To: Docket ID No. EPA-HQ-OW-2009-0819-0068
From: Becky Hayat, NRDC
Edward R. Osann, NRDC
Date: September 20, 2013
Re: Steam Electric Effluent Guidelines: Associated Water Savings and Benefits to Reduced Surface Water Withdrawals

I. INTRODUCTION

The following memorandum includes two separate but related discussions. The first part presents NRDC's analysis regarding the potential water savings associated with the regulatory options as set forth in the proposed guidelines. The second part of the memorandum will address EPA's failure to consider certain benefits to reduced surface water withdrawals as a result of the proposed guidelines.

II. REDUCTIONS IN WATER USE AS A RESULT OF THE PROPOSED GUIDELINES

Water is a major input in the generation of power at steam electric generating facilities. Besides cooling, large amounts of water are used by many steam electric power plants for handling solid waste, such as bottom ash and fly ash, and for operating wet flue gas desulfurization (FGD) scrubber systems. The demand for water by power plants can present a major challenge for water managers in regions with limited surface water resources, especially during times of drought. In the analysis supporting this proposed rule, EPA estimated the reductions in water use associated with each of the regulatory options. At the most stringent levels (Options 4 and 5), EPA calculated that power plants would reduce water use by 153 billion gallons per year, or about 419 million gallons per day (MGD).[1] Although power plant withdrawals of cooling water are substantially greater than this amount, the amount of process water that can be saved by these effluent guidelines is nearly as much water as is supplied to residential customers by all the water utilities in North Carolina[2], and thus a significant amount of water to save with any single regulatory measure.

A. Options 4 and 5 will create the greatest amount of water savings.

The varying levels of water savings among the regulatory options stem from differences in the technology basis for three particular types of wastestreams: fly ash transport water, bottom ash transport water, and FGD wastewater.

Under Options 4 and 5, the recommended technology basis for discharge limits on water used for transporting fly ash is dry handling. With respect to bottom ash, the recommended technology basis under Options 4 and 5 is dry handling or a closed loop system.[3] Dry handling of ash will significantly

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[1] U.S. EPA, *Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* 12-13 – 12-14 (April 2013) ("TDD").
[2] Kenny, J.F., Barber, N.L., Hutson, S.S., Linsey, K.S., Lovelace, J.K., and Maupin, M.A., 2009, Estimated use of water in the United States in 2005: U.S. Geological Survey Circular 134, *available at* http://pubs.er.usgs.gov/publication/cir1344.
[3] U.S. EPA, Proposed Rule, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 78 Fed. Reg. 34,432, 34,461-34,462 (June 7, 2013) ("ELGs").

reduce or eliminate water use associated with current wet transport systems. The technology basis for FGD wastewater under Option 5 (chemical precipitation and vapor compression evaporation) will significantly reduce water use because the condensed vapor can be recycled back into the FGD process or used in other plant operations (explained further below).[4] In contrast, the technology treatment for handling FGD wastewater under Option 4 would not be expected to reduce the amount of water used unless plants recycle FGD wastewater as part of their treatment system; however, as discussed further below, few plants are likely to recycle treated FGD wastewater, thus the potential for water savings under Option 4 is somewhat lower than the potential savings under Option 5.

B. <u>Options 4 and 5 will lead plants to convert to dry handling methods for fly ash, thereby resulting in significant reductions in water use.</u>

Under Options 4 and 5, EPA would establish a zero discharge effluent limitation requirement for discharges of pollutants in fly ash transport water, based on the use of dry fly ash handling technologies.[5] As a result, in order to comply with either option, plants that currently use wet transport systems to handle fly ash are likely to convert to dry handling methods, since the regulatory measure will prohibit *all* discharges of pollutants in fly ash transport water. Hence, significant reductions in water use will result when plants are no longer sending fly ash to surface impoundments.

Fly ash transport is one of the largest uses of process water at coal-fired power plants. Of those plants with wet fly ash systems, around 45 percent sluice their fly ash continuously, and 68 percent of plants using wet transport sluice their fly ash at least 12 hours per day. Based on responses to the Steam Electric industry survey that was sent to 733 power plants, the average fly ash transport water flow rate (i.e. discharge volume) is 2.4MGD.[6] EPA estimates that the steam electric industry discharged a total of 81.81 billion gallons of fly ash transport water to surface water in 2009[7], or about 224 MGD.

Nevertheless, dry handling of fly ash is a well-established practice within the industry, and most coal-fired plants that have come online since 1985 use dry handling for fly ash.[8] In fact, all of the newer electric generating units employ dry fly ash handling methods because the current New Source Performance Standards (NSPS), which were promulgated in 1982, prohibit the discharge of pollutants in fly ash transport water. In addition, many older generating units have also converted to dry fly ash handling systems that use air to transport the fly ash to storage silos instead of using water to sluice the ash.[9] As a result, of the coal- and petroleum coke-fired steam electric generating units that generate fly ash, 66 percent already operate dry fly ash transport systems, while another 15 percent operate both

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[4] U.S. EPA, *Incremental Costs and Pollutants Removals for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 6-106* (April 2013) ("Incremental Costs and Pollutants Removals").
[5] ELGs at 34,461.
[6] ELGs at. 34,449.
[7] TDD at 12-14.
[8] Bergesen and Hull, *Environmental Directory of U.S, Power Plants*, Edison Electric Institute, 1994.
[9] ELGs at 34,439.

wet and dry fly ash transport systems. The remaining 19 percent operate only wet fly ash transport systems, although not all of these plants discharge their fly ash transport water.[10]

Because most coal-fired generating units are already utilizing dry fly ash handling practices, we support EPA's proposal to require zero discharge of fly ash transport water for all existing power plants. A zero discharge standard based on dry ash handling would not only be the most effective method at eliminating all discharges of pollutants from fly ash, but it will also eliminate water use associated with current wet sluicing operating systems for handling fly ash, and thereby yielding water savings of over 200 MGD.

C. Options 4 and 5 will lead plants to convert to dry handling or closed loop systems for handling bottom ash, thereby resulting in significant reductions in water use.

Under Options 4 and 5, EPA would establish zero discharge effluent limitations for discharges of pollutants in bottom ash transport water, based on using either: 1) bottom ash handling technologies that do not require transport water, or 2) by managing a wet-sluicing bottom ash handling system so that it does not discharge bottom ash transport water or pollutants associated with the bottom ash transport water.[11] As is the case with fly ash transport water, if plants were to comply with the zero discharge requirement pursuant to Options 4 and 5, they would most likely convert to dry handling methods, which may be entirely dry and avoid all use of water, or in some cases may include a water bath at the bottom of a boiler in which the bottom ash is dropped and cooled, from which the bottom ash is then mechanically dragged out of the boiler along a conveyor belt and deposited in a pile adjacent to the building housing the boiler.[12] Regardless of which method a plant employs, significant amounts of water will be saved as a result of the plants having to comply with the zero discharge standard under Options 4 and 5.

For an individual power plant, bottom ash transport water flow rates are typically not as large as the fly ash transport water flow rates if a wet handling system for fly ash is in use. However, bottom ash transport water is still one of the larger volume flows for the fleet of steam electric power plants as a whole. In 2009, the total amount of bottom ash transport water discharged was 157 billion gallons per year[13], or about 430 MGD. Although many coal-fired and petroleum coke-fired plants operate dry bottom ash handling systems, an estimated 67 percent of all existing plants (79 percent of coal- and petroleum coke-fired generating units) wet sluice all or part of their bottom ash.[14]

Options 4 and 5 are the only regulatory alternatives that require zero discharge of pollutants from bottom ash transport water. While Option 4a also requires a zero discharge effluent limitation for bottom ash transport water, it only applies to individual generating units having a nameplate capacity

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[10] *Id.* at 34,449.
[11] ELGs at 34,462.
[12] This residual water that collects in the storage area as the bottom ash continues to dewater is typically completely recycled back to the quench water bath. Moreover, EPA does not consider this wastewater to be transport water because the transport mechanism is the drag chain, not the water. *See* TDD, pg. 4-21.
[13] TDD at 12-14.
[14] ELGs at 34,449.

greater than 400 MW.[15] EPA's explanation for setting the 400 MW limitation is that the potential compliance costs with a zero discharge standard for bottom ash transport water would be "substantial" if applied to all facilities, and that units less than or equal to 400 MW are more likely to incur disproportionately higher costs than those incurred by larger units.[16] The notable increase in water savings from Option 3 (in which effluent limitations are set to the current BPT effluent limitations and the recommended technology basis is surface impoundment) to Option 4a can be mainly attributed to the change in effluent limitations from the current BPT effluent limitations to a zero discharge standard for units more than 400 MW. Furthermore, the additional increase in water savings from Option 4a to Options 4 and 5 can be directly attributed to the elimination of the 400MW threshold.

However, EPA's justification for the 400MW threshold is seriously deficient, as the agency readily admits that "all plants, regardless of size, are capable of installing and operating dry handling or closed-loop systems for bottom ash transport water, and the costs would be affordable for most plants." In addition to comparing the relative economic burden between a 200 MW unit and a 400 MW unit, EPA also surmised that companies may choose to shut down 400 MW and smaller units instead of making new investments to comply with the proposed zero discharge bottom ash requirements. Even if this speculation turns out to be accurate, it still does not justify a 400 MW safe harbor for continued discharges of pollutants from wet bottom ash transport systems, because pursuant to the Clean Water Act's (CWA) BAT standard, EPA is required to set the most stringent standard that is economically achievable, which has been defined as costs that can be reasonably borne by industry.[17] Furthermore, EPA's analysis is unconvincing when confined to relative costs per MW in the absence of any estimates of actual dollars involved. It is a virtual truism that compliance costs per MW are going to be larger for a plant with a lower capacity than for a plant with a higher capacity. To say that the relative burden is greater for a smaller unit does not demonstrate that the actual burden on plants below 400 MW would result in any plant shutting down. Without providing the necessary documentation to support-this assertion, we cannot accept EPA's flawed rationale in setting a seemingly arbitrary 400 MW threshold for allowing continued discharges of pollutants from bottom ash transport water.

Because most existing plants operate wet bottom ash handling systems, the number of plants that will convert to dry handling systems, should Options 4 or 5 be implemented, will be substantial, and as a result, the reductions in water use by these plants will also be quite significant. Based on the above analysis, we urge EPA to reject the unsupported 400 MW threshold proposed in Option 4a. We also urge EPA to select Option 5, or at a minimum Option 4, as the final rule. In addition to removing the

[15] ELGs at 34,469.

[16] EPA noted that the average annualized cost of achieving zero discharge limits for bottom ash discharges per MW for a 200 MW unit is more than three times higher than the average cost for a 400 MW unit. *See id.* at 34,470.

[17] *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 516 (2d Cir. 2005) (holding that technology eliminating a discharge is economically achievable if the "costs can be reasonably borne by the industry); *see also BP Exploration & Oil, Inc. v. EPA*, 66 F. 3d 784, 799-800 (6th Cir. 1995) (rejecting industry demand for cost-benefit analysis because BAT "does not require cost-benefit analysis" and "EPA need only find… that the cost of the technology is reasonable").

most pollutants from steam electric power plant discharges[18], Option 5 would also yield the greatest reductions in water use as a result of requiring zero discharge for bottom ash transport water.

D. In addition to reductions in water use, dry ash handling methods may have additional benefits, such as decreasing O&M costs and bringing in additional revenue.

Besides reductions in water use, there are other benefits associated with the conversion from a wet ash handling system to a dry handling method. With respect to fly ash, dry handling has become the standard for new installations and retrofits over the last few decades. Based on industry responses to the Steam Electric survey, the reasons cited for installing dry handling systems include environmental remediation, economic opportunity, and the need to replace ash impoundments approaching full storage capacity.[19] Specifically, the economic opportunity refers to the potential for dry handling methods to lower O&M costs, as well as to the emergence of local markets, enabling the reuse and sale of fly ash and bottom ash to concrete suppliers.

i. Lower O&M Costs:

Using a dry handling system may be the most cost-effective choice in the long-run for steam electric generating facilities. The use of water in a wet handling system, as opposed to air as a cooling agent in a dry handling system, can incur additional costs. Factors such as water treatment, corrosion damages, and higher disposal and maintenance costs all should be considered as plants re-evaluate their wet ash handling practices.[20] Most plants that have converted from wet-to-dry fly ash handling did so in order to reduce costs.[21] With respect to bottom ash, one of the many advantages that follow a dry handling method is the decrease in O&M costs. A recent economic study[22] examined the relative costs of a Drycon[23] bottom ash system against the more traditional submerged scraper conveyor (SSC)[24] technology. The study is based on a typical European baseload pulverized coal fired power plant of 800 MW operating with imported coal. In examining the investment costs, although the Drycon system is more expensive than the SSC on a unit basis and the cost of associated crushing equipment is similar, the initial costs are offset by simpler transport and storage equipment and the lack of requirement of

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[18] ELGs at 34, 473.
[19] TDD at 4-23.
[20] United Conveyor Corporation, *Wet-to-Dry Conversion: Bottom Ash & Fly Ash Systems* (2009).
[21] Consumers Energy, a large public utility company located in Michigan, converted all of its fly ash handling systems to dry systems over the last decade. In addition to reduced water consumption, environmental benefits, and additional revenue from sale of dry ash to the construction industry, the company also noted that its conversion to dry ash handling resulted in significant cost savings to its customers by not having to landfill wet fly ash and/or bottom ash. These savings were estimated at more than $2 million annually. *See* Consumers Energy, *Coal Combustion Byproducts Management*, available at http://www.consumersenergy.com/uploadedFiles/CEWEB/OUR_COMPANY/Corporate_Social_Responsibility/The_Environment/coal-combustion-byproducts-management.pdf?n=3986.
[22] Power Engineering International, *Ash handling: Why dry bottoms are better than wet bottoms* (Jan. 5, 2010).
[23] Drycon is a dry bottom ash handling system, created by Clyde Bergemann Delta Ducon (CBDD), which uses fresh air to cool bottom ash while conveying. *See* CBDD, *Bottom Ash Conversion Options and Economics* (2011).
[24] The SSC system involves the collection, water quenching and mechanical conveying of bottom ash. It requires lower water usage than traditional hydraulic systems when a closed loop cooling system is used. *See id.*

water treatment equipment such as pumps, filters, heat exchangers etc. Considering the consumptions on an annual basis, the study found that due to the Drycon roller design, the friction losses are significantly reduced and therefore have a positive effect on energy consumption and resultant wear. In addition, the SSC requires the provision of cooling water. At the associated costs indicated, the study concluded that the annual operating costs of the Drycon system are approximately 47 percent of those of the SSC system.[25]

ii. Emerging Market for Usable Ash:

By using dry ash handling, the quality of the fly ash and bottom ash is improved. High-quality ash, when mixed with cement and water, increases the strength of concrete[26], thereby making it a sought-after product by the construction materials industry. As the market for usable ash product increases, the economic incentive for plants to convert to dry ash handling methods is also heightened.[27] Thus, converting to a dry handling method will not only reduce a power plant's water demand, but it may also provide additional revenues from the sale of fly ash and bottom ash.[28]

E. <u>With respect to FGD wastewater, Option 5 will yield the greatest reductions in water use.</u>

The water savings associated with FGD wastewater under Option 4 is insignificant for the following reasons: 1) reductions in water use would result *only if* plants recycle their FGD wastewater; 2) only for plants with a FGD wastewater discharge flow rate greater than 1,000 gpm is it actually cost efficient to implement additional recycle within the FGD system; and 3) plants can recycle only if they operate at relatively low chloride levels compared to the maximum allowable chloride concentration.

Under the effluent limitations requirement proposed in Option 4, EPA concedes that the technology basis for FGD wastewater (e.g. chemical precipitation and biological treatment) will not reduce the amount of water used unless plants recycle FGD wastewater as part of their treatment system.[29] Thus, in calculating the potential amount of reductions in water use with respect to the technology basis for treating FGD wastewater amongst the regulatory options, EPA had to operate under the assumption that plants would be both capable and willing to recycle their FGD wastewater. Moreover, the cost of the FGD treatment system is strongly influenced by the volume of the wastestream to be treated (i.e., gpm); hence, EPA stated that for these high flow plants (defined as plants with a FGD discharge flow rate greater than 1,000 gpm), it would be more cost efficient for them to implement additional recycle with the FGD system[30] because those FGD systems with large flow rates could incorporate some degree (or some additional degree) of water recycle within the FGD system as a means for reducing the purge flow sent to treatment, and thereby reducing the capital and O&M costs

[25] Id.
[26] Headwater Resources, *Fly Ash for Structural Concrete*, available at http://www.flyash.com/data/upimages/press/TB.10%20Fly%20Ash%20for%20Structural%20Concrete.pdf.
[27] Power Engineering, *Ash Handling Options for Coal-fired Power Plants* (Feb. 1, 2011).
[28] POWER*, The Better Environmental Option: Dry Ash Conversion Technology* (July 2011).
[29] ELGs at 34,522.
[30] Incremental Costs and Pollutants Removals at 4-13.

of the treatment system. Lastly, recycling FGD wastewater increases the level of chlorides in the FGD system, but because there is a maximum allowable concentration for chloride in the FGD system, only plants that have a sufficient margin between the operating chloride concentration and the maximum allowable concentration will be able to implement additional recycling of their FGD wastewater.[31]

In summary, from a cost efficiency point of view, only larger plants (i.e. plants with a FGD wastewater discharge flow rate greater than 1,000 gpm) are likely to recycle their FGD wastewater; furthermore, because plants only have the potential to recycle if they are operating below 80 percent of the maximum design level threshold, the majority of plants across the U.S. do not fit under this category and thus are not able to recycle their FGD wastewater.

Based on these aforementioned reasons, we urge EPA to choose Option 5, or at a minimum Option 4, as the final rule because in addition to requiring the most stringent standard for controlling pollutants, the projected water savings from the technology treatment for FGD wastewater will be at its maximum. As discussed above, the potential to produce water savings from FGD wastewater under Option 4 is limited.[32] By contrast, the technology basis for the effluent limitations and standards for FGD wastewater in Option 5 is chemical precipitation/coprecipitation used in combination with vapor compression evaporation.[33] This technology uses an evaporator to produce a concentrated wastewater stream and a reusable distillate stream. The concentrated wastewater stream is either disposed of or further processed to produce a solid byproduct and additional distillate. Because the evaporation process pulls out the chlorides in the FGD wastewater, the distillate water can be either recycled back to the FGD process or used in other plant operations (e.g. boiler make-up water). Consequently, plants that are subject to compliance with the technology standard under Option 5 will be able to recycle their FGD wastewater, resulting in greater reductions in water use.[34]

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[31] EPA used data from the Steam Electric Survey to identify the FGD systems with the potential capability to recycle their FGD wastewater and the amount of recycle that can be accommodated. For all "high flow" plants without some level of treatment in place, EPA compared each FGD system's current operating chlorides level to the specified maximum design chlorides limit provided in Part B Section 4 (Flue Gas Desulfurization Systems – Wet FGD System Information). Based on site visit discussions and data from the industry, EPA determined that plants can operate up to 80 percent of the maximum design chlorides level without significant corrosion concerns. As a result, EPA identified any system operating below 80 percent of the maximum design threshold as having the potential to recycle some FGD wastewater. FGD systems that already operate at or near the maximum chlorides design concentration would not be able to increase their level of recycle without potentially corroding the FGD scrubber system. Five of the 12 high flow plants were identified as having the potential to implement some level of FGD wastewater recycle. *See id.* at 4-13 – 4-14.

[32] This is further supported by the fact that based on responses from the Steam Electric industry survey that was sent out to the 733 plants, EPA estimated that only five plants would be able to incorporate recycling within their FGD systems based on the maximum operating chlorides concentration compared to the design maximum chlorides concentration. *See* ELGs at 34,522.

[33] ELGs at 34,460.

[34] In estimating the reductions in water use associated with the regulatory options, EPA operated under the assumption that plants would recycle their FGD wastewater as part of their treatment system if chemical precipitation and biological treatment were the applicable technology basis (Options 3, 4a, and 4). However, in arriving at these water savings estimations, EPA did not take into account the additional FGD wastewater that may be recycled under a chemical precipitation and vapor compression evaporation technology treatment (Option 5).

F. <u>Potential water savings under Options 4 and 5 will have an especially constructive impact on water-scarce regions of the U.S.</u>

In the southeastern and southwestern U.S., where the water-energy nexus problem is most visible, the benefit of reduced water withdrawals will be especially useful. In the past decade, the southeast has experienced particularly acute drought conditions and continues to suffer problems of decreasing water availability. In the southwest, where surface water resources are stretched thin, there is little available to meet growing demand, including new power sector needs. Even without factoring in the exacerbating role of climate change, water supply conflicts involving several major Southwest cities – including Denver, Albuquerque, Las Vegas, and Salt Lake City – are considered highly likely by 2015.[35] Thus, if EPA selected Option 5, or at a minimum Option 4, as the final rule, the resulting water savings will be especially helpful for those states facing deepening challenges posed by the water dependency of steam electric power plants.

For example, based on responses from the technical questionnaire of the Electric Steam industry survey, the Allen Steam Station, located in Belmont, NC and employing a wet fly ash handling system, reported that it generates approximately 9.61 MGD of fly ash transport water. The plant also indicated that 100% of its source for fly ash transport water is intake water, none of which is recycled back to the plant process. If the Allen plant were to comply with the effluent limitations standard pursuant to Options 4 or 5, it would most likely convert its existing fly ash wet handling system to a dry handling method and potentially reduce its water use by 9.61 MGD. In addition, the Marshall Steam Station, located in Terrell, NC reported that it, too, uses wet fly ash handling methods and generates approximately 10.56 MGD of fly ash transport water. The Marshall plant also draws its fly ash sluice water from nearby surface waters, and does not engage in recycling. Thus, if this plant were to comply with Option 5, it too would be likely to convert to dry fly ash handling and reduce its water consumption by 10.56 MGD. Both these plants in North Carolina draw water from the Catawba River; hence, if Options 4 or 5 were selected as the final rule, it could potentially result in a combined water savings of 20 MGD for the Catawba River Basin, augmenting the reliability of cooling water supplies for power generation as well as enhancing public water supplies and recreation uses downstream in North and South Carolina.

Further responses from the technical questionnaire reveal that the Four Corners Generating Station, located near Fruitland, NM, uses a wet bottom ash handling system and generates 7.27 MGD of bottom ash transport water. The plant also indicated that 100% of the source for the bottom ash transport water is intake water, none of which are recycled back to the plant process. Hence, if Options 4 or 5 were selected as the final rule, this New Mexico plant would be expected to switch to a dry bottom ash handling system, and consequently, the plant would reduce its water use by 7.27 MGD. In an arid state like New Mexico, where access to water can be highly contentious, 7.27 MGD is a significant amount of water to be saved.

This explains for why even though Option 5 is the only regulatory measure that proposes chemical precipitation/coprecipitation and vapor compression evaporation as the BAT for treating FGD wastewater, EPA's projected water savings for Options 4 and 5 are nevertheless the same (153 billion gallons per year).

[35] Union of Concerned Scientists, *The Energy-Water Collision: Power and Water at Risk* (June 2011).

G. Conclusion

The electricity sector's drain on water resources and the associated risks are undeniable. Thus, EPA must implement regulations that work to alleviate the mounting water stresses across the nation caused by electric power plants' dependency on water. We urge EPA to select Option 5, or at minimum Option 4, as its final rule, because in addition to eliminating almost all of the toxic pollutants discharged from power plants[36], it would also yield the greatest reductions in water use. EPA is obligated to implement the most environmentally protective regulatory measure that is economically achievable for industry. Options 4 and 5 are the only regulatory alternatives that would allow EPA to fulfill its mandate under the CWA.

III. EPA'S INCOMPLETE BENEFITS ANALYSIS REGARDING REDUCED SURFACE WATER WITHDRAWALS

As discussed above, the potential water savings resulting from the proposed guidelines may be particularly important for those regions of the U.S. where water is already in short supply. Given the enormous threat that steam electric power plants pose to the availability and quality of our water resources, any reductions in a plant's dependency on water will yield significant environmental and economic benefits. Yet, EPA identified only one type of benefit associated with reduced surface water withdrawals, which the agency limited to a very minimal qualitative discussion. Moreover, EPA failed to even mention – let alone quantify or monetize – other associated benefits to reduced surface water withdrawals. EPA must provide an accurate analysis of the full environmental and economic benefits to be gained as a result of the proposed guidelines – this is to ensure that in the end, the most environmentally protective regulatory option, which satisfies the BAT standard, will be chosen as the final rule.

A. EPA underestimated the benefits of reduced surface water withdrawals as a result of the proposed guidelines.

In EPA's Benefit and Cost Analysis[37] for the proposed guidelines, the agency identified "reduced impingement and entrainment mortality" as a type of benefit associate d with reduced surface water withdrawals. However, EPA went on to state, "Due to data limitations, EPA did not quantify and monetize these benefits as part of this analysis."[38] While we would like further explanation regarding why EPA could not quantify or monetize such benefits, we are more concerned with EPA's failure to take into account other associated benefits to reduced surface water withdrawals in addition to reduced impingement and entrainment mortality. It is well-established that large water withdrawals have many adverse impacts, including but not limited to, lowering groundwater recharge or natural stream flow levels (thus impacting instream flow[39]), and affecting fish, wildlife, or other living resources and their

[36] ELGs at 34,485 – 34,486 (Table IX-4).
[37] U.S. EPA, *Benefit and Cost Analysis for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category* (April 2013) ("BCA").
[38] BCA at 9-1.
[39] Instream flow refers to the state in which water remains in its natural course as opposed to water that has been diverted artificially for other purposes.

habitat.[40] Changes in instream flows in turn affect surrounding property values and recreational use (discussed further below). Said another way, reducing withdrawals can restore natural flows (in particular for water bodies with low flow conditions) and thereby impact aquatic life, property prices, and recreation.

B. Reduced surface water withdrawals may improve aquatic life and provide recreation benefits.

Maintaining instream flow is necessary for the protection of fish and aquatic life. Surface water withdrawals must be monitored so that sufficient water remains to fully support aquatic life. Reduced withdrawals will either restore instream flows in areas with low flow conditions, or increase natural stream flows, both of which will produce the additional benefit of improving aquatic ecosystems.[41]

Streamflow levels can also influence recreation benefits through a variety of mechanisms. Flow levels directly influence of quality of whitewater boating experiences as well as stream aesthetics for general shoreline use. Streamflow at any given time affects fishing via influences on the locations, distribution, and behavior of fish and aquatic insects. Flow levels also directly affect recreation carrying capacity – for example, the number of anglers that can use the same stretch of river at any one time without congestion problems may increase with flow. Over time, streamflows affect fish stock levels and associated angler catch rates, as well as general recreation and aesthetics via effects on streamside vegetation.[42] There exists a vast amount of literature examining the recreation benefits of instream flows. Most, if not all, of the studies have confirmed that recreation value is directly correlated with protecting instream flows and/or increasing natural flows.[43] Furthermore, in these studies, the recreation value of instream flow has been monetized using a WTP methodology, measuring the maximum a person would be willing to pay in excess of actual trip costs rather than to forego the experience.[44]

C. Reduced surface water withdrawals may increase agricultural productivity and property values.

In addition, water withdrawals may have a direct impact on water quality. First and foremost, withdrawing large amounts of surface water may have the effect of driving up the concentration level of pollutants in the remaining water body.[45] This is essentially known as the “dilution effect.” Moreover,

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[40] U.S. Geological Survey, *Simulation of the Effects of Water Withdrawals, Wastewater Return Flows, and Land-Use Change on Streamflow in the Blackstone River Basin, Massachusetts and Rhode Island* (2007); Susquehanna River Basin Commission, *Low Flow Protection Policy Related to Withdrawal Approvals* (Dec. 14, 2012).
[41] New Hampshire Dept. of Environmental Services, *Methods for Estimating Instream Flow Requirements for Protection of Aquatic Life, Guidance Document* (Nov. 16, 2010).
[42] Brown, T.C., J.G. Taylor, and B. Shelby, Assessing the direct effects of streamflow on recreation: A literature review, Water Resource Bulletin, 27(6), 979-989 (1991).
[43] Duffield, J.W., C. J. Neiler, and T.C. Brown, Recreation Benefits of Instream Flow: Application to Montana's Big Hole and Bitterrot Rivers, Water Resources Research, Vol. 28, No. 9, pgs. 2169-2181 (Sept. 1992); U.S. Dept. of the Interior Bureau of Reclamation, Economic Nonmarket Valuation of Instream Flows (April 2001).
[44] Id.
[45] U.S. Dept. of Agriculture, *Evaluating Benefits and Costs of Changes in Water Quality* (2002).

water quantity is often a contributing factor to other parameters of water quality – for example, as the quantity of water decreases, temperature may increase.[46] Conversely, as water quantity increases, salinity levels can decrease per unit of water. As river flow is diverted for irrigation, the concentration of total dissolved solids increases, reducing the productivity of agriculture. Without proper water quality, decreased crop production and disease may result.[47] Thus, there are various benefits to be gained from reductions in surface water withdrawals, and hence an improvement in water quality, for agriculture purposes.[48] Furthermore, there is ample evidence to show a significant direct correlation between water quality and surrounding property values.[49] Thus, if we operate under the assumption that large amounts of withdrawals negatively affect water quality, then we can draw the logical conclusion that reducing water withdrawals may also yield the additional benefits of increasing agricultural productivity and property prices.

D. Conclusion

In conclusion, we urge EPA to provide a more detailed explanation regarding why it failed to monetize and quantify the benefits of reduced impingement and entrainment mortality associated with reductions in surface water withdrawals. Moreover, EPA must take into account other benefits associated with reduced surface water withdrawals, including but not limited to, healthier aquatic ecosystems, higher recreational value, agricultural benefits, and increase in property values. EPA's failure to quantify/monetize the one type of benefit it identified in relation to reduced surface water withdrawals, along with its undercounting of other associated benefits, results in an unfair balancing act where the agency weighs complete costs against incomplete benefits. This biased cost-benefit analysis is especially troublesome for the most stringent regulatory options (e.g. Options 4 and 5) where EPA overestimated compliance costs and blatantly underestimated the benefits.

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[46] Id. at 7.
[47] Id. at 11-12.
[48] Such agricultural benefits gained from a water quality improvement have been measured in two ways: through changes in price to consumers, and through changes in the incomes received by owners of inputs used in the production of the good. *See id*.
[49] Steinnes, D.N., Measuring the Economic Value of Water Quality: The Case of Lakeshore Land." Annals of Regional Science 26: 171-176 (1992) (concluding that water quality measures significantly impact property values and each additional unit of change in Secchi disk readings (SDR) – used as a measure of objective water quality – resulted in a $206 change in average lot price near the lake).