IDAHO POWER®
An IDACORP Company

July 11, 2018

Comments of the Idaho Power Company on Idaho DEQ's §401 Certification of EPA Region 10's Proposed Hydropower General Permit

Sent Via Email to: Barry.Burnell@deq.idaho.gov
Barry Burnell
Water Quality Division Administrator
Idaho Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706

Dear Mr. Burnell:

Idaho Power Company (IPC) appreciates the opportunity to provide comments on the Idaho § 401 Water Quality Certification issued for the EPA Region 10 General Permit for Hydroelectric Facilities in Idaho. IPC submits the following comments for your consideration.

IPC believes that Idaho Department of Environmental Quality (IDEQ), and not EPA, should be the agency responsible for drafting a general permit for hydroelectric facilities located in Idaho. As you are well aware, on July 1, 2018, Idaho achieved primacy concerning IPDES rules governing individual permits. By the year 2020 Idaho DEQ will begin implementation of general permits in Idaho. During its development of the rules governing the IPDES, IDEQ worked closely in a rulemaking with EPA and potentially affected stakeholders to develop the same. It is anticipated that IDEQ would undertake the same collaborative process in order to develop and implement such a permit. Conversely, EPA Region 10 has developed its Hydropower General Permit without soliciting information before submitting it to potentially affected stakeholders for comment. Idaho Power, in comments submitted today, urges EPA Region 10 to halt its efforts to implement the Region 10 Hydropower General Permit, and allow the state of Idaho, once it has primacy concerning general permits, to develop its own hydropower general permit through collaborative rulemaking should the state believe that such a permit is appropriate.

However, in the event that EPA Region 10 proceeds with the Hydropower General Permit, IPC requests some clarification in IDEQ's § 401 certification. On page 1, the Water Quality Certification indicates that EPA does not intend to cover facilities that have a cumulative CWIS with design intake flow of greater than 2 mgd **and** that uses 25 percent or more of the water the facility withdraws for cooling purposes on an average monthly basis. Later, page 6 indicates that facilities that use or propose to use one or more CWIS with a cumulative design intake flow of greater than 2 MGD **or** that uses 25% or more of withdrawn water for cooling must obtain an

BRETT DUMAS
Director
Environmental Affairs
208-388-2330
208-433-2837 FAX
BDumas@idahopower.com
P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

individual NPDES permit and will require individual 401 certifications. Will permits for facilities that meet both or one of the criteria require individual certifications?

Thank you for the opportunity to comment. If there are any questions or need for clarification on any of the, please contact the undersigned. Idaho Power would appreciate any additional opportunity to work through items raised with IDEQ and Region 10.

Sincerely,

Brett Dumas
cc: Dru Keenan, EPA

Alaska Power Association
703 West Tudor Road, Suite 200
Anchorage, Alaska 99503-6650
(907) 771-5700
Fax: (907) 561-5547
www.alaskapower.org

July 11, 2018

Via E-Mail

Ms. Dru Keenan
Director, Office of Water and Watersheds
USEPA Region 10
1200 Sixth Avenue, Suite 115
OWW-191
Seattle, WA 98101
keenan.dru@epa.gov

Re: Comments of the Alaska Power Association on the EPA Region 10 Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho (IDG3600000)

Dear Ms. Keenan:

Alaska Power Association (APA), the statewide trade association for electric utilities in Alaska, respectfully submits the following comments on the EPA Region 10 Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho (IDG3600000), 82 Fed. Reg. 18,555 (Apr. 27, 2018).

Although the proposal from EPA Region 10 to issue National Pollutant Discharge Elimination System (NPDES) general permits for hydroelectric facilities discharging to waters within the State of Idaho does not apply to Alaska, we are concerned that EPA Region 10, which includes Alaska, would propose a requirement that appears contradictory to its intended application.

APA's members provide power to a half-million Alaskans from Utqiagvik to Unalaska, throughout the Interior and Southcentral, and down the Inside Passage. Hydroelectric generation is a significantly important source for many of our members, with new hydro projects coming online recently. Therefore, we take a keen interest in new requirements proffered by federal agencies affecting generation sources our members rely on.

Comments have been submitted to you on this issue from the National Hydropower Association (NHA) and the Utility Water Act Group (UWAG). We endorse those comments, and we agree that the EPA should direct the states and its Regions not to apply Section 316(b) of the Clean Water Act (CWA) to hydroelectric facilities.

The NHA/UWAG letter provides ample evidence that EPA has never issued a rule applying Section 316(b) of the CWA to hydroelectric facilities. This means there has been no chance for public comment on the merits or technical feasibility of applying the section to hydropower. Importantly, we agree with the NHA/UWAG letter that if EPA Region 10 does apply CWA Section 316(b) to hydroelectric generation it will be a significant expansion of EPA's regulatory jurisdiction and it would duplicate other federal and state requirements specifically designed to address these environmental impacts. This is cause for great concern within the electric utility industry.

APA also agrees that the legislative record from Congressional consideration of the CWA indicate Congress never intended Section 316(b) to apply to hydropower. Doing so now would not be consistent with the law.

Alaska's electric utilities are aware that regulations applied within an EPA Region have the potential to become region-wide, or even country-wide. Adding to the existing requirements for hydroelectric projects – which already follow a rigorous process from the Federal Energy Regulatory Commission and other agencies – is an unreasonable burden to ratepayers.

We urge EPA Region 10 to closely study the NHA/UWAG comments and reverse course on applying 316(b) requirements to hydroelectric facilities.

Sincerely,

Crystal Enkvist
Executive Director

C. Tom Arkoosh
tom.arkoosh@arkoosh.com

July 9, 2018

EPA Regional Director
Office of Water and Watersheds
U.S. EPA, Region 10
1200 6th Avenue, Suite 155, OWW-191
Seattle, WA 98101
Email: keenan.dru@epa.gov

Re: The United States Environmental Protection Agency (EPA) proposes to issue a National Pollutant Discharge Elimination System (NPDES) General Permit to discharge pollutants to the provisions of the Clean Water Act, 33 USC §1251, *et seq.*, to Hydroelectric Generating Facilities, Permit Number: IDG360000

Dear EPA Regional Director:

The following remarks are the comments of the Idaho Hydroelectric Power Producers Trust ("IdaHydro") regarding the proposed issuance of a National Pollutant Discharge Elimination System ("NPDES") Hydroelectric Generating Facilities General Permit ("GP") No. IDG360000. IdaHydro is an Idaho trust comprised of 12 members who own or operate 28 small hydropower production plants. "Small" hydroelectric plant signifies a facility of 10 Mw of capacity or less qualifying as a Qualifying Facility pursuant to the Public Utilities Regulatory Policy Act of 1978 ("PURPA"). These projects are administered and regulated pursuant to that Act; and pursuant to the plenary regulatory authority granted by the Idaho Legislature to the Idaho Public Utilities Commission. These bodies and their regulatory regime currently require oil containment and oil water separators.

PERMIT PARAMETERS

By its terms, the GP proposes NPDES coverage for hydroelectric facilities that are both "river projects and pump storage projects" for discharge of oil, grease, excess heat (temperature) pH, and backwash from cleaning of river debris and silt from the strainers screens. The discharges covered include direct and noncontact cooling water, equipment and floor drain water, equipment backwash strainer water, and equipment and facility maintenance waters. By giving a notice of intent to participate, a hydroelectric plant may participate under the permit's contemplated annual self-certification program, demonstrating compliance with the best management practices plan developed for that facility. The GP will authorize discharges of excess heat (temperature), pH, and oil and grease in limited amounts and/or with monitoring requirements, to the waters of the United States within the State of Idaho. Generally, misrepresentation in the application, nonperformance of any condition of the GP, or change of condition can result in termination of coverage under the permit.

The Environmental Protection Agency's ("EPA") review of hydroelectric facilities in other regions has led it to conclude the pollutants of concern are pH, oil, grease, and potentially temperature. In turn, EPA concluded these pollutants will contribute or cause excursion above state or tribe water quality standards, which the Clean Water Act in turn requires the EPA to impose water quality based effluent limits encompassed in the framework of the GP.

EPA summarizes that the GP aspires to the highest common denominator of beneficial uses in the receiving waters:

> Because the receiving waters contemplated by the general permit include all possible use designations and are subject to all possible water quality criteria, EPA has established effluent limitations and other requirements of the permits to maintain the most stringent possible water quality criteria. In this manner, the permits will be protective of all possible receiving water uses.

See, EPA Fact Sheet re: the GP, page 16.

PERMIT OPERATION

The GP imposes the above strictures through monitoring the outfalls of each participating project and requiring the obtained information be reported on a designated basis. The monitoring frequencies are:

- Once a month: equipment and floor drain water, or combinations.
- Continuous: temperature.
- Once per event: flood events.

Reporting, within six months of the effective date of the GP, must be via a secure internet application using NetDMR. Each project must develop and follow a quality assurance plan to secure the quality of monitoring and sampling. Further, each project must, within 90 days of the GP effective date, develop and follow a best management practices plan to prevent or minimize releases.

COMMENTS

While, on its face, the proposed GP addresses "river" projects, many of the affected hydroelectric facilities are located on irrigation canals. Acknowledging that Congress exempted agricultural return waters by designating these waters as not being a point source, and thus not within the jurisdiction of the Clean Water Act, the proposal to extend jurisdictional reach over these waters appears to directly conflict with the Congressional intent in excluding these waters.

Thus, it is IdaHydro's belief that the Clean Water Act either does not spread its jurisdiction over these waters; or, consistent with Congressional intent, the EPA should not seek to exercise this jurisdiction. Or, given that many of these small hydroelectric plants are on canals, the GP should not aspire to the highest common denominator by treating irrigation canal water as more pristine than it is.

IdaHydro does not have any information indicating that the concerns of the EPA concerning pollutants discharging from hydroelectric plants are a problem affecting water quality standards in any material way, and thus questions the need for permitting. Stated another way, this a solution of expensive monitoring and reporting without a problem to solve, and, thus, the program itself becomes a regulatory problem. The non-effect of small hydroelectric plants on water quality is especially evident concerning pH. IdaHydro has no information that running canal or river water through a turbine alters the pH of the water between intake and outflow. Further, any temperature measurement should give a credit for hydroelectric plants' cooling by energy conservation because electricity generated would otherwise result in heat in the water due to friction dropping through the channel. IdaHydro therefore recommends that hydroelectric plants, or at the least small hydroelectric plants, not be required to monitor and report.

IdaHydro perceives that compared to the paucity of information indicating that small hydroelectric projects potentially offend water quality standards, the reporting requirements are onerous and expensive. To put the processes and equipment in place for a small hydroelectric project, IdaHydro estimates that the installation process will cost each project $10,000+, and the reporting will cost $6,000 to $10,000 annually. This is unreasonable in face of the knowledge that the grossly substantial portion of water at outfall runs through a turbine physically blockaded from potential pollution. IdaHydro therefore proposes that instead of what amounts to continuous reporting, should the GP go forward on small hydroelectric projects, especially those located on canals, that only those plants discharging drain and cooling water in a volume of two percent or more of the water at the outfall be required to report. Further, given the onerous nature of the proposed reporting schedule, IdaHydro proposes that for those small hydroelectric plants required to report, the reporting be once annually for oil and grease. IdaHydro suggests that any more frequent reporting be imposed only in the event of specific information indicating a particular plant is offending water quality standards. Only those plants having cooling water intake that is greater than 2% of flow should report temperature.

Sincerely,

ARKOOSH LAW OFFICES

C. Tom Arkoosh

CTA/emc
Cc: Client

SENT VIA EMAIL TO: keenan.dru@epa.gov

July 10, 2018

Dru Keenan, Office of Water and Watersheds
U.S. Environmental Protection Agency Region 10
1200 6th Avenue, Ste. 155
Seattle, WA 98101

RE: Avista comments on EPA Region 10 Proposed NPDES General Permit for Hydroelectric Generating Facilities discharging to waters within the State of Idaho (NPDES Permit No. IDG360000)

Dear Ms. Keenan:

Avista appreciates the opportunity to provide comments on the proposed issuance of the National Pollutant Discharge Elimination System (NPDES) General Permit for Hydroelectric Generating Facilities discharging to waters within the State of Idaho (General Permit), which the Environmental Protection Agency (EPA) Region 10 proposed on April 27, 2018. We respectfully provide the following comments.

- **Stakeholder Engagement and Public Comment Opportunity Was Insufficient**
  As we understand it, the General Permit is being developed in response to a settlement agreement regarding federal hydroelectric generating (hydroelectric) facilities, and a backlog of NPDES permit applications for specific facilities. Federal facilities are not subject to Federal Energy Regulatory Commission (FERC) licensing, and should be treated separately from licensed hydroelectric facilities. One driver mentioned specifically was the 2014 settlement involving the Columbia Riverkeeper and the U.S. Army Corps of Engineers (Corps), regarding discharges from the Corps' Snake and Columbia Rivers dams. However, none of these dams are in Idaho, so the proposed General Permit wouldn't address them. The fact that EPA made no pre-rule contacts with FERC-licensed hydroelectric facility owners ahead of the draft permit is disappointing, and has led to serious defects in the draft permit. EPA should, if it proceeds with a general permit, engage hydroelectric facility owners to better understand the designs, uses of cooling water, current measures employed to eliminate or minimize spills, prevention of impingement and entrainment and the application of Clean Water Act authority in FERC licenses. The draft permit also suffers from a lack of clarity, particularly regarding applicability. In conversation, EPA indicated that if a facility has no "discrete discharge," there is no need for a permit or complying with the general permit. The proposed General Permit is not clear in this matter, nor in the applicability of 316(b) in terms of what constitutes an "intake structure," and to what degree that affects applicability. In short, EPA should start over with the general permitting process, in order to include relevant information pertaining to FERC licensed hydroelectric facilities, if it proceeds at all.

- **The General Permit is Unnecessary and Redundant**
  Hydroelectric facilities are already regulated through the FERC licensing process, which incorporates the Idaho's Clean Water Act (CWA) Section 401 Certification authority. FERC also requires maintenance and implementation of an Emergency Action Plan (EAP) for each of our hydroelectric facilities in Idaho. Additionally, these facilities are also required under 40 CFR 112, Oil Pollution Prevention Section "to prepare and implement a Spill Prevention, Control, and Countermeasure Plan," administered by the EPA. The EAP and Spill Prevention, Control, and Countermeasure Plan (SPCC) are in place in order to protect against any accidental release of oil and grease into a water of the U.S. In addition, Licensees have relied on the relicensing process under the Federal Power Act, which in turn triggers review and conditioning by Clean Water Act authorities, whether federal or state. The multi-year process provides extensive public involvement and agency oversight opportunities. EPA's proposed General Permit undermines the relicensing process by attempting to add new requirements outside of that process. Not only is this unnecessary, the additional benefits the General Permit would provide beyond the existing regulatory requirements already in place are unclear.

- **Inappropriate Application of §316b**
  The type of discharges that the General Permit seeks to regulate appear to coincide with the Clean Water Act §316(b) regulations relating to cooling water intake regulation. When §316(b) was revised and re-promulgated in 2014 the EPA expressly stated it was never intended to apply to hydroelectric facilities. In addition, during the rulemaking to re-promulgate §316(b), no information was requested or provided to EPA in order to make any determination about the engineering feasibility of the requirements of §316(b) as it would be applied to hydroelectric facilities.

  Accordingly, if EPA Region 10 singles out hydroelectric facilities in Idaho alone for regulation under the General Permit, which mirrors the requirements of the Clean Water Act §316(b), such action could be regarded as arbitrary and capricious.

  Furthermore, if EPA needs to apply §316(b) to hydroelectric facilities, it should do so through a formal rulemaking process, one informed by the realities of FERC regulated hydroelectric facility design and operation.

- **Idaho Delegated Authority of NPDES General Permits**
  Avista questions whether it is appropriate at this time for EPA Region 10 to propose a new and unique General Permit, applicable only to Idaho. As of June 5, 2018, EPA authorized the State of Idaho to administer and enforce the Idaho Pollutant Discharge Elimination System (IPDES) program, under the following "Schedule for the Transfer of Permitting Authority to Idaho."
    - Phase I – Individual Municipal Permits and Pretreatment on July 1, 2018.
    - Phase II – Individual Industrial Permits on July 1, 2019.
    - Phase III – General Permits (Aquaculture, Pesticide, CAFO, Suction Dredge, Remediation) on July 1, 2020.

- Phase IV – Federal Facilities, General and Individual Stormwater Permits and Biosolids on July 1, 2021.

According to this schedule, Idaho will begin implementing these general permits in 2020. It is anticipated that Idaho, should it believe that a hydroelectric general permit is appropriate, would undertake a collaborative process in order to develop and implement such a permit.

As such, Avista requests EPA Region 10 forego its efforts to implement the Region 10 Hydroelectric General Permit, and allow the state of Idaho to develop its own hydroelectric general permit through collaborative rulemaking should the state believe that such a permit is appropriate.

For the above stated reasons, Avista requests that EPA Region 10 discontinue further attempts to implement the proposed General Permit. However, should EPA proceed with the General Permit, we have the following comments specific to inconsistencies, when comparing it with the EPA Region 1 General NPDES Permit issued for Hydroelectric Generating Facilities in the States of Massachusetts and New Hampshire and Tribal Lands in Massachusetts.

- We recommend that the sample frequency for the EPA Region 10 General Permit match the final EPA Region 1 General Permit (i.e. quarterly sampling instead of monthly). There is no evidence that more frequent sampling is merited.

- We recommend that the monitoring adjustment opportunity incorporated in the EPA Region 1 General Permit be incorporated into the final Region 10 permit.
    - (i.e. On pages 42 and 43 of the response to comments for the Region 1 permit the following language is present: "After obtaining 10 valid pollutant samples for the outfall, indicating compliance with the pertinent permit limits, the permittee may submit a written request to EPA for a review of the pollutant monitoring data and a reduction in the monitoring frequency. In the case of water quality-based limits, EPA will formally notify the permittee if the monitoring frequency is reduced after reviewing the monitoring data results and other pertinent information to make a reasonable potential determination, in accordance with 40 C.F.R. § 122.44(d)(1), that these data show the discharge has no reasonable potential to cause or contribute to water quality standards violations. The permittee is required to continue testing at the specified monitoring frequency until written notice is received from EPA. The final permit has been revised to incorporate this monitoring frequency adjustment in a new Part I.H.5.")

- We recommend that Table 4 of the Region 10 General Permit be removed and replaced with the corresponding language in the final Region 1 General Permit due to safety concerns inherent to sampling during high water/flood events.

- We recommend the following language be added for clarity to Section V.A.1 of the Region 10 General Permit, "Samples taken in compliance with the monitoring requirements specified above shall be taken at a location that provides a representative analysis of the discharge." (Page 7, EPA Region 1 General Permit).

Thank you for the opportunity to comment. Please feel free to contact me at (509) 495-2941 if you have any questions or wish to discuss these comments further.

Sincerely,

Bruce Howard

Bruce Howard
Sr. Director of Environmental Affairs

c: Daniel Opalski, EPA

Department of Energy
Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

POWER SERVICES

July 11, 2018

In reply refer to: PGA-6

Via E-Mail

Daniel D. Opalski, Regional Director
Office of Water and Watersheds
U.S. EPA, Region 10
1200 6th Ave, Suite 1555
OWW-191
Seattle, WA 98101

Subject: Comments on the Draft NPDES General Permit IDG360000 for Wastewater Discharges from Hydroelectric Generating Facilities in Idaho

Dear Mr. Opalski:

The Bonneville Power Administration (Bonneville) appreciates the opportunity to provide comments on the Draft Idaho National Pollutant Discharge Elimination System (NPDES) for Wastewater Discharges from Hydroelectric Generation Facilities, permit number IDG360000. Bonneville's comments focus on clarifying certain aspects of the draft general permit and requesting specific changes to proposed monitoring parameters, monitoring frequency, and implementation timing.

Bonneville operates as a not-for-profit entity, selling cost-based electrical power and transmission services to benefit the Pacific Northwest, especially the public bodies and cooperatives which serve domestic and rural consumers. In providing these services, Bonneville must balance multiple public duties and purposes, including: assuring the Pacific Northwest of an adequate, efficient, economical and reliable power supply; promoting energy conservation and the use of renewable resources; and, consistent with the program developed by the Northwest Power and Conservation Council, protecting, mitigating, and enhancing fish and wildlife in the Columbia River basin that are affected by the development and operations of the federal hydroelectric projects from which Bonneville markets power.[1]

[1] Unlike most federal agencies, Bonneville does not receive annual congressional appropriations; instead, the agency is self-financed from revenues received from the sale of power and transmission services. Bonneville

While the U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation) are congressionally authorized to operate the hydroelectric projects in the Pacific Northwest for multiple purposes, Bonneville is the federal agency Congress authorized to market the power generated at these projects. In return, Bonneville is required to pay, either directly to the Corps or Reclamation, or as a reimbursement to the U.S. Treasury, (1) all costs associated with power-specific operations and assets (e.g. turbines) and (2) a share of "joint costs," which benefit or mitigate, for all purposes of the project (e.g. fish mitigation). For the 31 hydroelectric projects in the Federal Columbia River Power System (FCRPS), Bonneville's average share of joint costs totals 65% for capital investments and 80% for operations and maintenance expenses. The FCRPS projects that would be affected by this permit include but are not limited to Dworshak, Albeni Falls, Black Canyon, Boise Diversion, Anderson Ranch, Minidoka and Palisades. Any additional requirements applied to these hydroelectric projects under this or any other NPDES permit will increase Bonneville's costs, which in turn impact Bonneville ratepayers.

As the principal funding entity for the federal hydroelectric projects in Idaho, Bonneville respectfully submits the following comments:

1) **Applicability**: Bonneville requests that EPA revise the applicability language to identify the facilities that are intended to be covered by the draft general permit. Page 19 of the draft general permit states that a facility is ineligible for coverage if the "facility uses or proposes to use one or more cooling water intake structures with a cumulative design intake flow of greater than 2 million gallons per day (mgd) ***or*** the facility uses 25% or more of the water it withdraws for cooling water purposes on an average monthly basis" (emphasis added). The application and calculation process for these criteria is undefined. For hydropower facilities, Bonneville proposes that the 2 mgd criteria be used only for the specific cooling water volume, and the 25% criteria be calculated on the total river flow.

   Also, the Draft Idaho 401 Water Quality Certification language states, "It is DEQ's understanding that EPA does not intend to cover facilities . . . that have a cumulative design intake flow of greater than 2 million gallons per day (mgd) ***and*** the facility uses 25% or more of the water it withdraws for cooling water purposes on an average monthly basis" (emphasis added). Idaho's use of "and" is consistent with the implementing regulations for Section §316(b) (40 C.F.R. 125.91(a)). Thus, Bonneville requests that EPA is consistent with the implementing regulations in the general permit.

---

utilizes this revenue to not only pay for the continuing costs associated with its programs (including power, transmission, and fish and wildlife investments and maintenance) but also to repay the United States Treasury for the power share of the original federal investment used to construct the Federal Columbia River Power System. The Bonneville Administrator must operate the agency in a manner that allows it to recover its costs "in accordance with sound business principles." This includes the objectives of setting the lowest possible rates for Bonneville services, while enabling Bonneville to make timely repayments to the Treasury and simultaneously fulfilling multiple public purposes for the benefit of the Pacific Northwest.

2) **Water quality parameters:**

a. **pH:** Bonneville requests reconsideration of including pH as a required monitored parameter in the draft general permit. Since hydroelectric projects generally do not have the means to modify the pH of a waterbody, it is unclear why EPA would suggest monitoring this parameter. In addition, according to Table 1, page 18, of EPA's NPDES Fact Sheet that accompanied the draft general permit, it appears there are no water quality-limited streams for pH listed on Idaho's 303(d) list in the vicinity of the projects. Thus, requiring monitoring for a parameter that these projects generally cannot influence in areas where there is no water quality limitation for this parameter, seems needlessly burdensome in terms of cost and use of agency resources.

b. **Water temperature:** Bonneville requests reconsideration of the proposed temperature monitoring frequency proposed in the draft general permit. Page 24 of EPA's NPDES Fact Sheet that accompanied the draft general permit states, "EPA is proposing only a monitoring requirement for temperature. ***The EPA does not believe temperature discharges will cause an exceedance of the temperature standard based on review of similar facilities' monitoring reports.*** The EPA will review the collected temperature data from the monitoring reports and determine if an effluent[[2]] is necessary when the General Permit is up for renewal five years after it is issued" (emphasis added). Bonneville concurs with EPA's belief and expects that the temperature discharges from the hydroelectric projects will be de minimis. In that light, the requirement that continuous monitoring thermistors be installed at every discharge point is unnecessarily burdensome and will lead to needless and excessive costs. If EPA includes temperature monitoring for information gathering purpose only, Bonneville recommends that the temperature-monitoring requirement be revised to more representative sampling (e.g., one thermistor per family of turbines on a reduced monitoring frequency and for a shorter time frame). This will enable data collection in a reasoned and measured manner and avoid diverting limited agency resources.

c. **Oil and grease:** Bonneville recommends reducing the monthly grab sample monitoring for oil and grease to quarterly monitoring. This aligns with other regional practices and will reduce the monitoring and reporting burden placed on the hydroelectric operators.

3) **Submittal and implementation timing**: Bonneville requests that the Notice of Intent for the draft general permit and the Quality Assurance Project Plan submittal be extended to a minimum of 180 days and implementation requirements be extended to a minimum of 18 months. Some of the projects do not have experience or history implementing all of the actions contemplated in the draft general permit. Thus, additional time will be needed to evaluate, plan, design and document proposed actions to meet these new requirements as well as contract for equipment supply and installation for actual implementation.

[2] Flagging for EPA's awareness, that we believe the use of "effluent" in this context is a typographical error.

4) **Implementation cost**: Bonneville requests that the timing and extent of the monitoring requirements for temperature and oil and grease be re-evaluated for utility, practicability, and cost effectiveness. For example, at a larger FCRPS hydroelectric project, the costs associated with the draft general permit are estimated to be approximately $1 million for implementation plus a full time equivalent employee for the duration of the permit. Adding these estimated costs at multiple hydroelectric projects across the region will create a significant financial impact to Bonneville and the region's ratepayers.

Bonneville appreciates the opportunity to provide comments to help refine the draft general permit to ensure that any new requirements are reasonable, purposeful and cost effective. This is especially important to Bonneville because the draft general permit may be issued by other states, such as Oregon and Washington, which would further impact Bonneville's costs and the region's ratepayers. For awareness, Bonneville embarked on a multi-year effort at cost management for all of its program areas to help stabilize its revenue requirements and limit or eliminate the need for continued rate increases. Bonneville is seeking to keep its costs at or below current budget levels in order to ensure a sustainable path into the future that will allow continued provision of a diverse array of public benefits to the Pacific Northwest, including a reliable and effective carbon-free power supply, fish and wildlife protection, and energy conservation. Thus, we look forward to working with EPA to ensure any new requirements for hydroelectric facilities discharge monitoring provide important data for the region in a cost-effective manner.

Please feel free to contact me, or Kim Johnson, at kojohnson@bpa.gov or 503-230-3902 if you have any questions or need more information.

Sincerely,

Kieran Connolly
Vice President, Generation Asset Management
Bonneville Power Administration
kpconnolly@bpa.gov
(503) 230-4680

cc:
Dru Keenan, U.S. EPA, Office of Water and Watersheds
(keenan.dru@epa.gov)
Loren Moore, Idaho Department of Environmental Quality
(Loren.Moore@deq.idaho.gov)

July 11, 2018

Office of Water and Watersheds
U.S. EPA Region 10
Attn: Dru Keenan
1200 Sixth Ave., Ste. 155, OWW-191
Seattle, WA 98101
Keenan.dru@epa.gov

Submitted via email

RE: Public Comment on EPA's Draft General Permit for Hydroelectric Generating Facilities in Idaho

Dear Ms. Keenan:

Columbia Riverkeeper and Snake River Waterkeeper (collectively "Commenters") submit the following comments on the draft NPDES General Permit for Hydroelectric Facilities Discharging to Waters within the State of Idaho (Permit No. IDG360000) (hereafter "Draft Permit"). Commenters represent thousands of people that rely on clean water and healthy aquatic ecosystems in Idaho and elsewhere in the Columbia River Basin. Hydroelectric facilities discharge pollution via point sources to waters of the United States and, in turn, the U.S. Environmental Protection Agency (EPA) must regulate pollution from hydroelectric facilities pursuant to Clean Water Act (CWA) Section 402 and its implementing regulations. Academic, government, and industry studies, as well as oil spills reported to the National Response Center, demonstrate that hydroelectric facilities, including those regulated under the Draft Permit, discharge pollutants through point sources. Yet, to date, EPA and most states have failed to regulate hydroelectric facilities under Section 402. This must change.

Commenters support EPA's decision to regulate hydroelectric facilities under Section 402, which should result in significant and important reductions in toxic and conventional pollutants. Commenters offer the following comments to ensure the long-anticipated Draft Permit complies with the CWA and protects high-quality waters and healthy aquatic ecosystems.

I. EPA Must Revise the Draft Permit to Include Technology-Based Effluent Limits that Incorporate the Use of Environmentally Acceptable Lubricants.

Hydroelectric facilities consume and utilize large amounts of lubricants, including toxic and bioaccumulative oils. Under Section III, "Effluent Limitations, Monitoring and Reporting Requirements," the Draft Permit fails to incorporate technology-based effluent limits to reduce pollution from lubricants, including toxic oils. Commenters therefore urge EPA to revise the Draft Permit to incorporate the use of environmentally acceptable lubricants (EALs) and other technology-based methods to reduce oil pollution from hydroelectric facilities.

EPA's treatment of EALs in the Draft Permit marks a notable departure from EPA's treatment of EALs in the NPDES Vessel General Permit for Discharges Incidental to Normal Operation of a Vessel (VGP). As an initial matter, in both the VGP and Draft Permit, EPA defines EALs as "lubricants that are 'biodegradable' and 'minimally-toxic,' and are 'not bioaccumulative'" and lists specific products that qualify as EALs.[1] Under the VGP, EPA requires that permittees use EALs where technologically feasible to reduce pollution to waters of the U.S. The VGP includes a series of EAL-related requirements and categorizes those terms as "technology-based effluent limitations and related requirements."[2] For example, the VGP states:

> All vessels must use an EAL in all oil to sea interfaces, unless technically infeasible. 'Environmentally acceptable lubricants' means lubricants that are 'biodegradable' and 'minimally-toxic' and are 'not bioaccumulative' as defined in Appendix A of this permit. For purposes of requirements related to EALs, technically infeasible means that no EAL products are approved for use in a given application that meet manufacturer specifications for that equipment, products which come pre- lubricated (e.g., wire ropes) have no available alternatives manufactured with EALs, products meeting a manufacturers specifications are not available within any port in which the vessel calls, or change over and use of an EAL must wait until the vessel's next drydocking.
>
> If a vessel is unable to use an EAL, you must document in your recordkeeping documentation consistent with Part 4.2 why you are unable to do so, and must report the use of a nonenvironmentally acceptable lubricant to EPA in your Annual Report. Use of an environmentally acceptable lubricant does not authorize the discharge of any lubricant in a quantity that may be harmful as defined in 40 CFR Part 110.[3]

---

[1] EPA Vessel General Permit for Discharges Incidental to Normal Operation of a Vessel, Appendix A at 143 (2013) (hereafter "VGP").
[2] *See* VGP at Section 2 ("Effluent Limits and Related Requirements").
[3] VGP at 47; *see also id.* at 53 (stating "EPA encourages vessel operators to consider four stroke engines instead of two stroke engines for vessels generating wet exhaust that are covered under this permit. Use of a four stroke engine may minimize the discharge of pollutants to waters

The VGP also states, "to reduce the risk of any leakage or spills of harmful oils into the aquatic environment, EPA strongly encourages the use of environmentally acceptable lubricants in all above deck equipment."[4] Overall, the VGP embraces EALs as technological tool to reduce water pollution.

In contrast to the VGP, the Draft Permit addresses EALs in one subsection within the permit's Best Management Practices (BMP) Plan requirement, a "Special Condition."[5] The Draft Permit requires that permittees develop and comply with a BMP Plan. The BMP Plan must "[e]stablish specific best management practices or other measures that ensure" a series of requirements are met, including the requirement to:

> "[i]mplement purchasing procedures that give preference for Environmentally Acceptable Lubricant (EAL) for all oil to water interfaces, unless technically infeasible. For purposes of requirements related to EALs, technically infeasible means that no EAL products are approved for use in a given application that meet manufacturer specifications for that equipment; products which come pre-lubricated (e.g., wire ropes) have no available alternatives manufactured with EALs; or products meeting a manufacturers specifications are not available."[6]

EPA omits rationale in the Fact Sheet or elsewhere to explain why the agency fails to address EALs in the Draft Permit in a similar manner as the VGP. Like vessels regulated under the VGP, hydroelectric facilities interface with the aquatic environment and are a known source of oil pollution. Moreover, hydroelectric facilities in the Pacific Northwest and around the world are utilizing EALs to reduce pollution in aquatic ecosystems. For example, pursuant to a consent decree with Columbia Riverkeeper, the U.S. Army Corps of Engineers (Corps) studied the potential to increase use of EALs at eight dams on the Columbia and Snake rivers.[7] The Corps has already expanded the use of EALs at the dams at issue in *Columbia Riverkeeper v. U.S. Army Corps of Eng'rs*, and has plans to further expand the use of EALs at Corps dams.

---

subject to this permit. Where vessels utilize two stroke engines, environmentally acceptable lubricants (as defined in Appendix A of this permit) must be used unless technologically infeasible. If technologically infeasible, the vessel owner/operator must document in their recordkeeping documentation why they are not using environmentally acceptable lubricants.").

[4] *Id.* at 24.

[5] *See* Draft Permit, Section IV.B. at 20.

[6] *Id.*

[7] Attachment A (Victor F. Medina, *Evaluation of Environmentally Acceptable Lubricants (EALs) for Dams Managed by the U.S. Army Corps of Engineers* (2015); Attachment B (memorandum from U.S. Army Corps of Engineers to Columbia Riverkeeper); *see also* Attachment C (U.S. Bureau of Reclamation, *Environmentally Safe—"Green" Lubricants for Wicket Gates* (undated).

EPA must revise the Draft Permit to include robust terms, similar to the VGP, that require—unless technologically infeasible—the use of EALs at hydroelectric facilities as a technology-based effluent limitation.

II. EPA Must Review and Approve BMP Plans and Provide for Public Notice and Comment on the Plans.

BMP Plans constitute technology-based effluent limits, yet EPA fails to comply with the CWA and implementing rule requirements for technology-based effluent limits.[8] First, EPA's decision to usurp its regulatory role vis-à-vis the BMP Plans runs afoul of the CWA. *See e.g., Environmental Defense Center, et al. v. EPA*, 344 F.3d 832 (9th Cir. 2003) ("*EDC*"). EPA must review and approve plans; if it usurps this duty, the agency creates an impermissible self-regulatory scheme. Second, EPA must afford the public an opportunity to review and comment on the draft plans. The plans constitute "effluent limitations," which the public has a statutory right to review and offer comment upon. *See* 33 U.S.C. 1342(b)(3), *see also EDC*, 344 F.3d at 856. Commenters urge EPA to revise the Draft Permit to include new terms specifying EPA's review and approval role, as well as the opportunity for public notice and comment.

III. EPA Must Revise the Permit to Increase the Frequency of BMP Plan Compliance Reporting.

All NPDES permits must include monitoring and reporting requirements sufficient to ensure compliance with the permit's limitations. 40 C.F.R. § 122.44(i)(1). The Draft Permit requires that permittees submit BMP Plan Reports one time per year. Annual reporting undercuts the agency's oversight of permit compliance and ability to prioritize inspections based on current Plan compliance. EPA's lax reporting requirement also undercuts the public's ability to understand pollution discharges from an industrial facility and review permit compliance. Citizen action is a "proven enforcement tool" that "Congress intended [to be used…] to both spur and supplement government enforcement actions." CWA Amendments of 1985, Senate Environment and Public Works Comm., S.Rep. No. 50, 99th Cong., 1st Sess. 28 (1985). Commenters urge EPA to revise the Draft Permit to increase BMP Plan Report frequency to at least four times per year (*i.e.,* quarterly reporting).
//
//

---

[8] EPA should revise the Draft Permit's to clarify that BMP Plans constitute technology-based effluent limits.

IV. Conclusion.

Commenters request that EPA revise the Draft Permit to ensure compliance with the Clean Water Act and protect waters in the State of Idaho burdened by pollution from hydroelectric facilities.

Sincerely,

Lauren Goldberg
Staff Attorney, Columbia Riverkeeper
lauren@columbiariverkeeper.org

F.S. “Buck” Ryan, J.D.
Executive Director, Snake River Waterkeeper
buck@snakeriverwaterkeeper.org

MEMORANDUM FOR RECORD

SUBJECT: *Columbia Riverkeeper v. USACE*, No. 2:13-md-2494-LRS (E.D. Wash.) Settlement Agreement

Per the subject Settlement Agreement attached to the court's order of dismissal without prejudice entered on August 14, 2014, the Corps has obligations due by February 14, 2016, pertaining to the use of Environmentally Acceptable Lubricants (EALs) and the implementation of Oil Accountability Plans at the Bonneville, The Dalles, John Day, McNary, Ice Harbor, Lower Monumental, Little Goose, and Lower Granite dams on the Columbia and Snake Rivers. Following is a summary of the status of the Corps' fulfillment of those obligations.

a. Environmentally Acceptable Lubricants (EALs).

Paragraph 4(a) of the Settlement Agreement required the Corps to "complete an assessment of whether it is technically feasible to switch from using grease as a lubricant on certain 'in-water' equipment, including wicket gates for the hydropower turbines, navigation locks and certain fishway equipment, to using one or more EALs as a lubricant on such equipment . . .." The Settlement Agreement called for the Corps to complete this assessment within twelve months of the Settlement Agreement, *i.e.*, by August 2015, and "to switch to using one or more EALs as a lubricant on the in-water equipment where the Corps has determined that doing so is technically feasible" within eighteen months of the Settlement Agreement, *i.e.*, by February 2016.

The Settlement Agreement provides that "[t]he Corps' evaluation of technical feasibility will be confined to the question of whether one or more EALs can be used without risk of potential damage to the equipment." The Corps completed assessments by August 2015 and, due to the risk of potential damage to the equipment, determined that it was not feasible at that time to switch to using EALs. Based on the assessments, the Corps concluded that further testing would be necessary to demonstrate that an EAL does not pose a risk of potential damage to the equipment. After August 2015, the Corps continued to evaluate the use of EALs on in-water equipment at the Dams, to consider whether it may be feasible to switch to using EALs in the future. As a result of that further evaluation, as explained below, the Corps has determined that it will be feasible to switch to using EALs at the next scheduled maintenance in Fiscal Year 2017 for certain non-hydroelectric in-water equipment that has a negligible or low risk of potential damage. With regard to other in-water equipment, as set forth below, the Corps has decided to perform "proof of concept" testing to ascertain whether EALs may be feasible for use in the future.

i. <u>Identification of EALs</u>

EALs were defined in the Settlement Agreement to mean "those lubricants that have been demonstrated to meet standards for biodegradability, toxicity and bioaccumulation potential that minimize their likely adverse consequences in the aquatic environment compared to conventional lubricants, as set forth in Section 4 of EPA 800-R-11-002, 'Environmentally Acceptable Lubricants' (November 2011), and includes, but is not limited to, products labeled by [certain identified labeling programs]." In order to evaluate the feasibility of switching to EALs as provided in the Settlement Agreement, it was necessary for the Corps to perform additional research, after the Settlement Agreement was executed, to identify potentially suitable and commercially available lubricants meeting this definition.

The Settlement Agreement indicated that the Corps "already uses EALs on certain 'in-water' equipment at The Dalles and John Day dams." This statement reflected the Corps' use at those dams of the product "Mobil SHC 101 EAL," which is marketed as a grease "designed specifically for applications that require environmentally sensitive lubricants." See http://www.mobil.com/USA-English/Lubes/PDS/GLXXENGRSMOMobil_SHC_Grease_100_EAL_Series.aspx. During the Corps' assessment of the technical feasibility of switching to EALs at the dams, the Corps concluded that the Mobil SHC 101 EAL grease does not actually satisfy the criteria for "EAL" as defined in the Settlement Agreement. The "EAL" in its title stands for an "Environmental Awareness Lubricant", not "Environmentally Acceptable Lubricant." While the grease is characterized as "environmentally sensitive" or "environmentally friendly" by the manufacturer, and offers some benefits in environmentally sensitive applications, the grease is not labeled by any of the labeling programs identified in the Settlement Agreement and has not been demonstrated to meet the standards for bioaccumulation as set forth in the Settlement Agreement. Therefore, the Corps determined that different lubricants would need to be evaluated in order to satisfy the terms of the Settlement Agreement. The Corps included the in-water equipment at The Dalles and John Day dams along with the in-water equipment at the other six dams in the Corps' assessment of whether it is technically feasible to switch to EALs on certain in-water equipment.

The Corps approached the evaluation of EAL use by examining the feasibility of switching to EALs, as defined in the Settlement Agreement, on: (1) hydroelectric plant "in-water" equipment (including wicket gates for hydropower turbines) and (2) non-hydroelectric "in-water" equipment (including navigation locks and certain fishway equipment) at all eight dams. The assessments for each of these types of equipment are summarized below.

ii. Hydroelectric In-Water Equipment

The Corps contracted with HDR Engineering to assess the technical feasibility of switching to EALs on certain in-water hydroelectric plant in-water equipment. On July 28, 2015, HDR produced a report entitled "Environmentally Acceptable Lubricant Grease for Hydropower Applications." See Exhibit 1. The report identified various products that met the EAL criteria and concluded that based on laboratory data alone, switching to EALs appeared technically feasible on wicket gates. However, since there was an absence of wicket gate bushing performance history with the EAL shown to be most compatible, the report concluded that there was some “unquantified risk of damage to the equipment.” The report recommended that a “proof of concept” be completed to test a sampling of in-service equipment prior to full implementation. The report also looked at the feasibility of switching to EALs on wire ropes and recommended that further testing be done to check for compatibility issues between EALs and the in-service grease. Based on this information, the Corps concluded in August 2015 that it was not technically feasible (without risk of potential damage to the equipment) to switch to EALs at that time and that further testing and evaluation would be necessary.

The proof of concept test for hydropower wire ropes began on certain equipment at Ice Harbor in December 2015 and on certain equipment at Bonneville in January 2016. Testing will begin on other equipment at Ice Harbor in February or March 2016. The wire ropes will be monitored for 12 months. At the conclusion of the monitoring period, a determination of feasibility will be made. If deemed feasible, the Corps plans to switch to EALs on hydropower wire ropes at all eight projects. Testing of wicket gates is expected to begin in May 2016 at Lower Granite and The Dalles projects. Testing of wicket gates at Bonneville Second Powerhouse and McNary Dam is expected to follow in July and August 2016, respectively. The wicket gates will be monitored for 12 months after introducing the EAL grease. At the conclusion of the monitoring period, a determination of feasibility will be made. If deemed feasible, the Corps plans to begin switching to EALs on at each of the projects that have greased wicket gates.

iii. <u>Non-Hydroelectric In-Water Equipment</u>

The Corps utilized the U.S. Army Engineer Research and Development Center (ERDC) to evaluate the use of EALs on non-hydroelectric plant in-water equipment. In August 2015, ERDC produced a report entitled “Evaluation of Environmentally Acceptable Lubricants (EALs) Non-Hydropower Uses for NWD and NWW Dams.” See Exhibit 2. The report found that there were EAL greases available for non-hydroelectric uses and that these EALs appeared to meet performance needs. However, the report based this conclusion in large part on the Corps’ experience in using “environmentally friendly” greases, which were not demonstrated to be EALs as set forth in the Settlement Agreement. As noted in the report, the greases already in use by the Corps, such as Mobil SHC 101 EAL, were not labeled by any labeling program and lacked data for at least one of the EAL criteria. Based on this information and a lack of performance history in using EALs, the Corps concluded in August 2015 that it was not technically feasible (without risk of potential damage to the equipment) to switch to EALs at that time and that further testing and evaluation would be necessary.

After August 2015, the Corps assessed the level of risk of potential damage to various types of non-hydroelectric in-water equipment and continued to evaluate the feasibility of switching to EALs on this type of equipment. As a result of that further evaluation, in February 2016, the Corps determined that it will be feasible to switch to using EALs at the next scheduled maintenance in Fiscal Year 2017 for certain non-hydroelectric in-water equipment that require greasing and has a negligible or low risk of potential damage, provided that the equipment is not similar to the wire ropes that are undergoing the hydropower proof of concept testing. For the non-hydroelectric wire rope equipment that is similar to the hydroelectric wire rope equipment being tested, a determination of feasibility will be made following the conclusion of that testing.

For non-hydroelectric in-water equipment that has a moderate risk of potential damage when switching to EALs, the Corps will perform a proof of concept test. The Corps expects to initiate this testing in January or March 2017, which coincides with respective scheduled fishway and navigation lock equipment outages that will be necessary to initiate the test. The equipment will be monitored for 12 months after introducing the EAL grease. At the conclusion of the monitoring period, a determination of feasibility will be made. If deemed feasible, the Corps plans to begin switching to EALs on the in-water equipment that needs greasing.

b. Oil Accountability Plans.

Per paragraph 4(b) of the Settlement Agreement, the Corps has developed reports that include a description of the results of the monitoring and any assessments that occurred during the preceding reporting period. The Corps has made those reports publically available at
http://www.nwd.usace.army.mil/Missions/Environmental/OilAccountability.aspx.

FRANCES E. COFFEY
Chief, Program Support Division
Northwestern Division

Enclosures:

ENVIRONMENTALLY SAFE - "GREEN" LUBRICANTS FOR WICKET GATES

Leslie J. Hanna and Clifford A. Pugh, U.S. Bureau of Reclamation,

Water Resources Research Laboratory, Denver, Colorado

Introduction

Greases are commonly used in hydroelectric facilities to lubricate wicket gate bushings. However, the greases presently used in many facilities could contain lead, phosphorous, lithium, and benzene compounds which may ultimately be introduced into waterways and affect water quality, including effects on biological food chains. In an effort to address this issue, the Bureau of Reclamation (Reclamation) has conducted lubrication tests on candidate "environmentally acceptable" greases as possible replacements for greases currently used. Replacement of these lithium based greases requires that water quality standards are met, as well as providing lubrication and protection of surfaces to maximize the service life of the wicket gate bushings. Current Reclamation standards specify a 40 year service life for bushings. Also keep in mind that greases that are approved as "food grade" do not necessarily meet water quality standards. In order to assure that lubrication standards are met, laboratory tests were conducted. Some limited field tests have also been conducted at Reclamation's Hungry Horse Dam in Montana.

Reclamation's Water Resources Research Laboratory (WRRL) in Denver constructed a test facility and conducted tests to determine the relative lubricating performance of several candidate "green" lubricants. This paper compares these data with lubricating performance of a baseline lithium grease currently used in wicket gates. Additional chemical and physical property tests are also recommended, including toxicity and biodegradability (see Appendix A.) Often many of these tests are supplied by the manufacturer.

Scope of the study

- The study described in this paper concentrated on comparing relative lubricating performance of various greases. The work did not include analysis of other chemical and physical properties of the candidate greases. These additional tests would facilitate evaluation of the environmental effects of the various greases.
- The tests to date were all conducted at a constant water temperature (about 68 degrees Fahrenheit.) A proposal has been prepared to evaluate lubrication

performance at lower temperatures (about 34 degrees Fahrenheit.) This work has not yet been funded.

- The tests were performed on five candidate "green" greases, one lithium based grease, and one self-lubricating bushing. The lubricating properties are intended as a relative comparison.

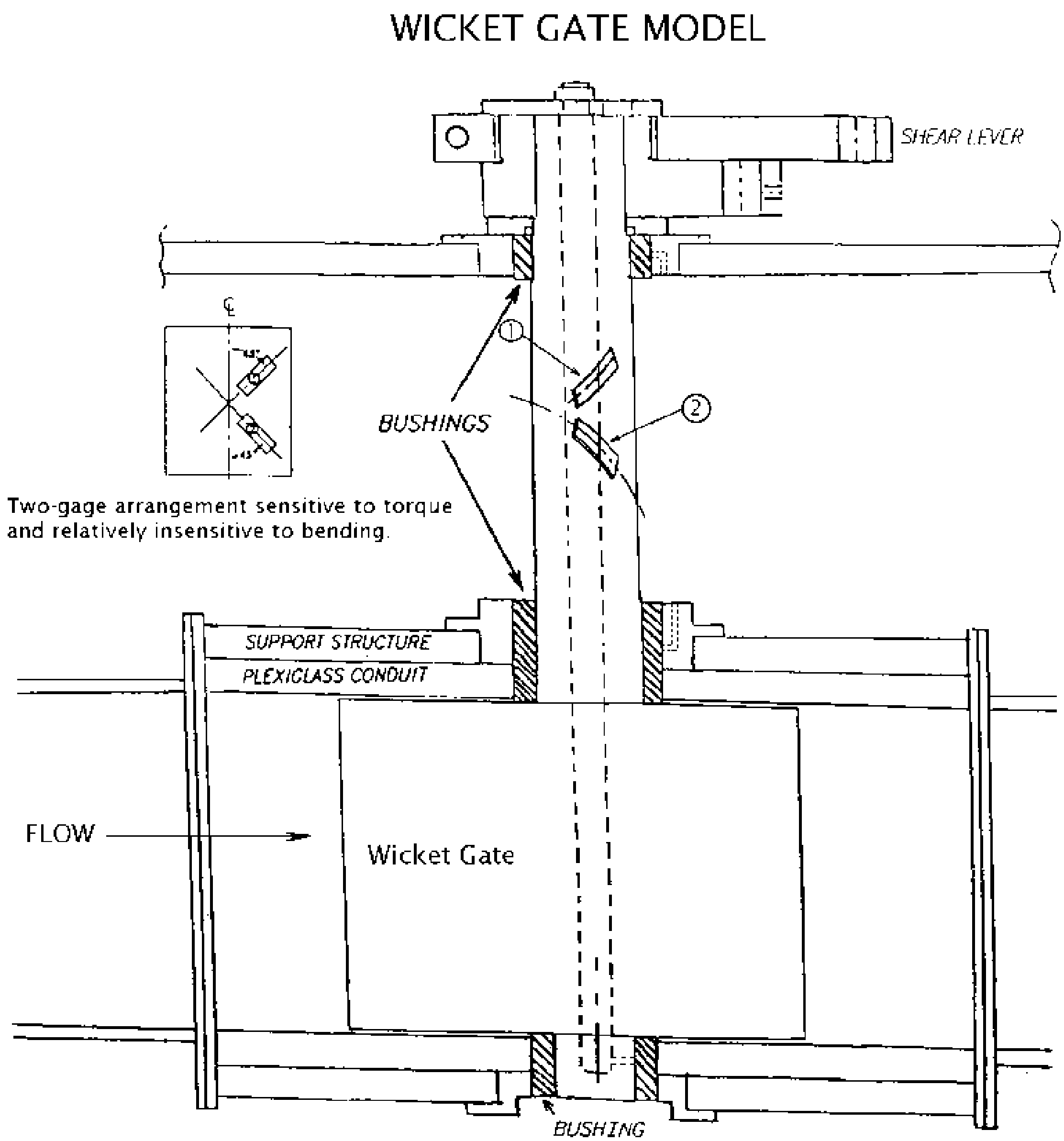


Figure 1 - Section through wicket gate model.

Mechanical Test Setup and Procedure

A test apparatus was developed by the WRRL to establish a standard test to compare the mechanical performance of various greases for wicket gate bushing applications. The test apparatus was based on a 1:4 scale model of a prototype wicket gate at the Mt. Elbert Powerplant near Leadville, Colorado. The model gate is enclosed in a rectangular conduit with flow and pressure through the model roughly scaled to represent flow through one wicket gate passage at Mt Elbert. The test head on the gate ranged from 21 ft to 54 ft. A motor driven operator is attached to the shear lever arm. The model gate is controlled to simulate gate movements under automated generator control (AGC), the most severe duty cycle experienced by a wicket gate. The operator cycles the gate continuously on a 20 second, 4 degree stroke - with a 7 second pause between each cycle. In addition, a full 22 degree closing and opening stroke is executed three times per equivalent prototype day. Equivilant model test time for each test conducted was 20 hours. This involved 1330 - 4 opening and closing cycles, and 40 - 22 opening and closing strokes. Gate torque measurements were used to predict relative performance. Torque was measured with strain gages mounted on the wicket gate shaft in the test rig as shown in figure 1.

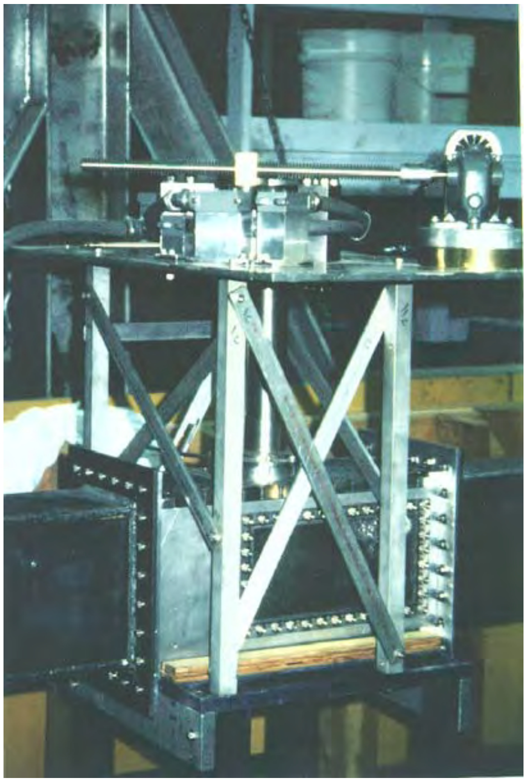


Figure 2 - Photograph of wicket gate test apparatus.

Test Results

Grease was injected into the bushings at four hour intervals, which simulates 60 hour prototype intervals. A lithium based grease (Lubricant A) was used as the baseline for performance comparisons.

Lithium based greases have typically been used for wicket gate lubrication. In addition, a test case using no grease (water lubricated) was used for comparison and to confirm the sensitivity of the test apparatus. Five "green" lubricants and one set of self-lubricated bushings were tested. The test apparatus and bushings were completely cleaned after each test case to prevent cross contamination between greases. The bushings were also inspected at this time for damage or scoring, but in each case showed none. Maximum gate torque was recorded twice per hour during the full gate stroke. Figure 3 is a typical strip chart recording of the stresses in the 2 strain gages on the gate shaft during a full (22)closing and opening stroke.

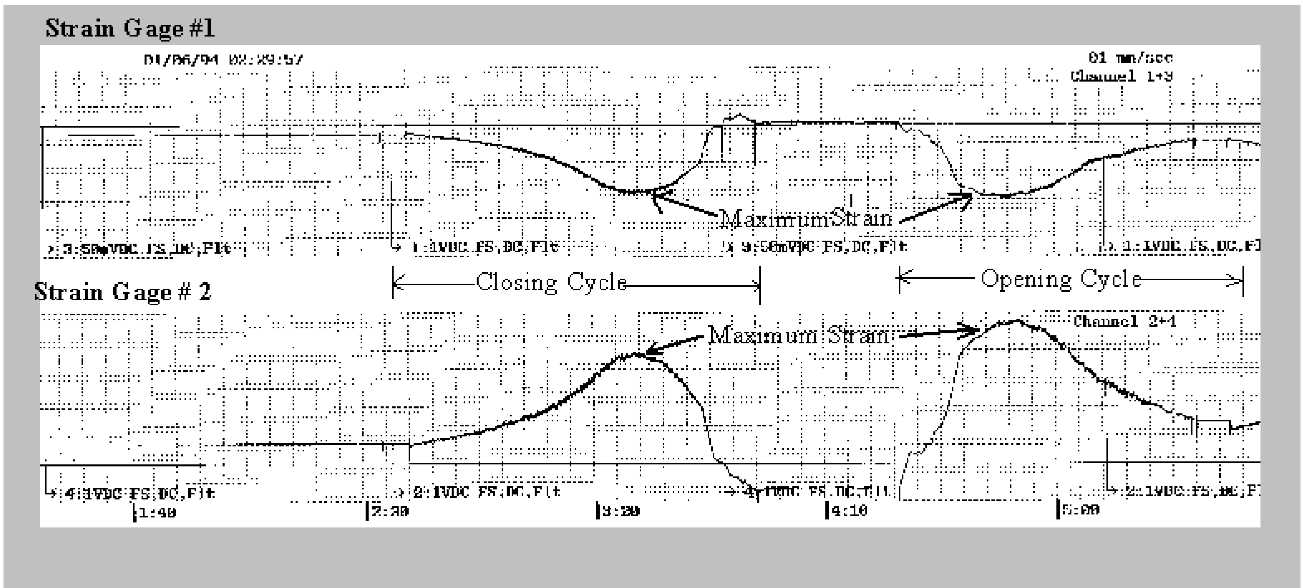


Figure 3. Typical recording of wicket gate closing and opening cycle.

The top curve on each graph in figures 4 and 5 displays the maximum test apparatus torque values (in 1000 lb-in) recorded during gate opening. The bottom curve on each graph displays the maximum torque values recorded during gate closing. To interpret the meaning of these graphs, a free body diagram of the test apparatus was used to analyze the forces acting on the gate. The difference between the opening and closing curves represents the torque due to twice the friction torque inherent in the system. Since the torque force is a function of the lubrication properties of the grease, this value provides a quantitative tool to compare the performance of the greases in a standardized test. The maximum torque values during a full cycle were recorded and plotted over time for each test case. Using this analysis, torque due to friction (near the end of the test when the friction had stabilized) for each test case is given in Table 1. Note from figure 4 that the friction torque for the "no lubricant" (water lubricated) case is still rising after 60 strokes.

The values given in Table 1 show a relative comparison of how these "green" lubricants will perform compared to the traditional lithium based grease. The results of these tests may be used as a baseline, in conjunction with field tests, to determine which lubricants will perform well in the field. Other mechanical properties of the grease such as workability will be important to the field personnel.

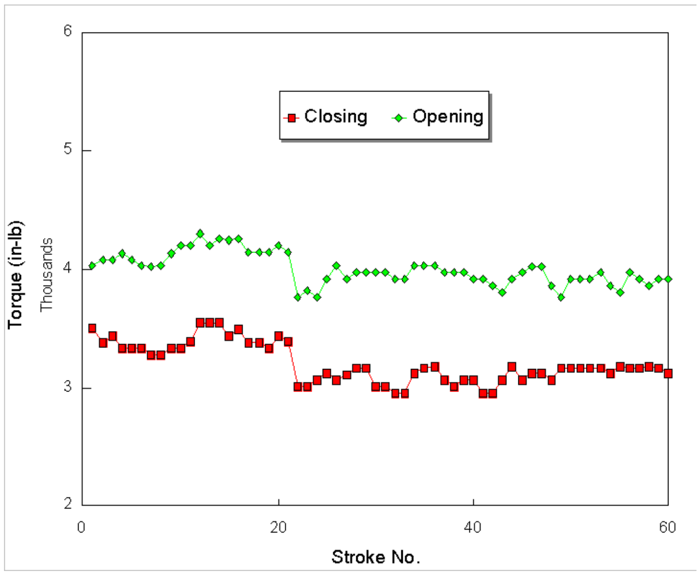


Figure 4- a) Baseline grease (Grease A) lithium based

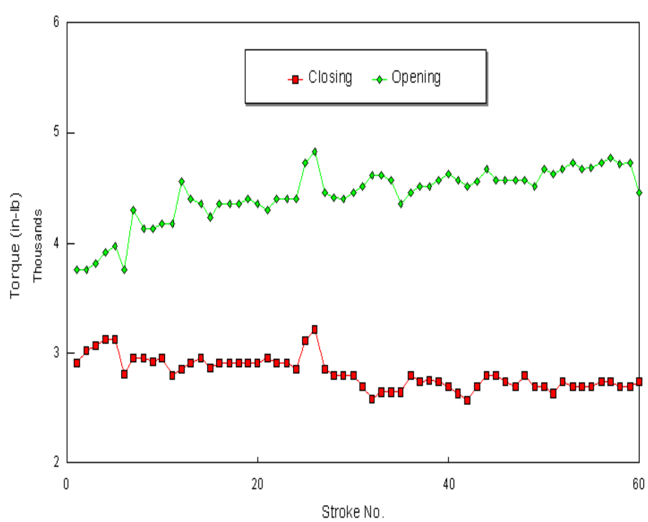
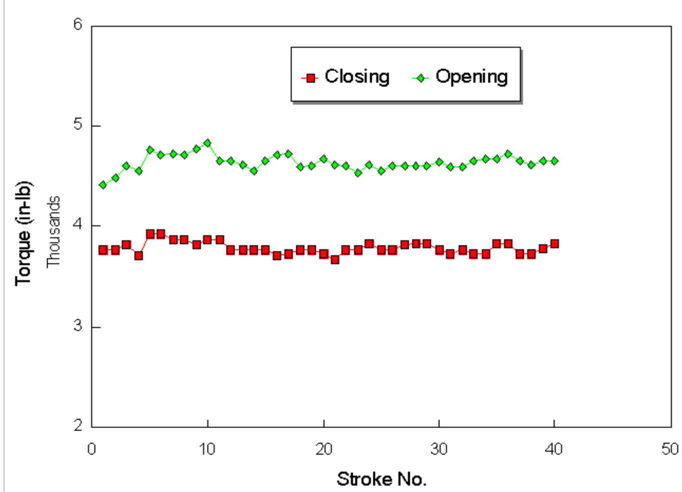


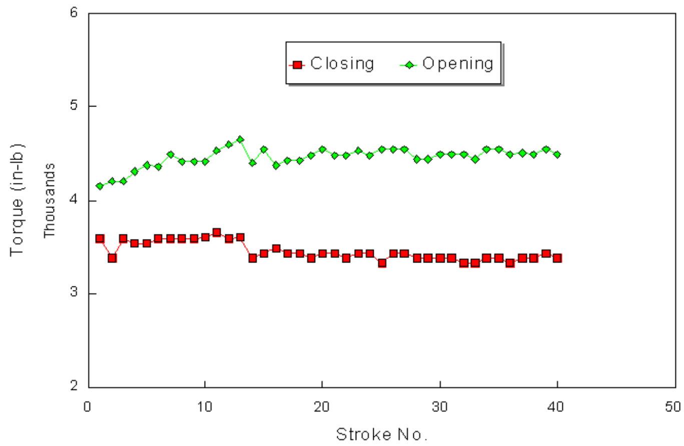
Figure 4- b) No Grease (Water only)

Figure 5. Maximum torque versus stroke for five "green" lubricants and one self-lubricated bushing.

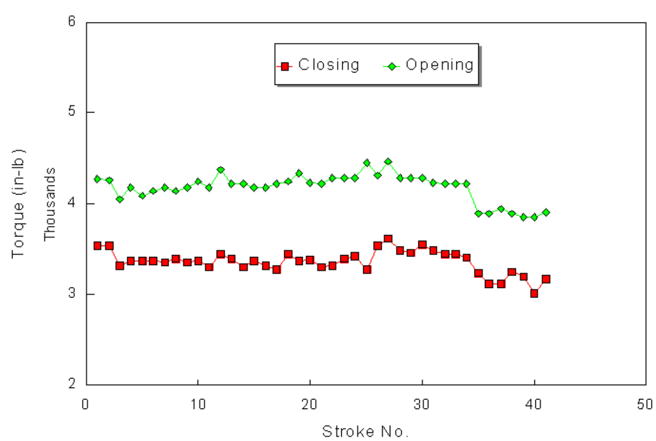
a) Lubricant B



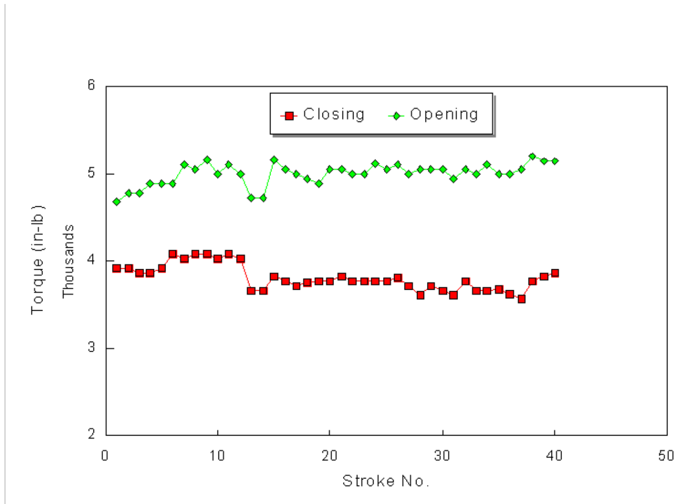
b) Lubricant C



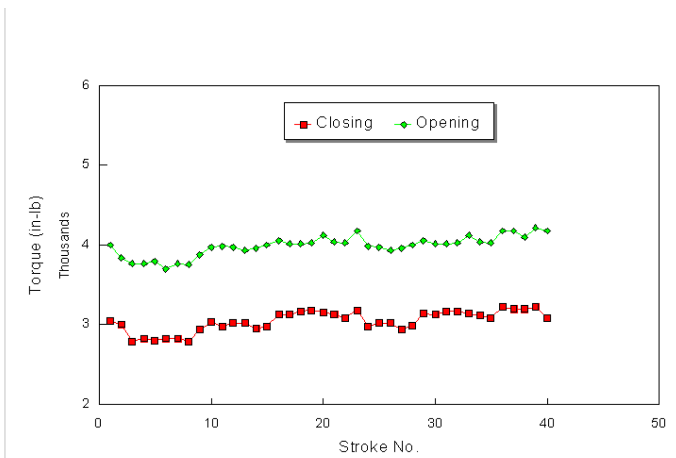
c) Lubricant D



d) Lubricant E



e) Lubricant F



f) Self-Lubricated bushing

Self-lubricated Bushing Tests

Results of tests conducted on a self-lubricated bushing indicate that the self lubricated bushing provides 86% of the lubrication difference between water-lubricated and the lithium-base lubricant. However, more extensive tests are needed to determine the long term viability of self-lubricated bushings. Wear characteristics of these bushings over an extended period of time are important, since no lubricant is being added; and because the greasing process also acts to purge sand and silt from the bushing.

Table 1. Friction torque indicating lubricating performance

TEST CASE	Type of * Lubricant	FRICTION TORQUE (in-lb)	Percent ** Lubrication
Lubricant A (lithium based grease)	**L**	**401**	**100**
Lubricant B	**FG**	**629**	**55**
Lubricant C	**SE**	**437**	**93**
Lubricant D	**FG**	**590**	**63**
Lubricant E	**CB**	**377**	**105**
Lubricant F	**FG**	**675**	**46**
Self-Lubricating Bushing	**-**	**470**	**86**
No Lubricant (Water only)	**-**	**905**	**0**

- L- Lithium, FG- Food Grade, SE- Synthetic Ester, CB- Canola Based
**** - Percent of the difference between no lubricant (water only) and the standard lithium based grease.**

Conclusions

- The lubrication tests performed by Reclamation as well as the property tests listed in Table A1, can be used as a basis for the selection of environmentally safe "green" lubricants. Selection of an environmentally safe lubricant should be based both on environmental standards and mechanical performance.
- The lubrication tests indicated that the ester based and canola based lubricants performed significantly better than the food grade greases that we tested. The "percent lubrication" (PL) for these two greases was 93 percent and 105 percent respectively. For the three food grade greases tested the average PL was 55 percent.
- More testing is recommended to ensure that mechanical performance as well as environmental standards are met. Many manufacturers have recently produced new products in an effort to meet environmental standards. However, until complete property tests are conducted, it will be difficult to determine the applicability of the products based solely on manufacturers' data and claims. In addition, more extensive tests will be required to determine the long term viability of self-lubricated bushings.

Disclaimer

The test apparatus was designed to simulate conditions encountered in Reclamation's applications. The results are intended to allow relative comparisons of the candidate grease's lubricating properties. These tests do not imply an endorsement by the Bureau of Reclamation for any commercial product. Actual lubricant performance will also depend on field conditions. The lubricants and self-lubricated bushing tested in these investigations were contributed by the manufacturers.

Appendix A

Lubricant Property Tests

A list of additional tests which may be important to consider in conjunction with the lubrication tests performed by WRRL are provided in Table A1 below. These tests were scheduled to be conducted on the same greases tested in the mechanical test rig, however funding limitations prevented completion of the tests. Some of the tests may be available through the manufacturer or provided on the material safety data sheets (MSDS). A discussion of these recommended tests as they relate to wicket gate grease applications follows:

1. LC_{50} for toxicity - This test has been the standard required in Canada. (The "microtox" test can be used initially as a screening device since it shows high correlation with the LC_{50} and is much less expensive). In the United States, the 1986 Environmental Protection Agency (EPA) standard "Quality Criteria for Water," includes the LC_{50} test as part of the criteria for oil and grease. Individual states determine their own regulations, but most states have adopted these criteria. Several of the lubricants tested have received a food grade designation. However, this designation alone does not guarantee that the grease is non toxic and environmentally acceptable.

2. Biodegradability (CEC L-33-T-82) - The Acronym CEC stands for Coordinating European Council. The test was developed to determine the biodegradability of lubricants in water. Vegetable oils and a number of synthetic esters easily meet biodegradability criteria. However, there are serious performance concerns for vegetable oils especially at low temperatures. Ester based lubricants can be designed to be readily biodegradable and non-toxic, and possess lubricant performance advantages over vegetable oils; however, they are higher in cost. Two of the lubricants tested were ester based lubricants.

3. Copper strip corrosion test (ASTM D4048) - This test identifies undesirable reactions of the lubricant with the bronze bushing that could lead to excessive and unnecessary wear. The copper corrosion test became of particular interest after field testing one of the "green" lubricants at Hungry Horse Dam in Montana. On inspection of the power unit, which had used this product for about 6 months, there appeared to be a copper coating on the wicket gate shaft. This was not seen on the units that had used the lithium based lubricant. A chemical analysis of a sample scraped from the shaft indicated that the sample contained a significant amount of copper. Additionally, a sample of the lubricant used in the model tests showed significantly more copper than an unused sample of the same grease (3640 mg/kg as opposed to 3 mg/kg in the unused sample). Galvanic and resistivity tests of the lubricant conducted by Reclamation's Materials Engineering Branch showed that the grease had high resistivity to current flow, thus eliminating this as the cause of the copper transfer. These results may indicate that the grease is chemically reacting with the bronze.

4. Element scan (ASTM D4951) - This test can distinguish which of the lubricants contain metal components that can be harmful if they find their way into the biological food chain.

5. Resistance to water spray (ASTM D4049) - This test serves as a relative indicator of how quickly the lubricant will be washed out of the bushings during field operations where it is subjected to high water pressure. One of the best ways to protect the environment is to simply put less grease into the waterways by using a lubricant that is not washed out easily and adjusting greasing schedules accordingly.

6. Rust preventive characteristics (ASTM D665) - Some of the "green" lubricants may not have adequate rust preventive additives needed for long term performance.

7. Compatibility with mineral oil - This is important since the "green" lubricants will, in most cases, be replacing mineral oil lubricants. Incompatibility of the new lubricants with the traces of mineral oil that will be left behind may cause formations of gums, varnishes or other insoluble contaminants.

8. Water solubility - This test can determine if the lubricant is absorbing water which comes into contact with it. If this tendency occurs, the lubricant may eventually become diluted with water which will change its lubricating properties and may cause rust or premature breakdown of the lubricant.

9. Storage stability - Biodegradable products may have a tendency to biodegrade on the shelf before they are put into service. This will test the tendency of the lubricant to do this.

10. EP properties or Timken rating (ASTM D2509) - This test determines the extreme pressure (EP) characteristics of the grease which are classified with a timken load rating. One question that has arisen in selecting lubricants is whether a high timken rating is required for wicket gate bushing applications. EP additives control wear rather than prevent wear. The EP additives react with the metal to form a compound which acts as a protective layer on the metal's surface, preventing metal to metal contact that can lead to scoring or failure. Under extreme pressure conditions this layer is sacrificial and wears away, protecting the metal. As this layer is removed, the EP additive acts to form another layer. To prevent excessive corrosion most EP additives are activated by excessive heat created during extreme pressure conditions, but do not react at room temperature. Although there is a question as to whether the point pressure within the wicket gate bushings is ever high enough to activate the EP additive, the timken ratings of greases currently being used in Reclamation facilities range from about 40 lb to 45 lb.

Table A1. Lubricant Property Tests. (Suggested by BC Hydro)

Test Name	Test Description	Test Method
Biodegradability	Developed to determine the biodegradability of lubricants in water	CEC L-33-T-82
Toxicity	Rainbow Trout will be exposed to lubricant-water dispersion	LC_{50}
Toxicity of degraded products	Same as above except degradation products of lubricants will be used	LC_{50}
Element scan	Determines elemental concentrations	ASTM D4951
Copper Strip corrosion	Determines lubricant's corrosiveness to copper	ASTM D4048
Rust preventive characteristics	Indicates the ability to prevent rust	ASTM D665
Resistance to water spray	Evaluates the ability of the lubricant to stick to a metal surface when subjected to direct water spray	ASTM D4049
Hydrolytic stability	Determines the stability of the lubricant in water	ASTM D2619
Compatibility with mineral oil	Determines the compatibility of the replaced mineral oil with the new lubricants	FTM 791C Method 3470.1
Water solubility	Determines water absorption of lubricant	In house test
Storage stability	Determines breakdown of lubricant during storage	FTM 791C Method 3467.1
Categorize grease	Determines if composition agrees with specification sheet	Infrared scan
Compatibilty with elastomers	Determines lubricant's effect on elastomers	ASTM D4289
Swelling of synthetic rubbers	Determines lubricant's effect on synthetic rubbers	FTM 791C Method 3603.5
EP properties - Timken	Determines EP characteristics	ASTM D2509
Wear characteristics	Determines relative wear preventive properties	ASTM D2266
Worked penetration	Determines consistency within NLGI grades	ASTM D217

ERDC WQTN-MS-9
August 2015

Evaluation of Environmentally Acceptable Lubricants (EALS) for Dams Managed by the U.S. Army Corps of Engineers

by Victor F. Medina

PURPOSE: The purpose of this study is to provide a preliminary assessment of Environmentally Acceptable Lubricants (EALs) for application in dams that are managed by the U.S. Army Corps of Engineers (USACE). The assessment will explore the environmental aspects of these lubricants and will also discuss their operational characteristics. This assessment is primarily through the literature available on this topic, and includes interviews with various experts.

BACKGROUND

Affected Dams. This project will focus on eight (8) dams in Washington State and Oregon:

- Bonneville
- John Day
- McNary
- The Dalles (Figure 1)
- Ice Harbor
- Lower Monumental
- Little Goose
- Lower Granite

Of these dams, three are reported to already have used EALs: Bonneville, John Day and The Dalles.

Structures. The settlement focuses on the application of EALs on "in-water" structures. These include wicket gates for hydropower turbines, navigation locks, and fishway equipment. The purpose of the assessment is to determine whether EALs could be safely used without compromising the target equipment. By in-water nature, the focus is primarily on greases, but other in-water lubricants could be affected.

Figure 1. The Dalles Dam, spanning the Columbia River between Washington state and Oregon.

Report Documentation Page

Form Approved
OMB No. 0704-0188

1. REPORT DATE **AUG 2015**	2. REPORT TYPE	3. DATES COVERED **00-00-2015 to 00-00-2015**

4. TITLE AND SUBTITLE **Evaluation of Environmentally Acceptable Lubricants (EALS) for Dams Managed by the U.S. Army Corps of Engineers**	5a. CONTRACT NUMBER
	5b. GRANT NUMBER
	5c. PROGRAM ELEMENT NUMBER
6. AUTHOR(S)	5d. PROJECT NUMBER
	5e. TASK NUMBER
	5f. WORK UNIT NUMBER
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) **U.S. Army Engineer Research and Development Center,,Vicksburg,,MS**	8. PERFORMING ORGANIZATION REPORT NUMBER
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)	10. SPONSOR/MONITOR'S ACRONYM(S)
	11. SPONSOR/MONITOR'S REPORT NUMBER(S)

12. DISTRIBUTION/AVAILABILITY STATEMENT
Approved for public release; distribution unlimited

13. SUPPLEMENTARY NOTES

14. ABSTRACT
The purpose of this study is to provide a preliminary assessment of Environmentally Acceptable Lubricants (EALs) for application in dams that are managed by the U.S. Army Corps of Engineers (USACE). The assessment will explore the environmental aspects of these lubricants and will also discuss their operational characteristics. This assessment is primarily through the literature available on this topic, and includes interviews with various experts.

15. SUBJECT TERMS

16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT **unclassified**	b. ABSTRACT **unclassified**	c. THIS PAGE **unclassified**	**Same as Report (SAR)**	**21**	

Standard Form 298 (Rev. 8-98)
Prescribed by ANSI Std Z39-18

LUBRICANTS

Purpose. Lubricants are used on moving surfaces and have several purposes, which are summarized by USACE (1999), EM 1424, and the USACE lubrication manual, which is currently being revised. Lubricants serve to reduce friction, making movement operations easier and less energy intensive, and they reduce wear on affected surfaces and dissipate heat. They also provide a protective barrier to oxidation, thereby reducing corrosion. Additionally, they can provide insulation, transmit chemical power, and seal against dirt, dust, and water.

Lubricants work by serving as a lower viscosity material between moving surfaces. The wearing surfaces are replaced by a material with a lower coefficient of friction. Any material that accomplishes this can serve as a lubricant, but the most common substances are oil and grease.

Types of Lubricating Oils/Greases

Mineral Oils. Typical lubricants are composed of petroleum fractions called mineral oils (Haus et al. 2001, Nagendramma and Kaul 2012). Mineral oil derivations are generally effective for most lubricating applications, and their performance is usually considered as a baseline for comparison in most studies. Mineral oils are also the least expensive of the lubricating materials, even lower cost than vegetable oils. Mineral oil lubricants can biodegrade, but the process is generally slow, and the toxicity of mineral oils tends to be problematic. However, used mineral oil lubricants can be recycled in certain applications.

Bio-based lubricants (Vegetable Oils). Biobased lubricants, often referred to as vegetable or plant oils or biolubricants, are lubricants derived from natural sources with minimal modification (Salimon et al. 2012). Vegetable oils are the most common and include canola oil, castor oil, palm oil, sunflower seed oil, sesame seed oil, rapeseed oil, soybean oil and coconut oil (Durak 2004, Jaydas and Prabhakaran Nair 2006, Miller et al. 2007, Nagendramma and Kaul 2012, Salimon et al. 2012). Tall oil is derived from trees and typically recovered during paper milling. Technically, animal oils also can be used, and historically, whale oil was a very effective lubricant. However, there are no animal oil lubricants on the market at this time. All of these sources generally have their lubricating properties derived from triglyceride esters (Nagendramma and Kaul 2012, Figure 2). Biobased lubricants have some limitations, particularly at low temperatures, but in the right application, their performance can actually match or even exceed that of mineral oils (Anand and Chhibber 2006). Furthermore, biobased lubricants can be modified thermally or chemically to improve certain performance characteristics. Biobased lubricants generally biodegrade quickly and are usually far less toxic than mineral oils. In fact, in most cases, biobased lubricants are the most environmentally friendly option.

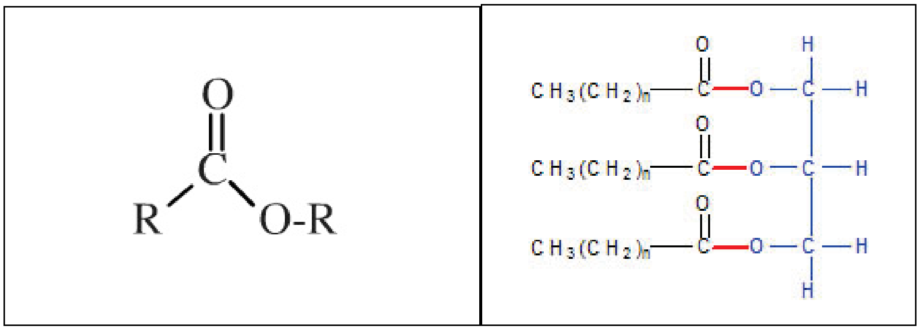


Figure 2. A generalized ester bond and a triglyceride ester (the common structure in biolubricants).

Synthetic Lubricants. Synthetic lubricants are formulated via chemical synthesis to create materials with desirable properties for lubrication (Nagendramma and Kaul 2012, USACE 1999). Chemicals used in synthetic lubricants can be derived from petroleum or from plant sources. Synthetic lubricants can be formulated to have properties far superior to mineral oil lubricants, and they can be synthesized precisely, so as to have unparalleled consistency of properties. Furthermore, it is possible to include labile structures that facilitate biodegradation while reducing toxic exposures compared to mineral oil lubricants. However, synthetic lubricants are significantly more expensive than either mineral-oil- or vegetable-oil-derived lubricants (Nagendramma and Kaul 2012, USACE 1999).

Synthetic Esters. Synthetic esters are lubricants generally derived from biological or petroleum sources, which are chemically modified to form a wider range of synthetic esters (Nagendramma and Kaul 2012, Figure 2 shows a basic ester structure). Synthetic ester-based lubricants are often derived for very high performance applications, such as racing and jet engines. They are also widely used for military applications, because they can be formulated to last far longer than mineral oil or biolubricants. They can be very expensive, however.

Polyalkaline Glycols (PAGs). PAGs are derived from petroleum sources, but are modified to form glycols (Beran 2003, Nagendramma and Kaul 2012, Figure 3). Overall, PAGs make up the smallest category of lubricants.

Polyalphaolefin (PAO) lubricants. PAO lubricants are synthetic oils that have been widely developed for a variety of uses, and have been used for many years. However, recent formulations have been developed to meet environmental performance criteria.

Additives. Lubricating oils typically include additives that can improve performance (Herdan 1997). These include oxidation inhibitors (anti-oxidants), rust inhibitors, extreme pressure agents, antiwear agents, and friction-reducing materials (Duzcukoglu and Acaroglu 2010, USACE 1999, Wright 2008). However, these additives can also affect the environmental effects of the lubricants, most commonly making them worse (particularly by increasing their toxicity). However, sometimes environmentally acceptable materials can be used as additives, improving the overall environmental friendliness of the product (Durak 2004).

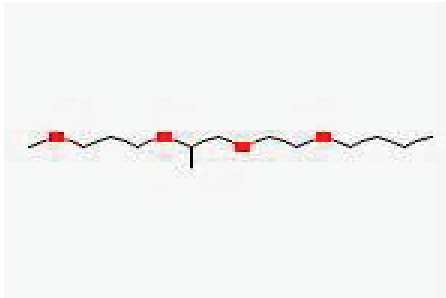


Figure 3. An idealized polyalkaline glycol (PAG) structure.

Blends. Different lubricating materials can be blended together to create new lubricant combinations that combine the strengths of the different materials. Blending can be effective, but it is also a complex process. Not all lubricating materials are miscible in others; thus when creating blends, one must consider compatibilities of the different stock materials.

Grease. Grease is a semi-fluid to a solid mixture designed for lubrication, and consists of a base oil, thickener(s), and additives (USACE 1999). The base oil (discussed in the sections above) actually provides the lubricating properties. Grease also contains thickeners, which are often referred to as soaps that act like a sponge that holds the lubricant together (USACE 1999, Wright 2008). These are generally solids or semi-solids to make the lubricant more thick, like a paste material. Metal soaps based on lithium, aluminum, clay, polyurea, sodium, and calcium are most common. Complex thickeners can be composed of metal soaps mixed with low-molecular-weight organic acids. Non-soap thickeners are sometimes used for high-temperature applications, and include bentonite and silica aerogels. Additives are generally added to customize performance.

Greases can differ in consistency based on their formulation, and these differences can be used in customizing their applications. The National Lubricating Grease Institute (NGLI) has a rating system that is called the NGLI consistency number or the NGLI grade. These range from 000 to 6, with a range from cooking oil to cheddar cheese. The most common greases used in the dam projects are from 0 to 3, which range from brown mustard to vegetable shortening. NGLI 2 is the most common consistency, and is termed “normal grease,” and has a consistency of peanut butter.

Greases are particularly useful for applications that run intermittently and for external applications. The thickener helps the lubricant stay in place without a containment system. The in-water applications specified by the Riverkeepers’ settlement are best served by greases.

Lubrication Needs of Dams. Dams use a very wide range of equipment that requires lubrication; as a result, dams use large amounts of lubricants and commonly have large quantities of lubricants on site. Turbines and electrical generating equipment use large quantities of lubricating oils. In-water structures, like wicket gates and lock gates, use greases. There are boats and maintenance equipment as well. Environmental releases of the lubricants are, apparently, common. These can be intentional, as in the case of in-water use of a lubricant, or unintentional, as in the case of a spill.

Environmental Effects of Lubricant Releases. It has been estimated that 40 kilotons of lubricating oils of all kinds are released into the environment annually (Bartz 1998). Betton (2010) estimated that 15% of lubricants used in the European Union are either unaccounted for or even intentionally released into the environment. Etkin (2010) estimated that a combination of leaks and operational releases of lubricating oils into marine waters reach a level of 36.9 to 61 million liters annually — about 1.5 times the size of the Exxon-Valdez oil spill — moreover, the cost of the environmental damage was estimated at $322 million (Etkin 2010).

Brunner and Salmon (1997) documented that oil and lubricant leaks from hydroelectric dams are a significant environmental risk, and they developed a model to assess risk for dams in Canada. Similarly, Verlind et al. (2004) reported that concerns over lubricating oil releases in Sweden led to research to develop new Kaplan runners for their turbines that reduced and even — in some cases — eliminated lubricating oil use. The Riverkeepers reported significant releases of oils of all kinds from dams on the Columbia and Snake Rivers (Johnson 2014). Reported leaks of up to 1,680 gallons are mentioned, and some of the leaks were reported to contain polychlorinated biphenyls (PCBs), which are highly regulated and very resistant to biodegradation (Johnson 2014).

ENVIRONMENTALLY ACCEPTABLE LUBRICANTS

Definition. "Environmentally friendly lubricants" is a loose term that defines a lubricant that would be expected to have a neutral-to-slightly-negative (within an acceptable level) impact on the environment if released. The term "Environmentally Acceptable Lubricant" (EAL) is a restrictive term that implies that the product has met certain requirements. The USEPA (2011) defines EALs as meeting specific, albeit broad, criteria for biodegradation, aquatic toxicity, and bioaccumulation (these are discussed in more detail in subsequent sections). Furthermore, the USEPA definition is particularly targeted for marine usages of lubricants, although its definitions could be applied to other usages. USACE (1999) discusses EALs in Chapter 8.

The EPA also defines EALs in its requirements of vessel general permit requirements (VGP) (USEPA 2013, see Appendix A). The definition is essentially identical to that found in 800-R-2-002, although some additional details are provided concerning testing. Therefore, we can determine that any grease certified to meet VGP requirements is an EAL.

Generally, it is assumed that mineral oil lubricants do not meet EAL requirements and that biolubricants are essentially EALs. However, the general definition of an EAL does not specify the composition of the lubricant; although some of the labeling programs do consider this (see Other Factors and Labeling sections).

Biodegradability. Biodegradability measures the breakdown of the chemical structure of the lubricant by microorganisms (USEPA 2011). Two types of biodegradation are identified in evaluating lubricants. Primary biodegradation is the loss of one or more active groups that reduces or eliminates the toxicity of the lubricants. Ultimate biodegradation is the mineralization of the compounds to carbon dioxide and water. Compounds that are inherently biodegradable are those that can degrade in any test, and those that are readily biodegradable show a fraction of removal within a specified time frame. Table 1 summarizes tests commonly used to determine the biodegradability of chemicals, and which are or can be used to assess lubricants.

Table 1. Commonly used test methods for measuring biodegradability (adapted from Willing 2001 and USEPA 2011).

Test Type	Test Name[a]	Measured Parameter[b]	Pass Level (degradation greater or equal)	Method[c]
Readily biodegradable[d,e]	DDAT	DOC	70%	OECD 301A
	Strum test	CO_2	60%	OECD 301B
	MITI test	DOC	70%	OECD 301C
	Closed bottle	BOD/COD	70%	OECD 301D
	MOST	DOC	70%	OECD 301E
	Sapromat	BOD/COD	60%	OECD 301F (OECD 2012 for all OECD tests)
	Shake flask test	CO_2	60%	EPA 560/6-82-003 (USEPA 1982b)
	Strum test	CO_2	60%	ASTM D-5864-11 (ASTM 2011)
	BODIS test	BOD/COD	60%	ISO 10708 (ISO 1997)
Hydrocarbon degradability	CEC test	Infrared Spectrum	80%	CEC L-33-A-934
Screening	CO_2 headspace	CO_2	60%	ISO 14593 (ISO 1999)

a DDAT = DOC Die away test, MITI – Ministry of Trade & Industry, Japan, MOST = Modified OECD Screening Test, BODIS = BOD of insoluble substances
b DOC = dissolved organic carbon, BOD = biochemical oxygen demand, COD = chemical oxygen demand
c OECD = Organization of Economic Cooperation and Development, EPA = U.S. Environmental Protection Agency, ASTM = ASTM International, ISO = International Organization for Standardization, CEC = Coordinating European Council.
d Tests that show a specific target degradation (implies mineralization) within a specific time period.
e Each of these tests also can be used to determine inherent biodegradability – if 20% biodegradation is observed during the test period.

Mineral oils typically biodegrade, but the processes are slow and may be incomplete. EALs tend to biodegrade faster and more completely, with vegetable oils in particular showing rapid rates (Aluyor et al. 2009). Battersby (2000) studied the degradation of various lubricating oils using the CEC L-33-A-93 test, and found that vegetable oils were >95% degraded in 21 days, while mineral oils range from 4 to 57% in the same time period. In general, the following pattern is found for biodegradability:

Mineral oil < Polyalkaline glycols < Synthetic esters < Biolubricants (Vegetable Oils)

Aquatic Toxicity. The second criterion that an EAL must meet is low aquatic toxicity. Like biodegradability, there are a number of toxicity tests that can be applied (Table 2).

Table 2. Aquatic toxicity tests applicable for EAL evaluation (Adapted from USEPA 2011).

Test & Species	OECD Number[a]	EPA Equivalent[b]
72 hour growth inhibition test, alga	201	EG-8
Acute immobilization test, Daphnia sp.	202	EG-1
Acute toxicity test, fish	203	EG-9
Prolonged toxicity test: 14 day study, fish	204	
Respiration inhibition test, bacteria	209	
Early-life stage toxicity, fish	210	
Reproduction test, Daphnia magna	211	
Short-term toxicity on embryo & sac-fry states, fish	212	

a OECD 2013
b Source: USEPA 1982a (EPA 560/6-82-002)

In general, mineral oil lubricants have relatively high toxic effects, while PAGs, synthetic esters, and biolubricants have low toxic effects. PAGs, however, can have higher levels of toxicity in some cases, due to their increased solubility resulting from the glycol groups.

Bioaccumulation. The third criterion that an EPA-defined EAL must meet is that it must be below certain thresholds for bioaccumulation. Bioaccumulation can be directly measured by exposing organisms to the contaminant, then measuring uptake. However, this type of measurement is complicated by the wide variety of environmental factors that can affect uptake. Furthermore, in the case of organic constituents, these can be transformed and degraded in the target organism, making measurements difficult. Finally, tests with organisms can be expensive. Because of these reasons, surrogate measurements have become more common when it comes to measuring bioaccumulation. In particular, the octanol-/water-partitioning coefficient (K_{ow}) is the common basis for assessing bioaccumulation. In a K_{ow} test, a chemical of interest is placed in a container containing both water and octanol, and the solution is vigorously mixed. The ratio of the contaminant in the octanol and in the water is then measured. Since differences frequently span orders of magnitude, K_{ow} is typically presented as a logarithmic scale (log K_{ow}).

Log K_{ow}s for marine environments tend to vary between 0 and 6. Substances with Log $K_{ow} < 3$ tend not to bioaccumulate, while those with $K_{ow} > 3$ area are considered as bioaccumulating. OECD 107 and 117 are common methods used to measure K_{ow} values for EAL purposes (OECD 2013a).

Other Considerations. Other considerations include the environmental fate of the material, such as its attenuation (particularly biodegradability) and its transport characteristics. Some assessments also factor in environmental effects related to the production of the lubricant: Are greenhouse gas emissions generated? Is the material made of renewable sources? Does the product contain hazardous or dangerous materials? Still other assessments factor in circumstances such as public perception of the lubricant material and stakeholder acceptance.

Labeling. There are several labels that have been developed that are generally accepted as defining a lubricant as an EAL. These include:

- Blue Angel – A label developed by Germany, which has now been accepted internationally as an acceptable standard. (http://www.ecolabelindex.com/ecolabel/blue-angel)
- Swedish Standard – A label developed by Sweden.
- Nordic Swan (Nordic Ecolabel) – A label jointly developed by Iceland, Norway, Denmark, Sweden, and Finland. Nordic swan is meant to consider the entire product life cycle. (http://www.nordic-ecolabel.org/)
- European Eco-label – Developed by the European Union (http://ec.europa.eu/environment/ecolabel/)
- OSPAR – Developed by the OSPAR commission to protect the Northeast Atlantic Ocean and its resources. (http://www.ospar.org/)

Table 3 summarizes the criteria for these labels.

Table 3. Criteria for labeling programs for EALs.

Labeling Program	Biodegradability	Aquatic Toxicity	Bioaccumulation	Other
Blue Angel	OECD 301B-F (Ultimate biodegradation) or CEC L-33-A-934 (primary biodegradation)	OECD 201-203	OECD 305 A-E or Kow	Dangerous materials, technical performance
Swedish Standard	ISO 9439	NA	None	Renewable content
Nordic Swan	NA	OECD 201-202	None	Renewable content, technical performance
European Eco-label	OECD 301 A-F (ultimate biodegradation), OECD 302C, or ISO 14593	OECD 201 & 202 (acute) and OECD 210 or 211 (chronic)	OECD 107, 117, or 123 (Kow for organic compounds) or OECD 305	Dangerous materials, restricted substances, renewable content, technical performance
OSPAR	OECD 306 (degradation under marine conditions)	Marine toxicity to 4 species	OECD 117 or 107 (Kow)	

Other labels may be acceptable, or a testing regiment could be presented to show that a lubricant meets EAL requirements. Modified assessment tools are available (Cunningham et al. 2004).

Recycling. Lubricants of all kinds can be recovered and recycled, which is a positive environmental practice (Betton 2010), but not all uses allow for these activities. Specifically, in-water lubrication does not allow for recycling.

Performance. Table 4 summarizes performance of EALs to mineral oil (polyaklylene glycols are PAGs, polyalpaole phines are PAOs, and dicarboylic acid ester and neopental polyesters are synthetic esters). EALs generally perform well compared to mineral oil lubricants. EALs typically are more mechanically durable and have superior lubricating properties (Pai and Hargreaves 2002). Mineral oils, however, tend to have better low temperature performance and have strong corrosion resistance.

Table 4. Performance of EALs as compared to Mineral Oil lubricants (adapted from Bartz 1998).

	Min. Oil	Polyalpha	Polyalkyl	DAE	N Polyest	Rape Seed
Viscosity Temperature Behavior (VI)	4	2	2	2	2	2
Low Temperature Behavior (Pourpoint)	5	1	3	1	2	3
Liquid Range	4	2	3	1	2	3
Oxidation Stability (Aging)	4	2	3	2/3	2	5
Thermal Stability	4	4	3	3	2	4
Evaporative Loss (Volatility)	4	2	3	1	1	3
Fire Resistance, Flash Temperature	5	5	4	4	4	5
Hydrolytic Stability	1	1	3	4	4	5
Corrosion Protection Properties	1	1	3	4	4	5
Seal Material Compatibility	3	2	3	4	4	4
Paint & Lacquer Compatability	1	1	4	4	4	4
Miscibility with Mineral Oil		1	5	2	2	1
Solubility of Additives	1	2	4	2	2	3
Lubircating Properties, Load Carrying Capacity	3	3	2	2	2	1
Toxicity	4	3/4	1/2	1/2	1/2	1
Biodegradability	4	3/4	1/2	1/2	1/2	1
KEY: 1 = excellent, 2 = very good, 3 = good, 4 = moderate, 5 = poor.						
Min. Oil = Mineral oil, Polyalpha = polyalphaolephines, polyalkl = polyalkyleneglycols, DAE = dicarboxylic acid esters						
N Polyest = Neopental polyesters, Rape seed = rape seed oil						
Adapted from Bartz (1998)						

In looking over the properties presented in Table 4, it is interesting to focus on the properties that would be most critical for in-water lubrication. These include oxidation stability (aging), evaporative loss (volatility), hydrolytic stability (reactions with water), and corrosion protection properties. In focusing on these, we see that — with some exceptions — EALs tend to outperform mineral oils in oxidative stability and evaporative loss. However, mineral oils outperform most EALs in terms of hydrolytic stability, low temperature performance (pour point), and corrosion protection (Aluyor et al. 2009).

It is clear from the literature that EALs are very effective, and can be used for most mineral oil applications. However, it is disappointing that some of the weaknesses of EALs (hydrolytic stability, low temperature performance, and corrosion protection) are incompatible with in-water application requirements. The limitations given in Table 4 are nonetheless generalizations for most products. Fortunately, there is a wide range of EAL products, and some have been developed that work better at low temperatures and have better hydrolytic stability (Birova et al. 2002, Erhan et al. 2006). For example, coconut oil has shown to be better at low temperature applications than most other vegetable oils (Jaydas and Prabhakaran Nair. 2006). Additives can also be used to improve performance (Erhan et al. 2006, Karmakar and Ghosh 2013), although these may also have undesirable environmental effects (Herdan 1997). Modification of vegetable oils via processes like epoxidation and hydroxylation can also improve low temperature performance and oxidative resistance, while maintaining high biodegradability (Arumugam et al. 2012, Sharma et al. 2006). Another strategy could be to investigate or even develop blends of existing mineral oils that have been proven to be effective and more readily biodegradable materials, to develop a mixture that meets EAL requirements (Nagendramma and Kaul 2012). For example, Haus et al. (2001) studied 32 mineral oil bases and found biodegradation ranged from 15 to 75%. Increasing aromatic and/or polar contents can increase biodegradability. Therefore, choosing the more biodegradable mineral oil stocks could meet EAL requirements for biodegradability, bioaccumulation, and toxicity. Ultimately, testing would be recommended to determine whether any lubricant replacement meets the protective needs of the equipment.

EALs have been used extensively in full-scale applications for decades. Pearson and Spagnoli (2000) documented on the order of a dozen applications ranging from pump applications, hydraulic oil applications, sewage outfall applications, maintenance of golf course equipment, and construction equipment maintenance – all with successful long-term performance.

Water Washout. In-water structures in dams may be subjected to strong water currents and cavitation. In particular, violent water currents can occur in the draft tubes that house the wicket gate bearings. ASTM D1264 is the standard test for evaluating water washout resistance of lubricating greases (ASTM International 2012).

Costs. Table 5 summarizes base costs of EALs in comparison with mineral oil-based lubricant. This table is generalized, in fact, some synthetic ester formulations can cost 20 times more than their mineral oil equivalent (Nagendramma and Kaul 2012).

Table 5. Cost comparison of EALs to mineral oil (adapted from USEPA 2011).

Lubricant Base Oil	Cost Ratio to a Comparable Mineral Oil Base Lubricant Cost
Bio-based lubricants (Vegetable oils)	1.2
Synthetic ester	2 to 3
Polyalkylene glycols	2 to 3

These comparisons indicate that EALs are more expensive than mineral oil-based lubricants. However, this is only a comparison of the base costs. There are other life-cycle costs that might change the overall cost comparison. For example, in many cases, EALs can actually last longer and outperform mineral oils (see above), which could result in lower quantity requirements. Other factors could be environmental management costs, which would likely be favorable for EALs. On the other hand, recycling benefits might be more favorable for mineral oils. Furthermore, costs of bio-based lubricants (vegetable oils and synthetic esters) can become more competitive with petroleum-based mineral oils as petrochemical costs increase (Aluyor et al. 2009).

Miller et al. (2007) performed a life-cycle analysis (LCA) on a proposed replacement of a mineral oil lubricant with a soybean-based lubricant for an aluminum manufacturing facility. Although the soybean lubricant was somewhat more expensive, this factor was offset because the use rate for the vegetable oil was actually lower than that for the mineral oil. The LCA also assessed overall environmental impact. The soybean oil had positive effects on the release of climate change constituents and reduced fossil fuel usage, but it did have the potential for overall increases in nutrient releases to the environment, which could have a negative, eutrophicating impact.

Start up. A key factor in considering a replacement material is its miscibility with the existing mineral oil lubricant. If the replacement lubricant had good miscibility, then it could simply be added as a makeup material over the existing lubricant. This saves the need to clean the surface, which might require the shutdown of the system during the cleaning. Consequently, in the short term, miscibility compatibility could be a very valuable parameter. However, if a replacement lubricant has significant advantages, then it might turn out to be better to go through the cleaning step if it is not compatible with the existing lubricant. Fortunately, some types of EALs tend to be highly miscible with mineral oil (Table 4). In particular, rape seed (vegetable) oil and polyalphaolefins (PAOs) have excellent miscibility with mineral oil while synthetic esters have good miscibility. PAGs, on the other hand, are not compatible to most mineral oils.

EAL testing for Dam Application. Some studies have been conducted on hydroelectric dam EAL applications. Hanna and Pugh (1998) conducted a Bureau of Reclamation study looking at environmentally acceptable alternatives to mineral oil. Food-grade greases, which are greases approved for incidental contact with food, but that do not necessarily meet EAL criteria, did not perform well. Two EAL greases, conversely, performed comparably (and in one case, significantly better) to a lithium-based mineral oil product. Darr (2002) discusses actual applications of EALs at Parker Dam in CA. Particular success was found with a canola-based VSG product (which was one of the products tested by Hanna and Pugh). As discussed above, The Dalles and and John Day reportedly used EALs, and data provided by Redman (2014) also indicates that an EAL is used on Dworshak's wicket gates. USACE 1999 indicated that the Huntington and Nashville Districts used EALs in lock-gate operations.

Alternatives to Lubricants in Dams. There are alternatives to using either mineral oil or EAL lubricants for in-water structures. First, a water-lubricated process could be used. This essentially means that no lubricant is used, only the surrounding water. Hanna and Pugh (1998) evaluated water lubrication and found that torque to move the test structure approximately doubled, and wear was expected to increase. Another alternative is to use self-lubricating surfaces. These are essentially coated surfaces in which the lubricant is incorporated into the parent material, which reduces friction and wear. There are plans to use self-lubricating structures on replaced pintle bearing bushings in lock structures in The Dalles dam (Ingram 2011). The Little Goose, Lower Monumental, Bonneville and McNary Dams also have self-lubricating bearings installed on some of their in-water structures (USACE 1999). These reduce operating costs and have an environmentally friendly benefit of not having any need for grease applications. However, this approach requires the replacement of the equipment, which is very expensive (on the order of tens of millions of dollars, USACE 2012 gives major lock renovation costs for numerous locks in the Rock Island District). There is also concern that self-lubricating bearings may actually need to be replaced sooner than conventional brass bearings.

LUBRICANTS IN THE COLUMBIA RIVER DAMS: Redman (2014) prepared a white paper on the lubricating practices of the six dams operated by the Walla Walla District (McNary, Ice Harbor, Lower Monumental, Little Goose, Lower Granite, and Dworshak). The following sections are based on this document.

In-Water Lubrication Structures for Walla Walla Dams. Two primary structures were identified requiring in-water lubrication: wicket gates and pintle bearings. Wicket gates are structures that control the amount of water flowing through the intake tunnel (penstock) through the hydroelectric turbine (Zimesnick 2010, Figure 4). As gates are opened, the turbines spin faster, generating more electricity. Wicket gates can be partially closed to slow down energy production during low-energy use periods and completely shut to allow for maintenance on the turbines.

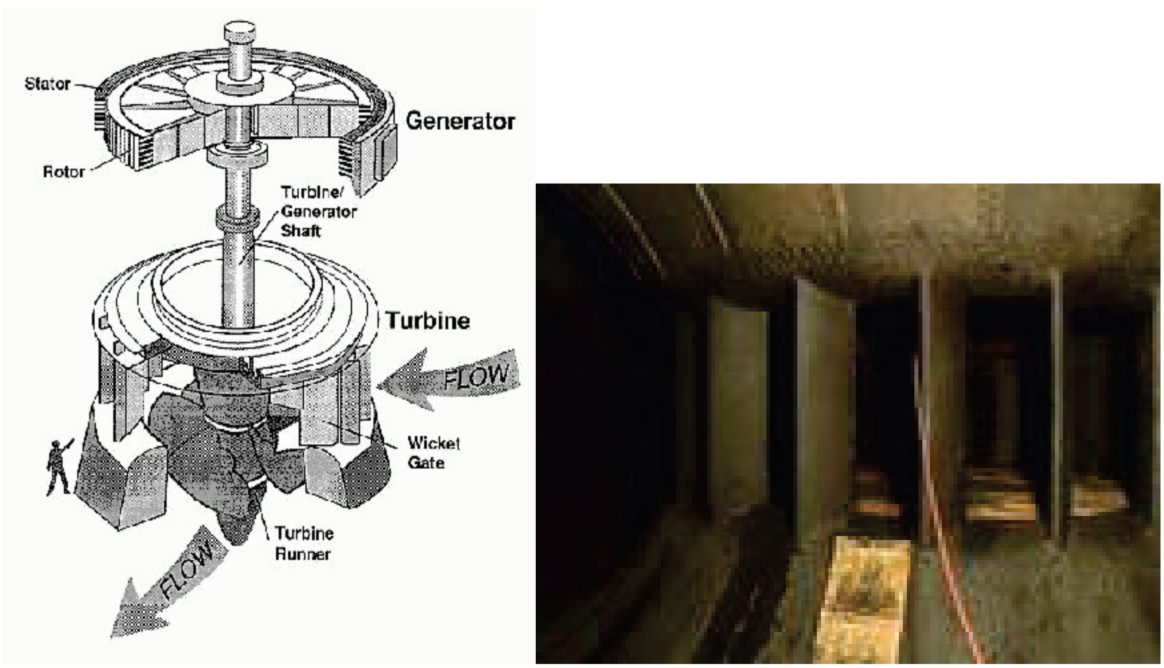


Figure 4. Schematic and picture of wicket gates (Parker Dam, Lake Havasu, CA).

Pintle bearings are hinge-like devices that support the weight of the gate and allow the gates to swing open and shut (Figure 5). These bearings are found on locks to allow shipping to navigate the dam and on gates that allow the dam to release water when needed. These have commonly been grease-lubricated bronze bearings, although self-lubricated bearings are becoming more prevalent.

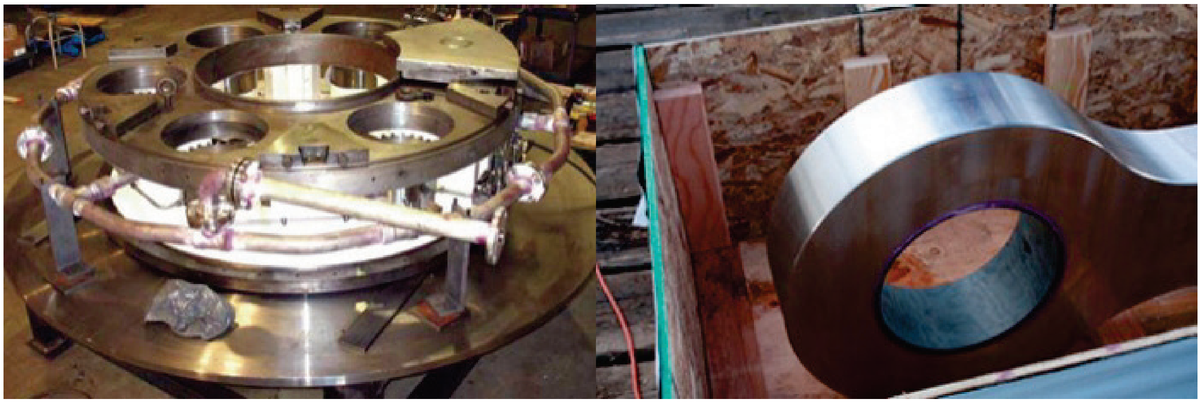


Figure 5. Pintle gate bearing (from the Rock Island Dam) and bushing (a self-lubricating bushing from The Dalles Dam).

One point to consider is the sheer size of the structures under discussion. Figure 6 is a lock gate that is undergoing repairs at The Dalles dam. The size is massive.

Figure 6. Repairs conducted on a lock gate at The Dalles Dam.

In-Water Lubricants Used for Walla Walla District-Managed Dams. Table 6 summarizes lubricating materials used for the wicket gates and pintle bearings for the Walla Walla Dams. One of these is classified as an EAL, ECO Fluids VSG Wicket Gate Grease (although this lubricant does not have associated bioaccumulation test data), although the Chevron FM ALC EP2 Food Grade is a foodgrade material (see section below).

Table 6. In-water lubricants used for Walla Walla district-managed dams (from Redmon 2014).

Dam	Wicket Gates	Pintle Bearings
McNary	Chevron Ultra Duty EP NGLI-0	Chevron Ultra Duty EP NGLI-0
Ice Harbor	Chevron Ultra Duty EP NGLI-0	Chevron Ultra Duty EP NGLI-0
Lower Monument	Chevron Ultra Duty EP NGLI-1	N/A
Little Goose	Chevron Ultra Duty EP NGLI-0	Chevron Ultra Duty EP NGLI-0
Lower Granite	Chevron FM ALC EP2 Food Grade	Chevron FM ALC EP1 Food Grade
Dworshak	ECO Fluids VSG Wicket Gate Grease	N/A

Table 7 summarizes the properties of these lubricants and Mobil 100 SHC Series EAL greases, which are used at The Dalles. The first two lubricants on the table are conventional mineral oil lubricants (Chevron Ultra Duty EP NGLI-0 and Chevron Ultra Duty EP NGLI-1). The next two are food-grade-quality greases, but are also mineral-oil-based and are not EALs (Chevron FM ALC EP1 Food Grade and Chevron FM ALC EP2 Food Grade). The last three greases (Mobil EAL 101 and 102 and VSG) are EAL greases. The Mobil greases are synthetic esters, while the VSG product is canola oil, bio-based grease. The EAL greases are comparable to the mineral oil greases for most of the data given, although the Mobil greases have a somewhat lower Four Ball Weld Pt forces (VSG is comparable). In a critical measure for in-water use, %Washout, the EALs have excellent numbers, particularly the VSG grease. This very preliminary assessment suggests that EAL products are available that can perform comparably to mineral oil greases.

Food Grade Lubricants. Redman (2014) reports that several dams use food-grade lubricants (Chevron FM ALC EP2 Food Grade) as environmentally friendly lubricants. However, these materials are not documented as EALs. Food-grade materials may not meet EAL criteria, such as biodegradability or toxicity. However, some food-grade materials do meet EAL standards. If there is a food-grade material of strong interest, then it should be possible to conduct basic testing to determine whether these meet EAL requirements — and if so — have then classified as such.

VSG Wicket Gate Grease. VSG Wicket Gate Grease is an EAL that is used at Dworshak Dam, which is a Walla Walla district-managed dam. General information on VSG is provided on the ECO Fluid website at (*http://fluidcenter.com/vsg.html*, see *http://fluidcenter.com/pdf/vsgtechdata.pdf* for a download of its technical sheet). VSG is a canola oil-based lubricant with a benign calcium sulfanate thickener that is readily biodegradable, and is designed for hydroelectric dam applications. It reportedly meets all performance standards. VSG reportedly offers excellent corrosion protection and is resistant to grease line plugging. It has excellent low temperature pumpability, yet stiffens upon water contact, allowing it to stay in bearing. VSG grease has an ASTM D-1264 washout loss (at 79.4 C, 175 F) of 1.21%. VSG is reportedly compatible with more lithium-based mineral oil greases. VSG is more expensive than most comparable mineral oil lubricants, but according to ECO Fluid, the small amounts needed annually mean that the actual increased costs assuming equivalent usages are minimal. Furthermore, some users have indicated that they actually use less VSG lubricant than they previously used, resulting in a net savings. The VSG product is equivalent to one of the EALs tested by Hanna and Pugh (1998) and used at the Parker Dam in CA (Darr 2002).

Table 7. Properties of in-water lubricants used in Walla Walla district-managed dams (from Redman 2014).

			Lubricant				
Properties	**Ultra Duty EP NGLI-0**	**Ultra Duty EP NGLI-1**	**FM ALC EP1**	**FM ALC EP2**	**Mobil SHC 101 EAL**	**Mobil SHC 102 EAL**	**VSG Wicket Gate Grease**
NLGI Number	**0**	**1**	**1**	**2**	**1**	**2**	**1**
Operating Temp, F Min Max	-15 270	-15 350	-4 325	-4 325			
Penetration @ 77 F	370	325	280	325	325	280	325
Dropping Pt, F	342	491	500	500	356	356	480
Four Ball Weld Pt. kgf	315	500	500	500	200	200	400
Four Ball Wear Scar, mm	0.45	0.43	0.60	0.60			0.42
Timken OK Load, lb	55	70	40	40			55
Water Washout, wt%	15	7			8.0	6.5	1.21
Lincoln ventmeter, psig @ 30 @ 70 F 30 F 0 F	100 200 1700	-- 250 975					20 110 42
Copper corrosion	--	1B			1A	1A	1B
Thickener, % Type	5.6 Lithium	7.0 Lithium complex	6.9 Aluminum complex	7.7 Aluminum complex	Lithium	Lithium	-- Calcium sulfanate
ISO Viscosity	460	320			100	100	
Kinematic Viscosity cST @ 40 C	400	383	200	200			

Mobil Oil EALs. Redman (2014) identified EALs manufactured by Mobil that might also be useful for the Columbia River Dams; the Mobil SHC 100 EAL series (see *http://www.mobil.com/USA-English/Lubes/PDS/GLXXENGRSMOMobil_SHC_Grease_100_EAL_Series.aspx*). The series consists of two products, 101 and 102 (Table 7). The SHC 100 series are designed to be high-performance greases to be used in environmentally sensitive applications, and both the 101 and 102 products are registered EALs. The SHC 100 series are synthetic ester formulations and are reportedly readily biodegradable. Both were tested using the OECD 203 aquatic toxicity test (OECD 2013b), and were "virtually non-toxic." Furthermore, both are specifically designed for in-water use for marine equipment, water treatment plants, and dams, locks, and waterways. As such, they have good adhesion and water resistance properties and offer excellent rust and corrosion protection. Both products use lithium thickeners, which are compatible with current lubricants used in the dams.

Huskey Specialty Lubricants ECOLube EP2 & Hydrolube. Huskey Specialty Lubricants produces two green lubricants that might be appropriate for in-water dam use: Ecolube EP2 and Hydrolube (see *http://huskey.com/PRODUCTS/IndustrialGreases/igrl/1/app/igrl*). Ecolube EP2 is a vegetable oil fortified by anti-oxidant, pressure, and anti-wear and anti-corrosion additives, and can be used in high- and low-temperature conditions (see *http://huskey.com/Product/item/12/Ecolube-EP2* for a specifications sheet). It is classified as readily biodegradable and contains no ozone-depleting chemicals, no SARA (Superfund Amendment and Reauthorization Act) Title 313 chemicals, no heavy metals, no greenhouse gases, no chlorine, no phenols, no volatile organic compounds, and no Proposition 65 chemicals. It is acceptable for use where incidental food or potable water contact may occur. Water washout data is not provided for Ecolube EP 2.

Hydrolube (see *http://huskey.com/Product/item/66/Hydrolube* for a specifications sheet) is particularly designed for high pressure, underwater environments found in hydroelectric dams. Like Ecolube, it does not contain any problematic chemicals or metals and is rated for incidental food and potable water contact. It comes in four grades, and has ASTM D1264 water washout values ranging from 0 to 1%, depending on the grade.

CONCLUSIONS/RECOMMENDATIONS: The following conclusions were drawn from this study:

- EALs can reduce the environmental impacts of in-water lubricant usage due to lower toxicity and higher biodegradability.
- The performance of EALs is comparable to mineral oil lubricants. In some areas, EALs can significantly outperform mineral oils lubricants. However, each lubricant type has relative strengths and advantages. Considering the focus on in-water use, EALs tend to outperform mineral oils in oxidative stability and evaporative loss, but mineral oils appear to have performance advantage in hydrolytic stability and corrosion protection. It appears likely that EALs will be able to meet the requirements needed for in-water uses.
- Two products in particular are promising. VSG Wicket Gate Grease is already being used at Dworshak Dam and has a history of effective use. And the Mobil SHC series 100 EALs are greases designed for in-water use and appear to have strong performance characteristics. Both the VSG and the Mobil products appear to be compatible with the lithium-thickened greases currently used.

- The base costs of EALs are higher than those of mineral oil lubricants. The EALs base costs can be as low as 1.2 times — or even as high as 4 times — higher than mineral oil base costs. Some reports even indicate that high performance synthetics can be up to 20 times higher. However, it is likely that life cycle costs of EALs are more competitive — and even advantageous — in some cases compared to mineral oils.

The following recommendations are proposed:

- ERDC should be prepared to conduct any testing to support EAL certification for any lubricant that is not labeled, but that could be a good choice for the northwest dams. Testing could be conducted on the food-grade greases currently used at Lower Granite Dam. Similarly, the Huskey Hydrolube is a promising grease product that is designed to be environmentally friendly, but is not categorized as an EAL. Testing could be performed to allow its use in order to meet the conditions of the settlement.
- Laboratory testing and field demonstrations may be warranted for new EAL application. ERDC could lead or assist in these studies.
- EALs are generally more expensive. However, in many cases, EALs can last longer than conventional lubricants, and EALs may not require the environmental management costs associated with mineral oils. Life cycle analysis would be a valuable tool to use for assessing the overall costs associated with EAL use as compared to those associated with conventional mineral oil grease use.

ADDITIONAL INFORMATION: This technical note was prepared by Victor F. Medina, Ph.D., P.E., Research Engineer, Environmental Laboratory, U.S. Army Engineer Research and Development Center. The study was conducted as an activity of the Water Operations Technical Support (WOTS) program. For information on WOTS, please contact the Program Manager, Dr. Pat Deliman, at Patrick.N.Deliman@usace.army.mil. This technical note should be cited as follows:

Medina, V.F. 2015. *Evaluation of environmentally acceptable lubricants (EALs) for dams managed by the U.S. Army Corps of Engineers*. ERDC TN-WOTS-MS-9, Vicksburg, MS: U.S. Army Engineer Research and Development Center.

REFERENCES

Aluyor, E. O., K. O. Obahiagbon, and M. Ori-jesu. Biodegradation of vegetable oils: A review. *Scientific Research and Essay* 4:543-548.

Anand, O. N., and V. K. Chhibber. 2006. Vegetable oil derivatives: Environment-friendly lubricants and fuels. *Journal of Synthetic Lubrication* 23:91-107.

Arumugam, S., G. Sriram, L. Subadha. 2012. Synthesis, chemical modification and tribological evaluation of plant oil as bio-degradable low temperature lubricant. *Procedia Engineering* 38:1508-1517.

ASTM International. 2011. *Standard test method for determining aerobic aquatic biodegradation of lubricants or their components*. D5864-11. West Conshohocken, PA.

ASTM International. 2012. Standard test method for determining the water washout characteristics of lubricating greases. D1264-12. West Conshohocken, PA.

Bartz, W. J. 1998. Lubricants and the environment. *Tribology International* 31:35-47.

Battersby, N. 2000. The biodegradability and microbial toxicity testing of lubricants – some recommendations. *Chemosphere* 41:1011-1027.

Beran, E. 2003. Structurally modified polyglycols as biodegradable base stocks for synthetic lubricants. *Journal of Synthetic Lubrication* 20:3-14.

Betton, C. I. 2010. Chapter 15. Lubricants and Their Environmental Impact. In *Chemistry and technology of Lubricants, 3rd Edition*, ed. Mortier, R.M. et al. New York, NY: Springer Science.

Birova, A., A. Pavlovicoa, J. Cvengros. 2002. Lubricating oils based on chemically modified vegetable oils. *Journal of Synthetic Lubrication* 18:291-300.

Brunner, W. J., and G. M. Salmon. 1997. Reducing the risk of environmental damage from oil spillage. *International Journal on Hydropower and Dams* 4:57-58.

Cunningham, B., N. Battersby, W. Wehrmeyer, and C. Fothergill. 2004. A sustainability assessment of a biolubricant. *Journal of Industrial Ecology* 7:179-192.

Darr, J. 2002. Using Biobased Lubricants at Hydroelectric Power Facilities. USEPA. *EPP Update* 10:10-11.

Durak, E. 2004. A study on friction behavior of a rapeseed oil as an environmentally friendly additive in lubricating oil. *Industrial Lubrication and Tribology* 56:23-37.

Duzcukoglu, H., and M. Acaroglu. 2010. Lubrication Properties of Vegetable Oils combined with boric acid and determination of their effects on wear. *Energy Sources, Part A.* 32:275-285.

Erhan, S., B. K. Sharma, and J. M. Perez. 2006. Oxidation and low temperature stability of vegetable oil-based lubricants. *Industrial Crops and Products* 24:292-299.

Etkin, D.S. Worldwide analysis of in-port vessel operational lubricant discharges and leakages. In *33rd Arctic and Marine Oilspill Program Technical Seminar* 529-554.

Hanna, L. J., and C. A. Pugh. 1998. Environmentally Safe "Green" Lubricants for Wicket Gates. *Bureau of Reclamation Water Operation and Maintenance Bulletin* 186:13-20.

Haus, F., J. German, G-A. Junter. 2001. Primary biodegradability of mineral base oils in relation to their chemicals and physical characteristics. *Chemosphere* 45:983-990.

Herdan, J. M. 1997. Lubricating oil additives and the environment. *Lubrication Science* 9:983-990.

Ingram, E. A. 2011. Bearing and Seals: Applying the Latest Technologies. Hydro Review. Available On-Line: http://www.hydroworld.com/articles/hr/print/volume-30/issue-4/articles/bearings-and-seals-applying-the-latest-technologies.html.

International Organization of Standardization (ISO). 1997. Water Quality – Evaluation in an aqueous medium for the ultimate aerobic biodegradability of organic compounds. Determination of biochemical oxygen demand in a two-phase closed bottle test. ISO 10708. Geneva, Switzerland.

International Organization of Standardization (ISO). 1999. *Water quality – evaluation of ultimate biodegradability of organic compounds in aqueous medium – method by analysis of inorganic carbon in sealed vessels (CO_2 headspace test)*. ISO 14593. Geneva, Switzerland.

Jaydas, N. H., and K. Prabhakaran Nair. 2006. Coconut oil as a base oil for industrial lubricants – evaluation and modification of thermal, oxidative, and low temperature properties. *Tribology International* 39:873-878.

Johnson, M. 2014. Riverkeeper fights to keep the dam(n) oil out of our river. *Columbia Riverkeeper River Currents*. Summer:6-7.

Karmakar, G., and P. Ghosh. 2013. Green additives for lubricating oil. *Sustainable Chemistry and Engineering* 1:1364-1370.

Miller, S. A., A. E. Landis, T. L. Theis, and R. A. Reich. 2007. A comparative life cycle assessment of petroleum and soybean-based lubricants. *Environmental Science and Technology* 41:4143-4149.

Nagendramma, P., and S. Kaul. 2012. Development of ecofriendly/biodegradable lubricants: An overview. *Renewable and Sustainable Energy Reviews* 16:764-774.

Organization of Economic Cooperation and Development (OECD). 2012. OECD Guideline for testing of Chemicals, Section 3 – Degradation and Accumulation. Adopted by the Council on 17 July 1992. Paris, France. Sections available for Download at: *http://www.oecd-ilibrary.org/environment/oecd-guidelines-for-the-testing-of-chemicals-section-3-degradation-and-accumulation_2074577x*.

Organization of Economic Cooperation and Development (OECD). 2013a. OECD Guidelines for the Testing of Chemicals. Section 1. Physical-Chemical Properties. Paris France. Sections available for Download at: *http://www.oecd-ilibrary.org/environment/oecd-guidelines-for-the-testing-of-chemicals-section-1-physical-chemical-properties_20745753*

Organization of Economic Cooperation and Development (OECD). 2013b. OECD Guidelines for the Testing of Chemicals. Section 2. Effects on Biotic Systems. Paris France. Sections available for Download at: *http://www.oecd-ilibrary.org/environment/oecd-guidelines-for-the-testing-of-chemicals-section-2-effects-on-biotic-systems_20745761*.

Pai, R., and D. J. Hargreaves. 2002. Performance of environment-friendly hydraulic fluids and material wear in cavitating conditions. *Wear* 252:970-978.

Pearson, S. L., and J. E. Spagnoli. 2000. Environmental Lubricants – An overview of onsite applications and experience. *Journal of the Society of Tribologists and Lubrication Engineers* 56:40-45.

Redman, D. 2014. EAL/Grease. *Walla Walla dams*. White Paper – Walla Walla District, Walla Walla, WA.

Salimon, J., N. Salih, and E. Yousif. 2012. Industrial development and application of plant oils and their biobased oleochemicals. *Arabian Journal of Chemistry* 5:135-145.

Sharma, B. K., A. Adhvaryu, Z. Liu, S.Z. Erhan. 2006. Chemical Modification of Vegetable Oils for Lubricant Applications. *JAOCS* 83:129-136.

Headquarters, U. S. Army Corps of Engineers (USACE). 1999. *Lubricants and hydraulic fluids*. Engineer Manual 1110-2-1424. Washington, DC:Headquarters, USACE.

USACE-Rock Island District. 2012. *Illinois waterway locks & dams*. Rock Island, IL: USACE-Rock Island District.

United States Environmental Protection Agency (USEPA). 1982a. *Environmental effects test guidelines – Part 2*. EPA 560/6-82-002. Washington DC: USEPA.

______. 1982b. *Chemical fate test guidelines*. EPA 560/6-82-003. Washington DC: USEPA.

______. 2011. *Environmentally acceptable lubricants*. EPA 800-R-11-002. Washington, DC: USEPA.

______. 2013. *Vessel general permit discharges incidental to the normal operation of vessels (VGP)*. Available on-line at: http://water.epa.gov/polwaste/npdes/vessels/upload/vgp_permit2013.pdf

Verlind, K-E, S. Leonsson, and S. Videhult.2004. Environmentally adapted technology for Kaplan runners. *International Journal on Hydropower and Dams*11:48-52.

Willing, A. 2001. Lubricants based on renewable resources – An environmentally compatible alternative to mineral oil products. *Chemosphere* 43:89-98.

Wright, J. 2008. *Grease basics. Machinery lubrication*. A Noria Publication. Available on-line: http://www.machinerylubrication.com/Read/1352/grease-basics.

Zimesnick, M. 2010. What does a wicket gate do in a hydro dam? *Renewable Energy Index*. Available on-line at: http://renewableenergyindex.com/renewable-energy-questions/what-does-a-wicket-gate-do-in-a-hydro-dam.

IDAHO CONSERVATION LEAGUE

208.345.6933 • PO Box 844, Boise, ID 83702 • www.idahoconservation.org

11 July 2018

Dru Keenan
US EPA Region 10
1200 Sixth Ave
Seattle, WA 98101

Loren Moore
401 Program Coordinator
Idaho DEQ
1410 N. Hilton Street
Boise, ID 83706

Submitted via email: keenan.dru@epa.gov and loren.moore@deq.idaho.gov

RE: Idaho Conservation League Comments on Draft General NPDES and Accompanying 401 Certification for Hydroelectric Generating Facilities, Permit Number IDG360000

Dear Mr. Keenan and Ms. Moore,

Thank you for the opportunity to comment on the draft General NPDES permit and accompanying 401 Certification (hereinafter "401 Cert") for hydroelectric generating facilities in Idaho.

Since 1973, the Idaho Conservation League has been Idaho's leading voice for clean water, clean air and wilderness—values that are the foundation for Idaho's extraordinary quality of life. The Idaho Conservation League works to protect these values through public education, outreach, advocacy and policy development. As Idaho's largest state-based conservation organization, we represent over 30,000 supporters, many of whom have a deep personal interest in protecting water quality and aquatic habitat throughout Idaho.

We thank you for the opportunity to review the proposed permit and ask that you please send us subsequent documents for this project. Our comments can be found following this letter. Please do not hesitate to contact me at 208-345-6933 ext. 23 or ahopkins@idahoconservation.org if you have any questions regarding our comments or if we can provide you with any additional information on this matter.

Sincerely,

Austin Hopkins

Conservation Associate

Applicability and Coverage fails to Regulate Total Dissolved Gas Discharge

As written, the proposed GP would not cover the discharge of pollutants from discharges over or through the dam. This is inconsistent with Section 301(a) of the CWA, 33 USC § 1311(a), which prohibits the discharge of pollutants to waters of the United States unless the discharge is authorized pursuant to an authorized NPDES permit.

The presence and operation of a hydroelectric facility is directly and solely responsible for the introduction of total dissolved gas as a pollutant. As water descends from atop or through the dam it collects atmospheric gases that become entrapped in the water as it plunges beneath the water surface below. This is effectively a "discharge" of this pollutant, and the dam itself is the point source. This fact is supported by multiple studies that have documented the role dams play in causing gas supersaturation through their operation (e.g. - Qu et al. 2011[1], Feng et al. 2010[2], Weitkamp and Katz 1980[3]).

The discharge of total dissolved gas is particularly concerning given the compounding effect of thermal discharges from these hydroelectric facilities. In their review of literature on dissolved gas supersaturation, Weitkamp and Katz (1980)[4] noted, "*increasing water temperatures will produce supersaturation in water that is initially saturated.*" Thus, not only does the operation of these facilities directly cause the discharge of total dissolved gas, the problem is exacerbated by the simultaneous discharge of excessive heat.

Total dissolved gas is a regulated pollutant under Idaho's water quality standards. IDAPA 58.01.02.250.01.b and 58.01.02.300. This GP must consider total dissolved gas as a pollutant of concern, and the final permit must include any necessary provisions to control discharges of total dissolved gas and comply with water quality standards. Failure to regulate the discharge of total dissolved gas from dams as part of this GP would violate Section 301(a) of the CWA, 33 USC § 1311(a).

Biological Evaluation Failed to Consider TDG Impacts on Fish

The operation of dams is known to cause total dissolved gas (TDG) pollution downstream of dams (see previous comment). Excessive TDG can have severe consequences for aquatic species present downstream. For example, DEQ's draft 2008 Pend Oreille River and Lake Total Dissolved Gas TMDL (TDG TMDL) highlights TDG impacts to fish as follows:

---

[1] L. Qu, R. Li, J. Li, K.F. Li and L. Wang. (2011). *Experimental study on total dissolved gas supersaturation in water*. Water Science

[2] J.J. Feng, R. Li, K.F. Li, J. Li, L. Qu. (2010). *Study on release process of supersaturated total dissolved gas downstream of high dam*. Journal of Hydroelectric Engineers. 29(1). Pg. 7-12.

[3] D.E. Weitkamp and M. Katz. (1980). *A Review of Dissolved Gas Supersaturation Literature*. Transactions of the American Fisheries Society. 109:659-702.

[4] Ibid.

"TDG supersaturation can cause gas bubble trauma in fish, and may limit habitat due to the potentially lethal presence of elevated gas levels in habitat areas. Gas bubble trauma occurs when TDG is transferred into the bloodstream while in solution and is then released as a gas while still in the body of the fish due to a change in pressure. As a result, gas bubbles form within the body cavity, fins, and/or gills. Development of internal gas bubbles can form in many body cavities, disrupting neurological, cardiovascular, respiratory, osmoregulatroy, and other physical functions (Stroud and Nebeker 1976, Weitkamp and Katz 1980, Fidler 1988, and Shrimpton et al 1990a and 1990b)."

Further, high concentrations of TDG can persist well downstream of a dam (see Figure 6 in Pend Oreille TDG TMDL).

Given this, we are concerned that the Biological Evaluation failed to consider impacts to aquatic species as part of their review of this permit. Previous regulatory documents have clearly illustrated the negative impact TDG can have on aquatic species. The EPA must redo their Biological Evaluation and include analysis of TDG impacts to aquatic species. Once the Biological Evaluation is complete, the EPA should make any necessary changes to the draft GP and hold a new public comment period using the updated information.

If EPA disagrees with our comment on this matter, we request that the EPA provide the legal and regulatory rationale for why an evaluation of TDG is not required under the Endangered Species Act (ESA).

Clarification Needed for New Dischargers

Regulations at 40 CFR 122.4(i) stipulate that, *"no permit may be issued…to a new source or a new discharger, if the discharge from its construction or operation will cause or contribute to the violation of water quality standards."* A "new discharger" is defined in §122.2 as follows:

New discharger means any building, structure, facility, or installation:
(a) From which there is or may be a "discharge of pollutants;"
(b) That did not commence the "discharge of pollutants" at a particular "site" prior to August 13, 1979;
(c) Which is not a "new source;" and
(d) Which has never received a finally effective NDPES permit for discharges at that "site."

The current draft GP excludes coverage to facilities that are new or have expanded their discharge since July 1, 2011; this appears incongruent with the August 13, 1979 date included in the definition of "new discharge." This discrepancy should be rectified in the final permit. For example, if a dam were constructed in 1984, would the EPA consider this as a new discharger? Notwithstanding the effective date for coverage, this is a new permit, and we believe facilities seeking coverage under this permit should all be considered "new" if they have not previously received an NPDES permit.

RPA for WQBEL

Regulations at §122.44(d)(1)(i) instruct the EPA to determine if a pollutant has the reasonable potential to cause a violation of water quality standards when issuing permits and defining limits. This assessment is commonly referred to as a reasonable potential analysis (RPA) and is required whenever a permit is originally issued or renewed. The RPA is typically included as an appendix to the permit. Based on the lack of an RPA for public review and commenting we assume the EPA has yet to perform an RPA for temperature.

Pursuant to §122.28(a)(3), general permits are subject to the same water quality-effluent limitations as individual permits. Thus, in order to comply with §122.44(d)(1)(i), the EPA must perform an RPA for all pollutants – including TDG – that will or may be discharged from facilities seeking coverage under this GP. If the RPA shows potential for violating water quality standards for any pollutant then the EPA must include effluent limits for said pollutant as part of the GP.

Temperature Limits for Discharges into Impaired Waters

When discussing temperature effluent limits, the EPA states that the general permit only includes monitoring requirements for temperature, citing that *"the EPA does not believe temperature discharges will cause an exceedance of the temperature standard based on review of similar facilities' monitoring reports."* We are concerned with the accuracy of this statement given the lack of support as required by regulations (see previous comment on RPAs) as well as the fact that 17 hydroelectric facilities are located on waters listed on the 303(d) list for temperature.

EPA states that only a few temperature TMDLs exist on these water bodies, and none provide a wasteload allocation (WLA) for hydroelectric facilities. Despite not having a specific temperature WLA for hydroelectric facilities, the EPA and DEQ are still required to assess the assimilative capacity of these impaired water bodies to ensure thermal discharges from the 17 facilities will not cause or contribute to a violation of water quality standards.

In their 401 Certification for this GP, DEQ asserts that monitoring of temperature in the effluent is sufficient for assessing compliance with water quality standards and established TMDLs. This approach is not consistent with the requirements stipulated in the CWA and associated regulations. The GP must include end-of-pipe thermal limits set at the applicable water quality standard. Anything less stringent would be in violation of not only the TMDL but also the CWA.

Narrative Criteria for Suspended Sediment

The GP includes the following narrative criteria for floating, suspended, or submerged matter:

> *Surface waters of the State shall be free of floating, suspended, or submerged matter of any kind in concentrations causing nuisance or objectionable conditions or that may impair designated beneficial uses. This matter does not include suspended sediment produced as a result of nonpoint source activities.*

With regards to the last sentence, we are curious as to how the EPA will distinguish between suspended materials resulting from nonpoint source activities with suspended material resulting from point source activities?

Antidegradation Review

We agree with DEQ's approach of requiring individual permits for new facilities seeking to discharge into Tier II waterbodies. However, as mentioned in previous comments, DEQ's use of July 1, 2011 as the threshold for "existing" sources is incongruent with the federal definition of "new discharge" defined in 40 CFR §122.2. As such, DEQ must amend this effective date and should only exclude from an antidegradation review facilities that have discharged prior to August 13, 1979. Facilities that have discharged after this date, but have never received a permit to do so, should be treated as a new discharger and undergo a full antidegradation analysis.

IDAHO GOVERNOR'S OFFICE OF ENERGY & MINERAL RESOURCES

C. L. "BUTCH" OTTER
Governor

JOHN CHATBURN
Administrator

304 N. 8th Street, Suite 250, P.O. Box 83720
Boise, Idaho 83720-0199

(208) 332-1660
FAX (208) 332-1661

July 11, 2018

Director, Office of Water and Watersheds
United States Environmental Protection Agency
Region 10
1200 Sixth Avenue, Suite 15, OWW-191
Seattle, Washington 98101

RE: United States Environmental Protection Agency's proposed Draft NPDES General Permit for Hydroelectric Generating Facilities in Idaho, #IDG360000

Thank you for the opportunity to provide comments on the United States Environmental Protection Agency's (EPA) proposed National Pollutant Discharge Elimination System (NPDES) Draft General Permit for Hydroelectric Generating Facilities in Idaho.

The State of Idaho believes EPA should withdraw its Draft NPDES General Permit for Hydroelectric Generating Facilities in Idaho so that Idaho may develop its own permits, similar to the other delegated states in Region 10. The State of Idaho recognizes that EPA has received 7 NPDES permit applications from a hydroelectric company seeking permission to discharge wastewater from their hydroelectric facilities. The State of Idaho would classify these hydroelectric facilities as a type requiring an industrial permit. Not wishing to delay the permitting request by the hydroelectric company, the State of Idaho recommends that EPA process these as individual industrial hydroelectric permits and seek individual Clean Water Act Section 401 Water Quality Certification from the IDEQ.

Until recently, Idaho was the only state in Region 10 that had not been delegated primacy for the NPDES program. On June 5, 2018[1], EPA approved the delegation of the NPDES program through the Idaho Pollutant Discharge Elimination System (IPDES) beginning on July 1, 2018[2]. During its development of the rules governing the IPDES, IDEQ worked closely in a rulemaking with EPA and potentially affected stakeholders. IDEQ will undertake a similar collaborative process in order to develop permits under the IPDES program.

In conclusion, the State of Idaho believes Region 10 should withdraw the Draft NPDES General Permit for Hydroelectric Generating Facilities in Idaho, so that the state may develop IPDES permits for wastewater discharges from these facilities. If you have any questions or would like clarification on any of the issues presented, please contact me.

Sincerely,

John Chatburn, Administrator
Idaho Governor's Office of Energy and Mineral Resources

[1] EPA's IPDES program signed approval letter to Governor Otter
[2] NPDES MOA Between IDEQ and US EPA Region 10

July 11, 2018

Comments of the Idaho Power Company on EPA Region 10's
Proposed Hydropower General Permit

Via E-mail: keenan.dru@epa.gov
Chris Hladick
EPA Region 10 Administrator
Office of Water and Watersheds
U.S. Environmental Protection Agency Region 10
1200 6th Avenue, Ste. 155
Seattle, WA 98101
Attention: Permit No. IDG360000

Re: Permit No. IDG360000– EPA Region 10's Proposed Hydropower General Permit

Dear Administrator Hladick:

On April 27, 2018, EPA Region 10 issued its proposed Hydropower General Permit for Idaho and accompanying Fact Sheet. On May 23, 2018, EPA notified interested parties that an extension of time had been granted in order to provide comments regarding the Proposed General Permit to EPA Region 10 and that such comments must be submitted on or before July 11, 2018. Accordingly, the Idaho Power Company (IPC) now provides these comments in response.

Draft General Permit

As a general matter, Idaho Power requests that EPA defer promulgating a general permit for Idaho until Idaho implements general permits under the Idaho Pollutant Discharge Elimination System (IPDES) program. As of July 1, 2018, Idaho has achieved primacy concerning IPDES rules governing individual permits. By the year 2020 Idaho will begin implementation of general permits in Idaho as well. During its development of the rules governing the IPDES, the Idaho Department of Environmental Quality worked closely in a rulemaking with EPA and potentially affected stakeholders to develop the same. It is anticipated that Idaho, should it believe that a hydropower general permit is appropriate, would undertake the same collaborative process in order to develop and implement such a permit. Conversely, EPA has developed its Hydropower General Permit without soliciting information before submitting it to potentially affected stakeholders for comment. Idaho Power urges EPA Region 10 to halt its efforts to implement the Region 10 Hydropower General Permit, and allow the state of Idaho, once it has primacy concerning general

BRETT DUMAS
Director
Environmental Affairs
208-388-2330
208-433-2837 FAX
BDumas@idahopower.com
P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

permits, to develop its own hydropower general permit through collaborative rulemaking should the state believe that such a permit is appropriate.

The type of discharges that the proposed Idaho-specific Hydropower General Permit seeks to regulate include §316(b) of the Clean Water Act, relating to cooling water intake regulation. When § 316(b) was revised and re-promulgated in 2014 it was never intended to apply to hydropower facilities. During the rulemaking to re-promulgate § 316(b) no information was requested or provided to EPA in order to make any determination about the engineering feasibility of the requirements of § 316(b) as it would be applied to hydropower facilities. Additionally, during the rulemaking process it was widely recognized that hydropower production facilities are already heavily environmentally regulated through the Federal Energy Regulatory Commission licensing process.

Idaho Power believes some clarification as to how its projects operate may be helpful in understanding why § 316(b) should not apply to hydroelectric facilities. Hydroelectric facilities do not have a "CWIS" as contemplated under § 316(b). In IPC facilities, a cooling water pipe inlet is directly connected to each individual hydroelectric unit's penstock or scroll case that is passing the river flow through the units. The cooling water piping may not exit in the draft tube, but rather at the downstream face of the power plant – making managing the tailrace operations at the draft tube ineffective for protecting fish. Because of the geometry and physics of this system, the potential for fish impingement and entrainment is very low and monitoring for fish is near impossible. In order to help illustrate the physical nature of this type of withdrawal, IPC has enclosed a figure representing a cross-section of a hydroelectric facility in which the cooling water system is identified (see Exhibit A).

More specifically, Section I of the permit and fact sheet defines which hydroelectric facilities are eligible and ineligible for coverage. At sub-section B, the permit states that "[t]his general permit does not cover….water discharged over or through the dam." As explained above, hydroelectric generating facilities do not have separate intake structure for cooling water system. It is unclear, based on the "types of discharge covered" whether any Idaho hydroelectric facility would be subject to the general permit coverage. It is further noted that within IPC's hydroelectric system of projects the cumulative volumetric percentage of river water used for cooling water is typically less than 1% of the total diversion. At such a low percentage of total river flow, the potential environmental impact from the cooling water discharge is extremely low to negligible.

At subsection I.C the Draft Permit sets out a number of parameters that would make a facility ineligible for coverage under the permit. C.1.5. states that a "facility [that] is new or has expanded since July 1, 2011" is ineligible for coverage. However, in the Fact Sheet accompanying the Draft Permit that same exclusionary parameter is described as "[h]ydroelectric facilities that are new or have expanded their discharge since July 1, 2011." IPC requests clarity as to whether a facility excluded because it has expanded since July 1, 2011, or only if it has expanded its discharge since July 1, 2011.

Similarly, subsection I.C.6 of the Draft Permit and the explanatory materials in the Fact Sheet create questions and ambiguities about when a facility would be ineligible for the general permit. The Draft Permit states that a facility would be ineligible when "[a] Water Quality Management Plan or Total Maximum Daily Load (TMDL) containing requirements applicable to such point source is approved." Alternatively, the Fact Sheet described this same disqualifying parameter as "[h]ydroelectric facilities with waste load allocations from a TMDL for pH, oil and grease and/or temperature." Does this mean that if a facility has a waste load allocation as the result of a TMDL for some, but not all of the discharges that it is ineligible? Or if there is an assigned waste load allocation for one of the discharges it is still eligible, but only for those discharges that do not already have an approved allocation? Clarification of eligibility will enable Idaho Power to determine which, if any, of its facilities may qualify for the general permit.

Furthermore, most hydropower producing facilities in the state of Idaho are currently required to file with FERC and maintain procedures in place pursuant to a Spill Prevention Control and Countermeasure Plan (SPCC) and an Emergency Action Plan (EAP). Each of these plans is in place in order to protect against any accidental release of oil and grease into a Water of the U.S. IPC would appreciate an explanation of what additional benefit is derived by the BMP Plan required pursuant to the proposed Draft General Permit.

The following is a list of specific items within the permit that should be addressed, with specific reference to the page and item within the Draft General Permit for reference.

Page 2. The Permittee is required to provide EPA with written notification that the BMP Plan has been developed or updated and implemented within 180 days after the effective date of the General Permit. The Permittee then must provide EPA written notification that the BMP Plan has been developed and implemented no later than 90 days after authorization to discharge under the General Permit. Will the Permittee have authorization to discharge within 90 days of the effective date of the permit to allow adequate time to meet both notification deadlines?

The 180-day requirement to notify EPA on Page 2 is inconsistent with information provided in Section IV.B.2, which indicates the Permittee must notify EPA and IDEQ that the plan has been developed and implemented within 90 days of the effective date of the General Permit, unless otherwise specified. The BMP Plan development, implementation and notification requirements for the Permittee and state requirements should be consistent in both Permit sections.

Page 8, Section I.C.3. Ineligible facilities include those that use or propose to use one or more cooling water intake structures (CWIS) with a cumulative design intake flow of greater than 2 million gallons per day (mgd) **or** the facility uses 25 percent or more of the water it withdraws for cooling water purposes on an average monthly basis. The Fact Sheet uses the similar exclusion language. The IDEQ Draft § 401 Water Quality Certification indicates that EPA does not intend to cover facilities that have a cumulative CWIS with design intake flow of greater than 2 mgd **and** that uses 25 percent or more of the water the facility withdraws for cooling purposes on an average monthly basis. Do excluded facilities need to meet both or one of the criteria? This clarification is critical to IPC's analysis of which, if any, hydroelectric plants are implicated under this permit.

Page 12, Item 15. Applicants discharging to waters listed on IDEQ's most recent 303(d) list for temperature where there is no waste load allocation in place must submit one complete season (May 1st through November 1st) of continuous temperature monitoring data with a copy of the NOI. The NOI must be submitted to EPA within 90 days of the effective date of the General Permit and a copy, including temperature data, provided to IDEQ at that time. Idaho Power operates 2 hydroelectric facilities that overlap with 303(d) listed waters without assigned waste load allocations (Swan Falls and Milner Dam).

The Draft General Permit was issued for Public Comment April 27, 2018 and timing of the Notice does not allow Idaho Power to install and complete a full season of temperature monitoring data for these facilities until November 1st, 2019. With the NOI due to EPA and IDEQ within 90 days of the Permit's effective date, it appears that Idaho Power will not be afforded an opportunity to discharge from Swan Falls and Milner Dam under a General Permit that becomes effective prior to mid-August, 2019. Timing of the Notice and the requirement to submit one season of monitoring data with the NOI does not establish a reasonable schedule for completion and submission of monitoring data that is not currently required.

Page 14, Section III.A. The EPA should provide guidance on what is considered "hazardous material", "toxic substances", etc.; and provide what is considered the threshold of having negative environmental impacts.

Pages 15-17, Tables 1, 2, and 5. The proposed General Permit anticipates monthly sampling for Oil and Grease. Presently, under existing EPA NPDES permits, Idaho Power samples those components quarterly. Rather than increase the sample frequency, Idaho Power requests that EPA maintain the quarterly sampling frequency, as that has already been deemed sufficient by EPA.

Page 15-17, Section III.B. Table 1-5. For our hydroelectric projects, equipment & floor drain discharges flow from a sump which prevents the discharge of oil by use of specific gravity separation and oil detecting equipment.

Page 15-17, Section III.B. Table 1-5. Why would a General Permit for smaller hydroelectric facilities require a 1/Month sample frequency for Oil and Grease while Individual Permits for larger hydroelectric facilities currently only require a sample frequency of 1/quarter? This seems excessive for smaller hydroelectric facilities.

Page 15-17, Section III.B. Table 1-5. Please define "Report 7DADM" for Temperature Effluent Limit. Current Individual Permits for larger hydroelectric facilities have an Effluent Limitation set at a temperature change of 10 deg. Celsius.

Page 17, Section 13. This section requires clarification. What is the basis for requiring the Permittee to use a monitoring method that will achieve a maximum Minimum Level for TSS of 5 mg/L (Appendix A) when there is no monitoring requirement for TSS and EPA acknowledges that TSS is naturally occurring and not a pollutant? This issue needs to be addressed at Appendix A as well.

Page 18, Item 13.d. Define "maximum Minimum Level" as used in this section and Appendix A.
Page 20-22, Section IV.B. Most of the functions of the BMP's are already covered under each facilities' current SPCC Plan, including notification to the EPA and IDEQ of an oil spill. The BMP's are not necessary if a facility has an active SPCC Plan.

Page 21, Section IV.B.5.e. According to the EPA's SPCC Rule, concerning a spill to water, oil is oil and no preference is given to EAL's. Please provide a basis for this NPDES General Permit's preferential treatment to EAL's.

Page 22, Item 6. Define the "BMP incident" that requires reporting to EPA and IDEQ.

Page 23, Item 2. This section requires facilities to implement the identified "Best Available Technology" to minimize adverse environmental effects of Cooling Water Intake Structures within 180 days of the effective date of the permit. Is EPA guaranteeing an authorization to discharge date that will allow the Permittee to implement BTA within 180 days of the Permit's effective date?

Furthermore, as has been noted elsewhere in these comments, for some facilities it may be impossible for Idaho Power to access and/or retrofit its' existing facilities to accomplish the required intake flow measurement and monitoring contemplated under this proposed General Permit. The monitoring requirements for intake flow measurement appear to have been derived from engineering specification that would be applicable to steam electric plants, and no consideration has been given to whether any technology exists that would allow hydroelectric plants to accomplish the same monitoring.

Page 23 Item 2. Paragraph a) the requirement is broadly applied to "resident fish and other aquatic species in the river". Aquatic species beyond "resident fish" could be broadly interpreted to apply to algal cells, zooplankton, aquatic insects and other aquatic life. Similar language is used in Paragraph b) regarding access to the draft tube areas. The aquatic species of concern in this requirement needs to be better defined. Requirements associated with fish impingement and entrainment (paragraphs d – f) are not possible relative to the location and design of the CWI location within hydropower dams. The CWI is a perforated plate on the wall of the scroll case and cannot be observed under operations of the facility. Further, the language refers to "episodes" of entrainment of impingement. Outside of the inability to observe impingement, the water through the CWI is continuous during plant operations such that there would not be episodic events. Further, the nature of the location of the CWI would inherently have very high sweeping velocities across the plate which would minimize the potential of fish impingement or entrainment. Similarly, the discharge location associated with a CWI is not in the draft tube of the hydropower plant. Prevention of fish and other aquatic species entering a draft tube (paragraph b) relative to a CW discharge implies that there is an attraction to the draft tube relative to the discharge. This is not the case and should not apply to hydropower facilities.

Page 23 Item 2. As discussed above, it is widely recognized that privately owned hydropower production facilities are already heavily environmentally regulated through the Federal Energy Regulatory Commission licensing process. In addition to the FERC authorities to consider protection, mitigation or enhancement recommendations by state and federal management agencies regarding fish and other aquatic species, FERC must also consult with federal agencies responsible for implementation of the Endangered Species Act as part of the relicensing process. Protection measures relative to hydropower operations are regulated and enforced through these mechanisms. Adding additional regulatory measures into an already heavily regulated industry is unnecessary and duplicative.

Page 26, Section V.A.2. EPA should provide examples for "whenever any discharge occurs that may reasonable be expected to cause or contribute to a violation that is unlikely to be detected by a routine sample."

Page 26-27, Section V.C. Why would a General Permit for smaller hydroelectric facilities require a monthly submittal for DMR's while current Individual Permits for larger hydroelectric facilities only submit quarterly DMR's. This seems excessive for smaller hydroelectric facilities.

Page 28-29, Section V.G. Why would the EPA require a 24-hour notice of non-compliance and a written submission within 5-days? Is the DMR submittal not sufficient for notification of non-compliance?

Page 29, Section V.G.5. The listed agencies are already notified of an oil spill through each projects' active SPCC Plan.

Page 40, Definitions. Define the terms "toxic substances" and "deleterious materials" as used in the Effluent Limitations on page 14.

Page 45, Appendix A. Why would a General Permit for smaller hydroelectric facilities set the maximum Minimum Level for Total Suspended Solids at 5 mg/L while Individual Permits for larger hydroelectric facilities currently set the maximum Minimum Level for Total Suspended Solids at 50 mg/L? This seems excessive for smaller hydroelectric facilities.

Page 45, Appendix A. Why would a General Permit for smaller hydroelectric facilities set the maximum Minimum Level for Temperature at 0.2 degree Celsius while Individual Permits for larger hydroelectric facilities currently set the maximum Minimum Level for Temperature Change at 0.6 degree Celsius? This seems excessive for smaller hydroelectric facilities.

Page 45, Appendix A. Why would a General Permit for smaller hydroelectric facilities set the maximum Minimum Level for Oil and Grease at 5 mg/L while Individual Permits for larger hydroelectric facilities currently set the maximum Minimum Level for Oil and Grease at 10 mg/L? This seems excessive for smaller hydroelectric facilities.

Page 45, Appendix A. Shouldn't all of these outflow pollutants be compared to the level at intake. They should be measuring the net change in pollution from going through the system, as opposed to just the amount of pollution present. The clear majority of pollution occurs before the water is ran through the cooling water or powerplant sump systems.

Page 48, Appendix C. As identified below, the term "significant" is used numerous times to describe what must be included in the BMP Plan.

- Item 2, <u>Description of Potential Pollutant Sources</u>. The BMP plan shall provide a description of potential sources which may reasonably be expected to add *significant amounts of pollutants* to internal facility drainage water discharges. Each BMP plan shall identify all activities and *significant materials* which may be potentially *significant pollutant sources*.
- Item 3. b, <u>Drainage</u>. For internal facility drainage water discharges that could reasonably be expected to contain *significant amounts of pollutants*, a prediction of the direction of flow, and an identification of the types of pollutants which are likely to be present in the discharges. Factors to consider include the toxicity of pollutants;

quantity of pollutants used; the likelihood of contact with internal facility drainage water discharges; and *history of significant leaks or spills*.

- Item 4. Inventory of Exposed Materials. The BMP plan shall include an inventory of the types of materials handled at the facility that potentially may be inadvertently spilled. Such inventory shall include a narrative *description of significant materials* that are or have been handled, treated, stored or disposed in a manner to allow exposure to internal facility drainage water between the time of three years before the active date of permit coverage and the present; …
- Item 5. Spills and Leaks. A list of list of *significant spills and significant leaks* of toxic or hazardous pollutants that occurred, during the three-year period prior to the active date of permit coverage, at areas that drain to an outfall associated with floor drains
- Item 7. Risk Identification and Summary of Potential Pollutant Sources. A narrative description of the potential pollutant sources from the following activities: loading and unloading operations; maintenance programs; and on-site waste disposal practices. The description shall specifically *list any significant potential source of pollutants* at the facility and for each potential source, any pollutant or pollutant parameter (e.g. biochemical oxygen demand, etc.) of concern shall be identified.
- Item 9. Trash Racks or Intake Screens. The Permittee shall amend the removal procedures whenever there is a change in the design, construction, operation, or maintenance which has a *significant effect on the deposition* of solid material on the trash racks or intake screens.
- Item 11. Flood/High Water Discharges. A permittee with flood/high water discharges authorized under the General Permit shall also develop and implement specific flood/high water practices and procedures to eliminate pollutants from areas of the facility that would be expected to *add significant amounts of pollutants* to the identified flood/high water discharges.

"Significant" can have a quantitative as well as qualitative meaning and Idaho Power is concerned with the level of effort that may be required to resolve perceived differences in application of the term. For instance, all of Idaho Power's hydroelectric facilities operate under Spill Prevention, Control and Countermeasures Plans (SPCC) that are developed and certified in accordance with requirements of 40 CFR Part 112. If oil enters the facility drainage system and drains to facility sumps that are certified and maintained under SPCC requirements, and which do not result in a release to water, Idaho Power would not consider the oil a *significant potential source of pollutants* or the spill a *significant spill*. Identify the factors that EPA will consider in determining "significance" for each item where factors have not been provided and the term is used.

Page 50, Appendix C, Item 9. This section requires trash removal procedures to include appropriate safety practices because the Permittee is responsible for employee safety at the facility. Identify EPA's authority to require submittal of employee safety procedures as OSHA is responsible for enforcing the OSH Act, 29 U.S.C. 651 *et. seq*. with the goal of assuring worker protection.

Fact Sheet

1. Page 9, Definitions: Define the terms "toxic substances" and "deleterious materials" as used in the IDAPA Surface Water Quality Criteria.
2. Page 19, Section C. Identify the timeframe for existing facilities to submit a request for an individual permit application if the facility is excluded from coverage under the General Permit.
3. Page 27, Section VIII.A. This section indicates the Draft General Permit proposes the hydroelectric facility complete and implement a QAP within 60 days of authorization to discharge. The Draft General Permit only proposes that the Permittee submit a QAP certification with the NOI due 90 days after the effective date of the permit. Ensure consistency between requirements in the Fact Sheet and Draft General Permit.

IDEQ 401 Water Quality Certification

Page 1. The Water Quality Certification indicates that EPA does not intend to cover facilities that have a cumulative CWIS with design intake flow of greater than 2 mgd **and** that uses 25 percent or more of the water the facility withdraws for cooling purposes on an average monthly basis. Page 6 indicates that facilities that use or propose to use one or more CWIS with a cumulative design intake flow of greater than 2 MGD **or** that uses 25% or more of withdrawn water for cooling must obtain an individual NPDES permit and will require individual 401 certifications. Will permits for facilities that meet both or one of the criteria require individual certifications?

Thank you for the opportunity to supply these comments to EPA. If there are any questions or need for clarification on any of the, please contact the undersigned. Idaho Power would appreciate any additional opportunity to work through items raised with Region 10.

Sincerely,

Brett Dumas
cc: Barry Burnell, IDEQ

SCROLL CASE
DRAFT TUBE
COOLING WATER PRIMARILY USED TO COOL UNIT GENERATOR AND BEARINGS
SCROLL CASE
PENSTOCK
PIPING DISTRIBUTES COOLING WATER TO WHERE IT WILL BE USED FOR UNIT COOLING. THIS SYSTEM IS TYPICALLY PRESSURE FED FROM THE HEAD OF THE UNIT.
COOLING WATER SYSTEM ENTRY POINT IS TYPICALLY LOCATED IN THE SCROLL CASE
IDAHO POWER COMPANY
Lower Salmon HYDRO-ELECTRIC DEVELOPMENT
showing
CROSS SECTION THROUGH POWER HOUSE AND GENERATING UNIT Nº 1
INTERESTING FACTS ABOUT THIS PLANT
CAPACITY .... 65,000 KW
OPERATING HEAD .... 59 FT
HEIGHT ..... 105 FT LENGTH ..... 1150 FT
CONCRETE IN STRUCTURE .... 30,000 CY
PLANT INVESTMENT $10,200,461
Legend
1 TRASH RACK STRUCTURE
2 INTAKE GATE SLOT
3 INTAKE
4 PENSTOCK AND SCROLL CASE
5 WICKET GATE OPERATING MECHANISM
6 DISTRIBUTOR AND WICKET GATES
7 PROPELLER TYPE TURBINE
8 DRAFT TUBE
9 DRAFT TUBE GATE SLOT
10 ACCESS GALLERY
11 BASEMENT FLOOR
12 OPERATING FLOOR
13 CONNECTING SHAFT
14 GENERATOR
15 HOUSING FOR GENERATOR
16 INTAKE GATE CRANE
17 GANTRY CRANE
18 DRAFT TUBE GATE CRANE
19 TRANSFORMER
20 TAKE-OFF TOWERS
21 FISH LADDER
ARROWS SHOW WATER FLOW THROUGH THE PLANT
GARDNER '55
F-203
20R-21778

July 11, 2018

Via E-Mail

Ms. Dru Keenan
Office of Water and Watersheds
U.S. Environmental Protection Agency, Region 10
1200 Sixth Avenue, Suite 155
OWW-191
Seattle, WA 98101
keenan.dru@epa.gov

Re: Comments of the National Hydropower Association and the Utility Water Act Group on the EPA Region 10 Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho (IDG360000)

Dear Ms. Keenan:

The National Hydropower Association and the Utility Water Act Group respectfully submit the following comments on the EPA Region 10 Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho (IDG360000), 83 Fed. Reg. 18,555 (Apr. 27, 2018). We appreciate the opportunity to provide comment on the proposal, which we believe raises significant issues for hydropower project operators in the region and beyond.

If you have any questions about these comments or wish to discuss the issues further, please contact Kerry McGrath at (202) 955-1510 or kmcgrath@HuntonAK.com

We appreciate your attention to this important matter.

Sincerely,

Jeffrey Leahey
Deputy Executive Director
National Hydropower Association
601 New Jersey Avenue, NW, Suite 660
Washington, DC 20001

Thomas Stanko
Consumers Energy Company
1945 West Parnall Road
Jackson, MI 49201
Chair, UWAG Cooling Systems Committee

Kerry L. McGrath
Hunton Andrews Kurth LLP
2200 Pennsylvania Avenue, NW
Washington, DC 20037
Counsel to National Hydropower Association and Utility Water Act Group

cc: Loren Moore, Idaho Department of Environmental Quality
(Loren.Moore@deq.idaho.gov)
David Ross, EPA Headquarters (Ross.davidp@epa.gov)
Lee Forsgren, EPA Headquarters (Forsgren.lee@epa.gov)
Andrew Sawyers, EPA Headquarters (Sawyers.andrew@epa.gov)
Owen McDonough, EPA Headquarters (McDonough.owen@epa.gov)

The National Hydropower Association and the Utility Water Act Group Comments on EPA's Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho

83 Fed. Reg. 18,555 (Apr. 27, 2018)

July 11, 2018

Executive Summary

With the U.S. Environmental Protection Agency ("EPA" or "Agency") Region 10's proposed National Pollutant Discharge Elimination System ("NPDES") general permit for hydroelectric facilities discharging to waters within the State of Idaho ("Proposed Permit") (IDG360000), 83 Fed. Reg. 18,555 (Apr. 27, 2018), EPA, for the first time in a rule or permitting action of general applicability, takes the position that hydroelectric facilities are subject to the requirements of Clean Water Act ("CWA") § 316(b), 33 U.S.C. § 1326(b), and EPA's 2014 Final Rule to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities, 79 Fed. Reg. 48,300 (Aug. 15, 2014) ("2014 Rule" or "Existing Facilities Rule").

Unlike the other facilities to which EPA has applied § 316(b), EPA has not established technology-based limitations and standards for hydroelectric facilities, nor would it be reasonable to do so given the *de minimis* nature of their discharges. EPA never collected any information on the design, location, construction, and capacity of pipes or other features used to divert water for use in cooling equipment in hydroelectric facilities, or on the environmental impacts of those features. As these comments will show, that omission is crucial because hydroelectric facilities differ substantially from the largely land-based steam electric plants and industrial facilities for which EPA developed the 2014 Rule and every other § 316(b) rule the Agency has adopted. Of equal significance, EPA has never considered any of the legal, technical, or economic issues involved in applying § 316(b) to hydroelectric facilities.

The Proposed Permit nevertheless relies on the 2014 Rule's standards for steam electric power and manufacturing plants to establish the Region's best professional judgment ("BPJ") about what "cooling water intake structure" ("CWIS") is the best technology available ("BTA") "to minimize [the] adverse environmental effects of [CWIS]" at hydroelectric facilities, and requires that the permit conditions reflecting those technologies be met within 180 days of the effective date of the permit.[1]

There are several key problems with Region 10's proposal. First, interpreting CWA § 316(b) to apply to hydroelectric generation facilities would be a significant expansion of EPA's regulatory jurisdiction and would duplicate other federal and state requirements specifically designed to address these environmental impacts. Second, EPA has never provided notice or an opportunity for comment on the applicability of § 316(b) to hydroelectric facilities. In fact, the Agency explicitly stated that withdrawals from hydroelectric facilities were not meant to be addressed in its Existing Facilities Rule. 76 Fed. Reg. 22,174, 22,190 (Apr. 20, 2011). It would be arbitrary and capricious, and contrary to the Administrative Procedure Act ("APA") requirements for fair notice and opportunity for comment, for EPA to now adopt such a novel, post-hoc interpretation. Third, even if EPA, after full and procedurally appropriate consideration of the issue, concluded that CWA § 316(b) applies to hydroelectric facilities (which NHA and UWAG believe it should not), the requirements of the 2014 Rule are not appropriate for such facilities, which are fundamentally different from the steam electric power and manufacturing plants EPA considered in that rulemaking, both in terms of the feasibility and cost of technology and the assessment of environmental impacts. Indeed, the 2014 Rule's requirements would be unnecessary in most cases because the rates of impingement and entrainment would be so low that additional controls would not be warranted.

In the Proposed Permit, Region 10 proposes to establish new BTA requirements based on its "best professional judgment" without first characterizing and evaluating the attributes of the facilities in question and determining whether they have already minimized adverse

[1] *See* EPA, NPDES Fact Sheet, Proposed Wastewater Discharges from Hydroelectric Generating Facilities General Permit, IDG360000, at 23 (Apr. 27, 2018) ("Proposed Permit Fact Sheet").

environmental effects and without identifying the technologies, measures, procedures, and methods the Agency anticipates facilities would use to meet the requirements imposed by the permit. In fact, it would be very difficult and, in some cases, infeasible, for many hydroelectric facilities to comply with the requirements outlined in the Proposed Permit and, even if some facilities could comply, the costs of doing so would likely far exceed any plausible environmental benefits. For all of these reasons, discussed in more detail in these joint comments, Region 10 should remove any § 316(b)-related provisions from the Proposed Permit. Finally, in addition to the § 316(b)-related measures, a number of discharge-related provisions in the Proposed Permit require clarification and/or revision.

Table of Contents

The National Hydropower Association and the Utility Water Act Group Comments on EPA's Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho

I. Introduction

EPA Region 10 has proposed to issue a NPDES general permit for hydroelectric facilities discharging to waters within the State of Idaho. 83 Fed. Reg. 18,555 (Apr. 27, 2018). With the Proposed Permit, EPA, for the first time in a rule or permitting action of general applicability, takes the position that hydroelectric facilities are subject to the requirements of CWA § 316(b), 33 U.S.C. § 1326(b), and EPA's 2014 Rule.

The Proposed Permit would apply only to hydroelectric facilities that require an NPDES permit to discharge pollutants associated with the operation of hydroelectric facilities to waters of the United States in Idaho, and that use water to cool some of that equipment, where the amount of cooling water falls below the 2014 Rule's qualifying thresholds.[2] Region 10 asserts that those hydroelectric facilities must meet CWA § 316(b) requirements established by the Director on a case-by-case, BPJ basis under 40 C.F.R. § 125.90(b). Proposed Permit Fact Sheet at 22-23, 28. The Proposed Permit purports to reflect Region 10's BPJ about what CWIS technology is the best available "to minimize [the] adverse environmental effects of [CWIS]" at hydroelectric facilities and requires that the permit conditions reflecting those technologies be met within 180 days of the effective date of the permit. Proposed Permit Fact Sheet at 23.

The Region's proposal to apply CWA § 316(b), even on a BPJ case-by-case basis, to hydroelectric facilities is neither compelled by nor consistent with the CWA. And, as demonstrated in these comments, even if CWA § 316(b) were applicable, the Region's proposed

[2] *See* Proposed Permit Fact Sheet at 19. The 2014 Rule's stringent requirements apply only to facilities that are point sources requiring an NPDES permit, withdraw from a water of the United States, use CWIS with a design intake flow of greater than 2 million gallons per day ("MGD"), and use 25 percent or more of the water withdrawn exclusively for cooling purposes. 40 C.F.R. § 125.91(a).

BPJ requirements are arbitrary and capricious for several reasons. First, the Fact Sheet demonstrates that the Region borrowed from and relies on a rule that EPA expressly stated did not apply to hydroelectric facilities and that the Agency adopted without any consideration of the technical feasibility or cost of application of such requirements to hydroelectric facilities. Proposed Permit Fact Sheet at 28.

Second, the Region has provided no independent analysis or support for any of the proposed requirements. Indeed, for many of the conditions imposed, neither the Fact Sheet nor the Proposed Permit provide any meaningful indication of technology or methods the permit might be expected to employ, nor does the proposal provide any discussion of the technical feasibility, costs, benefits, or other relevant factors associated with those conditions. This deficiency is not limited to the requirements based on EPA's 2014 Rule. The Region has not provided, for example, any analysis of or support for the Proposed Permit's requirement that, to comply with the proposed BTA requirements established for CWIS, facilities must maintain screening technologies established in National Marine Fisheries Service ("NMFS") Northwest Region's Anadromous Salmonid Passage Facility Design guidelines, which were developed by NMFS for hydroelectric turbines, not cooling water diversion pipes.

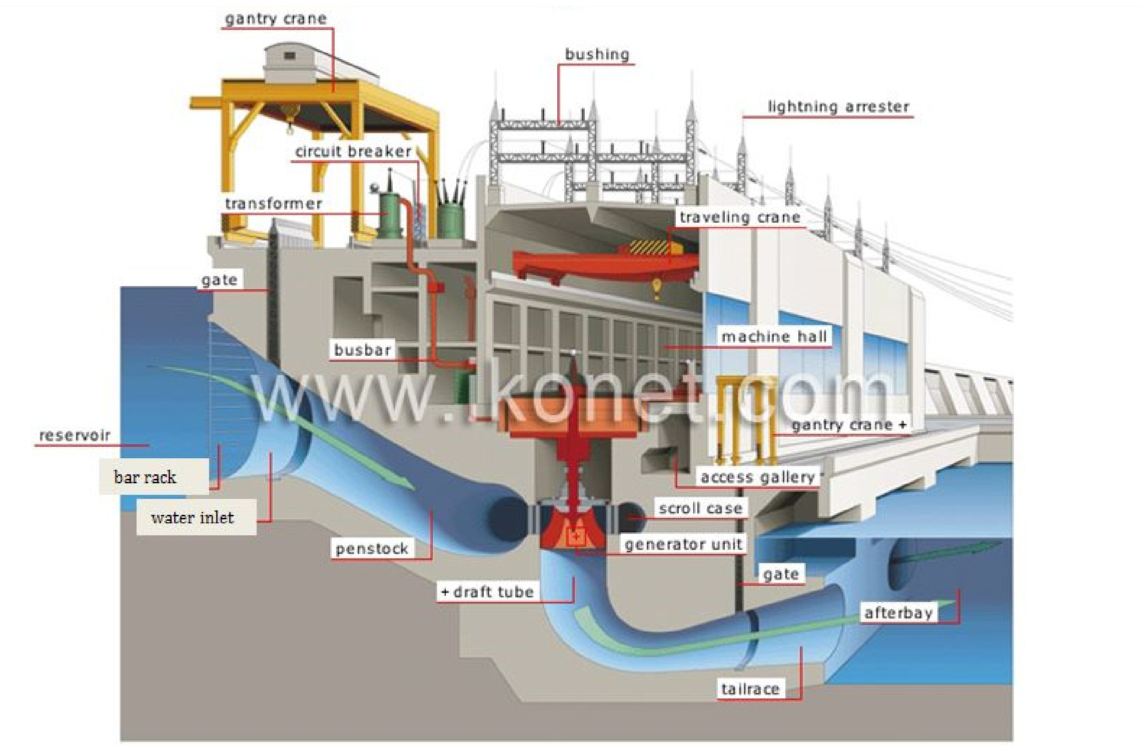
The National Hydropower Association ("NHA") is the national non-profit trade association dedicated to promoting the growth of clean, affordable, U.S. hydropower. It seeks to secure hydropower's place as a renewable and reliable energy source that serves national environmental, energy, and economic policy objectives. NHA's membership includes more than 240 companies, from Fortune 500 corporations to family-owned small businesses. NHA members include public and investor-owned utilities, independent power producers, developers, equipment manufacturers and other service providers. In the United States, hydropower plants provide about 6 to 7 percent of the nation's total electric generation and pumped storage hydropower plants provide the vast majority of energy storage, approximately 97 percent. NHA's membership includes Idaho companies that will be directly affected by the Proposed Permit.

The Utility Water Act Group ("UWAG") is a voluntary, non-profit, unincorporated group of 146 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. UWAG members operate hydroelectric facilities, power plants, and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. One of UWAG's purposes is to participate on behalf of its members in EPA regulatory actions under the CWA and in litigation arising from those regulatory actions. UWAG's membership includes owners and operators of hydroelectric facilities that would be affected by the adoption and issuance of the Proposed Permit.

Hydroelectric facilities vary significantly in terms of design and configuration, especially when it comes to the pipes and structures that divert water for purposes of cooling. Generally, water diverted for cooling is primarily sourced from three locations within the hydroelectric facility: (1) the penstock – a closed conduit or pipe that conveys water from the reservoir to the turbine, (2) the turbine scroll case – a spiral-shaped steel structure distributing water flow through the wicket gates located just prior to the turbine, or (3) a water inlet port located on the face of the dam. There likely are exceptions to these locations, because each facility has a unique, location-specific design to take maximum advantage of the hydraulics of that location. An individual facility may use one design exclusively, or may use a combination of designs. After use for cooling, diverted water is transferred downstream primarily via these methods: (1)

directed back to the penstock and re-used to generate electricity, (2) directed back to the scroll case (low head dams mainly) and re-used to generate electricity, (3) directed to the tailrace via the draft tube, or (4) direct transfer to the tailrace. The features of a typical hydroelectric facility are depicted in Figure 1, and an example of a facility diverting cooling water from the penstock is depicted in Figure 2.

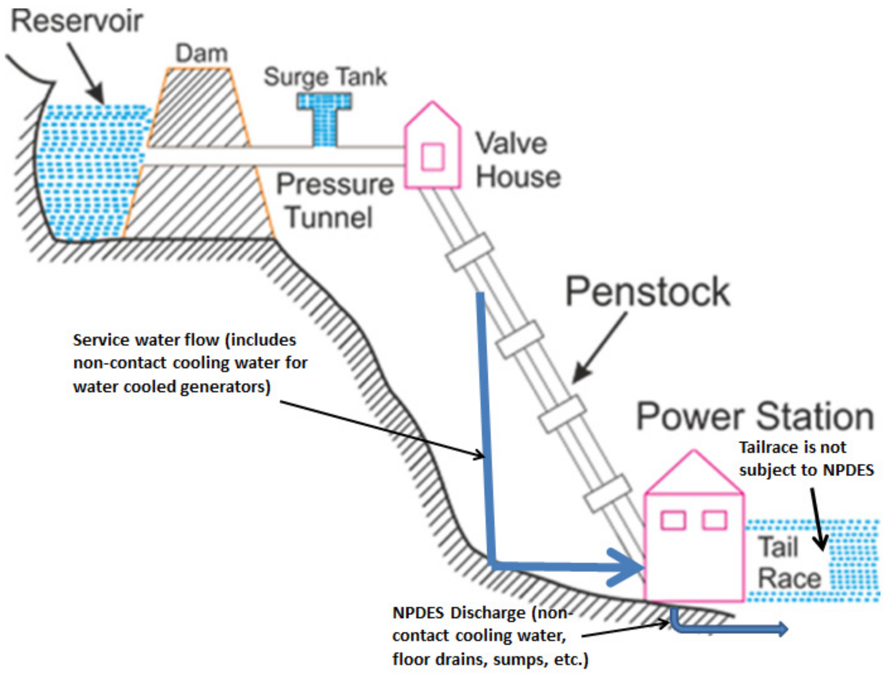
Figure 1[3]



---

[3] The Visual Dictionary, Cross Section of a Hydroelectric Plant, www.ikonet.com.

Figure 2



Accordingly, hydroelectric generating facilities do not have CWISs in the conventional industrial context upon which the current § 316(b) regulations were developed. Hydroelectric facilities bring a wide variety of technical challenges associated with characterizing impingement and entrainment, and applying technologies that EPA considered in its 2014 rulemaking as available for on-shore facilities. This is evident in the 2014 Rule's definition of a CWIS. EPA's regulations define CWIS as "the total physical structure and any associated construction waterways used to withdraw cooling water from waters of the United States. The [CWIS] extends from the point at which water is first withdrawn from waters of the United States up to, and including the intake pumps." 40 C.F.R. § 125.92(f). The 2014 Rule envisions the use of pumps to actively *withdraw* cooling water from surface waters that are waters of the U.S., but this broad definition is inappropriate for hydroelectric facilities, which are diversion structures by design – impounding water and transporting/passing water along a contiguous waterway to turn turbines used to generate electricity.[4] Relative to the total water transported through the facility, a very small amount of water is diverted for cooling. In general, cooling water accounts for less than 1% of the total water transported through the facility and in some cases less than 0.1%. For example, at the Keowee Hydro Station the cooling water is generally less than 0.01% of the total discharge flow.[5] As explained in further detail herein, given the wide range of configurations for hydroelectric facilities and different processes for diverting water for cooling, the best available technologies and sampling requirements imposed by EPA for steam electric power plants and manufacturing plants are not necessarily appropriate or practical for hydroelectric facilities. The Region 10 Proposed Permit fails to consider or account for these challenges.

II. EPA's Interpretation and Implementation of § 316(b) To Date

A. EPA's Prior Regulations Implementing § 316(b) Have Not Addressed Hydroelectric Facilities.

Section 316(b) provides:

> Any standard established pursuant to section 1311 of this title or section 1316 of this title and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

33 U.S.C. § 1326(b).

EPA has implemented this provision by issuing regulations that establish BTA standards for intake structures that become binding for a particular facility only after the standards are incorporated into an NPDES permit for discharges from a regulated facility. At no point during

[4] Hydroelectric facilities do not have conventional CWIS and their configurations vary. These comments refer to the mechanisms that divert cooling water as intakes, pipes, or diversion structures.

[5] South Carolina NPDES Permit No. SC0000515, Fact Sheet and Permit Rationale at 18 (Mar. 16, 2011).

EPA's long history of implementing § 316(b) have EPA's regulatory actions addressed or evaluated the applicability of CWA § 316(b) to hydroelectric facilities.

In 1976, EPA issued its first § 316(b) rule, 41 Fed. Reg. 17,387 (Apr. 26, 1976), but the Fourth Circuit remanded it to EPA on procedural grounds. *Appalachian Power Co. v. Train*, 566 F.2d 451 (4th Cir. 1977). EPA's remaining rule and guidance instructed NPDES permit writers to make case-by-case determinations regarding BTA for CWIS at point sources subject to EPA standards established pursuant to §§ 301 or 306. *See* 40 C.F.R. § 401.14 ("The location, design, construction and capacity of cooling water intake structures of any point source for which a standard is established pursuant to section 301 or 306 of the Act shall reflect the best technology available for minimizing adverse environmental impact, in accordance with the provisions of part 402 of this chapter."); 33 U.S.C. § 1342(a)(1)(B).[6] By its terms, § 401.14 applies only to those point sources for which technology-based standards are established under §§ 301 and 306. By contrast, even where hydroelectric facilities require NPDES permits for discharges, the limits imposed are largely water quality-based.[7] Although § 401.14 has been in effect since 1976, generally, neither federal nor state NPDES permitting authorities read § 401.14 as applicable to hydroelectric facilities that are issued NPDES permits for minor equipment-related discharges.[8]

[6] *See also* EPA, *Draft Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) Public Law 92–500*, at 4 (1977) ("The environment-intake interactions in question are highly site-specific and the decision as to best technology available for intake design, location, construction, and capacity must be made on a case-by-case basis.").

[7] *See*, *e.g.*, Arkansas NPDES Permit No. AR0048755, Statement of Basis at 6-7 (Apr. 13, 2017); Arkansas NPDES Permit No. AR0048763, Statement of Basis at 7 (Sept. 4, 2013); West Virginia NPDES Permit No. WV0078859, App. A § I.12 (Aug. 9, 2016); South Carolina Department of Health and Environmental Control, NPDES General Permit for Hydroelectric Generating Facilities, Permit No. SCG360000 (May 15, 2015).

[8] *See*, *e.g.*, NPDES General Permits for Hydroelectric Facilities in the States of Massachusetts and New Hampshire, Permit Nos. MAG360000, NHG360000 (Nov. 10, 2009); ADEM General Permit Rationale, Hydroelectric Facilities ALG360000 (Aug. 18, 2015); South Carolina Department of Health and Environmental Control, NPDES General Permit for Hydroelectric Generating Facilities, Permit No. SCG360000 (May 15, 2015); North Carolina Department of Environment and Natural Resources, NPDES General Permit No. NCG50000 (Oct. 1, 2015). We are aware of one exception, discussed in note 38, infra.

Since 1976, EPA has issued a series of regulations implementing § 316(b) for new facilities, as well as existing steam electric plants and manufacturing facilities. The Phase I rule established national technology-based performance requirements for new facilities that withdraw greater than 2 MGD of surface water and use at least 25 percent of the water they withdraw for cooling purposes. 66 Fed. Reg. at 65,255 (Dec. 18, 2001). The Phase II rule set requirements for existing steam electric plants with flows greater than 50 MGD, 69 Fed. Reg. 41,576 (July 9, 2004), but certain aspects of the rule were invalidated by the U.S. Court of Appeals for the Second Circuit and later withdrawn.[9] The rules for lower flow steam electric plants and all manufacturing facilities (known as the Phase III rules) were also withdrawn. 71 Fed. Reg. 35,006 (June 16, 2006). In place of the Phase II and III rules, in 2014, EPA issued a single rule for existing facilities – the 2014 Existing Facilities Rule.[10]

During the development of the Phase I, II, and III rules, EPA never suggested that any of those rules would apply to hydroelectric facilities, whether or not the facilities use cooling water or need an NPDES permit. None of EPA's Information Collection Requests ("ICRs") were directed at hydroelectric facilities, nor did EPA use any other method to collect or consider information on cooling water diversion or use by hydroelectric facilities. Variations in the locations, design, and configurations of cooling water "intakes" unique to hydroelectric facilities were never contemplated in EPA's previous facility surveys or technology evaluations for promulgating § 316(b) regulations for new or existing power generating facilities. EPA did not consider whether hydroelectric facilities could feasibly monitor or otherwise assess entrainment or impingement mortality associated with cooling water diversion or whether those facilities

[9] *Riverkeeper, Inc. v. EPA*, 475 F.3d 83 (2d Cir. 2007); 72 Fed. Reg. 37,107 (July 9, 2007).

[10] Final Regulations To Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities, 79 Fed. Reg. 48,300 (Aug. 15, 2014).

could distinguish such mortality from mortality occurring by virtue of the passage of water through the turbines. Nor did EPA consider the availability, performance, or cost of technologies for reducing entrainment or impingement mortality that might be caused by hydroelectric facilities' cooling water "intakes," which often consist of one or more relatively small pipes diverting water from within or coming off of the penstock or draft tube of a hydroelectric facility or in some other location depending upon the broader facility design and operation.

The development of EPA's 2014 § 316(b) Rule was no different; EPA's ICR solicited no information from any hydroelectric facility.[11] As discussed below, EPA stated in the preamble to the proposed rule that water withdrawals for generation of electricity by hydroelectric facilities were not subject to the rule. *See* 76 Fed. Reg. 22,174, 22,190 (Apr. 20, 2011). As a result of this express and unambiguous statement, EPA received no comments regarding the potential applicability of CWA § 316(b) to hydroelectric facilities or addressing the potential impacts of applying the proposed technology requirements to hydroelectric facilities. Indeed, in the final 2014 Existing Facilities Rule, EPA estimated that a total of 1,065 facilities (544 electric generators and 521 manufacturers) would be subject to the Rule. 79 Fed. Reg. at 48,305. None of those facilities were hydroelectric power generators.[12] Thus, EPA never collected the necessary information to evaluate impacts of the Rule on hydroelectric facilities, even though some hydropower generators divert more than 2 MGD and use 25 percent or more of the diverted water for cooling purposes.

[11] *See* Information Collection Request (ICR) for CWIS at Existing Facilities (Final Rule), OMB Control No. 2040-0257, EPA ICR No. 2060.07 (Aug. 2014).

[12] 2014 TDD at 4-24 ("From the universe of facilities with a steam electric prime mover and based on data collected from EPA's industry technical questionnaires and the compliance requirements for the final rule, EPA has identified 544 facilities to which the proposed rule is expected to apply.").

The 2014 Rule establishes requirements for existing facilities that: (1) have NPDES permits, (2) use one or more CWISs with a cumulative design intake flow ("DIF") of greater than 2 MGD to withdraw water from waters of the U.S., and (3) use 25 percent or more of the water withdrawn (on an actual intake flow basis) exclusively for cooling water purposes. 40 C.F.R. § 125.91(a). Facilities with CWISs that are subject to CWA § 316(b) that do not meet these criteria must meet § 316(b) requirements established by the permit writer on a case-by-case, BPJ basis. 40 C.F.R. § 125.90(b). EPA's final 2014 Existing Facilities Rule made no mention of hydroelectric facilities in the preamble or regulatory text.

B. The Proposed NPDES General Permit Inappropriately Seeks to Apply § 316(b) Requirements to Hydroelectric Facilities.

The Proposed Permit[13] would apply only to facilities below the 2 MGD and 25 percent cooling water threshold. Proposed Permit Fact Sheet at 28.[14] The Fact Sheet indicates that facilities above the 2 MGD and 25 percent cooling water threshold would have to obtain an individual NPDES permit, and (assuming the individual permit is a federal permit issued by Region 10) an individual § 401 water quality certification, and comply with the comprehensive requirements of the 316(b) Rule. *Id.* For facilities below the 2 MGD and 25 percent cooling

[13] The timing of the Proposed Permit coincides with the announcement that EPA has approved the application by the State of Idaho to administer and enforce the Idaho Pollutant Discharge Elimination System ("IPDES") program regulating discharges of pollutants into waters of the United States under its jurisdiction. 83 Fed. Reg. 27,769 (June 14, 2018). Under a Memorandum of Agreement ("MOA") between the Idaho Department of Environmental Quality and EPA Region 10, EPA will transfer the administration of specific program components to the State over a four-year period. Idaho will assume NPDES permitting and enforcement authority for general permits, such as the proposed general permit for wastewater discharges from hydroelectric generating facilities, by July 1, 2020.

[14] As discussed on page 31, the text of the Proposed Permit is inconsistent with the Fact Sheet and the 401 Water Quality Certification in its discussion of the thresholds facilities must meet to qualify for the permit (i.e., whether facilities above the 2 MGD *and* 25 percent cooling water threshold are ineligible or whether facilities that meet either the 2 MGD *or* 25 percent cooling water thresholds are ineligible). For purposes of these comments, we are assuming that Region 10 intended that facilities that are ineligible for coverage under the Proposed Permit are those facilities that use greater than 2 MGD *and* use 25 percent or more of the water for cooling purposes.

water threshold, the Proposed Permit would set BTA requirements that must be implemented within 180 days of the effective date of the permit, including, for example:

- manage tailrace operations to prevent fish access to the draft tube areas;
- cease or reduce the intake of cooling water whenever withdrawal of source water is not necessary, *i.e.*, during equipment testing or maintenance activities;
- return all observed live impinged fish to the source water to the extent practicable;
- conduct weekly monitoring to identify what species are impinged;
- maintain a physical screening or exclusion technology consistent with NMFS Northwest Region's Anadromous Salmonid Passage Facility Design guidelines; and
- properly operate and maintain CWIS, including any existing technologies to minimize impingement and entrainment.[15]

In addition, permittees also would have to prepare a report to be submitted to Region 10 at least 180 days prior to permit expiration that would include extensive information regarding the CWIS and source waterbody, including, for example:

- if the combined design capacity of all CWISs is greater than 1 MGD, the measures to be taken by the facility to maintain a daily maximum surface water withdrawal of 1 MGD;
- maximum monthly average intake of the CWIS during the previous five years;
- whether the facility withdraws cooling water at a rate commensurate with a closed-cycle cooling system;
- maximum through-screen design intake velocity;
- detailed description of screening and exclusion technology employed to prevent impingement and entrainment at the CWIS; and
- report of the prior five-year results from the required impingement and entrainment monitoring program.[16]

The Fact Sheet states, "EPA will use this information to assess the potential for impingement and entrainment at the CWIS, evaluate the appropriateness of any proposed

[15] Proposed Permit, § IV.C.2.

[16] Proposed Permit, § IV.C.3.

technologies or mitigation measures, and determine any additional requirements to place on the facility's CWIS in the next permit cycle." Proposed Permit Fact Sheet at 28-29. The Idaho Department of Environmental Quality ("IDEQ") has certified that, if the permittee complies with the terms and conditions of the Proposed Permit and the conditions set forth in the water quality certification, "there is reasonable assurance" the covered hydroelectric facilities' discharges "will comply with the applicable requirements" of the CWA and Idaho Water Quality Standards.[17]

The Region provides no analysis or support for applying § 316(b) requirements to hydroelectric facilities. The Fact Sheet demonstrates that the Region relied on and drew heavily from EPA's 2014 Rule in establishing CWIS-related requirements in the Proposed Permit. *See* Proposed Permit Fact Sheet at 28. But nowhere in the Proposed Permit or Fact Sheet does the Region provide any support or independent analysis for the measures it proposes to require for hydroelectric facilities.

III. CWA § 316(b) Does Not Apply to Hydroelectric Facilities.

A. Hydroelectric Generation Facilities Are Not Subject to CWA § 316(b).

By its terms, § 316(b) applies only where EPA establishes standards under §§ 301 and 306 for point sources. Unlike the other facilities to which EPA has applied § 316(b), EPA has not established such technology-based limitations and standards for hydroelectric facilities, nor would it be reasonable to do so given the *de minimis* nature of their discharges. As the United States Supreme Court has recognized, absent clear direction from Congress, courts will view (and agencies should view) with skepticism statutory interpretations that extraordinarily expand regulatory jurisdiction. *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2444 (2014). Interpreting CWA § 316(b) to apply to hydroelectric generation facilities would be a significant

[17] IDEQ Draft § 401 Water Quality Certification for NPDES Permit Number IDG360000 (Mar. 29, 2018).

expansion of EPA's regulatory jurisdiction and would duplicate other federal and state requirements specifically designed to address these environmental impacts.

The limited legislative history for § 316(b) indicates that Congress did not intend for § 316(b) to apply to hydroelectric facilities. From November 1971 to October 1972, Congress considered various bills that eventually would become the CWA. On September 28, 1972, the conference committee substantially amended § 316, modifying that provision to insert for the first time a provision addressing cooling water intakes structures, and submitted its report for approval by both the House and Senate.[18] During the House of Representatives consideration of the conference report, Rep. Donald Clausen (R-CA1) made the following statement in support:

> Section 316 was originally included in the House-passed water pollution control bill because of the belief that the arguments which justified a basic technological approach to water quality control did not apply in the same manner to the discharges of heat…. [S]team-electric generating plants are the major source of the discharges of heat…. Section 316(b) requires the location, design, construction, and capacity of cooling water intake structures *of steam-electric generating plants* to reflect the best technology available for minimizing any adverse environmental impact.[19]

Rep. Clausen's statement indicates that Congress intended § 316(b) to apply to steam electric generating plants, not hydroelectric generating facilities that harness the power of falling or fast-moving water to drive turbines to produce electricity.[20] In contrast, steam electric power plants heat water into steam that drives the electric-generating turbines, typically requiring considerably more cooling water to safely operate the facility. It is these facilities that were Congress' focus when it promulgated CWA § 316(b).

---

[18] *See* H.R. Rep. No. 92-1465, at 68, 137 (Sept. 28, 1972).

[19] House Consideration of the Report of the Conference Committee (Oct. 4, 1972), *reprinted in* 1 A LEGISLATIVE HISTORY OF THE WATER POLLUTION CONTROL ACT AMENDMENTS OF 1972, at 262–64 (1973) (statement of Rep. Clausen) (emphasis added).

[20] We recognize that some U.S. Courts of Appeals have held that § 316(b) applies to other industrial facilities that use cooling water beyond steam electric plants (*e.g.*, iron and steel). *See*, *e.g.*, *Appalachian Power Co. v. Train*, 566 F.2d 451, 457-58 (4th Cir. 1977). But those decisions did not consider whether all facilities that must obtain an NPDES permit are subject to § 316(b).

In promulgating CWA § 316(b), Congress would have understood, as discussed in more detail below, that other statutes and regulations governed consideration of environmental impacts from water diversion structures. For example, Congress would have been well aware that the Federal Power Act ("FPA") licensing process for hydroelectric facilities requires evaluation of environmental impacts and conditions to protect and mitigate impacts to fish and wildlife-related habitat. Congress gave no indication that it intended such facilities to be subject to additional requirements under CWA § 316(b), nor would such requirements have made sense in light of the other mechanisms in place under the FPA. There is no evidence that Congress intended CWA § 316(b) to apply to hydroelectric facilities, and, indeed, the limited legislative history for that provision indicates that Congress intended § 316(b) to address adverse environmental impacts associated with industrial facilities, such as steam electric generating facilities, for which the statute requires EPA to establish nationally applicable effluent limitations guidelines and new source performance standards. There is no basis in the statute for EPA's new interpretation that § 316(b) can apply to hydroelectric facilities.

B. Establishing § 316(b) Requirements for CWISs at Hydroelectric Facilities Would Conflict With and Duplicate Other Federal and State Requirements Already in Place.

The statutory scheme Congress established under the FPA, and other federal statutes, demonstrates Congress' intent that the Federal Energy Regulatory Commission ("FERC") address, through the FERC hydropower licensing process, all issues relating to the use of water by non-federal hydroelectric facilities, including any water quality issues raised by a State CWA § 401 certification.[21]

[21] This section focuses on hydroelectric projects that require FERC authorization because those are the most common facilities for our members. Certain non-federal hydroelectric facilities, such as small projects (5 MW or less) or projects conducted on an existing conduit (*e.g.*, irrigation canal), do not require FERC licensing because those projects would result in minor environmental effects (*e.g.*, projects that involve little change to water flow and

The comprehensive development standard of FPA § 10(a)(1) requires that licensed hydroelectric projects be best adapted to a comprehensive plan for improving or developing a waterway, including, among other uses, for the adequate protection, mitigation, and enhancement of fish and wildlife (including related spawning grounds and habitat). 16 U.S.C. § 803(a)(1). Section 10(a)(1) grants FERC the authority to require the modification of any project and of the plans and specifications of the project works before approval. Thus, to the extent that participating resource agencies, which are actively involved in the licensing process, identify during licensing significant issues relating to impacts from diversion and use of cooling water at hydroelectric facilities, those impacts would be considered by FERC in ensuring that the project will be best adapted to a comprehensive plan.

Section 10(j) of the FPA provides for the full participation of federal and state fish and wildlife agencies in recommending conditions for the protection, mitigation, and enhancement of fish and wildlife resources affected by the development, operation, and management of the hydroelectric project.[22] Such conditions are based on recommendations received pursuant to the Fish and Wildlife Coordination Act from NMFS, the U.S. Fish and Wildlife Service ("FWS"), and state fish and wildlife agencies. As part of the application for a hydroelectric license (or relicense), applicants must submit an environmental report to FERC describing the fish and wildlife that occur within the vicinity of the project and downstream areas affected by the

---

use and are unlikely to affect threatened and endangered species), but they are still subject to a similar process and subject to mandatory terms and conditions set by federal and state fish and wildlife agencies and by the Commission. 18 C.F.R. § 4.30. Other federal, non-FERC regulated hydroelectric facilities are generally authorized by Congress and owned by the U.S. Bureau of Reclamation or the U.S. Army Corps of Engineers and in some circumstances must comply with National Environmental Policy Act provisions regarding impacts to aquatic resources associated with operational changes, as well as formally consult with the U.S. Fish and Wildlife Service where federally threatened and endangered species are potentially impacted.

[22] 16 U.S.C. § 803(j)(1).

project, and must identify any federally listed threatened or endangered species.[23] The same report also must describe any measures recommended by consulting fish and wildlife agencies for mitigating such impacts and protecting fish and wildlife.[24]

Additional requirements to evaluate potential impacts to aquatic species exist under the Endangered Species Act ("ESA") and the National Environmental Policy Act ("NEPA"). Pursuant to ESA § 7 and FERC's corresponding regulations, FERC has an obligation to ensure that any project it authorizes is not likely to jeopardize the continued existence of any federally listed endangered or threatened species.[25] To satisfy this requirement, FERC directs project sponsors to engage in informal consultation with NMFS and/or FWS to determine whether the project will impact a federally listed species.[26] Unless NMFS or FWS concludes that the proposed hydroelectric facility is not likely to adversely affect federally listed species, the project sponsor must prepare a Biological Assessment containing the results of detailed surveys, potential impacts, and proposed mitigation to eliminate or minimize such impacts.[27] Where the consulting agency concludes that the project will result in the "incidental take"[28] of listed species, NMFS or FWS will prepare a Biological Opinion that may include reasonable and prudent measures to avoid jeopardy and must include a statement specifying the impact (*i.e.*, the amount or extent of incidental take), and reasonable and prudent measures considered necessary or appropriate to minimize the take of listed species.[29] Through this process, FERC will

---

[23] 18 C.F.R. §§ 4.51(f), 4.41(f).

[24] *Id.*

[25] 16 U.S.C. § 1536.

[26] 18 C.F.R. § 380.13.

[27] *See* 18 C.F.R. § 380.13(b).

[28] "Incidental take" refers to "takings that result from, but are not the purpose of, carrying out an otherwise lawful activity." 50 C.F.R. § 402.02.

[29] *See* 16 U.S.C. § 1536(b)(4); *see also* 50 C.F.R. § 402.15(i).

determine, in consultation with federal fish and wildlife agencies, which conservation and mitigation measures should be implemented to minimize impacts. In other words, the ESA process frequently results in the imposition of measures to protect listed species that might be impacted by operations of hydroelectric facilities, including the diversion of cooling water.

NEPA review requires the development by FERC of a Finding of No Significant Impact ("FONSI"), an Environmental Assessment ("EA"), or an Environmental Impact Statement ("EIS") for a project. Entrainment, impingement, and other impacts on fish and wildlife are analyzed in these environmental documents. For example, within the EA for a hydroelectric project in Arkansas, FERC concluded that "[b]ased upon [Arkansas Game and Fish Commission] observations, current levels of turbine entrainment and mortality of fish is [sic] not considered to be a significant issue at these projects."[30] Likewise, comprehensive entrainment studies were developed as part of the application process for the Catawba-Wateree and Yadkin-Pee Dee, hydroelectric projects spanning the Carolinas. The EIS for the Catawba-Wateree project found that "entrainment does not appear to adversely affect survival and growth of young of target sport and forage species populations,"[31] and the EIS for the Yadkin-Pee Dee project found that there is "no indication that entrainment is having significant adverse effects on resident fish populations, because project reservoirs and riverine reaches support robust fish populations and an excellent sport fishery."[32] Similarly, for the Smith Mountain Hydroelectric Plant, a pumped storage facility in Virginia, an entrainment study qualitatively evaluated entrainment for selected species based on reservoir and turbine intake characteristics, water

---

[30] FERC, Environmental Assessment for Hydropower License, Project No. 271-062, at 66 (Dec. 2001).

[31] FERC, Final Environmental Impact Statement for Hydropower License, Project No. 2232, at 178 (July 2009).

[32] FERC, Final Environmental Impact Statement for Hydropower License, Project No. 2206, at 138 (Apr. 2008).

velocity and swim speed data, and life history characteristics.[33] FERC concluded in the EIS for the project that the "loss of individual fish from entrainment and mortality is not expected to result in any substantial effects to the fishery at the Project."[34] The analyses above address entrainment associated with all water passing through the projects, including the enormous amounts of water that go through the turbines for electricity generation. While these studies generally do not focus on entrainment specific to the small pipes and other structures – often within or off of the penstocks – that various hydroelectric facilities use to divert water for service water and cooling purposes, withdrawals and entrainment impacts from these cooling water diversions would be exceptionally smaller. In addition, FERC frequently addresses the issue of fish impingement and entrainment by requiring licensees to screen their intakes to prevent or minimize fish from entering the penstock, which can eliminate or reduce the possibility of impingement or entrainment during the diversion of water from the penstock for cooling purposes.

Furthermore, CWA § 401 provides states broad authority to impose conditions as part of state-issued water quality certificates in the context of the licensing and relicensing of projects. FERC may not issue a license unless the state has either issued or waived the water quality certificate. States have used this authority to impose conditions related to fisheries, aesthetics, recreation, and more.[35] Such conditions are considered "mandatory," meaning that FERC has no discretion but to include them in a license.

---

[33] *See* FERC, Final Environmental Impact Statement for Hydropower License, Project No. 2210, at 119-126 (Aug. 2009).

[34] *Id.* at 126.

[35] *See*, *e.g.*, *S.D. Warren Co. v. Maine Bd. of Envtl. Prot.*, 547 U.S. 370 (2006) (holding FERC-licensed dams must comply with state certification that required operator to maintain stream flow and allow passage for certain fish and eels).

In accordance with the authorities described above, fish and wildlife agencies often recommend protection, mitigation, and enhancement measures to offset any known impacts of hydroelectric facilities for aquatic species. In some cases, FERC license conditions may go further than the 2014 Rule would to minimize adverse environmental impacts associated with hydroelectric operations because they can include habitat restoration which, although not allowed as BTA for steam electric and manufacturing facilities captured under the Existing Facilities Rule, serves to provide habitat for individual species, life stages (such as spawning and rearing of young), or entire communities of aquatic organisms affected by hydroelectric operations. Thus, the FERC licensing process already provides for measures to minimize adverse environmental impacts of hydroelectric operations and may, at times, be more stringent than § 316(b) requirements. Any imposition of § 316(b) requirements, either through application of the 2014 Rule or a case-by-case BPJ determination, would be duplicative of existing federal and state requirements already in place. As the Alabama Department of Environmental Management ("ADEM") has recognized, "[t]he purpose of 316(b) of the [CWA] is to reduce mortality to fish and other aquatic organisms impacted by cooling water intake structures," but, for hydroelectric facilities, "the impacts to aquatic organisms are already addressed" and "have been extensively studied under the [NEPA] and [FERC] regulatory frameworks and subsequently granted 401 certifications."[36]

IV. EPA's 2014 Rule for Existing Facilities Did Not Consider Hydroelectric Facilities.

Even if CWA § 316(b) were applicable to hydroelectric facilities, which it is not, the Region's proposed BPJ requirements are arbitrary and capricious because the Region borrowed from and relies on a rule that EPA expressly stated did not apply to hydroelectric facilities and

[36] *See* ADEM General Permit Rationale, Hydroelectric Facilities ALG360000, at 3 (Aug. 18, 2015).

that the Agency adopted without any consideration of the technical feasibility or cost of application to hydroelectric facilities.

A. EPA Has Never Provided Notice or an Opportunity to Comment on the Applicability of § 316(b) Requirements to Hydroelectric Facilities.

Under the APA, 5 U.S.C. § 553(b)(3), an agency must publish in the *Federal Register* a notice of proposed rulemaking, which "shall include . . . either the terms or substance of the proposed rule or a description of the subjects and issues involved." After the notice is published, the agency must "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments." 5 U.S.C. § 553(c). The APA's notice-and-comment mandate is "designed (1) to ensure that agency regulations are tested via exposure to diverse public comment, (2) to ensure fairness to affected parties, and (3) to give affected parties an opportunity to develop evidence in the record to support their objections to the rule and thereby enhance the quality of judicial review." *Int'l Union, United Mine Workers of America v. Mine Safety and Health Admin.*, 407 F.3d 1250, 1259 (D.C. Cir. 2005). These procedures "ensure that the broadest base of information would be provided to the agency by those most interested and perhaps best informed on the subject." *Phillips Petroleum Co. v. Johnson*, 22 F.3d 616, 620 (5th Cir. 1994).

To ensure regulated entities have fair notice, "the final rule the agency adopts must be a 'logical outgrowth' of the rule proposed." *Long Island Care at Home, Ltd. v. Coke*, 551 U.S. 158, 174 (2007). Under this principle, the law asks "whether the affected party 'should have anticipated' the agency's final course in light of the initial notice." *Covad Commc'ns. Co. v. FCC,* 450 F.3d 528, 548 (D.C. Cir. 2006) (citation omitted). While a final rule need not be an exact replica of the proposed rule, "if the final rule deviates too sharply from the proposal, affected parties will be deprived of notice and an opportunity to respond to the proposal." *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 547 (D.C. Cir. 1983).

As explained above, prior to the implementation of the 2014 Rule, there had never been any indication from EPA or Congress that CWA § 316(b) could apply to hydroelectric facilities. Moreover, there was no way to anticipate from the proposed Existing Facilities Rule that EPA would apply the technology-based standards to hydroelectric facilities. Hydroelectric facilities had no notice that those facilities could be subject to new NPDES requirements as a result of the 2014 rulemaking, nor were they provided an opportunity to comment on the many ways in which technologies that EPA evaluated for steam electric power and manufacturing plants cannot be considered BTA for hydroelectric facilities. In the preamble to the proposed rule for existing facilities, EPA explicitly stated that withdrawals from hydroelectric facilities were not meant to be addressed by the Existing Facilities Rule:

> Given the diversity of industrial processes across the U.S., there are many other industrial uses of water not intended to be addressed by today's proposed rule . . . Warming water at liquefied natural gas terminals, and *hydro-electric plant withdrawals for electricity generation are not cooling water uses and are not addressed by today's proposal* . . . .

76 Fed. Reg. at 22,190 (emphasis added).

In light of EPA's history of *not* applying CWA § 316(b) to hydroelectric facilities and because EPA's explicit statements confirmed that hydroelectric facilities would not be covered by the Existing Facilities Rule, private and public entities that own or operate hydroelectric facilities did not provide comments to address the potential impacts of the Existing Facilities Rule's proposed requirements.[37] Applying the Existing Facilities Rule to hydroelectric facilities, therefore, cannot be a logical outgrowth of the proposed rule. Thus, any attempt now by EPA to

[37] There is no reference to hydroelectric facilities in EPA's 467-page response to comments document. Response to Comments Document for the Final 316(b) Existing Facilities Rule (May 19, 2014) (EPA-HQ-OW-2008-0667-3679).

apply the Rule's requirements to hydroelectric facilities, which has been done only on rare occasions through post hoc determinations for particular facilities[38] and now in the Proposed Permit, is contrary to the APA's requirements for fair notice and opportunity for comment.

B. EPA Did Not Consider Technologies for Hydroelectric Facilities or Evaluate the Potential Impacts of Applying the Rule's BTA Standards to Hydroelectric Facilities.

EPA's final 2014 Rule and preamble provide no discussion of the applicability of § 316(b) or the Rule to hydroelectric facilities. In fact, the administrative record for the 2014 Rule is replete with indications that EPA did not consider impacts to hydroelectric facilities when evaluating potential technologies or the associated costs and benefits. For example, in the Economic Analysis for the final 2014 Rule, EPA stated that "[t]he final rule is only relevant for power generators that use substantial amounts of cooling water, and …[o]nly prime movers with a *steam-electric generating cycle* use large enough amounts of cooling water to be subject to the final rule."[39] The analysis goes on to describe steam electric facilities as those generating units

[38] In one of the few instances where EPA has asserted that § 316(b) and the 2014 Rule apply to hydroelectric facilities, it is clear that EPA's determination was made behind the scenes, well after the 2014 Rule was promulgated, and without a notice-and-comment rulemaking that evaluated the potential implications of such a determination. The 2016 NPDES Permit Fact Sheet for the Smith Mountain Hydroelectric Plant in Virginia stated, "Significant discussion was held during this reissuance regarding the applicability of CWA section 316(b). [The applicant's] position is that hydropower stations are not subject to section 316(b). However, after consultation with EPA, a determination was made that the facility is subject to CWA 316(b) and the [Existing Facilities] Rule. The determination was that § 316(b) 'applies' to hydropower facilities if waters of the U.S. are withdrawn and used for cooling purposes." VPDES Permit Program Fact Sheet, Permit No. VA0088765, at ¶ 30 (June 13, 2016). Other states that have considered the issue have determined that § 316(b) does not apply to hydroelectric facilities, *see, e.g.,* ADEM General Permit Rationale, Hydroelectric Facilities ALG360000 (Aug. 18, 2015) (ADEM agrees that the § 316(b) rule is "not applicable" to hydroelectric facilities), or have continued to issue NPDES permits for hydroelectric facilities without § 316(b) requirements, *see, e.g.,* South Carolina Department of Health and Environmental Control, NPDES General Permit for Hydroelectric Generating Facilities, Permit No. SCG360000 (May 15, 2015); North Carolina Department of Environment and Natural Resources, NPDES General Permit No. NCG50000 (Oct. 1, 2015).

[39] Economic Analysis for the Final 316(b) Existing Facilities Rule at 2A-4 (May 2014) (emphasis added) ("2014 Economic Analysis").

that are fueled by "coal, gas, oil, waste, nuclear, geothermal, and solar steam."[40] EPA does not include hydroelectric facilities in its analysis of the economic impact of the Rule on electric generation units, nor does EPA analyze the economic impact of the rule on hydroelectric facilities, in particular.[41] Likewise, in the Technical Development Document for the 2014 Rule, EPA includes the following exhibit that provides the estimated number of facilities that would be subject to the 2014 Rule by fuel type and prime mover category, but the table does not include hydroelectric facilities:

Exhibit 4-26. 316(b) electric power facilities by plant type and prime mover

Plant type[a]	Prime mover	Number of 316(b) electric generators[b,c]
Coal steam	Steam turbine	342
Gas	Steam turbine	73
Nuclear	Steam turbine	56
Oil	Steam turbine	29
Other steam	Steam turbine	25
Total steam	Steam turbine	525
Combined cycle	Combined cycle	33
Total		559

[a] Facilities are listed as steam electric if they have at least one steam electric generating unit.
[b] Facility counts are weighted estimates generated using the original 316(b) survey weights.
[c] Individual values do not sum to reported total due to rounding as the result the application of statistical weights.
Sources: U.S. EPA, 2000; U.S. DOE, 2007 (GenY07); U.S. EPA Analysis, 2010

2014 TDD Exhibit 4-26.

Similarly, EPA's benefit analyses did not consider hydroelectric facilities. To evaluate the benefits of the 2014 Rule's requirements, EPA extrapolated data from 98 model facilities based on information EPA received in the 2000 ICR.[42] In its 2000 ICR, however, EPA did not request information from any hydroelectric facilities. EPA ultimately narrowed its research

[40] *Id.*; *see also* Technical Development Document for Final Section 316(b) Existing Facilities Rule at 4-23 (May 19, 2014) ("2014 TDD") ("Only prime movers with a steam-electric generating cycle use large enough amounts of cooling water to fall under the scope of the proposed rule.").

[41] In fact, the only discussion of hydroelectric facilities in EPA's Economic Analysis is a general description of hydroelectric facilities' contribution to electricity generation. *See* 2014 Economic Analysis at 2A-3.

[42] *See* Benefits Analysis for the Final Section 316(b) Existing Facilities Rule at 3-5 (May 2014).

activities to focus on traditional utilities, nonutility power producers, and four other industrial categories that utilize large quantities of cooling water. "Traditional utilities and nonutility power producers that use cooling water were further limited to those plants that generate electricity by means of steam as the thermodynamic medium (steam electric) because they are associated with large cooling water needs."[43] Therefore, hydroelectric facilities, which do not generate electricity through the use of steam, were excluded from EPA's original data request, which was later used to support EPA's analysis of the Existing Facility Rule's benefits.

In fact, EPA concluded that "[u]nits with water turbines, or 'hydroelectric units,'… do not use a steam loop and do not use cooling water …."[44] As Region 10 now appears to understand, hydroelectric facilities occasionally do use cooling water, although they do so in small amounts, and their use of cooling water certainly was not the focus of the 2014 Rule.

If EPA had actually considered the technical feasibility and cost for application requirements and any technology and associated monitoring requirements for hydroelectric facilities, it would have understood that what is BTA for steam electric power and manufacturing plants is not necessarily BTA for hydroelectric facilities. EPA previously has recognized that a different BTA may be appropriate for other types of facilities with CWISs. For example, EPA determined that, for existing offshore oil and gas platforms, no retrofit technology was BTA. EPA studied the facilities and "could not identify any technologies (beyond the protective screens already in use) that are technically feasible for reducing impingement or entrainment in such existing facilities." 79 Fed. Reg. at 48,310. As discussed in more detail in Section IV.B below, there are similar challenges for hydroelectric facilities.

[43] Information Collection Request, Detailed Industry Questionnaires: Phase II Cooling Water Intake Structures & Watershed Case Study Short Questionnaire at 4 (Aug. 18, 1999).

[44] 2014 TDD at 4-22.

EPA cannot impose § 316(b) requirements on hydroelectric facilities without engaging in proper notice-and-comment rulemaking that evaluates the availability and feasibility of potential technologies for hydroelectric facilities. Region 10's Proposed Permit and Fact Sheet do not fulfill this requirement. Accordingly, it is unlawful for Region 10 to impose on hydroelectric facilities CWA § 316(b) requirements – whether they are based on BPJ determinations or the 2014 Rule – without following the necessary procedures or conducting this type of evaluation.

V. Even if § 316(b) Did Apply to Hydroelectric Facilities, Which it Does Not, the Requirements of the 2014 Rule Are Not Appropriate for Such Facilities, Which Are Fundamentally Different From Facilities Covered by the Rule.

The requirements that EPA established in the 2014 Rule are not appropriate for hydroelectric facilities, which are fundamentally different from the steam electric power and manufacturing plants EPA considered in that rulemaking.

As discussed above, EPA did not consider hydroelectric facilities in establishing BTA in its 2014 Rule. EPA explained in the preamble to the 2014 Rule that, to establish BTA for the facilities covered by the Rule, EPA considered: "the availability and feasibility of various technologies," "costs associated with these technologies," the technologies' economic impacts, "effectiveness of these technologies in reducing impingement mortality and entrainment," and additional factors, such as "location, age, size, and type of facility." 79 Fed. Reg. at 48,328. For this analysis, EPA made a number of assumptions based on data and information from steam electric power plants and manufacturing plants that do not take into account technology costs or feasibility for hydroelectric facilities.[45]

---

[45] For example, in evaluating impingement data and performance standards, EPA relied on 26 impingement mortality data sets at 17 facilities, none of which included hydroelectric facilities. 79 Fed. Reg. at 48,323; 2014 TDD Exhibit 11-3. As another example, in the final rule, EPA adjusted its assumptions for costs of modified traveling screens with fish returns in response to feedback that its proposal had underestimated those costs. 79 Fed. Reg. at 48,324. The adjustments EPA made in its evaluation of technology costs included: to correct its misplaced assumption that modified traveling screens were available at most facilities, EPA assigned higher cost technologies (*e.g.*, larger intakes, wedgewire screens with through-screen design velocities of 0.5 fps) for intakes that use passive

The assumptions that EPA made for the facilities it considered in its 2014 Rule do not necessarily apply for hydroelectric facilities. There are numerous different configurations for hydroelectric facilities and, in particular, their pipes and structures that divert cooling water. Nearly every facility has unique, location-specific design attributes to take maximum advantage of the hydraulics of that unique physical location. For example, some hydroelectric facilities have a hole bored through the penstock in which a perforated flange is used to attach a small pipe used to gravity feed service and cooling water equipment. Some hydroelectric facilities have pipes that come off the scroll case. Others have separate pipes that come off the face of the dam. For these three configurations, water that is gravity- or pressure-induced feeds through the pipe to cool and service the equipment. Other facilities have separate intake pump houses upstream of the powerhouse. For those facilities, there is a distinct and separate intake used for service water and cooling purposes. Pumped storage facilities pump water from lower reservoirs to higher elevation reservoirs during times of low electric demand and then release water from the upper reservoir to drive turbines during periods of high electric demand. In one pumped storage facility, cooling water is drawn from the cavity between the inner and outer walls of the power house, while service water is drawn from a single intake at the tailrace of the plant.

Given the wide range of configurations for hydroelectric facilities and different processes for diverting water for cooling, the technologies that EPA found to be the best available technologies and sampling requirements for steam electric power plants and manufacturing plants are not necessarily appropriate or practical for hydroelectric facilities.

---

screens; EPA increased capital costs for the fish return component and included additional costs for those with particularly difficult circumstances, such as very long intake canals and submerged offshore intakes. *Id.*; 2014 TDD at 8-2 to 8-6 (explaining EPA's model facility approach and modifications to the cost tool). EPA did not consider application of the technology to hydropower facilities.

For example, at many hydroelectric facilities, conducting impingement or entrainment sampling at the pipe or structure taking in cooling water would be very difficult, or even unsafe, due to turbulence. Sampling equipment may not be able to withstand water flows and forces and could break away, potentially damaging the facility.

In addition, many of the impingement technology options that are established as BTA in the 2014 Rule would not be feasible at most hydroelectric facilities. For example, one of the impingement options is to use a maximum 0.5 feet per second through-screen design velocity, 40 C.F.R. § 125.94(c)(2), but for many hydroelectric facilities, the only way to retrofit an intake pipe within the penstock to meet that through-screen design velocity would be to increase the size of the intake opening, which in some cases would require dam reconstruction and could actually increase entrainment because of the increase in the volume of water passing through the intake. Similarly, another impingement option is to operate an intake structure with a maximum through-screen velocity of 0.5 feet per second, § 125.94(c)(3), but it would be impossible to measure the actual velocity at the intake for most hydroelectric facilities because the magnitude and force of the water is so great as it is going through the penstock that no monitoring equipment could be located near the intake. Nor would it be feasible to install modified traveling screens, § 125.94(c)(5), on the small pipes that are used by many hydroelectric facilities to take in cooling water. At least three of the impingement options, §§ 125.94(c)(5)-(7), require an impingement technology performance optimization study, which would be very difficult, if not impossible, for many hydroelectric facilities that would not be able to conduct impingement sampling at the intake.

Indeed, the 2014 Rule's requirements would not be necessary in most cases because the rates of impingement and entrainment would be so low that additional controls would not be warranted. Some hydroelectric facilities have in place screens to prevent debris of a certain size from entering the penstock (and therefore the cooling water pipe), and at many facilities, the water passes through a strainer before being used for cooling purposes. Some of these strainers are backwashed to a plant sump. In our members' experience, fish are rarely (if ever) observed in strainer baskets or in backwash to the plant sump. Moreover, for many hydroelectric facilities, due to the high velocity and volume of water passing through the penstock and by the entrance to the intake, the rates of impingement would be so low that additional impingement controls would be useless. The same is true for entrainment at many of these facilities. For hydroelectric facilities, the *de minimis* exception for impingement established in the 2014 Rule, 40 C.F.R. § 125.94(c)(11), would be applicable more often than not. And the fact that there is not a *de minimis* exception for entrainment in the 2014 Rule would create issues for many hydroelectric facilities that would have no way of further minimizing the already very minor rates of entrainment.

EPA clearly did not consider hydroelectric facilities when it was establishing the requirements under the 2014 Rule. As explained above, such requirements are not appropriate or feasible for hydroelectric facilities, which are fundamentally different from facilities covered by the 2014 Rule.

VI. The § 316(b) Measures Required in the Proposed General Permit Are Inappropriate for Hydroelectric Facilities.

Even if § 316(b) applied to hydroelectric facilities, which it does not, the measures that Region 10 proposes as BTA in the Proposed Permit are inappropriate for the hydroelectric facilities to which the Proposed Permit, if finalized, would apply. As Region 10 acknowledges, each generating facility is unique in its location, physical layout, and operational pattern.[46] The documentation Region 10 has supplied provides no information on the specific attributes of the "intake structures" used to supply cooling water used by the hydroelectric facilities to which any final permit would apply. Indeed, the Fact Sheet reflects no attempt to characterize or consider the wide range of variation among existing cooling water intakes at hydroelectric facilities. That variation is important because site-specific factors may make it difficult or impossible for many facilities to comply with some or all of the proposed requirements.

The Region also made no effort to assess whether those intakes, as currently configured and operated, are causing any meaningful environmental impacts not already minimized in the licensing and NEPA review process. It is difficult to understand how Region 10 could have exercised its BPJ that the intake of cooling water at hydroelectric facilities requires further control without first collecting at least some information from which to evaluate whether the diversion of relatively small amounts of water that otherwise would flow through the facility were likely to cause any meaningful incremental environmental impacts. Even if it were appropriate to apply § 316(b) to these facilities (which NHA and UWAG believe it is not), the exercise of BPJ for existing facilities requires at least some understanding of the location, design, construction, and capacity of the "intake structures" involved and the environmental impacts occurring. Region 10 put the cart before the horse, imposing new "BTA" requirements without first evaluating the attributes of the facilities in question and determining whether or not they already have minimized adverse environmental impacts.

Region 10 also failed to identify the technologies, measures, procedures, and methods that it anticipates facilities would use to meet the requirements imposed by the permit. Nor did

[46] EPA Region 10, Biological Evaluation of the NPDES General Permit for Hydroelectric Facilities Within the State of Idaho, Permit Number IDG360000, at 8 (Feb. 2018).

Region 10 consider how the BTA requirements it seeks to impose may overlap or conflict with FERC license conditions. As discussed below, many of the proposed requirements dictate an outcome (like returning fish to the waterbody or managing tailrace operations to prevent fish access to draft tube areas) without any discussion of what technology or other measures the Region expects the facility to use to accomplish that outcome. The record is equally devoid of any assessment of the feasibility and costs of using whatever technologies, procedures, or methods might be needed to satisfy those requirements, or the level of performance or environmental benefits likely to be achieved. Indeed, some of the measures Region 10 has proposed could be read to apply to hydroelectric facilities as a whole, including parts of the facility (e.g. tailrace) that are not part of the process for diverting cooling water.

The availability and cost of specific technologies and measures, the impact of those costs on affected facilities, and the environmental benefits of requirements based on those technologies are all important factors that EPA acknowledged it needed to consider before establishing its nationally applicable § 316(b) regulations for facilities withdrawing cooling water above the applicable thresholds. EPA also considered feasibility, cost, and benefits in establishing permit application requirements, including those dealing with biological monitoring and other data collection and analysis, reporting, and recordkeeping. Based on its consideration of those factors, EPA was unable to justify imposing any specific BTA technology requirements on facilities below the applicable flow threshold or any uniform application requirements for entrainment for facilities with "actual intake flows"[47] at or below 125 MGD. Yet Region 10

[47] Actual Intake Flow ("AIF") "means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the past three years. After October 14, 2019, Actual Intake Flow means the average volume of water withdrawn on an annual basis by the cooling water intake structures over the previous five years. Actual intake flow is measured at a location within the cooling water intake structure that the Director deems appropriate. The calculation of actual intake flow includes days of zero flow. AIF does not include flows associated with emergency and fire suppression capacity." 40 C.F.R. § 125.92(a).

proposes to impose a host of new § 316(b) requirements without identifying the technologies on which they are based, determining that they are in fact available for the facilities in question, and evaluating their costs and benefits. In particular, the Region failed to consider the important social costs (*e.g*. energy reliability, renewable electricity generation) of imposing new requirements.

In fact, it would be very difficult for many hydroelectric facilities to comply with the requirements outlined in the Proposed Permit. In some cases (*e.g.*, weekly monitoring, returning impinged fish to source water), the requirements Region 10 has proposed are far more onerous than those EPA concluded should apply only to facilities with design flows greater than 2 MGD and actual intake flows greater than 125 MGD. Moreover, even if some facilities could meet some of those requirements, the costs likely would far exceed any plausible environmental benefits.

UWAG and NHA provide the following specific comments on the Proposed Permit's BTA requirements:

- The 2014 Rule establishes requirements for existing facilities that: (1) have NPDES permits, (2) use one or more CWISs with a cumulative DIF of greater than 2 MGD to withdraw water from waters of the U.S., **and** (3) use 25 percent or more of the water withdrawn (on an actual intake flow basis) exclusively for cooling water purposes. 40 C.F.R. § 125.91(a). Facilities with CWISs that are subject to CWA § 316(b) that do not meet these criteria must meet § 316(b) requirements established by the permit writer on a case-by-case, BPJ basis. *Id.* § 125.90(b). The Fact Sheet and Section 401 Water Quality Certification state that the Proposed Permit would cover facilities that fall below the threshold of "2 MGD or less **and** less than twenty-five percent used exclusively for cooling . . . ." Proposed Permit Fact Sheet at 28 (emphasis added); *see also* Section 401 Water Quality Certification at 1. The Proposed Permit, however, states that facilities are ineligible for coverage and must apply for an individual NPDES permit if the facility "uses or proposes to use one or more [CWISs] with a [DIF] of greater than 2 [MGD] **or** the facility uses 25 percent or more of the water it withdraws for cooling water purposes on an average monthly basis." Proposed Permit at 8 (emphasis added). Although, as explained throughout these comments, NHA and UWAG do not believe CWA § 316(b) or the 2014 Rule are applicable to hydroelectric facilities even on a case-by-case BPJ basis, if Region 10 plans to rely on the 2014 Rule, it must be consistent throughout the

Proposed Permit and supporting documents, and clarify that facilities that are ineligible for coverage under the Proposed Permit are those facilities that use greater than 2 MGD **and** use 25 percent or more of the water for cooling purposes.

- 2(a): The Proposed Permit would require permittees to "manage the intake operations to minimize injury to resident fish and other aquatic species in the river," but the Region provides no analysis of the range of existing hydroelectric cooling water intake operations and how their operations could be managed to minimize injury to resident fish and other aquatic species.

- 2(b): The Proposed Permit would require facilities to "manage tailrace operations to prevent fish access to the draft tube areas to minimize injury of fish and other aquatic species." The tailrace and draft tube, however, are not subject to EPA's NPDES permitting authority. Moreover, the cooling water piping may not exist in the draft tube, but rather at the downstream face of the power plant, making managing the tailrace operations at the draft tube ineffective for protecting fish. Because of the geometry and physics of this system, the potential for fish impingement and entrainment is very low, and monitoring for fish is nearly impossible. To the extent that fish access to the tailrace and associated injury from contact with turbine runners constituted a significant resource issue, the existing FERC licensing process would be adequate to fully address the impacts in consultation with fish and wildlife agencies.

- 2(c): The Proposed Permit would require permittees to "cease or reduce the intake of cooling water whenever withdrawal of source water is not necessary," but the Region provides no analysis of, or evidence for, the feasibility or efficacy of ceasing or reducing the intake of cooling water at these hydroelectric facilities.

- 2(d): The Proposed Permit would require permittees to "return all observed live impinged fish to the source water to the extent practicable." The Region provides no analysis that impingement occurs, or can even be discerned, at all types of cooling water intakes or that screening fish and returning fish to the source water is technically feasible.

- 2(e): The Proposed Permit directs permittees not to spray impinged fish or invertebrates with chlorinated water. EPA provides no analysis of, or evidence for, the feasibility or efficacy of restricting the use of chlorinated water at hydroelectric cooling water intakes for minimizing adverse effects of impingement and entrainment.

- 2(f): The Proposed Permit would require permittees to "design an impingement and entrainment monitoring program," and the monitoring is to be conducted "at least weekly." However, as explained above, conducting impingement or entrainment sampling at the pipe or structure taking in cooling water would be very difficult, and even unsafe. Moreover, in the FERC licensing process, study and monitoring needs are determined in consultation with federal and state fish and wildlife agencies. The FERC process is robust and sufficient for determining whether monitoring may be justified and is technically feasible for evaluating fish impingement and entrainment at the cooling water intake.

- 2(g): The permittee is directed to retain the results of this monitoring program on site "for inspection and for submission to EPA as required in Part 4(l) of this Section," but the reference to 4(l) is confusing, given this section (*i.e.*, IV.C) contains no Part 4(l).

- 2(h): The Proposed Permit would require permittees to maintain physical screening or exclusion technology consistent with the guidelines of NMFS Northwest Region's Anadromous Salmonid Passage Facility Design. These guidelines, however, are designed based on physical screening and exclusion technology for the hydroelectric turbines and the bypass operations and are not likely to be feasible at many of the cooling water intakes. Region 10 could not require such technologies for the turbines themselves, which are outside the scope of EPA's NPDES authority.

- 2(i): The Proposed Permit would require the permittee to "operate and maintain the CWIS including any existing technologies used to minimize impingement and entrainment," but it is not clear what technologies could be used at hydroelectric facilities to minimize impingement and entrainment. The Region provides no analysis or explanation.

The information report required under the Proposed Permit's section IV.C.3 has requirements that are excessive and, in some instances, inconsistent with the section IV.C.2 BTA requirements. UWAG and NHA provide the following specific comments on the Proposed Permit's CWIS report requirement:

- 3(d): Reporting requirement 3(d) refers to measures to be taken to maintain a daily maximum surface withdrawal of 1.0 MGD, but such measures are not listed among the BTA requirements.

- 3(e): EPA requests maximum monthly average intake data during the previous five years, but these data may not be collected at hydroelectric cooling water intakes because the intake volume is so small.

- 3(f): Reporting requirement 3(f) refers to whether the facility withdraws cooling water at a rate commensurate with a closed-cycle cooling system without any analysis or explanation as to how this might be relevant to the operation of small cooling water intakes at hydroelectric facilities.

- 3(o): Reporting requirement 3(o) for a report of the five-year results from the impingement and monitoring program called for in Part 2(f) is not supported by any analysis of the need for, technical feasibility, or costs of conducting such a monitoring program. Again, monitoring would not be technically feasible at many facilities, and EPA has not identified how the monitoring information would be applied to future BTA determinations.

VII. EPA Should Clarify Certain Other Requirements in the Proposed General Permit.

In addition to the § 316(b)-related measures addressed above, there are a number of discharge-related provisions in the Proposed Permit that require clarification and/or revision, including the following:

- Eligibility for Permit Coverage: On page 8, the Proposed Permit states that a facility is ineligible for coverage if "[t]he facility is new or has expanded since July 1, 2011." The Fact Sheet states, however, that facilities are not covered by the Proposed Permit if they "are new or have expanded *their discharge* since July 1, 2011." Fact Sheet at 19 (emphasis added). EPA should clarify whether a facility is excluded if it has expanded since July 1, 2011, or whether it is excluded only if the discharge has expanded since July 1, 2011. Similarly, the Proposed Permit states that a facility would be ineligible when "[a] Water Quality Management Plan or Total Maximum Daily Load (TMDL) containing requirements applicable to such a point source is approved," Proposed Permit at 8, but the Fact Sheet states that this applies to facilities "with wasteload allocations from a TMDL for pH, oil, and grease and/or temperature" would be ineligible. Fact Sheet at 19. EPA should clarify whether a facility is ineligible if it has a wasteload allocation as a result of a TMDL for some, but not all of the discharges, or whether a facility could be eligible for only those discharges that do not already have an approved wasteload allocation.

- Existing Measures to Prevent Release of Oil and Grease: In accordance with their FERC license and related requirements, most hydropower producing facilities in the state of Idaho are currently required to maintain procedures in place pursuant to a Spill Prevention Control and Countermeasure (SPCC) and Emergency Action Plan (EAP). Each of these plans is in place in order to protect against any accidental release of oil and grease into a water of the United States. It is unclear, therefore, what additional benefit would derive from the Proposed Permit's Best Management Practices (BMP) Plan requirement.

- BMP Plan Notification: Under the Proposed Permit's "Schedule of Submissions," the permittee must provide EPA with written notification that the BMP Plan has been implemented within 180 days after the effective date of the permit. Proposed Permit at 2. This schedule also indicates that the permittee must notify EPA that the BMP Plan has been implemented within 90 days after authorization to discharge under the General Permit. *Id.* Can EPA guarantee that the permittee will have authorization to discharge within 90 days of the effective date of the permit to allow the permittee to satisfy these obligations on time? Moreover, the 180-day period specified on page 2 of the Proposed Permit is inconsistent with the requirement on page 20 that the permittee submit written notice to EPA and IDEQ that the BMP Plan has been developed and implemented within 90 days of the effective date of the permit. EPA should correct page 20 to use the 180-day period previously specified.

- BTA Notification: Likewise, pursuant to section IV.C.2, facilities withdrawing cooling water must implement BTA within 180 days of the effective date of the permit. Proposed

Permit at 20. Can EPA guarantee that the permittee will have authorization to discharge within enough time to implement BTA within 180 days of the permit's effective date?

- BMP Plan Shield: Part IV.B.5 of the proposed permit would require the permittee to implement BMPs or other measures that "ensure" compliance with a host of vaguely or inconsistently stated objectives. For example, Section IV.B.5(a) would require BMPs to "ensure" that oil, grease, and hydraulic fluids from "all sources" "do not enter the river," apparently in any amount, and regardless whether this would be feasible or necessary to meet water quality standards. Proposed Permit at 21. Yet, section IV.B.5(c) would require only BMPs that "*minimize* the leaking of hydraulic oil or other oils." *Id.* (emphasis added.) As another example, section IV.B.5(d) would require the permittee to "reduce" its reliance on lubricants that come into contact with river water, and sections IV.B.5(e) and IV.B.5(j) would require a "preference" for "environmentally acceptable lubricants" and PCB-free lubricants, paint, and caulk, but no criteria are specified in the permit for evaluating what reductions are required or for exercising these preferences. *Id.* at 21-22. Requirements such as these leave permittees unfairly exposed to agency enforcement actions and citizen suits even when the permittees have complied with them in good faith. To prevent this, the requirements should be stated more clearly and objectively, and the permit should include a provision that a permittee's compliance with the BMPs specified in its required BMP Plan constitutes compliance with section IV.B of the permit. Such a "plan shield" would be consistent with NPDES permit requirements because section IV.B.3(c) authorizes EPA to require changes in the BMP Plan "at any time" if EPA determines that the BMP Plan does not meet the minimum requirements of section IV. But allowing a permittee to rely on the BMPs in its BMP Plan unless and until EPA directs changes in those BMPs would prevent the permittee from being unfairly subject to an enforcement action based on second-guessing the adequacy of the BMPs that it has selected in good faith to comply with the permit's vaguely worded BMP requirements.

- NOI Requirements for Facilities Discharging to § 303(d) Listed Waters: According to the Proposed Permit, facilities that would like coverage under the general permit must submit their initial application or Notice of Intent ("NOI") within 90 days after the effective date of the permit. Proposed Permit at 2. On page 12, item 15, however, applicants discharging to waters listed on IDEQ's most recent CWA § 303(d) list for temperature must submit one complete season (May 1 through November 1) of continuous temperature monitoring data with a copy of their NOI. Facilities that discharge to § 303(d) listed waters for temperature will likely not be able to submit an NOI with one complete season of continuous temperature monitoring data within 90 days after the effective date of the permit. It would make more sense for facilities to begin this sampling once the permit becomes effective. EPA should clarify that such facilities can submit this sampling information after the sampling period has concluded or when the permit is renewed. If this requirement is not adjusted, several facilities in Idaho that would otherwise qualify for coverage under the Proposed Permit would not be eligible. In addition, there is a lack of detail in the Proposed Permit and the Section 401 Water Quality Certification regarding where the monitoring should occur and the sampling intervals. EPA should provide more information on these requirements.

- Effluent Limits Apply Only to Pollutants Added by the Facility: Sections III.A.1-6 of the Proposed Permit would prohibit the "discharge" of various materials that would impair beneficial uses or cause other adverse effects in the receiving water. Proposed Permit at 14. In addition, sections III.A.8-12, Tables 1-5, set forth numeric limits that would apply to the facility's "effluent." *Id.* at 14-17. Consistent with EPA's longstanding position, the Proposed Permit should be revised to clarify that these prohibitions apply only to pollutants that are *added* to receiving waters by the facility, and not to pollutants that are *passed through* the facility from upstream waters, including pollutants contained in facility reservoirs.

- Sampling Frequency: The Proposed Permit delineates four types of discharges that must be sampled, some on a monthly basis. Proposed Permit at 15-17. Monthly sampling is not needed, and there are limited benefits, if any, associated with the extensive sampling scheme proposed. Indeed, the 2009 Region 1 general permit for hydroelectric facilities requires less frequent sampling for similar discharges. For example, whereas the Proposed Permit requires sampling for flow, pH, and oil and grease for cooling water once per month, the Region 1 permit requires sampling once per quarter.[48]

  EPA Region 1 initially proposed monthly sampling, but UWAG and NHA noted in their 2004 joint comments[49] on the Region 1 proposal that monthly sampling is not needed and that there are limited benefits, if any, associated with the extensive sampling scheme Region 1 proposed. UWAG and NHA explained that many of the activities proposed to be regulated under the general permit are periodic in nature and may occur only once or twice a year and, therefore, monthly monitoring would be wasteful. *Id.* at 9. We also noted that obtaining monthly samples could present a substantial logistical challenge to owners and operators due to extreme weather conditions, sample holding time, and lab accessibility. Data that NHA and UWAG member organizations acquired during the FERC licensing process show that the sample results would be well below the discharge limitations that were proposed by Region 1. Region 1 recognized these concerns and, in the final 2009 Region 1 permit, EPA reduced the sampling frequency. In its Response to Comments on the Region 1 permit, EPA stated that it "determined a less frequent monitoring frequency will still provide adequate pollutant monitoring data.…"[50]

  Region 10 has provided no principled basis for requiring sampling more frequently than Region 1 determined was sufficient in the 2009 Region 1 general permit. We recommend that Region 10 reduce the sampling frequencies to, at the very least, align with the sampling frequencies that Region 1 determined to be reasonable in the 2009 Region 1 general permit.

---

[48] *See* EPA Region 1 General Permits Under the NPDES for Hydroelectric Generating Facilities, Permit Nos. MAG360000 and NHG360000, at 3-4, 6 (Nov. 10, 2009) ("Region 1 Permit").

[49] Joint Comments of NHA and UWAG on the Draft NPDES General Permits MAG360000 and NHG360000 for Hydroelectric Generating Facilities, at 9-10 (Jan. 16, 2004).

[50] EPA Region 1 General Permit Response to Comments NPDES General Permit Nos. MAG360000 and NHG360000, at 42. ("Region 1 Response to Comments").

- Flood/High Water Discharges: The Proposed Permit would impose effluent limitations and monitoring for maintenance-related water during flood/high water events and for equipment-related backwash strainer water. Proposed Permit at 16. In the Region 1 permit, however, EPA recognized that "sampling discharges from emergency flood devices can be dangerous and impracticable," and determined that the monitoring and reporting requirements it had proposed for the flood water discharges were "inappropriate." *See* Region 1 Response to Comments at 19. As a result, the Region 1 permit required only limited monitoring and reporting for facility maintenance-related water during flood/high water events and did not require monitoring for equipment-related backwash strainer water. Region 1 Permit at 6. Region 10 should make similar adjustments to the Proposed Permit.

- Monitoring Adjustment Opportunity: The Region 1 Permit allows for the permittee to request a reduction in the monitoring frequency of any pollutant after 10 valid pollutant samples for the outfall indicate compliance with the pertinent permit limits or demonstrate no reasonable potential to cause or contribute to water quality standards violation. Region 1 Permit at 23. We recommend that EPA revise the Proposed Permit to include the same adjustment opportunity.

- BMP Incident: Under section IV.B.6, facilities must prepare a written report to EPA and IDEQ within seven days after a "BMP incident" has been addressed. However, this term is not defined in the permit. Proposed Permit at 22. EPA should define "BMP incident."

- Toxic Substances v. Toxic Pollutants: Pursuant to section III.A.2, the permittee must not discharge "toxic substances" in concentrations that impair the designated beneficial uses of the receiving water. Proposed Permit at 14. Also, section V.I addresses "Changes in Discharge of Toxic Substances." *Id.* at 29. EPA should clarify whether "toxic substances" are equivalent to "toxic pollutants" as defined in 40 C.F.R. § 122.2.

- "Deleterious Materials": Similarly, section III.A.3, Proposed Permit at 14, and section V.G.5, *id.* at 29, refer to "deleterious materials," but these materials are not defined. These terms should also be defined.

- Total Suspended Solids (TSS) Levels: The Proposed Permit requires a monitoring method that will achieve a maximum Minimum Level for TSS of 5 mg/L. But there is no monitoring requirement for TSS, and EPA acknowledges that TSS is naturally occurring. Proposed Permit at 17, 45. EPA must explain the basis for such a requirement. In the Region 1 general permit for hydroelectric facilities, for example, this issue was resolved by removing the requirement to monitor TSS.

- "Maximum Minimum Level": The table in Appendix A lists the "maximum Minimum Level (ML)" for pollutants in the permit. Proposed Permit at 45. EPA must clarify how facilities should apply this standard.

- "Significant": Appendix C uses the term "significant" in multiple places to describe what must be included in the BMP Plan, but the term "significant" is not defined in the

Proposed Permit. EPA should clarify the factors that will be used to determine when a spill, event, or some other occurrence is "significant."

VIII. Conclusion

In sum, EPA Region 10 should not apply CWA § 316(b) to hydropower facilities. Section 316(b) was intended by Congress to address CWIS at steam electric and similar facilities, not hydropower projects. Furthermore, EPA CWIS regulations do not call for application of § 316(b) to hydropower facilities, and those regulations were not developed with any consideration of doing so, making it highly inappropriate for Region 10 to seek to impose the regulations or elements of them on the facilities. As noted above, the FPA and CWA § 401 fully protect both water quality and fish and wildlife in the context of hydropower facilities. Therefore, Region 10 should remove any § 316(b)-related provisions from the Proposed Permit.

UWAG and NHA appreciate the opportunity to comment on the Proposed Permit and provide factual information regarding operation of our members' hydroelectric facilities. No commenter, however, can make up for the lack of a comprehensive administrative record in the first instance that provides the Agency's evaluation of the availability and feasibility of potential technologies for hydroelectric facilities. We hope that EPA will pursue our recommendations and we look forward to working with you to address these meaningful issues.

NWHA
NORTHWEST HYDROELECTRIC ASSOCIATION

July 9, 2018

Via E-Mail: keenan.dru@epa.gov
Daniel Opalski, Director
U.S. Environmental Protection Agency Region 10
1200 6th Ave., Ste. 155
Seattle, WA 98101

Attention: Permit No. IDG360000

Re: Permit No. IDG360000 – EPA Region 10's Proposed Hydropower General Permit

Ladies and Gentlemen:

The Northwest Hydroelectric Association (NWHA) appreciates the opportunity to provide comments to the subject draft general permit (Permit). NWHA is dedicated to the promotion of the region's waterpower as a clean, efficient energy while protecting the fisheries and environmental quality which characterize our Northwest region. NWHA's membership represents all segments of the hydropower industry – public and private utilities; independent developers and energy producers; manufacturers and distributors; local, state and regional governments including water and irrigation districts; consultants; and contractors. While the bulk of our membership is located in the Northwest, including Northern California and Western Canada, our membership also includes entities from other states as well as national and international firms. NWHA and its members therefore have a keen interest in the subject Permit.

General Comments

NWHA questions the timing, necessity, and scope of this Permit. As background, hydroelectric facilities are periodically licensed by the Federal Energy Regulatory Commission (FERC). The licensing process often takes many years to complete while environmental impacts from facilities are rigorously evaluated. Many federal agencies, state agencies, Tribes, environmental groups and private citizens are actively involved in the licensing process. By the time a facility is licensed by FERC, the environmental impacts of the operation of the facility have been thoroughly evaluated and mitigation is imposed to minimize impacts to water quality and aquatic life. Many NWHA members have recently gone through the FERC relicensing process. Almost all water "discharged" from hydroelectric facilities is water utilized for the generation of electricity and not subject to NPDES requirements under applicable law. Therefore, we question the necessity of this Permit which is designed to address water quality and aquatic life impacts associated with only a small portion of facility operations. Such impacts have

JAN LEE
Executive Director

PO Box 2517
Clackamas, OR 97015

(503) 545-9420
(503) 631-7299 Fax

www.nwhydro.org
jan@nwhydro.org

For a list of Directors, please visit our website.

previously been evaluated by FERC, state and federal fishery agencies and the Idaho Department of Environmental Quality (IDEQ). No justification is provided by EPA as to why the Permit is necessary at this time even though most facilities have been operating for decades. NWHA is concerned that the Permit imposes duplicative, burdensome and unnecessary requirements to address what appears to be only theoretical impacts associated with facility operations. NWHA is unaware of any incidents at facilities in Idaho which caused any environmental impacts that the Permit is attempting to address, or which has not already been addressed in the FERC licensing process. Therefore we request that EPA reconsider issuing the Permit as there is no demonstrated need for the Permit at hydroelectric facilities in Idaho which are already highly regulated by federal and state agencies.

In terms of timing of the Permit, we question why a general permit is necessary at this time. Again, we are not aware of any specific problems associated with the operation of hydroelectric facilities in Idaho that requires a general permit at this time. We understand that IDEQ is taking over the NPDES Permit program from EPA in phases. To the extent there may be specific water quality impacts associated with the operation of hydroelectric facilities in Idaho that have not been addressed in the FERC License, we believe that IDEQ should decide whether it makes sense to issue a general permit for hydroelectric facilities and not EPA. Therefore we believe EPA should delay issuance of the Permit until IDEQ takes over the general permit portion of the NPDES program from EPA, and the agencies and stakeholders can then decide whether it makes sense to issue any type of NPDES Permit for hydroelectric facilities.

Finally, in terms of scope of the Permit, (assuming that a general permit is appropriate) we believe that a best management practice (BMP) approach is the best way to address any environmental issues associated with specific discharges from hydroelectric facilities. However we question the need for additional numeric limits for oil and grease and pH that are proposed in the Permit. If EPA is going to finalize the Permit, we request that the numeric limits be dropped and that only BMPs be imposed. This would be consistent with other general permits EPA has issued such as general stormwater permits. Also, the proposed numeric limits are not practical for hydroelectric facilities because the discharges covered in the Permit are from only a small portion of the actual discharges from facilities and segregating the discharges for purposes of compliance monitoring is not otherwise practical.

Probably the most concerning and problematic portion of the scope of the Permit is the supposed technology-based limits for cooling water intake structures (CWIS) imposed in the Permit which were derived from EPA's CWIS Rule at 40 CFR Part 125, Subpart J. We incorporate by reference the joint comments by the National Hydropower Association (NHA) and the Utility Water Act Group on the subject Permit regarding the application of the CWIS Rule to hydroelectric facilities. EPA has already publically taken the position that the CWIS Rule does not apply to hydroelectric facilities during development of the CWIS Rule. We believe it is inappropriate for EPA now to reconsider that position in connection with a general permit in Idaho. We are unaware of EPA imposing CWIS requirements for hydroelectric facilities anywhere else in the country and certainly such a limit was not applied in the general hydroelectric permit issued by Region 1 EPA a few years ago. We believe it is inherently unfair for EPA to single out facilities in Idaho for these requirements.

Also, in terms of establishing a case by case technology-based limit (BPJ limit) on hydroelectric facilities (assuming *arguendo* that the small portion of hydroelectric facilities water intakes that is used for cooling may be potentially subject to the CWIS requirements), it does not appear from the Fact Sheet that EPA evaluated the appropriate factors in setting a BPJ limit. For example, it does not appear that there was any cost impact analysis done by EPA to support imposition of CWIS requirements in the Permit nor does it appear that EPA actually evaluated any Idaho-specific hydroelectric facilities to determine if the CWIS requirements were practical or even made sense. As an example, information that would be critical to determining whether some type of CWIS requirement was appropriate for Idaho facilities would be an understanding on the amount of water diverted for cooling water, whether the impact of such diversions could be segregated from the diversion of water for generation of electricity and how the imposition of any CWIS requirement would affect compliance with a facility's FERC license. Failure to consider such information for Idaho facilities is contrary to EPA Guidance on how permit-writers should set BPJ limits. Accordingly for the above reasons, we request that the CWIS requirements in the Permit be removed.

Specific comments

Page 1, First paragraph. Remove reference to "groundwater remediation discharge facilities." This appears to be a typographical error.

I.B. Types of Discharge Covered. Please clarify what is meant by use of the term "backwash strainer water." Solids on backwash strainers, intake screens and trash racks all come from upstream sources and therefore discharges downstream from these features should not be considered a Clean Water Act "discharge" subject to NPDES Permit requirements since there is not an addition of a pollutant. Please clarify what type of backwater strainer water is subject to NPDES Permit requirements.

I.C.3 Facilities Ineligible for Coverage. As noted above, reference to CWIS requirements should be removed from the Permit because the CWIS Rule does not apply to hydroelectric facilities. If EPA decides to leave this provision in place, please revise to make clear that a facility is only ineligible for coverage if cooling water intake structures are designed to divert greater than 2 million gallons per day and the facility uses 25% or more of the water it withdraws for cooling water purposes. If a hydropower facility uses less than 25% of water withdrawn for cooling purposes it should not be disqualified from coverage. This is consistent with the structure of the CWIS Rule.

II.B. Required Information in Notice of Intent., 12. No Dilution Statement. As noted in our general comments, at many facilities, the permitted discharges are combined with water (unpermitted) utilized for the generation of electricity prior to discharge downstream. It may be difficult or impossible for a facility operator to certify no dilution. Please consider removing this requirement from the Permit as it is not required under the Clean Water Act.

II.B.15 Temperature monitoring for discharges to temperature impaired water without a TMDL. At many facilities, the type of temperature monitoring will not have been collected prior to submission of a NOI. Please consider removing this as a condition of filing an NOI but rather include it as a condition of the Permit. If EPA or IDEQ later determines a facility is causing or contributing to temperature violations downstream from cooling water discharges, there are remedies under the Permit to address such a situation.

III.A. Solids. This provision requires solids from trash racks and intake screens to be removed and disposed in accordance with state law. The materials found in the trash racks and intake structures are already in the water and therefore management of this material should not be addressed in a NPDES Permit.

III.A. Monitoring. Please consider changing the frequency of monitoring in Table 1, 2 and 5 to quarterly rather than once per month. Such a monitoring frequency would be consistent with EPA Region 1's general permit. Also consider a provision in the Permit which allows for less frequent monitoring after approval by EPA or IDEQ similar to language in Region 1's general permit. Finally consider deleting Table 4 and replace it with the corresponding requirements in the Region 1 general permit for flood events. Region 1 determined in their general permit that due to safety reasons, effluent limitations and monitoring were not required during flood events. The same safety concerns apply to Idaho facilities.

IV.B. Best Management Practices, 5(b). Tracking of all oil used at a facility (as opposed to oil with a water interface) is not appropriate and burdensome. There are many uses for oil products at a facility (e.g., paint, road maintenance, landscaping, etc.) that will never interface with the water and therefore should not be regulated in the Permit.

IV.B.5.(e). Consider eliminating the provision requiring implementation of purchasing procedures that give preference to EALs. This provision is too vague and it appears inappropriate for EPA to be dictating that a facility purchase a certain type of product in a federal permit. Also the provision appears to be vaguely tied to third party equipment manufacturer warranties. Compliance with a permit provision should not be tied to third party decisions.

Thank you for consideration of our comments. In closing, we believe the Permit is a solution in search of a problem and therefore is not necessary. We are unaware of any discharge-related problems associated with hydroelectric facilities in Idaho. Almost all aspects of hydroelectric facilities are heavily regulated by FERC and any environmental impacts associated with these facilities have already been addressed in FERC licenses and associated environmental impact analyses, 401 certifications and other consultations. We believe it would be inappropriate to move forward with the Permit at this time. However, the industry would welcome the opportunity to meet with EPA and IDEQ to discuss ways to address whatever legitimate concerns may be associated with hydroelectric facilities.

Please do not hesitate to contact me at (503) 545-9420 or at jan@nwhydro.org with any questions or additional follow-up.

Sincerely,

Jan Lee
Executive Director, NWHA

PACIFICORP

Pacific Power |
Rocky Mountain Power
825 NE Multnomah, Suite 1500
Portland, OR 97232

By Fax (206-553-1280) and Email (keenan.dru@epa.gov)

July 11, 2018

Mr. Daniel D. Opalski
Director, Office of Water and Watersheds
U.S. Environmental Protection Agency, Region 10
1200 Sixth Avenue, Suite 155, OWW-191
Seattle, WA 98101

EPA's Proposed NPDES General Permit for Hydroelectric Facilities Within the State of Idaho (IDG360000)

Dear Mr. Opalski:

PacifiCorp respectfully submits the following comments on EPA's proposed NPDES general permit for wastewater discharges from hydroelectric generating facilities in Idaho (No. IDG360000). 83 Fed. Reg. 18,555 (Apr. 27, 2018). PacifiCorp provides electric power to 1.9 million customers in six western states, including more than 77,000 customers in Idaho, where it operates as Rocky Mountain Power. Hydropower is an important component of PacifiCorp's power generation portfolio. We own 41 hydropower facilities with a total generating capacity of 1,135 megawatts (MW), including the Ashton (6.85 MW) and Bear River (77 MW) developments in Idaho.

PacifiCorp appreciates the opportunity to comment on the efforts by EPA and the Idaho Department of Environmental Quality (IDEQ) to develop an NPDES general permit for wastewater discharges from Idaho hydroelectric facilities. As discussed below, however, some of the proposed permit conditions are unclear, impractical, or exceed the appropriate scope of the NPDES program. Hydroelectric facilities are substantially different from the industrial and municipal facilities for which the NPDES program has been developed over the last 45 years. Not only are the systems that generate and discharge wastewater very different, they are only a small component of the complex systems for moving water through hydroelectric facilities to generate power. While wastewater discharges are subject to the NPDES program, discharges for power generation and other purposes are not. PacifiCorp believes that additional thought needs to be given to developing NPDES permit conditions that, in the specific context of a hydroelectric facility, are clear, practical to implement, and regulate only wastewater discharges.

PacifiCorp endorses and incorporates by reference the comments on the proposed general permit submitted by the National Hydropower Association (NHA) and the Utility Water Act Group (UWAG). In addition, PacifiCorp submits the following comments on specific provisions of the proposed permit.

Cover Page

- The reference to "groundwater remediation facilities" in the first paragraph should be removed and replaced with "hydroelectric generating facilities." (In Part VIII of the proposed permit, there is also an inappropriate reference to "groundwater remediation facility" in the definition of "influent.")

Part I

- There is a typographical error in Part I.A. The reference to "Part 0.C" should be to "Part I.C."

- Part I.C.3 would exclude from general permit coverage facilities that use "one or more cooling water intake structures with a cumulative design intake flow of greater than 2 million gallons per day (mgd) ***or*** . . . use 25 percent or more of the water it withdraws for cooling water purposes on an average monthly basis." (Emphasis added.) The stated purpose of this exclusion is to require an individual NPDES permit for facilities that are subject to promulgated cooling water intake requirements pursuant to Clean Water Act (CWA) subsection 316(b). This provision should be deleted or revised for several reasons[1]:

    - As discussed elsewhere in these comments and in the comments submitted by NHA and UWAG, CWA subsection 316(b) cooling water intake provisions are inapplicable to hydroelectric facilities. Accordingly, they should not be a basis for excluding facilities from general permit coverage.

    - Even if hydroelectric facilities were subject to promulgated CWA subsection 316(b) requirements, those requirements apply only to facilities that (a) have "cooling water intake structures with a cumulative design intake flow . . . of greater than 2 million gallons per day; ***and*** . . . [use] "[t]wenty-five percent or more of the water the facility withdraws on an actual intake flow basis . . . exclusively for cooling purposes." *See* 40 C.F.R. § 125.92(a)(2)-(3). *Both* criteria must be met for the requirements to apply—the intake structures must have a cumulative design intake flow of 2 mgd or more *and* 25 percent or more of the actual flow must be used exclusively for cooling purposes. Accordingly, the exclusion, if otherwise appropriate, should read: "Hydroelectric facilities that have cooling water intake structures with a design intake flow of greater than 2 mgd ~~or~~ ***and*** use ~~more than~~ 25% ***or more*** of the withdrawn water ***on an annual intake flow basis exclusively*** for cooling purposes."

---

[1] The accompanying fact sheet states that the proposed exclusion is derived from Idaho's draft CWA section 401 certification conditions for the permit. These comments have also been provided to IDEQ. To the extent that these and other comments on the proposed permit are relevant to the draft section 401 certification, PacifiCorp requests that IDEQ consider and treat them as comments on the draft certification.

to monitor the discharge that is subject to the effluent limit before it combines with a discharge that is not subject to the effluent limit. To address these concerns, the condition could be revised to read as follows: "Include a statement that the owner/operator of the facility will not use dilution as a form of treatment to comply with ***technology-based numeric*** effluent limits in the General Permit. ***This requirement shall not apply to any dilution that results from an inability to practicably monitor a discharge that is subject to a technology-based effluent limit before the discharge commingles with a discharge that is not subject to the limit.***"

- Part II.B.15 would require the NOI to include "continuous temperature data collected over one season with season defined as May 1st through November 1st" for cooling water discharges to waters listed on IDEQ's most recent CWA subsection 303(d) list for temperature and for which no TMDL has been approved. PacifiCorp has several concerns with this requirement:

  - The requirement does not define precisely where the continuous temperature data must be collected. For some facilities, it may not be possible or feasible to monitor cooling water discharges before the discharges combine with other discharges or water flowing through the facility that is not regulated by the permit.

  - This data in itself will be meaningless in the absence of information on background temperatures and dilution and other modeling to determine the contribution of the heat load in the cooling water discharge to receiving water temperatures.

  - Requiring this information to be included in the NOI could delay a facility from obtaining coverage under the general permit for a year or more.

  Any required collection of temperature or other monitoring data should be undertaken after the facility has obtained coverage under the permit. This requirement should be removed from the NOI requirements.[3]

Part III

- Parts III.A.1-6 would prohibit the "discharge" of various materials that would harm designated uses or cause other adverse effects in the receiving water. The permit should clarify that these prohibitions apply only to the discharge of pollutants that are added by the hydroelectric facility and regulated by the permit, and not to pollutants that are passed through the facility from upstream waters, including pollutants contained in facility reservoirs. These pollutants are not regulated by the NPDES permit program. *See, e.g.,*

[3] Idaho's draft section 401 certification includes a condition that would require continuous temperature monitoring data to be included in the NOI. For the reasons described in the text, PacifiCorp asks that IDEQ delete or revise this condition of the draft certification.

National Wildlife Fed'n v. Consumers Power Co., 862 F.2d 580, 584 (6th Cir. 1988); *National Wildlife Fed'n v. Gorsuch*, 693 F.2d 156, 165 (D.C. Cir. 1982).

- Parts III.A.7 would require solid materials to be removed from trash racks and intake screens and disposed of in accordance with best management practices (BMP) developed pursuant to Permit Appendix C, Part 9. Although it may be appropriate, in order to prevent materials from reentering waters of the United States, to regulate materials that a facility removes from trash racks and screens, the permit cannot regulate materials that a facility merely passes downstream or require the facility to remove trash and other materials from waters of the United States. To address this concern, this condition could be revised as follows: "Solid materials ~~shall be~~ ***that a facility removes*** ~~removed~~ from ~~the~~ trash racks or intake screens and ***from waters of the United States shall be*** disposed of in accordance with . . . ."

- Part III.A.8, Table 1, would require cooling water effluent monitoring, as well as "intake/control gate" monitoring for temperature. It may not be possible or feasible, however, to monitor cooling water effluent in isolation or to monitor temperature at "intake/control gates." The permit does not clearly define these locations or provide for alternative sampling locations in the event that sampling at the specified locations is not feasible. In addition, for facilities that have multiple cooling water discharge outfalls of approximately the same size and type, the permit should include an option for monitoring only one of these discharges if the NOI designates the outfall to be monitored and provides a justification that the thermal component of the discharge from that outfall will be similar to the thermal component of the outfalls that are not monitored.

- Parts III.A.8-12, Tables 1-5. The proposed effluent limits specified in these tables should be applied only to pollutants added by the facility and not merely passed through the facility from upstream waters, including pollutants contained in facility reservoirs. These pollutants are not regulated by the NPDES permit program. *See, e.g., National Wildlife Fed'n v. Consumers Power Co.*, 862 F.2d 580, 584 (6th Cir. 1988); *National Wildlife Fed'n v. Gorsuch*, 693 F.2d 156, 165 (D.C. Cir. 1982).

- Parts III.A.8-12, Tables 1-5. The fact sheet states that the permit's monthly sampling frequency requirement is to determine the monthly variability of the discharge, but this in itself does not justify monthly sampling. Because the pollutant discharges that are authorized by the permit are unlikely to vary substantially from month-to-month because of the characteristics of the operations that generate the pollutants, the monthly sampling requirement should be changed to quarterly absent a justification for more frequent sampling.

- Part III.A.8, Tables 1-5. The notes to each table refer to quarterly monitoring, but none of the tables requires quarterly monitoring.

- Part III.A.12, Table 5. Monitoring combined effluent discharged through a plant sump will be often be infeasible or impossible because the sump operates much like a large oil-water separator with a pump pulling from the bottom of the sump and discharging underwater into the tailrace. A sample taken from the surface of the sump will not be representative of the discharge.

Part IV

- Part IV.B.5 would require the permittee to implement best management practices or other measures that "ensure" compliance with a host of requirements that are either vague or unreasonable or both. For example, IV.B.5(a) would require BMPs to "ensure" that oil, grease, and hydraulic fluids from "all sources" "do not enter the river," apparently in any amount, regardless whether this is feasible or necessary to meet water quality standards. Yet, Part IV.B.5(c) would require only BMPs that "minimize the leaking of hydraulic oil or other oils." As other examples, Part IV.B.5(d) would require the permittee to "reduce" its reliance on lubricants that come into contact with river water, and Parts IV.B.5(e) and IV.B.5(j) would require a "preference" for "environmentally acceptable lubricants" and PCB-free lubricants, paint, and caulk, but there are no criteria for evaluating what reductions are required or for exercising these preferences. The vagueness or infeasibility or both of these requirements leaves permittees unfairly exposed to agency enforcement actions and citizen suits even if they attempt to comply in good faith with the requirements. To prevent this, the requirements should be stated more clearly and objectively, and the permit should include a provision stating that a permittee's compliance with the BMPs specified in its BMP Plan constitutes compliance with Part IV.B of the permit. Such a "plan shield" would not be inconsistent with NPDES permit requirements because Part IV.B.3(c) authorizes EPA to require changes in the BMP Plan "at any time" if EPA determines that the BMP Plan does not meet the minimum requirements of Part IV.

- Part IV.B.6 would require a written report to EPA and IDEQ of a "BMP incident" within 7 days after "the incident has been successfully addressed." The permit, however, does not describe or define a "BMP incident." If this requirement is retained, the permit should define what constitutes a reportable "BMP incident."

- Part IV.C. includes requirements for cooling water intake structures. As discussed above in the comments on Part I.C.3, these provisions are inappropriate for hydroelectric facilities. Moreover, what constitutes a "cooling water intake structure" in the context of a hydroelectric facility is not sufficiently defined or described. For example, the requirements of Part I.C.3 should not apply to penstocks and other conveyances that pass water through or around a dam for power generation simply because a small amount of this water is diverted for equipment cooling.

- Part IV.C.2(b) would require management of "tailrace operations to prevent fish access to the draft tube areas to minimize injury of fish and other aquatic species." Whatever "cooling water intake structure" may mean in the context of hydroelectric facilities, it does not include the facility's tailrace, which is the discharge from the facility. Even if CWA subsection 316(b) requirements applied to hydroelectric facilities, Part IV.C.2(b) is beyond the scope of subsection 316(b) and EPA's implementing regulations. Moreover, the discharge from the tailrace is not a discharge that is subject to regulation under the

NPDES program. *See, e.g., National Wildlife Fed'n v. Consumers Power Co.*, 862 F.2d 580, 584 (6th Cir. 1988); *National Wildlife Fed'n v. Gorsuch*, 693 F.2d 156, 165 (D.C. Cir. 1982). Accordingly, Part IV.C.2(b) should be removed from the permit.

Thank you very much for considering these comments.

Sincerely,

Mark Sturtevant

Mark Sturtevant
Managing Director, Renewable Resources

cc: Mr. Loren Moore, IDEQ (Loren.Moore@deq.idaho.gov)
Mr. Barry Burnell, IDEQ (barry.burnell@deq.idaho.gov)
Ms. Lyn VanEvery, IDEQ (lyn.vanevery@deq.idaho.gov)
Ms. Dru Keenan, EPA Region 10 (keenan.dru@epa.gov)
Mr. John Chatburn, Idaho Governor's Office of Energy and Mineral Resources (IOEMR) (john.chatburn@oer.idaho.gov)

Pollow, George

From: Chip Bloomer <Chip.Bloomer@pgn.com>
Sent: Wednesday, July 11, 2018 8:39 AM
To: Keenan, Dru
Subject: Draft General Permit No. IDG360000 – PGEs Comments

Dear Mr. Keenen:

Portland General Electric Company (PGE) appreciates the opportunity to comment on the draft general hydropower Permit No. IDG360000. PGE operates several hydropower plants in the Pacific Northwest, and as such supports the comments submitted by the Northwest Hydro Association (NWHA).

Respectfully,

Chip Bloomer
Senior Environmental Project Specialist
Portland General Electric Company

Region 10 EPA Tribal Consortium (RTOC)
2206 W. Sherman St. Spokane, WA 99203
Coordinator Phone: 907-512-9446
rtoccoordinator@region10rtoc.net
www.region10rtoc.net

June 11, 2018

Director, Office of Water and Watersheds
USEPA Region 10
1200 Sixth Avenue, Suite 155, OWW-191
Seattle, WA 98101

RE: Proposed Issuance of NPDES General Permit for Hydroelectric Facilities within the State of Idaho Docket ID No. FLR-9977-16-Region 10

Dear Madam or Sir:

This letter is sent on behalf of the Tribal Caucus members of EPA Region 10's Tribal Operations Committee (RTOC). This letter is not sent on behalf of EPA Region 10 or any employees of EPA, but solely tribal government representatives of the RTOC. These comments are submitted in response to the request for public comment regarding "Proposed Issuance of NPDES General Permit for Hydroelectric Facilities within the State of Idaho," Docket No. FLR-9977-16-Region 10.

The Region 10 RTOC includes Tribes across Alaska, Washington, Idaho, and Oregon. Clean water is essential to many Tribes, not just as a source of sustenance, but also for cultural, medicinal, and spiritual reasons. The ability of Tribes to control pollution and protect water quality is vital to the survival of Tribes. Almost no activity on the reservation has more potential for significantly affecting the economic and political integrity and the health and welfare of all reservation citizens than water use, quality, and regulation.

The chemical, thermal and physical changes which flowing water undergoes when it is dams have serious impacts on water quality and fisheries. Slow-moving or still reservoirs can heat up, resulting in abnormal temperature fluctuations which can affect sensitive species. This can lead to algal blooms and decreased oxygen levels. Other dams decrease temperatures by releasing cooled, oxygen-deprived water from the reservoir bottom.

RTOC strongly supports the adoption of this proposed NPDES permit. We believe this is an important first step toward fulfilling the substantive requirements of the Clean Water Act.[1] The drafters of the Clean Water Act use the word integrity. This means that Idaho's waterways must

[1] 33 U.S.C.S. § 1251(The issue is how to implement a streamlined permitting process without compromising the biological, chemical, and physical integrity of Idaho's waterbodies).

to be pure, sound, and unimpaired.[2] This commitment to integrity extends to the health of all species impacted by dams, including the bull trout, Chinook salmon, Snake River sockeye salmon, and Kootenai River white sturgeon.[3]

a. Expand List of Pollutant Sources Covered and Add Conditions

The proposed permit would enable hydroelectric generating facilities to legally discharge pollutants into rivers including cooling water, drain water, maintenance water, backwash strainer water, and combinations thereof.[4] The RTOC requests that the permit be expanded to include the list of pollution sources identified in the August 4, 2014 settlement between the Columbia Riverkeeper and the Army Corps,[5] specifically the permit should address discharges from powerhouse drainage sumps, unwatering sumps, spillway sumps, navigation lock sumps, wicket gate bearings, turbine blade packing/seals, and discharges of cooling water systems. Moreover, the permit should require the following actions to reduce potential pollution from the dams:

1. Environmentally Acceptable Lubricants ("EALs"): Require dam owner/operators to use EALs on "in-water" equipment, including wicket gates for the hydropower turbines and fishway equipment.

2. Oil Accountability Plans: The dam owner/operator should develop an Oil Accountability Plan ("OAP") intended to account for oils and greases used, including the oils and greases used in the turbines, wicket gate bearings, and fishway equipment.

b. Minimize Impacts of Fish

The fact sheet states that the proposed permit is unlikely to affect fish, snails, and a rare species of orchid "adversely."[6] This potential impact on the fish—however small—is of primary interest to Tribes.[7] Where other species are critical to maintaining the balance of a holistic ecosystem that includes the fish, we are concerned about any change in that ecology. That said, an initial

---

[2] *Integrity*, Blacks Law Dictionary (10th ed. 2014).
[3] *Nota bene* that bull trout are a threatened species
[4] *Proposed Issuance of NPDES General Permit for Hydroelectric Facilities Within the State of Idaho*, 83 Fed. Reg. 18555 (proposed Apr. 37, 2018); *See Idaho Dairymen's Ass'n v. Gooding Cty*., 148 Idaho 653, 659, 227 P.3d 907, 913 (2010) (the [Clean Water Act] allows states, including Idaho, to certify that projects requiring a NPDES permit comply with state water quality standards); *S. D. Warren Co. v. Me. Bd. of Envtl. Prot*., 547 U.S. 370, 373 (2006) (federal licensing of hydroelectric dams held to require state certification, under § 401 of Clean Water Act (33 U.S.C. § 1341), that operation of dams would not violate federal or state water-protection laws).
[5] Available at https://www.columbiariverkeeper.org/sites/default/files/2014/08/Proposed-Order-with-Settlement-Agreement.pdf.
[6] Wastewater Discharges from Hydroelectric Generating Facilities General Permit NPDES Fact Sheet, (EPA Publication No. IDG360000), 30-31.
[7] *See United States v. Washington*, 506 F. Supp. 187, 192 n.11 (W.D. Wash. 1980) ("Are you not my children and also children of the Great Father? What will I not do for my children, and what will you not for yours? Would you not die for them? This paper is such as a man would give to his children and I will tell you why. This paper gives you a home. Does not a father give his children a home? This paper secures your fish? Does not a father give food to his children?"); *No Oilport! v. Carter*, 520 F. Supp. 334, 371-72 (W.D. Wash. 1981) ("a duty is imposed upon the United States 'to refrain from degrading the fish habitat to an extent that would deprive the tribes of their moderate living needs.'").

evaluation suggests that the risk to the fish and other species is low.[8] The permit should be conditioned to minimize any and all impacts to fish. It is because the survival of fish is imperative for our physical, cultural, and spiritual health that we advocate here for permitting that retains an active and present dialogue with place.

We appreciate your consideration of these comments.

Sincerely,

William (Billy) J Maines

William (Billy) J. Maines
Region 10 RTOC, Tribal Caucus Co-chair

---

[8] See Jeffrey M. Gaba, *Generally Illegal: NPDES General Permits Under the Clean Water Act*, 31 HARVARD ENVIRONMENTAL LAW REVIEW 409 (2007) (discussing the potential policy concerns that could arise as a consequence of generalized NPDES permitting).

July 11, 2018

Daniel D. Opalski, Regional Director
Office of Water and Watersheds
U.S. EPA, Region 10
1200 6th Ave, Suite 1555
OWW-191
Seattle, WA 98101

Re: USACE Comments to EPA's DRAFT Proposed Issuance of NPDES General Permit for Hydroelectric Facilities within the State of Idaho (IDG360000)

Dear Mr. Opalski:

The U.S. Army Corps of Engineers (Corps) offers the following comments on the Draft General Permit referenced above:

Comment 1
Reference Section III. Effluent Limitations, Monitoring and Reporting Requirements:

Tables 1 through 5 appear to require monitoring no less frequently than once per month or event, but each table also includes a note referring to quarterly monitoring, indicating that less-frequent monitoring may be sufficient. Monthly effluent monitoring may pose an unnecessary burden to the hydroelectric operator. Given that changes occur infrequently, quarterly monitoring provides a reasonable time period and would still satisfy permit goals. Suggest monitoring period be extended from monthly to quarterly.

Comment 2
Reference Section III.A.8. Effluent Limitations, Monitoring and Reporting Requirements for Non-Contact Cooling water.

Cooling water outfalls at large hydroelectric facilities are numerous and homogeneous. Monitoring one or two outfalls will serve the same purpose as monitoring every outfall and will eliminate the burden and expense to the operating project. Recommend modifying requirement for facilities with multiple and similar outfall locations to include a representative sample of outfalls at a facility.

Comment 3
Reference Section III.A.10. Effluent Limitations, Monitoring and Reporting Requirements for Maintenance-related Water.

Requirement for monitoring maintenance-related outfalls is not feasible where unwatering pumps run continuously or on frequent cycles. Complying with this section is not practicable due to the requirement to sample each maintenance event. Recommend clarification or elimination of this effluent limitation and monitoring restriction.

Comment 4

Reference Section III.A.11 Effluent Limitations and Monitoring Requirements for Facility Maintenance-Related Water during Flood/High Water Events and for Equipment-Related Backwash Strainer Water and III.A.12 Effluent Limitations, Monitoring and Reporting Requirements for any Combination of the Following: Cooling Water, Equipment and Floor Drain Water, Maintenance-Related Water, and Maintenance-Related Water during Flood/High Water Events and Equipment-Related Backwash Strainer Water.

Text of these sections state: “Monitoring for equipment-related backwash strainer water is not required.” Recommend eliminating any reference to back wash strainer from the title of this sections and eliminate back wash strainer from the permit since monitoring is not required.

Comment 5

Reference Section III.A.12. Effluent Limitations, Monitoring and Reporting Requirements for any Combination of the Following: Cooling Water, Equipment and Floor Drain Water, Maintenance-Related Water, and Maintenance-Related Water during Flood/High Water Events and Equipment-Related Backwash Strainer Water.

It is unclear whether flood/high water refers to conditions on the river or the powerhouse, so recommend further clarification or definition.

Comment 6

Reference Section IV. B.5.d) Best Management Practices (BMP) special requirement: “Reduce the reliance on lubricants for all facility equipment that come in contact with river water such as spill gate mechanisms, turbine gate mechanisms, etc.”

This special condition is vague and likely not enforceable as written. Without clarifying the term "reduce the reliance on lubricants", permittees may be unable to demonstrate compliance. Additionally, while reduction may be practicable, elimination of lubricants is not achievable. Please eliminate this special condition, or modification to acknowledge that reduction of lubricant use may not be possible or that reduction of lubricant use is done to the extent practicable.

Comment 7

Reference Section IV.B.5.e) Best Management Practices (BMP) special requirement: “Implement purchasing procedures that give preference for Environmentally Acceptable Lubricant (EAL) for all oil to water interfaces, unless technically infeasible.”

This special requirement needs further clarification. The term “technically infeasible” should be further defined to account for risk involved in switching to EALs on high risk equipment without adequate testing. Recommend that determination of "technically feasible" be left to the operator’s discretion, pending testing, to prevent risk of equipment failure. If this BMP is simply intended to require a policy that EALs be considered when selecting oil-based lubricants, then further clarification is needed. Additionally, the BMP should focus on the application of lubricants in oil to water interfaces, not “purchasing procedures.” Recommend replacing the term “purchasing procedures” with another term, such as “utilization” or “selection” of lubricants.

Comment 8
Reference Section IV.C.2.b). Special Conditions, Minimize the Impact of Entrainment and Impingement of Cooling Water Intake Structure.

Most Corps hydroelectric dams do not have the technical capability to shut down access to draft tube areas. At Corps facilities a slow roll to flush fish is performed before installing stop logs, followed by fish salvage activities. Recommend revising draft permit language to the following: “Employ best management practices to limit fish access to draft tube areas to minimize injury to fish and other aquatic species."

Comment 9
Reference Section V.A.3. General, Monitoring, Recording and Reporting Requirements, Representative Sampling (Routine and Non-Routine Discharges).

Collecting samples as soon as every spill or discharge event reaches an outfall may not be possible. Spills are often not detected without a sheen, and may not be immediately recognized. These situations would be handled in accordance with hydropower dam spill plans. Please eliminate this requirement or attaching limiting clauses such as “as soon as possible,” and “To the extent operator is capable of doing so without jeopardizing operations, the operator shall collect samples.”

Respectfully submitted,

David J. Ponganis SES
Programs Director
Northwestern Division, USACE

United States Department of the Interior

BUREAU OF RECLAMATION
Pacific Northwest Region
Snake River Area Office
230 Collins Road
Boise, ID 83702-4520

IN REPLY REFER TO:

JUL 1 1 2018

PN-6520
2.1.4.13

VIA ELECTRONIC MAIL ONLY

Mr. Dan Opalski
Director, Office of Water and Watersheds
Environmental Protection Agency, Region 10
1200 Sixth Avenue
Seattle, WA 98101

Subject: Comments on the National Pollution Discharge Elimination System (NPDES) General Permit (GP) for Hydroelectric Generating Facilities General Permit

Dear Mr. Opalski:

The Bureau of Reclamation appreciates the opportunity to review the Draft NPDES General Permit IDG360000 for Hydroelectric Generating Facilities. Reclamation commends the Environmental Protection Agency (EPA) for attempting to find a reasonable permitting approach for the implicated federal facilities. We write here to express some concerns over the proposed GP requirements which, as crafted, place unnecessary financial burdens on the American taxpayer and hydroelectric energy rate payers. Reclamation's specific comments and suggestions are attached and summarized herein.

The Biological Evaluation (BE), a document prepared by the EPA for the U.S. Fish and Wildlife Service, that accompanied the draft GP Permit raised some concerns for Reclamation. The studies presented in the document found that, of the previous facilities where such water quality data exists, no facilities posed a serious water quality concern as it related to pH, oil and grease, or temperature. The EPA repeatedly stated in the BE that it had concluded that none of the pollutant discharges listed in the GP (i.e., temperature, pH, and/or oil and grease) posed adverse effects to any species of concern and often, such as in the case of oil and grease, were "magnitudes of concentration lower than where effects are likely to adversely affect [them]." Reclamation believes that the EPA's studies, as presented, indicate that hydroelectric facilities pose a very low risk to receiving waters and that the low level of risk should be reflected in the scope and frequency of monitoring required in the permit.

The proposed monitoring requirements of all cooling water intakes and all facility outfalls for 1-hour continuous temperature data; monthly oil and grease, and monthly pH are unnecessary to provide reasonable assurance that they do not interfere with attainment of water quality targets.

Reclamation suggests that, at the very least, the monitoring frequency and extent should be reduced. Reclamation proposes representative sampling on a quarterly basis. Additionally, the Notice of Intent (NOI) portion of the process should allow for the exemption of small, inaccessible, or dangerous outfall locations from regular monitoring.

As a general matter, Reclamation's reservoirs are slightly stratified and cool the river water downstream of its associated hydroelectric facilities. Reclamation's hydroelectric facility penstocks take water from depth. This water is generally much cooler than surface water. Moreover, these releases of cooler water do not even qualify as regulated discharges. Reclamation suggests that temperature measurements need only be taken in two locations: (1) a surface forebay location above the dam, and (2) at a well-mixed location downstream of the hydroelectric facility. This monitoring methodology would supply the EPA with the most realistic assessment of hydroelectric facility impacts to receiving waters. It would also be the most cost-effective method for rate and tax payers.

Additionally, the GP proposes an impractical time table for completing a NOI and permit application which borders on the impossible. For instance, the draft GP requires that an NOI must be completed within 90 days of the issuance of the final NPDES permit and that the initial GP be completed within 180 days. The Idaho Department of Environmental Quality and the EPA require six months of continuous temperature data to be submitted as part of the initial NOI. Reclamation does not currently collect continuous temperature data on cooling water structure intakes or facility outfalls. Hourly temperature collection at every cooling water intake structure would require extensive retrofitting on many of its facilities. This time frame is impractical and does not allow sufficient time to comply with the permit requirements because Reclamation does not currently possess this data.

Reclamation appreciates the opportunity to provide comments to assist in improving the permit. However, given the short timeframe outlined in the proposed permit process, Reclamation would like to request a meeting with the EPA to discuss the broader implications of the permit prior to the final draft release. Reclamation requests that you have someone from your staff contact Mr. Alan Monek, Water Quality Coordinator, at 208-685-6926 or amonek@usbr or myself at 208-383-2246 to set a date that best accommodates your staff's schedule.

Sincerely,

ACTING FOR

Roland K. Springer
Area Manager

Attachment - 1

Comment #	Document	Page	Citation	Restriction	Reclamation Comment
1	Fact Sheet	13	I. A.	"A hydroelectric generating facility includes the generating station (station), dam(s), reservoir(s), canal system or tunnel system..."	**Page 13 of the Fact Sheet defines a hydroelectric generating facility as "the generating station (station), dam(s), reservoir(s), canal system or tunnel system..."** **Will monitoring be required at all 'facility' discharges, such as agricultural diversion canals, if oil/grease are used on wire ropes, radial gates, etc.? Can this requirement exist in a BMP document, yet not be enforceable through the permit? If so, is it a condition of the General Permit that should be stated?** **Reclamation suggests adding language to the permit that provides clarification about what portions of the facility must and which portion might not require monitoring. Please provide examples in the language.**
2	Fact Sheet	13	I.A.	"A hydroelectric generating facility includes the generating station (station), dam(s), reservoir(s), canal system or tunnel system..."	**Hydroelectric facilities' penstocks are located at depth in the reservoir waterbody and thus send cooler water to the downstream receiving waterbody than would otherwise be the case. If reservoirs are considered a part of the hydroelectric facility, than it should be acknowledged that this cooling effect will ALWAYS far exceed any de minimus temperature increases from facilities' cooling system(s).** **If EPA and IDEQ are concerned about "accurately calculating thermal loading to the receiving [water]body", the appropriate monitoring location(s) would be upstream and downstream of the hydroelectric facility. Reclamation believes that this is the most accurate and reasonable method to determine the impacts to the receiving waterbody.** **Reclamation suggests using surface forebay water temperatures (upstream) and river gaging station temperatures (downstream) at a well-mixed location for the identification of facility impacts to receiving waterbodies. Reclamation could provide QA/QC temperature data at these two locations (Reclamation currently collects this data below some facilities). Tax and ratepayer costs would be much more reasonable and a more accurate accounting of the true impacts to the receiving waterbody could be ascertained.**
3	Fact Sheet	15	II.B. Types of Pollutants	"The pollutants associated with wastewaters from the above discharges are oil, grease, excess heat (temperature), pH, and debris..."	**Will the permit require temperature monitoring at every drain outfall? Monitoring very small outfall drains will be overly burdensome to facilities when the impact of such drains is insignificant. EPA states in the Biological Evaluation that hydroelectric facilities would likely contribute a "de minimus temperature increase and would not result in an impact on the receiving water's support of aquatic uses or specifically, the species of concern."** **Given that EPA has already concluded that temperature additions from hydroelectric facilities will be 'de minimus', Reclamation would like to see a minimum discharge over which temperature monitoring will be required (e.g. 1 cfs).**
4	Fact Sheet	16	III.C. Surface Water Criteria	"The narrative criteria applicable to all surface waters of the State..."	**Page 16 of the Fact Sheet states, "Floating, Suspended, or Submerged Matter: Surface waters of the State shall be free of floating, suspended, or submerged matter of any kind in concentrations causing nuisance or objectionable conditions."** **Would a facility (i.e. "generation station, dam, reservoir") be held accountable for contributing to nuisance algae above/below the dam due to normal operations as a part of the permit? This requirement should be more properly addressed in a TMDL than a General Permit.** **Reclamation requests that EPA add language to the permit or fact sheet to clarify and address the questions listed above.**
5	Fact Sheet	19	IV.C. Coverage Under Individual NPDES Permit	"...applications must be submitted no later than 180 days prior to anticipated discharge."	**General and Individual permit timeframes are unrealistic. Many facilities will require retrofitting to collect continuous temperature data. EPA should consider offering an administrative extension of a minimum of 1 year for the first year of the General Permit for large facilities to accommodate contracting, installation and data collection.**
6	Fact Sheet	21	V.B.8 Facility Information	"IDEQ requested in their draft 401 Certification that the EPA include a requirement that hydroelectric facilities discharging to waters listed on IDEQ's most recent 303(d) list for temperature and for which a temperature TMDL has not been approved must submit"..."continuous temperature data collected for one season with season defined as May 1 through November 1."	**Given the short timeframe for compliance with the GP once it is released (180 days), Idaho's 401 Certification for continuous temperature data from the previous year is not realistic since few or none of the facilities are currently collecting this data. Reclamation suggest that we provide our best available data as part of the NOI application such as forebay/downstream surface water temperatures.** **This requirement will also be addressed in the State's 401 Certification document.**
7	Fact Sheet	23	VI.B.	"Effluent limitation guidelines have not yet been developed by EPA for hydroelectric generating facility discharge."	**Effluent limitation guidelines should be developed BEFORE a General Permit is required or issued for hydroelectric facilities. Studies presented in the Biological Evaluation suggest that the facilities will not have a measurable impact on water quality with respect to temperature, oil & grease, or pH; however, Reclamation and rate/tax payers will incur a financial burden for what appears to be a study. Science-based guidelines should be developed and presented in the draft permit before it is finalized.**

Comment #	Document	Page	Citation	Restriction	Reclamation Comment
8	Fact Sheet	24	VI.B.Temperature	"In this first issuance of the General Permit, the EPA is proposing only a monitoring requirement for temperature. **The EPA does not believe temperature discharges will cause an exceedance of the temperature standard based on review of similar facilities' monitoring reports.** The EPA will review the collected temperature data from the monitoring reports and determine if an effluent is necessary when the General Permit is up for renewal in five years after it is issued."	Page 24 of the Fact Sheet states, "In this first issuance of the General Permit, the EPA is proposing only a monitoring requirement for temperature. The EPA does not believe temperature discharges will cause an exceedance of the temperature standard based on review of similar facilities' monitoring reports. The EPA will review the collected temperature data from the monitoring reports and determine if an effluent is necessary when the General Permit is up for renewal in five years after it is issued." Based on previous reviews, EPA does not believe temperature inputs from hydroelectric facilities will cause any significant temperatures or will affect species of concern (also stated in the Biological Evaluation). Reclamation expects the new reporting requirements related to temperature will result in significant additional costs. All facilities will require expensive retrofitting to capture intake & outlet temperatures and ongoing reporting requirements will require significant labor costs. The temperature monitoring requirement is being proposed for a stated non-issue. Page 24 of the Fact Sheet states "EPA does not believe temperature discharges will cause an exceedance of the temperature standard base on review of similar facilities' monitoring reports." Further, the previous studies, summarized on Page(s) 47-48 found temperatures to be "de minimus" and not likely to affect aquatic life or any species of concern." Reclamation suggests that these costly requirements be removed from the permit until a sound scientific basis can be presented for their addition into the permit. If temperature must still be measured to provide reasonable assurance to the State, Reclamation suggests that the level of monitoring (e.g. 1-hr at all outfalls) be reduced in scope and frequency. See Comment 2 and Comment 3.
9	Fact Sheet	26	VII. Basis for Effluent and Surface Water Monitoring	"Section 308 of the CWA…require monitoring in permits to determine compliance with effluent limitations. Monitoring may also be required to gather effluent and surface water data to determine if additional effluent limitations are required and/or to monitor effluent impacts on receiving water. IDEQ is requesting in their draft 401 Certification of this General Permit that the EPA include a requirement that the permittee monitor the intake water at the point of intake or control gate for temperature."	Page 26 of the Fact Sheet states, "Section 308 of the CWA…require monitoring in permits to determine compliance with effluent limitations. Monitoring may also be required to gather effluent and surface water data to determine if additional effluent limitations are required and/or to monitor effluent impacts on receiving water. IDEQ is requesting in their draft 401 Certification of this General Permit that the EPA include a requirement that the permittee monitor the intake water at the point of intake or control gate for temperature." This temperature monitoring requirement that temperature be taken at the control gate is burdensome and expensive. It will require retrofitting existing facilities. If IDEQ is interested in determining if any temperature impacts are discernible, Reclamation would suggest that permittees be allowed to monitor temperatures in dam forebays and at the gages below the dam where both are already present. Years of past data exist for these locations in Reclamation facilities. Measurements at these locations would describe if any downstream effects can be witnessed in waters below the facilities. See comments 2, 3 & 8.
10	Permit	N/A		Power production is often incidental to irrigation water. Turbines are often shut off in the winter while the reservoir fills. Will monthly sampling/hourly temperature data collection be required at the unit intakes/outfalls during periods in which the units are offline?	Power production is often incidental to irrigation water. Turbines are often shut off in the winter while the reservoir fills. Will monthly sampling/hourly temperature data collection be required at the unit intakes/outfalls during periods in which the units are offline? Will monitoring be required for units when they are out of service? Reclamation requests clarification for monitoring requirements for either units temporarily out of service or decommissioned units. These requirements should be clearly addressed in the General Permit and/or Factsheet.
11	Permit	8	I.A.C.3 Facilities Ineligible for Coverage	"The facility uses or proposes to use one or more cooling water intake structures with a cumulative design intake flow of greater than 2 million gallons per day (mgd) or the facility uses 25 percent or more of the water it withdraws for cooling water purposes on an average monthly basis."	Reclamation does not understand the language that determines ineligibility of facilities under the general permit. The language found on Page 8 of the Permit states, "The facility uses or proposes to use one or more cooling water intake structures with a cumulative design intake flow of greater than 2 million gallons per day (mgd) or the facility uses 25 percent or more of the water it withdraws for cooling water purposes on an average monthly basis." Reclamation suggests defining what constitutes a facility withdrawal and better state the 25% requirement. Also, it might be more easily understood if these statements are presented in the affirmative (Eligible requirements instead of Ineligible requirements).
12	Permit	10	II. A. 1.	"...in accordance with the requirements listed in Part I.R of this Permit."	There is a reference to Part I.R on Page 10 that does not exist in the document. Please correct.
13	Permit	11	II. B. 5.	"...number of turbines and the combined turbine discharge (installed capacity)"	Will monitoring be required for units when they are out of service? Reclamation requests clarification for monitoring requirements for either units temporarily out of service or decommissioned units. Reclamation suggests that if decommissioned units are identified in the NOI, the facility should continue to be covered under the General Permit and a new Individual Permit would not be required if the units are brought back online.

Comment #	Document	Page	Citation	Restriction	Reclamation Comment
14	Permit	12	II.B.15.	"Hydroelectric facilities that discharge to waters listed on IDEQ's most recent 303(d) list for temperature and for which a temperature TMDL has not been approved must submit the following temperature data collected from their cooling water discharges with their NOI to IDEQ: a. Continuous temperature data collected over one season" (May-Nov).	Page 12 of the Draft General Permit states, "Hydroelectric facilities that discharge to waters listed on IDEQ's most recent 303(d) list for temperature and for which a temperature TMDL has not been approved must submit the following temperature data collected from their cooling water discharges with their NOI to IDEQ: a. Continuous temperature data collected over one season" (May-Nov). Reclamation does not currently collect this specific data and extensive retrofitting will be required before such data can be collected. Reclamation does sometimes have temperature data at forebay and downstream gaging station temperature readings and would suggest using this type of data, where available, at the time of NOI application for these circumstances. Reclamation suggests that best available data be sufficient for initial General Permit application purposes.
15	Permit Fact Sheet	15-17 24	Tables	There is some divergence in the permit from the justification in the Fact sheet. The Fact sheet states that EPA believes that a MONTHLY AVERAGE of 10 mg/L is appropriate for oil and grease sheen.	There is some divergence in the permit from the justification in the Factsheet. The Factsheet states that EPA believes that a MONTHLY AVERAGE of 10 mg/L is appropriate for oil and grease sheen (see Tables on pages 15-17 of the GP vs Page 24 of the Fact Sheet). Page 24 of the Factsheet states, "EPA has established average monthly oil and grease limitations of 10 mg/L to represent the concentration at which there is an oil sheen on surface waters. The Region believes that this limit is a reasonable standard for facilities that have a reasonable potential for oil and grease discharge. Oregon and Washington have similar narrative criteria." Please provide a justification for why the GP requirement of 10 mg/L (DAILY AVERAGE) is used when the basis for the concentration requirement is an EPA monthly concentration average. Also, how is the daily average calculated when only 1 grab sample per month is collected. Will this daily concentration be based twelve once-a-month grab sample measurements? Please clarify these discrepancies.
16	Permit	15-17	Table 1-5	All tables have a sub note about quarterly monitoring, but all monitoring is either monthly or by event.	Permit tables located on pages 15-17 have sub notes about quarterly monitoring requirements; however, no quarterly monitoring requirements are listed in the tables-only monthly requirements. Monthly oil & grease and pH requirements pose an unnecessary financial hardship on tax/rate payers. Quarterly monitoring would be just as representative and much more cost effective and is the regulatory/industry standard. Additionally, many lubrication systems are on automatic pumps. It may be less burdensome and more accurate to track lubricant usage and water discharge through each component to come up with a more accurate average concentration for oil and grease. Reclamation suggests reconsidering periodic frequency of monitoring events and alternate methods for determining oil & grease concentrations.
17	Permit	22	IV. B. 8. b	Part VI. G. (Signatory Requirement).	On page 22 of the General Permit, Part VI.G. (Signature Requirement) should read Part VII.G. Update General Permit language to reference proper section.
18	Permit	26	V. C. 2.	with requirements of Part VIII.G	On page 26 of the General Permit, Part V.C.2 (Signature Requirement) should read Part VII.G. Update General Permit language to reference proper section.
19	Permit	45	Appendix A. Table	ML for TSS is listed.	Page 45 of the General Permit, Appendix A. table lists TSS. This is not a requirement of the General Permit and should be removed.
20	Bio Eval	10	Equipment and Floor Drain Water	"These discharges can be intermittent and seasonal and the outfalls in certain stations can be inaccessible for sampling purposes."	EPA states on Page 10 of the Biological Evaluation, "These discharges can be intermittent and seasonal and the outfalls in certain stations can be inaccessible for sampling purposes." There are indeed challenging areas in many of our dams that are difficult or impossible to sample. Reclamation suggests a process for exempting outfalls from monitoring requirements that may jeopardize the safety of its employees in the event that measurements are required--perhaps through the NOI outfall identification process.
21	Bio Eval	43-47	5.3.Determining Receiving Water as a Result of Permit Limits: Oil and Grease	"The EPA gather data from existing permitted hydro-electric facilities and permit applications and used the data to determine exposure concentrations resulting from the proposed effluent limits and then compared those results with known effect endpoints of the species of concern...From the data gathered, the EPA derived the percentage of effluent flow (outflows covered by the permit) to total hydro-electric facility discharge flow...the significance of these differences is that the concentration of any pollutant present in the discharges would be greatly diluted once the discharges are combined." "Using the median flow volume and the maximum oil and grease concentration results in an oil and grease concentration of 0.0013 mg/L. The median flow and average oil and grease value result in a calculated oil and grease concentration of 0.0003 mg/L. When combined with the critical flows examined above, the expected oil and grease concentrations are many orders of magnitude below any concentrations of concern."	EPA states on Pages 43-47 in the Biological Evaluation, "The EPA gather data from existing permitted hydro-electric facilities and permit applications and used the data to determine exposure concentrations resulting from the proposed effluent limits and then compared those results with known effect endpoints of the species of concern...From the data gathered, the EPA derived the percentage of effluent flow (outflows covered by the permit) to total hydro-electric facility discharge flow...the significance of these differences is that the concentration of any pollutant present in the discharges would be greatly diluted once the discharges are combined." "Using the median flow volume and the maximum oil and grease concentration results in an oil and grease concentration of 0.0013 mg/L. The median flow and average oil and grease value result in a calculated oil and grease concentration of 0.0003 mg/L. When combined with the critical flows examined above, the expected oil and grease concentrations are many orders of magnitude below any concentrations of concern." EPA's discussion outlines that all available information suggests that normal Oil & Grease discharges from hydroelectric facilities pose little, if any, danger of reaching concentrations that would adversely affect aquatic life or species of concern; however, the additional monitoring measures will be a financial burden to tax/rate payers. If EPA's best evidence available suggests that oil and grease concentrations from hydroelectric facilities are not of any concern, Reclamation suggests that monitoring requirements for these contaminants be changed from a monthly frequency to a quarterly frequency until such time that data shows that there is a reasonable concern of these concentrations reaching values that might adversely affect aquatic life or species of concern.

Comment #	Document	Page	Citation	Restriction	Reclamation Comment
22	Bio Eval	47-48	5.3 Determining Receiving Water as a Result of Permit Limits: Temperature	"The proposed GP does not impose a temperature limit on cooling water discharges and instead imposes a monitoring requirement. The rational for not imposing a temperature limit is based on the EPA's assumption that these discharges are not going to cause an exceedance of the State of Idaho's temperature standard? "Comparing all the temperature data reported for both facilities (almost 200 observations), the maximum temperature increase at Oxbow was 0.01764E C with a 25% mixing zone and 0.01603E C at Hells Canyon with a 25% mixing zone. This maximum increase occurred during only one month of the year-July. While the waterbody itself may exceed the thresholds determined to be protective of salmonids and trout, the thermal load that the discharge of cooling water from hydro-electric plants would contribute to the receiving water's temperature would be <u>insignificant</u> (less than 0.02EC). The EPA considers this a de minimus temperature increase and would not result in an impact of the receiving waters support of aquatic uses or specifically, the species of concern."	**EPA states on Pages 47-48 of the Biological Evaluation, "The proposed GP does not impose a temperature limit on cooling water discharges and instead imposes a monitoring requirement. The rational for not imposing a temperature limit is based on the EPA's assumption that these discharges are not going to cause an exceedance of the State of Idaho's temperature standard...Comparing all the temperature data reported for both facilities (almost 200 observations), the maximum temperature increase at Oxbow was 0.01764E C with a 25% mixing zone and 0.01603E C at Hells Canyon with a 25% mixing zone. This maximum increase occurred during only one month of the year-July. While the waterbody itself may exceed the thresholds determined to be protective of salmonids and trout, the thermal load that the discharge of cooling water from hydro-electric plants would contribute to the receiving water's temperature would be insignificant (less than 0.02EC). The EPA considers this a de minimus temperature increase and would not result in an impact of the receiving waters support of aquatic uses or specifically, the species of concern." EPA's discussion indicates that their best available information suggests that temperature inputs from hydroelectric facilities pose no likely danger of reaching concentrations that would adversely affect aquatic life or species of concern and that all heat inputs would be "de minimus"; however, the additional monitoring measures will be an unreasonable financial burden to tax/rate payers. Unless other peer reviewed evidence is provided, the temperature studies presented in the Biological Evaluation should provide EPA and IDEQ with reasonable assurance that no downstream temperature impacts will be realized from hydroelectric facilities. Reclamation suggests that this monitoring requirement be removed from the General Permit until such time that studies suggest the facilities might be a significant contributor to downstream water temperature. If temperature must still be measured to provide reasonable assurance to the State, Reclamation suggests that the level of monitoring (e.g. 1-hr at all outfalls) be reduced in scope and frequency. Reclamation suggests using surface forebay water temperatures (upstream) and river gaging station temperatures (downstream) at a well-mixed location for the identification of facility impacts to receiving waterbodies. Reclamation could provide QA/QC temperature data at these two locations (Reclamation currently collects this data below some facilities). Tax and ratepayer costs would be much more reasonable and a more accurate accounting of the true impacts to the receiving waterbody could be ascertained. See comments 2, 3, 8 and 9.**
23	Bio Eval	48-49	5.4.1 Fish	"Where bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, Snake River steelhead are found in proximity to the discharges from hydroelectric facilities, the maximum temperature change resulting from cooling water discharges would be 0.017EC, which the EPA considers de minimis. Therefore, the EPA concludes the temperature change resulting from facilities covered by the General Permit is insignificant and thus is not adversely to affect bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, and Snake River steelhead." (EPA emphasis)	**EPA states on Pages 48-49, ""Where bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, Snake River steelhead are found in proximity to the discharges from hydroelectric facilities, the maximum temperature change resulting from cooling water discharges would be 0.017EC, which the EPA considers de minimus. Therefore, the EPA concludes the temperature change resulting from facilities covered by the General Permit is insignificant and thus is not adversely to affect bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, and Snake River steelhead." (EPA emphasis) Why is EPA requiring temperature monitoring if its own data has led it to conclude any temperature changes "insignificant" to the most threatened and environmentally sensitive aquatic species? This additional level of monitoring is not needed; however, it imposes additional financial burdens on tax/rate payers. Reclamation suggests using surface forebay water temperatures (upstream) and river gaging station temperatures (downstream) at a well-mixed location for the identification of facility impacts to receiving waterbodies. Reclamation could provide QA/QC temperature data at these two locations (Reclamation currently collects this data below some facilities). Tax and ratepayer costs would be much more reasonable and a more accurate accounting of the true impacts to the receiving waterbody could be ascertained. See comments 2, 3, 8, 9 and 22.**
24	Bio Eval	49	5.4.1 pH	"Discharge monitoring data demonstrates that hydroelectric facilities discharges have an average pH of 6.97, which is within the permitted limits. This is within the range protective of salmonids, bull trout and steelhead. Therefore, the EPA concludes the effluent limit for pH limit is not likely adversely to affect bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, and Snake River steelhead." (EPA emphasis)	**Page 49 of the Biological Evaluation states, "Discharge monitoring data demonstrates that hydroelectric facilities discharges have an average pH of 6.97, which is within the permitted limits. This is within the range protective of salmonids, bull trout and steelhead. Therefore, the EPA concludes the effluent limit for pH limit is not likely adversely to affect bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, and Snake River steelhead." (EPA emphasis) Why is EPA requiring pH monitoring if its own data has led it to conclude that pH falls within permitted levels that is protective of fish? However, the proposed additional sampling imposes additional financial burdens on tax/rate payers. Reclamation suggests removing the pH sampling requirement from the permit and/or 401 State Certification until such time that any new data suggest that temperature contributions from hydroelectric facilities pose and adverse impact to aquatic life or species of concern. If pH must be monitored, Reclamation suggests that the frequency be changed from monthly to quarterly and that a minimum size of outfall, such as 1 cfs, be used to limit scope of monitoring to only those outfalls likely to impact the receiving waters.**

Comment #	Document	Page	Citation	Restriction	Reclamation Comment
25	Bio Eval	49	5.4.1 Oil and Grease	"The results are all at least two orders of magnitude below concentrations where effects may occur to aquatic species and represent extremely conservative analysis. Actual operating conditions may result in concentrations lower than those provided above. In addition to the effluent limits imposed by the GP, the BMP provisions would further reduce or eliminate the amount of oil and grease being discharged by the hydroelectric facilities. Therefore, the EPA concludes the effluent limit for oil and grease is not likely to adversely affect bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, and Snake River steelhead." (EPA emphasis)	**EPA states on Page 49 of the Biological Evaluation, "The results are all at least two orders of magnitude below concentrations where effects may occur to aquatic species and represent extremely conservative analysis. Actual operating conditions may result in concentrations lower than those provided above. In addition to the effluent limits imposed by the GP, the BMP provisions would further reduce or eliminate the amount of oil and grease being discharged by the hydroelectric facilities. Therefore, the EPA concludes the effluent limit for oil and grease is not likely to adversely affect bull trout, Snake River sockeye, Snake River Spring, Summer, and Fall chinook salmon, and Snake River steelhead." (EPA emphasis)** **Why is EPA requiring oil & grease monitoring if studies of past facilities show that oil and grease are not a likely concern? However, the additional monitoring measures will be a financial burden to tax/rate payers.** **Reclamation suggests removing oil & grease from the draft permit until such time that data shows that there is a reasonable concern of these concentrations reaching values that might affect aquatic life or species of concern. If oil and grease must be monitored, Reclamation suggests that the frequency be changed from monthly to quarterly and that a minimum size of outfall, such as 1 cfs, be used to limit scope of monitoring to only those outfalls likely to impact the receiving waters.**
26	Bio Eval	50	5.5 Clean Water Act 316(b) Requirements	"The proposed GP calls for a series of measures to be implemented at hydroelectric facilities to minimize the impacts of entrainment and impingement from cooling water intake structures…The GP pertains to facilities [that] would not fall under the regulations (drawing less than 2MGD of cooling water or using less than 25% of the intake for cooling water), therefore the EPA developed the measures based on best professional judgement [BPJ]."	**EPA states on Page 50 of the Biologic Evaluation that, "The proposed GP calls for a series of measures to be implemented at hydroelectric facilities to minimize the impacts of entrainment and impingement from cooling water intake structures…The GP pertains to facilities [that] would not fall under the regulations (drawing less than 2MGD of cooling water or using less than 25% of the intake for cooling water), therefore the EPA developed the measures based on best professional judgement [BPJ]."** **Reclamation already implements BMPs and uses BPJ as it relates to impingement and entrapment of fish and other aquatic life. These plans are also often required as part of Reclamation's consultation with FWS. The 316(b) would only result in additional record keeping through duplication of records and would be an unnecessary cost to tax/rate payers.** **Reclamation suggests removing this regulatory requirement from the GP and/or State's 401 Certification process. At the very least, the ongoing plan should be recognized in the NOI process and exempted from the final permit. Reclamation would review suggestions for fish impingement and entrainment reductions strategies from EPA.**

ARKOOSH
LAW OFFICES

C. Tom Arkoosh
tom.arkoosh@arkoosh.com

July 9, 2018

EPA Regional Director
Office of Water and Watersheds
U.S. EPA, Region 10
1200 6th Avenue, Suite 155, OWW-191
Seattle, WA 98101
Email: keenan.dru@epa.gov

Re: The United States Environmental Protection Agency (EPA) proposes to issue a National Pollutant Discharge Elimination System (NPDES) General Permit to discharge pollutants to the provisions of the Clean Water Act, 33 USC §1251, *et seq.*, to Hydroelectric Generating Facilities, Permit Number: IDG360000

Dear EPA Regional Director:

The following remarks are the comments of the Idaho Hydroelectric Power Producers Trust ("IdaHydro") regarding the proposed issuance of a National Pollutant Discharge Elimination System ("NPDES") Hydroelectric Generating Facilities General Permit ("GP") No. IDG360000. IdaHydro is an Idaho trust comprised of 12 members who own or operate 28 small hydropower production plants. "Small" hydroelectric plant signifies a facility of 10 Mw of capacity or less qualifying as a Qualifying Facility pursuant to the Public Utilities Regulatory Policy Act of 1978 ("PURPA"). These projects are administered and regulated pursuant to that Act; and pursuant to the plenary regulatory authority granted by the Idaho Legislature to the Idaho Public Utilities Commission. These bodies and their regulatory regime currently require oil containment and oil water separators.

PERMIT PARAMETERS

By its terms, the GP proposes NPDES coverage for hydroelectric facilities that are both "river projects and pump storage projects" for discharge of oil, grease, excess heat (temperature) pH, and backwash from cleaning of river debris and silt from the strainers screens. The discharges covered include direct and noncontact cooling water, equipment and floor drain water, equipment backwash strainer water, and equipment and facility maintenance waters. By giving a notice of intent to participate, a hydroelectric plant may participate under the permit's contemplated annual self-certification program, demonstrating compliance with the best management practices plan developed for that facility. The GP will authorize discharges of excess heat (temperature), pH, and oil and grease in limited amounts and/or with monitoring requirements, to the waters of the United States within the State of Idaho. Generally, misrepresentation in the application, nonperformance of any condition of the GP, or change of condition can result in termination of coverage under the permit.

The Environmental Protection Agency's ("EPA") review of hydroelectric facilities in other regions has led it to conclude the pollutants of concern are pH, oil, grease, and potentially temperature. In turn, EPA concluded these pollutants will contribute or cause excursion above state or tribe water quality standards, which the Clean Water Act in turn requires the EPA to impose water quality based effluent limits encompassed in the framework of the GP.

EPA summarizes that the GP aspires to the highest common denominator of beneficial uses in the receiving waters:

> Because the receiving waters contemplated by the general permit include all possible use designations and are subject to all possible water quality criteria, EPA has established effluent limitations and other requirements of the permits to maintain the most stringent possible water quality criteria. In this manner, the permits will be protective of all possible receiving water uses.

See, EPA Fact Sheet re: the GP, page 16.

PERMIT OPERATION

The GP imposes the above strictures through monitoring the outfalls of each participating project and requiring the obtained information be reported on a designated basis. The monitoring frequencies are:

- Once a month: equipment and floor drain water, or combinations.
- Continuous: temperature.
- Once per event: flood events.

Reporting, within six months of the effective date of the GP, must be via a secure internet application using NetDMR. Each project must develop and follow a quality assurance plan to secure the quality of monitoring and sampling. Further, each project must, within 90 days of the GP effective date, develop and follow a best management practices plan to prevent or minimize releases.

COMMENTS

While, on its face, the proposed GP addresses "river" projects, many of the affected hydroelectric facilities are located on irrigation canals. Acknowledging that Congress exempted agricultural return waters by designating these waters as not being a point source, and thus not within the jurisdiction of the Clean Water Act, the proposal to extend jurisdictional reach over these waters appears to directly conflict with the Congressional intent in excluding these waters.

Thus, it is IdaHydro's belief that the Clean Water Act either does not spread its jurisdiction over these waters; or, consistent with Congressional intent, the EPA should not seek to exercise this jurisdiction. Or, given that many of these small hydroelectric plants are on canals, the GP should not aspire to the highest common denominator by treating irrigation canal water as more pristine than it is.

IdaHydro does not have any information indicating that the concerns of the EPA concerning pollutants discharging from hydroelectric plants are a problem affecting water quality standards in any material way, and thus questions the need for permitting. Stated another way, this a solution of expensive monitoring and reporting without a problem to solve, and, thus, the program itself becomes a regulatory problem. The non-effect of small hydroelectric plants on water quality is especially evident concerning pH. IdaHydro has no information that running canal or river water through a turbine alters the pH of the water between intake and outflow. Further, any temperature measurement should give a credit for hydroelectric plants' cooling by energy conservation because electricity generated would otherwise result in heat in the water due to friction dropping through the channel. IdaHydro therefore recommends that hydroelectric plants, or at the least small hydroelectric plants, not be required to monitor and report.

IdaHydro perceives that compared to the paucity of information indicating that small hydroelectric projects potentially offend water quality standards, the reporting requirements are onerous and expensive. To put the processes and equipment in place for a small hydroelectric project, IdaHydro estimates that the installation process will cost each project $10,000+, and the reporting will cost $6,000 to $10,000 annually. This is unreasonable in face of the knowledge that the grossly substantial portion of water at outfall runs through a turbine physically blockaded from potential pollution. IdaHydro therefore proposes that instead of what amounts to continuous reporting, should the GP go forward on small hydroelectric projects, especially those located on canals, that only those plants discharging drain and cooling water in a volume of two percent or more of the water at the outfall be required to report. Further, given the onerous nature of the proposed reporting schedule, IdaHydro proposes that for those small hydroelectric plants required to report, the reporting be once annually for oil and grease. IdaHydro suggests that any more frequent reporting be imposed only in the event of specific information indicating a particular plant is offending water quality standards. Only those plants having cooling water intake that is greater than 2% of flow should report temperature.

Sincerely,

ARKOOSH LAW OFFICES

C. Tom Arkoosh

CTA/emc
Cc: Client