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CLIMATE CHANGE AND HYDROPOWER GENERATION

PETER J. ROBINSON*

Department of Geography, University of North Carolina, Chapel Hill NC 27599, USA and Southeast Regional Climate Center, Columbia, SC 27201, USA,

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ABSTRACT

Many electric utilities use small reservoirs in mountainous regions to generate hydropower to meet peak energy demands. Water input depends on the water budget of the catchment, whereas output depends on user demand, which is influenced by temperature. Hence reservoir performance depends on climatic factors and is sensitive to climate change. A model, based on the systems of Duke Power and Virginia Power in the south-eastern USA, was developed to simulate performance. The annual maximum draw-down of the reservoir, which represents the minimum dam size needed to maintain continuous energy generation, is considered here. The model was tested for four regions in the eastern USA using 1951–1995 observations. The amount of draw-down depended on the linked daily sequences of precipitation and temperature, the former dictating the water available, the latter influencing both evaporation and energy demand. The time and level of the annual extreme emphasized that small changes in the timing of a dry spell had a major impact on the draw-down. Climatic changes were simulated by uniformly increasing temperatures by 2°C and decreasing precipitation by 10 per cent. The resultant draw-down increased from current simulated values by about 10 per cent to 15 per cent with extremes up to 50 per cent. This was of the same order, but in the opposite direction, as the change created by a 10 per cent increase in the efficiency of energy generation. Without such an efficiency increase, many utilities will face the prospect of reduced or less reliable hydroelectric generation if climate changes in the manner examined here. © 1997 by the Royal Meteorological Society. *Int. J. Climatol.*, 17: 983–996 (1997).

(No. of Figures: 9 No. of Tables: 3 No. of Refs: 13)

KEY WORDS: climate change impacts; electrical energy; water budget models; USA, eastern

1. INTRODUCTION

The production and use of electrical energy is influenced by the weather in a great variety of ways (Jäger, 1983) and as a consequence energy utilities are concerned with atmospheric forecasts on scales ranging from the daily (Haijtink, 1990) to the seasonal (Changnon *et al*., 1995). In the longer term, there is also concern with potential climate change. Various climate scenarios have been used to suggest possible impacts, but the results indicate a range of outcomes, good and bad, depending not only on the climate but also on the operation of the utility itself (McKay and Allsopp, 1981; Linder *et al*., 1987). For all impacts, however, there is major concern with the variation in customer demand for power caused by daily weather changes. The major weather element involved is temperature, although several others, such as wind and humidity, can be significant at times (Robinson, 1996). Relationships between demand and temperature have been developed (e.g. Warren and LeDuc, 1981; Robinson, 1997) which indicate that demand is at a minimum at temperatures near 18·3°C. As a consequence, heating and cooling degree days with an 18·3°C base have long been used for temporal and spatial comparisons of demand (Downton *et al*., 1988). Demand commonly rises more rapidly with rising temperatures and increased air conditioning needs than with falling temperatures and an increase in heating requirements. The nature of the relationship, however, depends on the level of technology and economic status of the region.

Within this general context the present paper explores an aspect of the impact of climate change on utilities: the influence of possible climate change on the water needs for hydroelectric power generation. This is

*Correspondence address: Department of Geography, CB# 3220, Saunders Hall, University of North Carolina, Chapel Hill, NC 27599-3220 USA.

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undertaken specifically for two utilities in the south-eastern USA, and thus is applicable to their climate, geographical setting, and operational modes. Nevertheless, the approach was designed for general applicability. The two utilities, Duke Power Company in North and South Carolina, and Virginia Power Company in Virginia (Figure 1), generate some power from a series of relatively small hydroelectric systems in mountainous areas some distance from the population centres where demand is concentrated. In several cases the systems are used primarily to meet short-term peak demands, which are common on summer afternoons. Water is released from the reservoir and falls through the generating turbines at this time of high demand, with the resultant power supplementing that generated by other methods. These other methods tend to be large fossil and nuclear fuel driven facilities with a great deal of inertia. During periods of low demand, commonly during the night, their excess power is used to pump water back into the reservoir ready for the next cycle. Although this produces an efficient use of the water available, continuous 100 per cent reuse is not possible because no system can be anywhere near 100 per cent efficient. Nevertheless, the small hydrogenerating systems add flexibility to the whole utility system and can be used as long as water is available in the reservoir. This water availability depends on precipitation to fill the reservoir and on temperature, which controls evaporative losses and use for required energy generation. The specific concern here is how climate change influences water availability in a reservoir. Thus the emphasis is on the energy aspect of the water use, not the water resources themselves. These could be of equal or greater significance in some areas (see, e.g. Gleick, 1993; Kaczmarek, 1996).

A modelling approach, based on water balance concepts, was adopted. The model was constructed based on a generalization of a specific individual hydroelectric generating system. Generalization was necessary because the actual daily operation of an individual system depends on many non-climatic factors, which may on any day completely overshadow the atmospheric ones. Thus the formulation was designed to isolate the long-term climatic influence and not only to ensure that suitable data were available for the analysis of operations in the current and future climates, but also to allow a broader evaluation for a variety of systems in a variety of climates. In particular, uniformity was maintained in the way of expressing climatic impacts. Throughout the work the impacts are expressed in terms of the amount of draw-down of water from a full reservoir. Consequently the reservoir level is always zero, indicating a full reservoir, or a negative value. The lower the value (i.e. the more negative), the lower the reservoir level.

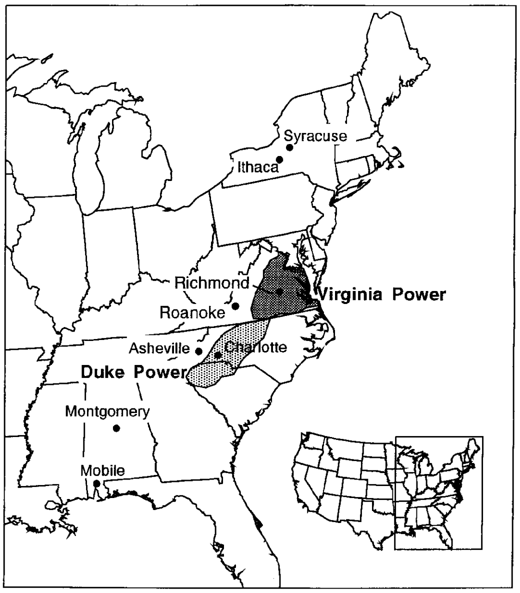

Figure 1. The eastern USA showing the service areas of the two utilities used in the analysis and the location of the station pairs considered.

2. THE RESERVOIR DEPLETION MODEL

The theoretical basis for the model is considered in this section. The calibration for a specific set of systems is discussed in the following one. A reservoir was located in a (mountainous) area where temperature and precipitation are characterized by a particular climatological observing station. It was assumed that temperature and precipitation were homogeneous over the whole reservoir catchment area, so that runoff to the reservoir could be determined as the difference between the precipitation and the evaporation. Evaporation was itself dictated by the temperatures. The runoff, with suitable time lag, flowed into the reservoir and raised the level. This reservoir provided power for a heavily population area where the fluctuations in demand were determined by the local temperature conditions. Generation of the appropriate power to meet the demand lowered the reservoir level. Thus a daily water budget was established. The annual minimum reservoir level represents the maximum demand and indicates the size of the impoundment needed to meet demand. Any increase in this depletion depth with climatic change implies the need for additional facilities, whether a bigger dam or a new reservoir. For the present purposes whenever the water budget is such as to raise the level to the top of the dam, that water is simply allowed to run off downstream and is not considered further.

The reservoir level L is given by:

$$L_t = L_{t-1} + \Delta L \tag{1}$$

where subscripts t and $t-1$ represent conditions one day apart. The value of L is negative, representing the level below capacity. When the reservoir is full all surplus water runs off automatically and $L = 0$. The value for ΔL is given by:

$$\Delta L = R - U(T_{\mathrm{p}}) \tag{2}$$

where R is water inflow to the reservoir, and U is water use for hydroelectric generation to meet the demand created by population centre temperature T_{p}. The water available for runoff R is the difference between precipitation P and evaporation E, which is driven by the temperature over the catchment, T_{c}. Variables P and E are assumed to be uniform over the catchment. Half of the available water arrives at the reservoir each day, the other half being held in storage, S. This becomes available the following day. A distinction was made between conditions when the precipitation and storage together exceeded the evaporation by more or less than 1 mm, so that:

$$R = a_{\mathrm{c}}\{P_t - E_t(T_{\mathrm{c}}) + S_{t-1}\}/2 = S_t \qquad (P_t + S_{t-1}) - E_t(T_c) \geq 1\mathrm{mm} \tag{3a}$$

$$R = a_{\mathrm{c}}\{S_{t-1}/2\} = S_t \qquad (P_t + S_{t-1}) - E_t(T_{\mathrm{c}}) < 1\mathrm{mm} \tag{3b}$$

where a_{c} is the area of the catchment, including the reservoir. Equation (3a) simulates moist situations with rapid runoff immediately after rain, followed by a slow decrease in base flow into the reservoir. Equation (3b) applies for drier conditions, when potential evaporation exceeds the combined precipitation and water storage, where it is assumed that half of the stored water runs off, and the only evaporation is the daily precipitation itself.

Daily evaporation from the basin surface was modelled empirically using:

$$E(T_{\mathrm{c}}) = [p + q\{1 - \cos(2d\pi/365)\}] \times T_{\mathrm{c}} \tag{4}$$

where d is the Julian day, T_{c} is the temperature of the station in the catchment near the reservoir and p and q are constants, 0·053 and 0·072 respectively. North Carolina Climate Division temperature data were used with regional open water (pan) evaporation observations to establish a transfer function (mm day^{-1} °C^{-1}) between temperature and evaporation for each month. The value varied with month, reflecting the influence of day length. Consequently a sinusoidal model was then fitted to the monthly data to give daily estimates. The formulation was constrained such that $E = 0$ when $T < 0$. Equation (4) estimates daily potential evapotranspiration which, in the moist humid south-eastern USA, is commonly close to the actual value. In other environments this might not be appropriate and a correction factor would be needed.

The water demand for hydrogeneration was developed from the known relationships between temperature and energy demand for the Duke and Virginia utilities (Robinson, 1997). Energy demand is given by:

$$D(t) = N(t) + N(t) \times w(T_{\rm p}) \quad (5)$$

where D is the total demand, N is the non-weather sensitive portion, w is the weather coefficient and t and T are time and temperature respectively. For computational convenience, this can be rewritten with $W = 1 + w$, as:

$$D(t) = N(t) \times W(T_{\rm p}) \quad (6)$$

In order to establish the form of $W(T)$, a linear regression relationship between total demand and time was first established. Thereafter the percentage departure of the actual daily load from the regression estimate for that day was determined as the normalized load. This was then treated as a function of temperature to give the appropriate empirical form of $W(T)$ (Figure 2).

For the hydropower generation system the demand $H_{\rm d}$ can be expressed as:

$$H_{\rm d} = N_{\rm u} \times W(T_{\rm p}) \quad (7)$$

where $N_{\rm u}$, the average load as defined in (6), here represents the portion of the total load to be met by this hydroelectric system. This is met using the potential energy released by falling water. This is modelled directly as the product of that potential energy and the efficiency of the mechanical system used to convert the falling water to electrical energy. Thus the energy produced, $H_{\rm p}$, is:

$$H_p = U(T_{\rm p}) \times h \times s_{\rm e} \times a_{\rm r} \times r \times g \quad (8)$$

where U is the depth change in a reservoir with surface area $a_{\rm r}$, with a power generation system with hydraulic head h and an overall energy conversion efficiency $s_{\rm e}$. Variable r is the density of water and g is the acceleration of gravity. For convenience, the generating system characteristics can be treated as:

$$c_{\rm u} = h \times s_e \times a_{\rm r} \times r \times g \quad (9)$$

where $c_{\rm u}$ is a system coefficient representing the energy production per unit change of reservoir depth. Thus, combining and rearranging equations (7)–(9):

$$U(T_{\rm p}) = \{N_{\rm u} \times W(T_{\rm p})\}/c_{\rm u} \quad (10)$$

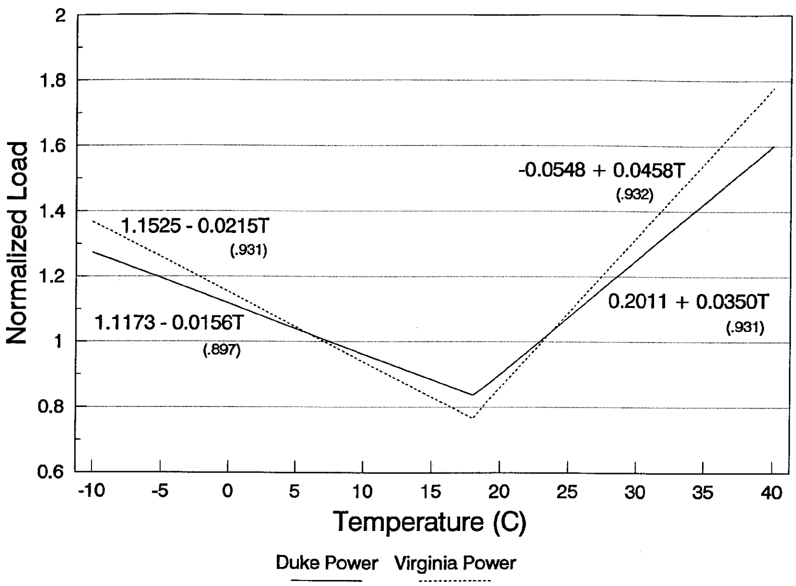

Figure 2. Relationship between ambient temperature and normalized load for the Duke Power and Virginia Power service area (after Robinson, 1997). The regression equations (with correlation coefficients in parentheses) between W and T are indicated.

With this formulation, the only data required to run the model are daily temperature and precipitation values for a location near the reservoir and daily temperatures for a station representing the major energy demand centres for the utility. Suitable data are commonly available. In the present case they were obtained from the Southeast Regional Climate Center. Precipitation was converted to millimetres and temperature to degrees Celcius at the outset, and all calculations undertaken in this system. Records for 1949–1995 were used. However, the first 2 years were used for model spin-up to allow the soil storage, initially set at 0·1 m, and reservoir levels, set to zero, to become stable. All subsequent results apply to the 1951–1995 period.

3. MODEL CALIBRATION

The Duke and Virginia Power regions were used for model calibration and initialization. For Duke Power it was assumed that the reservoir was in the mountains of western North Carolina. Nantahala Lake was used as the model, with the values generalized somewhat. The Asheville airport station, about 100 km north-east of the lake but having a long period of virtually uninterrupted high quality observations, was used to represent the catchment. This station is somewhat drier than the regional average, so Highlands, a wetter and somewhat closer station with a less continuous record, was used for some comparisons. The city of Charlotte represented the population cluster. For Virginia Power the stations of Roanoke and Richmond, VA, played the same respective roles. For this utility the reservoirs have similar configurations to Nantahala Lake, which was therefore used throughout. Thus $a_r = 10$ km^2, $a_c = 10\,000$ km^2, and $h = 100$ m. The mechanical energy conversion system efficiency s_e was assumed to be 0·25. This is high for a mechanical device, but is realistic here because of water reuse with night-time pumping. This system therefore has $c_u = 0{\cdot}0025$.

Virginia Power is capable of producing about 12–15 percent of its required energy from about 30 relatively small hydropower reservoirs (Dr Allen Mitchem, pers. comm.). Because that load during 1995 was about 200 000 MWh day^{-1} ($7{\cdot}27 \times 10^{14}$ J day^{-1}), each hydropower system needs to provide about $3{\cdot}6 \times 10^{12}$ J day^{-1}. This represents N_u. The depth of water falling from the reservoir to meet this need depends on c_u. With a reservoir having $c_u = 0{\cdot}0025$, this is approximately 1·4 m. The reservoir must, therefore, be in a catchment big enough, and with sufficient water surplus, to meet that demand on a long-term basis, and the reservoir must be deep enough to survive through dry spells.

The 1949–1995 precipitation and temperature data were used to explore the influence of changes in catchment size and system coefficient (Table I). Asheville–Charlotte and Highlands–Charlotte were used with the Duke Power data, Roanoke–Richmond with the Virginia Power load relationship. The sensitivity was expressed as the lowest reservoir level achieved during the period. As both a_c and c_u increased, the depth of water needed in the reservoir decreased. For a given c_u this decrease is rapid for small a_c, but by 10 000 km^2 the change in U with a_c is minor. Similarly, for a given a_c a change in c_u has a greater influence on U when c_u is small. The influence of the precipitation on the basin is seen in the difference between the Asheville and Highlands results, with the higher precipitation station requiring less depth. With the Nantahala configuration the depth using the wetter station is somewhat less than that of the drier one. The results in general, however, suggest that within a fairly broad range of a_c and c_u results are likely to be similar, although absolute depths will depend on the actual values

Table I. Minimum reservoir depth (m) as a function of catchment area a_c (1000 km^2) and hydropower system coefficient c_u ($\times 10^5$) for three catchment–population pairs. Values used in analysis are in bold

Area (a_c)	c_u (Asheville–Charlotte)				c_u (Roanoke–Richmond)				c_u (Highlands–Charlotte)			
	125	250	375	500	125	250	375	500	125	250	375	500
1	16704	279	90	47	13300	153	82	57	336	86	48	34
4	190	88	54	38	229	112	74	55	134	51	32	23
7	179	79	51	38	226	111	74	55	105	47	31	23
10	170	**76**	50	37	224	**110**	73	54	98	**46**	30	22
13	160	76	50	37	223	110	72	54	94	45	30	22
16	154	75	49	37	222	109	72	54	93	45	29	22

adopted. In particular, the minor generalization of the size of the Nantahala catchment should have very little influence.

Reservoir response to the current climate variability was assessed with the two station pairs already indicated, and with two more added to increase the range of climate types considered (Figure 3). For both the Asheville–Charlotte and Roanoke–Richmond pairs the interannual variability in utility water demand was small compared with both the great precipitation variability and the smaller, but still marked, evaporation variability. There was no clear correspondence between total precipitation or evaporation and the minimum depth occurring during the year. The relationships, however, can be explained by interactions within the year, using three examples for the Asheville–Charlotte station combination (Figure 4). 1983, seemingly a wet year with a moderate evaporative demand but a large reservoir draw-down, had a wet winter and spring, culminating in a week with over 150 mm of rain. This was followed by a mid-summer dry spell where evaporation and demand was high, creating a rapid fall in level to the minimum level some 75 m below full. In contrast, the two dry spells in 1986 occurred in the spring and early summer, before evaporation and demand peaked. Consequently draw-down was less rapid, and the lowest level reached was much less than that of 1983, even though annual precipitation was less and evaporation was greater. During 1989 there were virtually no dry spells and the reservoir remained near full throughout the year. This comparison thus emphasizes that the distribution of lengths and timing of dry spells are of as much concern as actual precipitation and evaporation values in controlling reservoir levels. Similar arguments could be made for all years, including 1991 in Roanoke, where an extensive drought lasting over 3 months in the late summer created an unprecedented low reservoir level. Because pumped storage, records of which are not available, is used with the actual reservoirs, direct comparison between model estimates and observations of reservoir level are not possible. Nevertheless, operational experience, albeit somewhat anecdotal, is in accord with the model. Nantahala experienced almost complete draw-down one year in the late 1960s (but

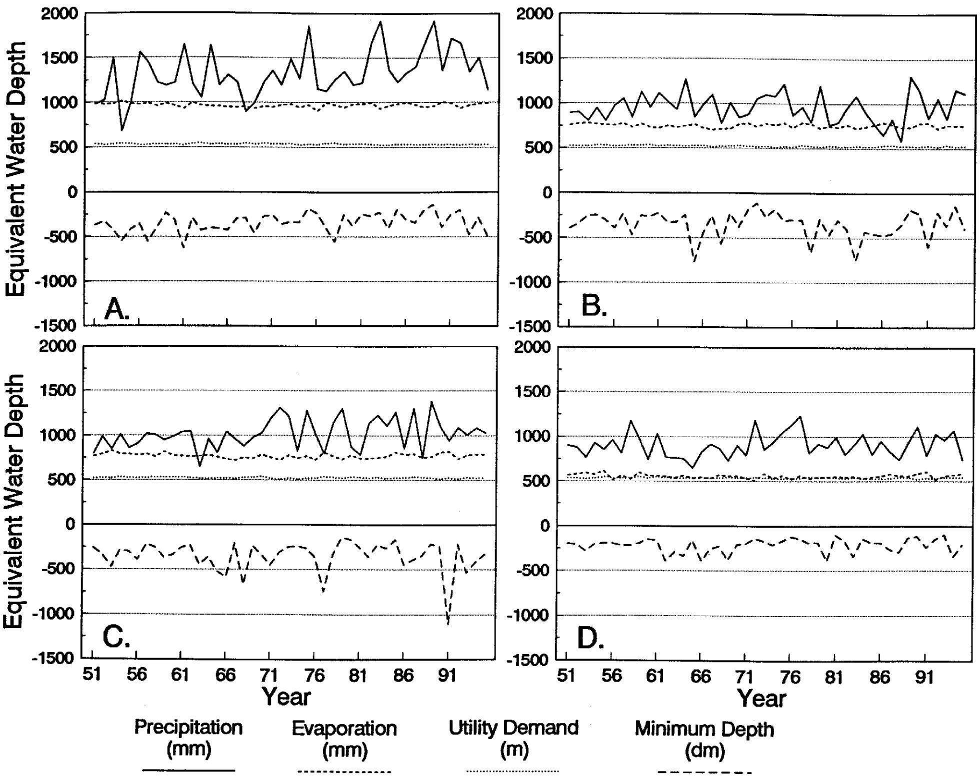

Figure 3. Annual (1951–1995) total precipitation and evaporation, maximum reservoir depth, and energy demand for (A) Montgomery–Mobile, (B) Asheville–Charlotte, (C) Roanoke–Richmond, (D) Ithaca–Syracuse.

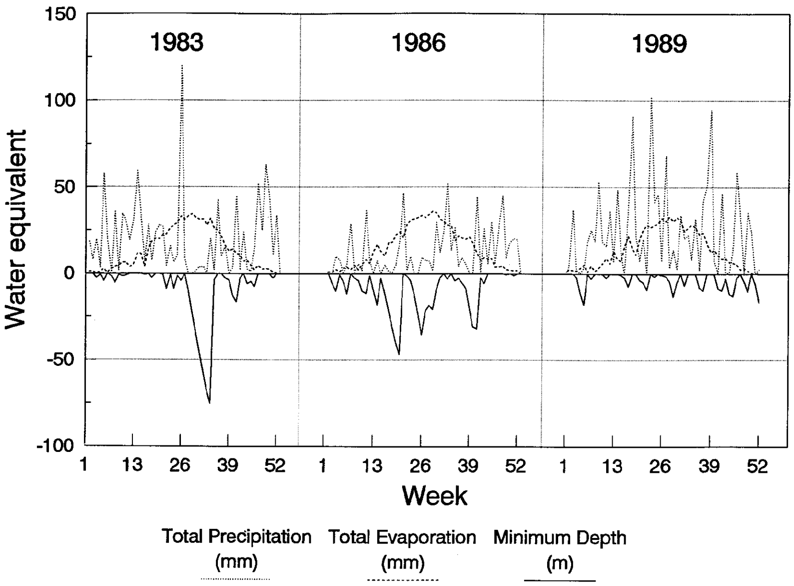

Figure 4. Weekly total precipitation and evaporation and average reservoir depth for 1983, 1986, and 1989 for the Asheville reservoir, with demand centred on Charlotte.

unfortunately was drained for servicing in the mid-1980s), whereas Virginia Power had low levels in some lakes in 1977, and major problems with hydropower generation in 1991.

The range of climatic types available for investigation was expanded by introducing two additional station pairs (Figure 1). The Montgomery–Mobile (Alabama) pair used the Duke Power relationship and represented an extension to a warmer, wetter regime. The second pair, Ithaca–Syracuse (New York) typified a cold-winter area and used the Virginia Power relationships. They were used for comparison only, and there is no suggestion that these particular combinations might be suitable for hydroelectric power generation. The results for the current climate (Figure 3), however, demonstrate that the interannual variability in minimum depth is similar for all combinations despite the differences in climate. The variability for the more northerly Ithaca–Syracuse combination did tend to be relatively small, whereas that for Montgomery–Mobile was only slightly larger despite the much larger variation in annual total precipitation. The variability of summer precipitation for the Virginia and North Carolina pairs appears to be the major factor leading to the highest variability in these regions.

4. IMPACT ASSESSMENT

In order to assess the potential impact of climatic change on the hydropower systems, scenarios of future climate were needed. One well-established approach is to use general circulation model (GCM) output for future conditions combined with a time series analyses for current conditions. This is relatively straightforward for temperatures (Chen and Robinson, 1991), but daily precipitation series are more problematic. Indeed, it is difficult to obtain suitable values even for monthly totals (e.g. Jones and Hulme, 1996). Consequently an approach using the observational data directly was adopted. This is akin to sensitivity testing rather than to true scenario development, but the results are likely to be much more solidly based on climatic reality.

The first and simplest scenario was a uniform change in daily temperatures across the area and the year. This was undertaken for all four station combinations. Uniform changes of $+2$ and -2°C were imposed for each day of the historical record (Figure 5). The increase reflects a reasonable GCM estimate for the eastern USA, whereas the 2°C decrease is included for comparison and analysis purposes. Using the heating (HDD) and cooling degree day (CDD) definitions of Soule and Suckling (1995), who were also concerned with energy in the south-east USA, a 2°C temperature increase creates a decrease of 250 and 130 in the average HDD at Charlotte and Montgomery respectively, and a corresponding CDD increase of 260 and 360. Soule and Sucking (1995) found fluctuations in the last few decades, generalized for the whole region, of the order of 400 for HDD and 200 for CDD. Hence the changes postulated here are entirely possible within the normal fluctuation of climate. For the present purposes, equal temperature changes at the mountain station and the population centre, and no precipitation changes, were assumed. The impact of higher temperatures was, as anticipated, an increase in depth, with lower temperatures having the opposite effect. The distinction between the two was clearest at the warmest station pair, Montgomery–Mobile (Figure 5A), where almost all temperature increases led to increases in energy demand. With the minimum depth commonly occurring in summer, virtually all temperature changes involved values above 18·3°C, and thus a consistent relationship between higher temperatures, higher demand, higher evaporation, and greater draw-down. At the cooler stations the timing of the dry spell had a greater influence. The 1988 dry spell at Ithaca–Syracuse (Figure 5D) occurred in mid-July, when temperatures were around 23–25°C. There was then a direct relationship between temperature change and depth change. However, 1986, was an example of a year with a marked increase in depth in warmer conditions, but only a small decrease in cooler ones. Here the dry period was earlier in the season (end of May) when temperatures were around 18–20°C. The cooling changed the demand from air conditioning to heating across the 18·3°C threshold (Figure 2) and thus had little net effect. Indeed, at this cool station pair there were 15 occasions when the postulated 2°C increase in temperature led to a decrease in draw-down, and another 15 cases where cooling increased the depth. The two intermediate stations pairs had similar, but less marked, results. For example, similar arguments hold for the conditions of the Asheville–Charlotte pair in 1983 and 1986 (Figure 4), and the lack of any dry period in 1989 precludes any major influence as a result of a perturbed climate.

The sensitivity of level changes to temperature changes was thus dependent on the time of the major dry period each year (Figure 6). Of the four station pairs, all except Montgomery–Mobile showed a distinct increase in sensitivity in the summer. Commonly when the dry spell occurred in winter there was a decrease in draw-down in the warmer conditions. Conditions were much more uniform through the year for the Montgomery–Mobile region, reflecting the extended period of elevated temperatures. Here, however, the precipitation regime was such that no dry spells occurred during the winter period, so no complete annual cycle was apparent.

When the precipitation regime was modified, without temperature change, by increasing or decreasing the precipitation each day by 10 per cent, the differences in reservoir level are similar to those for the temperature

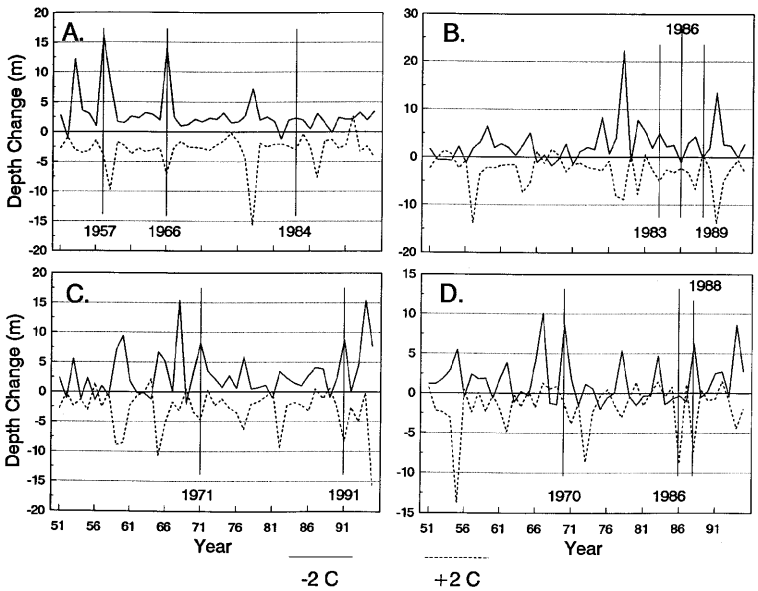

Figure 5. Annual difference in minimum reservoir depth between current climate and a climatic change where each day is uniformly changed by -2 and $+2$°C at both the reservoir and the population centre. There is no change in precipitation regime. Shown are (A) Montgomery–Mobile, (B) Asheville–Charlotte, (C) Roanoke–Richmond, (D) Ithaca–Syracuse. Years specifically discussed in the text are indicated.

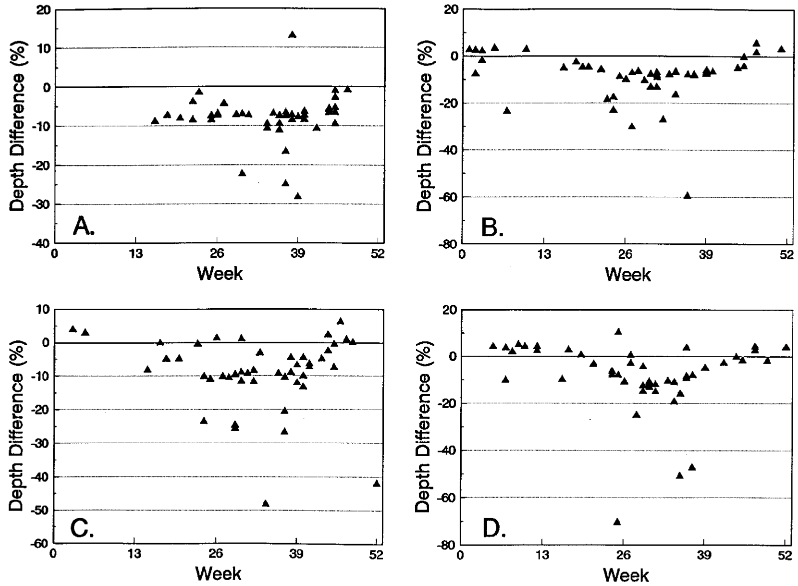

Figure 6. Percentage difference in minimum reservoir depth caused by a temperature increase of 2°C for the 1951–1995 period as a function of the week of the year. Shown are (A) Montgomery–Mobile, (B) Asheville–Charlotte, (C) Roanoke–Richmond, (D) Ithaca–Syracuse.

change (Figure 7). In some cases an increase in precipitation led to considerably less draw-down, whereas a decrease did not lead to an equivalent increase in depth. The situation for the Montgomery–Mobile pair in 1957 was an example (Figure 8). Here, although actual precipitation amounts were small, the increase was sufficient to maintain a full reservoir for an extra week, rather than initiate small draw-down. This, combined with the equally small increase in the precipitation during the draw-down period, was enough to have a major impact on the total decrease in level. When the precipitation was decreased, on the other hand, the small change did not affect the pattern of level changes, and had a minor impact. Other examples of a small initial deficit at the onset of an extended dry period occurred in 1971 for the Roanoke–Richmond and in 1970 for the Ithaca–Syracuse pairs, all giving much less draw-down in wetter conditions, but little change in drier ones. The opposite response to precipitation changes occurred at Montgomery–Mobile in 1984 (Figure 8). Here the period of lowest levels commenced after the reservoir had been full for only 1 week. A long completely dry spell followed. Any increase in precipitation prior to this drought was immaterial for a full reservoir, and hence had no subsequent influence. A decreased rainfall, however, prevented the reservoir completely filling after the previous, albeit short, dry spell, so that the draw-down began with the reservoir below full. The final type of major change, when both precipitation increases and decreases have major consequences, occurred in 1966 (Figure 8). The dry spell started when the reservoir was already somewhat depleted. There was some precipitation throughout the period. Hence precipitation changes could be translated directly into level changes.

Simultaneous changes in temperature and precipitation, rather than independent ones, are the norm. Two such scenarios, combinations of the previous ones, were created: a hotter, drier situation which should maximize the extra draw-down, and a cooler, wetter one which should demand less water. Results were expressed in terms of absolute depth to emphasize the overall patterns (Figure 9). The general year-to-year variability for all four stations was maintained, but the details were modified considerably. In three of the four cases the year of lowest depth was changed, and the ranks and magnitudes of almost all years were altered. Although an extreme value analysis is beyond the scope of this paper, this result strongly suggests that estimates of the reliability of a reservoir to provide power during dry periods under a changed climate cannot be made by simple extrapolation of the current conditions.

At the same time that climate is changing, energy technology will also be changing. In the present context, changes in turbine efficiency will influence production, and changes in appliance efficiency will influence per

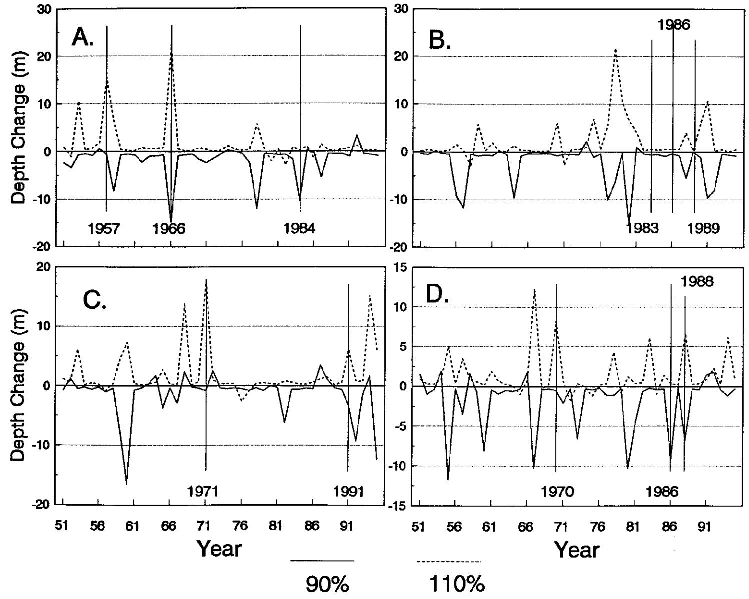

Figure 7. Annual difference in minimum reservoir depth between current climate and a climatic change where each day's precipitation over the reservoir catchment is changed by 90 per cent and 110 per cent. There is no change in temperature regime. Shown are (A) Montgomery–Mobile, (B) Asheville–Charlotte, (C) Roanoke–Richmond, (D) Ithaca–Syracuse. Years specifically discussed in the text are indicated.

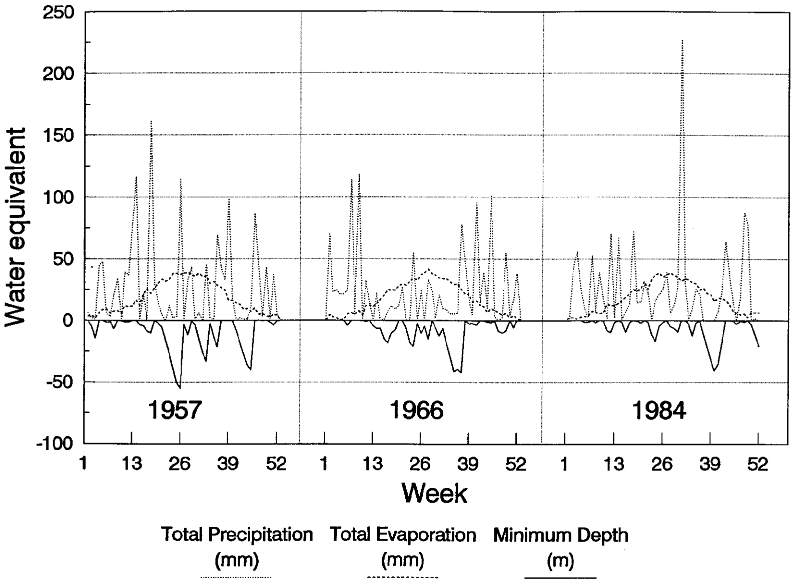

Figure 8. Weekly total precipitation and evaporation and average reservoir depth for 1957, 1966 and 1984 for the Montgomery reservoir, with demand centred on Mobile.

capita energy use. Further, demographic, economic and social changes will influence the total use for any utility system. It is not the purpose here to predict the rate, direction, or amount of these changes, but rather to compare the magnitude of some possible changes with those arising from climatic change. Hence three reasonable types of change, in the mix of weather and non-weather sensitive demand, in appliance efficiency, and in turbine

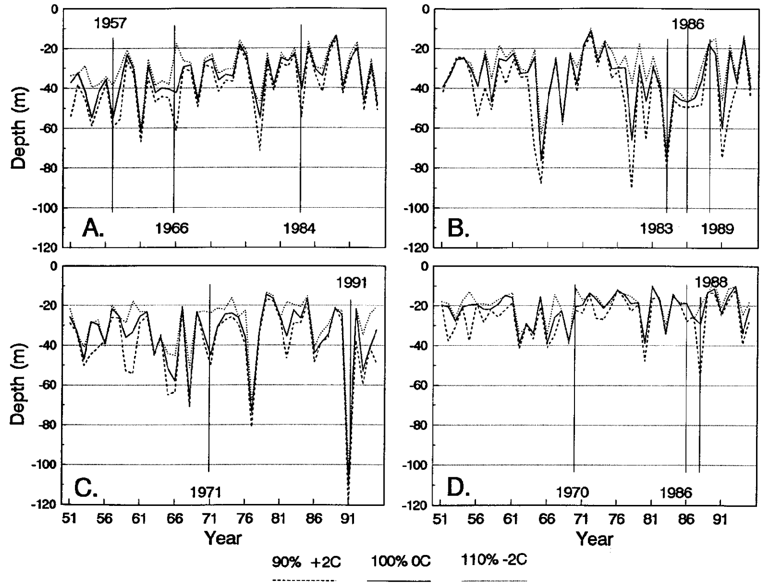

Figure 9. Annual absolute values of minimum reservoir depth in the current climate, a warmer (+2°C) and drier (90 per cent current precipitation) one, and a cooler (−2°C) and wetter (110 per cent) climate. Shown are (A) Montgomery–Mobile, (B) Asheville–Charlotte, (C) Roanoke–Richmond, (D) Ithaca–Syracuse. Years specifically discussed in the text are indicated.

efficiency, were postulated. The difference in the relationship between normalized load and temperature (i.e. Figure 2) for Duke Power and Virginia Power reflects the existing mix of energy uses. The former has a relatively large industrial, non-weather sensitive, base and thus is less sensitive to temperature than is Virginia Power. One possibility for future conditions, therefore, is a change in the industrialization of the service area. Some concept of the possible impact on the minimum reservoir levels can be gained for each station pair by using the opposite load–temperature relationship to that used so far. Thus the minimum depth for Asheville–Charlotte and Montgomery–Mobile in the current climate was compared using the Virginia Power relationship with that from the Duke Power one used so far. The opposite calculation was used for the other two station pairs. In all cases the depth change was about 2 per cent (Table II), but no clear pattern of the direction of the change emerged.

An increase in hydropower system efficiency, the other change in generation technology which could be considered, was simulated directly by increasing the efficiency of turbine of turbine operation, s_e, by 10 per cent (Table II). In all cases, not surprisingly, the minimum depth was decreased. In most cases the depth change was about 10 per cent. This approximate 1:1 relationship was apparent for other changes in s_e. The same approximate relationship also held for changes in other elements of c_u.

The influence of changes in the efficiency of energy use by the consumer can be approached by modifying the relationships shown in Figure 2. An initial assumption was made that a 10 per cent increase in efficiency was possible for high temperature conditions through changes in air conditioner technology. No change in heating technology was anticipated. Using a generalized value for the average total system load for each utility at the end of 1991, the load change per degree was estimated for temperatures above 18·3°C using equation (6). This rate of

Table II. Percentage change in minimum depth as a result of technological changes. A negative value indicates an increase in draw-down. Absolute values of depth are shown in bold for the base conditions

	Montgomery–Mobile	Asheville–Charlotte	Roanoke–Richmond	Ithaca–Syracuse
Duke relation	**62·4**	**76·4**	− 1·81	− 2·31
Virginia relation	1·76	− 2·23	**110·4**	**38·9**
+ 10 per cent turbine efficiency	9·29	9·29	9·33	9·51
+ 10 per cent A/C efficiency	0·96	1·83	1·09	0·26

change was then decreased by 10 per cent to reflect the increased efficiency and the new normalized load relationships established. The results, for comparison with Figure 2, were:

$$L = 0{\cdot}2711 + 0{\cdot}0315\ T \quad \text{for Duke Power}$$

$$L = 0{\cdot}0368 + 0{\cdot}0412T \quad \text{for Virginia Power}$$

These were substituted into the model and used with the current climate data (Table II). The result in all cases was a decrease in the minimum depth of around 1 per cent. The change was smallest for Ithaca–Syracuse, where there was a relatively short annual period of high temperatures that could be influenced by the change. Further, it was only at this pair of stations that the year of the minimum depth changed, for this or any other of the technology analyses. Only at these New York stations was there a suite of years in the current climate where the minimum depths were very similar (Figure 9). Changes in technology therefore influenced them in different ways, leading to the change in minimum year. At the other stations the relatively minor changes established by technology were insufficient to modify the pattern established by the climatic regime.

5. DISCUSSION AND CONCLUSIONS

For many utilities, including Duke Power and Virginia Power, hydroelectric power is used to help meet daily peaks in energy demand. Sufficient storage to meet the demand must be maintained. The prime factor influencing water availability is the water budget of the reservoir catchment, whereas demand is strongly influenced by temperatures in the region of maximum population. Thus reservoir performance is determined largely by the daily weather sequence. The actual size of the reservoir is dictated, given the energy generation needs, by local topography, catchment area, and dam size and is dependent on whether or not the utility uses excess energy at non-peak times to pump water back into the reservoir storage. A model has been developed, based on a typical reservoir configuration and utility energy need, to assess the influence of weather sequences on performance. Performance was characterized by the fluctuation in water level below reservoir capacity. The model tracks daily reservoir levels, but the major focus was on the minimum water level each year, which represents the maximum size of dam needed to ensure continuous generation. This emphasizes that the model was designed explicitly for an analysis of the potential impacts of long-term climate change. A short-term model of reservoir operation would need to incorporate many other activities of the utility, including many non-climatic ones, and the isolation of those climatic factors would be lost.

Performance in the current climate with current technology, using observations for 1951–1995 for four pairs of climatic stations in the eastern USA, was assessed. For each station pair, one represented conditions at the reservoir, the other those at the population centre. The major influence on minimum depth was the timing and length of dry periods and their relationship to temperature. A dry spell in winter, with low evaporation and energy demand, led to a slow draw-down, whereas the same precipitation sequence in the high evaporative and energy demand conditions of summer caused a rapid fall in level. Within this seasonal cycle, short-term conditions controlled the actual time and value of the minimum depth. Draw-down associated with a long spring drought could dominate in a year having a short hot spell within the drought, whereas a similar rainfall sequence in another spring could be overshadowed by a short dry period with high temperatures in mid-summer.

The actual minimum depth indicated by the model for the current climate is shown in Table III. For the various climatic and technological changes the deviation from this value is shown. The climate scenario where temperature was increased uniformly by 2°C each day gave an increase in minimum depth, as did precipitation scenarios where each value was decreased by 10 per cent, both without a temperature change and with a 2°C increase. The magnitude of the change, however, varied greatly between station pairs and scenarios. The temperature increases dominated for the Montgomery–Mobile and Roanoke–Richmond pairs, at Ithaca–Syracuse the temperature and precipitation effects seemed additive, leading to a depth increase of almost 50 per cent. The Asheville–Charlotte pair had relatively small changes for the individual-element scenarios, but a major change approaching 20 per cent of current maximum depth, with the combined one. When the opposite situation, a 2°C cooling and a 10 per cent precipitation increase, was examined, the changes were generally in the opposite direction but somewhat smaller. At Ithaca–Syracuse this cool, wet scenario produced an increase in depth,

Table III. Variation in extreme depth (m) from the current climate for various postulated future conditions. The actual extreme depths, for the 1951–1995 period, are indicated

	Current climate	+2°C	90 per cent	90 per cent +2°C	110 per cent −2°C	+10 per cent turbine	+10 per cent A/C
Montgomery–Mobile	62·4	−8·5	−4·8	−9·1	2·9	5·8	0·6
Asheville–Charlotte	76·4	−5·4	−0·8	−13·7	6·9	7·1	1·4
Roanoke–Richmond	110·4	−8·3	−3·3	−8·8	9·4	10·3	1·2
Ithaca–Syracuse	38·9	−4·6	−10·2	−16·6	−0·2	3·7	0·1

primarily because of the increased energy demand for winter heating. All of these analyses, however, re-emphasized the importance of the sequence and timing of precipitation events, where the impact of the changed climate could lead to large changes or be almost insignificant.

The climate-induced changes were compared with those postulated to result from technological changes. A 10 per cent increase in energy generation efficiency, which could result from an improvement in turbine design or, more likely, more efficient use of non-peak energy for pumped storage, led to a major decrease in maximum depth. This change was of the same order as that of the warm dry scenario. However, changes resulting from a postulated 10 per cent increase in air conditioner efficiency were an order of magnitude less.

These results indicate that hydroelectric generating systems are highly sensitive to climatic fluctuations. Relatively small climate changes can lead to major changes in the draw-down of reservoir levels. A warm dry climate scenario, such as is commonly suggested as arising from anthropogenically induced climate change, led to major increases. They were similar in magnitude to the decreases which could be anticipated from a 10 per cent increase in generation system efficiency. The climatic influence, however, varied greatly from one region to another, and was highly dependent on the timing of dry spells and their relationship to temperature. As a result the time series of annual minimum reservoir depths was modified in a complex way which varied with location and scenario. It appears likely that an extreme value analysis of these annual minima would provide useful information about reservoir system performance, including indications of situations where a reservoir may become dry, in the future. However, the scenarios presented here, postulating uniform changes, were relatively simple. More realistic ones, based on GCM output, are required for an adequate analysis. Such scenarios, containing linked sequences of daily precipitation and temperature over small areas, are beginning to be available. Once they have been evaluated, an extreme value analysis represents the next step in specifying the links between hydropower generation and climate.

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