Estimating Hydropower's Contribution to the Control of Greenhouse Gas Emissions

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ABSTRACT

One of the environmental effects of hydropower operation that should be evaluated in licensing decisions is the general benefit to air quality. Hydropower's contribution to the reduction of greenhouse gas (GHG) emissions is an increasingly important component of these air quality benefits. The Oak Ridge Competitive Electricity Dispatch (ORCED) computer model is one method that can be used to quantify these benefits. ORCED provides a relatively simple method that is applicable and cost-effective and that has been successfully applied in other GHG studies. ORCED can be used to calculate a region-specific value of the carbon intensity factor (CIF, kg carbon/MWh) that would be associated with likely replacement power (i.e., a regionally representative mix of coal, gas, and other energy sources). The project's plant factor and operational mode (e.g, baseload versus peaking) can also be incorporated in the CIF calculation. The resulting parameter can then be multiplied by the energy output of the hydropower project that is being analyzed to estimate a CO_2 emission value that is avoided by the project's operation.

Background

Licensing decisions for nonfederal hydropower are required to evaluate the full range of costs and benefits of individual projects, including both power and nonpower considerations. One important effect of hydropower is a general benefit to air quality, because hydropower is free of atmospheric emissions that are associated with many other types of energy production. Hydropower's contribution to the reduction of greenhouse gas (GHG) emissions is a relatively new issue that may be considered in licensing decisions. A consistent method is needed for addressing the air quality benefits of hydropower, including the control of GHG emissions.

Recent studies by the U.S. Department of Energy (DOE) have focused on the challenge of controlling GHG emissions (IWG 1997, 2000; NLD 1997). These studies conclude that a diverse mix of clean, renewable technologies is an essential part of the GHG emission solutions of the future and that hydropower is a valuable part of these renewables.

This paper describes one approach that can be used to quantify the relation between hydropower licensing and GHG emissions. The method emphasized here is based on an existing model that was developed at Oak Ridge National: the Oak Ridge Competitive Electricity Dispatch (ORCED) computer model (Hadley and Hirst 1998).

Valuing Energy Production

Hydropower's contribution to GHG emission control is related to avoided emissions (i.e., emissions that would occur if hydroelectricity had to be replaced by another fossil-fueled energy source). The estimation of an appropriate value for avoided emissions is complicated, because there is not a single equation to calculate the emissions that are *not* produced at hydropower projects. The characteristics of avoided emissions depend on the type of power that is displaced by hydropower generation. If a kilowatt-hour were not generated at the hydro plant, what plant would have generated it? The answer depends on a range of factors: the time of day, the plants already on the system, the plants available, their variable costs, the type of fuel they use, their efficiencies, even the transmission losses and constraints. These factors are regionally and seasonally variable.

GHG Measurement Units

A common unit for measuring GHG is metric tons of carbon. Although carbon is largely emitted as carbon dioxide gas (CO_2) when it is burned, small percentages are also emitted as carbon monoxide (CO) and methane (CH_4), which eventually convert to CO_2 in the atmosphere. Other GHGs are ozone (O_3) and nitrous oxide (N_2O). The atmospheric warming effect of GHGs other than CO_2 can be represented relative to the effect of CO_2. The exact relationship between the gases is complicated by factors such as the wavelength of radiation absorbed, decomposition of gases in the atmosphere, and other atmospheric chemical reactions that can increase or decrease greenhouse gas effects. The warming value will change over time as the other gases are converted to CO_2 or otherwise removed from the atmosphere. In general, CH_4 is 56 times more potent than CO_2 over a twenty year period, but over 100 years this difference drops to 21 times, and over 500 years it drops to 7 times the effect of CO_2 (EIA 1999b). Nitrogen oxide (NO_x) is not a greenhouse gas on its own, but it can combine with CO to promote the formation of ozone. However, the greenhouse impact of power plant NO_x emissions compared to CO_2 emissions is several orders of magnitude less. More information is available in the annual *Emissions of Greenhouse Gases in the United States* from the Energy Information Administration (EIA) (EIA 1999b).

It is often useful to put GHG emissions into a more familiar context to illustrate their impact or value. One such measure is the equivalent emissions from automobiles ("car equivalent"). A standard vehicle with a mileage rating of 22.4 miles per gallon emits 401 g/mile of GHG (as CO_2), including refining and other steps in the fuel cycle (Wang 1999). Traveling 12,000 miles per year, the vehicle will emit roughly 1.3 metric tons of carbon. A car equivalent value for hydropower GHG benefits can be calculated by dividing the tons of carbon avoided by the car emission rate. The resulting car equivalent value is an

approximate measure of the number of cars that would have to be removed from the roads to compensate for the GHG emissions avoided by hydropower production.

Replacement Values

The total amount of generation from a hydropower facility for a given year is generally fixed by hydrologic factors, such as the amount of rainfall or snowpack upriver. The timing of the generation, though, can be altered and can greatly influence the type of power that ends up being displaced by the hydro generation. Since the types of plants displaced can have significantly different GHG emissions, changes in the production profile may change the total emissions and avoided costs even though total generation is the same.

If the total energy from a particular plant is limited, it makes the most economic sense to use that plant's output to displace the highest cost production. Highest cost sources are typically plants that are called on infrequently or that are either older, inefficient steam plants fueled by gas or oil or are combustion turbines. As more energy is available for a given hydro facility size, the plant factor increases and lower cost plants are displaced. These lower-cost sources may be more efficient steam plants or turbines, or they could include combined cycle or coal-fired plants.

The operating characteristics of a specific hydropower plant will affect what its most likely replacement source would be. Minimum flow rates, the amount of storage available, seasonal variations in rainfall, local operating agreements, and other environmental concerns can all change the timing and level of facility operation. Day-to-day operational planning is a complex business, especially with multiple dams along a single river. The hydropower production schedule will influence the amount of water available for dams downstream and their production rates. While detailed analysis can be complex, simplifying assumptions and analytical techniques can be used to give reasonably accurate estimates, as described in the next section.

Estimation Methods

Different levels of modeling complexity can be used in estimating GHG benefits. The simplest approach is to make an *a priori* assumption of the type of power that would replace hydropower production and then use a representative carbon intensity factor to calculate the relevant carbon emissions. Average carbon intensity factors range from 266 kg C/MWh for a coal-fired steam electric plant to 90 kg C/MWh for an advanced gas combined cycle plant (Table 1; EIA 1999a and 1999b). For example, if the loss of a hydro facility would be replaced by increased coal-fired production at 33 percent efficiency then carbon emissions would increase 266 kg per MWh. If the facility had a capacity of five MW and a plant factor of 50%, replacement with coal-fired production would generate about 5,800 tons of carbon per year. This is equivalent to 4,500 vehicles.

Table 1. Carbon intensity factors of selected types of power plants (Source: EIA 1999a and 1999b).

Energy Source	*Efficiency*	*Heat rate (Btu/kWh)*	*Carbon intensity factors*	
			(kg C/MBtu)	*(kg C/MWh)*
Coal Steam	33%	10,339	25.74	266
Oil Steam	33%	10,339	21.49	222
Gas Steam	33%	10,339	14.47	150
Oil -- Combustion Turbine	25%	13,648	21.49	293
Gas -- Combustion Turbine	25%	13,648	14.47	197
Gas -- Combustion Turbine	40%	8,530	14.47	123
Gas -- Combined Cycle	50%	6,824	14.47	99
Advanced Gas -- Combined Cycle	55%	6204	14.47	90
Coal Gasifier / Combined Cycle	50%	6,824	25.74	176

If the specific plant displaced by hydropower in a system cannot be identified, then more detailed modeling may be needed to evaluate the regional power system within which a hydropower project is located. For example, a load-dispatch model can be used to describe the demands on the system and dispatch available power plants to meet those demands. Running the model twice, once with and once without the hydropower plant being considered, will show the change in GHG emissions. This systematic approach provides more accurate information based on the plants that are on the margin for that region. If the hydro capacity is significant relative to the overall system, it may be necessary to make an assumption of what capacity might have been constructed if the hydro facility is not available. Since the analysis is taking the difference of two large numbers, it is important that both numbers reasonably represent the options available.

More detailed models can range in complexity from intermediate-level, PC-based models that generalize production and demand to very sophisticated models that incorporate the

transmission system constraints and hour-by-hour dispatching. The simpler, intermediate-level models give relatively good information on marginal plants and do not require the large amount of information and computing power that the more complex ones do. However, intermediate-level models do not account for some of the interactions within a power system that can affect real-world operations and system performance, such as transmission constraints.

Transmission constraints can change the operations by making certain plants in a region unable to replace power lost from the hydro facility or by requiring that the plant operate for voltage support or other reason. Time-specific modeling allows calculations based on minimum plant operation factors, ramping speeds, incremental heat rates, and hydro storage limits. The more complex models may also incorporate capacity expansion over time, such that hydropower losses may be replaced by new construction over time. The justification for these more detailed models will be depend on the nature of specific licensing proceedings.

The ORCED Model

The ORCED model is an existing, load-dispatch power system model that is intermediate in its complexity. ORCED was initially developed with support from the U.S. Environmental Protection Agency and has been used in a number of recent studies on GHG reductions, regional power pricing, stranded cost calculations, and generation adequacy. It runs using Microsoft Excel and can be run relatively easily on any Macintosh or Windows personal computer. The ORCED version used in this study divides the U.S. into multi-state regions that are consistent with the structure of the North American Electric Reliability Council (NERC). Each NERC region is represented in ORCED with a set of 52 “bins” of power plants, ignoring transmission constraints. The report ORCED: Simulating the Operations and Costs of Bulk-Power *Markets* (Hadley and Hirst 1998) gives additional detail on the structure and operation of ORCED. Additional information on the model is also available on the Internet at http://www.ornl.gov/orced/.

Although the ORCED spreadsheet model is relatively simple, it captures the key features of the U.S. electricity system as it functions with competitive bulk-power markets. In particular, generating units bid their variable costs (the sum of fuel costs plus variable O&M costs) into a market; the market selects the cheapest units to meet demand for each point in time. All generators are paid the same price during each point in time, the price bid by the highest-cost unit then operating.

Because the ORCED model is structured to deal with 52 plants, the list of power plants in a region must be consolidated. To do this consolidation, a separate workbook is provided for each of the ten NERC regions containing a list of all the power plants in each. Power plant characteristics come from the data set used by the EIA for their *Annual Energy Outlook 1999* (EIA 1998a). The EIA data set includes approximately 19,000 units across the country and specifies such values as operations and maintenance costs, heat rates, fuel types, age, and emissions rates. Separate information from the EIA website

describing regional fuel costs was used. Maximum power demands for each region were taken from EIA's Electric Power Annual (EIA 1998b). The ORCED application used for this paper is based on data from the year 1997. More recent data has become available, but it has not yet been translated into a form that could be used by ORCED.

Calculating Hydropower GHG Benefits

The ORCED model can be used to estimate the source of power that would replace hydropower and the GHG emissions that would be produced by this replacement power, as described here.

NERC Regions

It is necessary to consider each hydropower plant in a regional context, because each plant's emission-control benefits are dependent on the marginal plants that it replaces (or is replaced by). Different parts of the country have a different mix of plants, fuel costs, and demands, that create a different mix of plants that are on the margin. The scale of the region studied is important to the results. The region must be right size to include those plants and demands that interact with the facility in question. Too small of a region loses the impacts of power sales into or out of it. A region that is too large incorporates power plants or demands that are irrelevant to the facility that is being studied. For the current implementation of ORCED, regions are defined as the U.S. portions of the ten NERC regions. This configuration can be changed if necessary.

The NERC regions are widely used for reporting and analyzing the electricity industry in the U.S. While there is trading of power between the regions, the bulk of power within each region is used within the region. The NERC regions are also small enough to capture the plant mix unique to each region that can be influenced by the hydro power in question. Further work could be done in segregating some of the larger regions, such as the WSCC (the Western states), or representing significant power flows into or out of the region, such as with FRCC (Florida).

Regional Carbon Intensity Factors

Each region has a different mixture of plants on the margin. ORCED provides information on the percentage of time each type of fuel is on the margin, which gives an indication of the carbon intensity for the region (Table 2). Note that the MAPP, MAIN and ECAR regions have coal as their dominant marginal fuel, while ERCOT and WSCC are dominated by natural gas. NPCC and FRCC have oil as a large proportion of the marginal fuel mix, even though it only provides a much smaller percentage of the total mix of generation.

The carbon intensity factor for each region can be calculated by running the ORCED model both with and without a hydro facility and comparing the carbon emissions. For the data shown in Figure 1, a 100 MW hydro facility was added to each region's

Table 2. Regional composition (percentage) of marginal fuel types (Source: application of ORCED with EIA 1997 data).

Fuel type	*NERC Region (values are percent of time on margin)*									
	ECAR	*ERCOT*	*FRCC*	*MAAC*	*MAIN*	*MAPP*	*NPCC*	*SERC*	*SPP*	*WSCC*
Gas	8	97	57	48	6	22	59	39	79	96
Coal	88	0	2	38	91	69	3	55	21	4
Oil	2	2	38	14	2	8	38	4	0	0
Uranium	0	0	0	0	0	0	0	0	0	0
Water	0	0	0	0	0	0	0	0	0	0
Other	1	0	0	0	0	1	0	0	0	0

Note: Numbers do not necessarily add to 100 because of rounding and modeling of unserved energy. Regional definitions are: ECAR = East Central Area Reliability region; ERCOT = Electric Reliability Council of Texas; FRCC = Florida Reliability Coordinating Council; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP =Mid-Continent Area Power Pool; NPCC = Northeast Power Coordinating Council; SERC = Southeastern Electric Reliability Council; SPP = Southwest Power Pool; WSCC =Western Systems Coordinating Council.

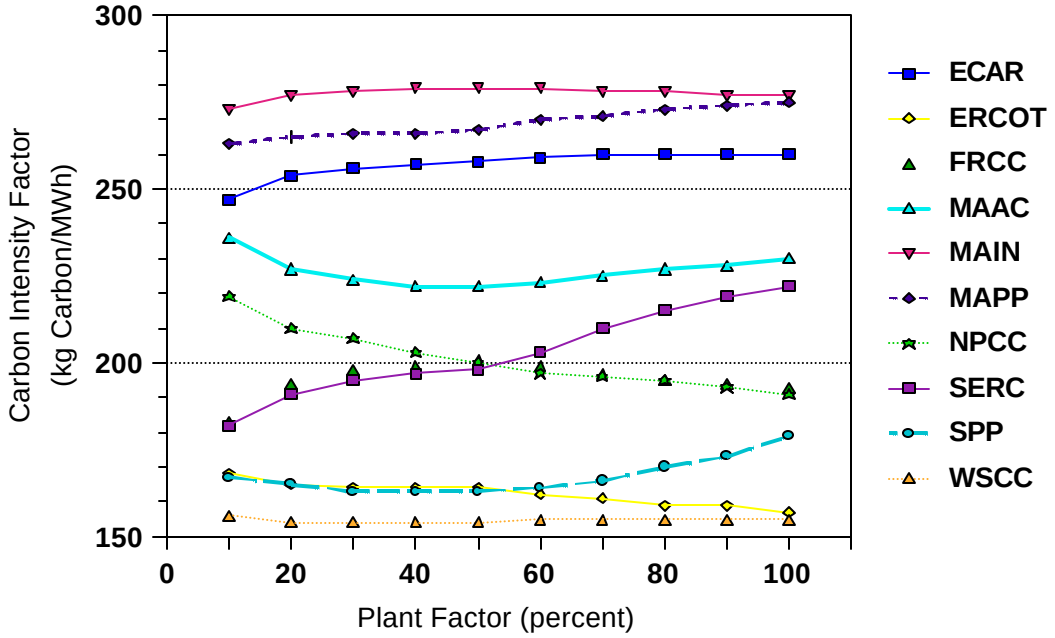

Figure 1. Regional carbon intensity factors (kg C/MWh) as a function of hydropower plant factors (Source: ORNL application of ORCED with EIA 1997 data).

reference case. The hydro facility was operated at ten different plant factors, from 10 to 100 percent. This analysis indicates that there are significant differences among the regions in the carbon intensity factors that should be used in evaluating hydropower's GHG benefits. For some regions, the curve is relatively flat, because one fuel dominates the marginal production for the region. Other regions show an increase or decline with increasing capacity factor due to either change in the marginal fuel mixture or efficiency of plants on the margin. The Southeast region (SERC) shows the greatest variation as displaced production shifts from gas to a mixture of gas and coal. It should be relatively accurate to simply interpolate for capacity factors between those listed in the table. This should provide a quick answer to the GHG impact of any hydro facility. The impact of changes to a facility could be calculated by determining the emissions before and after any changes and then subtracting.

As a consequence of the various fuels on the margin, the carbon intensity factor (kg/MWh) for displaced hydro will vary depending on the part of the year that the hydro operates. If a hydro facility is largely used for peaking, with a plant factor less than 20 percent, then it mainly displaces the higher cost fuels of gas or oil. As it increases in plant factor it continues to displace those fuels but also displaces lower cost coal. This can gradually change the carbon intensity factor to reflect the new mix of fuels displaced. Another factor that can change the intensity factor, even with no change in fuel, is the change in technology using that fuel. Plants with low efficiency are both higher cost and have higher carbon intensity factors than high efficiency plants using the same fuel. As the plant factor for hydro increases, it displaces more lower-cost, more-efficient plants with lower carbon intensity factors.

Sensitivities

Several modeling assumptions can affect the estimate of avoided GHG emissions. The effects of these assumptions can be examined with sensitivity analysis, as follows.

The results shown above were based on the assumption of a 100 MW addition to the reference case for each region. Because the factor is a rate based on the amount of energy displaced, the values should not change drastically based on the size of the facility. To see, we conducted the same set of runs assuming a 5 MW reduction in regional capacity. The results were essentially the same, with the carbon intensity factor changing by less than one kg/MWh in all cases.

One common issue in hydropower relicensing is the change in operations from peaking to run-of-river. This creates more generation during the baseload time period and less during peaking. Consequently, additional baseload generation will be displaced instead of peaking power. To study this, we assumed a 5 MW facility in the SERC region with an average plant factor of 40 percent. In the peaking mode, it operates mainly during the high cost period, displacing gas production. (The plant does not operate at 5 MW for 40% and 0% for the rest of the year because hydro is represented in ORCED by a reduction of the load duration curve. This limits the shape of the production curve for hydro but also better

represents typical operations.) For run-of-river mode we have the facility run at 2 MW year-round. Actual operations would vary through the year, but there is no connection between power level and system demand level. Actual changes to hydro facilities may be a mix of the two, increasing the baseload operation, but still having some additional production during the times of peak demand.

We examined the SERC region because it has a larger change in the carbon intensity factor than other regions as marginal production changes from gas to coal. The results were that the peaking facility had a carbon intensity factor of 197 kg/MWh and displaced 3,450 tons of carbon (equivalent to 2,600 cars). The baseload facility had an intensity factor of 222 kg/MWh, saving 3,900 tons carbon, or 3,000 cars.

Case Studies

Two case study applications of ORCED have been made to illustrate how this proposed approach would work. For each of these projects, region-specific carbon intensity factors were calculated by running the ORCED model for the WSCC region with the projects and then with the alternatives (i.e., without Clark Fork projects or with the White River project at different plant factors). An additional sensitivity was run with the Clark Fork projects to see the result if more coal capacity is on the margin. This was done by making some of the gas steam plants “must-run”, moving them lower in the loading order and thereby raising coal plants onto the margin. This reflects the possibility that the gas steam plants are too far away or transmission is too constrained for them to be affected by the loss of the Clark Fork projects.

Clark Fork Projects

Washington Water Power recently completed a successful relicensing of its projects on the Clark Fork River in Bonner County, in northern Idaho and Sanders County, in northwest Montana: the 466-megawatt (MW) Noxon Rapids Project (FERC No. 2075) and the 231-MW Cabinet Gorge Project (FERC No. 2058). Combined, these two projects generate an annual average of 2,836,000 MWh, enough electrical energy to serve 235,000 average residences in the Pacific Northwest.

By producing hydroelectricity, the Clark Fork projects displace the need for other power plants to operate, thereby avoiding some power plant emissions and creating an environmental benefit. The amount of GHG emissions that are avoided depends on the type of power displaced, which is region-specific. In the Western States Coordinating Council (WSCC) reliability region where the Clark Fork projects are located, the capacity mix includes a proportionately large amount of hydropower, relative to other parts of the country. If transmission constraints are not considered, the WSCC marginal capacity is largely gas-fired steam generation, which has typical GHG emission rates of about 150 kg/MWh of carbon. Without the Clark Fork projects, annual carbon emissions in this region would increase by 440 thousand metric tons per year. The comparable GHG emissions for the total WSCC region are estimated at 75 million metric tons for carbon.

The emission avoidance benefit of the Clark Fork projects is equivalent to emissions of more than 340,000 passenger cars. If transmission constraints force coal plants to make up 30-40 percent of the marginal capacity mix, the projects' emission avoidance benefit would be about 9 percent greater that those estimated with a gas-only marginal capacity. In other regions of the country where there is less hydropower and more electricity production from high-carbon fossil fuels, the emission avoidance benefits would be even greater, because the emission rates from marginal capacity would be higher than WSCC rates.

White River Project

White River Project is a hydro facility in Washington that consists of four units, two rated at 15 MW and two at 20 MW, for a total of 70 MW. Three alternative modes of operation were evaluated, with annual total generation at 371.9, 332.7, and 296.0 GWh respectively. These are equivalent to annual plant factors of 60.6, 54.3, and 48.3 percent. Using the highest plant factor as the base, we find that reducing the plant factor to 54.3 percent lowers the carbon savings by 6,300 tons (4,800 cars) and avoidable costs increase by $1.2 million. The carbon intensity factor for the reduced generation is 160 kg/MWh, and the net cost increase is $30.6/MWh. This cost includes the cost of increased gas generation less the cost of the incremental hydro production. For the plant factor of 48.3 percent, carbon additions are 12,000 tons (9,100 cars) and the cost increase is $2.3 million.

Conclusions

The production of hydroelectricity is associated with significant reductions in the nation's GHG emissions, although the specific amount of this benefit is difficult to measure directly. ORCED provides a relatively simple method to estimate the GHG benefits of hydropower. If more precise answers are required, then other large-load flow or capacity expansion models may need to be used. However, for most cases ORCED provides a mechanism to get results without the high cost or long time of these large models. ORCED can be used to calculate a region-specific value of the carbon intensity factor that would be associated with likely replacement power, and that factor can be adjusted to account for the hydropower projects plant factor. The resulting carbon intensity factor can then be multiplied by the energy output of the hydropower project that is being analyzed to produce a CO_2 savings that is associated with the project's operation. This GHG emission can then be converted to an equivalent value the number of cars needed to produce the same emission or to some other common measure, to put this savings in a more easily understood measure. This analytical approach can be adapted to evaluating alternative plant operations, such as shifts from peaking to baseload. The model also generates the marginal cost of power for a given region, allowing the user to determine the economic impact of the generation.

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