Development and Implementation of an Optimization Model for Hydropower and Total Dissolved Gas in the Mid-Columbia River System

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Abstract: Managing energy, water, and environmental priorities and constraints within a cascade hydropower system is a challenging multiobjective optimization effort that requires advanced modeling and forecasting tools. Within the mid-Columbia River system, there is currently a lack of specific solutions for predicting how coordinated operational decisions can mitigate the impacts of total dissolved gas (TDG) supersaturation while satisfying multiple additional policy and hydropower generation objectives. In this study, a reduced-order TDG uptake equation is developed that predicts tailrace TDG at seven hydropower facilities on the mid-Columbia River. The equation is incorporated into a general multiobjective river, reservoir, and hydropower optimization tool as a prioritized operating goal within a broader set of system-level objectives and constraints. A test case is presented to assess the response of TDG and hydropower generation when TDG supersaturation is optimized to remain under state water-quality standards. Satisfaction of TDG as an operating goal is highly dependent on whether constraints that limit TDG uptake are implemented at a higher priority than generation requests. According to the model, an opportunity exists to reduce TDG supersaturation and meet hydropower generation requirements by shifting spillway flows to different time periods. A coordinated effort between all project owners is required to implement systemwide optimized solutions that satisfy the operating policies of all stakeholders. DOI: 10.1061/(ASCE)WR.1943-5452.0000827. © 2017 American Society of Civil Engineers.

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Introduction and Background

Within the mid-Columbia River system (mid-C), elevated total dissolved gas (TDG) pressures in waters near hydroelectric dams are a pressing environmental concern (Beeman et al. 2003). The health and well-being of fish and other aquatic species necessitates an acceptable range of TDG that is often exceeded in the tailrace of high-head dams. After prolonged exposure to waters supersaturated with TDG, fish may experience bubble nucleation in the vascular system as they escape or travel into regions with reduced ambient pressures (Ebel 1969; Weitkamp and Katz 1980; McDonough and Hemmingsen 1985). Fish mortality is observed when bubble formation is sufficient to obstruct blood flow; in addition, bubble growth under the skin, mouth, gills, and eyeballs can lead to chronic tissue damage (Ebel and Raymond 1976; Weitkamp et al. 2003).

The complex physical processes that produce TDG supersaturation occur principally in the tailrace of hydropower facilities (Politano et al. 2007). At the convergence point of energetic spillway releases and relatively quiescent tailwater, atmospheric gases are entrained into the flow in the form of large air pockets. Turbulence and energy dissipation act to shear the pockets into smaller bubbles. As bubble diameter diminishes, the interfacial area increases, enhancing gas dissolution (Gulliver et al. 1990). Small bubbles are transported into deep reaches of the stilling basin, where increased hydrostatic pressures compress the bubble further, creating favorable conditions for dissolution of air into water. As pressure increases with depth in the stilling basin, too does the capacity of the water to hold dissolved gas. The combination of bubble generation, breakup, and dissolution, along with the propensity of water to supersaturate with increasing depth, leads to tailrace TDG pressures that are elevated above ambient atmospheric conditions during times of high spill (Pickett et al. 2004; Politano et al. 2012).

Management of TDG in the mid-C entails a coordinated effort across many large hydropower projects. The seven hydropower dams along 321 river kilometers (200 river miles) represent a total installed capacity of approximately 14,240 MW, nearly 18% of conventional hydropower capacity in the United States distributed across less than 0.5% of the total number of hydropower plants. The mid-C hydropower projects contribute more than 50 million GWh of renewable electricity to the grid annually...
The result of a complex and coordinated effort between several federal agencies and public utility districts (PUDs) (Fig. 1 and Table 1). Grand Coulee sits at the head of the mid-C, a storage facility owned and operated by the U.S. Bureau of Reclamation (USBR), and is the largest hydropower facility in the country. Hydroelectric power from Grand Coulee is scheduled and marketed by the Bonneville Power Administration (BPA). Chief Joseph, owned and operated by the U.S. Army Corps of Engineers (USACE), is located 82.9 river kilometers (51.5 river miles) downstream of Grand Coulee. Close coordination between these two federal projects and the five downstream nonfederal projects is required to deliver hourly and weekly flow estimates such that each facility can be operated in compliance with operating policy constraints. Wells, owned and operated by Public Utility District No. 1 of Douglas County (Douglas PUD), is a hydropower facility with a spillway located directly above the generating units. This design incorporates restricting barriers into the spill bay that improve attraction flow while minimizing spill, making Wells the most efficient fish bypass system on the mainstem of the Columbia River (Douglas County Public Utility District 2013). The Rocky Reach and Rock Island projects are owned and operated by Public Utility District No. 1 of Chelan County (Chelan PUD), and the final two projects, Wanapum and Priest Rapids, are owned and operated by Public Utility District No. 2 of Grant County (Grant PUD). The large storage capacity of Grand Coulee contrasts with the run-of-river operation of all downstream projects, where projects are managed to accommodate the variable and substantial flow releases upstream.

The Pacific Northwest Coordination Agreement (PNCA), a formal arrangement between USACE, USBR, BPA, and 14 major utilities signed in 1964, laid the initial groundwork for hydro operators to optimize systemwide hydropower generation through coordinated operation. The goal of the agreement was to optimize firm load-carrying capacity and amount of usable secondary energy for each facility and jointly for the entire hydroelectric system of the Pacific Northwest (BPA et al. 1993). The evolution of the local power system, need for a minute-to-subminute decision framework, improved understanding of the environmental impacts of hydropower operation, and the priorities of additional reservoir multipurpose beneficiaries have all led to an increasingly complex and challenging multiobjective approach to mid-C project coordination (Clement et al. 2014a). Although hydropower assets are considered one of the most flexible and reliable renewable energy generators, hydroelectric plants are generally authorized, built, and operated as

*Table 1. Characteristics of the Hydropower Dams on the Mid-C*

<table>
<thead>
<tr>
<th>Project name</th>
<th>Rated head (m)</th>
<th>Installed capacity (MW)</th>
<th>Average annual energy generationa (MWh)</th>
<th>Powerhouse hydraulic capacity (m³·s⁻¹)</th>
<th>Average summer spillway flowb (m³·s⁻¹)</th>
<th>Average summer tailrace TDG concentrationb (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grand Coulee</td>
<td>100.6</td>
<td>6,809</td>
<td>22,086,436</td>
<td>7,929</td>
<td>122</td>
<td>110.1</td>
</tr>
<tr>
<td>Chief Joseph</td>
<td>49.7</td>
<td>2,620</td>
<td>11,586,035</td>
<td>6,201</td>
<td>323</td>
<td>110.0</td>
</tr>
<tr>
<td>Wells</td>
<td>22.3</td>
<td>840</td>
<td>4,353,300</td>
<td>6,230</td>
<td>481</td>
<td>111.9</td>
</tr>
<tr>
<td>Rocky Reach</td>
<td>28.0</td>
<td>1,300</td>
<td>6,369,413</td>
<td>6,230</td>
<td>731</td>
<td>114.8</td>
</tr>
<tr>
<td>Rock Island</td>
<td>12.5</td>
<td>624</td>
<td>3,501,447</td>
<td>6,230</td>
<td>654</td>
<td>114.3</td>
</tr>
<tr>
<td>Wanapum</td>
<td>24.4</td>
<td>1,092</td>
<td>4,771,758</td>
<td>5,040</td>
<td>1,031</td>
<td>113.1</td>
</tr>
<tr>
<td>Priest Rapids</td>
<td>24.4</td>
<td>956</td>
<td>4,685,160</td>
<td>5,040</td>
<td>1,181</td>
<td>113.5</td>
</tr>
</tbody>
</table>

bSummer average taken from April–August for 2004–2012.
part of a broader multipurpose project that may include irrigation, navigation, environmental, recreation, or flood-control water management objectives. Within the mid-C hydropower system, for example, the terms of the hydropower license generally set maximum and minimum limits on reservoir pool elevations in consideration of all reservoir beneficial uses. System behavior is then dictated by nonpower water and environmental policy objectives formulated through biological opinions, treaties, and other water-use agreements (e.g., the PNCA), followed finally by power objectives (Clement et al. 2014b). To better optimize local system operations, the seven projects on the mid-C have entered into the mid-Columbia Hourly Coordination Agreement, implemented through the formation of a central dispatch center (mid-C Central) to which uncoordinated generation requests are sent and optimized based on current system conditions, policies, and constraints. Coordinated requests are then dispatched to nonfederal project owners with consideration of generating capacity, inflow conditions, reservoir pool levels, environmental resource needs, and other project and system-level priorities and constraints (Acker et al. 2012; Magee et al. 2011).

System-level mid-C operational constraints vary by project owner type (i.e., federal versus nonfederal), nature of the constraint, terms of the operational license, season, and location. Federal project constraints carry a high priority within the system—they must be met before other objectives can be satisfied. Most system-level environmental constraints are medium-level priorities, whereas power production at nonfederal projects is generally a lower-priority constraint (Clement et al. 2014a). At Priest Rapids, for example, the order of operational priorities is fish migration, flood control (becomes number one priority if structural integrity is an issue), recreation and reservoir pool levels, navigation, and power production (Acker et al. 2012). Constraints on TDG, developed to conform to state water-quality standards (Maynard 2008), must be managed in the context of all additional constraints, many of which are higher priority. The State of Washington has established a limit of 110% TDG saturation for all surface water, although three separate TDG exemptions have been adopted for hydroelectric projects that use voluntary spill for juvenile fish passage: (1) tailrace TDG cannot exceed 125% in any 1-h period, and (2) tailrace TDG and (3) TDG in the forebay of the next downstream project shall not exceed 120 and 115%, respectively, measured as a 12-h average over the highest consecutive hourly readings over a 24-h period (Frantz 2013). Projects are required to outline a TDG management strategy in an annual gas-abatement report, which generally consists of minimizing and managing spill through the hourly coordination agreement, allocating spill to specific spill bays, avoiding scheduled maintenance during times of high spill, and maximizing powerhouse flows (e.g., Douglas County Public Utility District 2013; Frantz 2013; Keeler 2014) Despite these strategies, TDG supersaturation from Grand Coulee down through Priest Rapids remains a prevalent environmental concern during the voluntary spill season that lasts from early April through mid-August [Figs. 2(a and c)].

The current approach to system-level TDG management on the Columbia River is based on a spill priority system established by USACE that lists the order in which each project will spill and the maximum amount of water to be spilled (Pickett et al. 2004). The spill priority list provides a reference for the expected TDG supersaturation under all possible spill conditions at all projects. Projects are assigned a daily spill cap, an estimated spill rate that will produce a target level of TDG supersaturation in the tailrace. The spill priority list and caps are set based on daily consideration of fish and environmental objectives, current TDG levels, weather conditions, forecasted TDG levels, and power demand, among other variables. Although this comprehensive approach to TDG management does include a TDG predictive model (Schneider and Hamilton 2009), and despite several models having been developed to predict and assess TDG uptake at Columbia River hydropower projects (Palmer and Cohan 1987; Columbia Basin Research 2000; Politano et al. 2009; Schneider and Hamilton 2009; Hadjerioua et al. 2015; Politano et al. 2017), the authors are not aware of any generalized models or tools capable of optimizing the systematic interdependencies of hydropower operation, basin-scale TDG production, and existing water management objectives and constraints. An optimization model has the ability to allocate spill ideally across projects to minimize systemwide TDG production while meeting power and nonpower water management objectives. This capability is

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**Fig. 2.** Daily average tailrace TDG and spillway discharge for (a and b) Grand Coulee; (c and d) Priest Rapids from 2004–2012 (solid line); maximum and minimum observed values are used to bound an upper and lower range, respectively.
unprecedented in existing mid-C operational models and would prove a valuable advancement in decision support compared to the current spill priority system.

Mid-C Central currently uses RiverWare 7.0. to forecast and optimize hydropower system operations. RiverWare (Eschenbach et al. 2001; Zagona et al. 2001), a general multimedia river, reservoir, and hydropower optimization modeling tool for short-term operations and long-term planning, was first applied to the mid-C system by Magee et al. (2011) to evaluate the impact of wind generation on hydropower system performance, including the ability to meet environmental objectives, among which are TDG constraints. Their study demonstrated the potential cost to TDG objectives of using hydro to balance loads, particularly in high-flow periods. Results were obtained using a successive linear goal programming approach for the nonlinear TDG equations (Columbia Basin Research 2000), which could not guarantee convergence or finding a global optimum.

This study aims to incorporate refined TDG equations in RiverWare to enhance the linear goal programming solver to converge on a locally optimal solution and implement the solution completely within RiverWare without external scripting. Application to the mid-C system will demonstrate the tradeoffs between meeting the TDG constraints and meeting requests and other system objectives. The resulting modeling framework will provide a generalized tool for including TDG constraints in hydro systems with a complex set of operational objectives and constraints.

Data Acquisition

Hourly data records of TDG, water temperature, headwater and tailwater elevations, and volumetric flow discharge for power generation and spill for 2004–2012 were obtained for all seven facilities on the mid-C. TDG data were obtained from Dataquery, a USACE hydrometeorological data search engine for the Pacific Northwest (United States Army Corps of Engineers 2016). Data for missing values of tailwater TDG values for Rocky Reach and Rock Island were acquired from Chelan PUD (W. Frantz, personal communication, 2015). Flow data for Grand Coulee and Chief Joseph were retrieved from Columbia Basin Research (2015), and the outlet works rating curve and tailwater information were used to disaggregate power generation and spill flows. Flow data for the remaining five facilities were available in Dataquery.

Fixed Monitoring Station Description

The mid-C water-quality (WQ) measurement program maintained by the USACE relies on two fixed monitoring stations (FMS) located in the reservoir and tailrace, respectively, of each facility. USACE maintains a working relationship with each dam owner for the collection and reporting of water-quality data. The FMS, described in project water-quality management program reports (e.g., Public Utility District No. 1 of Chelan County 2005), generally consists of a multiprobe device enclosed in a submerged casing or conduit at a depth of roughly 4.5–6 m. The upstream FMS is affixed to the upstream face of the dam or a nearby dock or pier, and the downstream FMS is fastened to a bank, bridge, or scaffolding. Both FMS locations include telemetry that enables automatic collection and transmission of measurements to the USACE Corps Water Management System (CWMS). A full list of FMS instrumentation, installation, and calibration procedures, and quality control criteria has been provided by the U.S. Army Corps of Engineers (2013).

Placement of the upstream FMS is based on accessibility and the need to capture a representative, fully mixed TDG reading. Although the forebay FMS at several dams on the Snake and Lower Columbia River has reported thermally induced TDG spikes when placed at a depth shallower than 15 m (Carroll 2004), this issue has not been observed at mid-C projects. The downstream FMS is positioned to measure TDG at a point where all flows are assumed fully mixed. State and tribal mixing-zone provisions allow an area of maximum TDG immediately downstream of the structure to be excluded from WQ compliance (Pickett et al. 2004), because fish move quickly through this region with no adverse effects. The presence of dynamic processes that persist a considerable distance downstream, including lateral TDG exchange and flow entrainment in the stilling basin, complex spill bay flow patterns, recirculation, intense mixing, and degassing (Turan et al. 2006; Schneider 2012) introduce notable challenges in setting a location that obtains accurate and consistent measurements that reflect a true cross-sectional average. Therefore, the downstream FMS may be located from 0.5 to 14.5 km downstream of the dam.

Data Filtering

An additional level of data quality control was conducted to supplement the formal USACE procedures. Hourly entries were removed when water temperatures were below 0°C or above 26.7°C, when TDG saturation was below 50% or above 300%, when data were physically inconsistent with facility characteristics, or when unfeasible flow values or water surface elevations were present. The need for flow, TDG, and water surface elevation data for each hour led to the removal of the full hourly entry if one or more of these values were not available. Spillway deflectors installed at Chief Joseph in 2008 to help prevent bubbles from descending into the tailrace significantly increased water entrainment, modifying the flow pattern with respect to previous years (Politano et al. 2009; Schneider 2012). To avoid confounding two separate tailrace flow regimes, all Chief Joseph data before 2008 were removed from the data set. Finally, data were excluded at Grand Coulee when the forebay elevation was less than 386 m. Spill flow passes through outlet tubes when the forebay is less than roughly 386 m, producing higher TDG per volume of water than spill flow that passes through drum gates at higher forebay elevations. For simplicity, the higher elevation operating rule was chosen, which represents approximately 72.5% of spill events.

The total number of hourly data records remaining after filtering is given in Table 2. The number of filtered records with no spillway flow is also displayed to provide a sense of how often spill is carried out at each project, and thus how often TDG uptake can be predicted. The majority of data for the five downstream projects contains spill events, with Grand Coulee and Chief Joseph, the two largest projects, spilling a smaller magnitude than downstream projects [Figs. 2(b and d)] and less frequently. Several FMS locations only record TDG data between April 1 and August 31, when

Table 2. Filtered Data Records

<table>
<thead>
<tr>
<th>Project name</th>
<th>Number of hourly data records</th>
<th>Number of filtered hourly data records</th>
<th>Number of filtered hourly data records with spill flow = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grand Coulee</td>
<td>74,531</td>
<td>55,144</td>
<td>51,235</td>
</tr>
<tr>
<td>Chief Joseph</td>
<td>74,446</td>
<td>20,065</td>
<td>15,475</td>
</tr>
<tr>
<td>Wells</td>
<td>74,534</td>
<td>31,548</td>
<td>6,774</td>
</tr>
<tr>
<td>Rocky Reach</td>
<td>59,229</td>
<td>18,604</td>
<td>—</td>
</tr>
<tr>
<td>Rock Island</td>
<td>74,526</td>
<td>28,223</td>
<td>4,570</td>
</tr>
<tr>
<td>Wanapum</td>
<td>74,526</td>
<td>35,902</td>
<td>13,650</td>
</tr>
<tr>
<td>Priest Rapids</td>
<td>74,527</td>
<td>33,176</td>
<td>12,784</td>
</tr>
</tbody>
</table>
TDG compliance becomes an operational concern (USACE 2013), thus leading to a small percentage of hourly data records once filters are applied.

**TDG Uptake Model Development**

A reduced-order equation for TDG uptake at hydropower dams was developed based on the underlying physical processes of air entrainment and mixing in the tailrace. The generalized empirical approach that was applied has numerous practical and mathematical benefits. A reduced-order model developed, calibrated, and validated using data from existing FMSs softens the need for expensive near-field TDG studies, and enables a simplified recalibration as more data become available. Further, modeling the mechanistic processes of gas exchange requires knowledge or estimates of dynamic physical parameters that are not easily measured in space or time at each structure, such as bubble-size distributions, bubble residence times, and liquid film coefficients (Geldert et al. 1998; Orlins and Gulliver 2000; Witt and Gulliver 2012), and large uncertainties in TDG prediction persist even in complex hydrodynamic models that account for these variables (Politano et al. 2009). Finally, a generalized predictive equation can be applied as a supplemental tool in daily hydropower optimization software or in long-term basin planning scenarios to assess the impact of system-wide hydropower decisions on TDG distributions.

**General Methodology**

The mathematical approach assumes a simplified TDG predictive equation can be developed based on two significant physical processes: TDG production through air entrainment and bubble dissolution, and the mixing of spillway flows with lateral powerhouse flows (Fig. 3). Both processes occur in the mixing zone, generally defined as the aerated region of the tailrace and assumed to be within ~300 m (1,000 ft) of the spillway for hydropower projects on the mid-C based on observations of flow conditions, scale physical models, and field measurements (Schneider and Hamilton 2009). The dependent variable, tailrace TDG (TDG$_t$), is modeled as a function of spillway flow ($Q_s$), powerhouse flow ($Q_p$), lateral powerhouse flows entrained into the spillway region ($Q_e$), tailwater depth ($H_t$), and forebay TDG (TDG$_f$). Both forebay and tailrace TDG are assumed well-mixed at the respective locations of the fixed monitoring stations and are expressed as a percentage equivalent to the ratio of TDG pressure to ambient atmospheric pressure

$$TDG = \frac{P_{atm} + P_{TDG}}{P_{atm}} \times 100\% = \left(1 + \frac{P_{TDG}}{P_{atm}}\right) \times 100\% \quad (1)$$

where $P_{atm}$ is ambient atmospheric pressure; and $P_{TDG}$ = TDG gauge pressure.

**Air Entrainment at the Spillway**

Dissolution of bubbles entrained during the plunging of spillway flows in the tailrace (air entrainment) is considered the primary source of TDG supersaturation in mid-C hydropower projects. Although there is a continuous mass transfer across the free-surface interface, the contribution of this surface transfer to TDG concentrations in the mixing zone is commonly considered negligible (Gulliver 2014). Several authors have shown a strong correlation between TDG levels and tailwater depth (Pickett et al. 2004; Urban et al. 2008; Li et al. 2009), because pressure exerted on a plunging bubble increases with depth from the free surface, and so too does the equilibrium pressure for bubble-water mass transfer. The most significant parameter to limit the gas transfer from entrained air into the flow is the depth where bubbles are in equilibrium with tailrace pressures. For large turbulent rivers that produce a substantial amount of bubbles through air entrainment, the bubble distribution is assumed to be well-mixed downstream of the mixing zone with a mean position of one-half the depth of the river (Geldert et al. 1998). In this study, it is assumed that mass transfer occurs at the average bubble depth, defined as one-half the tailrace depth. The TDG gauge pressure is thus modeled as the equilibrium pressure exerted on bubbles at the average bubble depth

$$P_{TDG} = 0.5 \rho g H_t \quad (2)$$

where $\rho$ = water density (kg m$^{-3}$); $g$ = acceleration due to gravity (m$^2$ s$^{-1}$); and $H_t$ = tailwater depth (m), taken as the instantaneous tailwater elevation minus the average stilling basin elevation.

The total dissolved gas of flows subject to air entrainment is determined by combining Eqs. (1) and (2), and multiplying by a dissolution efficiency coefficient

$$TDG_u = \left[1 + \frac{0.5 \rho g H_t}{P_{atm}}\right] \times 100\% b_1 \quad (3)$$

where TDG$_u$ = percent supersaturation of aerated flow; and $b_1$ = dissolution efficiency coefficient, calibrated for each structure and representative of how effective each tailrace is at dissolving bubbles under equilibrium pressure.

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**Fig. 3.** Schematic of air entrainment, powerhouse-flow entrainment, and model parameters
Powerhouse Lateral Flows

The flow used to drive hydroelectric turbines in the powerhouse is not exposed to entrained air bubbles, and thus the TDG pressures of flow released from the powerhouse are assumed equivalent to the TDG pressure in the forebay. If this TDG pressure is undersaturated with respect to local conditions in the tailrace, it will be driven toward an equilibrium saturation at that local condition when exposed to bubbles. As the high-energy surface jets from the spillway enter the tailrace, they draw water laterally into the jet region from the powerhouse release region through a phenomenon called water entrainment. High-fidelity numerical models that accurately predict water entrainment show that powerhouse flows accelerate toward the spillway region as the spillway jets decelerate, and the presence of bubbles suppresses jet turbulence, which leads to a slower decay in jet strength and thus stronger water entrainment for bubbly flows (Turan et al. 2006; Politano et al. 2009).

For model simplicity, the dependence of water entrainment on the energy of spillway flows is taken as a linear relationship bounded by the total powerhouse flow, as proposed by Schneider and Hamilton (2009). Without spillway discharge, there is no mechanism to attract powerhouse flows into the spillway region and no air-entrainment mechanism to drive local TDG supersaturation. As spillway flows increase relative to powerhouse flows, both bubble production and water entrainment ramp up to a point when nearly all powerhouse flows are exposed to bubbles entrained at the spillway. This relationship is expressed as

\[ Q_e = \min\{Q_p, \max\{(b_2Q_s + b_3), 0\}\} \]

where \( Q_e \) = flow entrained into the spillway region; \( Q_p \) and \( Q_s \) = total powerhouse and spillway flows, respectively; and \( b_2 \) and \( b_3 \) = model coefficients that represent the site-specific geometric configuration of the spillway in relation to the outflow direction of the powerhouse. The use of two fitted coefficients for water entrainment reflects the need to address the inconsistency, among all sites, of the location of the downstream fixed monitoring station with respect to the hydropower facility.

The magnitude of flows subject to spillway aeration, \( X_a \), is taken as the sum of spillway and entrained flows normalized by the total project flow

\[ X_a = \frac{Q_s + Q_e}{Q} \]

and the proportion of flows that carry background TDG pressures downstream from the forebay is taken as the powerhouse flow minus the entrained flow normalized by the total project flow

\[ X_f = \frac{Q_p - Q_e}{Q} \]

where \( Q = \) sum of \( Q_p \) and \( Q_s \).

Tailrace TDG

The uptake of TDG in the tailrace is modeled as the sum of flow-weighted contributions of aerated and nonaerated flows, or by combining Eqs. (3)–(6)

\[ \text{TDG}_{1s} = X_a\text{TDG}_a + X_f\text{TDG}_f \] (7)

where \( \text{TDG}_{1s} \) = simulated tailrace TDG; and \( \text{TDG}_f \) = measurement at the fixed monitoring station in the forebay.

Eq. (7) predicts tailrace TDG during spill events. If there is no spill, a common occurrence, the underlying assumptions of powerhouse lateral flows and air entrainment at the spillway are no longer valid, because powerhouse outflows are not attracted toward the spillway region, and there is generally no mechanism contributing to TDG uptake in the region between the water conveyance intake and powerhouse outlet. In this study, an average baseline TDG uptake, \( \text{TDG}_b \), is computed for each structure for all no-spill events. The sum of \( \text{TDG}_f \) and \( \text{TDG}_b \) is taken as \( \text{TDG}_{1s} \) for no-spill events, giving the final form of the TDG uptake model as follows:

\[ \text{TDG}_{1s} = \gamma(X_a\text{TDG}_a + X_f\text{TDG}_f) + (1 - \gamma)(\text{TDG}_f + \text{TDG}_b) \]

where

\[ \gamma = \begin{cases} 1 & \text{if } Q_s > 0 \\ 0 & \text{if } Q_s = 0 \end{cases} \]

Calibration, Validation, and Uncertainty

For all seven mid-C hydropower projects, model calibration to determine the coefficients \( b_1 \), \( b_2 \), and \( b_3 \) is carried out through a least-squares regression that minimizes the difference between model output [TDG] and field measurements [TDG]. Only hourly entries with spill \( Q_s > 0 \) are used for model calibration. The calibration and validation data sets are partitioned to include a representative sample of wet and dry years based on average annual flow conditions in the mid-C as measured at USGS flow gauges upstream of Wells and downstream of Priest Rapids. Data from calendar years 2008–2010 comprise the calibration set for all projects, and the validation set contains data for years 2004–2007, 2011, and 2012 with one notable exception. Spillway deflectors were installed at Chief Joseph in 2008 to help prevent bubbles from descending into the tailrace. The deflectors significantly increased water entrainment, modifying the flow pattern with respect to previous years (Politano et al. 2009; Schneider 2012). Validation at this project is carried out exclusively during 2011 and 2012 to avoid confounding two separate tailrace flow regimes.

The statistical parameters used to evaluate the fit of the calibrated model include the root-mean-square error (RMSE) and coefficient of determination \( (R^2) \). These values are displayed for validation and calibration sets, along with TDG, and model coefficients, in Table 3. All validated data sets show strong agreement between the model prediction and measurements, indicating that the distinct contributions of \( X_a \) and \( X_f \) predict the behavior of air and water entrainment over a wide range of spills and inflow TDG levels. The coefficient of determination is above 0.9 and the RMSE is between 1.1 and 2.3% for all validated data sets, consistent with the results of complex TDG predictive models (Orlins and Gulliver 2000; Urban et al. 2008; Politano et al. 2009, 2017).

All data from calibration and validation data sets were modeled with Eq. (8) and compared with measurements to provide a system-level overview of TDG uptake predictive capability (Figs. 4–6).

<table>
<thead>
<tr>
<th>Project name</th>
<th>TDG ( b_1 )</th>
<th>( b_2 )</th>
<th>( b_3 )</th>
<th>( R^2 )</th>
<th>RMSE ( R^2 )</th>
<th>RMSE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grand Coulee</td>
<td>−0.09</td>
<td>0.56</td>
<td>1.09</td>
<td>0.79</td>
<td>2.33</td>
<td>0.94</td>
</tr>
<tr>
<td>Chief Joseph</td>
<td>0.08</td>
<td>0.71</td>
<td>1.51</td>
<td>3.54</td>
<td>0.93</td>
<td>2.54</td>
</tr>
<tr>
<td>Wells</td>
<td>0.5</td>
<td>0.49</td>
<td>0.34</td>
<td>−73.8</td>
<td>0.96</td>
<td>0.94</td>
</tr>
<tr>
<td>Rocky Reach</td>
<td>−0.56</td>
<td>0.77</td>
<td>1.10</td>
<td>263.2</td>
<td>0.86</td>
<td>1.51</td>
</tr>
<tr>
<td>Rock Island</td>
<td>0.0</td>
<td>0.94</td>
<td>0.03</td>
<td>119.4</td>
<td>0.95</td>
<td>1.27</td>
</tr>
<tr>
<td>Wanapum</td>
<td>0.78</td>
<td>0.78</td>
<td>0.30</td>
<td>58.8</td>
<td>0.93</td>
<td>1.69</td>
</tr>
<tr>
<td>Priest Rapids</td>
<td>0.1</td>
<td>0.90</td>
<td>0.01</td>
<td>172.8</td>
<td>0.97</td>
<td>1.10</td>
</tr>
</tbody>
</table>
The percentage error, \( (TDG_{\text{sim}} - TDG_{\text{m}})/TDG_{\text{m}} \), is presented as a frequency distribution below each plot. The clear trend captured by the model is an increase in tailrace TDG with spill. High-spill events are modeled particularly well at Chief Joseph, Wells, Rock Island, and Priest Rapids, where simulated TDG is distributed tightly along a perfect 1:1 fit to measurements. The corresponding percentage error of the simulations at these structures is also tightly distributed around 0%, with the majority of modeled points contained within a range of \( \pm 5\% \) error and RMSE values between 1.1 and 1.6% of measured TDG. The outliers corresponding to extreme events at Grand Coulee and Wanapum, although clearly visible on the plots, only make up a small fraction of the total sample, as evident from the frequency distribution plots.
Discussion of Results

An example of the predictive capability of Eq. (8) is displayed in Fig. 7, which shows simulated and measured tailrace TDG for all projects during the month of July 2009. The model captures a number of distinct system characteristics well, including the range of maximum to minimum TDG throughout the system, daily and weekly fluctuations in TDG, overall system variability in TDG magnitude, and most importantly, project-specific dependence of TDG uptake on spillway flow. Some projects maintain a consistent Q_s throughout the month that does not appear to correlate with daily or weekly variability in TDG [Figs. 7(f and g)]. Two projects pass almost no flow over the spillway [Figs. 7(a and b)] but still exhibit daily TDG patterns based on TDG_f. The remaining projects show distinct daily patterns with strong correlation between TDG and Q_s [Figs. 7(c–e)]. Proper simulation of this markedly diverse behavior indicates project geometry, TDG characteristics of the incoming flow, and hourly operational data must be known and accounted for in a predictive model. Calibration of model coefficients that characterize lateral powerhouse flows and the magnitude of flows subject to spillway aeration can be used to sensitize TDG uptake to spillway discharge.

Powerhouse Lateral Flows

The geometries of each facility govern the behavior of lateral-flow entrainment (Fig. 8). Several structures were constructed with spillway and powerhouse outlet flows that converge in the stilling basin, enabling greater lateral attraction of Q_p. The structural orientation at Chief Joseph [Fig. 8(b)] is particularly suited for lateral-flow entrainment, because powerhouse outflows run perpendicular to the direction of spillway flows. When Q_s exceeds approximately 40% of maximum spill levels, all powerhouse flows are laterally entrained and subject to supersaturation. The installation of spill deflectors at this location likely helps to mitigate the effects of X_p-TDG_a by limiting bubble depth in the plunge pool. At the remaining three structures shown in Fig. 8, it is rare that the full quantity of Q_p is entrained by Q_s and subject to supersaturation. The unique hydrocombine configuration at Wells means Q_p has less of a physical meaning. With spillway bays located above the powerhouse outlets, it is probable that intense mixing of Q_p and Q_s occurs immediately downstream of the facility, but the action of spillway jet deceleration that leads to flow entrainment at conventional facilities is not applicable.

Moving vertically up each plot, it is evident that a single value of Q_s can lead to drastically different levels of lateral entrainment based on the relative difference between Q_p and Q_p'. The general trend across all structures is that higher Q_p results in less lateral entrainment at a given Q_s. Some anomalous behavior is observed near the origin of the plots for Grand Coulee and Wanapum, where entrainment increases sharply at low Q_s and low Q_p'. At these locations, the value of Q_p is lower than Q_s and approaching the

Fig. 6. (a) Simulated versus measured TDG_t for Priest Rapids indicated by Q_s; (b) frequency distribution of percentage error

Fig. 7. Comparison of simulated (solid line) and measured (scatter points) TDG, during the summer of 2009 for (a) Grand Coulee; (b) Chief Joseph; (c) Wells; (d) Rocky Reach; (e) Rock Island; (f) Wanapum; (g) Priest Rapids
theoretical value of $Q_e$. This situation does not occur frequently, however, because $Q_p$ is nearly always operated to meet the rated discharge for a given head. Moving horizontally across each plot, the same $Q_e/Q_p$ ratio can represent a range of $Q_s$ and $Q_p$.

**TDG Uptake Mechanisms**

Although the respective contributions of $X_f$ and $X_a$ toward the fully mixed tailrace outflow TDG fluctuate based on the magnitude and mix of $Q_s$ and $Q_p$, [Eqs. (5) and (6)], two distinct facility-level behaviors may influence this relationship. These dynamics are highlighted at Wanapum over a 5-day range in June and July 2009 (Fig. 9). First, the magnitude of $X_a$ is very clearly proportional to diurnal spill releases between 500 and 2,000 m$^3$·s$^{-1}$, evidenced by the increase in $X_a$TDG at the expense of $X_f$TDG [Fig. 9(a)].

When spill releases remain constant but powerhouse flows vary dramatically to meet the system energy needs [Fig. 9(b)], a similar variability in $X_a$TDG is observed. However, this behavior is clearly driven by diurnal powerhouse patterns that decrease the proportion of $Q_p$ in the tailrace. Because powerhouse flows are reduced in magnitude, at times below the quantity of spillway flow, a higher percentage of powerhouse flows are laterally entrained and supersaturated, and the contribution of $X_a$TDG becomes significant despite the relatively low spill magnitude. The minimum function in Eq. (4) coupled with the project-specific estimate of $Q_e$ as a function of $Q_s$ determine the point at which all powerhouse flows are laterally entrained and supersaturated.

These behaviors are important to highlight for two key reasons. First, there is a highly dynamic relationship between energetic spill releases, downstream zone of supersaturation, lateral attraction of powerhouse flows, and dilutive capacity of powerhouse flows. Many of the decisions driving this behavior (i.e., mix of $Q_p$ and $Q_s$) are made based on system-level policies and coordination across multiple structures. Foreknowledge of how system management decisions will affect TDG on an hourly, daily, weekly, and seasonal basis is extremely valuable in forecasting simulations. Second, system load patterns directly influence the behavior of tailrace TDG. Powerhouse flow patterns correspond with power system requirements, which may vary drastically from the early morning hours through the late afternoon and evening. When powerhouse flows are reduced, an inversely proportional increase in spillway flows may or may not be necessary. Quantifying how TDG levels may change with each scenario is a critical step toward a better understanding of the tradeoffs between hydropower generation and environmental impact.

**Implementation in RiverWare**

A previous RiverWare optimization model of the mid-C used a preemptive linear goal programming approach, which solves a series of prioritized objective functions, many of which are designed to minimize the violation of constraints (specific mid-C system constraints are described in the “Mid-C Operating Policy and Constraints” section). After optimizing each objective function, the objective function’s value is locked in place so that lower-priority objectives cannot degrade higher-priority objectives. The RiverWare optimization method used in this study extends this approach through successive linear programming. Successive linear programming approximates nonlinear and nonconvex functions with linear functions, and with each successive solution of the linear program, the linear approximation is adjusted. This process continues until convergence criteria are met. This approach is necessary because Eqs. (5)–(8) are nonlinear in the decision variables, $Q_p$ and $Q_s$. The specific formulation of the optimization model is detailed in Table 1.
corresponds to a constraint being unviolated. Presented in terms of degree of satisfaction, where 100% satisfaction have been locked in place or are fully satisfied. Each repetition is an
This process is repeated until all of the constraints for this priority
largest violation(s), and then minimize the remaining violations.
extends this concept to successive iterations that lock in place the
largest constraint violation for a given priority. Repeated Minimax
tion that minimizes the violation of constraints, this study applies a
Although
Successive Linear Preemptive Goal Programming
Although RiverWare has many ways of creating an objective function that minimizes the violation of constraints, this study applies a
Repeted Minimax approach. Traditional Minimax minimizes the
largest constraint violation for a given priority. Repeated Minimax extends this concept to successive iterations that lock in place the
largest violation(s), and then minimize the remaining violations.
This process is repeated until all of the constraints for this priority have been locked in place or are fully satisfied. Each repetition is an
iteration in solving a Repeated Minimax goal. The results are presented in terms of degree of satisfaction, where 100% satisfaction corresponds to a constraint being unviolated.

For computational efficiency, RiverWare performs a change of variables from violation variables to satisfaction variables:
Satisfaction = Maximum possible violation − Violation. The Maximum possible violation comes from either a higher-priority constraint on the same variable or linear expression. For example, a physical bound on a variable may be used. With the substitution of variables, minimization is replaced by maximization and vice versa.

Mid-C Operating Policy and Constraints
The TDG uptake equation is integrated into the broader mid-C RiverWare optimization model to predict tailrace TDG and provide
a means to constrain TDG in forecasting scenarios by allocating spillway and generation flows based on predicted uptake. The mid-C RiverWare model is driven by a complex operating policy expressed by 60 individually prioritized operating goals, each of which may be a single objective or a set of constraints (Clement et al. 2014a, b). These policies are prescribed by the many agreements that govern the operation of the system, including those of the constituent PUD project owners and those that describe hourly coordination efforts between the federal and nonfederal projects (Public Utility District No. 1 of Chelan County 2005). These policies are reflected in RiverWare in the form of soft constraints with objective functions to satisfy them to the extent possible. One can generally categorize these policies as high, medium, and low priority. The high-priority constraints may only be violated when unavoidable in the most extreme scenarios. Medium-priority constraints may require some manual relaxation if they are initially unattainable, but they are eventually satisfied. Low-priority constraints use whatever flexibility is remaining to guard against future uncertainty and maximize the position of the reservoirs for future operations.

The high-priority policies that must be maintained include
(1) licensed minimum and maximum reservoir pool elevation levels; (2) minimum flows in the Vernita Bar reach directly below Priest Rapids Dam; (3) conservative constraints that approximate BPA’s operation of Grand Coulee and Chief Joseph dams; and (4) several high-priority flow constraints for fish survival that vary by season based on the stage of development of the fish. An additional high-priority constraint governs how much power the mid-C PUDs may borrow from BPA. This is referred to as positive bias, and the balance of power owed is termed accumulated exchange, which is repaid with negative bias. BPA limits both positive and negative bias and accumulated exchange. Mid-C Central also limits the ramping rate of bias. For purposes of this model, when bias is used, the outflows from Grand Coulee and Chief Joseph dam are adjusted accordingly without changing the power delivered by these dams to BPA’s system. In practice, BPA may adjust the bias request in some other way, but this model does not attempt to optimize the BPA reservoirs.

The medium-priority policies are requests for power and TDG constraints. The PUDs that own the nonfederal mid-C projects sell or lease shares to a number of participants who may have shares in multiple projects. Each participant makes a cumulative request for power from their shares for each hour. The requests are limited by the combined position of the paper ponds (unused energy stored in reservoirs from their shares) and the generation capacity of their shares. Mid-C Central then schedules the projects to meet the collective requests from all participants, termed the total nonfederal generation request. This is analogous to a single utility meeting the load from their customers.

The low-priority policies include (1) special operations, namely modified elevations and flows for maintenance and reservoir recreation events; (2) target operating range for headwater elevations;
of TDG levels and the ability to meet the medium priority goal of minimization of spill; (5) drafting for peak generation; and (6) efficient use of the water, i.e., maximizing ending reservoir elevations and minimizing accumulated exchange.

Historically, mid-C Central has manually managed TDG as a special operation with a medium priority, just before generation requests. Within this model, the TDG constraints are added as another medium-priority policy. Specifically, TDG is constrained in the forebay of Priest Rapids Dam and in the mixed outflow below the dam to be at or below 110% every hour. These constraints reflect a larger effort managed by the USACE to control TDG levels on the Columbia River. The USACE was historically concerned with TDG below each dam in the mid-C. Recently, mid-C Central suggested TDG could be minimized in the middle and lower sections of the Columbia River by minimizing TDG in the tailrace at Priest Rapids. The argument is based on the fact that low TDG levels in the forebay of Priest Rapids reflect low TDG levels upstream, and minimization of TDG uptake at Priest Rapids ensures low TDG levels will persist as the mid-C flows into the Lower Columbia River. The focus on minimizing tailrace TDG at Priest Rapids has added operational flexibility for most mid-C projects and has generally resulted in lower TDG levels than the historical approach of minimizing TDG at each structure.

Test Case Study

The test case study compares three TDG policy alternatives as middle-priority policies:
1. No TDG constraints;
2. Requests before TDG: requested nonfederal generation has higher priority than the 110% TDG constraints at Priest Rapids Dam; and
3. TDG before requests: the 110% TDG constraints at Priest Rapids Dam have higher priority than the requested nonfederal generation.

Alternatives 2 and 3 both modify TDG and generation requests as medium-priority policies. Alternative 3 most closely resembles the policy followed by mid-C Central.

A typical forecasting exercise for mid-C Central will include the simulation of hourly operations for a 72-h planning horizon. The solutions subsequently inform mid-C Central of optimal actions. In this test case, the three policy alternatives are implemented in a 72-h optimization beginning at 11:00 a.m. on July 2, 2015, a typical summer period with TDG issues. The inputs include hydrologic inflows and requests for nonfederal generation, among others.

The runtime for the mid-C model varies depending on which constraints are active in the model and which constraints are violated. Generally speaking, the runtime is approximately 1 min on a modern desktop computer. With TDG constraints added, the model was automatically rerun with improved approximations until it converged in 10 iterations. The overhead of the iterations was negligible. Thus, going forward, one would expect the average run time to be roughly 10 min. Performance improvement could certainly be undertaken in the future with TDG objective functions included to be roughly 10 min.

Performance improvement could certainly be undertaken in the future with TDG objective functions included to be roughly 10 min. Per-}

Table 4. Tailrace TDG Saturation at Priest Rapids and Generation Request Satisfaction

<table>
<thead>
<tr>
<th>Soft constraint</th>
<th>Alternative 1: No TDG constraints (%)</th>
<th>Alternative 2: Requests before TDG (%)</th>
<th>Alternative 3: TDG before requests (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Largest TDG saturation</td>
<td>117.9</td>
<td>113.3</td>
<td>110.0</td>
</tr>
<tr>
<td>Smallest generation/request</td>
<td>100.0</td>
<td>100.0</td>
<td>91.5</td>
</tr>
<tr>
<td>Largest generation/request</td>
<td>(2,652 MW/2,897 MW)</td>
<td>(1,763 MW/1,554 MW)</td>
<td>113.5</td>
</tr>
</tbody>
</table>

The effects of each TDG policy scenario are compared in terms of TDG levels and the ability to meet the medium priority goal of minimizing spill; (5) drafting for peak generation; and (6) efficient use of the water, i.e., maximizing ending reservoir elevations and minimizing accumulated exchange.
propose a multiobjective solution that is unlikely to be realized with traditional TDG control efforts.

Alternative 3 fully satisfies the TDG constraints, with TDG\(_{1,o}\) below 110% on July 2 and at 110% for the remainder of the simulation. Satisfaction of TDG constraints is achieved at the expense of nonfederal generation requests—generation shortfalls are observed in the first few hours and generation surpluses for the majority of remaining hours [Fig. 10(b)]. Surpluses are a commonly observed outcome that occurs when spill is reduced and the balance of flows must be passed through the powerhouse. The shortfalls are an unexpected result of this research, a result of spill reallocation to earlier time periods produced from a complex interaction of hundreds of constraints at different priorities and time periods. Goal programming sensitivity analysis was used to determine which higher-priority goals could reduce the shortfalls if they were modified. Five main factors have been identified that explain these results: (1) shifting the generation in time to meet TDG constraints requires a debiting and crediting of generation, per se, against requests for nonfederal generation; (2) limits on the availability of bias provided by BPA to the lower mid-C dams and limits on ramping bias that could otherwise make up the shortfall; (3) constraints on the operation of federal projects lead to an inflow pattern on nonfederal projects that does not always match the generation request pattern; (4) introduction of TDG optimization constraints; and (5) the initial nonfederal requests themselves.

To elaborate more broadly, the initial nonfederal requests are not feasible in Alternative 3 with the degree of bias allowed by BPA in this scenario. If Alternative 3 priorities had been implemented in an operational setting, mid-C Central would have communicated the need for the participants to adjust generation requests. These are not, however, firm nonfederal generation requests. Rather, participants have flexibility to deviate from their requests, within their contractual rights, and may be directed to do so by mid-C Central to ensure feasible system operation. In practice, after high-priority environmental constraints are met, participant request flexibility is limited by a combination of generation capacity, flexibility in generation timing as a function of inflows and available storage volume, and lagged transport of flow and TDG between reservoirs.

<table>
<thead>
<tr>
<th>Priority number</th>
<th>Soft constraint</th>
<th>Alternative 1: No TDG constraints</th>
<th>Alternative 2: Requests before TDG</th>
<th>Alternative 3: TDG before requests</th>
</tr>
</thead>
<tbody>
<tr>
<td>42</td>
<td>Special operations pool elevations</td>
<td>100.00%</td>
<td>5.90%</td>
<td>3.65%</td>
</tr>
<tr>
<td>43</td>
<td>Special operations outflows</td>
<td>94.01%</td>
<td>71.32%</td>
<td>85.65%</td>
</tr>
<tr>
<td>44</td>
<td>Special operations generation</td>
<td>1.64%</td>
<td>1.64%</td>
<td>1.64%</td>
</tr>
<tr>
<td>45</td>
<td>Rock Island target operating range</td>
<td>62.60%</td>
<td>1.64%</td>
<td>0.00%</td>
</tr>
<tr>
<td>47</td>
<td>No nonfederal spill</td>
<td>80.57%</td>
<td>80.57%</td>
<td>87.27%</td>
</tr>
<tr>
<td>51</td>
<td>Sequenced nonfederal outflows first 4 h</td>
<td>79.81%</td>
<td>25.04%</td>
<td>23.61%</td>
</tr>
<tr>
<td>52</td>
<td>Equal nonfederal draft</td>
<td>71.64%</td>
<td>39.41%</td>
<td>50.38%</td>
</tr>
<tr>
<td>54</td>
<td>Sequenced nonfederal outflows</td>
<td>68.29%</td>
<td>68.29%</td>
<td>73.93%</td>
</tr>
<tr>
<td>55</td>
<td>Smallest accumulated exchange</td>
<td>2,240,680 MWh</td>
<td>2,240,622 MWh</td>
<td>2,240,803 MWh</td>
</tr>
<tr>
<td>56</td>
<td>Largest accumulated exchange</td>
<td>100.00%</td>
<td>100.00%</td>
<td>100.00%</td>
</tr>
<tr>
<td>57</td>
<td>Balance reservoir elevations and accumulated exchange</td>
<td>96.32%</td>
<td>91.40%</td>
<td>88.93%</td>
</tr>
<tr>
<td>58</td>
<td>Maximize nonfederal ending storage</td>
<td>88.58%</td>
<td>81.87%</td>
<td>83.95%</td>
</tr>
<tr>
<td>59</td>
<td>Minimize bias usage</td>
<td>33.33%</td>
<td>6.11%</td>
<td>0.75%</td>
</tr>
<tr>
<td>60</td>
<td>Maximize total energy storage</td>
<td>281,188,633 MWh</td>
<td>281,071,660 MWh</td>
<td>281,089,936 MWh</td>
</tr>
<tr>
<td>61</td>
<td>Minimize weighted outflow</td>
<td>432,380 MW</td>
<td>437,285 MW</td>
<td>438,665 MW</td>
</tr>
<tr>
<td>62</td>
<td>Minimize weighted turbine release</td>
<td>420,656 MW</td>
<td>420,656 MW</td>
<td>421,056 MW</td>
</tr>
</tbody>
</table>

Fig. 10. (a) Optimized tailrace TDG at Priest Rapids for Alternatives 1, 2, and 3; (b) compared to the generation surpluses and deficits for all nonfederal mid-C projects that correspond with Alternative 3.
These factors are highlighted to suggest that, in theory, an opportunity exists to more closely meet generation requests and/or reduce or flatten TDGs levels in the mid-C through closer coordination of operational choices made by BPA and the mid-C PUDs. An improved use of bias and a shift in time of outflows from Chief Joseph may help match inflows into the nonfederal projects with the nonfederal generation requests. Such coordination would represent a significant change in policy that would have to be studied first, and from a modeling perspective, would require a less constrained operation of the federal projects. In practice, there are many practical and organizational reasons to be cautious about any policy changes.

Conclusions

This work summarized the development of a predictive equation for TDG uptake at hydropower facilities on the mid-Columbia River and detailed the incorporation of the equation into RiverWare for use in forecasting and optimizing basin-scale water, energy, and environmental priorities and constraints. The reduced-order linear approach demonstrated the utility of a simplified model for estimating complex three-dimensional hydrodynamics in the tailrace. This methodology can be extended to a wide range of hydropower facilities to abate TDG supersaturation upon a simple calibration of coefficients that quantify both the extent of mixing between power-house and spillway flows and dissolutton efficiency of the tailrace.

The results offered herein indicate that complex interdependent hydropower system decisions can be modeled successfully through successive linear preemptive goal programming. The TDG predictive equation represents a qualitative policy constraint that can be optimized to minimize TDG within a hydropower operator’s planning horizon. Depending on the rank of TDG minimization within a suite of broader policy objectives, TDG levels may be reduced or minimized even when power generation requests are considered at a higher priority. However, it is evident that generation shortages and surpluses result from placing TDG mitigation as a higher priority than power generation, due largely to the reallocation of spill among projects. In practice, hydropower operators and system coordinators may have economic motivations for resisting scenarios that create these conditions. This improved RiverWare model presented in this study can serve as a platform to theoretically and quantitatively explore the economic and environmental tradeoffs between coordinated water management decisions and various power and environmental policy-ranking scenarios.

Appendix. Linearization of the TDG Equations

Tailrace TDG from Eq. (7) is reformulated as a flow-weighted combination of spillway TDG and powerhouse TDG. The spill weight is increased and powerhouse weight is decreased by the entrainment of powerhouse flows

\[ \text{TDG}_{t,s} = X_s \text{TDG}_{t,a} + X_f \text{TDG}_f \]

\[ = \frac{(Q_s + Q_e)\text{TDG}_{t,a} + (Q_p - Q_e)\text{TDG}_f}{Q} \]  

(9)

The following equations represent constraints in the optimization model, and the variables refer to optimization model variables and not actual measurements. The subscripts remain unchanged for ease of presentation. Tailrace TDG is estimated in the optimization with a linear approximation of this equation

\[ \text{TDG}_{t,o} = \text{TDG}_{t,s} \text{(estimate)} + \Delta \text{TDG}_{t,o} \]  

(10)

where both TDG\text{,o} and \( \Delta \text{TDG}_{t,o} \) are optimization variables; and TDG\text{,s(estimate)} is calculated with Eq. (9) based on the previous optimization solution. The parameter \( \Delta \text{TDG}_{t,o} \) is constrained in the optimization with

\[ \Delta \text{TDG}_{t,o} = \frac{\partial \text{TDG}_{t,s}}{\partial \text{TDG}_{t,a}} \Delta \text{TDG}_{t,a} + \frac{\partial \text{TDG}_{t,s}}{\partial \text{TDG}_f} \Delta \text{TDG}_f \]

\[ + \frac{\partial \text{TDG}_{t,s}}{\partial Q_s} \Delta Q_s + \frac{\partial \text{TDG}_{t,s}}{\partial Q_p} \Delta Q_p \]

\[ + \frac{\partial \text{TDG}_{t,s}}{\partial Q_e} \Delta Q_e + \frac{\partial \text{TDG}_{t,s}}{\partial Q} \Delta Q \]  

(11)

where the partial derivatives are calculated based on the previous optimization solution

\[ \frac{\partial \text{TDG}_{t,s}}{\partial \text{TDG}_{t,a}} = \frac{Q_s + Q_e}{Q} \]

\[ \frac{\partial \text{TDG}_{t,s}}{\partial \text{TDG}_f} = \frac{Q_p - Q_e}{Q} \]

\[ \frac{\partial \text{TDG}_{t,s}}{\partial Q_s} = \frac{\text{TDG}_p}{Q} \]

\[ \frac{\partial \text{TDG}_{t,s}}{\partial Q_p} = \frac{\text{TDG}_t}{Q} \]

\[ \frac{\partial \text{TDG}_{t,s}}{\partial Q_e} = \frac{\text{TDG}_o - \text{TDG}_p}{Q} \]

\[ \frac{\partial \text{TDG}_{t,s}}{\partial Q} = - \frac{\text{TDG}_o(Q_s + Q_e) + \text{TDG}_f(Q_p - Q_e)}{Q^2} \]  

(12)

To improve convergence of the optimization, when either \( Q_s \) or \( Q_p \) but not both are near zero, the partial derivatives are calculated as if the small flow variable is zero in Eq. (9). When both \( Q_s \) and \( Q_p \) are near zero, the average of the partial derivatives from these two cases is used. The simulation calculations are unchanged for all of these cases.

Each of the \( \Delta \) variables in Eq. (11) are further constrained in the optimization model as follows:

\[ \text{TDG}_f = \text{TDG}_f \text{(estimate)} + \Delta \text{TDG}_f \]  

(13)

\[ Q_s = Q_s \text{(estimate)} + \Delta Q_s \]  

(14)

\[ Q_p = Q_p \text{(estimate)} + \Delta Q_p \]  

(15)

\[ \Delta Q_o = \Delta Q_s + \Delta Q_p \]  

(16)

The equation for \( \Delta Q_o \) depends on which equation is governing water entrainment [Eq. (4)]. If \( Q_e = Q_p \) and \( Q_p > 0 \) in the previous solution, then

\[ \Delta Q_e = \Delta Q_o \]  

(17a)

Otherwise

\[ \Delta Q_e = b_2 \Delta Q_s + b_3 \]  

(17b)

The forebay TDG is equal to a time lagged routing of the tailwater TDG of the upstream reservoir, and so are the \( \Delta \) variables

\[ \Delta \text{TDG}_f \text{(res, time)} = \Delta \text{TDG}_f \text{(upstream, time – lag)} \]  

(18)

where lag is estimated as 5 times the hydrologic lag time between dams.

The only optimization variable for \( \text{TDG}_a \) from Eq. (3) is tail-water elevation; thus, the constraint on \( \Delta \text{TDG}_a \) is

\[ \Delta \text{TDG}_a = \left( \frac{0.5 \rho g TW}{P_{\text{atm}}} \times 100\% \right) b_1 \]  

(19)
because the constant term $1 \times b_1$ in Eq. (3) drops out after applying the $\Delta$ operator.

In tailwater elevation for the mid-C reservoirs physically depends on the total outflow and/or the tailwater base value for the current and previous hours. If both outflow and the tailwater base value affect tailwater elevation, the constraint on the $\Delta$ variables is

\[
\Delta TW = \frac{\partial TW}{\partial BV} \Delta BV + \frac{\partial TW}{\partial BV_{t-1}} \Delta BV_{t-1} + \frac{\partial TW}{\partial Q} \Delta Q
\]  

(20)

If tailwater elevation at a given reservoir does not depend on outflow or tailwater base value, then the associated terms drop out of Eq. (9).

For the mid-C reservoirs, except for Priest Rapids, the tailwater base value is equal to the downstream pool elevation

\[
\Delta BV_{\text{reservoir}} = \Delta PE(\text{downstream reservoir})
\]  

(21)

where $\Delta PE$ = pool elevation in the forebay of the downstream reservoir. The next reservoir downstream of Priest Rapids, McNary, is far downstream, and its pool elevation does not affect the Priest Rapids tailwater elevation.

Pool elevation is a function of reservoir storage, formulated as a constraint of the form

\[
\Delta PE = \frac{\partial PE}{\partial S} \Delta S
\]  

(22)

where $\Delta S$ = change in storage. Using the incremental version of the mass-balance equation, the final constraint is written

\[
\Delta S = \Delta S_{t-1} + (\Delta Q_m - \Delta Q) \cdot \text{timestep}
\]  

(23)

where $\Delta Q_m$ = reservoir inflow; and the timestep of the optimization model is 1 h.

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