Operational constraints and hydrologic variability limit hydropower in supporting wind integration

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Abstract
Climate change mitigation will require rapid adoption of low-carbon energy resources. The integration of large-scale wind energy in the United States (US) will require controllable assets to balance the variability of wind energy production. Previous work has identified hydropower as an advantageous asset, due to its flexibility and low-carbon emissions production. While many dams currently provide energy and environmental services in the US and globally, we find that multi-use hydropower facilities would face significant policy conflicts if asked to store and release water to accommodate wind integration. Specifically, we develop a model simulating hydroelectric operational decisions when the electric facility is able to provide wind integration services through a mechanism that we term ‘flex reserves’. We use Kerr Dam in North Carolina as a case study, simulating operations under two alternative reservoir policies, one reflecting current policies and the other regulating flow levels to promote downstream ecosystem conservation. Even under perfect information and significant pricing incentives, Kerr Dam faces operational conflicts when providing any substantial levels of flex reserves while also maintaining releases consistent with other river management requirements. These operational conflicts are severely exacerbated during periods of drought. Increase of payments for flex reserves does not resolve these operational and policy conflicts.

Keywords: wind integration, renewables, climate change, hydropower, electricity markets, ecosystem services

Online supplementary data available from stacks.iop.org/ERL/8/024037/mmedia

1. Introduction

Since the electric power sector in the US collectively represents a substantial source of greenhouse-gas emissions, the rapid deployment of low-carbon electric generation technologies has been identified as a potentially important climate mitigation pathway (Pacala and Socolow 2004). Wind and solar technologies produce no greenhouse gases during the operation phase and have substantially lower life-cycle greenhouse-gas footprints compared to fossil fuels (Fthenakis and Kim 2007), so electric grid operators are engaging in a variety of programs to integrate wind and solar on a large scale (Anderson and Cardell 2012, Apt et al 2012, Cardell and Anderson 2010, Climatewire 2010, MISO 2011, Mount et al 2010, Sustainable Business Oregon 2012, The Brattle Group 2012, UWIG 2011). Difficulty in predicting variability of large-scale intermittent renewables has motivated focus on low-carbon energy storage as a potentially important enabler of widespread wind and solar power deployment, but existing battery energy storage technologies have high costs. Existing hydroelectric dams represent a possible energy...
storage option as they are the largest source of renewable electricity generation in the US (EIA 2012). Europe already uses hydroelectricity to a large extent to compensate for fluctuations in wind and solar power output. The collective hydropower capacity in the US is more than 78 000 MW, perhaps 50% of what might be needed (in terms of grid balancing capability) to achieve a 20% wind energy penetration in the US grid without substantially affecting the reliability of grid operations (NREL 2010, US Department of Energy 2008).

While the technical potential for utilization of hydroelectricity as storage to complement wind and solar power is large, many hydroelectric facilities in the US are ‘multi-use’, operating under complex agreements designed to satisfy a large number of social objectives and whose operational requirements are very difficult to adjust. In particular, some environmental objectives under which multi-use dams operate may conflict with the objective of providing wind integration services to electric grids. To illustrate these conflicts, we simulate the decision of a hydropower operator in the US Southeast (within the PJM Regional Transmission Organization) to provide a type of wind integration service that balances unexpected changes in wind power output. Our analysis focuses on the allocation challenges that emerge during droughts and when reservoir operations are altered to improve downstream ecological conditions. We focus on the US Southeast due to hydroelectric data availability, as well as the region’s population pressures and growing uncertainties associated with hydrological extremes (Seager et al 2009). While economics and competitive pricing of energy storage services is important (NREL 2012), our analysis finds that even if these services are properly priced within the context of electricity market operations, a multi-use dam could provide only small amounts of wind integration services (a few percentage points of what a large system like PJM would require) before operational conflicts would emerge. These operational conflicts are subject to strong institutional constraints at the federal, state, and local levels that pricing alone cannot resolve, at least in the current US regulatory environment. The impacts of the operational conflicts will only be exacerbated given increasing likelihoods of hydrologic extremes and growing regional water supply demands. Projections of multi-use dams’ support of wind integration must better resolve these challenges.

The remainder of the letter is organized as follows. Section 2 describes the model, including the case study. The full problem formulation is presented in the online supplementary material (available at stacks.iop.org/ERL/8/024037/mmedia). Section 3 follows with the results, and section 4 ends with policy suggestions and conclusion.

2. Model description

2.1. Case study: Roanoke river basin

Our model simulates reservoir allocation decisions at Kerr Dam, a multi-purpose hydroelectric dam located at the headwaters of the Roanoke River Basin. The US Corps of Engineers (USACE) develops policies governing operations at Kerr Dam. Dominion Power manages Kerr and two downstream dams, Gaston and Roanoke Rapids (whose operations mirror those at Kerr). Releases from this dam system feed into the federally protected floodplains of the Hardwood Bottomland Forest, which has recently had over $40 million of conservation funds invested to improve its long-term viability (Whisnant et al 2009). Releases at Kerr are influenced by a large number of factors. The energy declaration sets a weekly schedule for the upper bound on total allowable power generation, while the dam’s guide curve sets a lower bound rule for reservoir elevation and operational controls on releases. Kerr Dam’s operations are influenced by federally mandated policies (e.g., flood control requirements and low-flow regulations) enforced by the USACE. Dominion has wide discretion for controlling intra-weekly reservoir releases and storage within the limits set by the USACE. While Dominion’s service territory is a part of PJM, Kerr Dam also provides low-cost energy to local electric distribution companies (collectively known as ‘preference customers’) that lie outside PJM’s electrical territory, in coordination with the Southeastern Power Administration (SEPA) (Fernandez et al 2012).

Our analysis considers two water policy scenarios. The first is based on the historical practices at Kerr Dam, while the second is an alternative water control plan seeking to enhance the downstream environment, which we term the ‘ecosystem services’ scenario (Kern et al 2012). The policies define two distinct guide curve constraints, which we term business-as-usual (BAU) and ecosystem services (see table S.1 of online supplementary material available at stacks.iop.org/ERL/8/024037/mmedia). Historical practice at Kerr Dam has been for Dominion to schedule operations during times of peak electricity demand, effectively chasing peak spot market electricity prices (Pacala and Socolow 2004). The ecosystem services scenario requires a high volume, short duration release schedule that more closely follows natural flow levels to enhance the spawning season of nearly fifty fish species, in particular striped bass (March–June) (Whisnant et al 2009). The ecosystem services releases pose a conflict when they do not coincide with peak generation patterns. Under both the BAU and ecosystem services (ECO) guide curves, Dominion faces the decision to sell electricity in the PJM spot market or allocate capacity for compensating for errors in PJM’s wind power forecast via the flex reserves market as shown in figure 1. Kerr Dam is modeled as a revenue-maximizing firm (we neglect operational costs in our analysis) that must make hourly capacity allocation and production decisions between these two markets.

We simulate hydropower production decisions across a hydro-climatic gradient that captures the region’s transition from a wet year to a 1-in-100 year drought over the period from 2006 to 2008 (Seager et al 2009). This hydro-climatic gradient provides insight into how rapid changes in inter-annual water supplies affect dam operations.

\[\text{We note that the ‘spot’ market in PJM is actually a one-day-ahead forward market. The distinction between spot and day ahead is not important for the purposes of our analysis.}\]
Figure 1. Illustration of operational constraints and decisions faced by Dominion when acting as a revenue-maximizing agent. Flex reserve scenarios consider one of two operational guide curves that regulate releases from Kerr Dam—BAU and ECO. At each hour Dominion makes a decision to sell Kerr Dam capacity to solely the spot market (a) or re-allocate capacity away from the spot market to a flex reserve market (b). Preference customers are a contractual demand that must be met with possible revenue arbitrage depending upon the difference between the low cost, fixed SEPA price and the spot market price (see online supplementary material for further problem formulation explanation available at stacks.iop.org/ERL/8/024037/mmedia).

especially as population pressures and droughts are growing concerns in the Northern Coastal Plain area of North Carolina (Kern et al. 2012, NCDC, 2011, Seager et al. 2009). We assume that Dominion has perfect knowledge of wind forecast errors in PJM and can thus make perfectly informed decisions to allocate capacity to the flex reserve market or to spot market sales. Incorporating uncertainty in Dominion’s expectation of the wind forecast error is a topic of ongoing research, but the assumptions used in this letter reflect the best possible case for a multi-purpose dam offering capacity for wind integration services while managing other objectives. The policy conflicts that we find when the flex reserve provision is introduced into Kerr Dam’s decision making would be exacerbated in the absence of perfect information. This is particularly true during drought years and suggests the increasing difficulty of balancing operational objectives, particularly with additional stresses induced by climate change (Seager et al. 2009).

3. Results

Our model assesses Kerr Dam’s incentives and barriers for diverting capacity away from the spot energy market to the flex reserve market, under the assumption that Kerr Dam possesses perfect information regarding prices in both markets and the errors in PJM’s forecast of wind energy output (i.e., oversupply and undersupply). Our modeling results, detailed in this section, suggest that even under this best-case information scenario, the incentives for multi-purpose dams to provide substantial participation in the flex reserve market would require storage and release policies that conflict with other operational objectives.

3.1. Willingness to offer capacity for low-carbon electricity
integration is constrained by other environmental
performance goals

This section presents the simulated flex reserves decisions under the BAU and ECO guide curves, under the assumption that prices in the flex reserves market are similar to those prevailing in the regulation market in PJM. Figure 2 shows the cumulative distribution function (CDF) of hourly capacity allocations in the flex reserve market as a percentage of total flex reserves demanded by PJM to compensate for errors in the wind forecast. The figure focuses on oversupply events under the BAU and ECO guide curves during peak and off-peak hours from 2006 to 2008. Thus, figure 2 highlights how water scarcity between different years influences the decision to offer flex reserves in both peak and off-peak hours. The guide curves constrain Kerr’s ability to provide oversupply flex reserves, where these amounts vary depending upon the type of guide curve, the hydrological conditions, magnitude of the wind forecast error, as well as the time of day where flex reserves are requested. Results for providing flex reserves during undersupply events are shown in figures S.2, S.5 and S.6 in the online supplementary material (available at stacks.iop.org/ERL/8/024037/mmedia).

Since multi-purpose dams typically store large volumes and have the capability to ramp output up or down rapidly, we might hypothesize that Kerr would be more willing to offer capacity into the flex reserve market under the BAU guide curve, which is generally less constraining (i.e., it permits more flexible releases throughout the year). Based on our data, the timing and magnitude of releases required under the ECO guide curve correspond more closely with the timing and magnitude of flex reserves that PJM would demand (see also figure S.2 from the online supplementary material). The capacity allocated for flex reserves under the ECO guide curve exceeds allocations under the BAU guide curve, except during the severe drought year in 2008. Our findings in figure 2 are different than in Fernandez et al. (2012), which found that opportunity costs associated with smoothing the level of wind energy output (as opposed to compensating for deviations between forecasted and actual output) are substantially larger under the ecosystems guide curve. We define opportunity costs as the foregone revenue when a unit of the dam’s capacity is re-allocated away from the spot energy market and towards the flex reserves markets. When the energy declaration is extended from a weekly to a bi-weekly upper bound on generation for both the BAU and ECO guide curves during over and undersupply of wind power, Kerr allocates enough capacity to meet 100% of the requested forecast error even during severe drought conditions. Operational conflicts may be significantly reduced if the time length of the guide curve schedule was altered, yet such regulatory changes prove quite challenging given the institutional barriers surrounding water rights in the US.

Previous work (NREL 2012) has argued that pricing of new ancillary services products to facilitate renewables...
Figure 2. The cumulative distribution function (CDF) of the percentage of the capacity allocated for balancing wind forecast errors during an oversupply of wind power during peak hours (left) and off-peak hours (right) under the BAU (solid) and the ECO (dashed) guide curves.

integration is crucial; our prior model simulations (Fernandez et al 2012) have made similar arguments based on the notion of pricing ancillary services based on opportunity costs. While we agree that price is an important component of a well-functioning market, we emphasize that our results in figure 2 are primarily due to policy constraints embodied in Kerr Dam’s guide curve (both the BAU and ECO guide curves) and not due to inefficient pricing of ancillary services. Figure 3 displays the results of a sensitivity analysis, using the ECO guide curve, in which we increased the price for flex reserves (up to the current PJM price cap of $1000 MWh$^{-1}$) and the optimization problem presented in section 2 was solved for each price level. We note that Kerr Dam can seldom provide more than 20% of the requested flex reserves to balance wind forecast errors without violating either of the alternative guide curves’ release constraints. Willingness to provide flex reserves is highest during off-peak hours in the spring of 2007 but drops substantially during these same months when transitioning to a sustained drought in 2008. Spring is an indicator of environmentally related policy constraints since the spawning season falls during these months, indicating that enhancing river conditions supports releases for flex reserves outside peak hours and severe drought conditions. (See figures S.3–S.6 in the online supplementary material available at stacks.iop.org/ERL/8/024037/mmedia for further price sensitivity analysis and description of data.) Our results suggest that even if prices for flex reserves properly reflect opportunity cost, multi-use hydroelectric dams may not be the lowest-cost option to provide wind integration services.

While operational constraints embodied in the guide curve and weekly energy declaration represent the biggest barrier to increased utilization of Kerr Dam for flex reserve provision at current market prices, large-scale wind penetration may change daily pricing patterns in PJM’s spot energy markets and would thus have some effect on our
Figure 3. The capacity allocation for balancing an oversupply of wind power during hourly average monthly peak (left) an off-peak hours (right) from 2006 (top), 2007 (middle) and 2008 (bottom). All results are under the ecosystem services guide curve. We only show results up to a 50% price increase of the prevailing regulation prices within the market price cap. Darker regions indicate a higher allocation and white a lower allocation.

analysis. Quantitative estimates are beyond the scope of the present letter but qualitatively we would expect the following. First, large-scale wind could be expected to depress average prices in day-ahead electricity markets (for evidence of this from Germany, see Nicolosi and Fursch 2009 and Weigt 2009). Daily variance in prices, however, may increase if the variance in net load (total electricity demand less wind energy production) increases. Second, to the extent that prediction errors do not decline as the magnitude of wind energy penetration increases, the value of flex reserves would increase and their price would thus need to rise. Overall, we would expect that the opportunity cost of providing flex reserves from Kerr Dam would decline. It is possible that the increase in the value of flex reserves may outweigh the decline in day-ahead energy prices to the point where Kerr Dam’s revenue-maximizing strategy would be to dedicate all of its capacity to the provision of flex reserves. In this case, the implicit costs of operational constraints would rise even higher.

3.2. Policy adjustments to promote the provision of wind integration services

Operational constraints play a pivotal role on how Kerr Dam’s storage and release policies meet multiple objectives. While an electric-system operator would likely have a portfolio of potential suppliers in a market for flex reserves, it is useful as a bounding analysis to consider how the guide curve for Kerr Dam would have to change in order for Kerr to provide varying percentages of the total flex reserves demanded by PJM. Figure 3 illustrates how the ecosystem services guide curve cannot accommodate the timing and amount of the total
Opportunity cost represents the potential flex reserves revenue that Kerr forgoes due to release limitations set by the ecosystem services guide curve (panel (a) in figure 4). In 2006, the wet year conditions show a reduced inter-annual opportunity cost increase from $8646 when providing 10% of requested flex reserves to $159 506 when providing 100% of requested flex reserves (panel (b)). In 2008, the opportunity costs when providing 10% of requested flex reserves increases from $28 983 per year to $303 428 per year when providing 100% of requested flex reserves. Opportunity costs increase along with the quantities of flex reserve capacity offered, but these opportunity costs represent just over 2% of historical revenues from selling into PJM’s day-ahead energy market (assuming that PJM regulation prices are a suitable proxy for prices that would prevail in the flex reserve market).

Although both operational guide curves provide annual or semi-annual release volumes that would be sufficient to meet 100% of the flex reserve demand, altering the regulations governing their weekly release schedules to support these volumetric adjustments is not feasible under the current policies constraining the system. From January to June 2008, the BAU guide curve annual releases at Kerr historically reached $3.53 \times 10^{14}$ cubic feet (11 times larger than what would be required to support all flex reserves demanded by PJM on a semi-annual basis). The ECO guide curve permits annual releases that would have reached $1.58 \times 10^{14}$ cubic feet (4 times larger than what would be required to support all flex reserves demanded by PJM). However, aggregate annual to semi-annual releases fail to account for the operational constraints that Kerr Dam operators would face over shorter time horizons. Providing 100% of the requested flex reserves would require that the USACE’s weekly energy declarations strongly deviate from their historical baselines (i.e., up to 200% increases in some periods). Based on week-to-week adjustments to the energy declaration in 2008, Kerr would then need to exceed the total volume of water released under the ecosystem services guide curve ($1.58 \times 10^{14}$ cubic feet) by nearly 20% (panel (c)), an infeasible adjustment given current regional water allocation and legal constraints.

Building on the results of figure 4, we performed a sensitivity analysis extending USACE’s energy declaration from being weekly to a bi-weekly basis. This effectively would give the operator at Kerr more flexibility to allocate energy production within each two-week time horizon. We found that extending the energy declaration time horizon in this way eliminates any operational constraints in providing flex reserves from Kerr Dam, i.e. Kerr could provide all of the requested flex reserve capacity without any violations of the guide curve. This analysis further underscores our conclusions that operational constraints for hydroelectric dams providing wind integration services arise from constraints in the timing of releases rather than the volume of the releases. We can conclude that relaxing Kerr Dam’s operational constraints in this way would enable it to provide higher volumes of wind integration services, but this policy conclusion comes with substantial opportunity costs.

**Figure 4.** Illustration of the (a) opportunity cost, (b) energy adjustments, (c) and percentage of the total volume used to smooth increments of the total wind forecast error from 2006 to 2008 under ECO guide curve. Panel (a) describes the annual opportunity costs representing the revenues that could have been realized from selling flex reserves at current regulation market prices. Panel (b) describes the quantity of the energy adjustments needed annually to balance increasing percentages of the forecast error (MWh). Panel (c) describes the volumetric deviation from the guide curve as a percentage of the total volume of water released when complying with the guide curve that is used to compensate for varying percentages of the wind forecast error across all hours in the simulation period.
with some caveats. First, changing the USACE’s energy declaration would be a complex, challenging and potentially contentious endeavor involving an act of the US Congress (since Kerr is part of the federal hydropower system). Second, our analysis of the bi-weekly energy declaration assumes that relevant environmental variables can be predicted with considerable accuracy two weeks into the future. Forecasts of bi-weekly stream flow, precipitation and wind power output at the hourly level face fundamental predictability limits (Lorenz 1969), so it is reasonable to expect that these forecast errors would be quite large. In the face of large forecast errors for environmental variables, it is possible that the USACE’s energy declarations would be inconsistent with Kerr Dam’s multi-sector service obligations.

4. Policy suggestions and conclusion

Large-scale wind integration requires supplemental energy reserves. Hydroelectric dams have a combination of ramping and storage characteristics, combined with low marginal operating costs and low-carbon emissions, making them appealing candidates to provide these reserves. Our analysis, however, suggests that the magnitude and timing of releases needed to compensate for errors in the wind power forecasts may require substantial changes in multi-purpose reservoirs’ operations, especially in regions with significant hydro-climatic variability and increased electricity and multi-sector water demands. Our conclusions differ from those of NREL (2012) by suggesting that fundamental water management policy changes for reservoir releases, in addition to pricing reform in ancillary services markets will be necessary to successfully integrate wind using hydroelectric power (see also Fernandez et al 2012). Current regulation prices appear to provide little incentive for Kerr Dam to accommodate a large amount of the wind power supply forecast errors (see figures 2–4). Even if prices are increased substantially, the greater challenge of managing conflicts between energy and water management policies for multi-purpose dam releases will not be resolved. Moreover, the institutional barriers are exacerbated by climate extremes (droughts) and other resource demands (ecosystem services).

Results from this study provide the best-case scenario for similar multi-purpose dams balancing water and energy policy goals while operating within the US federal laws that control a reservoir’s operations and services. Utilization of hydroelectric dams to facilitate rapid low-carbon electricity development in the US requires a more integrated approach to water and energy policy development. We urge an emphasis on cooperative policy making that carefully and realistically considers both the energy and the water sectors’ operational management practices for dealing with growing hydrological uncertainties and rising demands for electricity and water. Climate change is projected to increase the inter-annual variability of the hydrologic cycle and exacerbate extreme droughts, suggesting the need to incorporate flow projections into electric-system planning in areas that have not traditionally done so. Existing river basin water allocation agreements and regulatory constraints strongly limit the adaptivity of reservoir operations. These policies need substantial revision before individual reservoirs can compensate for the variability of wind generation across the electrical grid. Joint water–energy systems planning is necessary to coordinate how each sector’s regional utilities balance their competing demands, growing risks from climate change, and how excess water supply capacities are currently exploited to meet demands. The legal frameworks for water rights in the US pose a challenge for revising reservoir laws and utility coordination as they do not permit a high degree of flexibility (Sheer 2010). We recommend that the path forward is through improved policy planning or soft paths (Gleick 2002), where the governance of US water–energy systems must be improved to yield resilient institutions. Attaining resilient water–energy institutions will require improved coordination across these sectors and governance changes that permit increased adaptivity in how they can address their competing demands and climate change risks.

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