# RiverWare Model Development for Integrated Hydropower and Wind Generation Analysis on Columbia Basin

Final Project Report to UT-Battelle / Oakridge National Laboratory
for Subcontract: 4000097293

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**December 20, 2011**



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## *Abstract*

Interest in renewable energy in general and wind generation in particular has grown in recent years. Hydropower offers the potential to help coordinate renewable generation with power demand. The capability of hydropower to assist in this way is limited by non-power operational constraints. This research builds a framework with a realistic hydropower model of the Mid-Columbia River to evaluate the impact of wind generation on the hydro system, including the ability to meet environmental constraints. The framework is flexible with respect to wind penetration and variability to facilitate a wide range of options for future researchers. The framework was tested with a no-wind scenario and a wind scenario based on synthetic wind generation model. The test illustrates the ability of the framework to show meaningful differences between alternative wind scenarios.

# 1 Introduction

This research develops a framework for identifying the effects of alternative wind scenarios on the operation of the Mid-Columbia River using the RiverWare modeling tool with preemptive linear goal programming. The next subsection describes the Columbia River Basin and the Mid-Columbia River in particular and notes the treaties and agreements that govern the Mid-Columbia River. The following subsection briefly describes RiverWare and the functionality used to model the Mid-Columbia River. The RiverWare model of the Mid-Columbia River is described in Section 2 in three subsections: the physical model of reservoirs, hydro plants and river reaches along with the methods and data used; the operating policies and their priorities; and the modeling of Total Dissolved Gas (TDG). Section 3 describes the Wind-Hydro Modeling Framework and the synthetic wind model we developed to test the framework. Section 4 presents the results of testing the framework with this simple wind model.

The intent of this research project is to develop a modeling framework that can be used in subsequent studies of the effects of wind generation on the Mid-Columbia system. It illustrates the level of detail of physical process and operational policy modeling appropriate to address this issue and proposes some metrics for evaluating the effects of wind on the system performance. Because we have not used a realistic wind scenario, the results do not reflect realistic effects of wind on the Mid-Columbia system performance.

## 1.1 Mid-Columbia River

The Columbia River and its tributaries cover parts of British Columbia in Canada and Washing ton, Oregon, Idaho, and Montana in the United States. The Canadian reservoirs are managed by BC Hydro. Some of the U.S. reservoirs are owned by either the U.S. Army Corps of Engineers (USACE) or the U.S. Bureau of Reclamation (USBR) and are coordinated by the Bonneville Power Administration (BPA). The remaining U.S. reservoirs are privately owned and operated with varying degrees of coordination with BPA. The largest storage capacity of the Columbia River is in Canadian reservoirs. Canada and the U.S coordinate operations based on the Columbia River Treaty. Under the treaty, the Canadian entitlement is one half of the additional U.S. power generated because  of the Canadian storage. U.S public and private operations are coordinated to meet treaty obligations through the Pacific Northwest

Coordinating Agreement. Figure 1 shows the Columbia River Basin and its reservoirs. For additional information, BPA, USBR, and USACE have published an informative overview: The Columbia River System Inside Story (2001).


**Figure 1: Columbia River Basin**

The Mid-Columbia River includes five non-federal reservoirs, from upstream to downstream: Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids. Wells is operated by Douglas County Public Utility District (Douglas PUD). Rocky Reach and Rock Island are operated by Chelan County PUD. Wanapum and Priest Rapids are operated by Grant County PUD. The PUDs have sold and leased “slices” of their projects to other utilities, which are referred to as “participants.” The participants share in all aspects of the projects, including the energy available, generation capacity available, energy storage capacity, and the cost of generation. Participants may own shares of several projects and can draw on the cumulative capabilities of their slices. The five non-federal projects are coordinated by the “Central” operations group for the Mid-Columbia projects, currently housed within Grant PUD. Central coordinates the reservoirs to meet all of the participants’ power requests subject to constraints including environmental requirements, license limits, and other operational constraints.

Under the Mid-Columbia Hourly Coordination Agreement, the participants coordinate generation and flows with the two upstream federally owned projects, Grand Coulee and Chief Joseph. In practice, this coordination is carried out between Central and BPA. One motivation for the agreement is that the storage in Lake Roosevelt behind Grand Coulee dam is considerably larger than the storage in the other projects. A more in depth summary of the major agreements governing the Mid-Columbia River can be found in Appendix A of the Rocky Reach Water Quality Plan.

An important facet of the coordination between BPA and Central is generation “bias.” Positive bias is created when the federal projects increase generation beyond BPA’s needs and equally decrease the non-federal generation below the participants’ requests, essentially lending energy from the federal projects to the non-federal projects. Negative bias exists when the generation relative to the requests is reversed, effectively paying back the loaned energy. The total amount of energy owed by the non-federal projects to the federal projects at any given time is called “accumulated coordinated exchange.” BPA places constraints on both bias and accumulated coordinated exchange, and these constraints vary with time. For example, BPA occasionally requires accumulated coordinated exchange to be zero.

Hydropower is a major source of power in the Pacific Northwest. Recently, wind power has also become a significant source of power and there is significant potential to increase wind generation in the region. One challenge in the region is that combined wind and hydropower generation can occasionally exceed power demand and result in negative economic values for power generation. During these periods, either wind generation or hydropower generation must be curtailed. Wind power can be curtailed by adjusting blade angles, but this can lead to economic stress for the wind generators and raises contractual issues for BPA. A reduction in hydropower can be accomplished by reducing flows or spilling flows instead of generating. However, required flows may limit flow reductions and spill generally increases the production of TDG and may be limited by fish mortality caused by excess TDG concentration.

## 1.2 RiverWare

RiverWare is a general river system modeling tool for constructing and running site-specific models without users needing to develop or maintain the supporting software. RiverWare has been used for operations and planning for a wide variety of river basins, notably including models used by USBR, USACE, and the Tennessee Valley Authority (TVA). RiverWare was developed by the Center for Advanced Decision Support for Water and Environmental Systems (CADSWES) at the University of Colorado and continues to be enhanced to meet new modeling needs.

Models are constructed in RiverWare by dragging “objects” such as reservoirs and reaches from a palette and linking them together. Individual objects are customized by selecting appropriate “methods” for modeling physical processes and providing the individual parameters for these methods. In Section 2.1 we will describe the specific objects and methods used to model the Mid-Columbia River.

RiverWare has three solution mechanisms: simulation, rulebased simulation, and optimization. In simulation, objects calculate the consequences of any known inputs. For example, if initial storage levels, unregulated inflows, and all reservoir releases are known, then simulation can calculate the storage levels in the reservoirs for all time periods based on the mass balance equations of the reservoirs and routing equations in the river reaches between the reservoirs. For rulebased simulation, the user specifies prioritized “if-then” rules in lieu of some of the input values. For example, reservoir release rules that consider downstream demands, minimum flows, flood control policies or hydropower generation targets set the reservoir releases to meet these needs according to accepted operating policies. A specific rule could set the release based on the current storage. After the rule has set the release value, the reservoir can simulate, i.e., use its mass balance equation to solve for a new storage value. Then other rules can be executed. To address conflicting objectives, higher priority rules can overwrite the effects of lower priority rules but not vice versa. While all three controllers are used in the Mid-Columbia RiverWare model, the solution is predominantly determined by optimization. The optimization solution is a preemptive linear goal program — a series of linear programs in which higher priority objectives are not sacrificed for lower priority objectives. The objectives are expressed by the user in a set of prioritized constraints and objectives (called “goals”) that expresses the operating policies of the projects. Soft constraints are re-interpreted as objective functions to minimize deviations from meeting the soft constraints. While alternative approaches are available in RiverWare, the Mid-Columbia RiverWare model uses only one approach when multiple soft constraints have deviations at the same priority level: the largest deviation is minimized, and after that deviation has been minimized the process is repeated for the remaining deviations. This is referred to as repeated minimax.

The actual solution sequence for a complete optimization run is: simulation, optimization, rulebased simulation. In simulation, the consequences of any input values are calculated and stored. These calculations may reduce the size of the optimization model becaue they result in values of decision variables. The optimization, using the CPLEX solver, then successively solves a linear program with each of the objectives starting with the highest priority. The final optimal solution is a set of values for all the model decision variables at all timesteps for which input values have not been specified. Last, a special rulebased simulation is run which selectively sets values in the model to parts of the optimal solution and makes minor adjustments to correct for approximation errors. In the Mid-Columbia Model, the optimal values set in the model are turbine release, regulated spill, bypass, and other user defined variables which will be described later. Additional information about RiverWare optimization can be found in Eschenbach et al. (2001).

In addition to using RiverWare interactively, RiverWare can be run in “batch mode” without a user interface. Batch mode is an efficient and reliable way of putting RiverWare through an automated sequence of steps. These steps are specified with the RiverWare Command Language (RCL), a specialization of the widely used Tool Command Language (TCL). As we will explain in more detail later, this study uses batch mode in two ways: to implement Successive Linear Goal Programming (SLGP) for the modeling of nonlinear total dissolved gas equations and to mimic changing operations as a result of changing wind forecasts with overlapping RiverWare runs.

Additional information about RiverWare and its capabilities are described by Zagona et al. (2001, 2005) and in the RiverWare documentation (http://cadswes.colorado.edu/PDF/RiverWare/documemntation/).

# 2 Mid-Columbia RiverWare Model

## 2.1 RiverWare Physical Process Model

In this section we describe the RiverWare model of the Mid-Columbia River. The model is explained in greater detail in Clement et al. (2011a).

The model was built by CADSWES primarily with data supplied by Central, Grant PUD and Chelan PUD. Central also relayed data obtained from BPA for Grand Coulee Dam and Chief Joseph Dam and data for Wells Dam from Douglas PUD. TDG equations and data were obtained from the Columbia River Salmon Passage Model (CRiSP) developed by the University of Washington (2000) and to a lesser extent the System Total Dissolved Gas (SYSTDG) model developed by USACE (2009).

The model has a one hour time step with a variable length planning horizon. We anticipate that Central will integrate the model into their short term planning with varying durations for different purposes including planning for the rest of the day, planning several days or even a week in advance, or studying the effect of proposed changes. In Section 3 we will discuss a wind study prototype that uses a one week planning horizon. The model is set up to use default values for planning studies that can be overridden by known values in an operational setting. An important example of default values is the start and end dates of various operational seasons that vary from year to year based on weather and biological conditions.

The RiverWare model includes the following seven dams, from upstream to downstream: Grand Coulee, Chief Joseph, Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids. In addition, the model includes objects representing inflows from the Okanogan River, the Methow River, the Chelan River, the Entiat River, the Wenatchee River, and Crab Creek, all of which flow into the non-federal projects. The flows from these streams are inputs to the model. The river reach below Priest Rapids is also modeled because it includes an environmentally sensitive area, Vernita Bar. Figure 2 illustrates the objects included in the model.

The reservoirs are contiguous: the backwater from each reservoir reaches the next upstream dam. To represent this in the RiverWare model, the pool elevation for each reservoir is linked to the tailwater of the upstream reservoir. The thin lines connecting reservoirs in Figure 2 represent these links. The reservoirs are sufficiently long that there is a time lag between the release at one dam reaching the outlet works of the next downstream dam. The RiverWare model captures this lag by inserting Reach objects between the dams and using a constant lag time for each reach. This lag time ranges from 0.75 hours to 1.75 hours for the Mid-C reservoirs.

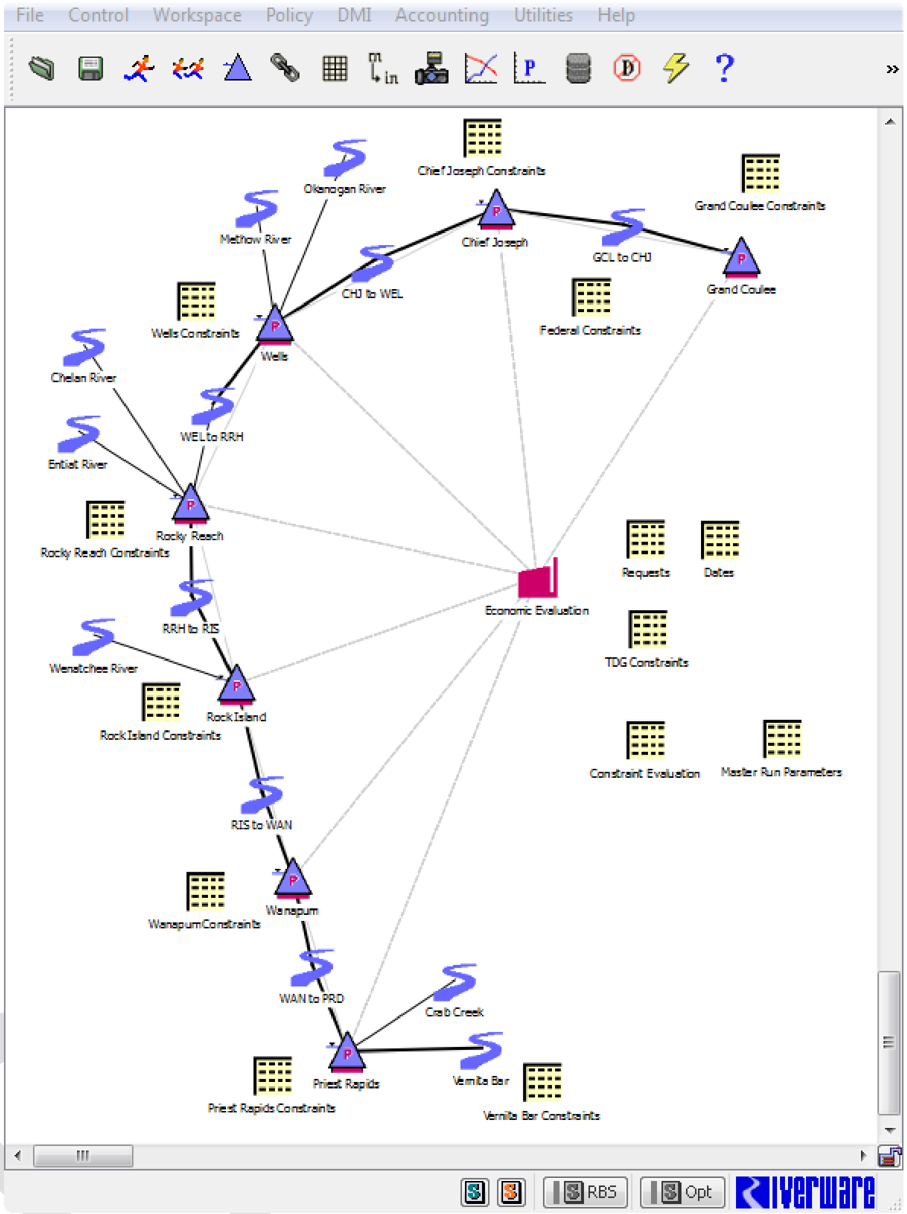


**Figure 2: Mid-Columbia River in RiverWare**

The main control point for monitoring flows at Vernita Bar is a USGS gauge(USGS 12472800) downstream of the Priest Rapids Dam. After performing regression analysis, the flow at the gauge was determined to be both a function of releases from Priest Rapids and an autoregressive term for the previous hour's flow at the gage. The estimated equation for flow is

$$USGS(t) = 0.325 \text{ Priest Rapids.Outflow}(t) + 0.3 \text{ Priest Rapids.Outflow}(t\text{-}1) + 0.375 \text{ USGS}(t\text{-}1).$$

RiverWare was enhanced to allow a combination of lags and autoregressive terms for reach flow. In this particular case the equation translated into a lag of 0.48 hours to reach the gage and autoregressive weights of 0.625 for current flows and 0.375 for previous flows.

The main method selections of note used to model the reservoirs in RiverWare were the “Plant Efficiency Curve” method of calculating hydropower generation; the “Tailwater Stage Flow Lookup”and “Tailwater Base Value Plus Lookup” methods for tailwater calculations; and the “Regulated Plus Bypass Spill Calc” method. The Plant Efficiency Curve method models power generation at a plant level as a function of operating head and turbine release. The data for specific points on the power generation surface are entered in a three column table with one row for each combination of the three values. Linear interpolation is used for values between the specific points. To facilitate interpolation, the table is composed of a series of blocks of data with each block having a different, constant operating head. Within each block of constant operating head, turbine release and associated power generation are systematically varied. The Tailwater Stage Flow Lookup method computes tailwater elevation as a function of both outflow and the downstream stage level. The data modeling is similar to the power modeling; the method uses a three column table to represent the surface and interpolates between the specific data points in the table. The Regulated Plus Bypass Spill Calc method models two separate spill methods. For the Mid-Columbia model the “normal” spillway is modeled as Regulated Spill with effectively infinite capacity while Bypass Spill is used to model alternative spillways for fish, such as fish ladders, with a limited capacity. Additionally, each of the Reservoirs has an Elevation Volume Table with discrete values representing the nonlinear curve of pool elevation vs. storage. Linear interpolation is used as needed to calculate values between the discrete points in the table.

## 2.2 Mid-Columbia RiverWare Optimization Policy

The Mid-Columbia policies represented in the model are based on discussions with Central, Grant PUD, and Chelan PUD. After the model was completed, the same parties verified the policy in the model.

In this section we summarize the policies in the RiverWare model of the Mid-Columbia River at a conceptual level. While most of the policies may seem straightforward, translating them into linear constraints and objectives can sometimes be more complicated. A good example of a complex policy in this model would be the amount and order of drafting reservoirs to meet minimum flows at Vernita Bar. A lengthy description of the details of implementing all of the policies is provided in Clement et al. (2011a).

The Mid-Columbia policies in the model represent Central’s decision making perspective. Thus, the model incorporates operational constraints that the Mid-Columbia must meet and generation requests from participants.

In addition, the model allows for alternative levels of coordination with BPA in the operation of Grand Coulee and Chief Joseph. At one extreme, the model allows Central to completely specify operations at Grand Coulee and Chief Joseph from BPA with no flexibility in bias or flows. In this case, it is assumed that BPA’s plan would incorporate all of the operational constraints on these two reservoirs. At the other extreme, the model can suggest optimal use of bias at Grand Coulee and Chief Joseph from Central’s perspective while meeting operational constraints on these reservoirs and meeting BPA’s requested generation. Such a solution could be the starting point for coordination discussions between Central and BPA. Between these two extremes, the model can optimize bias within additional constraints that BPA may communicate to Central. For the runs reported here, the bias at the federal projects is limited to 600 MW, but otherwise bias has been unconstrained.

In the remainder of this section we summarize the Mid-Columbia objectives and constraints and their priority levels. For ease of exposition some priority levels will be grouped together in this discussion even though the model breaks them out into separate priority levels. Also, some of the constraints are active only during the appropriate seasons.

- *User Defined Variables*: RiverWare allows user-defined variables in optimization to supplement the variables defined by the physical model. The equations defining these variables in terms of other variables have the highest priority in the Mid-Columbia model and will always be satisfied. The following variables are defined for use in later policy constraints: daily high and low outflow for Priest Rapids, revised request for Chief Joseph Accumulated Deficiency (CJAD), bias and accumulated deficiency at Grand Coulee and Chief Joseph, and variables related to computing TDG concentrations.
- *Repayment of CJAD*: CJAD arises seasonally and on weekends when BPA is obligated to release water from Chief Joseph to meet flow requirements downstream at Vernita Bar. However, BPA is allowed to temporarily delay this flow and repay it later in the week. Further complicating matters, forcing repayment at the required time could be potentially disadvantageous to Central. Thus, the constraints in the RiverWare model are written so that Central can require BPA to repay CJAD on time or intentionally postpone repayment of CJAD to the mutual benefit of Central and BPA.
- *High priority operations*: Coming after the variable definitions in priority are legal constraints that are virtually never violated: licensed minimum and maximum pool elevations, flood control at Pateros, and minimum flows at Vernita Bar.
- *Federal project constraints*: From Central's perspective, the constraints at the federal projects have the next highest priority levels. These constraints include the requested total daily release at Chief Joseph, tailwater and drawdown restrictions at Grand Coulee, cold weather generating capability at Chief Joseph, accumulated deficiency and repayment at Chief Joseph, federal generation requests, and scheduled 6-hour and 24-hour federal outflows.
- *Spills for fish*: The next priority is a combination of seasonal spills through the regulated and bypass outlets for the benefit of fish health and migration.
- *TDG constraints*: These constraints are to meet a variety of forebay and tailrace TDG limits which vary by season and are designed to reduce fish mortality. Some limits are instantaneous while others are rolling averages. The limits used in the model are based on a private communication with Central.
- *Vernita Bar flow requirements*: Vernita Bar has a variety of seasonal flow requirements to enhance fish populations at various stages of development. All of the flow requirements are based on measurements at the USGS gage downstream of Priest Rapids. If necessary, each of the Mid-Columbia projects may be drafted to meet the limits. The amount of draft and order of drafting is reflected in different priority levels below the priority of meeting the flows at Vernita Bar.
- *Minimize spill at federal projects*: The next objective is to minimize spill at the federal projects to the extent possible given the higher priority constraints.

- *Flow band constraints for fish*: During certain seasons, fish populations particularly benefit from steady flows. To accomplish this aim the changes in releases within a day from Priest Rapids are constrained to "flow bands." The size of the bands each day depends upon the previous day's flows.
- *Spawning flows at Vernita Bar*: The next priority is to meet flow requirements (between specified max and min flows) at Vernita Bar in daylight hours during the spawning period.
- *Summer recreational pool levels*: During summer holiday weekends, recreation on the river is higher than usual, and if flexibility exists the pool elevations are kept above specified limits. Central hasn't finalized these limits, and they were deactivated for the wind study.
- *Non-federal minimum generation*: The next priorities are to meet nonfederal minimum generation requirements at each project and the total generation requests of the nonfederal participants.
- *Coordinate bias and accumulated exchange with BPA*: Optionally, bias and accumulated exchange may be limited to target values if possible. The use of these constraints allows Central to model different levels of coordination with BPA.
- *Wells pool elevation for goose nesting*: During goose nesting season, the pool elevation at Wells must be above a specific value.
- *Special operations*: The model has deactivated constraints for special operations at the next priority. These constraints would be activated when operations are restricted for one time operations such as unit outages, maintenance, or recreation.
- *Vernita Bar flow minimum target for spawning*: During daylight hours of spawning season, exactly equaling the minimum flow level is the best flow to provide at Vernita Bar to benefit the fish. (A refinement of the max/min constraints in a higher priority policy.)
- *Maximize energy position at end of planning horizon*: Within the limits of the above constraints, Central would prefer to maximize its energy position at the end of the planning horizon. This position is a combination of maximizing reservoir elevations and minimizing accumulated exchange that must be repaid to BPA in the future. The next group of constraints pushes the system in this direction, striking a balance between energy in storage in the reservoirs and accumulated exchange.

While this completes Central's stated policy, testing has revealed many alternative optima. Alternative optima have the same value of the objective function but can differ significantly in terms of operations. If several possible operations are of equal value, the one that is most similar to the operations at the previous time periods would be the most practical choice. Additional temporary constraints have been added to use the alternative optima to generate solutions with smoother outflow and turbine release patterns without sacrificing any of the stated policy. These additional constraints are likely to be modified by Central as the model is put into production use.

## 2.3 Total Dissolved Gas Model

The RiverWare modeling of TDG is based on the CRiSP Model developed at the University of Washington (2000). The two exceptions are the modeling of TDG concentration of the spillway at Grand Coulee and TDG scrubbing from wind. These elements were not available in the CRiSP model. Instead the RiverWare model for these elements is based on the SYSTDG model developed by the Corps Northwestern Division (2009) as part of the Reservoir Control Center Water Quality Program.

The lag time for TDGs traversing the reservoirs was estimated to be five times the lag times for flows. This estimate is based on a private conversation with Central.

Modeling TDGs was one of the more complicated aspects of the RiverWare optimization model. The primary difficulty arises from using a linear optimization method with nonlinear, non-convex, and non-separable functions for TDG tailrace concentrations. The TDG concentration is calculated as follows:

$$(1)\ C_M = \frac{C_S(Q_S+Q_E)+C_T(Q_T-Q_E)}{Q_S+Q_T}$$

where

$\boldsymbol{C_S}$ – spillway concentration above 100% saturation, i.e. supersaturated, usually leads to creation of TDG with higher values as spill increases. The concentration is a function of the amount spilled and generally tends to be near linear at first transitioning to a negative exponential function towards a maximum TDG. The exact formula used varies by reservoir and is based on previous modeling experience and calibration.

$\boldsymbol{C_T}$ - turbine release concentration, supersaturated, which normally equals the forebay concentration.

$\boldsymbol{C_M}$ – tailrace concentration, supersaturated, after mixing the turbine release and spill (even though complete mixing may take place slightly downstream).

$\boldsymbol{Q_S}$ - spill.

$\boldsymbol{Q_T}$ – turbine release for the entire plant.

$\boldsymbol{Q_E}$ - part of powerhouse flow which is entrained. The entrained flow has the same TDG concentration as spill instead of turbine release. This quantity is effectively added to spill and deducted from turbine flow. The entrained flow is the lesser of turbine flow and a fixed fraction of spill. The fraction differs by reservoir.

The RiverWare model addresses these nonlinear functions using a variation on Successive Linear Programming (SLP) adapted for goal programming which we will call Successive Linear Goal Programming (SLGP). The concept is simple: a first order Taylor series approximation based on estimated turbine release and spill can be used for the nonlinear functions. For a given goal program, the nonlinear functions are approximated as linear functions. Based on the turbine release and spill in the optimal solution, the Taylor series approximations can be recalculated. SLGP is the successive iteration of optimization and approximation. These iterations are implemented in RiverWare by using batch mode to make individual RiverWare runs, adjust the approximations, and repeat until the solution converges or a maximum iteration limit is reached.

Unfortunately, there is no guarantee of convergence and the resulting solution can potentially be a local optimum rather than a global optimum. For these reasons, this use of SLGP in this setting should be viewed technically as a heuristic optimization rather than an optimization method with a guaranteed global optimum. Nevertheless, the method succeeds because the solution is relatively stable and we have modified the Taylor series approximations to avoid potential instability related to the non-convex portions of the curves. The details of the modifications are beyond the scope of this discussion, but they are described completely in Clement et al. (2011a).

# 3 Wind-Hydro Modeling

The motivation for this research is to develop a general framework for future research to compare the impact wind generation scenarios on a realistic hydropower system, the Mid-Columbia River. The framework has been designed so that it can be utilized for future research with alternative wind integration scenarios regardless of the wind forecast model being employed. This flexibility allows the user to test the effect of wind on the hydro system based on any chosen wind model with various levels of wind penetration, variability and forecast error.

In this section we describe the wind-hydro modeling framework that was built to use the RiverWare model of the Mid-Columbia River described in Section 2. In order to test the framework we devised an intentionally simple synthetic wind generation model, used it within the framework, and compared the results with the results for a no-wind scenario. The modeling in this section is described in greater detail in Clement et al. (2011b). The results of the test are presented in Section 4.

## 3.1 General Wind-Hydro Framework

The effect of wind generation on Mid-Columbia operations is to change the hydropower generation requests from participants and to change the generation requests at both federal projects, Grand Coulee and Chief Joseph. The change in requests with the addition of wind power to the generation mix is a potentially complex economic interaction of wind modeling and forecasts, power demand and forecasts, and other changes in the generation by other sources of power. The wind-modeling framework uses the three generation requests and their forecasts to drive the hydropower model. This allows future researchers full latitude to choose how wind scenarios affect hydropower generation requests and the other sources of power.

The framework is intended to mimic hydro scheduling that incorporates wind by making a new hydro plan every six hours for the next week based on the forecasts available at that time. This design is based on solving a series of one week RiverWare optimization runs with a one hour time step. The first six hours of the first run are implemented. The next run starts six hours later with a new forecast, and the first six hours of this run are implemented. This process is repeated 28 times and together the runs span two weeks minus six hours, 330 hours, in all. The end result is a one week “master” run that uses the first six hours from each of the 28 runs. The master runs are implemented using RiverWare in batch mode. The batch mode script steps through the 28 runs importing forecasts from and exporting results to Microsoft Excel and running all three solvers for each run. If TDGs come into play during any of the 28 runs, batch mode will iterate through the SLGP for each of those runs. Two different wind alternatives can be compared by comparing the results of their respective master runs.

### 3.1.1 Wind-Hydro Framework Input

The inputs for a given master run are a RiverWare Mid-C model with policy, the model data including a hydrologic inflow scenario, a one week planning horizon for the master run, and the data for 28 forecasts. Each forecast contains three hydropower generation requests for each time period: the Grand Coulee request, the Chief Joseph request and the combined non-federal request. These generation requests reflect the combined demand for wind and hydropower minus the forecasted wind generation. The first six hours of each forecast reflect the actual generation request. There are no other formal constraints on the forecasted requests. Any change from one forecast to the next is allowed. If the forecasted requests cannot be satisfied by the RiverWare model, the RiverWare model will minimize deviations to the extent possible.

Forecasts are entered in a Microsoft Excel workbook, and the data are imported automatically into RiverWare during the batch run. In a similar manner, alternative hydrologic scenarios can be tested by simply entering a new set of inflow data in the Excel workbook. Alternative scenarios can also be tested by running the model for different dates to observe the impacts of wind integration in the context of varying seasonal policy constraints. Changing the dates for the run period in the model will automatically activate the appropriate policy constraints for that season.

### 3.1.2 Wind-Hydro Framework Ouput

Outputs from the first six hours of each individual Master Step run are saved as the final outputs for the Master Run. Expression slots (user-defined outputs) in the RiverWare model take standard RiverWare outputs, such as outflows, pool elevations, power generation, and use them to evaluate whether specific, critical policy constraints have been met. These expression slots display the magnitude by which a constraint was violated at each time step. This allows the user to determine whether various levels of wind generation have an impact on the hydro system's capability to meet all non-power constraints. RiverWare exports these constraint satisfaction results automatically to a Microsoft Excel workbook for convenient viewing. The following list is a summary of the constraints that are evaluated:

- Generation meeting all power requests
- Vernita Bar Protection Level Flow
- Vernita Bar spawning period daylight flow limits
- Priest Rapids flow band limits
- Fish spill minimums for non-federal projects
- Total dissolved gas concentration limits at all projects

In addition to constraint satisfaction, other values of interest that we use to test the overall system performance are also exported to the same Excel workbook that contains the constraint satisfaction results. These include spill, turbine release, power, spilled energy, and energy in storage.

In addition, all of the final outputs for a master run are stored in the RiverWare model file. This allows additional analysis to be carried out on scenario results beyond what is automatically exported to Excel.

## 3.2 Testing the Wind-Hydro Framework

In order to test the Mid-Columbia model with wind integration, two scenarios were created. The first scenario is a no-wind scenario with zero forecast error based on historic generation requests. The second scenario is a synthetic wind scenario created solely for the purpose of demonstrating the framework and its capability to show impacts from wind generation on the system. While intended to be sufficiently realistic to test the framework, the synthetic wind scenario is not based on a validated wind scenario. It is not intended to be used to derive any conclusions about the Mid-Columbia system's capacity to integrate wind generation or its performance in a real wind integration scenario.

The effect of introducing wind generation into a power portfolio is potentially complicated. For the test, we do not want to simply reduce hydropower generation as a result of increasing wind; this would be an unrealistic assumption. It seems more likely that a combination of thermal generating sources would be reduced or not built in the future. To simplify this analysis, we assume that a constant amount of other generation equal to the average wind generation would be removed from the system. This would be equivalent for example to not building a future nuclear power plant that had generation equivalent to the average wind generation. Thus, the wind scenario modifies the request in the no-wind scenario by adding a quantity equal to the average wind generation (removing the nuclear plant), and subtracting the wind generation.

As part of the test, additional policy constraints are added to lock in the federal outflows at Grand Coulee and Chief Joseph for the first 24 hours of each of the 28 runs based on the forecast. This reflects a reasonable assumption: the federal projects would want to lock in their operations a day in advance. However, in order not to limit the general wind-hydro framework by building this assumption into the framework, these policy constraints can be easily activated or deactivated as desired by future researchers.

### 3.2.1 Synthetic Wind Model

To evaluate the effects of wind on the hydro system performance, we need a synthetic wind generation model that generates wind that has some attributes of real wind. We also need a wind forecast model that can be used in the model solution; the optimal solution is based on the forecast of the wind, but the forecast is not always accurate. Both the synthetic wind generation model and the generation of the imperfect wind forecast are described in this section.

We designed the synthetic wind model with the three main attributes of real wind time series data: an autoregressive term so that wind in one period is correlated with wind in the previous period; a tendency to return to the average value for the time of year and time of day; and a random component. Additionally we arbitrarily chose the maximum capacity of the wind generation such that it significantly contributes to the hydro system requests and generation capacity, but it not so large as to overwhelm the hydro system capacity.

For the model's wind forecast, the forecasted values are assumed to be a combination of the last "known" value of wind and a return to the long term average with more distant forecasts more heavily influenced by the long term average. To accomplish this we use an exponential decay function, $e^{-kt}$, to weight the last known value of wind generation, resulting in the weight gradually going from 1 to 0 as the forecast time $t$ increases. The remaining weight, $1 - e^{-kt}$, is applied to the long term average wind generation for a given time of year and time of day.

For the synthetic wind generation model, at each timestep *t* we know the wind generation at *t-1*, so the weights are constant at *t=1*. To model random fluctuations we use a standard normal distribution with mean 0 and standard deviation σ. Both the decay term, k, in the weighting factors and the standard deviation, σ, are parameters that can be adjusted easily. We somewhat arbitrarily chose these parameters to generate a reasonable looking wind scenario. We did not attempt to validate these values against any particular wind data. Future researchers might choose these values to match an observed wind pattern.

The synthetically generated wind data must be scaled and bias corrected to conform to the specified maximum and average values. The rational for the values we selected and the scaling and correction computations are described below.

The unscaled wind generation model is as follows, where the Max and Min terms adjust the wind generation to fall between 0 and the maximum wind generation capacity.

$$W_{A,t}^{U} = Min\left[W_M, Max\left(0, a(1)W_{A,t-1}^{U} + \left(1 - a(1)\right)\overline{W}_{DP,t} + N(0,\sigma)\right)\right]$$

where

$t =$ Time step ranging from 0 to 330

$W_{A,t}^{U} =$ Unscaled "Actual" wind generation (MW) at time $t$, a random variable

$W_M =$ Maximum wind generation (maximum capacity)

$a(\Delta t) =$ Coefficient weighting the combination of recent wind vs. the long-term average

$$a(\Delta t) = e^{-k\Delta t}$$

$k =$ Coefficient of an exponential function, used to calculate the weighting toward recent wind generation, $a(\Delta t)$. The value of k was selected experimentally to achieve desired weighting characteristics. (See Table 1.)

$\overline{W}_{DP,t} =$ Average generation (MW) at time $t$ (from the assumed daily profile of average values)

*N* = normal distribution

$\sigma =$ Standard deviation of 1-hour forecast error in a normal distribution

We developed the scaled daily profile, $\overline{W}_{DP,t}$, based on several desired attributes: a daily generation pattern similar to the unscaled regional wind generation in the Pacific Northwest, $\overline{W}_{DP,t}^{U}$, and the ability to scale this pattern based on a specified maximum wind generation, $W_M$, and a specified wind capacity factor, C. To achieve these aims we used

- The average daily profile of wind generation for January from BPA for the years 2008-2011 for the unscaled daily profile,
- $W_M$ = 2000 MW to be comparable with Mid-Columbia hydropower generation, and
- C = 30% as a fairly average capacity factor.

Figure 3 shows both the Unscaled Daily Profile from the BPA data and the resulting Scaled Daily Profile. The scaling factor is 1.140.

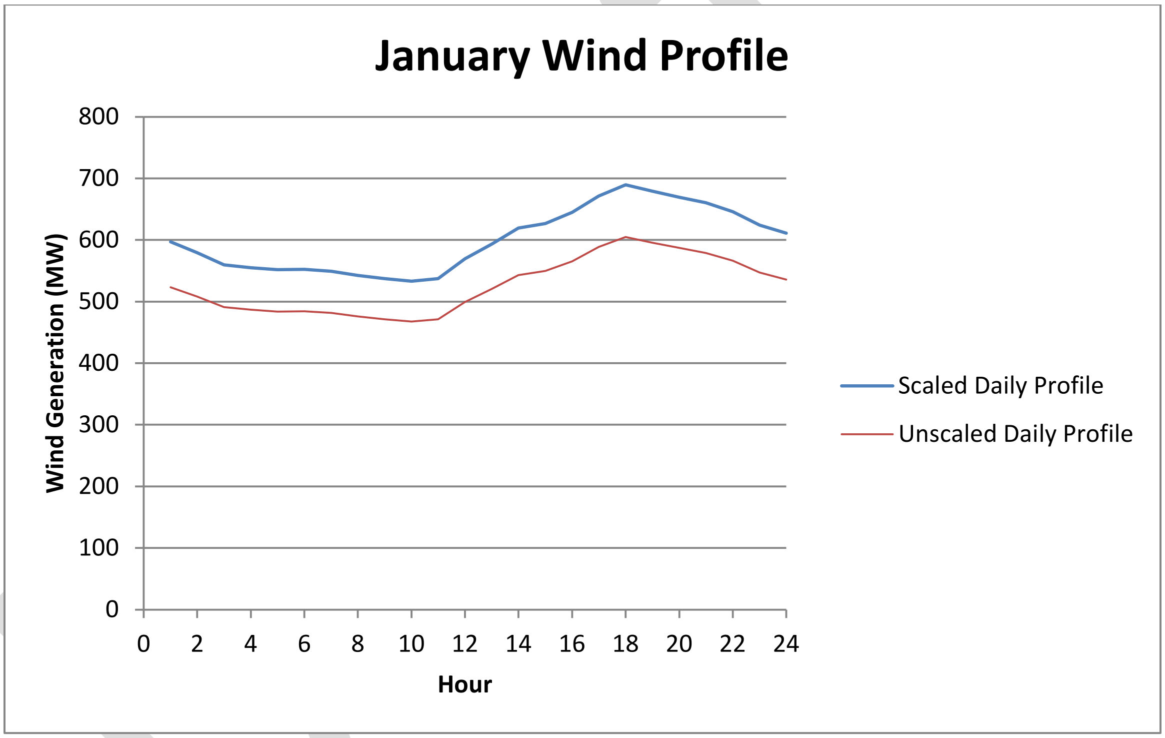


**Figure 3: Scaled and Unscaled Daily Profiles**

Future research could substitute a different unscaled daily profile or alternative parameter values, $W_M$ and C, to model alternative wind scenarios

The capacity factor, C, represents the percent of maximum generation that is produced on average over a long time period T, 330 hours in this case.

$$C = \frac{\sum_{t=1}^{T} W_t}{W_M T}$$

In our case, we wish to specify C and use that to scale our unscaled wind generation. Rearranging the equation for C, and using the unscaled daily profile instead of actual wind generation, the equation for the scaling factor is

$$S_{DP} = \frac{CW_M T}{\sum_{t=1}^{T} \overline{W}_{DP,t}^{U}}$$

and

$$\overline{W}_{DP,t} = S_{DP}\overline{W}_{DP,t}^{U}$$

Returning to our calculation of the unscaled synthetic wind generation, $W_{A,t}^{U}$, we notice that these values need to be rescaled back to the desired capacity factor because several factors can cause the capacity factor to change during generation of the actual wind: autoregressive drift, the Min and Max operations, and possibly bias in the random number generator. The drift caused by the autoregressive term is the largest factor; once a perturbation is introduced from the Normal distribution term the effect can persist and lead to a series with a different capacity factor, C. The corrective scaling calculation is similar to that of the daily profile,

$$S_A = \frac{CW_M T}{\sum_{t=1}^{T} W_{A,t}^{U}}$$

and the scaling is

$$W_{A,t} = S_A W_{A,t}^{U}$$

The next step in our synthetic wind modeling is to calculate wind forecasts using our knowledge of the wind model. Specifically, a forecast for wind based on the synthetic wind model is

$$W_{F,t,t'}^{U} = Min\left[W_M, Max\left(0, a(t-t')W_{A,t'} + \left(1 - a(t-t')\right)\overline{W}_{DP,t}\right)\right]$$

where

$t'$ = Last known time step for a 6-hour block (i.e. hour 6 of the individual Master Step run)

As with the actual wind generation, we rescale the forecasts for the same reasons.

$$W_{F,t,t'} = S_F W_{F,t,t'}^{U}$$

where the scaling factor, $S_F$ , was chosen to minimize the bias error.

Grand Coulee, Chief Joseph and the Non-federal projects were each assumed to receive a constant percentage of the total wind generation. This implies that there is a perfect correlation between the wind generation for all three. In reality, while these three wind generations are likely to be positively correlated, differences in weather with geographic diversity would prevent perfect correlation. The fractions are

$F_{GCL}$ = Grand Coulee fraction of total wind generation and forecast error,

$F_{CHJ}$ = Chief Joseph fraction of total wind generation and forecast error,

$F_{NF}$ = Non-federal fraction of total wind generation and forecast error.

Given the historic requests used in the no-wind scenario,

$R^{H}_{GCL,t}$ = Historic request at time $t$ for Grand Coulee, based on Mid-Columbia observed request data,

$R^{H}_{CHJ,t}$ = Historic request at time $t$ for Chief Joseph, based on Mid-Columbia observed request data,

$R^{H}_{NF,t}$ = Historic request at time $t$ for Non-federal projects, based on Mid-Columbia observed request data,

we can calculate the "actual" generation requests to use in the wind scenario, taking care to prevent negative generation requests:

$$R^{A}_{GCL,t} = Max\left(0, R^{H}_{GCL,t} + F_{GCL}CW_{M} - F_{GCL}W_{A,t}\right)$$

$$R^{A}_{CHJ,t} = Max\left(0, R^{H}_{CHJ,t} + F_{CHJ}CW_{M} - F_{CHJ}W_{A,t}\right)$$

$$R^{A}_{NF,t} = Max\left(0, R^{H}_{NF,t} + F_{NF}CW_{M} - F_{NF}W_{A,t}\right)$$

Similarly, we can distribute the forecast error

$$E_{t,t'} = W_{F,t,t'} - W_{A,t}$$

to calculate the forecasts:

$$R^{F}_{GCL,t} = Max\left(0, R^{A}_{GCL,t} - F_{GCL}E_{t,t'}\right)$$

$$R^{F}_{CHJ,t} = Max\left(0, R^{A}_{CHJ,t} - F_{CHJ}E_{t,t'}\right)$$

$$R^{F}_{NF,t} = Max\left(0, R^{A}_{NF,t} - F_{NF}E_{t,t'}\right)$$

### 3.2.2 Synthetic Wind Model Test Data

A sample scenario was run in the Mid-Columbia RiverWare model based on historic hydrology and power request data for the week of January 8-14, 2010. A "No Wind Scenario" was run using the historic request data as inputs to the model with no forecast error. Then a "Wind Scenario" was run with the same hydrologic data and with request forecasts based on the historic requests and the wind model described above. The average daily profile of wind generation used for the "Wind Scenario" was based on January wind generation data from Bonneville Power Administration (BPA 2011) from the years 2008-2011. The parameters used are in the table below.

**Table 1: Parameter values used in demonstration stochastic wind model**

| Parameter | Description | Value |
|---|---|---|
| $k$ | Exponential coefficient | 0.05 |
| $\sigma$ | Standard deviation for wind gen | 300 MW |
| $W_M$ | Max wind capacity | 2000 MW |
| $C$ | Wind capacity factor | 0.3 |
| $S_{DP}$ | Actual wind scaling factor | 1.140 |
| $S_A$ | Actual wind scaling factor | 0.792 |
| $S_F$ | Wind forecast scaling factor | 1.061 |
| $F_{GCL}$ | Grand Coulee fraction | 0.4 |
| $F_{CHJ}$ | Chief Joseph fraction | 0.2 |
| $F_{NF}$ | Non-federal fraction | 0.4 |

The resulting wind generation time series and the net "Actual" Request time series for both the "No Wind Scenario" and the "Wind Scenario" are displayed in Figure 3 and Figure 4 respectively.

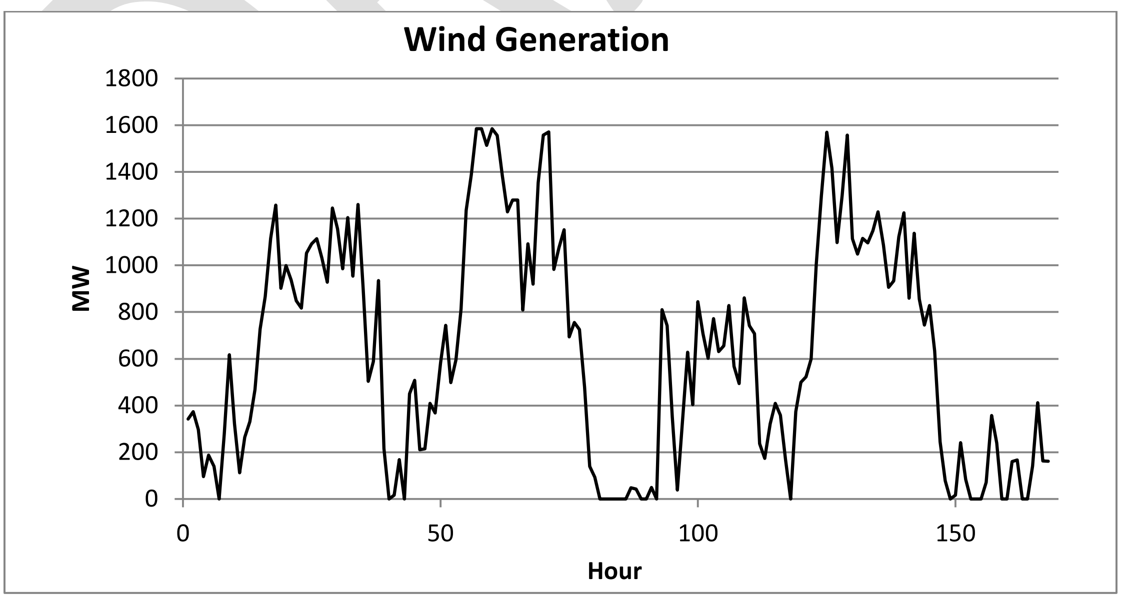


**Figure 4: Synthetic Wind Generation**

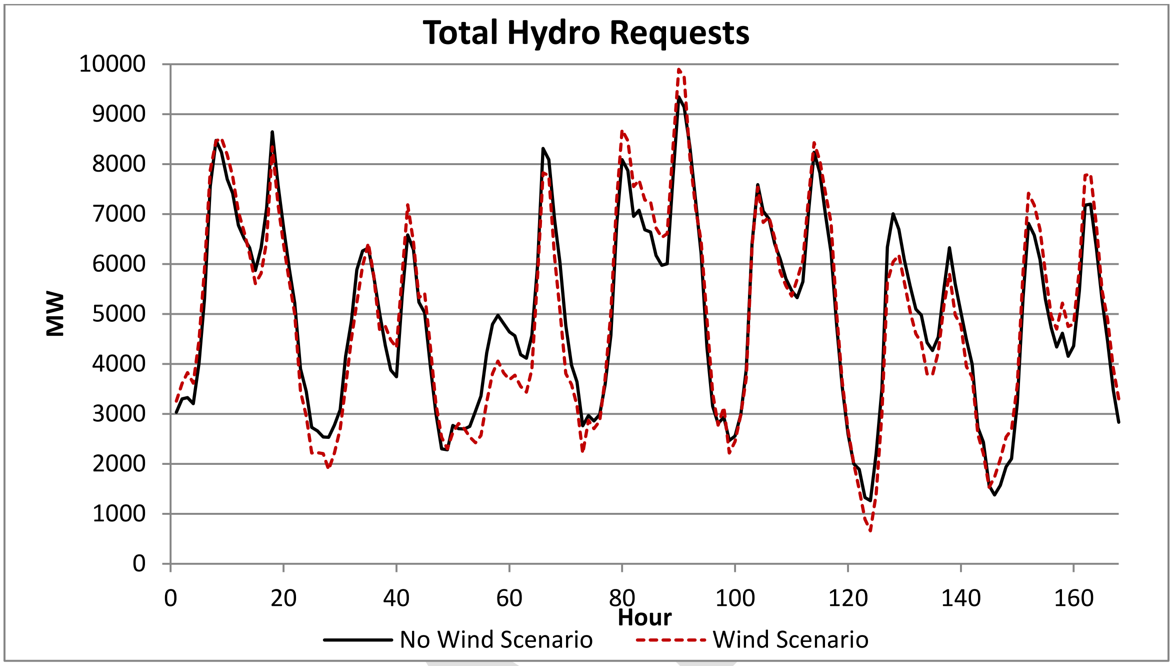


**Figure 5: Total Hydropower Requests**

While the synthetic wind model is not part of the Hydro-Wind Modeling Framework, CADSWES will make it available to researchers both as a working example of using the framework and for any additional value it might have for generating new wind scenarios.

# 4 Wind-Hydro Test Results

In this section we present the differences between the test wind and no-wind scenarios to illustrate the kinds of differences that the Hydro-Wind Framework can produce.

The framework evaluated the satisfaction of major policy constraints for both scenarios. In both cases the policy constraints were satisfied. The explanation for this is that these constraints had relatively high priority, and forward looking optimization was able to correct for problems caused by forecast error before the forecast error could result in unsatisfied constraints. An alternative wind scenario or different hydrologic conditions may result in a different outcome.

We analyzed other outputs of the scenarios and identified several metrics for comparing the system performance with and without the wind. These are: Spill, Cumulative Spill as Energy, Total Energy in Storage, TDG Concentration, and Ramping.

Spill at the non-federal reservoirs differed between the two scenarios and looked similar to the spill illustrated at Wanapum, Figure 5. In general, the wind scenario had more spill and more periods of spill, but in some time periods the no-wind scenario had greater spill. There was no spill at the federal reservoirs.

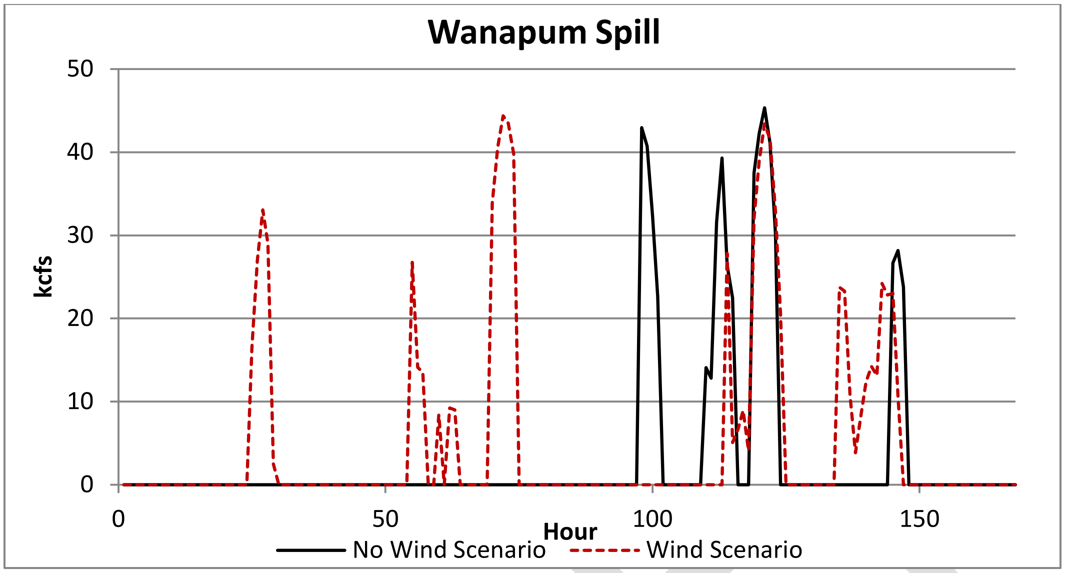


**Figure 6: Wanapum Spill**

If spill is measured in terms of energy lost to spill, we can plot the cumulative loss of energy to spill for the entire non-federal system, Figure 6. Viewed from this perspective, the no-wind scenario is clearly preferable to the wind scenario for the hydro system.

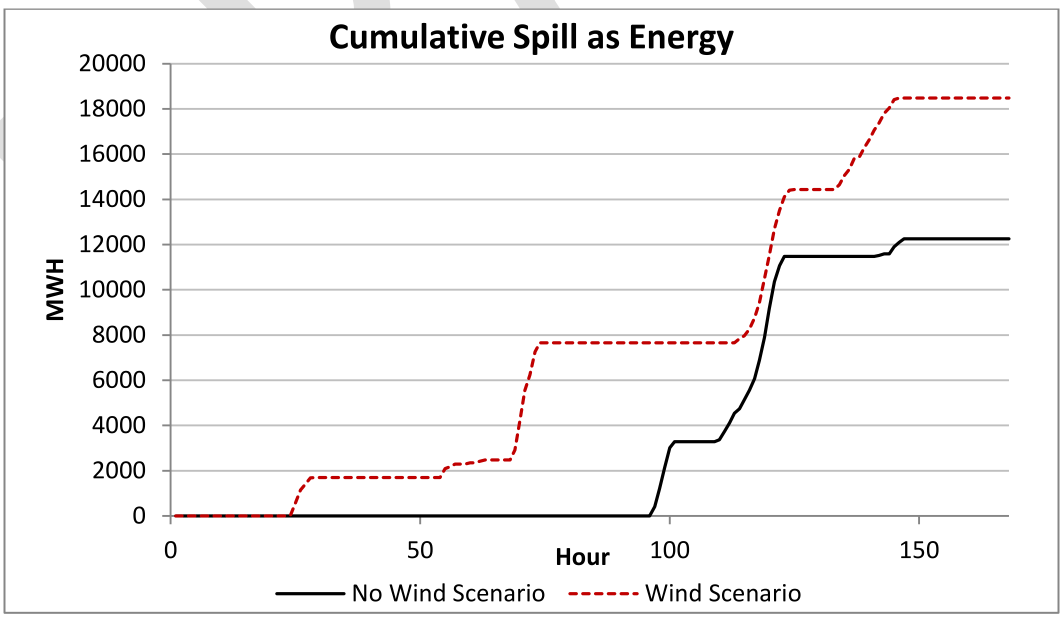


**Figure 7: Cumulative Non-Federal Spill**

The increased spill in the wind scenario resulted in higher TDG values at the non-federal reservoirs, occasionally hitting or even surpassing the limits. TDG at Wells, Figure 7, is fairly typical of the TDG results at the other non-federal reservoirs.

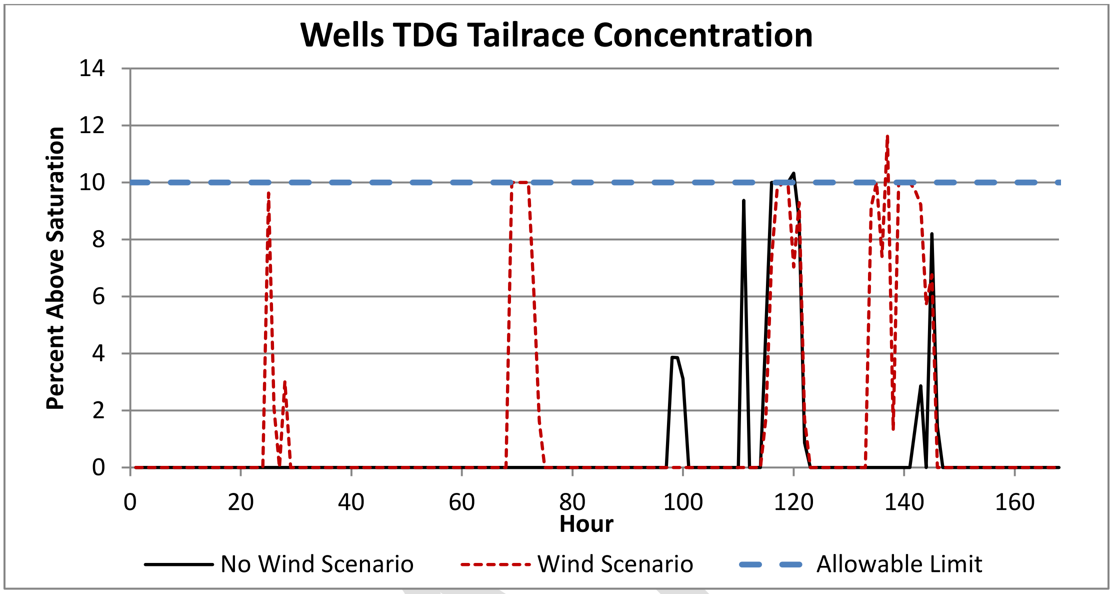


**Figure 8: Wells TDG Tailrace Concentration**

The wind scenario generally had greater ramping both up and ramping down than the no-wind scenario. The ramping duration curve for Rock Island illustrates the difference in Figure 8.

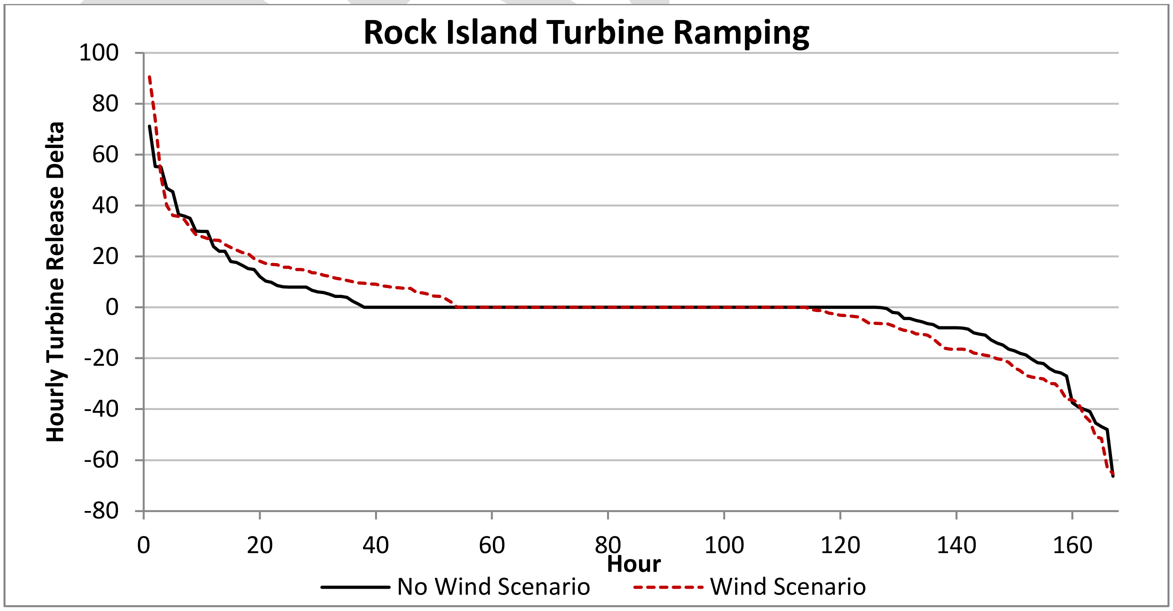


**Figure 9: Rock Island Turbine Ramping**

# 5 Conclusions

CADSWES has built a RiverWare model of the Mid-Columbia River with data and policy supplied and verified by Chelan PUD, Grant PUD, and Central. The model includes important details including modeling flows and environmental constraints at Vernita Bar and constraints on TDGs. This detailed model was the first step in creating a Wind-Hydro Framework for modeling the impact of alternative wind scenarios on hydro operations and the satisfaction of policy constraints and objectives. The framework was tested with a no-wind scenario and a wind scenario based on a synthetic wind model. Both scenarios satisfied the policy constraints but the framework did show that there were notable differences in some important variables including spill, cumulative spill as energy, TDG concentrations, and turbine ramping.

Although these differences cannot be interpreted as reflecting the actual effects of wind on the hydro system, the modeling framework has been demonstrated to function and can be used for future research using realistic wind scenarios.

## *Acknowledgements*

The authors are grateful for the contributions to this research made by Brennan Smith, Oak Ridge National Laboratory, Joe  Taylor, Mid-Columbia Central, and Scott Buehn, Chelan PUD and the cooperation of others at Chelan PUD and Grant PUD.

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