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Restoring the natural flow regime of a large hydroelectric complex: Costs and considerations

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A B S T R A C T

Electricity generated from hydropower is considered a clean energy source because it is both renewable and non-carbon emitting. However, large hydroelectric complexes can generate a wide range of deleterious impacts on downstream ecosystems. The purpose of this article is to describe an approach for estimating the system-wide electricity costs of altering the operation, called reoperation, of a large hydroelectric complex for the purpose of partially restoring natural downstream ecosystems. We study the effect of reoperating the Akosombo hydroelectricity complex in Ghana because the Akosombo plays a critical role in regional electricity production and the construction of the Akosombo Dam substantially altered the natural flow of the Volta River. We do this by comparing the observed operations for a one-year period spanning 2004–2005 with reoperation scenarios that have the goal of making the dam outflow pattern closer to the inflow pattern. We quantify the impact of these reoperation strategies on regional electricity costs using a calibrated model of productivity at the Akosombo Dam and a model of regional electricity generation and trade. We find that if annual generation stays essentially the same with increased wet season generation offsetting decreased dry season generation, the increase in annual costs to the West African Power Pool is about $20 million. If dam operation is altered to be as close to run of river as possible, annual generation decreases due to water spillage, and system-wide costs increase $155 million.

1. Introduction

Hydroelectricity is considered a clean energy source because it is renewable and non-carbon emitting unlike electricity generation from fossil fuels. However, large hydroelectric dam complexes are not environmentally benign. The degree to which dams alter natural river flow patterns is a key determinant of their adverse impact on downstream ecosystems. Operating hydropower as load-following units is particularly deleterious because of the speed and frequency of changes in flow. Turning water flows on and off daily can destroy a riverine ecosystem and fishery because fish cannot adapt to the radical and frequent changes in flows and because the morphology of river channels is scoured by the release of sediment-starved water. Natural aquatic environments have evolved expecting pulse flows during wet seasons, and low flows during dry seasons.

Policymakers consider reoperation of existing hydroelectric dams an approach to partially restoring upstream and downstream ecologies affected by them while maintaining some of their benefits, such as clean and reliable electricity generation. Dam reoperation is also being considered as a response to climate change [1]. Reoperation is loosely defined and can include anything from a slight modification in the dam's outflow regime to complete restoration of natural flows, as in run-of-river (ROR) operation.

The purpose of this article is to describe an approach for estimating the system-wide electricity costs of altering the operation of a large hydroelectric complex. If electricity can be produced at the same cost regardless of when it is generated, then the timing of dam operation does not matter. However, the marginal cost of

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power generation varies widely throughout the day, season, and year. Even a slight modification of an electric-generation maximizing operation plan at a hydroelectric dam can have significant impacts on system-wide costs and energy security in an electricity insecure region [2].

One hydroelectric complex being considered for ROR operation is the Akosombo Dam in Ghana [3]. Ghana is strategic in generating electricity from the Akosombo when it is most valuable for the country, but that leads to distortions in natural riverine flow. We study the effect of reoperating the Akosombo dam so that reservoir outflows more closely resemble reservoir inflows. One way to create an outflow pattern that better matches inflows is to purposefully open spillways to allow water to bypass the hydroelectric generators. We compare current operations for a representative year spanning 2004–2005 to two reoperation scenarios that bring dam outflows closer in line with dam inflows in cases that (a) do and (b) do not include water spillage.

The effects of reoperation on electricity production at Akosombo (and the nearby Kpong Dam) are estimated using a relationship derived from Akosombo dam level and lake surface area data in Ref. [4]. Generally, reoperation to achieve outflow equal to inflows may not be achievable due to physical dam limitations and the time pattern of daily inflows. We use a spreadsheet model that accounts for the relationship between inflows, outflows, water height in the dam, and power output per unit of water released through the turbines. This model also respects physical limitations of the dam including turbine capacity, spillway height, spillway capacity, and minimum height of water for generation to occur. This model is used to estimate the seasonal power generation by the hydropower complex under alternative operation scenarios. The cost of changes in electricity production are estimated using Purdue's West African Power Pool Model (WAPP), a comprehensive optimization model of electricity generation, transmission, and trade in West Africa. WAPP is a mixed integer program that is implemented in GAMS and solved using the CPLEX Optimizer. The model determines least cost dispatch by hour type in a non-chronological sense, and determines optimal investments in generation and transmission capacity expansions. WAPP is adapted to address the problem of reoperation by introducing seasonality into the model as well as exogenous specification of hydropower dam release and spillage timing. Details regarding WAPP, including data inputs, model structure, and WAPP's strengths and weaknesses, can be found in the appendices.

We first describe the Akosombo/Kpong operation model including derivation of the dam height/productivity relationship and hydroelectric plant parameters. The operation model is used to estimate electricity generation under three operations scenarios. We then estimate the resulting changes in system costs when the reoperation regimes are implemented in WAPP. Finally, we use the WAPP model to develop curves relating the cost of spillage to the volume of spill. A more complete description of the WAPP model can be found in the appendices. An assessment of environmental benefits associated with dam reoperation is beyond the scope of this paper; rather, we focus on the changes in costs of operating the electrical supply system so as to bring the dam outflow closer to the Volta River's natural flow pattern.

2. Dam operation model

The model described here is used to simulate the operations of the Akosombo/Kpong hydroelectric dam complex. The model enables us to analyze the effect of reoperation on electricity generation and reservoir spillage. The model is calibrated based on a combination of actual operations observations for the year 2004–2005 and data regarding the relationship between the level and surface area for Lake Volta. Daily inflows used are those from July 1, 2004–June 30, 2005 because total inflows for that one-year period approximately equal an average year's total inflows. Long-term average inflows into the impoundment are 31,007 MCM [5], while the inflows for July 1, 2004–June 30, 2005 were 30,436 MCM. However, data from 2007 is used to calibrate a productivity parameter because a dam retrofit was completed in March 2006 that increased the power production capacity of the dam by 108 MW.

The dam operation model is designed to simulate electricity generation and spill given an exogenous daily net inflow pattern (net of seepage and evaporation) and an exogenously specified daily water release for generation purposes. The model calculates average daily reservoir water level, power and energy output, and in the event that spillage must occur, the amount spilled. The model accounts for physical limitations of the dam including: turbine capacity, spillway height, spillway capacity, and minimum height of water for generation, etc.

2.1. Daily calculation details

The dam operation spreadsheet model is a deterministic daily control model with a one-year time horizon yielding 365 daily time periods indexed by t (=1,2,3, …,365). The model is implemented in an Excel© spreadsheet. Water volume variables are specified in million cubic meters (MCM), electric energy variables are specified in gigawatt hours (GWh), and water levels are specified in meters (M), unless otherwise indicated. Table 1 provides operating parameters for the Akosombo/Kpong dam complex, and Table 2 lists model variables.

Daily net inflows in period t are measured as water inflows to the Akosombo reservoir less leakage and evaporation. Daily reservoir final volume is calculated by subtracting discharge and spill from the sum of the day's initial volume plus net inflows.

$$V_{t+1} = V_t + N_t - D_t - S_t \quad (1)$$

Net inflows are exogenously given, and discharge through the turbines is the control applied. Discharge must be limited to turbine throughput capacity, which is reduced if the lake level falls below a critical level, as given in Table 1. When the water level falls below the minimum full operation height, we assume the complex can still run at one-third of full capacity, which is an approximation to observed discharge rates during times when the lake level was below the critical level. In a daily series of operating heights, Marfo (2009) lists 71.62 M as the lowest level of (limited) operation for the years 1998–2007. Thus, we assume discharge capacity is 0 MCM/day below 71.62 M. Spill reflects reservoir spillage due to storage volumes exceeding reservoir (dam) capacity. We assume Kpong, downstream from the Akosombo complex, has at least the same spill capacity as Akosombo. Spill is normally avoided unless the dam is full – i.e. the volume of water may be well above the bottom of the spillway before spillage is actually initiated. As with discharges for generating electricity, spill is also exogenous. However, two factors limit the allowable values for spill. First, spill cannot exceed the amount that reduces the volume of the dam to a height that is at or below the bottom of the spillway. Second, spill cannot exceed the maximum rate of spill (X in Table 1). There is also a third factor that limits the allowable combined discharge/spill pattern over time. It is mathematically possible that the height of the water could exceed the height of the *top* of the spillway. In this event, the top of the dam would be breached with disastrous results. This potential outcome of the model is a result of having exogenous net inflows and allowing the generation and spill patterns to be set by the user. Our data regarding the height of the dam is not completely consistent. The Volta River Authority (VRA) website lists

Table 1
Akosombo plant parameters.

Description	Abbreviation	Parameter
Maximum discharge rate[a]	M	137 MCM/day
Volume at bottom of spillway[a]	B	108,627 MCM
Maximum spillage rate	X	294 MCM/day
Maximum operating water level (breach)	BR	84.73 M
Minimum full operation water level	FO	73.15 M
Minimum limited operation water level	LO	71.62 M
10-year average volume, July 1[b]	Avg	92,421 MCM
Average volume, less one St. Dev.[b]	Min	75,646 MCM
Average volume, plus one St. Dev[b]	Max	109,197 MCM
Power conversion factor for Akosombo[c]	P^A	0.0019 MWh/M/MCM
Power conversion factor for Kpong[c]	P^K	0.0319 MWh/M/MCM

[a] The Volta River Authority (1997).
[b] Adapted from VRA Annual Reports (2005–2014).
[c] Calibrated by Authors from VRA Annual Report (2007).

Table 2
Akosombo operation model variables.

Description	Abbreviation	Units
Net inflows in period t	N_t	MCM
Initial reservoir volume in period t	V_t	MCM
Average height in period t	H_t	M
Discharge through turbines in period t	D_t	MCM
Spill in period t	S_t	MCM
Electricity generation in period t	G_t	GWh
Electricity losses in period t	L_t	GWh

Akosombo's maximum operating height as 84.73 M. Thus, we assume the dam breaches when the water level rises above this height. The maximum operating height is close to the highest level listed in data from Ref. [4]; which is listed as 85.2 m. Whatever the correct value, any operation plan that involves exceeding it is viewed as infeasible.

To determine the power output associated with releases through the turbines, it is essential to know the height of the surface water or head. Head is a determinant of the potential energy of the water stored in a hydroelectric dam, and is proportional to the difference in elevation between the water source and the turbine. However, the units of reservoir inflows, releases, and spill are all in million cubic meters – a volume measurement. Hence, we need to develop a relationship between reservoir volume and water level. Fortunately [4], provide six data points for the relationship between the surface area of the Akosombo reservoir and the height of the water (see Table 3). We assumed a linear relationship for surface area as a function of water height between the data points for levels of the surface water. For example, we assume that for level L between 60.8 m and 76.1 m, the dam area is given by the function $A(L) = 2331 + (5766{-}6799)\text{x}\ (L - 60.8)/(76.1{-}60.8)$. By integrating reservoir area with respect to level we construct the relationship between volume and water level for the six data points (see the third column of numbers in Table 3). The constant of integration is set so that the volume of water in the reservoir when evaluated at the level of the water at the start of 2007 reported by VRA is equal to the volume of water reported at the start of 2007.

Table 3
Water level, area and volume relationships for Akosombo.

Level (M)[a]	60.8	76.1	79.1	82.2	84	85.2
Area (Km^2)[a]	2331	5766	6799	7848	8482	8897
Volume (MCM)[b]	25,480	87,179	106,328	128,650	143,582	154,177

[a] Source: [4].
[b] Source: Authors' calculations.

To calculate the power generation in MWh one must know the volume of release (MCM) and the head (meters). What is known from (1) is the total volume of water in the dam. The data in Table 3 are used to determine the level given volume via linear interpolation. The dam-specific turbine productivity parameters P^d are calibrated so that average electricity generation per day equals the average water level times the average water release per day, where all data are for 2007, resulting in a value of 0.0019 for Akosombo and 0.0319 for Kpong. Daily electricity generation is then calculated as the product of the dam's power conversion factor, head (height of the water above the turbines), and volume of water sent through the turbines:

$$G_t^d = P^d \times D_t \times H_t^d \quad d = A\Big(\text{Akosombo}\Big),\ K\Big(\text{Kpong}\Big) \tag{2}$$

Power generation at Kpong is not assumed to vary by height of head because its head is typically regulated within less than 1 m throughout the year. The fixed level of head assumed for the Kpong is 15 M. The productivity parameter for Kpong is estimated in the same way as Akosombo's. Note that because the Kpong is operated as a run of river generating facility, the volume of discharge through the Akosombo's turbines is also treated as being the volume of discharge through the Kpong turbines. As a side calculation, the foregone electricity generation due to spillage is calculated the same way as electricity generation with spillage replacing discharge:

$$L_t^d = P^d \times S_t \times H_t^d. \quad d = A\Big(\text{Akosombo}\Big), K\Big(\text{Kpong}\Big) \tag{3}$$

3. Dam operation scenarios

We consider three discharge regimes and three different starting volumes for a total of nine scenarios. The starting volumes are based on the 10-year average Akosombo dam volume for July 1. The years considered are 2005–2014 where July 1 dam volumes are estimated from "Volta Lake Regulation" charts in VRA Annual Reports. Along with the 10-year average July 1 water volume, we subtract and add one standard deviation from the mean to obtain "average," "low," and "high" starting water volumes. Operation scenarios begin on July 1 to allow maximum flexibility in specifying generation and spill. July 1 is near the beginning of the wet season, so beginning the model year then avoids running into dam operating limits (i.e. water below turbine intakes), which would tend to occur using a calendar year model. Note that the purpose of these simulations is not to develop a stochastic optimization model of dam operations with multiple objectives. Rather, we abstract from the stochastic nature of dam inflows and associated policies for dam operations to illustrate the range of outcomes in terms of electricity generation and spillage under different dam operation scenarios. For a discussion of dynamic stochastic optimization of dam operation models, see Ref. [6].

The three discharge regimes are summarized as follows: 1) actual July 1, 2004—June 30, 2005 discharges scaled such that annual net inflows over the period equal annual discharges; 2) maximum flow operation such that annual net inflows equal annual discharges while avoiding spillage, with outflows concentrated at the start of the wet season; 3) the closest approximation to ROR operation, including spillage, where annual net inflows equal annual net outflows but dam breach is avoided. The first discharge regime is meant to approximately reflect current dam operations practices, and serves as a basis for comparison with the other regimes. The second discharge regime is designed to maximize the contiguous period during which discharges through the turbines are at their maximum, resulting in a significant period of flushing of the river downstream of the dam during the wet season. The third discharge regime attempts to mimic the pre-dam downstream flow pattern as closely as is practical, and on days when inflows exceed turbine capacity, spillage will occur. Electricity generation is reported as the sum of generation at Akosombo and Kpong over the full year. Each discharge regime will be discussed in greater detail in the sections that follow.

For each reoperation scenario, we require that the Akosombo storage volume at the start of the year is equivalent to its volume at the end of the year. This requirement allows us to isolate all reoperation costs to be within a single year. If closing water volume exceeded water volume at the start of the year, then future discharges would have to be discounted until all of the year's inflows had been discharged. By containing all costs within a single year, we avoid the burdensome task of calculating costs and benefits spilling into the future.

The 30,436 MCM net water inflow regime for the year July 1, 2004—June 30, 2005, is approximately the long-term average annual net inflows for the dam. To establish a common electricity generation value between the baseline scenarios of the spreadsheet and WAPP models, we transform the inflow data to ensure that total electricity generation from Akosombo in the scaled discharges, high water volume scenario equals 5100 GWh, which is the average annual generation that is used by ECOWAS for planning purposes [7]. This is achieved by first scaling actual discharges so that total net inflows equal total discharges for July 1-June 30; then, both net inflows and discharges are scaled by a common factor so that electricity generation equals 5100 GWh. This scaled pattern of net inflows totals 32,550 MCM for the year and is used for all other dam operation scenarios. The following figure depicts the scaled net inflows into the Akosombo dam for July 1, 2004—June 30, 2005 (Fig. 1).

3.1. Scaled observed discharges

Actual discharges from July 1, 2004—June 30, 2005 are scaled such that annual net inflows equals total annual discharges. The scalar applied to the actual daily discharges is calculated as:

$$\frac{\sum_{t=1}^{365} N_t}{\sum_{t=1}^{365} D_t} \tag{4}$$

Then, both discharges and net inflows are scaled up by a common factor so that electricity generation (in the high starting volume scenario) is 5100 GWh for the Akosombo Dam and 1037 GWh at the Kpong station for a total of 6137 GWh from the hydroelectric complex. The resulting net inflow pattern is used in all other dam operation scenarios.

3.1.1. Average starting volume

Operation of the dam using the 10-year average starting volume for July 1 under the scaled discharge regime does not result in violation of any operational constraints. The water level reaches its minimum of 76.81 M on July 10, well above the 73.15 level needed for full operation of the turbines, and reaches its maximum level of 79.98 M on November 4, well below the level for dam breech of 84.73 M. Annual net inflows are equal to annual discharges with a total of 5909 GWh of power production at the Akosombo/Kpong complex. This level of generation is lower than the 6137 GWh indicated in the previous sub-section because the 10-year average starting volume of water results in lower head and lower generating efficiency than that used by ECOWAS.

3.1.2. Scaled discharge with low starting volume

With a low starting water volume, the scaled discharges regime decreases the water level so rapidly that the dam water level falls below the full operational capacity level in early July. From July

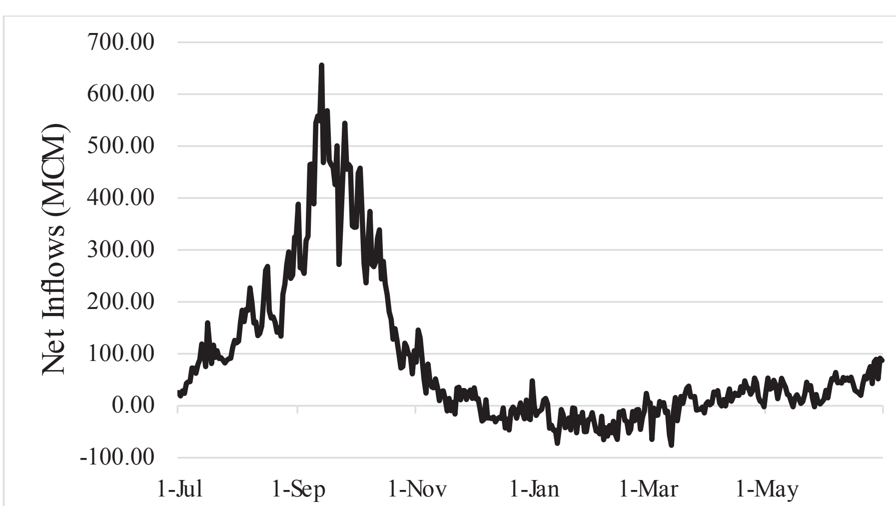

Fig. 1. Akosombo dam (scaled) net inflows, 7/1/04—6/30/05.

4–July 9, the dam is operated at the reduced maximum flow level of 45.67 MCM per day. Scaled discharges are resumed on July 10, where daily discharges are increased by 0.9% so that annual net inflows equal total annual discharges. Under the scaled discharge regime, annual energy production is 5718 GWh, a decrease of 191 GWh that reflects the loss of water efficiency due to lower head.

3.1.3. Scaled discharge with high starting volume

Under scaled discharges and a high water volume, the Akosombo water level does not approach the critical level for spillage or breach. It reaches its highest level of 82.26 M on November 4 and produces a total of 6137 GWh from both Akosombo and Kpong stations.

3.2. Maximum spill-free flow operation

The purpose of maximum spill-free flow generation scenario is to run the turbines at full capacity for the fewest consecutive days such that annual net inflows equal annual discharges and spillage is not necessary, thus obtaining the maximum flushing period without spillage. The discharges are scheduled to begin as early as possible to coincide with the rainy season. With a daily maximum discharge rate of 137 MCM and 32,550 MCM total net inflows for the year, 238 days of maximum turbine outflows are necessary for total net inflows to equal discharges. December, January, February, and March have negative total net inflows across the month, so they are not considered as part of the wet season and discharges are zero in these months. Thus, the 238 days of maximum turbine outflows are initiated from July through November and mid-April through the end of June. Note that this is not the electricity maximizing discharge regime; contiguous discharges from early November through June would maximize generation, but this does not represent a restoration of natural flow as much of the discharge would occur in the dry season. By optimally timing discharges, the electricity generation maximizing scenario (under maximum flow operation) only produces three more GWh, or an increase of 0.05%, than the scenario we model, so the difference is minor.

3.2.1. Maximum spill-free flow operation with average starting volume

With a starting volume of 92,421 MCM, there are no operational constraints to consider under maximum flow operation. The only consideration is the timing to begin discharges, which in this case is on April 7 to coincide with the beginning of steady water inflows. Discharges end on November 30 because total discharges to that point equal net inflows for July 1 – June 30. The regime results in 5878 GWh of energy generation (Fig. 2).

3.2.2. Maximum spill-free flow operation with low starting volume

As in the scaled discharges scenario with the low starting water volume, the active operational constraint is the minimum height for full operation, 73.15 M. With the turbines operating at full capacity starting July 1, the dam level falls below the minimum height for full operation by July 3. The dam level wavers around this critical level until August 1 (the start of the heaviest rains), at which point the dam is capable of operating at full capacity until November 30. Total energy production is 5689 GWh between the two power stations.

3.2.3. Maximum spill-free flow operation with high starting volume

The active operational constraint under maximum flow operation with a high starting volume is the maximum water level the dam can hold, 84.59 M. This operational constraint is avoided by starting maximum flow discharges begin on April 7, as in the average starting volume scenario; so high volumes of water are discharged before the heaviest water inflows begin in August and September. Again, discharges end on November 30. With no spillage, annual discharges are equal to total net inflows with a total energy production of 6110 GWh.

3.3. Run of river operation

The idea behind run of river operation is that daily discharges should be set to (positive) daily net inflows. In situations where daily net inflows exceed the maximum discharge capacity of 137 MCM, spillage is used to simulate run of river operation. On days when net inflows are negative (water losses due to evaporation and seepage exceed water flowing into the dam), discharges are set to zero. In situations where a day's net inflow exceeds maximum discharge capacity plus maximum spillage capacity (294 MCM), the excess water is discharged or spilled in the nearest subsequent day(s) to closely approximate run of river. With this approach, total net inflows and total discharges plus spillage for the year will not be equal due to the non-negativity of discharges and the fact that some net inflows during the dry season are negative. To correct this discrepancy, discharges are scaled down by a common daily factor

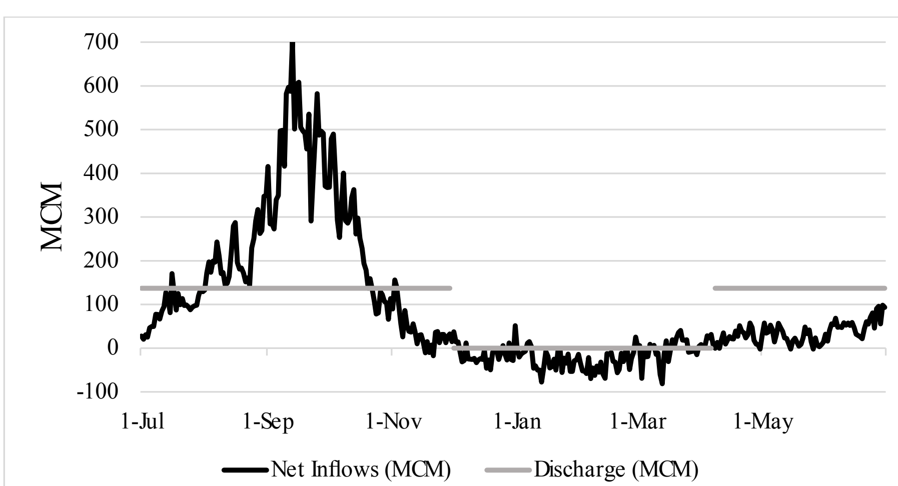

Fig. 2. Maximum Flow Generation vs. Net Inflows, Average Starting Volume.

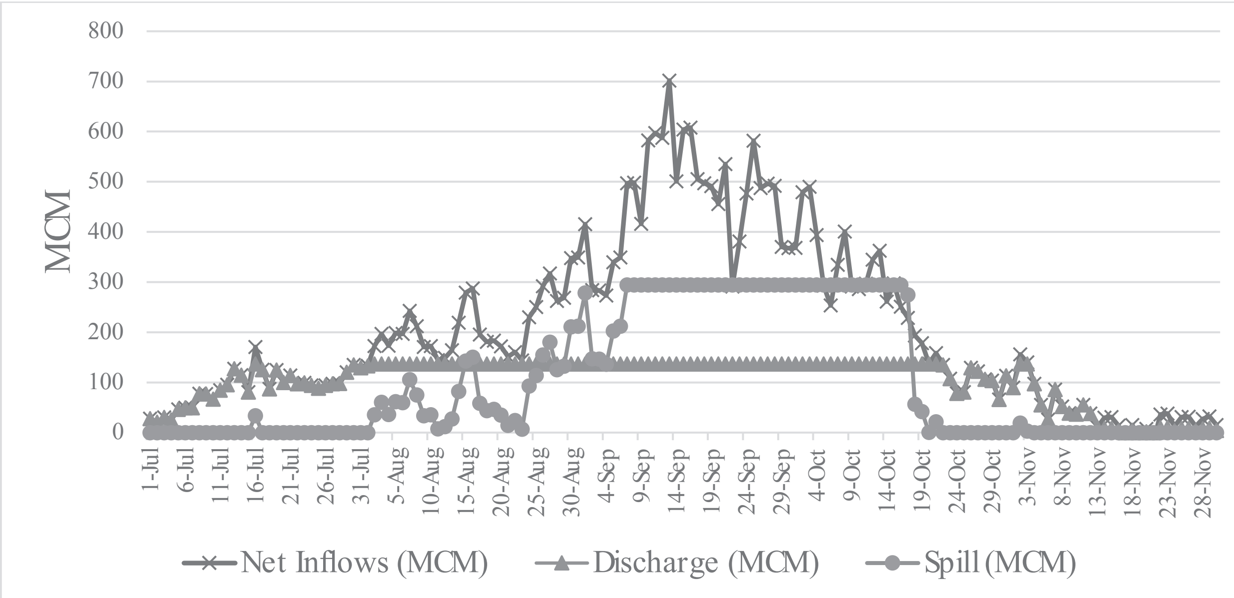

Fig. 3. Run of river discharges and spill, high starting height, July–December.

in the period following the final day of spillage. In the low and average starting volume scenarios, the water level is always below the bottom of the spillway, making spillage impossible. In these scenarios, water built up in the dam due to inflows exceeding discharge capacity is discharged as quickly as possible by operating the turbines at their maximum rate in subsequent days until net inflows equal discharges once again. This discharge pattern is similar to the maximum flow regime for these scenarios in that there are extended periods with maximum discharge through the turbines and no spill. They differ because when net inflows are non-negative but less than capacity, discharge volume equals the net inflow (unless there is a backlog of releases that were delayed from the previous days due to net inflows exceeding turbine capacity). As usual, annual net inflows are equal to annual discharges plus annual spillage.

3.3.1. *Run of river operation with average starting volume*

With the average starting water volume, the water level is always below the bottom of the spillway, similar to the low starting volume scenario. Thus, the discharge regime with the average starting volume is equivalent to that with a low starting volume. Total discharges equal annual net inflows for total power generation of 5893 GWh.

3.3.2. *Run of river operation with low starting volume*

With a low starting water inventory, the water level is again always below the bottom of the spillway (79.41 M) so that spillage is not technically possible. Thus, the closest approximation to run of river operation is to discharge at turbine capacity when net inflows exceed this capacity during the rainy season. Run of river discharges are carried out until early August, when net inflows exceed turbine capacity. At this point, discharges at turbine capacity are carried out until net inflows once again equal discharges, when run of river discharges can be initiated again. For the whole year, total discharges equal annual net inflows with a total power generation of 5694 GWh. This is even lower energy production than the ROR average starting volume scenario because head is lower with the lower initial water level.

3.3.3. *Run of river operation with high starting volume*

The discharge and spillage regime with a high starting volume is different from those with a low or average starting volume because spillage is now possible. The other operational constraint that should be monitored is the level at which the dam breaches, but this level is never reached in this scenario. The dam breaches at a water volume of 150,166 MCM but under this regime the water level only reaches a volume of 110,997 MCM. The first day of spillage occurs on July 16, and the final day of spillage occurs on November 3. For the year, total discharges are 52% of net inflows where the other 48% is lost as spill. Power generation for the year totals 3140 GWh and power losses total 2930 GWh. The net inflows, discharge, and spill patterns with the ROR regime and high starting water volumes are displayed in Fig. 3.

3.4. *Summary of reoperation results*

The power generation resulting from the combinations of initial dam water volume and operations regime are summarized in Table 4. The differences across regimes are similar, given the initial starting volume with the exception of run of river with the high starting volume. The similarity is due to the fact that the same amount of water is discharged over the course of the year, so that only the time pattern varies. The difference in power output is due solely to differences in head. Note that the scaled regime results in higher power output for each starting water volume. With the high starting volume, the run of river regime power output is much lower than the other regimes because of spillage. As noted above, the losses due to spillage are quite large, amounting to about 48% of the potential power for that case.

4. WAPP implementation

The WAPP model, as described in the appendix, is similar to an economic dispatch model typically used by electrical engineers to determine which generators in a spatially distributed network should be used at different times to serve spatially distributed load in a cost minimizing manner. A slightly modified version of this model is used here to capture changes in system costs when the

Table 4
Dam operation results — discharges, spill, generation, and energy losses.

Initial Water Volume and Operations Regime	Discharges (MCM)	Spill (MCM)	Total Power (GWh)	Losses (GWh)
Average Starting Volume				
Scaled	32,550	0	5909	0
Maximum Flow	32,550	0	5878	0
Run of River	32,550	0	5893	0
Low Starting Volume				
Scaled	32,550	0	5718	0
Maximum Flow	32,550	0	5689	0
Run of River	32,550	0	5694	0
High Starting Volume				
Scaled	32,550	0	6137	0
Maximum Flow	32,550	0	6110	0
Run of River	16,844	15,706	3140	2930

Akosombo/Kpong dams are reoperated. The version of WAPP used here has been augmented to allow for seasonally constrained (i.e. wet and dry) hydroelectric dam discharges. This enhancement enables us to model the impact of reoperation when discharges are constrained to just one season. We consider four scenarios comprised of a baseline scenario and three scenarios that characterize those from the reoperation model (scaled discharges, maximum flow operation, and ROR operation). The baseline scenario models the system without constraints on seasonal generation and with Akosombo/Kpong generation at their validated[1] level (6137 GWh). The scaled discharges scenario implements the same total generation for Akosombo/Kpong as the baseline scenario, but the quantity of generation per wet/dry season is constrained by the actual timing of generation in the reoperation model. The maximum flow operation scenario specifies that all generation must occur in the wet season, and because this style of reoperation led to decreased electricity generation, total potential generation from Akosombo/Kpong is slightly reduced to 6110 GWh, which is the generation level found in the reoperation model. The ROR operation scenario specifies significantly less potential generation than the baseline model due to losses from spill. The timing of generation in the run of river scenario is also constrained by season.

Results of the four scenarios implemented in WAPP are displayed in Table 5 below. The simulations assume the high initial dam water volume (109,197 MCM). Currency figures are reported in millions of US$ and electricity is reported in GWh.

There is no difference in system costs between the seasonally unconstrained baseline model and the scaled discharges model. Though there is a significant change in the timing of generation between the two scenarios, there is enough slack in imports, exports, and unserved energy so that the optimal cost remains unchanged.

As we would expect, total system costs increase in the maximum flow operation and run of river scenarios due to decreased potential generation from Akosombo/Kpong. The change in objective value from the baseline scenario to the maximum flow and run of river regimes is approximately $20 million and $155 million, respectively. In these cases, the lost generation from Akosombo/Kpong is first replaced by relatively more expensive generation by thermal units in Ivory Coast, followed by even more expensive thermal generation in Mali. These changes can be observed in the import/export results. In all scenarios, the unserved energy units occur in Niger and Nigeria. The maximum flow and run of river scenarios experience an increase in unserved energy to make up for the seasonally constrained supply from Akosombo/Kpong.

Our operation model of maximum flow generation resulted in decreased electricity generation, though this is partially a consequence of using the particular model year 2004–2005. If the maximum flow regime is initiated when the dam is at its highest level in a given year, it is possible that maximum flow generation could actually achieve greater electricity generation than the baseline model due to higher productivity from higher head. However, when we model a scenario in WAPP where joint generation from Akosombo/Kpong is the same as the baseline 6137 GWh, but discharges must occur in the wet season, the result is still an increase in system-wide costs of $20 million, or just slightly less than our reported maximum flow scenario. This is because the marginal benefit of increased generation in the wet season is nearly zero, yet the marginal benefit of increased generation in the dry season is 277 $/MWh (roughly the cost of unserved energy). There is little profitable trade associated with increased Akosombo/Kpong generation in the wet season, but the lack of Akosombo/Kpong generation in the dry season imposes major costs on the power pool.

4.1. Cost of spill

The WAPP model can be used to develop a short-run cost curve for spill, which presents the cost of electricity lost due to spillage as a function of the amount spilled. As spill volume increases, the cost per MCM spilled increases. The function is developed by the successive tightening of the hydro-generation availability constraint for the Akosombo Dam in the seasonally-constrained maximum flow scenario with high initial water volume to determine the least-cost response of other thermal inputs to the decreased resource availability. Cost estimates range from $2000/MCM for smaller (less than 10,000MCM) spill amounts to over $35,000/MCM for spills in excess of 15,790 MCM. Fig. 4 presents the per unit (MCM) cost of spill estimated using the WAPP model.

In our WAPP model for estimating the cost of spill, as the amount of spill increases and the amount of hydro generation from Akosombo decreases, and the model turns to the thermal units elsewhere in the system which have more expensive unutilized generating capacity to meet the demand. This results in a step-wise cost function relating the marginal cost per unit of spill to spill volume. The steps in the marginal spill cost curve each have as the height the cost of generating electricity from a particular available generating unit. The step length is equal to the spill volume corresponding to the amount of excess electricity available from the generating unit. There is an indirect cost of spill at the Akosombo Dam that is not reflected in Fig. 4, i.e. downstream spill at Kpong. We assume that Kpong does not have greater turbine capacity than Akosombo, thus any spill above turbine capacity at Akosombo must

[1] From "Generation and Master Plan Study for Ghana" prepared by Tractebel in November 2011.

Table 5
WAPP model results, high initial water volume.

	Base Model[a]	Scaled Discharges	Maximum Flow	ROR
WAPP Cost of Electricity (USD mil.)	$ 9007	$ 9007	$ 9028	$ 9162
Cost Increase from Base (USD mil.)			$ 20	$ 155
Akosombo/Kpong Total Power Generation (GWh)	6137	6137	6110	3140
Akosombo/Kpong Wet Season Generation (GWh)	4742	3937	6110	3106
Akosombo/Kpong Dry Season Generation (GWh)	1394	2200	0	34
WAPP Unserved Energy (GWh) Wet Season	2001	1684	1656	1765
WAPP Unserved Energy (GWh) Dry Season	2582	2898	2980	3045
Ghana Unmet Reserves	0	0	0	0
Rest of WAPP Unmet Reserves	3644	3644	3644	3644
Imports (from - by), Wet Season				
Benin - Nigeria	2111	2116	2111	1906
Burkina Faso - Ghana	0	0	0	523
Ghana - Togo	3729	3729	3729	3512
Ivory Coast - Burkina Faso	456	443	444	343
Ivory Coast - Ghana	2898	2847	2035	3748
Mali - Ivory Coast	85	66	133	469
Togo - Benin	2678	2683	2678	2462
Imports (from - by), Dry Season				
Benin - Nigeria	1216	1211	1164	1194
Burkina Faso - Ghana	0	0	311	627
Ghana - Togo	1811	1811	1756	1789
Ivory Coast - Burkina Faso	146	159	428	390
Ivory Coast - Ghana	1069	1120	1820	1820
Mali - Ivory Coast	218	236	181	423
Togo - Benin	1497	1492	1442	1474
Exports (from - to), Wet Season				
Benin - Nigeria	2222	2227	2222	2006
Burkina Faso - Ghana	0	0	0	537
Ghana - Togo	3825	3825	3825	3602
Ivory Coast - Burkina Faso	467	454	456	352
Ivory Coast - Ghana	2957	2905	2076	3825
Mali - Ivory Coast	87	68	136	481
Togo - Benin	2678	2683	2678	2462
Exports (from - to), Dry Season				
Benin - Nigeria	1280	1275	1225	1257
Burkina Faso - Ghana	0	0	318	643
Ghana - Togo	1858	1858	1801	1835
Ivory Coast - Burkina Faso	150	163	439	400
Ivory Coast - Ghana	1090	1143	1858	1858
Mali - Ivory Coast	223	242	186	434
Togo - Benin	1497	1492	1442	1474

[a] The Base Model does not constrain the Akosombo/Kpong hydro system generation by season. All other scenarios constrain generation to the wet and dry seasons as specified in lines four and five in Table 5. The wet season is defined to be weeks 14–48, or roughly mid-April to the beginning of December.

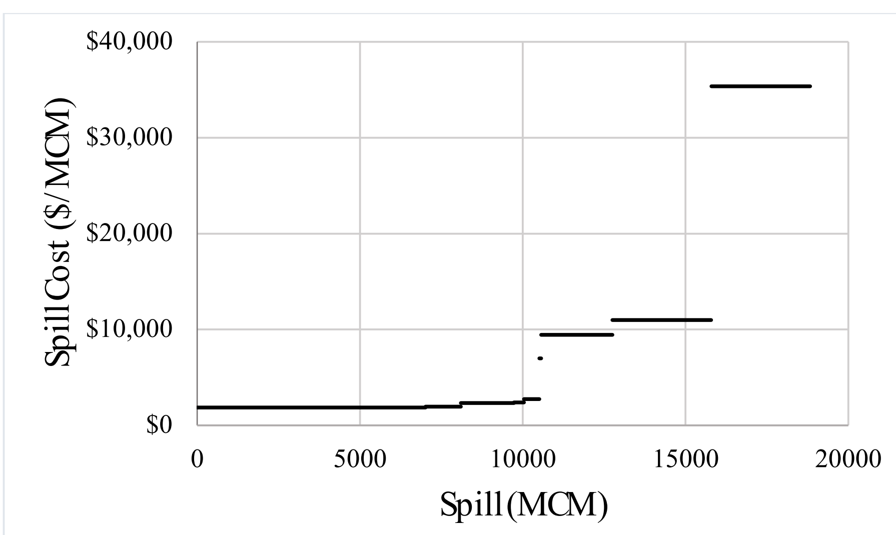

Fig. 4. Marginal cost of spill, maximum flow scenario and high initial water volume.

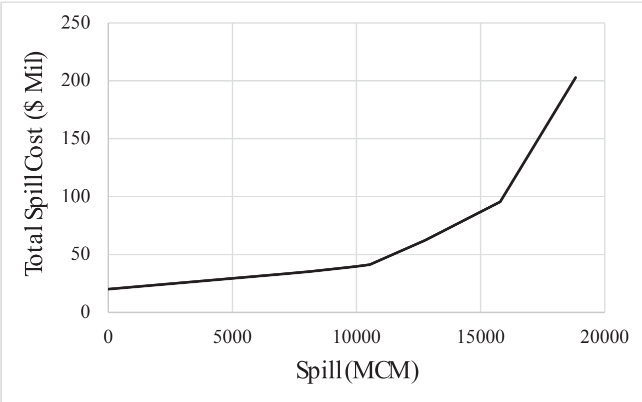

Fig. 5. Cost of spill, maximum flow scenario and high initial water volume.

also be spilled at Kpong, where there is little impoundment. This magnifies the increase in total system costs due to spill at Akosombo and is reflected in the $155 million increase in system-wide costs in the ROR scenario.

Fig. 5 translates the marginal cost of spill (Fig. 4) into a spill "supply" curve, which presents the same information as Fig. 4 but illustrates the total (rather than marginal) cost of spill as a function of spillage quantity.

In any spillage scenario, when the amount of electricity available from the Akosombo complex is reduced from its validated level, the model turns to the Ivory Coast Azito units, the cheapest underused units in the system, to make up for the electricity lost by the initial volume of spill. Once the remaining Azito generating capacity is fully utilized, the model turns to the gas-fueled Darsalam generator in Mali. After Darsalam the next cheapest available generation source is Balangue, also in Mali. The cost of replacing electricity increases dramatically, as seen by the first step in the supply curve in Fig. 4, when the least-cost replacements shift to Burkina Faso. The next major step in the supply curve reveals all remaining generating units being fully used, and the cost of unmet demand in the model becomes the last and most expensive option to "satisfy" demand. This cost is usually set at the short run cost of customers generating their own electricity, assumed to be 300 $/MWh, which is an estimate of the cost of power from portable diesel generators. In fact, Nigeria, as a result of chronic electricity shortages, spends as much on diesel fuel for such backup generators as the country does on electricity purchased from the grid.

Our method for estimating the cost of spillage vastly oversimplifies a complex estimation problem. The amount of electricity generated by a hydro plant is a complex interaction of events, some under the control of the reservoir managers (e.g., turbine flow rates during the year) and some not, most prominently the forces of nature, such as seasonal rainfall. The uncertainty this introduces into the estimation of the costs of spillage is enormous. On the one hand, during a year with unusually high rainfall, like 2010, spillage may be "free" in that the level of Lake Volta was so high at the end of the rainy season that spillage was required to maintain the integrity of the dam itself. In other dry years, no amount of increased dry season storage could raise the lake level to a point where spill can technically occur; spill costs in such a year are infinite.

5. Conclusions

Reoperating a hydroelectric dam to meet environmental objectives leads to increased system-wide electricity costs because the cost-minimizing dispatch plan is no longer feasible due to the environmental constraints. The magnitude of the cost increase depends on the marginal cost and availability of other generation resources. When the hydroelectric dam is a pivotal electric generation resource in the region, as is the case of the Akosombo Dam, the system-wide cost increase can indeed be large.

If the Akosombo/Kpong hydroelectric dam complex is reoperated so as to restrict discharges to the wet season, the change in the system-wide cost of electricity generation and transmission depends on whether yearly generation decreases or remains unchanged. If yearly generation stays (nearly) the same through increased wet season discharges offsetting decreased dry season discharges, as in our maximum flow scenario, the increase in system-wide costs is on the order of $20 million. These increases in costs are due to seasonal deviations from the optimal dispatch order and increases in line losses due to increased trade. If yearly generation decreases due to spillage, as in our ROR scenario, system-wide costs increase dramatically to $155 million. The additional increase in cost over the maximum flow scenario is largely due to the lost generation opportunity of the spilled water. This electricity must be made up from other generating resources in the WAPP system. Because maximum flow operation minimizes the cost of dam reoperation on electricity generation, evaluating the impact of releases at maximum flow rate on downstream ecology and human welfare should be a priority in evaluating the benefits versus costs for dam reoperation.

There are several limitations in the above analysis regarding what reoperation scenarios are achievable and their costs. First, the initial level of the dam in combination with inflows and dam operating limits make some of our reoperation scenarios infeasible. In particular, unless the initial level of the dam is sufficiently high *and* inflows are sufficiently abundant, spillage and the associated high volume of water released from the dam is not possible. In this situation, net inflows that exceed turbine capacity cannot be matched with outflows due to the impossibility of spillage. This occurs in situations where it is not possible for the height of the water in the dam to reach the bottom of the spillway. Alternatively, if the initial level of the dam is sufficiently high, and inflows are sufficiently abundant, then spillage is the only alternative to a potentially catastrophic dam breach. This was the case in 2010 when wet season inflows were so large that spill had to be initiated to prevent the reservoir overflowing. In a sense, these two situations place bookends on the cost of achieving a spillage target — they are infinite in the case of low starting level and inflows precisely because spillage is not physically feasible, and they are costless in the case of high starting level and inflows because they are a necessary consequence of safe dam operation.

Second, while our ROR scenario did not increase unserved energy in WAPP, larger spills (>16,000 MCM) at Akosombo/Kpong in the wet season could increase unserved energy, especially in Nigeria. We do not consider the political ramifications of dam reoperation on cooperation within WAPP due to unbalanced cost impacts across borders.

One potential strategy that was not evaluated and could contribute to increasing flow rates during the wet season would be to retrofit the dam spillways with run-of-river turbines. If the efficiency of these turbines is comparable to the existing generators, the loss of electricity for water releases through the spillway would be moderated, thereby increasing maximum flow while reducing the cost of foregone electricity. However, given that the type of ROR turbines that would likely be most appropriate for use in the spillway operate with negligible head, it seems unlikely that the productivity of water released through them via the spillway would be on a par with the main dam turbines. Further [8], discuss safety standards when designing and implementing ROR operations.

Evaluation of these types of retrofit options and safety considerations is beyond the scope of the present analysis because an engineering assessment of the feasibility of and best options for retrofitting the spillways would be needed.

This paper focuses only on the cost of reoperation of the Akosombo/Kpong complex while ignoring reoperation benefits. An incomplete list of downstream effects caused by the construction of the dam complex that may be partially alleviated by reoperation includes: decreased agricultural productivity because natural flooding no longer leaves rich alluvial deposits that improve soil fertility in the overlying upland areas; an increase in the growth of exotic weeds, which has choked off the once-lucrative shell fishing industry; an increase in cases of malaria; an increase in snail vectors which transmit bilharzias or "snail fever"; the formation of a permanent sandbar in the downstream estuary; decline or disappearance of many commercially valuable species, such as clams, blue crab, shrimps, shad, and herring; and finally, an increase in downstream coastal erosion. One cost of reoperation we do not consider is potential recurrence of cases of river blindness, which was virtually eradicated by the construction of the Akosombo/Kpong hydroelectric complex.

The method for evaluating system-wide electricity costs of dam reoperation introduced in this paper can be applied to other systems of electricity transmission and trade. Such an analysis would require developing a dataset for the relevant dispatch region, which could be a regional, national, or multi-country power pool. The WAPP model framework detailed in the appendices could serve as a framework for that part of the analysis. In addition, operations data for the impoundment hydropower complex including operating parameters and net inflows for the study period would be required. Used in tandem as described in this paper, estimates of the cost of dam reoperation could be made.

One limitation of the analysis presented here was the lack of availability of net reservoir inflows for multiple years. While it appears that the selected year spanning 2004–2005 is close to average in the sense of total net inflows, that year had a specific temporal pattern of net inflows that could be quite different even for a year with a similar total net inflow. Thus, expanding the analysis to multiple years-worth of net inflow data could improve the assessment of system costs of reoperation.

Future research on this topic should focus on 1) the benefits of reoperation, viz. the efficacy and value of downstream improvements on riverine ecology and human welfare under different reoperation scenarios; 2) the engineering feasibility, cost, productivity, and best options for retrofitting spillways with run-of-river generators, and; 3) the impact of spillway retrofits designed to increase the range of water heights at which spillage is feasible on the efficacy and value of downstream improvements under alternative reoperation scenarios.

Statement regarding role of funding source and disclaimer

This work was partially supported by the Natural Heritage Institute (NHI). NHI defined the problem scope but was not involved in model development and analysis. Coauthors Gregory Thomas, President of NHI, and Daniel P. Loucks provided critical review of parts of the model and contributed to the Introduction section. This paper was submitted for publication at the sole discretion of the authors. The views expressed in this article are solely the views of the author(s) and do not represent the views of the Federal Energy Regulatory Commission or the United States Government.

Appendix. A– Description of the WAPP Model

The model developed is a static version of the most recent incarnation of Purdue's dynamic West African Power Pool (WAPP) Model [23]. The model is designed to determine the hourly system-wide generation and transmission pattern that minimizes the operating cost of the West African Power Pool (WAPP) "Zone A" generation units and transmission system so as to meet a given hourly demand pattern during a specified year in the future. Zone A includes Benin, Burkina Faso, Ivory Coast, Ghana, Niger, Nigeria, and Togo. In the analysis reported here, Mali is also included due to the expressed export plans of Ivory Coast and Ghana. The modeled year is 2017, and generation units and transmission lines that are expected to be available by then are treated as given and fixed for the optimization. The model also includes the potential for generation and transmission expansion in the form of integer variables. Given that there is sufficient existing generation and transmission to meet demand for the modeled year, there is no new construction of generation or transmission in the scenarios we model due to high capital costs.

The model is very similar to what is called an "Economic Dispatch" model by electrical engineers, which has a similar objective. It differs from a full economic dispatch model in that it does not take into account unit ramp rates (the rates at which units can change output), voltage stability constraints on the operation and transmission of the units, and other such constraints. Furthermore, true economic dispatch models include the unit commitment decision as a binary variable [9]. Because WAPP does not include startup or shutdown costs, units are always "turned on," though a unit's ability to produce power is constrained by other factors such as output capacity. Very importantly, it does not take into account the load flow equations which govern how electricity will flow in a network in response to changing demands and supplies. Thus, it is called a "DC flow" model by electrical engineers, where it assumes that the system operator has the ability to control the paths electricity will take in the system to correspond to least cost flow patterns, as is the case when all transmission lines are DC, rather than AC, lines.

The year of the optimization, 2017, was chosen at the time this work commenced to be far enough in advance to allow completion of all WAPP units indicated by the Tractebel WAPP model [7,10] to be "decided" either as part of the WAPP expansion plan, or as a "national project" by the participating countries. "Candidate" projects identified by each country were not included because by definition they were still in the planning stage with no construction started, and hence too uncertain to assume they would be completed by 2017.

Data Incorporated in WAPP

The static nature of the model has implications for the type of data collected to populate it. Principally, cost data governing the optimization of the system should include only "out of pocket" or "marginal" costs – costs associated with the operation, but not the cost of construction of the units, and costs that only change with a change in the output of the units – for example, no fixed O&M costs are included as these would be incurred regardless of the level of operation of the generating and transmission assets.

Generation Data

Five major data sources have been used in the study:

- "ECOWAS Electricity Data Set #6", January 2003, Purdue University Power Pool Development Group, F.T Sparrow and Brian

Bowen, Purdue University, Institute of Interdisciplinary Studies, 1293 Potter Engineering Center, West Lafayette, In 47,907 [23];

- "EREP; Prospects for Renewable Power in the Economic Community of West African States", International Renewable Energy Agency (IRENA), December 2012, updated and released in 2013 as "West African Power Pool; Planning and Prospects for Renewable Energy [11]; "
- The ECOWREX database created by The ECOWAS observatory for Renewable Energy and Energy Efficiency, available on their web site, current to 2012 [13];
- "Update of the ECOWAS Master Plan for the Generation and Transmission of Electrical Energy; Draft Final Report, Volume 1: Study Data" Sept 2011, Tractebel Engineering Report prepared for WAPP [7]; and
- An additional study for Ghana entitled "Generation and Master Plan Study for Ghana" prepared for GridCo by Tractebel in November 2011 (which appears to have been based on much the same data for the WAPP Zone A system as was contained in the "WAPP Master Plan" document) [10].

Portions of all five data sets were used in this analysis. Data on units installed prior to 2003 were taken from the Purdue 2003 document. Data on those units installed between 2003 and 2011 were taken from the EREP Document and the ECOWREX data set. Data on decided (i.e. WAPP approved) and national priority (i.e. not approved by WAPP but part of the country's plan) projects for the period 2012–2017 were taken from the Tractebel report prepared for WAPP for all countries except Ghana, and data on decided and national units for Ghana was taken from Tractebel's report prepared for GridCo. All of the later documents provided useful checks on the data provided in earlier reports; the vast majority of data in this report has been confirmed at least twice, and frequently three times in these databases [16,18,20–22].

The data on each of the units in the model are shown in Table A1. Note that fuel is described by type (gas, diesel, heavy fuel oil, light fuel oil, gas) and by the mode of delivery (domestic gas, imported gas, domestic coal, imported coal, oil delivered to the coast, oil delivered inland).

Table A.1
WAPP Zone A Thermal Units Capacities and Operating Parameters

Country.Unit	Capacity (MW)	Capacity Factor (Fraction)	Heat Rate (MBtu/MWh)	Fuel Cost ($/MBtu)	Variable O&M	Forced Outage Rate (Fraction)	Unforced Outage Rate (Fraction)	Reserve Margin (Fraction)
BEN.Akpakpa	31.0	0.2000	10.560	24.985	31.00	0.040	0.060	0.19
BEN.AllSmallDiesel	7.6	0.5770	10.560	28.690	22.00	0.060	0.063	0.19
BEN.Cotonou	20.0	0.4200	15.350	14.725	2.00	0.040	0.060	0.19
BEN.Maria Gleta/CAI	80.0	0.8500	12.700	11.685	5.00	0.080	0.070	0.19
BEN.Nattitingou	12.0	0.9300	9.500	28.600	10.00	0.100	0.070	0.19
BEN.Parakou	25.0	0.9300	9.500	28.600	10.00	0.100	0.070	0.19
BEN.Porto Novo	14.0	0.9300	9.500	28.600	10.00	0.100	0.070	0.19
BEN.Tag-Cve	28.0	0.9300	9.500	11.680	10.00	0.100	0.070	0.19
BFA.Bobo 1	20.0	0.7700	13.800	28.690	46.00	0.040	0.060	0.19
BFA.Bobo 2	50.0	0.7304	7.283	28.690	42.00	0.010	0.020	0.19
BFA.Komsilga III	36.0	0.8300	8.550	18.620	7.10	0.100	0.070	0.19
BFA.Komsilsa_I and II	54.0	0.8300	8.550	18.620	7.10	0.100	0.070	0.19
BFA.Kossodo	36.0	0.9200	15.000	28.690	38.00	0.060	0.020	0.19
BFA.Ouaga 1	15.2	0.7293	14.200	28.690	43.00	0.090	0.070	0.19
BFA.Ouaga 2	38.0	0.6077	15.030	28.690	40.00	0.040	0.060	0.19
GHA.Abroadze	120.0	0.8000	7.701	9.025	5.00	0.070	0.077	0.19
GHA.Kpone	220.0	0.8500	10.800	9.025	3.50	0.060	0.070	0.19
GHA.Mine Reserve (MRP)	80.0	0.8000	12.835	9.025	4.50	0.197	0.066	0.19
GHA.Sunon-Asogli	180.0	0.6800	7.891	11.685	2.00	0.074	0.082	0.19
GHA.TAPCO-CC	300.0	0.8000	7.557	9.025	5.00	0.218	0.082	0.19
GHA.TEMA TTIPP-CC	300.0	0.8500	7.277	11.685	5.00	0.070	0.077	0.19
GHA.TICO-CC	300.0	0.8000	7.277	9.025	5.00	0.070	0.077	0.19
GHA.TT2PP	45.0	0.8500	10.507	9.025	4.50	0.090	0.066	0.19
ICO.Abbata I,II, III	402.0	0.8500	8.800	9.025	2.00	0.080	0.070	0.15
ICO.Azito 1 & 2	420.0	0.8400	8.780	9.025	9.20	0.080	0.080	0.15
ICO.Ciprel I (IPP)	210.0	0.8400	10.360	9.025	1.20	0.080	0.080	0.15
ICO.Ciprel II (IPP)	333.0	0.8500	8.800	9.025	2.00	0.080	0.070	0.15
ICO.Rental Unit	200.0	0.7000	12.100	9.025	2.50	0.050	0.070	0.15
ICO.VridiCIE	86.0	0.5600	12.800	9.025	1.20	0.120	0.080	0.15
MAL.Aggreko	30.0	0.8300	12.100	28.600	10.10	0.100	0.070	0.19
MAL.Albatios BOOT	92.0	0.8000	9.500	18.620	10.00	0.100	0.110	0.19
MAL.Balange	32.0	0.8300	9.500	28.600	10.10	0.100	0.070	0.19
MAL.Balingue	48.6	0.7900	9.500	18.620	10.00	0.100	0.110	0.19
MAL.Darsalam 1/Diesel Generators ODS	12.0	0.7900	9.500	28.690	10.00	0.100	0.070	0.19
MAL.Darsalam 2/Gas Turbine ODS	25.0	0.8500	15.600	28.690	2.51	0.080	0.070	0.19
MAL.Diesel Generators_OHF fuel	177.0	0.8300	8.550	18.620	7.10	0.100	0.070	0.19
MAL.Sikasso	14.1	0.7900	10.600	28.690	10.00	0.100	0.110	0.19
NGA.IRENA Combined Cycle	1041.0	0.8100	6.820	9.025	2.00	0.080	0.070	0.19
NGA.IRENA Gas Turbine	1997.0	0.8500	11.120	9.025	2.50	0.080	0.070	0.19
NGA.IRENA SteamTurbine	1190.0	0.8500	10.570	9.025	3.10	0.080	0.070	0.19
NGA.New CC	1696.0	0.7500	7.400	11.685	2.50	0.080	0.070	0.19
NGA.New GT	3105.0	0.7500	10.100	9.000	2.50	0.080	0.070	0.19
NGR.Coal Steam Turbine	32.0	0.8300	10.800	3.100	3.10	0.100	0.070	0.19
NGR.Gas Turbine EFGASExGT	20.0	0.8500	12.700	11.685	2.50	0.080	0.100	0.19
NGR.Niamey 2 (cold reserve)	15.4	0.7900	9.500	28.690	10.00	0.100	0.110	0.19
NGR.TahouaMalbaza	14.6	0.7900	10.400	28.690	10.00	0.100	0.110	0.19

(continued on next page)

Table A.1 (*continued*)

Country.Unit	Capacity	Capacity Factor	Heat Rate	Fuel Cost	Variable O&M	Forced Outage Rate	Unforced Outage Rate	Reserve Margin
	(MW)	(Fraction)	(MBtu/MWh)	($/MBtu)		(Fraction)	(Fraction)	(Fraction)
TOG.CentraleDeKARA	4.0	0.5900	12.590	28.690	21.00	0.130	0.060	0.19
TOG.Contoor/Lome	100.0	0.5100	10.650	24.980	10.00	0.100	0.110	0.19
TOG.CTL (Cold Reserve)	14.0	0.2000	10.970	18.620	22.00	0.040	0.060	0.19
TOG.Sulzer- Lome (Cold Reserve)	7.0	0.2000	12.200	28.690	21.00	0.040	0.060	0.19
TOG.TAG-Lome (Cold Reserve)	25.0	0.4200	15.350	11.685	2.00	0.020	0.100	0.19

The WAPP model formulates hydro units as each having a given amount of electricity available for use any hour during the year. The generation potential for each hydro unit is based on the historical amount of yearly generation in years with "normal" inflow into each reservoir. The WAPP model limits Akosombo generation to 5100 GWh, which approximates average historical yearly generation. Since then, average generation has been steadily creeping upward so that in 2014, the last year information is available, generation was 6700 GWh. This was at least partially caused by the increasing volumes of water flowing into Lake Volta during the wet season and corresponding rising Lake Volta levels (See VRA 2011 Annual Report, pg. 22). Rather than increase Akosombo's generation estimate, Akosombo generation is maintained at the original level to keep the estimate consistent with generation estimates for the other 21 hydro reservoirs modeled in the WAPP system. Table A2 presents the capacity and operating parameters for hydro units used in the WAPP model.

Transmission Data

The heavy red lines in Fig. A1 show the locations of the long distance high voltage transmission tie line system expected to be used to transmit electricity between the countries of Zone A. Mali, while not in Zone A, is included because it figures so prominently in the export plans of both the Ivory Coast and Ghana (Fig. A1). The voltages of these lines are in the 225—330 kV range, with small line losses in the range of 3—5%.

Table A.2
WAPP Zone A Hydro Units Capacity and Operating Parameters

Country.Unit	Capacity	Capacity Factor	Potential Generation	Variable O&M	Forced Outage Rate	Reserve Margin
	(MW)	(Fraction)	(MWh/yr)	($/MWh)	(Fraction)	(Fraction)
BEN.Adjaralla East	0.0	1.000	183,000	n.a.	0.0150	0.10
BEN.Nangbeto East	32.5	0.880	86,000	8.90	0.3200	0.10
BFA.Bagre	16.0	0.650	55,000	7.14	0.0083	0.10
BFA.Kompienga	14.0	0.630	47,000	7.20	0.0083	0.10
BFA.Niofila & Tourni	2.0	0.300	4800	23.65	0.0042	0.10
GHA.Akosombo	900.0	0.490	5,100,000	0.10	0.0200	0.10
GHA.Bui	342.0	0.700	962,900	0.10	0.0100	0.10
GHA.Kpong	140.0	0.900	1,037,000	0.10	0.0200	0.10
ICO.Ayame1	22.0	0.592	101,000	9.30	0.0500	0.15
ICO.Ayame2	30.0	0.594	100,000	9.10	0.0500	0.15
ICO.Buyo	165.0	0.740	900,000	8.90	0.0500	0.15
ICO.Kossou	175.0	0.650	505,000	10.20	0.0500	0.15
ICO.Soubre	0.0	1.000	1,116,000	2.00	0.0500	0.15
ICO.Taabo	190.0	0.720	850,000	8.80	0.0500	0.15
MAL.Felou - MLI	27.9	1.000	147,150	2.00	0.0500	0.15
MAL.Gouina - MLI	0.0	1.000	279,000	2.00	0.0500	0.15
MAL.Manaantali - MIL	104.0	1.000	416,000	2.00	0.0500	0.15
MAL.Petit Kenie	0.0	1.000	199,000	2.00	0.0100	0.15
MAL.Selingue	46.0	1.000	224,000	2.00	0.0500	0.15
MAL.Sotuba	5.7	1.000	39,000	2.00	0.0500	0.15
NGA.Jebba	458.0	0.830	2,373,000	2.00	0.0500	0.10
NGA.Kainji	420.0	0.650	2,475,000	2.00	0.0500	0.10
NGA.Shiroro	480.3	0.500	2,628,000	2.00	0.0500	0.10
NGR.Kandadji	0.0	1.000	629,000	2.00	0.0500	0.10
TOG.Adjaralla West	0.0	1.000	183,000	2.00	0.0500	0.10
TOG.Nagbeto West	32.5	0.880	85,000	n.a.	0.0500	0.10

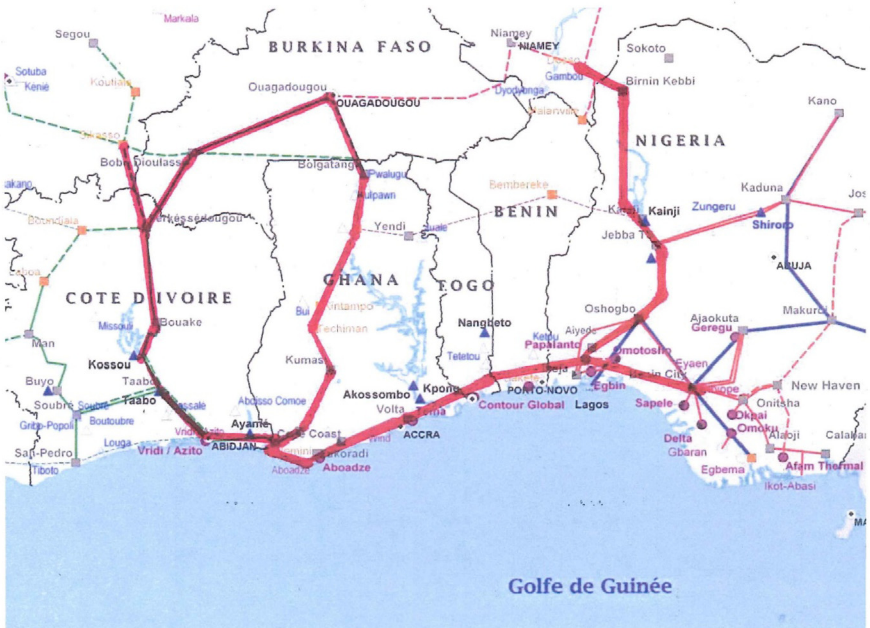

Fig. A1. WAPP Zone A Transmission System Map.

Demand Data

Three sources of demand data are available. (a) The full data set contained in Purdue's WAPP data set #6, which contains yearly peak demand (MW), a typical 52-week pattern of daily peak demands, yearly energy demand (MWh), and a typical weekly hourly demand pattern for each country. While this data is 10 years old, the typical 52-week pattern and typical weekly hourly pattern shapes usually change slowly and have probably not changed significantly since they were originally created. Hence, we assume they can be scaled so that total annual energy demands equal projected demands for the year being modeled; (b) the data set in the Tractebel WAPP report, which contains 2011 estimates of yearly peak and energy demand for each country; (c) the [11] report, which contains yearly total energy projections (MWh) for each country, but no yearly peak projections. We have chosen to use Data Set #6, the typical 52-weekly peak demand and hourly typical week MWh demand patterns scaled up to match the weekly peak MW and energy MWh forecasts contained in the Tractebel WAPP document.

Appendix B. WAPP Model Strengths and Limitations

As with every model, the WAPP model has strengths – uses for which it is best suited – and limitations. These are summarized in this appendix.

Model Strengths

The model determines the system trade pattern that minimizes the total out of pocket system cost of meeting the demands specified in the model. Thus, the model guarantees that no trades remain which benefit both the exporter and importer alike; if such trades were to remain, the model would have discovered them in the optimization process, since implementing them would have further reduced the total cost of meeting demand.

This result is extremely useful, because under certain conditions, it is exactly the trade pattern that would emerge if the market were "fully competitive," which is economists' jargon for a condition where no seller or buyer has enough volume in the market to allow it to control the price outcome of the matching process – that is all agents act as passive price takers, rather than price makers. (Other models exist, but this is the most tractable relevant for our purposes).

The pattern is exactly that which would arise in the spot markets for electricity that exist in the US and elsewhere if they were fully competitive, where suppliers and demanders enter their hourly bids to sell and buy into the markets as price takers, with no control over the final price beyond their bids to buy and sell.

As discussed in Appendix A, the version of WAPP implemented in this paper is a single-year model, thus allowing us to avoid the dimensionality issue commonly encountered in multiyear hydropower operation models [15].

Model Limitations

First of all, there is no guarantee that the initial WAPP markets for electricity will meet the "fully competitive" conditions described above. It is much more likely that initially, the actual trade patterns that result from WAPP markets will arise from a series of individual trades between countries where each share control over the determination of the final transaction price. Nonetheless, as WAPP markets become more competitive, the trade patterns will tend toward those patterns displayed by the optimization process used in the model.

Secondly, while the model identifies the flows between countries which minimize total system costs, it cannot in all circumstances positively identify the sources or destinations of such imports/exports. This is because of the near certainty that the least cost solution will involve wheeling power country A to country C across country B's grid, preventing positive identification of the source of imports or the destination of exports between countries. Power pools usually specify that a wheeling country cannot capture the majority of the gains from trade in such a wheeling arrangement by buying the power from the originating country at just above its marginal cost, and reselling it to the importing country at just below its avoided cost. Power pools do this by setting a "fair charge" for the use of the wheeling countries grid, based not on the gains from trade that drive the flow, but on the costs to the wheeling country of accommodating the additional flow, plus a fair return on its investment in its grid.

This situation is unfortunate, because without knowledge of the specific wheeling arrangements, it is usually difficult if not impossible for the model to estimate the likely prices that would be associated with such imports in the WAPP system, by agreement set by the average of the export countries marginal cost of generation and the import countries costs avoided by the imports, with transmission loss shared between the buyer and seller.

However, since the purpose of the model is to determine the incremental cost of.

Ghana's additional dry season electricity required or additional revenue from wet season electricity sold associated with the dam reoptimization, and if these changes are of small enough magnitude, it is possible that the resulting changes in flows can be attributed to specific sources and destinations in the model. Thus, if it is observed that there is 200 MWh increase in Ghana's imports accompanied by a corresponding 105 MWh increase in both Ivory Coast and Togo exports with no other changes, we can be assured that we have identified the source and destination of the incremental power. We can then determine the avoided costs of Ghana's imports and the incremental cost of Ivory Coast and Togo exports by the shadow prices of the demand constraints of the three countries, and thus are able to calculate the price of the two transactions.

Even if, in addition, Togo imports from Benin increased by 105 MWh with no other change, we could be sure the 105 MWh was wheeled from Benin across Togo to Ghana, thus again enabling us to determine the transaction price for the Benin/Ghana trade, subject to reasonable assumptions regarding wheeling charges.

However, there is no guarantee that this will happen; it is possible that a small change in Ghana's generation pattern will set in motion a whole set of small changes in the production patterns in all countries, making it impossible to determine sources or destinations. The hope is that the small changes in Ghana's generation pattern will likely result in an understandable change in the pattern of other countries generation schedules.

Appendix C. Another Approach to Assessing the Cost of Spill

There is no precise measure of the tradeoff in terms of electricity production between a unit increase in head water level and a unit of spill because the tradeoff is situational. The tradeoff is situational because it depends on the following factors:

- The timing of the 'withheld' unit discharge that raises the head water level
- The timing of the unit spill
- The head water level over the period when the head water level is raised by one unit
- The head water level at the time of the unit spill
- The dam operation strategy

The tradeoff also depends on technical considerations, such as:

- Whether the head water level is high enough to reach the bottom of the spillway
- Whether the 'withheld' unit discharge puts the dam in danger of beaching

The method of using WAPP in this paper to calculate the cost of spill does not consider all of these factors, nor is there a straightforward way to do so. As mentioned before, an alternative method for thinking about the cost of spill is the duration of time required for the cost of one unit of spill to be offset by already-realized productivity gains. Using a 5% discount rate and the operation model used in this paper, we estimate that the cost of spill outweighs productivity benefits unless more than 14 years have passed. Like our WAPP estimate of the cost of spill, this estimate requires numerous assumptions (not least the discount rate).

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