-stream flows. A more detailed description of this item is provided in Section 7.6 and in the FCRPS BA (Appendix B.2.1, pages 5-9).

7.5.7 Chum Flows

Grand Coulee may be used to help meet tailwater elevations below Bonneville Dam to support chum spawning and incubation. The chum operation is described in more detail in Section 7.4.

7.5.8 Priest Rapids Flow Objective

Grand Coulee will be operated to help meet Priest Rapids weekly flow objective to support fall Chinook salmon spawning and incubation.

7.5.9 Spill

Involuntary spill at Grand Coulee Dam will be managed in coordination with Chief Joseph Dam; see Sec. 6.5. Grand Coulee will be operated to minimize TDG production.

7.6 Chief Joseph Dam

Construction of spillway flow deflectors at Chief Joseph Dam was completed in October 2008. A spill test was conducted in April 2009 to characterize the performance of the flow deflectors in reducing TDG production. Spill amount and spill pattern configuration were varied during the test associated TDG levels were measured and recorded. A final report on the test results is expected in late 2010. Information from the report will aid in developing a spill swap plan between Chief Joseph and Grand Coulee dams to help minimize TDG production and reduce the TDG burden that carries downstream through the system.

7.7 Priest Rapids Dam

7.7.1 Spring Operations

The spring flow objective at Priest Rapids Dam is 135 kcfs from April 10 to June 30. There is no summer flow objective for Priest Rapids Dam.

7.7.2 Hanford Reach Protection Flows

Grant County PUD manages the discharge from Priest Rapids Dam at the following intervals during the year to provide protection for the spawning, incubation and rearing of fall Chinook salmon.

- October-November, reverse loading (low flows during daylight hours, spill excess at night) to reduce the formation of redds at high river elevations on Vernita Bar
- November-May, maintain "Critical Elevation" in the Hanford Reach (minimum flow restriction to prevent dewatering of redds)
- March-June, reduce daily flow fluctuations to decrease mortality to juvenile fall Chinook from stranding and entrapment

7.8 Dworshak Dam

7.8.1 Spring Operations

The purpose of the spring flow augmentation, is to maintain a 95% probability of refilling Dworshak while also maximizing the releases of stored water from Dworshak reservoir in order to maximize the chance of meeting the Lower Snake spring flow objective and aid out-migrating salmon and steelhead. During the spring, the AAs will operate Dworshak Dam to improve the probability of meeting the flow and refill objectives, refilling by about June 30. The reservoir is deemed to be at “full” at elevations of 1,599 ft. or above. If both these objectives cannot be achieved, the TMT will make an in-season recommendation, weighing considerations unique to each particular year and project.

7.8.2 Flow Increase for Dworshak National Fish Hatchery Release.

Project will release 4-6 kcfs from Dworshak, if necessary, in order to move juvenile fish into the mainstem Clearwater River during the spring hatchery releases. Note: not in NMFS 2010 Supplemental BiOp.

7.8.3 Summer Operations

Summer flow augmentation is provided from Dworshak to increase listed fish survival by improving water quality (moderating river temperatures), and increasing water velocities in the lower Snake River.

The summer temperature moderation and flow augmentation releases from Dworshak will be shaped with the intent to maintain water temperatures at the Lower Granite tailrace fixed monitoring site at or below 68º F. The Corps maintains and operates a water quality analysis model (CEQUAL-W2), which is used in-season to forecast water temperatures and inform Dworshak release decisions. The model extends from Dworshak (Clearwater River) and Hells Canyon (Snake River) dams downstream through Ice Harbor Dam. Dworshak releases generally are sufficient to provide effective temperature management in the Lower Granite tailrace but can be overwhelmed by extremely hot weather or high discharges of warm water from Hells Canyon Dam.

During the summer, the AAs draft Dworshak within the NMFS 2010 Supplemental BiOp's specified draft limits based on flow recommendations provided by TMT. TMT considers a number of factors when developing its flow recommendations, such as: the status of the migration, attainment of flow objectives, water quality, and the effects that reservoir operations will have on other listed and resident fish populations.

During the summer (July and August) the AAs will operate Dworshak to help meet flow/temperature objectives. The AAs plan to draft Dworshak to 1,535 ft. by August 31 and draft to approximately 1,520 ft. in September. The extension of the draft limit into September assures that water will be released consistent with the Snake River Basin Adjudication Agreement (SRBA). Releases under the SRBA will be determined in the annual plan prepared by the Corps, NOAA, Nez Perce, and BPA and presented to TMT for implementation.

The maximum project discharge for salmon flow augmentation is limited to releases generating Total Dissolved Gas (TDG) within state of Idaho and Nez Perce Tribal water quality standards calling for of no greater than 110% TDG.

7.8.4 Fall/Winter Operations

After summer fish operations are completed (including the Nez Perce (SRBA) operations in September), flows from Dworshak will be limited to minimum discharge (one small turbine operating above the cavitation zone and within 110% TDG, approximately 1,600 cfs) unless higher flows are required for flood control, emergencies, or other project uses. The purpose of these actions is to manage the filling of Dworshak reservoir while operating the project for multiple uses. Flows from Dworshak also may be maintained above minimum flow if Corps analysis determines there is flexibility to release a volume of water above minimum flow and still maintain a high reliability of meeting spring refill objectives.

Dworshak will provide minimum flows, while not exceeding the Idaho State TDG water quality standard of 110%.

Opportunities to shift system flood control requirements from Brownlee and Dworshak to Grand Coulee will be considered periodically between January 31 and April 15. See section 4.5 on Flood Control Shifts for more details.

7.9 Brownlee

Opportunities to shift system flood control requirements from Brownlee to Grand Coulee will be considered. See section 4.5 on Flood Control Shifts for more details. The shifts could occur between January 31 and April 15. The reservoirs need to be back to their specific URC by April 30. The purpose of this shift is to allow Brownlee to be at higher elevations to increase the probability for increased spring flows in the Snake River. These shifts may be implemented after coordination with TMT. The shifts typically occur in drier years when they will not compromise flood control.

7.10 Lower Granite Dam

7.10.1 Reservoir Operations

Lower Granite will operate within 1 ft. of Minimum Operating Pool (MOP) from approximately April 3 until small numbers of juvenile migrants are present (approximately September 1) unless adjusted to meet authorized project purposes, primarily navigation. TMT will provide a recommendation. The purpose of this action is to provide a smaller reservoir cross section to reduce juvenile salmon travel time and reduce flow fluctuations. Elevations may be modified to maintain the minimum navigation channel requirements. The purpose of this action is to provide a smaller reservoir cross section, believed to reduce juvenile salmon travel time, and reduce flow fluctuations.

7.10.2 Turbine Operations

To enhance juvenile passage survival, turbines at Lower Granite will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.10.3 Spring Flow Objectives

The April final runoff volume forecast at Lower Granite Dam for April to July determines the spring flow objective at Lower Granite Dam. When the forecast is less than 16 million acre-feet (MAF), the flow objective will be 85 kcfs. If the forecast is between 16 and 20 MAF, the flow objective will be linearly interpolated between 85 and 100 kcfs. If the forecast is greater than 20 MAF, the flow objective will be 100 kcfs. The planning dates for the spring flow objective are from April 3 to June 20. These flow objectives are provided as a biological guideline and will likely not be met through the entire migration season in all years because the flow in the Snake River primarily depends on the volume and shape of the natural runoff. Flow in the Snake River during this period is supported by drafting Dworshak Dam and flow augmentation water from the Upper Snake River. Dworshak storage is released from the April 10 elevation to the April 30 flood control elevation at a rate that does not exceed the State TDG water quality standards (110 % TDG) at the project.

7.10.4 Summer flow objectives

The June final runoff volume forecast at Lower Granite Dam for April to July determines the summer flow objective at Lower Granite Dam. When the forecast is less than 16 MAF, the flow objective will be 50 kcfs. If the forecast is between 16 and 28 MAF, the flow objective will be linearly interpolated between 50 and 55 kcfs. If the forecast is greater than 28 MAF, the flow objective will be 55 kcfs. The planning dates for the summer flow objective are from June 21 to August 31. Summer flow objectives are provided as a biological guideline. Flow in the Snake River is supported by the summer draft, though tends to follow the natural hydrograph.

7.10.5 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.10.6 Juvenile Fish Transport Operations

Transport operations are defined in appendices B and E of the 2011 FPP.

7.11 Little Goose Dam

7.11.1 Reservoir Operations

Little Goose will operate within 1 ft. of MOP from approximately April 3 until small numbers of juvenile migrants are present (approximately September 1) unless adjusted to meet authorized project purposes, primarily navigation. This normally occurs in late August. The purpose of this action is to provide a smaller reservoir cross section to reduce juvenile salmon travel time and reduce flow fluctuations. Elevations may be modified to maintain the minimum navigation channel requirements. The navigation lock tailwater gage at Lower Granite Dam will be used to ensure minimum navigation channel requirements are met. The purpose of this action is to provide a smaller reservoir cross section, believed to reduce juvenile salmon travel time, and reduce flow fluctuations.

7.11.2 Turbine Operations

To enhance juvenile passage survival, turbines at Little Goose will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

Additionally, during the juvenile migration season, the lower operating limit of unit 1 will be manually re-set as indicated in Table 9.

Table 9. Operating limits for Little Goose turbine unit 1 during the 2011 spill season.

Lower Limit	Upper Limit	Condition
115 MW (~16,000 cfs)*	Varies w/Head	With extended-length submersible bar screens installed
125 MW (~17,500 cfs)*	Varies w/Head	Without extended-length submersible bar screens installed

* Discharges are approximate.

Unit operation control within the Generic Data Acquisition and Control System (GDACS) program tends to balance flows across available operating units. This alternative preferred operation will at times; result in an unbalanced operation where more flow is passing through unit 1 than other available operating units. A greater flow through unit 1 has been shown in the Little Goose general physical model to be very effective in disrupting an eddy that tends to form downstream of the powerhouse along the south shore. Disrupting the eddy optimizes the tailrace conditions for both adult passage and juvenile egress with the temporary spillway weir operating in spillbay 1.

7.11.3 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.11.4 Juvenile Fish Transport Operations

Transport operations are defined in appendices B and E of the 2011 FPP.

7.11.5 Waterfowl Hunting Enhancement

In order to enhance waterfowl hunting, the Little Goose pool is held constant several times a week from October to January.

7.12 Lower Monumental Dam

7.12.1 Reservoir Operations

Lower Monumental will operate within 1 ft. of MOP from approximately April 3 until small numbers of juvenile migrants are present (approximately September 1) unless adjusted to meet authorized project purposes, primarily navigation. The purpose of this action is to provide a smaller reservoir cross section to reduce juvenile salmon travel time and reduce flow fluctuations. Elevations may be modified to maintain the minimum navigation channel requirements. The purpose of this action is to provide a smaller reservoir cross section, believed to reduce juvenile salmon travel time, and reduce flow fluctuations.

7.12.2 Turbine Operations

To enhance juvenile passage survival, turbines at Lower Monumental will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.12.3 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.12.4 Juvenile Fish Transport Operations

Transport operations are defined in appendices B and E of the 2011 FPP.

7.13 Ice Harbor Dam

7.13.1 Reservoir Operations

Ice Harbor will operate within 1 ft. of MOP from approximately April 3 until small numbers of juvenile migrants are present (approximately September 1) unless adjusted to meet authorized project purposes, primarily navigation or if alternative reservoir operations are recommended and adopted as part of the Ice Harbor Dam Configuration and Operation Plan. The purpose of this action is to provide a smaller reservoir cross section to reduce juvenile salmon travel time and reduce flow fluctuations. The purpose of this action is to provide a smaller reservoir cross section, believed to reduce juvenile salmon travel time, and reduce flow fluctuations.

7.13.2 Turbine Operations

To enhance juvenile passage survival, turbines at Ice Harbor will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.13.3 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.13.4 Waterfowl Hunting Enhancement

In order to enhance waterfowl hunting, the Ice Harbor pool is held constant several times a week from October to January.

7.14 McNary

7.14.1 Turbine Operations

To enhance juvenile passage survival, turbines at McNary projects will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.14.2 Spring Flow Objectives

The spring flow objective at McNary Dam is set according to the April final runoff volume forecast at The Dalles Dam for April to August. When the forecast is less than 80 MAF the flow objective will be 220 kcfs. If the forecast is between 80 MAF and 92 MAF the flow objective will be linearly interpolated between 220 kcfs and 260 kcfs. If the forecast is greater than 92 MAF the flow objective will be 260 kcfs. The planning dates for the spring flow objective will be from April 10 to June 30. The flow objective is provided as a biological guideline and will not be met through the migration season in all years due to variability in volume and shape of the natural runoff.

7.14.3 Summer Flow Objectives

The summer flow objective at McNary Dam is 200 kcfs. The planning dates for the summer flow objective will be from July 1 to August 31. The flow in the summer at McNary is supported by various flow augmentation measures. There is a limited amount of water available for flow augmentation and summer flow objectives are provided as a biological guideline.

7.14.4 Weekend Flows

Weekend flows are often lower than weekday flows due to less electrical demand in the region. During the spring and summer migration period (April through August), the AAs will strive to maintain McNary flows during the weekend at a level which is at least 80% of the previous weekday average.

7.14.5 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.14.6 Waterfowl Nesting

To improve waterfowl nesting conditions in the McNary pool between March and May each year, the pool is operated in the top 1 ft. of the pool range for several hours every 4 days.

7.14.7 Waterfowl Hunting Enhancement

In order to enhance Waterfowl hunting, the McNary pool is held constant several times a week from October to January.

7.14.8 Juvenile Fish Transport Operations

Transport operations are defined in appendices B and E of the 2011 FPP.

7.14.9 Maintenance

Significant powerhouse outages will occur daily in August with the possibility of extending into September to allow for the construction of a section of new transmission line at the McNary substation. The exact details of this outage have been coordinated in the FPOM forum and included into the 2011 FPP. The outage will occur daily in August with potential to continue into September if flows or temperatures are too high requiring the work period to be extended.

7.15 John Day Dam

7.15.1 Navigation Lock Replacement

During December 2010 until February 2011, the John Day downstream navigation lock is scheduled for replacement. For a very limited time period, operations will require specified tailwater requirements at John Day that could, in turn, challenge system operations to meet chum tailwater limits below Bonneville Dam. To provide the appropriate flow for chum, and the requested John Day tailwater, The Dalles forebay would have to be operated as close to full as possible. Any unexpected, unplanned, system perturbations such as power or transmission issues, hydrologic or model forecast error, or other special operations coinciding with the lifts, could result in deviating from the preferred chum tailwater range below Bonneville.

7.15.2 Reservoir Operations

John Day pool will operate within a 1.5 ft. range of the minimum level that provides irrigation pumping from April 10 to September 30. The purpose of this action is to provide a smaller reservoir cross section to reduce juvenile salmon travel time.

7.15.3 Turbine Operations

To enhance juvenile passage survival, turbines at all the Lower Columbia projects will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.15.4 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.15.5 Goose Nesting

To encourage geese to nest in areas that are not typically inundated by frequent fluctuations in the John Day pool between March and May each year, the reservoir is operated in the top 1 ft. of the range for several hours every 4 days.

7.15.6 Tribal Fishing

To accommodate tribal fishing, the John Day pool may operate within a 1.5 ft. operation range during tribal fishing seasons.

7.16 The Dalles Dam

7.16.1 Turbine Operations

To enhance juvenile passage survival, turbines at all the Lower Columbia projects will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.16.2 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.17 Bonneville Dam

7.17.1 Turbine Operations

To enhance juvenile passage survival, turbines at all the Lower Columbia projects will be operated within 1% of peak efficiency during the juvenile and adult migration seasons (April 1 through October 31; see appendix C of the 2011 FPP).

7.17.2 Spill Operations

Spill operations for fish passage are defined in appendix E of the 2011 FPP.

7.17.3 Chum Operation

See section 7.4 for a detailed discussion on the chum operation.

7.17.4 Tribal Fishing

To accommodate tribal fishing, the Bonneville pool is normally held between elevation 75.0 and 76.5 ft. during tribal fishing times. Often the pool is held to a 1.5 ft. range.

7.17.5 Spring Creek Hatchery Release

Bonneville Dam turbine operations (i.e. reduced turbine loading) for the April and May releases of tule fall Chinook from the Spring Creek National Fish Hatchery will be determined at a later date with discussions at the TMT.

8 Specific Operations

8.1 Spill operations general

8.1.1 TDG Criteria

The Corps will continue to manage spring and summer spill for fish passage to the state of Oregon and Washington's TDG water quality criteria with all applicable waivers and exemptions. These levels are referred to as gas caps. The project maximum flow rate or spill discharge level that meets but does not exceed the gas cap, is referred to as the TDG spill cap. The gas caps are constant, whereas, spill caps may vary daily depending on flow, temperature, and other environmental conditions.

8.1.2 Adjustments to Spill

The TDG level is managed daily in response to changing conditions and adjustments in spill for fish passage will be made to manage the operation consistent with the states' TDG water quality criterion. Power system and other project emergencies, including unplanned/unanticipated facility maintenance or outages, may necessitate temporary adjustments in accordance with established protocols. A more detailed description of spill management operations are outlined in Appendix 4.

Power system and other project emergencies, including unplanned/unanticipated facility maintenance or outages, may necessitate temporary spill adjustments in accordance with established protocols.

The spill rates represented above assume average runoff conditions; however, actual conditions may require adjustments to these spill rates. Actual spill rates may increase above the specified rates resulting in instances where the TDG levels exceed water quality criterion. The Corps tracks these TDG instances and defines the instance types and attributes as summarized below in the following table.

Table 10: Type of TDG Instances

Types of Instance	
Type 1 Condition	**TDG levels exceed the TDG standard due to exceeding powerhouse capacity at run-of-river projects resulting in spill above the BiOp fish spill levels. This condition type includes:**
• High runoff flows and flood control efforts.	
• BPA load requirements are lower than actual powerhouse capacity.	
• Involuntary spill at Mid Columbia River dams resulting in high TDG levels entering the lower Columbia River.	
• Involuntary spill at Snake River dams resulting in high TDG levels entering the lower Columbia River.	
Type 1a Condition	**Planned and unplanned outages of hydro power equipment including generation unit, intertie line, or powerhouse outages.**
Type 2 Exceedance	**TDG exceedances due to the operation or mechanical failure of non-generating equipment. This exceedance type includes:**
• Flow deflectors unable to function for TDG abatement with tailwater elevations above 19 - 26 feet at Bonneville Dam.	
• Spill gates stuck in open position or inadvertently left open.	
• Increased spill in a bulk spill operation to pass debris.	
• Communication errors, such as teletype were transmitted but change was not timely made or misinterpretation of intent of teletype by Project operator.	
Type 2a Exceedance	**Malfunctioning FMS gauge, resulting in fewer TDG or temperature measurements when setting TDG spill caps.**
Type 3 Exceedance	**TDG exceedances due to uncertainties when using best professional judgment, SYSTDG model and forecasts. This exceedance type includes:**
• Uncertainties when using best professional judgment to apply the spill guidance criteria, e.g., travel time, degassing, and spill patterns.	
• Uncertainties when using the SYSTDG model to predict the effects of various hydro system operations, temperature, degassing, and travel time.	
• Uncertainties when using forecasts for flows, temperature and wind.	
• Unanticipated sharp rise in water temperature (a 1.5 degree F. or greater change in a day).	
• Bulk spill pattern being used which generated more TDG than expected.	

Spill below the specified rates could occur during low runoff conditions when meeting minimum generation levels at a project requires reducing spill rates. This would most likely occur in late July and August. Minimum generation and spill rates are specified in the 2011 FPP. Spill also may be reduced or curtailed to accommodate navigation safety issues or other critical unplanned needs (i.e. health and human safety, dam safety, prevent equipment failure, maintain transmission stability, etc.).

To make adjustments in response to changes in conditions, the Corps will utilize the existing Regional Forum committees. Changes in spill rates when flow conditions are higher or lower than anticipated will be coordinated through the TMT. This could include potential issues and adjustments to the juvenile fish transportation program, or fish passage emergency.

8.1.3 Spillway Operations

Actual hourly spill quantities at dams will be slightly greater or less than specified levels. The AAs will meet the requested spill levels to the extent possible, as described. However, actual spill levels depend on the precision of spill gate settings, flow variations in real time, varying project head (the elevation difference between a project's forebay and tailwater), automatic load following and other factors. Operations considerations are as follows:

Spill discharge levels: Due to limits in the precision of spill gates and control devices, short term flow variations, and head changes, it is not always possible to discharge the exact spill levels, or as stated in RCC spill requests (teletypes) to projects that call for discrete spill discharges. Therefore, spillway gates are opened to the gate settings identified in the FPP project spill pattern tables to provide spill discharge levels that are the closest to the prescribed spill discharge levels.

Spill percentages: Spill percentages are considered target spill levels. The project control room operator and BPA duty scheduler calculate spill levels to attempt to be within ±1% of the target percentage for the following hour. Prescribed or specified percentages may not always be attained due to low discharge conditions, periods of minimum generation, spill cap limitations, temporary spill curtailment for navigation safety, and other unavoidable circumstances. Operators and schedulers review the percentages achieved during the day and will attempt to adjust spill rates in later hours if necessary, with the objective of ending the day with a daily average spill percentage that achieves the specified spill percentage.

8.1.4 Minimum Generation

The Corps has identified minimum generation flows derived from FPP tables which specify turbine operation within the ±1% of best efficiency range. These minimum generation flows are approximations and do not account for varying head or other small adjustments that may result in variations in the reported minimum generation flow values and spill amount. Conditions that may result in minor variations include:

1. Varying pool elevation: as reservoirs fluctuate within the operating range, flow rates through the generating unit change.
2. Generating unit governor "dead band": the governor controls the number of megawatts the unit should generate and cannot precisely control a unit; variations can be ± 1% to 2% of generation.
3. System disturbances: once the generator is online and connected to the grid, it responds to changes in system voltage and frequency. These changes may cause the unit to increase flow and generation slightly within an hour.
4. Individual units may behave slightly differently or have unit specific constraints.
5. Generation control systems regulate megawatts (MW) generation only, and not flow through turbines.

All of the lower Snake River powerhouses may be required to keep one generating unit on line at all times for power system reliability. During low flows, one generator is run at the bottom of the 1% of best efficiency range. All of the Snake River plants have 2 “families” of turbines with slightly different capacities. In most cases one of the smaller units, with somewhat less generation and flow, will be online during these times. At the Snake River dams, the smaller units are generally numbered 1 – 3 and are the first priority for operation during the fish passage season. However, if smaller units are unavailable, one of the larger units may be used. Further, at Lower Monumental, generating unit 1, which is the first priority unit during fish passage, is damaged and cannot operate at the low end of the design range. However, because this unit is a fish passage priority TMT may recommend use of this unit, which will result in higher turbine discharge rates than shown in the Lower Monumental Summer Operation Considerations section below. In addition, Ice Harbor units cannot be operated at the lower end of the 1% of best efficiency range. These units experience cavitation at a generation level somewhat higher than the lower 1% limit, which damages the turbine and can be detrimental to fish.

8.1.5 Low Flow Operations

Low flow operations on lower Snake and lower Columbia projects are triggered when inflow is not sufficient to provide for both minimum generation and the planned spill levels. In these situations, the projects will operate either one unit at minimum generation (Snake River projects) or at minimum powerhouse flow (Columbia River projects) and spill the remainder of flow coming into the project. As flows transition from higher flows to low flows, there may be situations when flows recede at a higher rate than forecasted. In addition, inflows provided by non-federal projects upstream are variable and uncertain. The combination of these factors may result in instances where unanticipated changes to inflow result in forebay elevations dropping to the low end of the MOP. Since these projects have limited operating flexibility, maintaining minimum generation and the target spill may not be possible on every hour.

Also during these low flow operations, additional flow that is passed through a dam as the result of navigational lockages becomes more apparent. This is because the volume of water needed to empty the navigation lock during periods of low flow is a greater percentage of the total flow than it had been earlier in the season. As a result, the official recorded spill percent through the spillway appears to be reduced since it does not include this volume of water needed to empty the navigation lock.

8.1.6 Operations for Transmission Stability

Because projects must be available to respond to within-hour load variability to satisfy North American Electric Reliability Council reserve requirements ("on response"), project operations may result in not meeting hourly spill requirements, mostly at McNary, John Day, and The Dalles dams. In addition to within-hour load variability, projects on response must be able to respond to within hour changes that result from intermittent generation (such as wind generation). During periods of rapidly changing loads and intermittent generation, projects on response may have significant changes in turbine discharge within the hour while the spill quantity remains the same within the hour. Under normal conditions, within-hour load changes occur mostly on hours immediately preceding and after the peak load hours, however, within-hour changes in intermittent generation can occur at any hour of the day. Sometimes, several hours after peak load hours, the project may be decreasing total outflow and generation faster than the corresponding spill decreases causing the percent spill to be slightly higher. Due to the high variability of within-hour load, these "Transmission Stability" hours may have a greater instance of reporting actual spill percentages that vary more than the +/- 1% requirement than other hours.

8.2 Canadian Storage for Flow Augmentation

8.2.1 Columbia River Treaty Storage

The purpose of the actions below is to see if more water from Canadian storage projects can be obtained for flow augmentation. One (1) MAF of Columbia River Treaty (Treaty) storage will be requested and negotiated when available with British Columbia (BC) Hydro to be provided and released during the migration season.

Annual agreements between the U.S. and Canadian entities to provide flow augmentation storage in Canada for U.S. fisheries needs will include provisions that allow flexibility for the release of any stored water to provide U.S. fisheries benefits in dry water years, to the extent possible:

- Providing the greatest flexibility possible for releasing water to benefit U.S. fisheries May through July;

- Giving preference to meeting April 10 elevation objectives or achieving refill at Grand Coulee Dam over flow augmentation storage in Canada in lower water supply conditions; and

- Releasing flow augmentation storage to avoid causing damaging flow or excessive TDG in the U.S. or Canada.

BPA and the Corps will continue to coordinate with Federal agencies, States and Tribes on Treaty operating plans.

8.2.2 Non-Treaty Storage (NTS)

BPA and BC Hydro have negotiated a non-Treaty storage agreement to provide for storage during the spring with subsequent release in July and August 2011, for flow enhancement as long as operations forecasts indicate that there is water available in spring to be stored and can be released in July and August.

8.2.3 Non-Treaty Long-Term Agreement

BPA will seek to negotiate a new long-term agreement on use of non-Treaty space in Canada so long as such an agreement provides both power and non-power benefits for BC Hydro, BPA, and Canadian and U.S. interests. As part of these negotiations, BPA will seek opportunities to provide benefits to ESA-listed fish, consistent with the Treaty. If a new long-term non-Treaty agreement is not in place, or does not address flows for fisheries purposes, BPA will approach BC Hydro about possibly negotiating an annual/seasonal agreement to provide U.S. fisheries benefits, consistent with the Treaty.

8.2.4 Non-Treaty Coordination with Federal Agencies, States, and Tribes

Prior to negotiations of new long-term or annual non-Treaty storage agreements, BPA will coordinate with Federal agencies, States, and Tribes to obtain ideas and information on possible points of negotiation, and will report on major developments during negotiations.

8.2.5 Non-Treaty Storage (NTS) Refill

BPA, in concert with BC Hydro, will refill the remaining non-Treaty storage space by June 30, 2011, as required under the 1990 non-Treaty storage agreement. Refill will be accomplished with minimal adverse impact to fisheries operations.

8.3 Upper Snake River Reservoir Operation for Flow Augmentation

Reclamation will attempt to provide 487 KAF annually of flow augmentation from the Reclamation projects in the Upper Snake River basin consistent with its Proposed Action as described in the November 2007 Biological Assessment for O&M of its projects in the Snake River basin above Brownlee Reservoir. Reclamation's flow augmentation program is dependent on willing sellers and must be consistent with Idaho State law.

8.4 Bonneville Chum Operations

The AAs plan to operate the FCRPS to provide flows to support chum salmon spawning, incubation and egress from the Ives/Pierce Islands spawning areas. The Bonneville chum spawning and incubation operation affects approximately 10% of the natural spawning area for the ESA listed Columbia River chum. Non-listed lower Columbia River fall Chinook also spawn in the area. The NMFS 2010 Supplemental BiOp recognizes that access to spawning habitat in the Ives/Pierce area is primarily a function of the water surface elevations greater than 11.2 ft. above mean sea level (msl). Managing the water surface elevation with the operation of Bonneville Dam has proven to be an effective means of protecting this spawning area. Providing spawning access to Hamilton Creek and Hardy Creek is similarly a function of sufficient tailwater elevation but must be coupled with sufficient rainfall events to get the creeks flowing sufficiently. As addressed in the NMFS 2010 Supplemental BiOp, chum salmon spawning operations have lower priority than spring flow objectives or summer refill. If all of the BiOp objectives cannot be met, the AAs will work with NOAA Fisheries and the regional salmon managers to identify operations that would best benefit salmon while maintaining other fish protection measures. There are two phases of chum operations; spawning which generally runs from late October through late December, and incubation and egress which runs from late December to early April.

8.4.1 Spawning Phase

In the first week of November (or when fish arrive) Bonneville Dam will begin operating to provide a tailwater (TW) range of 11.3 - 11.7 ft. until spawning ends or December 31. The official project tailwater gage is located on the Oregon side .9 miles downstream of Bonneville Dam First Powerhouse, 50 ft. upstream from Tanner Creek at river mile 144.5 ft. Generally, the range of outflow from Bonneville Dam required to maintain this tailwater elevation can vary from less than the project minimum discharge of 70 kcfs up to 135 kcfs. This range demonstrates the affect natural conditions downstream of Bonneville Dam have on the water surface. Tides, wind, wave and inflows to the Columbia River downstream of Bonneville Dam are all uncontrolled and difficult to predict.

In addition to the uncertainty of conditions downstream of Bonneville Dam there are just as many variables upstream. Generally, the flow at Bonneville Dam is augmented by storage releases from Grand Coulee Dam. This water takes approximately 24 hours to arrive at Bonneville Dam and must pass through several non-federal dams that can alter the shape of the flow. Also, the amount of unregulated flow into the Columbia River above Bonneville Dam is difficult to predict. The ability to operate Bonneville Dam to a particular tailwater constraint is contingent on the ability of the hydrosystem to manage all of these variables.

The hydrosystem is rarely able to maintain the 11.3 - 11.7 ft. operation during day-light hours throughout the spawning period. Significant fall rain events will typically intervene; therefore the operation must be modified to accommodate these varied conditions. Research performed in 2005 to assess the impacts of higher flows (day and night) on chum salmon redd development indicated that increases in flows up to 175 kcfs delayed spawning until flows dropped back to base levels (125 kcfs) but did not force fish to abandon their redds and search for new locations. Extra chum spawning flows may be available from Lake Pend Oreille (Albeni Falls Dam) during fall drawdown when drafting to elevation 2051 as part of the planning process for winter draft for kokanee spawning. The SOR for Albeni Falls draft is formulated, usually in September, by the USFWS and IDFG in coordination with NMFS and other concerned parties. Through TMT, if water supply is deemed insufficient to provide adequate mainstem spawning or continuous tributary access, as appropriate, provide mainstem flow intermittently to allow fish access to tributary spawning sites if adequate spawning habitat is available in the tributaries. The following is a list of steps that generally captures the progression of the operation as river flow increases until the point where TMT typically convenes to discuss the options ahead.

8.4.1.1Chum Spawning Operational Steps

The steps 1 through 6 below describe the transition from complete control of the operation to conditions where the daytime range cannot be managed.

1. Operate Bonneville tailwater elevation (TWE) between 11.3 - 11.7 ft. TWE all hours daily.

2. As needed, to pass water in excess of that needed to meet item 1, increase the TWE up to 18.5 ft. anytime between the hours 1700-0600.

3. If item 2 is insufficient to pass excess flow, increase TWE up to 12.5 ft. anytime between the hours of 0600 – 1700daily.

4. If items 2 and 3 are insufficient to pass excess flow, discuss options with TMT for passing additional water during daytime hours. Discussions typically include higher TWE, larger operating range (1 ft. vs. .4 ft.), daytime spikes in flow, multi-day increases in TWE, etc. Generally, the options will depend on weather and flow conditions and the number of actively spawning fish present.

There are several conditions that typically overwhelm the chum spawning operation for multiple days. These events are usually seen well in advance and the course of action to implement is discussed at TMT. Below are some examples of the conditions where the chum operation cannot be managed within the agreed constraints.

- Conditions downstream of Bonneville produce high TWE regardless of the discharge at Bonneville such as high tides and high inflows to the Columbia River downstream of Bonneville. Bonneville can be discharging the project minimum and still exceed the target TWE range.

- Heavy westside precipitation events increase inflow to the Columbia River both upstream and downstream of Bonneville. This condition combines a low required flow at Bonneville and uncontrolled inflows to the Columbia River above Bonneville. In the absence of storage capacity in the lower river, there is little control over the resulting TWE below Bonneville.

8.4.2 Incubation and Egress

Washington Department of Fish and Wildlife (WDFW) will determine when chum spawning is complete; this usually occurs no later than the end of December. Following the completion of spawning, the operation is shifted to provide a tailwater elevation (to be determined by TMT) equal to or greater than the elevation of the highest established redds. This elevation is typically around 11.3 ft. - 11.5 ft. msl during normal water years. Redds established due to conditions beyond the control of the action agency may not be protected. This operation continues until the completion of emergence and egress which can extend to the start of the spring flow management season around April 10. At that time, spring flow augmentation volumes generally provide sufficient flows to maintain the protection elevations necessary. If the emergence period extends beyond April 10 and the decision is made to maintain the tailwater, TMT will need to discuss the impacts of TDG associated with spill for fish passage at Bonneville Dam and its potential for negatively affecting fry in the gravel. Bonneville typically starts its spring spill around April 10, but a delay in the start of spill may be needed.

Revisit the chum protection level decision at least monthly through the TMT process to assure it is consistent with the need to provide spring flows for listed Columbia and Snake River stocks.

8.4.3 Considerations for Dewatering Chum Redds

While a conservative approach to managing tailwater elevations during spawning reduces the risk of dewatering redds, it does not eliminate dewatering as a possibility. The conditions in each year vary too dramatically to allow for the development of set criteria for whether or not to dewater redds, therefore the basis for a dewatering decision depends greatly on in-season conditions so are best made in TMT. Factors that should be considered in making a dewatering decision include:

- The number and percentage of the total redds which would be affected by the decision

- Emergence timing based on temperature units

- The percentage of the total chum population that spawned at other locations

- The component of the overall population that these redds represent
- Status of the FCRPS reservoir elevations
- Expected benefit to reservoir levels and river operations which would be provided by the dewatering decision
- Precipitation and runoff forecasts
- Expected river operations due to power market environment
- Status of the upriver spring Chinook listed stocks
- Existence and status of a brood contingency plan

8.4.4 Dewatering Options

Consideration of options to minimize the impacts should a decision be made to lower the protection level for the spawning, incubation and egress follow:

1. If water supply conditions indicate that it is not possible to maintain this minimum tailwater elevation at Bonneville Dam, flow will be provided at times during the chum- emergence season to allow juveniles to depart from Hamilton and Hardy Creeks. Details will be set through coordination in TMT.

2. Early season forecasts can be used by TMT to determine a level of caution when choosing the spawning elevations to provide below Bonneville. A general apprehension to provide tailwater elevations above 11.5 ft. is prudent in most years. Fall precipitation can lead to chum spawning at higher elevations than intended. It may be difficult to commit to providing those elevations without a solid water supply forecast.

3. Manage flows below what is necessary for mainstem spawning to discourage redds from being established in the area.

4. Shaping flows in a manner that would discourage redd development above a particular elevation. Reverse load factoring with nighttime discharges more than 75 kcfs over the daytime discharge level have occurred without impacting where chum redds were placed.

5. Shaping flows as low as possible during the day with one or two spikes of flow as short of duration as possible can also discourage redd development.

8.5 Description of Variable Draft Limits

Variable Draft Limits (VDL’s) are period-by-period draft limits at Grand Coulee and Hungry Horse from January-March 31. These are planned limits to Firm Energy Load Carrying Capability (FELCC) generation to protect the ability to refill Grand Coulee and

Hungry Horse to their April 10 elevation objectives with an 85% and 75% confidence respectively.

The VDL's are based on: (1) The April 10 elevation objective which is calculated from the forecasted March 31 and April 15 flood control elevations (2) statistical inflow volumes (85% exceedance for Grand Coulee and 75% exceedance for Hungry Horse), (3) actual downstream and project flow objectives, to meet at-site and Vernita Bar requirements, and (4) refill requirements at upstream projects and the flow forecasts which drive such upstream requirements.

VDL's are calculated monthly from January through March after updated volume forecasts and flood control elevations have been issued. The VDL at the end of a period (e.g., January 31) is computed as the carryover storage needed to meet the next periods' storage and outflow requirements with the goal of refilling to the elevation objective on April 10.

For example, Grand Coulee's January VDL is computed as:

- The expected April 10 Flood Control elevation based on January forecast.
- Minus February 1-April 10 inflow volume of 2,424 ksfd (85% statistical inflow volume). This volume data is reduced by Banks Lake pumping
- Plus February 1 to April 10 minimum discharge requirement for Vernita Bar.
- Plus expected and realistic upstream refill requirement in February 1 to April 10 while observing the applicable upstream reservoir elevation limits.

The VDL is not a mandatory draft elevation and operation above the VDL is acceptable as long as it is not a higher elevation than flood control curve, FELCC is already being met, and at-site and downstream flow objectives are also being served. Also, VDL's at Grand Coulee are further limited by VDL lower limits of 1260 ft. in January, 1,250 ft. in February and 1,240 ft. in March.

8.6 The Lake Roosevelt Incremental Storage Release Project of the Washington State Department of Ecology, Columbia River Water Management Program.

8.6.1 Fish Flow Releases Advisory Group

The Fish Flow Releases Advisory Group (FFRAG) supplies a mechanism for fisheries comanagers to provide advice to Washington State Department of Ecology (Ecology) and Reclamation on the disposition of the one-third of active storage water that will be made available to augment instream flows ("fish water") through the development of new storage facilities, pursuant to 90.90.020 RCW.[10] At present, FFRAG has developed recommendations for the disposition of water to be released to offset permitted withdrawals related to the Lake Roosevelt Incremental Storage Releases project. Established in March 2009, FFRAG members include fish managers from Washington Department of Fish and Wildlife, National Marine Fisheries Service, U.S. Fish and Wildlife Service, Yakama Indian Nation, Confederated Tribes of the Umatilla Indian Reservation (represented by Columbia River Intertribal Fish Commission), and Confederated Tribes of the Colville Reservation. WDFW chairs the group, and the Director of Ecology's Office of Columbia River and a representative of the U.S. Bureau of Reclamation also participate. The committee functions on the basis of consensus. Decisions of the group manifest in the form of recommendations/advice to Ecology and Reclamation.

8.6.2 Lake Roosevelt Incremental Storage Releases

The Lake Roosevelt Incremental Storage Releases portion of Washington State's Columbia River Water Management Program (CRWMP) result in additional water withdrawals from Lake Roosevelt for both out-of-stream use and instream flows. The Incremental draft results in a release of 82,500 acre-feet in most years, or about 1.0 foot of draft at Lake Roosevelt. For every two acre-feet of water put to out-of-stream use, one acre-foot of water will go to instream flows ("*no net loss plus one-third*"). In years when the March 1 final forecast of April through September runoff at The Dalles is less than 60 million acre-feet, an additional draft of 50,000 acre-feet for interruptible water users and instream flow will occur, for a total draft of 132,500 acre-feet or about 1.8 feet of draft. Releases are allocated as shown in Table 9.

Table 9. Lake Roosevelt Incremental Storage Release Allocations

Amount	Use	Description
30,000 acre-feet	Odessa Subarea (not shown in release distribution tables)	Water pumped to Banks Lake and delivered through the Columbia Basin Project to the Odessa Subarea, offsetting groundwater pumping.
25,000 acre-feet	Municipal / Industrial	Water released from Grand Coulee dam and withdrawn from the Columbia River at various sites downstream.
27,500 acre-feet	Instream flow ("fish")	Water released to instream flow corresponding with the out-of-stream components above.

10 **90.90.020 Allocation and development of water supplies. …** (1)(a) (ii) One-third of active storage shall be available to augment instream flows and shall be managed by the department of ecology. The timing of releases of this water shall be determined by the department of ecology, in cooperation with the department of fish and wildlife and fisheries comanagers, to maximize benefits to salmon and steelhead populations.

33,000 acre-feet	Interruptible water users (“drought”)	In drought years, offset withdrawals from some interruptible water right holders along the Columbia River at various sites downstream.
17,000 acre-feet	Instream flow (“drought fish”)	Water released to instream flow corresponding to the drought interruptible component.

8.6.3 Releases Framework and Accounting for Lake Roosevelt Incremental Draft

The only way to demonstrate that the water came from Lake Roosevelt and not stream flows during the juvenile fish migration period is to draft Lake Roosevelt. Based on RPA 4 in the 2008 FCRPS BiOp, there are two elevation objectives during the juvenile fish migration period: (1) end of June (early July) refill, and (2) August 31 draft, the latter of which is forecast based. When water is released in the April-through-June spring period from the Lake Roosevelt incremental draft water account, then Lake Roosevelt would need to miss refill by that amount. Lake Roosevelt would draft below the end of August draft limit by the amount released in both the spring and July-August summer flow augmentation periods. Following (Table 10) is the FFRAG framework showing recommended distribution of incremental storage releases across months (Apr-Sep) under four water-year types: wet, average, dry, and drought. End-of-period accounting point elevations are also provided for each scenario.

Table 10 – Release of Lake Roosevelt Incremental Draft Water

Water Year Scenario	Purpose	Volume in acre-foot (Lake Roosevelt equivalent draft in feet)						
		Apr	May	June	July	Aug	Sept	Oct
A.”Wet”	Odessa	2,012	3,963	5,976	7,988	5,976	3,049[1]	1,036
	M&I	2,000	3,988	4,875	4,694	4,944	4,500[1]	
	Fish	0	4,950	5,500	5,775	5,775	5,500[1]	
	Total	33,401 (0.4)[2] (refill to 1289.6)			68,665 (0.9)[2,3] draft to 1279.1		12,799[1]	1,036
B.”Average”	Odessa	2,012	3,963	5,976	7,988	5,976	3,049[1]	1,036
	M&I	2,000	5,250	6,000	5,750	6,000		
	Fish	0	6,875	6,875	6,875	6,875		
	Total	38,951 (0.5)[2] (refill to 1289.5)			78,415 (1.0)[2,3] (draft to 1277 or 1279)[4]		3,049[1]	1,036
C.”Dry”	Odessa	2,012	3,963	5,976	7,988	5,976	3,049[1]	1,036
	M&I	3,700	8,850	5,700	3,250	3,500		
	Fish	4,675	16,775	6,050	0	0	0	
	Total	57,701 (0.7)[2] (refill to 1289.3)			78,415 (1.0)[2,3] (draft to 1277)		3,049[1]	1,036
D.”Drought”	Odessa	2,012	3,963	5,976	7,988	5,976	3,049[1]	1,036
	M&I	4,200	8,350	5,700	3,250	3,500		
	Fish	6,050	15,400	6,050	0	0		

	Interruptible	4,620	7,590	3,960	6,930	9,900		
	Fish	3,740	9,520	3,740				
	Total	90,871 (1.1)[2] (refill to 1288.9)			128,415 (1.7)[2,3] draft to 1276.3			4,085[1,5]

1 The FCRPS BiOp, RPA action 4 (Grand Coulee) says: *"If the Lake Roosevelt drawdown component of Washington's Columbia River Water Management Program (CRWMP) is implemented, it will not reduce flows during the salmon flow objective period (April to August). The metric for this is that Lake Roosevelt will be drafted by an additional 1.0 foot in non-drought years and by about 1.8 feet in drought years by the end of August."* Because of the way this RPA action is written, Reclamation cannot shift release of CRWMP water into September and still operate consistent with this RPA action; however, the volume of water shown here for September are so small that they cannot be measured.

2 Additional draft at Lake Roosevelt in feet. Water surface elevation can only be measured to the nearest 10^{th}.

3 To demonstrate that the water comes from Lake Roosevelt, the end of August draft includes both spring and summer releases.

4 August 31 draft to 1278 or 1280 is based on July final water supply forecast.

5 In drought years, irrigation water is drafted from Banks Lake in September, then refilled from Lake Roosevelt in October.

8.6.4 2011 Operations

The amount and timing of water to be released in 2011 won't be determined until the March final Water Supply forecast for April – September at The Dalles is completed. Estimates of 2011 incremental storage releases will be included in the 2011 spring/summer update.

8.7 Public Coordination

Actions in the WMP will be coordinated with NOAA Fisheries, USFWS, and the states and tribes in preseason planning and in-season management of flow and spill operations. This coordination will occur in the TMT process and will utilize the best available science. At all appropriate decision points, the AAs will routinely seek timely input and concurrence from the USFWS on all matters affecting USFWS listed fish through the Columbia River Treaty, IJC, and all other decision making processes involving trans-boundary waters in the Columbia River basin. This will include notification of all meetings and decision points and provision of opportunities to advise the AAs during meetings and in writing, as appropriate.

9 Water Quality

9.1 Water Quality Plans

The Corps has completed a comprehensive Water Quality Plan (WQP) outlining the physical and operational changes that could be used to improve the overall water quality in the mainstem waters of the Clearwater, Snake, and Columbia rivers. The plan was updated in January 2009 and can be found at http://www.nwd-wc.usace.army.mil/tmt/wq/studies/wq_plan/wq200814.pdf

9.1.1 Total Dissolved Gas Monitoring

Exposure to high levels of TDG over long periods of time can be harmful or lethal to fish. Environmental monitoring in the waters impacted by operations at the dams is necessary where voluntary spill is employed for juvenile fish passage to ensure that gas levels do not exceed TDG thresholds established in NMFS BiOps, and applicable state water quality criteria. The Corps TDG monitoring program is described in the TDG Monitoring Plan of Action, which included data quality criteria for fixed monitoring stations, goals related to the accuracy, precision, and completeness of data at each fixed monitoring station and the methodologies that are used in the attempt to achieve those goals, calibration protocols (data quality control), data review and corrections (data quality assurance), and completeness of data. The Plan of Action can be found at http://www.nwd-wc.usace.army.mil/tmt/wqnew/tdg_and_temp/2010/app_b.pdf

The Reservoir Control Center is responsible for monitoring the TDG and water temperature conditions in waters impacted by Corps projects on the Columbia and Snake rivers. To assess water quality conditions in these waters, the Corps operates TDG and temperature monitors in the forebays and the tailwaters of the lower Columbia River/lower Snake River dams, and other selected river sites. The Corps prepares a Total Dissolved Gas Management Plan (TDG Management Plan) each year (see Appendix 4), which is a supporting document for the WMP. This TDG Management Plan provides detailed definitions of spill, spill conditions, TDG management measures, the rationale and process for setting spill caps, the TDG management policies, and the TDG monitoring program, and modeling. This plan is consistent with both the U.S. Fish and Wildlife Service and the National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinions (BiOps).

10 Dry Water Year Operations

Flow management during dry years is often critical to maintaining and improving habitat conditions for ESA-listed species. A dry water year is defined as the lowest 20th percentile years based on the NWRFC's averages for their statistical period of record (currently 1971 to 2000) using the May final water supply forecast for the April to August period as measured at The Dalles (71.8 maf). The AAs will complete the following activities to further the continuing efforts to address the dry flow years:

- Within the defined "buckets" of available water (reservoir draft limits identified in Reasonable and Prudent Alternative (RPA) Action 4), flexibility will be exercised in a dry water year to distribute available water across the expected migration season to optimize biological benefits and anadromous fish survival. The AAs will coordinate use of this flexibility in the TMT.
- In dry water years, operating plans developed under the Treaty may result in Treaty reservoirs being operated below their normal refill levels in the late spring and summer, therefore, increasing flows during that period relative to a standard refill operation.
- Annual agreements between the U.S. and Canadian entities to provide flow augmentation storage in Canada for U.S. fisheries needs will include provisions

that allow flexibility for the release of any stored water to provide U.S. fisheries benefits in dry water years, to the extent possible.

- BPA will explore opportunities in future long-term NTS storage agreements to develop mutually beneficial in-season agreements with BC Hydro to shape water releases using NTS space within the year and between years to improve flows in the lowest 20th percentile water years to the benefit of ESA-listed Evolutionary Significant Units (ESUs), considering their status.
- Upon issuance of the FCRPS Biological Opinion, the AAs will convene a technical workgroup to scope and initiate investigations of alternative dry water year flow strategies to enhance flows in dry years for the benefit of ESA-listed ESUs.
- BPA will implement, as appropriate, it's Guide to Tools and Principles for a Dry Year Strategy to reduce the effect energy requirements may pose to fish operations and other project purposes.
- Annual agreements between the U.S. and Canadian entities to provide flow augmentation storage in Canada for U.S. fisheries needs will include provisions that allow flexibility for the release of any stored water to provide U.S. fisheries benefits in dry water years, to the extent possible.

11 FCRPS Hydrosystem Performance Standards

The AAs will operate the FCRPS hydrosystem as described in this 2011 WMP, in an adaptive management framework, to make progress towards meeting biological performance goals. Those goals are contained in the 2008 NOAA Fisheries Biological Opinion as supplemented in the 2010 Supplemental BiOp. Adult and juvenile fish survival estimates from research, monitoring, and evaluation studies will be considered in annual planning as future plans are developed.

12 Conclusion

The 2011 WMP has been coordinated with and reviewed by the TMT. Seasonal action plans will be developed as described in the introduction to this plan. Additionally, operations may be adjusted in-season based on recommendations from the TMT.

Appendix 4

2011

Total Dissolved Gas

Management Plan

Table of Contents

1.0 Introduction

In various parts of the Columbia and Snake River systems, elevated levels of total dissolved gas (TDG) saturation are observed where spill at dams occurs. A TDG Management Plan is developed annually and is included as Appendix 4 in the annual Water Management Plan. This TDG Management Plan provides detailed information addressing TDG management measures, the process for setting spill caps, TDG management policies, and the TDG monitoring program and modeling. This plan is consistent with the 2000 U.S. Fish and Wildlife Service (USFWS) Biological Opinion, and the NMFS 2008 Biological Opinion and NMFS 2010 Supplemental Biological Opinion (NMFS 2010 Supplemental BiOp).

1.1 Background

In the late 1990's, it was recognized that development of a systemwide TDG model would assist with in-season management of voluntary spill. This idea was incorporated into the NMFS 2000 Biological Opinion, RPA Action 133 which encouraged the development of a TDG model for spill management. As a result, the Corps began developing a TDG model called SYSTDG, which is an hourly time step model used to forecast the TDG levels at the Columbia and Snake River dams and to assist setting daily spill caps. The SYSTDG model estimates TDG production resulting from dam operations on the Columbia River from Grand Coulee Dam to Bonneville Dam, on the lower Snake River from Lower Granite Dam to the confluence with the Columbia River, and from Dworshak Dam on the Clearwater to its confluence with the Snake River and takes into consideration the hydraulic design of the dams, the unique river hydrologic conditions. The SYSTDG model incorporates a number of factors (e.g. total river flow, conditions and the cumulative effects of project management of the river system).

During the 2004 spill season, the SYSTDG model was used for the first time as a river operations management tool to evaluate TDG on the Columbia and Snake rivers and to assist in the setting of spill caps at each of the dams where voluntary spill for fish occurred. At the conclusion of the spill season, a review of the performance of the SYSTDG model was completed and included in the 2004 Dissolved Gas and Water Temperature Monitoring Report. The same statistical evaluation of SYSTDG model performance was done for the 2005 through 2010 spill seasons. These statistical evaluations are included in the annual Dissolved Gas and Temperature Annual Report for each of those spill seasons, and are also available on the RCC Water Quality Programs webpage at: http://www.nwd-wc.usace.army.mil/tmt/wqnew/

The SYSTDG model will continue be used as a TDG management tool into the foreseeable future. Updates of the SYSTDG model occur as necessary when there are operational or structural modifications to the spillway, new spill patterns, or new TDG research that can be used to refine the model performance.

1.2 State Water Quality Standards

The federal Clean Water Act establishes the 110 percent TDG criteria for rivers which the states of Washington and Oregon adopted into their state water quality standards. The states of Washington and Oregon have authorized exceptions (rule adjustment or waiver respectively) to these standards as long as the elevated TDG levels provide for improved fish passage through the spillway without causing more harm to fish populations than through other passage routes.

The five year 2010-2014 Oregon TDG waiver specifies that TDG levels are not to exceed 120 percent in the tailwaters as measured as the average of the twelve highest hourly readings in any one day. Oregon no longer includes criteria for TDG in the forebays. The five year 2010-2014 Washington rule adjustment specifies that TDG levels are not to exceed 120 percent in the tailwaters and 115 percent in the forebays of downstream dams as the average of the twelve highest consecutive hourly readings in any one day. They also specify that TDG levels are not to exceed 125 percent on a one-hour basis (State of Washington) or on a two-hour basis (State of Oregon). Since the states of Washington and Oregon have different TDG standards, the Corps will manage spill at the Lower Columbia and Snake River dams to the more stringent of the two.

In previous years, the States of Oregon and Washington specified the method of calculating the "daily percent TDG" as an average of the 12 highest hourly readings in a given day. Since 2006, both states have changed their methods for calculating the high 12 hour average. In November 2006, Washington Department of Ecology (WDOE) changed their method of calculating percent TDG to involve using a running consecutive 12-hour average. The daily high consecutive 12-hour TDG level is determined as the highest of the average value of each preceding 12-hour interval for each hour of the day. Oregon's revised method of calculating the "daily percent TDG" to an average of the 12 highest hourly readings in a given day for tailwater gauges only.

2.0 TDG Management

The TDG management measures differ depending on the category of spill, thus it is important to understand the definitions of voluntary and involuntary spill.

2.1 Voluntary and Involuntary Spill

There are two categories of spill: voluntary and involuntary. Voluntary spill occurs when spill is implemented in accordance with BiOp spill operations and applicable state water quality criteria. Voluntary spill is defined as the passing of water through the spillway gates of a dam to facilitate passage of juvenile salmon past the dam or passage of water to aid fish downstream migration. Spill at dams that pass juvenile salmonids decreases the residence time of juvenile salmon in the forebay of dams. Voluntary spill is also used at Dworshak Dam on the Clearwater River to provide for flow augmentation and to improve temperature conditions in the lower Snake River. The amount of voluntary spill is evaluated daily so that the resulting TDG levels associated with spill operations are consistent with the applicable state water quality criteria waiver or rule adjustment as described above. These TDG levels are referred to as "gas caps." The term "spill cap" is defined as the amount of spill necessary for TDG levels to reach the gas cap.

Involuntary spill occurs when hydrologic conditions result in flows which exceed the hydraulic capacity of power generation facilities. Involuntary spill is driven largely by local conditions at the dam (i.e. turbine capacity plus available storage is less than inflow). Other causes for involuntary spill include management of reservoirs for flood control, scheduled or unscheduled turbine unit outages of various durations, passing debris, or any other operational and/or maintenance activities required to manage dam facilities for safety and multiple uses.

2.2 Two Approaches to Managing TDG

There are two general approaches to TDG management: setting spill caps, and setting the order of dams to spill on the spill priority list.

- Values on the spill priority list serve as a reference for expected TDG production at the dams over a range of spill levels.
- There are times when not all of the units are operating at full capacity because there is insufficient market or demand for the energy and it becomes necessary to spill water. In these situations, TDG is managed by spilling according to the order provided on the spill priority list. During involuntary spill due to lack of market, there is the ability to move generation between dams, spilling at non-mainstem dams according to the spill priority list so that TDG is lower on the mainstem e.g. spilling 2 kcfs at Dworshak instead of 15 kcfs at Bonneville. This TDG management measure is implemented by initiating spill at dams according to the spill priority list by going from top-to-bottom, and left-to-right (see Table 1). The total amount spilled at any given dam will depend on the magnitude of the lack of market condition and will vary hourly.

Since TDG spill caps are important in managing TDG, this plan provides detailed explanations of why and how the spill caps are set.

2.2.1 Setting Spill Caps

The Corps Reservoir Control Center (RCC) Water Quality Unit sets the daily spill caps with the objective of operating consistent with applicable state TDG standards, reduce incidental take, reduce unsafe TDG levels in shallow areas, protect and limit damage to the physical dam structures, and minimize TDG production.

2.2.2 Spill Caps

The NMFS 2010 Supplemental BiOp and the 2011 Fish Operations Plan call for the Corps to provide spill for fish passage on the lower Columbia and lower Snake Rivers up to the State water quality waiver and rule adjustment limits. Table 1 summarizes the initial spill caps and spill priority for managing spill. The spill caps are updated, as needed based on real-time TDG information.

TABLE 1
Initial Spill Caps for 2011 in kcfs

Project	**Spill Cap to Generate Specific Percentage of Total Dissolved Gas (TDG)**					
	110%	**115%**	**120%**	**125%**	**130%**	**135%**
LWG	20	30	41	90	125	200
LGS	10	15	32	80	110	250
LMN	10	15	31	55	110	250
IHR	30	45	95	125	135	240
MCN	40	80	145	230	290	450
JDA	20	60	120	240	300	600
TDA	20	60	125	250	260	600
BON	50	65	100	150	250	270
CHJ	19	50	100	160	160	160
GCL-outlet tubes	0	5	10	20	35	50
GCL-drumgates	0	20	40	75	120	130
DWR	37%	42%	50%	60%	70%	75%

2.2.3 The Spill Order on the Spill Priority List

Since the project order for spilling listed on the Spill Priority List is important for managing TDG levels, when spill occurs due to lack of load, the spill order must be established before the high flows occur which is usually in mid-May. Before the beginning of spill season on April 3, RCC prepares an initial Spill Priority List based on the factors listed below. This list may be revised during the spill season depending on the location of the fish, research, river conditions and other circumstances. The spill priority lists are discussed in the TMT and revised accordingly.

When establishing the order of which dams should spill first, the following factors are considered:

- Location of Fish: If TDG levels are at or below 120 percent with high involuntary spill, the dams with the most fish are listed first on the priority list so the most fish are benefited with the high spill and flows.
- Location of High TDG: When TDG levels are above 120 percent with high involuntary spill, the dams with the most fish are listed last on the priority list so the least fish are harmed with the high spill and flows.
- Location of Fish Research: When fish research is planned or in progress, those dams are low on the priority list so the studies can remain intact as designed.
- River Reaches: Dams are considered in one of three blocks: Lower Snake; Lower Columbia and Middle Columbia. For example, if several Lower Snake dams need to be moved to low priority on the list, then the whole block of dams (LWG, LGS, LMN and IHR) are moved to the last on the list.

- Special Operations: Dams with special operations such as construction, maintenance or repair are placed last on priority list.
- Collector Dams: During low flow years, the collector dams (LGS, LWG, LMN, and MCN) are placed low on the priority list.
- Special Fish Conditions: If there are special fish conditions, such as disease or a special release, the dam is moved to first place on the priority list so the fish receive the maximum spill.

3.0 Process for Setting Spill Caps

This section provides a detailed explanation of how spill caps are set. There are several steps involved in setting daily spill caps, including evaluating SYSTDG simulations, review results and discuss proposed spill caps internally and with NOAA Fisheries.

3.1 Factors That Determine Spill Caps

The determination of spill caps at each individual dam is dependent upon an array of variables:

1. SYSTDG Model: The SYSTDG model is used as a real-time operations tool to forecast the TDG production levels for all the dams with the assumption that the following day conditions will be the same as the current day. With these model results and information obtained from the other factors listed above, a new spill cap can be determined.

2. Spill Operations: Fish spill operations for the dams are included in the Biological Opinion subject to adaptive management. These spill operations can be a percent of the total river flow, a flat spill rate, or spill to the spill cap. The spill operations are among the most influential factors for determining the spill caps.

3. High 12 Hour Average TDG Reading: A review of the previous day's high 12 hour average TDG reading of the dam forebay and tailwater fixed monitoring station (FMS) is used to indicate whether the spill caps needs to be increased or decreased. The high 12 hour average TDG readings are among the most influential factors for determining the spill caps.

4. Web Reports Used in Spill Review: The Corps has developed many web reports that summarize dam and water quality data, which are used in spill review and spill cap change decisions as follows.
    a. A program that calculates the amount of BiOp voluntary spill compared to how much BiOp voluntary spill actually occurred
    b. A report that calculates the percentage of spill at certain dams
    c. Data on flow, generation, spill, forebay elevation, TDG levels, and water temperature
    d. Tributary data for the Columbia River Basin
    e. Unit generation and spill bay data
    f. Water temperature string data
    g. 10-day flow forecasts for the lower Columbia and Snake rivers

5. <u>Physical Design and Characteristics of Dams:</u> TDG levels that are generated in the tailwaters of each dam depend upon many factors including the amount of spill passing through the spillway, the pattern of spill through the spillway, the amount of flow through the powerhouse, structure of the stilling basin, the presence (or absence) and elevation of flow deflectors, the presence (or absence) of divider walls, and river characteristics immediately below each dam. These individual characteristics are taken into account when assigning spill caps.

6. <u>Travel Time:</u> The time it takes water to move from one dam to the next depends upon the distance between dams and the flow rate in the river. Because of this, changes in spill at an upstream dam and the resulting change in TDG levels will not be seen in the forebay of the downstream dam for several hours or days.

7. <u>Water Temperature:</u> Climatic conditions can cause increases in water temperatures, which in turn can cause increases in TDG levels. The rule of thumb for water temperature is that a $1^{o}C$ ($1.8^{o}F$) increase in water temperature can result in a 2 to 3 percent increase in TDG. The impact of changing climactic conditions on water temperature is difficult to predict so air temperature is used as a surrogate. If it is expected that significant increases in air temperature are expected in a specific region, then it will be assumed that water temperatures would also be increasing and spill caps will be adjusted appropriately.

8. <u>Degassing:</u> As waters flow from one dam to another, degassing can occur. Experience has shown that winds above 10 mph enhance degassing. Therefore, wind conditions (in combination with other ambient conditions) are used to predict levels of degassing and are included in the SYSTDG model used to determine daily spill caps. In addition, with flows below 200 kcfs, significant degassing of TDG occurs in the river between the Bonneville Dam and the Camas/Washougal FMS. However, when flows increase above 200 kcfs, little or no degassing has been observed.

9. <u>Flow Variations:</u> Spill decisions are often affected by forecasts of river flows. Also, there are variations in flow on a weekly basis. On weekends, demand for power typically drops as compared to during the workweek, so flows may drop on weekends.

10. <u>Maintenance and Repairs:</u> During an average spill season, there are many units that are out of service for various reasons. Scheduled maintenance and repair activities will reduce the amount of powerhouse capacity of a dam. The type of maintenance and repair activity and how it will affect flows through the dam is taken into account in order to assign appropriate spill caps.

11. <u>Experimental Test Schedules:</u> The scheduling of various investigative studies can result in alterations in the normal operation of a dam. Examples of such alterations including modified spill pattern tests, removable spillway weir tests, and modified spill operations (e.g. at Ice Harbor, 50 percent spill operations for 24 hours for two days and then BiOp spill operations for the next two days).

12. Minimum Spill: During low flow conditions, there are minimum voluntary spill discharge at Ice Harbor (15.2 kcfs); 25 percent at John Day and at Bonneville (75 kcfs).

13. Minimum Generation: A minimum amount of flow for power generation is needed for electrical grid stability. During low flows, the minimum generation requirement will limit the spill rate from dams.

14. Definition of Daytime and Nighttime: The definition of daytime and nighttime effects how long the spill level is maintained so a spill cap can be set a little higher knowing that it will be in effect for only a few hours. This factor is especially true for Bonneville where the definition changes frequently throughout the spill season.

3.2 How Daily Spill Caps Are Set

Spill caps are set for each dam and are adjusted daily or as needed, depending on actual TDG readings and the variability of the factors that determine spill caps listed in Section 3.1. These factors are reviewed daily and spill cap adjustments are made daily to ensure that TDG concentrations are consistent with state water quality criteria. The following is a more detailed description of how the spill caps are adjusted and set:

Step 1-Review Data: The various web reports that show flow forecast, weather forecast, flow, spill, generation, forebay elevation, unit outage information and water quality data are reviewed. The previous day data in terms of the determinant factors are compared against the ESA operation requirements. When there are discrepancies between actual spill and expected spill, RCC Water Quality Unit investigates the causes.

Step 2-Investigation of Discrepancies: When there are discrepancies between actual spill and expected spill, RCC Water Quality staff coordinate with the following:

A. Unit Outage Coordinator – Are there unit or line outages occurring that are effecting spill operation? If there are, how many units or lines are down and how long, will it be until they return to service?
B. Fish Biologist – Sometime there are special fish research operations or special fish operations that RCC Water Quality staff needs to be informed about.
C. The Control Room Operators – RCC Water Quality staff discusses spill operations discrepancies to find out the reason. Based on this information, RCC Water Quality staff will need to talk to either Unit Outage Coordinator or the Fish Biologist.

Step 3-Document Spill Review: As RCC Water Quality staff performs Step 2 data review, the spill change decision is documented to identify what type of TDG exceedance occurred, the current spill cap, which dams need to have their spill caps changed, the rational for the spill cap change, spill and flow ranges and what are the new proposed spill caps. The spill change decision form documents the results of the data review and the final decisions that were made on spill caps.

Step 4-Run SYSTDG Model: RCC Water Quality staff checks the proposed spill caps with what the SYSTDG model suggest. It may be necessary to run several simulations until the right spill caps for all of the dams are obtained since a change at one location effects the next one downstream.

Step 5-Spill Cap Change Discussion: The RCC Water Quality staff who performed Step 2 data review discusses the SYSTDG model results and data review findings. Typically the team members negotiate to reach an agreement on what the new spill caps should be.

Step 6-Comments from NOAA Fisheries: The final completed spill change decision form is faxed to NOAA Fisheries water quality/spill specialist by 10:00 to allow them time to review spill decisions. RCC Water Quality staff waits until 12:00 for their comments about our proposed spill cap changes. If the NOAA Fisheries representative has questions or wants to discuss or negotiate changes to the spill caps, a RCC Water Quality staff answers their questions, negotiates, and resolves technical issues with the NOAA Fisheries representative. All questions and issues that are non-technical and are policy in nature are referred to the RCC Chief. Final spill caps will be sent out once the RCC Chief and the NOAA Fisheries representative reach an agreement.

Step 7-Submit the New Spill Priority List: RCC Water Quality staff calls BPA real-time scheduling and the Control Room Operator to inform them that a new spill priority will be sent out with the new spill cap. RCC Water Quality staff sends out the new spill priority list with the new spill caps by 13:00.

4.0 TDG Management Policies

The highlights of the 2011 TDG Management policies are as follows:

- Manage dam operations to the extent practical in accordance with CWA and state water quality standards, modified through waivers and rule adjustments.
- Provide voluntary spill for fish consistent with the 2011 Fish Operations Plan.
- Dams will be operated to its authorized purposes.

Voluntary spill policies:

a. Flows will be regulated to maximize potential for voluntary spill.
b. Experiment with promising new spill patterns.
c. Discontinue or postpone field research and non-critical unit service and maintenance schedules that create (or have potential for creating) high localized TDG levels, especially when and where high numbers of listed fish are present.
d. Spill to improve juvenile fish passage while avoiding high TDG supersaturation levels or adult fallback problems. Specific spill levels will be provided for juvenile fish passage at each dam that will be consistent with applicable State TDG criteria.
e. When dam voluntary spill occurs, the dams will be operated to manage TDG consistent with waiver or rule adjustment criteria without jeopardizing flood control objectives.
f. Accommodate special spill requirements/restrictions for research, adult passage, etc. that have the full endorsement of all concerned parties.

Involuntary spill policies:

- When possible, the Corps will manage involuntary spill to minimize TDG production as described in section 2.2.3.
- Implement the spill priority discussed in Sections 2.0 and 3.0. Spill will start as specified in the Spill Priority List unless and until a different priority is recommended by the TMT.

The management of spill at each dam is based on TDG levels measured at specific forebay and tailwater FMS. The current locations of these gauges are based on extensive studies that have been conducted since 1996. The Corps will continue to coordinate with the States of Oregon and Washington on voluntary spill for fish passage, and provide technical information to inform the process. Future spill operations may be modified through the implementation planning process and adaptive management. The Corps' decision on the spill program will consider water quality effects along with the results of spill studies, biological evaluations, and the relationship to achieving BiOp performance standards.

5.0 TDG Monitoring Program

In support of the spill management program, a TDG monitoring program has been established and is described in the Dissolved Gas Monitoring Plan of Action. This monitoring program is revised to include changes in the FMS system and evaluated by regional representatives.

A copy of the 2010 Dissolved Gas Monitoring Plan of Action can be obtained from the RCC Water Quality Programs webpage, Dissolved Gas and Water Temperature Monitoring Report, 2010, Appendix B found at: http://www.nwd-wc.usace.army.mil/tmt/wqnew/

ATTACHMENT D

Affidavit of Alex J. Spain

EXHIBITS TO SPAIN AFFIDAVIT

BPA's Thermal Displacement Offer Letter and Term Sheet,
February 2011

BEFORE THE
FEDERAL ENERGY UNITED STATES OF AMERICA
REGULATORY COMMISSION

Iberdrola Renewables, Inc.;	)	
PacifiCorp;	)	
NextEra Energy Resources, LLC;	)	
Invenergy Wind North America LLC; and Horizon Wind Energy LLC,	)	Docket No. EL11-44-000
Petitioners,	)	
v.	)	
Bonneville Power Administration,	)	
Respondent.	)	

AFFIDAVIT OF ALEX J. SPAIN IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

1. My name is Alex J. Spain. My business address is 905 N.E. 11th Avenue, Mail Stop: PTF-5, Portland, OR 97208-3621. I have been the Trading Floor Manager of the Bonneville Power Administration (BPA) since May 2010. As such, I have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's Answer.

2. Prior to becoming the Trading Floor Manager I managed the Trading Floor's Day Ahead and Hourly trading group for over 3 years and prior to this managerial position, I was a Day Ahead Trader for nearly 2 years. The BPA Trading Floor works closely with BPA's Power and Operations Planning groups to manage the generation output of the 31 dams and one nuclear plant that constitute the Federal Columbia River Power System (FCRPS). The BPA Trading Floor generally focuses on short-term marketing decisions of less than 12 months. Prior to joining the Trading Floor, I was a financial analyst and risk analyst for BPA. I graduated with a

B.A. from the University of California at San Diego (UCSD), and have an M.B.A. degree from the University of Southern California (USC). I have been employed by BPA since June 2002

3. My comments below outline the commercial arrangements and marketing efforts deployed by the BPA Trading Floor since June 2010. My affidavit includes three sections. The first is a chronological overview of the marketing and outreach efforts that the Trading Floor conducted through the past year. The second section lists the portfolio of creative and non-standard transactions we successfully negotiated to hedge our spring 2011 over generation concerns, and the final section includes lessons we learned from our extensive outreach efforts to expand our markets in search of Spring 2011 load.

Chronological Overview of Marketing and Outreach Efforts

4. BPA's energy production varies by large amounts from year to year and season to season based primarily on water supply. Some years BPA has surplus energy not needed to serve its wholesale customer base, which it sells into the West Coast's bulk electricity marketplace. Usually BPA sells surplus power on a short-term basis (less than 12 months), but it also sells for longer periods as circumstances warrant. Starting in Q3 2010 (July through August) the BPA Trading Floor established a series of May/June LLH sales strategies to hedge the 2011 spring runoff season. Standard LLH consists of off-peak energy Monday through Saturday hour ending 1 thru 6, 23 and 24 and Sunday hour ending 1 through 24. When HLH is referenced in this paper, it consists of on-peak energy Monday thru Saturday hour ending 7 through 22. Initially our spring 2011 LLH marketing strategy was conservative given the large amount of time, operational, and stream flow uncertainty inherent in our spring operations. BPA's spring hydro operation, similar to its other hydro operations, is determined by the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Reclamation) whom Congress has authorized and given statutory responsibility for achieving multiple hydro obligations. During the spring

and early summer BPA is responsible for marketing power from the FCRPS in compliance with its obligation to follow strict flood control draft and summer refill curves established by the Corps that involve drafting the FCRPS to flood control in April and refilling across May and June to be full after the July 4th weekend.

5. This strict daily and monthly operation is extremely susceptible to unforeseen weather and load events. In dry years or during extreme load events, the BPA Trading Floor finds itself purchasing large amounts of spring energy to ensure summer refill and in wet years or when loads are low, we find ourselves struggling to sell a large amount of power to manage the speed and magnitude of refill across May and June. The magnitude of this spring uncertainty is tremendous. BPA can be either surplus or deficit by thousands of megawatts daily. Needless to say, BPA faces a tremendous amount of spring inventory and operational uncertainty and a large amount of this uncertainty invariably falls upon our LLH energy curves. During the spring months, LLH energy is the first to disappear in dry years when stream flows are low and it is the quickest to turn surplus in wet years when stream flows exceed the FCRPS generation and storage abilities. Lack of flexibility is most prominent on the Snake River where the FCRPS hydro projects are "run of the river" and have negligible storage.

6. Throughout the summer of 2010, the BPA Trading Floor ventured cautiously into selling spring 2011 energy. It wasn't until the beginning of Q4 (Oct thru December) that the Northwest energy markets and our internal weather forecasters began to see the emergence of a La Niña weather pattern developing in the Pacific. Despite the forecast, debate would continue for months as to how the 2011 La Niña winter would compare to prior La Niña years. More specifically, La Niña was the forecast, but how this weather phenomenon would drive FCRPS spring 2011operations and energy inventory remained very uncertain. Normally a La Nina weather pattern signals a wet and cold winter in the Northwest with substantial snow in the

mountains. However, the correlation is weak and a La Nina is not a sure guarantee of a wet winter and prolific spring runoff. In fact some La Nina winters can be quite dry, such as the 2001 winter when the Northwest experienced persistent winter drought conditions and total flow at The Dalles (the standard area for measuring Columbia River flows) were only slightly higher than 50% of average.

7. Through the remainder of 2010, despite an abundance of inventory uncertainty, the BPA Trading Floor elected to augment its cautious price point strategy with a volumetric sales strategy that ignored price and targeted weekly sales volumes. In addition, we added Q2 (April thru June) marketing strategies to help address May and June liquidity concerns. May and June LLH energy was difficult to sell individually, but combining them into a Q2 LLH energy sales strategy improved liquidity and made it easier for us to sell May and June energy. Packaging April energy into a Q2 marketing strategy was not without risk. April is an operationally challenging month for BPA. The FCRPS storage projects, including Grand Coulee, are operated as close to their flood control elevations in April as possible to manage expected spring runoff and to provide spring flows for salmon. Once drafted to the flood control target, the projects may be required to pass inflow (e.g. hold the reservoir steady) until the Corps determines that refill operations may begin. If April Northwest temperatures are low resulting in high loads and low stream flows due to a delayed snow melt, BPA can find itself dangerously short of energy the first half of April as we wait for spring run-off and authorization from the Corps to draft Grand Coulee. Historically BPA markets April energy extremely cautiously and conservatively, but this year was different. This year we were willing to take more risk to hedge the La Niña weather pattern and our increasing spring 2011 over generation and lack of market concerns.

8. Before the end of the year we also explored the possibility of hedging our May and June LLH inventory by purchasing LLH daily Puts. A Put gives us the right to sell energy to the other

party at a predetermined price. Puts are options to deliver energy, not obligations, and appeared to be a good insurance vehicle to protect BPA from having to spill in May and June because of insufficient load without increasing our purchase risk in the event of a dry year. We contacted a number of counterparties with a heavy presence in the Northwest power markets but found few sellers, expensive option fees, and offers that provided limited price protection given that May and June LLH energy prices were already trading below historical averages. We did buy 100 MWs of daily May and June LLH Puts but it became apparent to us that the options market was not liquid enough to hedge our spring over generation concerns which we believed could easily exceed thousands of May and June LLH MWs in above average stream flow events.

9. After recognizing that the standard option market was insufficient to meet our hedging needs, we tried to work with counterparties to build non-standard options with both daily and monthly option characteristics, but we were largely unsuccessful. The non-standard options were difficult to price, counterparties found them difficult to hedge and hence were reluctant to participate, and the quotes we did receive continued to include few MWs and provided very little price protection. Throughout the winter months we periodically ventured into the standard and non-standard options market but counterparties were few, prices were high, and volume was low every time we ventured into the market. As the La Niña weather pattern grew stronger, mountain snowpack increased, and prices fell, the number of counterparties willing to explore creative solutions to our over generation concerns eroded.

10. At the start of Q1 2011 (January thru March) it was pretty clear the Pacific was in the midst of a strong La Niña weather pattern but the Northwest's hydrologic outlook remained in doubt. Throughout January the Northwest River Forecast Center's (NWRFC) January thru July water supply forecast measured at The Dalles was near the 30-year historical average of 107.3 million acre feet (MAF). At first glance these forecasts looked promising but the Canadian

portion of this measurement was below average and dropped between mid-December and late January. The Canadian portion is critical in forecasting our spring and summer inventory because snow runoff from the Canadian basin effects all federal generation on the Columbia River and usually lasts longer that U.S. basin snow runoff. The U.S. portion of the water supply measurement includes Snake River basin snowpack readings which are lower in elevation and more susceptible to sudden and short spring runoff events. Snow runoff from the Snake River basin is extremely valuable to BPA, but in the early winter our focus is on the Canadian snowpack and how it might affect FCRPS operations and generation patterns throughout the spring and summer.

11. In late January, faced with continued inventory uncertainty and persistently low prices, we again adjusted our 2011 spring marketing strategy to be more aggressive. We had already shown a willingness to increase our April purchase exposure, we had already transitioned away from a price points and towards a volumetric sales strategy, and we had already scoured the market for standard and non-standard options. In late January we decided to go directly after the Northwest thermal generation owners with an economic displacement offer. The letter and displacement terms we offered thermal owners is attached to this affidavit and was sent to the following counterparties:

Avista Corp	Portland General "PGEM"	Centennial Energy Resources
Idaho Power	Pac NW Generating	PacifiCorp
PPL Montana	Puget Sound energy	TransAlta Corp.
Seattle City and Light	Sierra Pacific Power	

12. The economic displacement offer was mailed February 9th and expired February 28th. It included a lower and upper price cap to put up to 1000 MWs FLAT of federal hydro energy in May and June for two to three weeks in exchange for thermal displacement. Point of delivery was within the BPA balancing authority area, but the start date, duration, and volume were flexible. Additionally we included a 5-day notification and option fee paid by BPA to encourage

thermal owners to step forward. The mailing and e-mail notifications were sent but there were no interested parties prior to February 28th when our offer expired.

13. Our economic thermal displacement offer had to include a termination date because of the large amount of BPA energy and price risk involved. We could not withhold 1000 MWs of FLAT federal hydro capacity indefinitely in a west coast energy market that was trading lower each week. At some point, we were going to have to revert back to the market and chose February 28th as the cutoff. We continued to discuss displacement opportunities with thermal generators through the winter and spring, but our standard offer expired in late February with no takers, forcing us back to the standard energy markets for load.

14. Between late February and early March two things became increasingly clear. First, thermal owners were not interested in what we believed was an aggressive and fair May/June economic displacement offer and second, the La Niña weather pattern was getting stronger. No longer was the Canadian snowpack below average, it had fully recovered and was poised to join the above average readings already prevalent in the U.S. basin.

15. In March we continued to reach out to thermal owners to understand their spring generation patterns and to see if we could tailor a thermal displacement contract that met their needs. We focused our attention on those thermal owners who historically did not shut down in low priced markets. Primarily we focused on generators east of the Cascades in Montana and Wyoming. During this outreach period, the NWRFC water supply forecast increased from 102% to 107%. As the NWRFC water supply forecasts rose, what initially was a multi-day spring 2011 over generation concern became a multi-week concern that had the potential to last months. To combat this trend, we augmented our thermal displacement outreach program with an even larger and more aggressive spring 2011 sales strategy.

16. We exited Q1 2011 (Jan thru March) with a greater appreciation and understanding of the financial and operational complexities associated with displacing Northwest thermals that do not historically curtail their generation during Spring runoff, and our efforts were not fruitless. We were able to negotiate two large and flexible May/June sales that when combined, totaled more than 1000 MWs of LLH sales. Neither of the contracts was explicitly tied to specific thermal plant operation, but they did include a significant amount of LLH load (MWs) and they did include flexible start dates which were extremely important to us in timing our sales and load with our highly unpredictable spring run-off and load needs. Additional details concerning these transactions and others, plus what we learned during our outreach appear later in this affidavit.

17. As we entered Q2 2011 (April thru June) we continued our outreach program and spring marketing activity, but starting in April the Q2 contract no longer traded and we were left trying to sell May and June LLH energy as individual months. As the list of marketing tools and creative thermal displacement options diminished, the NWRFC water supply forecasts continued to rise and went from 107% of average March 31st, to 119% April 28th, and to 124% of average May 19th. Between March 31st and May 19th 17 MAF were added to a water supply forecast that averages 107.3 MAF. As quickly as our spring hydro generation forecasts rose, May and June LLH energy prices fell. First they fell below the Trading Floor's incremental costs of transmission and then they fell below zero. Both price thresholds are important because they represented moments in time when energy sales would have resulted in negative net revenues either for the BPA Power Service (BPA PS) business line or for the BPA agency.

18. BPA Trading Floor transaction policy prohibits the Trading Floor from conducting business that directly leads to expected revenue losses for BPA PS or BPA agency. The policy prohibits the Trading Floor from forward marketing at prices below market or below our incremental costs. If we sell power below either of these thresholds and we expect the

transaction will negatively affect BPA PS revenues, such actions are prohibited. We don't have to make money, but the Trading Floor can't conduct business in the forward markets in a way that it knows will negatively benefit BPA PS revenues. During periods of extremely low prices and abundant generation, the incremental cost that most often prohibits use from forward marketing is our exposure to incremental transmission costs.

19. The BPA Trading Floor has a significant amount of existing transmission and we continue to buy transmission as needed to cover our marketing activity. This year's rapid increase in spring energy inventory coupled with extremely low May and June LLH energy prices, however, quickly exposed the Trading Floor to forward energy prices that were below our incremental transmission cost threshold.

20. The BPA Trading Floor treats its existing transmission as sunk and assigns it a zero value, but once our sunk transmission is exhausted, our energy sales are exposed to a combination of monthly, weekly and hourly BPA transmission costs of \$2.29, \$2.91 and \$4.33 respectively. In order to follow our forward transaction policy of protecting BPA PS revenues, when our sunk transmission is completely depleted, the Trading Floor reverts to an incremental transmission cost price threshold that we believe protects BPA PS from negative net revenue transactions

21. In 2011, the only forward contract affected by the incremental transmission energy price threshold was the June MIDC LLH contract. The June LLH contract traded below the threshold April 18th and never recovered. Instead it continued its slide downward and started to trade negative May 11th. On April 18th the NWRFC water supply forecast was only 109% above average and considerable uncertainty remained in our May and June LLH inventory forecasts . Between April 18th and May 11th, however, instead of warm temps and early spring weather,

impressive storms continued to batter the Northwest and the NWRFC forecast quickly increased to 119% of average.

22. The BPA Trading Floor transaction policy switches from protecting BPA PS revenues to protecting BPA agency net revenues when we are trading within month energy products. Within month products consist of Balance of Month (BOM), weekly, daily, and hourly energy transactions. The policy switches from protecting BPA PS net revenues to protecting BPA agency net revenues when we transition to within month trading to protect BPA PS from negative revenue transactions for as long as there is monthly load, generation, and stream flow uncertainty. Once we are within the month and our operations and forecasts are better understood, we revert to a policy of no net cost to the BPA agency when sales are necessary to protect the FCRPS from Endangered Species Act (ESA) and Clean Water Act (CWA) risks. The policy shift allows us to sell free power throughout the BPA balancing authority area regardless of incremental transmission expense. We continue to require that all incremental non-BPA expenses be covered such as non-BPA transmission and CAISO fees, but all other expenses are internalized and we sell free BPA hydro power from within our balancing authority area to whoever has load.

23. Throughout April we continued to sell May/June LLH energy, but on May 11 Northwest daily and BOM prices joined the June LLH contract by trading negative. With LLH energy trading negative thru June, we found ourselves embroiled in a negative priced market with few LLH load opportunities that wouldn't directly harm BPA PS or BPA agency net revenues.

24. Facing a Northwest LLH energy market in the middle of May that was trading negative LLH energy through June, we shifted our attention to the southwest and began aggressively to market day ahead and hourly LLH energy into California and southwest markets at the Nevada Oregon Border (NOB) and the California Oregon Border (COB). Additionally, we began

exercising our daily May LLH Put and notified both counterparties of our two large non-standard flexible sale contracts that we intended to commence deliveries. Both contracts and the daily PUT provided over 1000 MWs of LLH load relief, but stream flows were such that we needed an additional 2000 to 3000 MWs of LLH load each day if we hoped to avert lack of market spill, elevating total dissolved gas levels, and environmental redispatch orders.

25. The monthly June MIDC LLH price never recovered above zero, and daily and hourly LLH market continued to trade negative thru the entire month of June. BPA traders sold as much free power as the market desired in the daily, hourly and BOM LLH markets whenever a willing purchaser appeared. We also continued to contact hydro and thermal generation owners in an endless effort to find LLH load, but most of our outreach efforts in May and June were halted by the same obstacles we faced in February during our initial outreach discussions. Namely thermal generators are often owned by multiple owners whom each have different financial, reliability and risk thresholds. Furthermore, the owners of these large thermals indicated that they were already operating at LLH minimum generation levels and that any additional LLH displacement would likely require that they take their thermal completely down. Complete displacement would then require not only LLH displacement energy, but also a combination of HLH energy, capacity, and ancillary services. These demands were both operationally and cost prohibitive.

26. The displacement prices quoted BPA were often tied to a thermal generator's marginal cost of operations which were well below market prices and allowed them to operate profitably across a 24-hr period. Furthermore, BPA didn't have the HLH energy and capacity requested. We would have had to source these products from a market that lacked hourly HLH capacity. Northwest generation resources were either displaced, in maintenance mode, already managing hydro run-off, or required considerable lead time, commitment, and price to generate. The

combination of both selling displacement energy below market and buying expensive HLH hourly energy to address any FCRPS energy shortages would have cost BPA PS and the BPA agency a considerable amount of money.

27. We succeeded in extending our two large non-standard flexible contracts into July, signed an economic thermal displacement contract with a thermal in the BPA balancing authority area, and signed other May through July contracts totaling more than 1 million MWhrs to hedge lack of market spill events. In addition, we discussed shifting our irrigation and our direct service industry loads from HLH to LLH to increase our LLH loads. We purchased put options to the regional trading hubs and we purchased reserves from our major DSI customer to free-up FCRPS HLH generation and reduce LLH spill. Despite our best efforts, however, we never were able to displace thermals outside our balancing authority area. We never were able to address their operational and financial needs without seriously and measurably damaging both BPA and PS net revenues. Their marginal costs were too low, their HLH energy and capacity needs were too high, and the displacement duration they requested was too long.

28. Much discussion has also been raised about the effect negative prices have on the market and the belief that BPA could address our over generation concerns by simply selling negative priced power. The BPA Trading Floor does not believe this to be the case and, on the contrary, we believe this policy could have destructive financial ramifications to a region whose primary spring generation source is a federal hydro asset whose operations, flexibility and storage limitations are discussed in multiple public forums and easily monitored. Furthermore, to fundamentally alter the region's LLH spring over generation concerns, apart from all the multi-ownership and HLH energy and capacity impediments BPA would have to overcome, we would have to consistently sell LLH energy at deep enough discounts to effectively drive the flat power price below a thermal generator's marginal costs. During our outreach efforts we were quoted

displacement prices of $6/MWhr. Hence, to drive the flat 24-hr price below $6/MWhr in a market whose 16-hr HLH price consistently traded above $20/MWhr, BPA would have to sell large amounts of 8-hr LLH energy at significantly negative prices. We believe maintaining the flat price low enough to entice non-federal generation to remain displaced would become increasingly difficult and perhaps impossible because as we displaced each cheap thermal generator, a more flexible thermal with a higher marginal cost would have to be enticed to fulfill the region's HLH load and reliability needs. HLH prices would have to rise in order to entice these more flexible thermals to generate across a shorter 16-hr HLH period. As HLH prices rose, the flat 24-hr price would also rise. With each cheap thermal displaced, HLH prices would rise to reflect the gradually increasing heat rate required to entice more expensive and flexible thermals to generate. The HLH/LLH prices split would widen and the region's rate payers would pay dearly as BPA, its largest supplier of spring energy found itself paying increasingly negative LLH prices to meet its environmental stewardship responsibilities while paying increasingly expensive HLH prices to meet it reliability statutes. This policy would be destructive financially to Northwest electricity rate payers and BPA chose to protect the financial well being of the region. In the Pacific Northwest, before the interconnection of over 3,500 MW of wind generation negative pricing was relatively rare even during high flow periods. Negative pricing was much more common this year, particularly on light load hours when generation exceeded loads. This phenomenon has also occurred in other balancing authority areas with a high penetration of wind generation.

29. So long as the danger of Environmental Redispatch persists, the BPA Trading Floor will offer free power across its balancing authority area and is willing to take a considerable amount of financial and scheduling risk on non-firm transmission to help ensure we have access to load inside and outside our balancing authority area. Between May 11th and June 30th, the BPA

Trading Floor has sold over 750,000 MWhrs of energy that we believe has resulted in either no value to BPA PS or the BPA agency revenues. Of this approximately 250,000 MWhrs were sold at zero.

Portfolio of Creative and Non-standard Transactions signed:

30. Chronological order according to trade date

1. 100 MWs LLH MIDC May Daily PUT
   Trade Date: 9/10/10
   Put was exercised daily starting mid-May

2. 100 LLH MIDC June Daily PUT
   Trade Date: 9/10/10
   Put was exercised daily through June

3. Energy Swap
   Trade Date: 2/9/11
   700 MWs FLAT x 21 Days with 5 day notice (352,800 MWhrs)
   Exercised May 22nd thru June 12th .
   352,800 MWhrs will be returned to BPA.

4. May/June flexible Put
   Trade Date: 2/22/11
   300 MWs LLH (HE 23,24 and 1 thru 6) x 28 days with 5 day notice (67,200 MWhrs)
   Exercised May 14th thru June 12th

5. May/June flexible COB Put
   Trade Date: 4/19/11
   175 MWs FLAT x 7 days
   We did not exercise this PUT due to COB LLH prices consistently trading at or above $0 and above the Put's strike price.

6. July 205 FLAT Sale to regional Investor Owned Utility (IOU)
   Trade Date: 6/1/11
   Sale facilitated the thermal displacement through early July.

7. Weekly Spill Swap
   Weekly coordination started June 2nd
   8 MWs FLAT (HE 1 – HE 5)
   Advanced coordination allowed non-federal hydro generation owners to spill project each night instead of running to meet load. Spill is replaced with free BPA power.

8. June/July Contingency Reserves re-purchased from regional direct service load.
   Trade Date: 6/7/11
   45 FLAT Capacity June 9th thru July 6th
   Additional HLH capacity allows BPA to generation and meet more of its operational objectives across the HLH hours when lack of market is less of a concern.

9. May/June flexible PUT extended through July 31^{st}.
Trade Date: 6/9/11
300 MWs LLH
Extension ensured LLH load originally intended to terminate June 12^{th} would continue thru July 31^{st} at prices >= $0/MWhr

10. Original Energy Swap Extended
Trade Date: 6/9/11
100 MWs FLAT (55,200 MWhrs)
Extension ensured 100 of original 700 flat load scheduled to stop June 12^{th} would continue thru July 4th at prices >= $0/MWhr

11. Thermal Economic Displacement of thermal within the BPA BAA
Trade Date: 6/14/11
600 MWs FLAT
FLAT load ensured LLH load June 16^{th} thru July 14^{th} >= $0/MWhr

12. TX Loss Energy Return Waivers
Business Practice posted 6/16
Tx Loss Return Waiver candidates contacted starting 6/20
Potential LLH Load: 200 to 300 MWs

Lessons Learned by Region:

West of Cascades (Oregon and Washington):

31. Historical analysis and discussion with natural gas and coal thermal owners west of the Cascades showed that this generation is displaced well before prices trade negative. Many of these thermal generators use the spring months to schedule maintenance on their thermal plants and we attempted to coordinate their thermal maintenance schedule with our run-off and load needs, but everyone indicated that their maintenance schedules are extremely inflexible. The parts, expertise, and maintenance crews needed to perform seasonal maintenance had to be scheduled months and sometimes years in advance. These highly specialized thermal maintenance crews have a tight schedules and they cannot adjust their sometimes international schedules according to Northwest weather and stream flows phenomena.

32. Discussions with generation owners west of the Cascades quickly reverted to a discussion of energy Puts and sales to the MIDC market. Paying an option fee to Put energy at MIDC or pre-arranging a sale to MIDC does little to solve the Northwest over generation imbalance. We did successfully negotiate a few significant flexible non-standard sales contracts but the primary

objective of our outreach efforts was to solve the Northwest's over generation imbalance problem not simply delaying it through timely sales.

33. Other noteworthy observations were that not all thermal owners are comfortable discussing thermal displacement contracts. One major regional investor owned utility, for example, informed us that their thermal operations were confidential and they didn't wish to discuss any displacement terms. Two major regional investor owned utilities also informed us that they needed to retain their thermal flexibility in part to help solve their own variable generation integration challenges.

Canadians:

34. Discussion with Canadian counterparties resulted in some LLH load. We successfully negotiated and extended a contract that provided significant LLH load to Canada but discussions were not without considerable challenges. Limited long-term firm transmission from BPA to the US/BC Border made commitments in excess of one hour or one day difficult. Furthermore, the Canadians were experiencing their own operational challenges as they too were facing difficult hydro conditions and limited hydro flexibility. In short, the Canadians had their own over generation concerns.

California and Southwest:

35. Similar to our discussions with our Canadian counterparts, discussions with our southern counterparts were also complicated by transmission and hydro constraints. Northern California had its own over generation concerns to deal with and firm transmission capacity in excess of hourly transmission was in short supply. We attempted to buy blocks of intertie transmission to California but there was either none available or the transmission prices we were quoted equaled or exceeded the value of energy being traded at COB and NOB. Buying expensive third-party transmission to sell power at prices below our transmission costs was prohibited because such

transmission purchases would have resulted in negative BPA PS or BPA agency net revenues. Generation owners intended to use their intertie transmission to mitigate their own Northwest over generation and negative price concerns, and others intended to use their intertie to arbitrage the expected price spreads between the Northwest and Southwest energy markets.

36. Throughout May, June and July, the Trading Floor has embarked upon an aggressive daily and hourly marketing strategy with the CAISO market that relied heavily on non-firm transmission. Whenever environmental redispatch and high levels of total dissolved gases across the FCRPS are a concern, our traders bid into the CAISO market in excess of our firm transmission capacity hoping that non-firm transmission capacity would be available. This strategy was successful when CAISO prices traded above our estimated Day Ahead and Hour Ahead CAISO grid management fees but it was unsuccessful when CAISO prices were below our grid management fees and negative. Selling energy into the CAISO market below our CAISO fees would result in negative revenue to BPA and was against Trading Floor transaction policy.

East of the Cascades (East of McNary and Hatwai):

37. Historical data showed us that that large coal plants east of the Cascades in Montana and Wyoming were our primary competitors for LLH load in the spring. These large thermal generators rarely uniformly shut-down in the spring and we devoted a large part of our thermal displacement outreach efforts to them. Unfortunately there were multiple financial, operational, and transmission hurdles that neither side could overcome.

38. In order to displace large thermal generators and substitute the energy, capacity and ancillary products they provide their host balancing authority and the load serving entity their generation supports, we were going to need a lot of firm transmission to multiple points of delivery. Capacity and ancillary products cannot reliably be scheduled on non-firm or hourly

transmission over long periods of time. In order to reliably displace these large thermal generators we were going to need a lot of firm transmission capacity to points outside the BPA balancing authority area that we did not have and that was not easy to purchase, if it was available in the first place.

39. For those discussions not hindered by available long-term firm transmission capacity, multiple ownership issues and a varying array of scheduling needs and risk policies made discussions extremely challenging and ultimately impossible. For example, we had a number of conversations with a thermal generation owner east of the Cascades about their coal unit but they indicated that they needed the flexibility to mitigate their own hydro over generation concerns.

40. The Colstrip coal units 1 thru 4 were also a focus of our outreach efforts. The total output of the four Colstrip coal units is owned by multiple counterparties. Some of these owners indicated that one of the coal units would more than likely be displaced during most of May and June and didn't warrant displacement discussions. Another owner deemed their thermal operations confidential and didn't want to discuss thermal displacement terms. Furthermore, they indicated that they relied in part on their thermal generation to integrate their own variable resources. A few owners indicated that their risk preference is to always have one deployable unit within their resource stack to meet reliability and load requirements. These owners of Colstrip are load serving entities that were skeptical of displacing their generation in exchange for an energy and capacity market supported almost entirely by hydro and variable wind. Colstrip also provides its host balancing authority valuable balancing reserves and ancillary services that the FCRPS simply could not provide with the necessary consistency required. And finally it is our understanding that Colstrip is far enough East that part of its generation can be sold into the southwest and Mid-Continent Area Power Pool (MAPP) markets where LLH prices are generally higher during the Northwest spring run-off period.

41. Colstrip displacement discussions were also hindered by multiple ownership issues. When discussing displacement terms, each owner had different financial needs, operational requirements, and risk aversions that we were going to have to accommodate. One Colstrip owner indicated they were willing to displace their share of a unit but requested a 30 day minimum displacement at a fixed price that was well below market. Selling flat energy below market would constitute an expected cost to BPA PS revenues and was not permissible under the Trading Floor's transaction policy. One counterparty wanted a shaped HLH product or hourly calls to cover their morning and evening capacity concerns. Another owner of Colstrip requested a displacement price that was also below market and requested a small amount of contingency reserves that were going to have to be scheduled on firm transmission to their balancing authority area. Successful discussions with one did not constitute a deal. In order to displace the various Colstrip generation units we were going to have to meet the needs of multiple Colstrip owners simultaneously. Each of the four Colstrip units is owned by multiple counterparties. We could not displace one owner's share of a Colstrip unit without displacing the other owners' share. We were never able to address the financial hurdles and the BPA federal hydro system was not going to be able to meet all the HLH energy, capacity, and ancillary needs requested. There was serious risk we were going to have to purchase these products in a HLH and capacity market that was expensive and often illiquid.

42. Although unsuccessful in displacing the thermals east of the Cascades during our outreach efforts, we continuously monitored prices, transmission availability, and FCRPS generation flexibility for displacement opportunities throughout the high water event. Market prices were never low enough to warrant equitable displacement, lack of firm transmission for the durations required was always a hindrance, and the combination of a cool spring, higher than average loads, and unexpected BPA unit outages never gave us the confidence that we could

provide the HLH energy, capacity, and ancillary products they needed for the duration of time they requested.

43. In addition to the Economical Thermal Displacement Term Sheet that was mailed to NWPP thermal generation owners in February, Trading Floor staff discussed spring 2011 over generation solutions with the following entities:

1. Modesto Irrigation District
2. Turlock Irrigation District
3. Iberdrola
4. Redding
5. PPL Montana
6. Idaho Power
7. Puget Sound Energy (PSEM)
8. Portland General
9. PacifiCorp
10. Calpine Energy
11. Clark Public Utilities
12. Shell Energy
13. PowerEx
14. TransAlta
15. Nevada Power
16. Western Area Power Administration (WAPA)
17. Alcoa
18. Teckcominco (Industrial load in Canada)

The types of transactions discussed included:

1. Spill Swaps
2. Out of region sales
3. Out of region displacements (East and SW WECC Coal)
4. Wind displacements
5. PUT Options
6. Energy Swaps
7. Energy for Transmission Swaps
8. Irrigation Spill and Generation changes

44. In review, the discussions we had with thermal owners this winter largely resulted in futile attempts due to one of the following reasons:

1. HLH vs LLH generation flexibility made it possible for Coal east of the Cascades to profitably operate at extremely low FLAT prices. If BPA wished to displace these generators, it would have required below market prices and a cost to our power customers.
2. Historical analysis showed that large thermals west of the Cascades were already likely to be displaced before LLH prices reached negative.
3. Utilities rely on coal for ancillary services and to help integrate their variable generation.
4. Some utilities are either unwilling to discuss thermal operations or adhere to risk policies that are skeptical of believing that a market supported almost exclusively by wind and hydro generation can reliably provide the market's energy, capacity, and ancillary service needs.

45. Attachments include the Economic Displacement Letter.

46. This concludes my Affidavit.

AFFIDAVIT

State of Oregon
County of Multnomah

NOW BEFORE ME, the undersigned authority, personally came and appeared, Alex J. Spain, who after being duly sworn by me, did depose and say:

That the above and foregoing is true to the best of his knowledge, information, and belief.

Alex J. Spain

SIGNED AND SWORN TO BEFORE ME ON THIS 18th Day of July, 2011

OFFICIAL SEAL
BARBARA M WILLARD
NOTARY PUBLIC - OREGON
COMMISSION NO 438867
MY COMMISSION EXPIRES APR. 28, 2013

Barbara M. Willard

NOTARY PUBLIC, STATE OF OREGON

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER SERVICES

February 15, 2011

In reply refer to:

The Bonneville Power Administration (BPA) Trading Floor, is reaching out to the Northwest Thermal owners to maximize Federal Columbia River Power System (FCRPS) generation, increase thermal flexibility, and to minimize dissolved gases during high stream flow events. Dissolved gases, resulting from excess spill, can harm fish and BPA is dedicated to minimizing the risk that this might occur in the future.

In June 2010, BPA faced a period of time when it had a temporary oversupply of generation due to surging spring runoff in the FCRPS, and high winds. During this period, the generation levels exceeded power demand and export capability. A lack of demand for the surplus federal hydropower, even at zero cost, threatened to create water conditions in the Columbia River dangerous to fish.

BPA managed through the June 2010 event, but with the potential for even higher stream flows and with more variable generations being integrated with the FCRPS, BPA is developing a list of action items it could use if faced with over generation events that threaten fish in the future.

One of these actions involves an aggressive outreach program by the BPA Trading Floor to Northwest thermal owners to discuss unique marketing transactions that help maximize FCRPS generation with the focus to minimize the levels of dissolved gases. To date, the BPA Trading Floor has contacted a number of thermal owners. We appreciate the time, energy, and creativity you have invested in sharing your feedback with BPA. We have learned a lot from these negotiations and are hopeful that this process results in transactions that help protect the health of the FCRPS and the reliability of the system.

We believe the enclosed Term Sheet accurately describes a transaction that is financially and operationally sound for both parties, with the appropriate notification requirements to facilitate greater thermal flexibility than was achieved in June 2010. We understand additional provisions may be necessary and we are eager to discuss them with you. This offer expires February 28th, 2011, and is capped at 1000 Flat MWs during the months of May through June 2011. Responses will be evaluated in the order they are received.

We want to know what you think about the enclosed Term Sheet and ask that you contact the BPA Trading Floor to discuss any alternatives to improved thermal flexibility and the safe operation of the FCRPS during fish passage season. Please address all inquires to Mark Miller, or Dan Le.

Mark Miller (503) 230-4003
Dan Le (503) 230-3144

Sincerely,

Alex Spain
Trading Floor Manager
(503) 230-5780

1 Enclosure:
Thermal Displacement Term Sheet

Cc:
Avista Corp
Centennial Energy Resources
Idaho Power
Pac NW Generating
Pacificorp
Portland General Electric
PPL Montana
Puget Sound Energy
Seattle City and Light
Sierra Pacific Power
Transalta Corporation

Proposed Term Sheet: May-June Displacement

Product:	Economic Thermal Displacement Energy
Buyer:	XXX
Seller:	Bonneville Power Administration (BPA)
Term:	Begin May 1, 2011, through June 30, 2011
Demand:	XXX FLAT (24 hr) Block MWs [Thermal Unit(s) must be off-line]
Notice:	12 Noon, Three (3) Trade Days advance notification
Duration:	14 Days Min / 21 Day Max [election made by BPA at time of notice]
Scheduling:	Scheduled within BPA's normal pre-schedule window.
Delivery:	To the extent transmission is available; BPA will provide and pay for Transmission required for delivery from the Federal Columbia River Power System to Load Balancing Authority identified by the Buyer.

Premium $1.00 / MWh paid by BPA

[XXX Mw x 1,464 hours] x $1.00 Mwh = XXX Total Premium

Energy Charge: For each day, an average daily price will be calculated and billed using the Intercontinental Exchange Mid-C Day Ahead Peak and Off-Peak indexes, specifically using the published volumetric weighted average index prices. The calculated average daily price is a weighted average based on the Peak and Off-Peak hours. The Peak and Off-Peak index prices used to calculate the daily average price will be constrained so that the price of each diurnal index will be capped at a specific Maximum Price and will be no lower than a specific Minimum Price.

Maximum Price:	$12.50 / MWh
Minimum Price:	$0.00 / MWh

Buyer notification:
Buyer provides BPA first right of refusal to sell at the prevailing market price, should thermal owner displace prior to receiving notification from BPA.

Service Type: WSPP Schedule C Firm Energy

Settlement Procedure: As described on the WSPP Agreement.

Additional Terms: Additional terms and products are negotiable and can be discussed as additions or in place of this term sheet.

ATTACHMENT E

Affidavit of Kurt O. Lynam

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.;	)	
PacifiCorp;	)	
NextEra Energy Resources, LLC;	)	
Invenergy Wind North America LLC; and	)	Docket No. EL11-44-000
Horizon Wind Energy LLC,	)	
Petitioners,	)	
v.	)	
Bonneville Power Administration,	)	
Respondent.	)	

AFFIDAVIT OF KURT O. LYNAM IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

1. My name is Kurt O. Lynam. My business address is 905 N.E. 11th Avenue, P.O. box 3621, Portland, Oregon 97208-3621. I am a Public Affairs Specialist assigned to the Public Communication team at the Bonneville Power Administration ("BPA"). As such, I have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's Answer.

2. I worked as the primary public affairs liaison to executives and subject matter experts on the overgeneration project team. I advised them on effective public engagement tools and techniques. I designed, reviewed and helped refine internal and external documents, including agendas and presentations for public meetings. I attended each of the three workshops and helped the meeting facilitators manage the dozens of

workshop attendees who participated by phone. To help make the overgeneration project more transparent and accessible to stakeholders outside BPA, I designed, refined and updated an external web site providing project-related information and updates. I also established and maintained an external e-distribution address list for interested stakeholders outside BPA. The project team used this address list to share project-related information and updates with participants who asked to join the group.

3. BPA held three public workshops to discuss the overgeneration problem and to explore alternative solutions to avoid having to implement Environmental Redispatch. BPA held the workshops on October 12, 2010, December 3, 2010, and February 25, 2010. There were over 60 non-BPA attendees at each workshop.

4. At the October 12, 2010, public workshop, a number of workshop participants suggested potential solutions to the overgeneration problem that BPA should explore. BPA investigated the feasibility of all of these ideas and has pursued those that appeared feasible, including reducing incremental reserves (reserves held out to increase hydro generation to compensate for a reduction in wind generation) for wind in addition to the reductions in decremental reserve reductions utilized in 2010; exploring the potential to shift irrigation load into nighttime periods; engaging with thermal resource owners to craft non-standard displacement offers, and others. A number of the other ideas that were generated at the public workshops were impractical, because they were outside Bonneville's control or would not be available for the upcoming runoff season. BPA summarized its efforts in a May 2011 document.

5. BPA released a Draft Record of Decision ("ROD") on Environmental Redispatch and Negative Pricing Policies on February 18, 2011. BPA posted the Draft ROD on its

website and notified workshop participants via email, and accepted public comments on the Draft ROD through March 11, 2011. BPA received 39 total public comments on the Draft ROD and posted those comments on its website.

6. BPA issued a Final ROD on Interim Environmental Redispatch and Negative Pricing Policies on May 13, 2011, issuing its final policies and responding to public comments.

7. This concludes my Affidavit.

AFFIDAVIT

State of Oregon
County of Multnomah

NOW BEFORE ME, the undersigned authority, personally came and appeared, Kurt O. Lynam, who after being duly sworn by me, did depose and say:

That the above and foregoing is true to the best of his knowledge, information, and belief.

Kurt O. Lynam

Kurt O. Lynam

SIGNED AND SWORN TO BEFORE ME ON THIS 18th Day of July, 2011

Barbara M. Willard

NOTARY PUBLIC, STATE OF OREGON

OFFICIAL SEAL
BARBARA M WILLARD
NOTARY PUBLIC - OREGON
COMMISSION NO 438867
MY COMMISSION EXPIRES APR. 28, 2013

ATTACHMENT F

Affidavit of Abbey J. Nulph

EXHIBIT TO NULPH AFFIDAVIT

BPA's Environmental Redispatch Business Practice

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.;	)	
	)	
PacifiCorp;	)	
	)	
NextEra Energy Resources, LLC;	)	
	)	
Invenergy Wind North America LLC;	)	
and	)	Docket No. EL11-44-000
Horizon Wind Energy LLC,	)	
	)	
Petitioners,	)	
	)	
v.	)	
	)	
Bonneville Power Administration,	)	
	)	
Respondent.	)	
	)	

AFFIDAVIT OF ABBEY J. NULPH IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

1. My name is Abbey J. Nulph. My business address is 7600 NE 41st Street, Suite 200 – TP-OPP-2, Vancouver, WA 98662. I am a Public Utilities Specialist at the Bonneville Power Administration ("BPA"). As such, I have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's Answer.

2. I managed the process to develop the business practices implementing Environmental Redispatch. I had the lead role in facilitating all public meetings discussing these business practices.

3. Originally there was only one business practice for implementing Environmental Redispatch. The *Environmental Redispatch* Business Practice was posted for a two-week public comment period on March 18, 2011. This comment period closed on April 1, 2011. Twenty-three (23) sets of written comments were submitted and BPA posted responses on April 13,

2011. During the comment period, BPA held a one-hour public conference call on March 25th to respond to questions and provide clarity on the intent of the original business practice.

4. The *Establishing Minimum Generation Levels for Environmental Redispatch* Business Practice, which was an excerpt of the original *Environmental Redispatch* Business Practice, was posted as immediately effective on April 8th. This business practice allowed non-federal, non-variable energy resources ("VER") to submit minimum generation levels to account for specific operating characteristics. This business practice needed to be posted as soon as possible to ensure that non-federal, non-VER generators within BPA's Balancing Authority Area had the opportunity to submit minimum generation levels prior to BPA's decision on whether to implement Environmental Redispatch. A second public conference call was held on April 8th to explain the reason for the separation of the business practices but technical difficulties, resulting from the large number of parties on the call, prevented a constructive conversation.

5. A third public conference call was held on April 15, 2011 – a different format was used for the call in the hopes that the previous difficulties would not occur again – at least one participant expressed frustration with the use of a third-party moderator, but BPA staff responded to each question that was asked, so I felt this was a successful call.

6. BPA had received minimum generation level information, consistent with the *Establishing Minimum Generation Levels for ER* Business Practice, from each of the forty-one (41) non-federal, non-VERs in its Balancing Authority Area by May 12, 2011.

7. On May 13, 2011, the *Final Record of Decision on BPA's Environmental Redispatch and Negative Pricing Policies* was signed, the updated *Environmental Redispatch* Business Practice was posted as immediately effective, and the communication protocols between BPA and the majority of the VERs within BPA's Balancing Authority Area, were successfully tested at 4:15 pm PPT.

8. The communication protocols outlined in the *Environmental Redispatch* Business Practice were first implemented at 11:50 pm PPT on May 17th.

9. The *Environmental Redispatch* Business Practice was updated (version 2) on June 16, 2011 to permit customers to request a waiver from In-Kind Loss Return obligations. This reduces the quantity of Environmental Redispatch that must be ordered by an amount equivalent to the non-federal generation output that is not dispatched to meet those obligations.

10. The *Establishing Minimum Generation Levels for Environmental Redispatch* BP (Attachment 1) lays out a process by which non-federal, non-VER generators within the BPA BAA may submit specific details about their resources' operating characteristics and/or establish a minimum generation level, that they can't operate below, for ER. This BP outlines the kind of considerations that may be taken into account in setting a minimum generation level for ER and includes items that would cause undue hardship or damage to the resources. BPA made it clear that this potentially commercially sensitive information would not be shared publically or with BPA's marketing function.

11. The *Environmental Redispatch* Business Practice (Attachment 2) lays out the sequence of steps BPA will take and the communication protocols that are employed immediately prior to, during, and immediately following an Environmental Redispatch event.

12. All non-federal generators within the BPA Balancing Authority Area are subject to Environmental Redispatch, with three exceptions:

- Seattle City Light's (SCL) 7 MW Columbia Ridge Landfill generator is in BPA's Balancing Authority Area but on SCL's Automated Generator Control (AGC) system, which means any reduction in plant output that isn't reflected in modified schedules would result in SCL's AGC moving (i.e., no ER relief). In essence, this plant is in SCL's Balancing Authority Area so they were excluded from Environmental Redispatch.

- Frederickson is a ~265 MW gas plant that straddles the BPA and Puget Sound Energy ("PSE") Balancing Authority Areas – regardless of the amount of generation, 51% is in BPA's Balancing Authority Area and 49% in PSE's. Without changes to BPA's AGC, making Frederickson subject to Environmental Redispatch would have impacted the BPA-PSE interchange. Frederickson was excluded from Environmental Redispatch because we did not have sufficient time to make these AGC changes.
- Boardman is a ~600 MW coal plant that straddles the BPA and Portland General Electric ("PGE") Balancing Authority Areas – regardless of the amount of generation, 10% is in BPA's Balancing Authority Area and 90% in PGE's. Without changes to PGE's AGC, making Boardman subject to Environmental Redispatch would have impacted the BPA-PGE interchange. Boardman was excluded from Environmental Redispatch because there was not sufficient time to identify and negotiate the necessary changes with PGE.

13. This concludes my Affidavit.

AFFIDAVIT

State of Oregon
County of Multnomah

NOW BEFORE ME, the undersigned authority, personally came and appeared, Abbey J. Nulph, who after being duly sworn by me, did depose and say:

That the above and foregoing is true to the best of her knowledge, information, and belief.

Abbey J. Nulph

Abbey J. Nulph

SIGNED AND SWORN TO BEFORE ME ON THIS 18th Day of July, 2011

Barbara M. Willard

NOTARY PUBLIC, STATE OF OREGON

OFFICIAL SEAL
BARBARA M WILLARD
NOTARY PUBLIC - OREGON
COMMISSION NO 438867
MY COMMISSION EXPIRES APR. 28, 2013

Attachment 1

Establishing Minimum Generation Levels for Environmental Redispatch

Version 1 Effective: 04/08/11

This Business Practice is a revised draft of language that had previously been included in the Draft Environmental Redispatch Business Practice. This new Business Practice reflects modifications and clarifications suggested by Customers during the comment period that closed April 1, 2011.

This Business Practice is effective immediately and implements the requirement that generator operators/owners of non-federal resources within BPA's Balancing Authority Area submit specific details about such resources' operating characteristics. This information will be necessary for BPA to implement the Draft Environmental Redispatch Business Practice, which won't be made effective until such time, if any, when the Administrator executes the Final Record of Decision (ROD) on Environmental Redispatch and Negative Pricing Policy.

⊟Purpose of Establishing Minimum Generation Levels for Environmental Redispatch

ER is designed to ensure the FCRPS is operated consistently with Clean Water Act (CWA) and Endangered Species Act (ESA) obligations, as well as BPA's obligations under the Pacific Northwest Electric Power Planning and Conservation Act (NWPA), under specific hydro and load conditions, and after all practicable mitigating measures have been implemented. When these conditions exist, BPA will issue ER orders to generators and replace scheduled generation in BPA's Balancing Authority Area (BAA) with Federal hydropower at no cost.

BPA does not intend for actions taken during an ER to cause undue hardship or damage to generating resources. To that end, operators/owners of non-federal, non-VER resources within BPA's BAA are encouraged to submit specific details about such resources' operating characteristics and/or establish a minimum generation level for ER. This information will be used to determine Dispatch Orders that may be issued during an ER.

⊟Generators Subject to Establishing Minimum Generation Levels for Environmental Redispatch

A minimum generation level for ER shall be established for all non-federal, non-VER generators in BPA's BAA. If no minimum generation level is established, BPA will assume the minimum generation level is zero.

☐Establishing Minimum Generation Levels for Environmental Redispatch

1. There are no minimum generation levels for VERs due to the fact that VERs do not have reliability factors dictating a lowest operating level.

2. Non-federal, non-VER generators that expect to have a need to continue operating during an ER event may establish a maximum downward ramp rate and/or a minimum generation level that they cannot drop below while operating. Reliability factors that should be considered when establishing minimum generation levels include, but are not limited to:
   a. Ancillary service commitments, such as supply of Operating Reserves,
   b. Applicable environmental constraints/laws/regulations, such as federal license/permit constraints for non-federal hydroelectric facilities,
   c. Generation levels that permit return to normal operations within 60 minutes of an ER ending,
   d. Generation levels required for stable plant operation,
   e. Maximum downward ramp rate over 10 minutes,
   f. Maximum duration for reduced generation,
   g. Minimum fuel take obligations,
   h. Minimum generating capacity needed for local reactive power support,
   i. Minimum time required to effect a change (for unstaffed resources),
   j. Nameplate rating of the plant,
   k. Safety requirements, and
   l. Testing requirements after planned generator maintenance outages.

3. Non-federal, non-VER operators/owners of resources within BPA's BAA shall notify BPA by noon on the last business day of every month of the minimum generation level for at least the next three months, as well as supply accurate contact information for the party that will effect changes in generation. **Data pertaining to the month of April 2011 shall be submitted no later than noon on April 8th, for the period beyond April 11th.** To change the minimum generation level mid-month, notify the BPA 3-Shift by noon of the WECC pre-schedule day. If no minimum generation level is established by the generator, then BPA will assume the minimum generation level is zero.

a. A template has been provided to facilitate the communication of information pertaining to minimum generation levels for ER.

b. Contact to establish minimum generation levels for ER:

3-Shift Phone: 503-230-5724
3-Shift Email: 3Shift@bpa.gov

c. This potentially commercially sensitive information will not be shared publically or with BPA's marketing function. BPA will treat this information as confidential.

Additional Information:

Policy References

• Administrator's Record of Decision (ROD) on Environmental Redispatch and Negative Pricing Policy

Related Business Practices

• Environmental Redispatch

Version History

There is no previous version of this business practice.

Attachment 2

Environmental Redispatch

Version 2 Effective: 06/16/11

BPA has issued an Interim final Record of Decision (ROD) on Environmental Redispatch and Negative Pricing Policy. BPA takes this action as a last resort, after exhausting other available tools. The agency's intent is to use Environmental Redispatch (ER) only for the time period when it is absolutely necessary. The Environmental Redispatch Business Practice is immediately effective and terminates March 30, 2012.

⊟Purpose of Environmental Redispatch

Environmental Redispatch is designed to ensure the FCRPS is operated consistently with Clean Water Act (CWA) and Endangered Species Act (ESA) obligations, as well as BPA's obligations under the Pacific Northwest Electric Power Planning and Conservation Act (NWPA), under specific hydro and load conditions, and after all practicable mitigating measures have been implemented, as identified in the ROD on Environmental Redispatch and Negative Pricing Policy. When these conditions exist, BPA will issue ER orders to generators and replace scheduled generation in BPA's Balancing Authority Area with Federal hydropower at no cost.

⊟Generators Subject to Environmental Redispatch

All non-federal generators in BPA's Balancing Authority Area are subject to ER.

⊟Establishing Environmental Redispatch Minimum Generation Levels

BPA has posted the Establishing Minimum Generation Levels for Environmental Redispatch Business Practice for establishing minimum generation levels for ER.

⊟Order of BPA Actions

BPA will first use voluntary Environmental Displacement (ED) to reduce generation in the balancing authority area. In the hour just prior to implementing ER, BPA will use ED to reduce non-federal generators subject to ER to their minimum generation levels for the next operating hour. When ER is put into effect during an operating hour, non-VER generators subject to ER that are operating above their minimum generating levels for ER are subject to ER first and then, if needed, VERs will be subject to ER as described below.

⊟Environmental Displacement Prior to Environmental Redispatch

1. Prior to implementing ER, BPA Power Services Trading Floor will contact non-federal generators and will make advance offers to displace non-federal generation with Federal hydropower.

2. BPA Power Services is also offering to make advance arrangements with Transmission Customers for waiving In-Kind Real Power Loss Return obligations to reduce spill. Once the Transmission Customer has requested a waiver and made arrangements with the BPA Power Services Trading Floor, BPA Power Real-Time will contact the Transmission Customer prior to implementing ER to request the Transmission Customer reduce the Transmission Loss Returns on their e-Tag. For arrangements to reduce In-Kind Real Power Losses, contact the Trading Floor: (503) 230-5610.

3. Customers interested in making advance arrangements may initiate contact with the BPA Power Services Trading Floor. Trading Floor Contacts:

Day-Ahead and Real-Time Manager: (503) 230-3183
Real-Time Power Marketing Desk: (503) 230-3650 or (503) 230-3651
RTMarketers@bpa.gov

⊟Curtailment of E-Tags

All generators are subject to curtailment of e-Tags at all times for system reliability and other reasons as described in the Curtailment and Redispatch Business Practice. If the curtailment reduces the sum of remaining e-Tags originating at the generator to a level that is less than the ER minimum generation level then the generator must fully comply with the curtailment and reduce generation regardless of the established ER minimum generation level.

⊟Notification that Environmental Redispatch is Imminent

1. Transmission Dispatch will make a posting with the category of 'Curtailment' on the Notices page of BPA Transmission Services' Open Access Same-Time Information System (OASIS) that an ER is imminent. The posting will include the expected duration of the ER event.

2. VERs should continue to schedule their forecast power output, including scheduled loss returns for the hour when an ER event is imminent. Continued accurate scheduling when an ER event is

imminent and during an ER event is critical for the success of Environmental Redispatch efforts. If ER is implemented, all under-generation relative to schedules will be provided by Federal hydropower.

☐Allocation of Environmental Redispatch Quantity

1. BPA Hydro Operations will determine the need to implement ER and will determine the amount of generation reduction required for each hour during the event. When ER is implemented, schedules from the generators will remain intact, but generation must be reduced.

2. In the hour prior to implementing ER for VERs Power Services Loads Desk will contact non-VER generators that are operating above their minimum generation level by phone and will request that the generator contact the Real-Time Power Marketing Desk to arrange an Environmental Displacement transaction that will bring the next hour schedule for the generator to the established minimum generation level. Generators that do not make arrangements for the next hour when requested to do so will be subject to a Dispatch Order from Transmission Services to reduce generation when ER is implemented.

3. If reductions from non-VER generators are insufficient to provide the required reductions, then VERs will receive a pro-rata allocation of the remaining required reduction. The pro-rata reduction for each VER is calculated by (Sum of Schedules for the generator)/(Sum of Schedules for the group) * required reduction.

☐Notification that Environmental Redispatch is in Effect

1. Transmission Dispatch will make a posting with the category of 'Curtailment' on the Notices page of BPA Transmission Services' Open Access Same-Time Information System (OASIS) that an ER is in effect.

2. BPA will post information on ER on the publicly-accessible Transmission Wind Operations web site with near-real time updates.
   a. The "BPA Balancing Authority Total Wind Generation & Wind Basepoint" link will provide information on the total amount of ER reduction.
   b. The "BPA Wind State" link will provide information on the ER state.

3. During an ER event, the imbalance signals to Customers self-supplying balancing reserves under the Customer Supplied Generation Imbalance (CSGI) Pilot will be offset by the amount of the CSGI Customer's share of the ER plus the amount of regulation and load following service being provided by BPA to the CSGI Customer. The

CSGI Customer will control its resources down so the total error for the Customer including the ER, regulation and load following offset is less than or equal to zero.

4. Non-VER generators should already be displaced in advance and not generating or be at minimum generation levels when ER is implemented. However, any non-VER generator operating above established minimum generation levels is subject to a Dispatch Order from Transmission Operations to reduce generation and is subject to Failure to Comply Penalty if the generator fails to reduce generation within 10 minutes to the limit in the Dispatch Order.
   a. Such Dispatch Order will be communicated via a phone call to the generator operator.

5. VERs will receive notification that ER is in effect via the same electronic signal they currently receive for a DSO 216 Limit Level 1 Alarm. Generators receiving this signal via ICCP or a Remote Telemetry Unit (RTU) will receive the ER alarm and generation Limit Target directly and generators that rely on iCRS Generation Advisor will receive the alarm and Limit Target via that application. A message of "ENVIRON REDISPATCH" will be indicated on iCRS Generation Advisor with the alarm that an Environmental Redispatch is in effect. VERs must reduce generation to within 2 MW of their Limit Target which will be at or below the generator's schedule for that hour. VERs that do not reduce output to within 2MW of the generation Limit Target within 10 minutes are subject to the Failure to Comply Penalty.

⊟Notification that an Environmental Redispatch Event has Ended

1. If system conditions improve to the point where ER for VERs is no longer required, the alarm status will revert to normal functionality for DSO 216 limits. This information will be visible on the publicly accessible Transmission Wind Operations website.

2. When system conditions improve to the point where ER is no longer required for non-VERs, Transmission Dispatch will make a posting with the category of "Curtailment" on the Notices page of BPA Transmission Services' Open Access Same-Time Information System (OASIS) that an ER is over. Transmission Dispatch will also contact by phone non-VERs that had been issued a Dispatch Order to reduce generation and advise them to return generation to schedule.

⊟Adjustments to Energy and Generation Imbalance Accounting During an Environmental Redispatch Event

1. For the hours when ER is in effect, the differences between scheduled and actual energy delivered by a generator given a generation limit or Dispatch Order to reduce generation will not be included in the Generation Imbalance Service account for the generator. The Energy Imbalance accounts for loads served by the affected generation will also be adjusted for those hours.

2. Hours will not be included in the Generation Imbalance account for a non-VER generator when the generator reduces generation to minimum generation level in response to a request from Power Services and the generator's schedule was served by Federal hydropower. The Energy Imbalance accounts for loads served by the affected generation will also be adjusted for those hours.

⊟Loss Returns and Obligations During an ER Event

BPA will provide power for redispatched schedules, including scheduled loss returns, during an ER event. Generating Customers are responsible for loss return obligation incurred for the schedules submitted during an ER event.

⊟Generating Customers' Operating Reserve Obligation During an ER Event

Generating Customers are responsible for the Operating Reserve Obligation for the schedules they submit during an ER event.

⊟Adjustments to NT Base Charge Billing Factor for Displaced or Redispatched Declared Customer Served Load

When ER is imminent or in effect, and NT Customers that have Declared Customer Served Load reduce generation in response to requests from Power Services or a Dispatch Order from Transmission Services, then the NT Customer will continue to receive an adjustment to their NT base charge as if the generator was serving the load.

⊟Additional Information:

⊟Policy References

- Administrator's Record of Decision (ROD) on Environmental Redispatch and Negative Pricing Policy

⊟Related Business Practices

- Energy Imbalance Service
- Establishing Minimum Generation Levels for Environmental Redispatch

- Failure to Comply
- Generation Imbalance Service
- Operating Reserves
- Real Power Loss Return
- Redispatch and Curtailment

Version History

There is no previous version of this business practice.

Out for Comment/Redline/Response to Customer Comments

- Environmental Redispatch, V1, Redline
- Environmental Redispatch, V1, Response to Customer Comments
- Environmental Redispatch, V1, Customer Comments

ATTACHMENT G

Declaration of Richard A. Ellison with
Affidavit of Allen C. Chan

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.; PacifiCorp; NextEra Energy Resources, LLC; Invenergy Wind North America LLC; and Horizon Wind Energy LLC, Petitioners, v. Bonneville Power Administration, Respondent.	)	Docket No. EL11-44-000

AFFIDAVIT OF ALLEN C. CHAN IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

1. My name is Allen C. Chan. My business address is 905 N.E. 11th Avenue, P.O. Box 3621, Portland, Oregon 97208-3621. I am an attorney at the Bonneville Power Administration ("BPA"). As such, I have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's Answer.

2. Richard A. Ellison was unavailable to sign the *Declaration of Richard A. Ellison in Support of Answer of the Bonneville Power Administration* ("*Declaration*").

3. Richard A. Ellison verified that he swore to the facts contained in the *Declaration* under perjury of law, and authorized an electronic signature on his behalf.

4. This concludes my Affidavit.

AFFIDAVIT

State of Oregon
County of Multnomah

NOW BEFORE ME, the undersigned authority, personally came and appeared, Allen C. Chan, who after being duly sworn by me, did depose and say:

That the above and foregoing is true to the best of his knowledge, information, and belief.

Allen C. Chan

SIGNED AND SWORN TO BEFORE ME ON THIS 18th Day of July, 2011

Barbara M. Willard

NOTARY PUBLIC, STATE OF OREGON

OFFICIAL SEAL
BARBARA M WILLARD
NOTARY PUBLIC - OREGON
COMMISSION NO 438867
MY COMMISSION EXPIRES APR. 28, 2013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Iberdrola Renewables, Inc.; PacifiCorp; NextEra Energy Resources, LLC; Invenergy Wind North America LLC; and Horizon Wind Energy LLC, Petitioners, v. Bonneville Power Administration, Respondent.	)	Docket No. EL11-44-000

DECLARATION OF RICHARD A. ELLISON IN SUPPORT OF ANSWER OF THE BONNEVILLE POWER ADMINISTRATION

I declare:

1. My name is Richard A. Ellison. My business address is 5411 N.E. Hwy 99, Vancouver, WA 98663. I am the manager of Dittmer Dispatch at the Bonneville Power Administration's ("BPA") Dittmer Control Center. As such, I have personal knowledge of the facts stated herein and I am providing this affidavit in support of BPA's Answer.

2. As the Manager of Dittmer Dispatch I manage the Dittmer Outage office. The Dittmer Outage Office schedules and arranges Transmission outages on the Federal Columbia River Transmission System ("FCRTS"). During the timeframe of the BPA's high water concerns (early May – early July 2011), I tasked the Dittmer Outage office to attempt to cancel, delay, and/or reschedule any transmission element outages which may

impact any transmission capacity internal and external to the FCRTS. Outages required that were needed to maintain a Safe and Reliable Power System where exempt from this direction. This direction included outreach to other utilities internal and external to the Pacific Northwest region to consider delaying and/or restricting transmission outages that impact Transmission capacities whenever possible, while still maintaining a Safe and Reliable Power System.

3. Dittmer Dispatch operates the FCRTS and is operator for the interties that connect the Pacific Northwest with other regions, such as the California-Oregon Intertie ("COI"), Pacific DC Intertie ("PDCI"), and the Northern Intertie. Dittmer Dispatch also has responsibility for scheduling transmission outages for maintenance on the FCRTS.

4. The Spring season is a generally a great time to perform transmission maintenance as power demand is low due to mild weather and the mild weather permits maintenance crews to get their work accomplished. As a result, most transmission maintenance is scheduled for the Spring.

5. Dittmer Dispatch was charged with reviewing all planned transmission outages for the months of May, June, and July 2011. This review was conducted to first determine if proposed outages had any detrimental effects to transmission capacity, and second to determine if these outages could be postponed and rescheduled to later dates outside of the projected high runoff timeframe. During times of reduced transmission capacity there is less ability for energy to flow, internal to the FCRTS and to other transmission systems through the interties. As a result, reduced capacity can hamper the ability to export generation outside of the Pacific Northwest.

6. For Spring 2011, Dittmer Dispatch worked with BPA's Field Services and external utilities in an attempt to delay and reschedule work that would require outages and reduce transmission capacity. Maintenance that was not of an emergency nature was performed earlier than scheduled, delayed until the Fall months, or even pushed to later years if the delay would not threaten the safe and reliable operation of the FCRTS. BPA has no control over any outages or equipment on another utility's transmission system. Most coordination with external transmission systems was to maximize transmission capacity on the COI and PDCI. For the timeframe in question, little transmission maintenance that would affect transmission capacity was scheduled on the PDCI, so most of the focus was on the COI. The California Independent System Operator (CAISO) is the scheduling entity for the transmission systems south of the COI, such as Captain Jack and Malin. While COI elements south of Captain Jack and Malin are owned and operated by utilities other than the CAISO, the CAISO coordinates the outages for those utilities and was the chief point of contact for attempts to modify outages south of the COI. Dittmer Dispatch worked with the CAISO to modify outage schedules for transmission facilities south of the COI to maximize transmission capacity on the COI.

7. The following is a summary of the outages that were rescheduled:

<u>BPA COI Related Outages</u>

Grizzly-Summer Lake 500kV (spacer replacement)

Original schedule: June 6-10, 2011.

Moved to: Fall, 2011 at the earliest

Buckley-Grizzly 500kV (spacer replacement)

Original Schedule: April 25-May 3, 2011

New Schedule: April 20-25, 2011

Slatt-Buckley 500kV (bird shield installation)

Original Schedule: May 10-14, 2011

New Schedule: April 11-17, 2011

John Day-Grizzly #2 500kV (disconnect repair)

Original Schedule: May 16-20, 2011

New Schedule: April 9, 2011 and again in the fall of 2011 (TBA)

John Day-Grizzly #1 500kV (disconnect repair)

Original Schedule: May 23-27, 2011

New Schedule: April 10, 2011 and again in the fall of 2011 (TBA)

McNary 500/230kV Transformer (McNary-John Day construction and new jack bus)

Original Schedule: May 2-20, 2011

New Schedule: August, 2011

Portland General Electric's Grizzly-Round Butte 500kV (corona ring and disconnect repair)

Original Schedule: May 23-27, 2011

New Schedule: June 13-17, 2011

PacifiCorp's Summer Lake-Malin 500kV (relay testing)

Original Schedule: May 9, 2011 (cancelled by PAC)

New Schedule: Sometime in 2012

Northern Intertie Related Outages

Sammamish-Klahanie section of Sammamish-Maple Valley 230kV (PCS maintenance)

Original Schedule: May 7-8, 2011

New Schedule: none at this time

8. In order to maintain system reliability, generation must match load. Generation in excess of load could lead to excess frequency and threaten the reliability of the transmission system. Allowing generation to exceed load for an extended period of time would also result in violation of North American Electric Reliability Corporation Reliability Standard BAL-001-1.a., Real Power Balancing Control Performance.

I declare under penalty of perjury that the foregoing is true and correct.

DATED this 18th day of July, 2011.

/s/ Richard A. Ellison

Richard A. Ellison

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Answer of the Bonneville Power Administration upon each person designated on the official service list compiled by the Secretary in Docket No. EL11-44 by electronic mail or by United States Postal Service where requested.

Dated this 19th day of July, 2011.

/s/ Barry Bennett
Barry Bennett
Attorney
Office of General Counsel - LC-7
Bonneville Power Administration
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