THE ROLE OF CLIMATE FORECASTS IN WESTERN U.S. POWER PLANNING

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ABSTRACT

We evaluate the benefits of potential electric power transfers between the Pacific Northwest (PNW) and California (CA) using a linked set of hydrologic, reservoir, and power demand simulation models for the Columbia River and the Sacramento-San Joaquin reservoir systems. The models provide a framework for evaluating climate-related variations and long-range predictability of regional electric power demand, hydropower production, and the benefits of potential electric power transfers between the Pacific Northwest (PNW) and California (CA). The period of analysis is 1917-2002. The study results show that hydropower production and regional electric power demands in the PNW and CA are out of phase seasonally, but hydropower productions in the PNW and CA have strongly covaried on an annual basis in recent decades. Winter electric power demand and spring and annual hydropower production in the PNW are related both to the El Niño Southern Oscillation (ENSO) and Pacific Decadal Oscillation (PDO) via variations in winter climate. Summer power demand in CA is related primarily to variations in the PDO in spring. Hydropower production in CA, despite recent covariation with the PNW, is not strongly related to ENSO variability overall. Primarily because of strong variations in supply in the PNW, potential hydropower transfers between the PNW and CA in spring and summer are shown to be correlated to ENSO and PDO and the conditional probability distributions of these transfers are therefore predictable with long lead times. Such electric power transfers are estimated to have potential average annual benefits of $136 and $79 million for CA and the PNW, respectively at the year 2000 regional demand level. These benefits are on average 11 to 27% larger during cold ENSO/PDO events and 16 to 30% lower during warm ENSO/PDO events. Power transfers from the PNW to CA and hydropower production in CA are comparable in magnitude on average.

1. Introduction and background

a. Energy terms and units

A discussion of terms and units used throughout the paper is warranted given the many different terms that are used to describe energy related variables. In a strict physical definition, power and energy are related by time (i.e. energy production is power integrated with respect to time). Unfortunately in common usage, “hydropower generation” or “electrical power” are terms that are often used to describe energy production or energy demand. This confusion is exacerbated by physical units like “aMW” (average megawatts) that are commonly used to describe energy production or consumption over some specified period of time. In the interest of consistency with common usage, we will refer to electrical energy (in units of aMW or MWh) generically as “electric power” throughout the text. In a few specific instances (e.g. in the case of peak power demands and capacity constraints associated with various kinds of infrastructure) we will also refer to power (i.e. MW) in its correct physical sense.

b. Overview

Climate and its variability have significant effects on electric power supply and consumption, and these effects have become increasingly predictable. Climate forecasts are now available globally and regionally at lead times from several weeks to a year or more. Seasonal to interannual climate along the west coast of the U.S. varies in such a way that California (CA) and the Pacific Northwest (PNW) are often out of phase. For instance, warm and dry winters in the PNW (and hence reduced hydropower production) usually occur at the same time as cool and wet conditions in southern CA. These conditions can now be forecast with some skill as much as a year in advance (see Section 1.c).

There are also important seasonal differences in hydropower resources and electric power demands in the PNW and CA. California's residential electric power consumption has regular peaks in both winter and summer, while power consumption in the PNW has a strong winter peak and relatively low demand in summer. Due to the nature of the water management systems and reservoir operating policies in each region, hydropower resources in the PNW are primarily available in winter and spring, whereas in CA hydropower resources are aligned with irrigation needs and are available primarily in spring and summer. These differences in the seasonality of supply and demand have facilitated existing arrangements to transfer electric power between the two regions, particularly in the spring when the PNW frequently has surplus hydropower resources.

To help understand these complex interactions between electric power supply and demand in the two regions, the second section of this paper describes a series of linked models and driving data sets used to simulate both the hydrology and reservoir operations of the Columbia River (Hamlet and Lettenmaier, 1999), and the Sacramento-San Joaquin (Van Rheenen et al. 2004) reservoir systems, and regional-scale electric power demand in CA and the PNW. In the third to fifth sections of the paper, we use these models and data sets to address the following questions:

1) If the current system of hydropower reservoirs and reservoir operating policies in both the PNW and CA had existed throughout the 1917-2002 reference period, what has been the annual and seasonal covariability of hydropower resources between these two regions?

2) How are electric power supply and demand related to climate variability in the two regions, and what is the potential for inter-regional electric power transfers as a function of climate variability? What is the economic value of these electric power transfers to the two regions?

3) What is the potential for use of weather and climate forecasts with lead times from a few weeks to a year or more for improving joint operations of PNW and CA hydropower generation, considering specifically the potential for incorporation of weather and climate forecasts in projection of electric power supply (hydropower), demand, and inter-regional transfer opportunities?

In the fifth section of the paper, we explore in particular the potential for improving operation of the existing intertie (~7500 MW capacity) between the PNW and CA using seasonal and interannual patterns of climate variability. This study extends previous work by Cayan et al. (2003), who examined the covariability of annual streamflows and hydropower production in the western U.S. as a function of climate variability.

For purposes of this exploratory analysis, we base our analysis on nowcasts, that is, on observed past patterns of variability. This approach implies perfect climate forecast capability. In future work we will evaluate the role of the accuracy of forecasts that might exploit these observed patterns, and hence operational improvements that can be realized in practice.

c. Climate variability and predictability in the western U.S.

Winter climate variability in the western U.S. is dominated by two phenomena: the El Niño Southern Oscillation (ENSO) on an interannual time scale and the Pacific Decadal Oscillation (PDO) (Mantua et al. 1997) on an interdecadal time scale. In the subsequent discussion we use the terms "warm", "neutral", and "cool" to describe different interannual phases of the ENSO and the PDO. These definitions are based on the Niño3.4 index (Trenberth 1997) and the PDO index (Mantua et al. 1997), respectively. A water year (October-September) is defined as a warm (cool) ENSO year if the December-February average Niño3.4 index anomaly is more than 0.5 standard deviations above (below) the mean. Similarly a water year is defined as a warm (cool) PDO year if October-March average PDO index anomaly is more than 0.5 standard deviations above (below) the mean. Neutral water years are those which are neither warm nor cool.

Winter climate in the PNW has a strong and coherent correlation with ENSO for both temperature and precipitation (Redmond and Koch 1991, Ropelewski and Halpert 1986, Mote et al. 2003). During warm ENSO events (El Niño), winter climate is typically warmer and drier than normal in the PNW and northern CA, cooler and wetter than normal in southern CA, and the risk of droughts is lower than normal in the desert Southwest. During cool ENSO events (La Niña) the PNW and northern CA typically experience cooler and wetter conditions than normal, southern CA typically experiences warmer and drier conditions, and the risk of droughts in the desert southwest is very high (Kiladis and Diaz 1989, Schonher and Nicholson 1989, Redmond and Koch 1991, Sheppard et al. 2002). The dividing line between these differing regional precipitation effects is often about 40^{o}N in northern CA, but varies from year to year (Dettinger et al. 1998). PNW winter precipitation and temperature variations are also strongly affected by the PDO (Redmond and Koch 1991, Mantua et al. 1997, Cayan et al. 1998). Constructive combinations of ENSO and PDO events, here after referred to as ENSO PDO events, tend to accentuate the precipitation and temperature effects associated with ENSO alone (Gershunov and Barnett 1998, Mote et al. 2003) with opposite effects in the PNW and in the Southwest (Gershunov and Barnett 1998). Streamflow variations, which in some respects are less noisy than precipitation variations, are also strongly related to ENSO and PDO signals both in the PNW and CA (Redmond and Koch 1991, Kahya and Dracup 1993, Dracup and Kahya 1994, Kahya and Dracup 1994, Cayan et al. 1999, Hamlet and Lettenmaier 1999).

Although long retrospective analyses are frequently lacking, there is evidence that the predictability of mid winter PDO and ENSO anomalies is reasonably good with lead times of about six months. Latif et al. (1998) review models predicting ENSO with some skill with up to one year lead time (Zebiak and Cane 1987). Oldenborgh et al. (2005) show that the European Center for Medium-Range Weather Forecasts model-based SST forecasting system has been a good ENSO predictor over the 1987-2001 period with lead times up to 5 months. Newman et al. (2003) and Schneider and Miller (2001) derive a simple regression-based method for estimating the PDO index with comparable lead times based on a forecast of an ENSO index and last year's PDO index value.

In comparison with winter climate, summer climate has proven to be much more difficult to predict and is not strongly linked to ENSO variability in either the PNW or CA. Recent work by Alfaro et al. (2004), however, has demonstrated that an above (below) average PDO index value in March, April and May is associated with a higher likelihood of above (below) seasonal average temperatures in June, July, and August in CA. In this study we corroborate these findings and investigate the prospects for making numerical forecasts of monthly summer electric power demands in CA based on a forecast of the PDO index using a long time series.

d. Modeling approach

Our overall approach is as follows. First, we use retrospective gridded climate data to drive the Variable Infiltration Capacity (VIC) macroscale hydrology model (Liang et al. 1994, Cherkauer and Lettenmaier 2003). The output from the VIC model is daily gridded runoff, which is used to drive a simple routing model (Lohmann et al. 1998) to produce daily streamflow simulations at selected reservoir inflow points. The simulated daily streamflows are aggregated to monthly time step, which is the time step at which the reservoir models operate. We apply a post-processing bias correction scheme (described in Section 2.b) to the simulated monthly flows. The bias corrected monthly streamflows are then used to drive two reservoir models, one for CA (CVmod, Van Rheenen et al. 2004) and the other for the PNW (ColSim, Hamlet and Lettenmaier 1999). These models simulate hydropower generation over the reference period 1917-2002, as if the existing system of reservoirs had been in place for the entire period. A power demand model simulates electric power demand in the PNW and CA as a function of climate conditions (primarily air temperature) over the reference period. We then evaluate the potential for power transfers in spring between the PNW and CA and estimate the economic value of these transfers using a simple power transfer model. Section 2 below describes the driving data sets and the models used. Section 3 analyzes the covariability of hydropower supply and power demand as a function of climate variability from 1917-2002. Section 4 analyses the PNW hydropower surplus that can be transferred to CA and its economic value. Section 5 discusses the potential for using long-range forecasts to increase the benefits of power transfers between the PNW and CA.

2. Data and models

a. Meteorological data

The National Climatic Data Center (NCDC) has recently completed a major project to convert all of the pre-1950 NCDC Cooperative Observer data to electronic form (NCDC DSI-3206 data set). Good station coverage is available for the Western U.S. from about 1915 on, which extends the digitized meteorological record by about 35 years in comparison with previously available digitized cooperative observer records from 1949 to the present (see Maurer et al. 2002). The gridded forcing data we use are produced using essentially the same methods (at 1/8 degree spatial resolution) used by Maurer et al. (2002). An important aspect of these methods is the representation of orographic controls on precipitation using the PRISM (Precipitation Regression on Independent Slopes Method) approach developed by Daly et al. (1994). An improvement to the Maurer et al. data incorporated in the meteorological data used here is an adjustment (Hamlet and Lettenmaier 2005) to assure that long-term trends are consistently reproduced, using as a reference the quality controlled Historical Climatology Network (HCN) (Karl et al. 1990) and a similar network for the Canadian portion of the PNW region (Historical Canadian Climate Database (HCCD), Mekis and Hogg 1999, Vincent and Gullett 1999).

b. Hydrologic model

The forcing data described above were used as input to the Variable Infiltration Capacity (VIC) model (Liang et al. 1994, Cherkauer and Lettenmaier 2003) over the PNW and CA regions for the period 1915-2002. Simulations were conducted in water balance mode using a daily time step. In water balance mode the iteration for an effective surface temperature to close the surface energy balance is avoided by assuming that the surface temperature is equal to the surface air temperature. The model was used to simulate streamflows at 23 locations in CA and

20 in the PNW (see Van Rheenen et al. 2004 and Hamlet and Lettenmaier 1999 for details). For purposes of evaluating performance of the hydrologic model, we had available to us naturalized (reservoir storage and diversion effects removed) streamflows, for the periods 1921-94 for CA (CDEC, California Data Exchange, California Department of Water Resources) and 1928-89 for the PNW (Adjusted Streamflow and Storage, Columbia River and Coastal Basins 1928-89, Bonneville Power Administration report prepared by A.G. Crook Company, July 1993).

Simulated streamflows were corrected for systematic bias in the hydrologic model using a quantile mapping technique described by Snover et al. (2003). The bias correction avoids uncertainties in simulation of hydropower production in the PNW and CA (see below), but does not greatly alter streamflow signals associated with climatic variations. The bias correction of monthly streamflows is based on the full period for which naturalized observed streamflows were available; from 1921-94 for the San Joaquin-Sacramento and 1928-89 for the Columbia. Figure 1 shows that the bias corrected streamflows for the Sacramento River at Bend Bridge correspond well with the naturalized observed streamflows over the entire time series. Similar agreement between observed and simulated hydrographs was found at other stations in the two regions (see also Hamlet and Lettenmaier 1999 and Maurer et al. 2002).

c. *Electric power demand models*

To understand the linkages between climate variability and power demand in the PNW and CA, and to provide energy demand targets to the ColSim reservoir model (as described below), a simple regional scale power demand model was developed for CA and the PNW, respectively. Daily average (Tavg) and maximum (Tmax) temperatures are reasonably well correlated with well-known climate indices associated with ENSO and PDO. Summer temperatures in CA are correlated with the PDO index in spring and winter temperatures in the PNW are correlated with both the Niño3.4 and PDO indices (correlations not shown, but our results are consistent with those of Alfaro et al. 2004, Redmond and Koch 1991, Halpert and Ropelewski 1992, Gershunov and Barnett 1998). During a warm ENSO and/or PDO event, the PNW tends to be anomalously warm in winter.

A preliminary analysis showed that PNW and CA power demands are out of phase on a seasonal time scale as PNW demand peaks in winter time whereas CA demand peaks in summer time (not shown). It also showed that PNW October to April observed daily and CA April to October peak hour demands are significantly correlated with population-weighted daily average temperature, respectively (Figure 2). Significance tests applied to the correlations presented here and in following sections are two tail t-tests where the null hypothesis is that the first time series is not correlated with the second (Hirsh et al. 1993). Lower correlations were obtained for the remainder of the year. A weekly cycle with higher loads during weekdays and lower loads during weekends was also observed, as well as lower loads during national holidays.

Monthly regression parameters using daily population-weighted average temperatures in the major urban centers, and day of week (weekday, weekend, or holiday) as explanatory variables were derived for the two regions. Although power demands are usually forecast using heating (HDD) and/or cooling (CDD) degree days, which are function of Tavg, HDD and CDD are most meaningful on seasonal to annual timescales, and daily Tavg was found to be an equivalent explanatory variable at daily time steps. The resulting regression models were trained using detrended (based on year 2000) daily FERC electricity loads for the WSCC region (http://www.ferc.gov/docs-filing/eforms/form-714/data.asp) from 1993 to 2000. The 1993-2000 annual electric energy use for Idaho, Oregon and Washington reported by the EIA was on average 72% (with standard deviation less than 1%) of the aggregated FERC annual values, probably because the spatial domain covered by the observed FERC electric power demand data extends significantly beyond the Columbia River basin's effective service area. Consequently, the 1993-2000 model-derived annual monthly average power demand for the PNW typically overestimates actual power demand from the Columbia hydropower system. To resolve this discrepancy we used annual energy use for the PNW as reported by the EIA to scale the output from the demand model, based on the ratio of the EIA annual values for 1993-2000 to the accumulated FERC values (Figure 3).

Similar problems with service boundaries or overlaps in reporting are probably present in the CA power peak demand data as well, but for the purposes of our analysis the absolute value of the CA demand time series (so long as it is reasonably consistent through time) is not as crucial, and we have ignored these potential issues in the subsequent analysis.

These demand models were then used to produce a long time series (1915-2002) of reconstructed daily energy demand in the PNW (MWh) and daily peak power demand (MW) in CA using the same gridded meteorological data sets used to force the VIC hydrology model. The PNW daily energy demand time series was then aggregated to monthly values in order to produce the time series of monthly electric energy needed to drive the ColSim reservoir model. The demand models show the greatest climate sensitivity in summer (May-September) in CA and in winter (November-April) in the PNW, although PNW simulated energy demand agrees reasonably well during the remaining portions of the year as well.

d. Reservoir models

The Columbia River reservoir model ColSim (Hamlet and Lettenmaier 1999) and the Central Valley reservoir model CVmod (Van Rheenen et al. 2004) represent the physical properties of the two water resources systems and their performance under current operational policies. The models assume that facilities, land use, water supply contracts and regulatory requirements are constant over this period, and represent a fixed level of irrigation development, (1990 in the case of ColSim and 2001 for CVmod). Both CVmod and ColSim operate at a monthly time step. The advantage of using reservoir models instead of observations is that they provide a temporally-consistent, long time series of hydropower production for the current level of development based on observed (1917-2002) reservoir inflows.

CVmod is a simplification of the California Department of Water Resources model CalSim II (Draper et al. 2004) and represents the major projects and operations (hydropower and irrigation) of the California Central Valley (State Water Project, Central Valley Project and others, see Van Rheenen et al. 2004 for more details). It is driven primarily by summer agricultural water demand, which in the model is a function of summer water availability (streamflow plus carry over reservoir storage) and the existing water rights structure. Because the agricultural water delivery in the model is not a function of summer climate or hydropower operations in CVmod, these aspects of the system are not considered in this analysis. Evaluation of the model's hydropower simulations in comparison with observations provided by the California Energy Commission (CEC) showed that while the assumption that hydropower generation follows releases for irrigation requirements is appropriate on an annual basis, it creates some seasonal bias in the model simulations during wet years. In these years, observations show more hydropower production in early spring (presumably to avoid later spill) than is predicted by CVmod.

The ColSim model is driven primarily by flood control rule curves (which vary with summer streamflow volumes) and electric power demand, with power demand divided into "firm" and "non-firm" energy targets. Baseline conditions for ColSim runs are multi-objective reservoir operating policies appropriate to the last decade of record, including recent changes in reservoir operations to make flood control more efficient, and to provide enhanced fish flows in winter and summer (Payne et al. 2004). Energy demand is specified in the model by assigning monthly system-wide energy targets. The seasonal shape of the ColSim firm energy targets was derived from the Pacific Northwest Loads and Study (2003 White Book) published annually by the Bonneville Power Administration, which is the major hydropower marketing entity in the PNW (45% of the power produced in the Northwest). Monthly firm energy targets were estimated using an iterative critical period analysis and are the same in each year of the simulation. In this study, non-firm targets vary from month to month as a function of climate. Non-firm energy targets are derived by subtracting the monthly firm energy demand from estimates of total energy demand for the Columbia hydropower system which is derived from the regression model. These non-firm energy targets represent time-varying monthly hydropower demands which may be supplied, wholly or in part, by projects within the multi-objective management framework simulated by the model.

We will use the time series of total available hydropower production in our subsequent analysis since this is an estimate of total energy availability from the system including the potential resources available for meeting needs outside the PNW. It is important to note that total simulated hydropower in the PNW is a function both of the system inflows (which are reflective of the natural hydrologic system and climate variability) and the effects of the reservoir operating rules and energy targets which drive the use of reservoir storage in the model.

3. Covariability of streamflow, hydropower production and electric power demand

In this section, we analyze the covariability of simulated streamflow, hydropower generation, air temperature and power demand time series. We also analyze the relationship of each variable to climate variability using the PDO index and the Niño3.4 index for the ENSO. The objective of this section is to determine how well each of the variables (streamflow, hydropower supply and power demand) are related to climate variability, how predictable they are at different times of year, and how they covary in time.

a. Streamflow

Annual streamflows are most strongly related to winter precipitation, and the timing of spring peak flows is related to temperature variations affecting the onset of snowmelt. Annual and summer streamflow volumes and the timing of peak flows in the PNW are strongly related to variations in the PDO and ENSO (Table 1, see also Hamlet and Lettenmaier 1999). In comparing Tables 1 and 2, it appears that northern and southern CA streamflow signals are in general out of phase with the PNW for ENSO and PDO composites. However, this apparent inverse relationship is not statistically significant, and in fact the hydropower time series for the PNW and CA are positively correlated as we show in the next section.

b. Simulated hydropower generation

PNW hydropower generation (Figure 4), as expected, is strongly related to the annual discharge (Figure 5). Figure 6 shows the standardized hydropower production in CA and in the PNW respectively for the 1917-2002 period as simulated respectively by CVmod and ColSim. CVMod and Colsim annual (water year) hydropower production are correlated at 0.52 (significant at the 95% level). Most of the CVmod simulated hydropower is located in northern CA, and this result is broadly consistent with previous studies showing that winter climate in northern CA frequently is in phase with the PNW (Dettinger et al. 1998). The streamflow analysis reported above strongly suggests that the observed annual covariance between the hydropower time series in the PNW and CA is not strongly associated with ENSO and PDO variabilities, but is instead caused by other factors (see e.g. Jain et al. 2005).

Because the Columbia is a strongly snowmelt dominated river, the hydropower generation in the PNW in June and July is correlated with climate signals from the previous winter – especially precipitation (Hamlet and Lettenmaier 1999, Hamlet et al. 2002). The annual (water year) hydropower generation is on average correlated with climate signals; negatively correlated with both ENSO (-0.23) and PDO (-0.27) (positive index value is warm). In particular, the simulated April-July average hydropower production is correlated at -0.24 with ENSO and -0.34 with PDO. These four correlations are significant at the 95% confidence level. Note that the largest effects occur when ENSO and PDO are in phase (Table 3). The climate signals for simulated CA hydropower generation are not as pronounced as in the PNW (Table 4). The small Columbia runoff to storage ratio of about 30% makes the interannual PNW reservoir operations relatively sensitive to climate variability while larger runoff to storage ratios of about 144% and 71% for the San Joaquin (south CA) and for the Sacramento (north CA), respectively, tend to diminish the importance of climate signals in individual years. Northern CA also is affected differently than southern CA by climate signals on an interannual time scale (Dettinger et al. 1998) and has a smaller runoff to storage ratio.

Tables 3 and 4 summarize the covariability of hydropower generation with climate. Hydropower is not a major part (13% on average during 1983-2000, California Energy Commission July 2003) of the total electric power generation in CA. Also, we assume that conventional resources (and energy imports) allow the CA demand to be met with high reliability by non-hydropower resources (albeit at potentially higher cost). For these reasons, we analyze the predictability of PNW-CA power transfers largely as a function of the PNW surplus power in spring and summer.

c. Electric power demand

This section assesses the predictability of air temperature and electric power demand in the PNW and CA. An exploratory analysis corroborates the results of Alfaro et al. (2004) for the predictability of CA summer temperatures based on March, April and May PDO sea surface temperature (SST) anomalies during 1950-2001. Figure 7 shows the 1917-2002 observed monthly average temperature and the average temperature derived from a regression of observed values with March, April and May PDO SST anomalies. CA summer temperatures tend to be above normal when March, April and May PDO SST anomalies are above normal.

The time scale of the analysis and the level of spatial aggregation used in this study create some important limitations on the predictability of power demand, because spatial and temporal aggregation tends to reduce its variability. CA's interannual variation in simulated regional peak demand at monthly timescales is around 2% of the interannual average (Table 3). Because several months are averaged together April-July monthly average peak demand has less variability than the demand in each month (Table 3). Likewise the variation of simulated PNW monthly power demand in winter as a function of ENSO variability is relatively small (less than 2%, not shown). Although a more detailed analysis is beyond the scope of this investigation, these findings highlight the need to evaluate the potential role of spatially disaggregated forecasts of power demand, particularly in CA in summer.

To summarize, both streamflows and hydropower production in the PNW are strongly related to PDO and ENSO variability, and are therefore predictable using ENSO and PDO forecasts at long lead times. Hydropower production in CA and PNW tends to covary, especially in the last several decades, however consistent ENSO signals in CA are lacking. Seasonal power demand in the PNW and CA is predictable from year to year using ENSO and PDO indices, but at the level of spatial and temporal aggregation used here, the variations associated with predictable climate variations are relatively small as a percentage of the total demand.

4. Electric power transfers: derivation, covariability with climate and economic value, potential for forecasting and trends.

In this section we describe the transfer model used in our analysis. We then estimate a baseline for the potential monthly benefits of electric power transfers from the PNW to CA under the current management policies and relate these benefits to climate variability associated with PDO and ENSO from 1917-2002.

a. The transfer model

We first estimate the surplus power production in the PNW by comparing the total hydropower production simulated by the ColSim model to the estimated regional demand in the PNW. If the total hydropower production is larger than the estimated regional demand, then the difference is assumed to be surplus. These values represent potential power transfers from the PNW to CA (or to other wholesale spot market customers).

In order to calculate under what conditions these potential power transfers would occur and how much they would benefit the two regions, we constructed a simple monthly time step power transfer model. The transfer model assumes that all of the surplus power in the PNW (as estimated above) is transferable to CA via the intertie subject to the following constraints:

1. The monthly transfer does not exceed the intertie capacity assuming a 10 hour transfer per day (i.e. 7500 MW * 10 h per day * (365/12) days per month = 2 281 250 MWh per month)
2. The power is available either at John Day Dam or at The Dalles, where the transmission lines are located
3. The transfer is economically advantageous to CA

The first constraint is based on the assumption that nighttime base loads in CA will be supplied primarily by conventional or nuclear steam plants that cannot be turned on and off easily and that power from the PNW would not be valuable at these times. In extreme years (e.g. water year 1997) when large amounts of surplus power are available from the PNW, this assumption might be violated, but in most years it seems reasonable to assume that the PNW hydropower will not be used to supply nighttime base loads in CA. The second constraint limits the potential transfer because transmission lines are located at John Day and The Dalles Dams. The third constraint is evaluated using simple estimates of seasonal power rates and transaction costs compared to estimates of the cost of generating power locally in CA. The surplus hydropower from the PNW is assumed to be transferred as hourly peaking values that would replace natural gas fired gas turbine generation. The cost to CA of replacement power from the PNW in this transaction is the sum of a fixed transmission cost of $3.39 per MWh to deliver the power over the intertie (http://www.transmission.bpa.gov/Business/Rates_and_Tariff/RatesDocs/2004RatesSummary.pdf) added to a seasonally varying rate structure for PNW power shown in Table 5 (http://www.bpa.gov/power/psp/rates/april-september2005_adjusted_power_rates.pdf). Assumed replacement power costs in CA are based on a fixed natural gas price of $6.10 per million BTUs and a thermal conversion efficiency of 0.35. This translates to a cost of $59.52 per MWh in CA. Natural gas prices in fact vary considerably from year to year based on a number of interrelated market forces that are difficult to predict, factors that we do not consider. The transfers (and their seasonal timing) are predominantly determined by the surplus power in the PNW, but the capacity of the intertie is frequently a binding constraint as well (32% of the time from April to July).

Benefits of the transfers to each region in each month are as follows:

PNW benefit = energy transfer * (undelivered rate from Table 5)

CA benefit = energy transfer * (local generation costs – delivered energy costs)

An example may be helpful in illustrating these calculations. Suppose that in a particular June in our long time series, 2 880 000 MWh of surplus energy is available from the PNW. This amount exceeds the intertie capacity (over a 10 h transfer), so the transfer amount is truncated to 2 281 250 MWh. The benefit to the PNW is then (2.281 million MWh * $22.53 per MWh = $51.396 million). The benefit to CA is (2.281 million MWh * $(59.52-23.63-3.39) per MWh = $74.14 million). Note that these are legitimate benefits to each region. If the PNW did not sell the power the water would have to be spilled from the lower Columbia dams, and, in the case of CA, PNW hydropower is a cheaper source than local gas turbine generation.

b. Economic value of power transfers and their relationship to climate variability

Figure 8 shows the transferable surplus hydropower (10 h average) in the PNW for warm and cold ENSO, PDO and constructive ENSO PDO signals. The April-July transferable surplus energy is correlated at -0.18 and -0.25 respectively with Niño 3.4 and PDO indices. The average transferable surplus power (averaged over 10 hours) for ENSO and PDO composites is shown in Table 3. The 1917-2002 average April-July simulated potential intertie from the PNW is 3215 aMW (average MW, here averaged over 10 hours), which is of the same order of magnitude of the simulated CA hydropower production (3542 aMW) and corresponds to about 8% of the CA peak demand. From 11% to 26% more than April-July long term average surplus hydropower is available for transfer during cool ENSO and/or cool PDO years. Similarly, from 17% to 19% less than average surplus hydropower is available during warm ENSO or warm PDO years and 28% less power than average is available during warm ENSO PDO years. Corresponding economic benefits are shown in Table 3. Average annual benefits from April-July electric power transfers are $136 and $79 million for CA and PNW respectively. These benefits are reduced by 26 and 30% respectively for CA and the PNW during warm ENSO and PDO years whereas benefits increase up to 26 and 27% during cold ENSO and PDO years. Benefits ranges from $101 to $166 million and $55 to $100 million respectively for CA and the PNW for the April-July period.

c. Probability of exceedence analysis

Decision-making using forecasts frequently requires probabilistic information, such as the likelihood that transfer of power from the PNW to CA will exceed a certain amount. Here we take a simple non-parametric approach to estimating the probability of exceedence of power transfers and their respective economic benefits as a function of retrospective climate conditions.

For simplicity, only 6 (warm ENSO PDO, warm ENSO and any PDO, cold ENSO and any PDO, cold ENSO PDO, any ENSO and warm PDO, any ENSO and cold PDO) of the 9 independent ENSO and PDO signal combinations are shown. For each of these categories, the monthly April-July benefits have been composited from the unconditional time series, ranked, and then assigned a probability of exceedance value using an unbiased quantile estimator (Cunnane formulation, Stedinger et al. 1993). Figure 9 shows that during cold events (cold ENSO, cold PDO or cold ENSO PDO) in June, there is above 65% chance that the transfer will be at maximum capacity (7500 MW) for 10 hours a day and will provide about 18% of the CA peak hour demand. This expectation is reduced to about 55% during average 1917-2002 climatology, to about 37% during warm ENSO or warm PDO years and to about 27% for warm ENSO PDO years. Note that the various climate categories are not necessarily independent of each other, and taken together will not reproduce the unconditional probability of exceedence values.

d. Sources of uncertainty

A number of sources of uncertainty influence our results. Estimates of hydropower production are based on a series of linked model simulations, which introduces uncertainty. These uncertainties are difficult to estimate, because reservoir system operations and power demand have not remained constant over time. However, because the simulated streamflow signals are consistently related to observed ENSO and PDO variability throughout the time series (see Section 2.a), the hydropower simulations associated with these hydrologic variations contain useful and self-consistent signals associated with the climatic variations examined here, any overall bias in the simulations not withstanding.

Probably the largest source of uncertainty surrounds estimates of regional power demand in the PNW, which, when combined with estimates of hydropower production in the PNW, determine the "surplus" hydropower available for transfer our simple transfer model. These estimates of demand are sensitive, for example, to the detrending of observed demand data used in creating the electric power demand models (see Section 2.c). Detrending the observed demand data based on year 1997 (resulting in a PNW demand 8% lower) produced simulated transfer benefits on average 17% and 20% higher, respectively for CA and the PNW, than those shown here (which are based on systematically higher observed demand data consistent with year 2000). Thus the absolute value of the benefits of power transfers is sensitive to potential changes in regional power demand.

Perfect climate signal forecasts were assumed for this study. In late summer such an assumption is justified by past ENSO prediction studies (see discussion Section 1.c), but a later paper will assess the sensitivity of the benefits to the uncertainty in the climate forecasts.

e. Increasing trend in 1917-2002 spring transferable energy

Figure 10 shows the April-July 1917-2002 PNW monthly surplus hydropower production that can be transferred and the corresponding CA benefit. An apparent increasing trend in spring transferable power is somewhat counter intuitive. In the most recent warm PDO epoch from 1977 to at least 1995, the transferable power is comparable in the cool PDO epoch from 1947-76 and is larger than the warm 1925-46 warm PDO epoch. This trend could be the result of either a decrease in the PNW daily demand and/or PNW increased streamflow. Trends in April-September average Tmax are on the order of 0.9 °C for the in the western US (Mote et al. 2005, Hamlet et al. 2005). The simulated April-July daily power demand in the PNW is not very sensitive to this increased temperature and does not significantly decrease. However, April-July streamflow in the PNW shows significant increasing trends (not shown). Moreover, very high flows in the early 1980s and late 1990s have tended to "reset" the Columbia's reservoir storage and have tended to keep reservoir system storage systematically higher in the most recent warm phase PDO, which results in greater efficiency of the hydropower system for the same amount of flow. These effects, when combined, largely explain the significant increasing trend in the transferable energy.

A similar analysis of the value of energy transfers was carried out from 1947, when the cold PDO epoch starts, to 2002 in order to determine how sensitive the results are to this upward trend. Because the ratio of warm over cold events is smaller in the 1947-2002 period than in the 1917-2002 (0.7 versus 0.84), the 1947-2002 average hydropower production is higher (3999 aMW over 10 hour a day) than its 1917-2002 average. Transferable surplus hydropower averages for cold ENSO, PDO and ENSO PDO are higher by 5 to 19% (of their 1917-2002 values) and averages for warm ENSO, PDO and ENSO PDO events are higher by 41 to 56%. The 1947-2002 average economic benefits are $169 and $98 million for CA and the PNW, respectively. ENSO and PDO signals for transferable surplus hydropower in the PNW appear to be weaker during that period. The average transferable surplus hydropower is closer to the capacity limit and therefore 1947-2002 economic benefit variability with climate is reduced. Benefits are 10% lower than the 1947-2002 average during warm ENSO PDO events, and are a few percent above average during cold events.

5. Forecasting timeline and potential applications

We have identified variations in hydropower supply and electrical demand in the PNW and CA, and related them to climate variations that are predictable with long lead times via PDO and ENSO forecasts. In this section we examine when the relevant climate information becomes available and we provide a general framework for how these findings could be integrated into power operations.

a. Forecasting and decision timeline

As of about June 1 a number of different kinds of information are available that are used in current energy-related decision processes. First, streamflows for the current year from June-September can be forecast with relatively high skill based on the known (previous) winter's climate and snowpack. Current reservoir contents in the PNW and CA are also known. Using this information, short term explicit estimates of hydropower production in the current summer (June to September) are made and frequently updated using in-house simulation models (of which ColSim and CVmod are simple and flexible representations). Earlier we have shown that CA summer power peak demand can be predicted via March, April and May PDO SST anomalies, which are fully observed by June 1 (although as noted in Section 3.c these signals are relatively small at a monthly time scale). We have also shown that we can extract quantitative information about the probability distributions for the PNW surplus hydropower production in the coming spring and summer via categorical forecasts of PDO and ENSO. Although we do not construct any specific optimization strategies here, the probability distributions described above could potentially be used to optimize PNW hydropower operations and consequently electric power transfers in the current summer as a function of long-range climate forecasts. To illustrate how this might happen we give an example of how an ENSO based climate forecast available on June 1 could be used to identify conditions when both regions would benefit from increased power transfers in late summer.

Suppose the March-May period immediately preceding the forecast date (June 1) shows a warm PDO anomaly, but the ENSO forecast for the coming winter is for cool ENSO conditions (wet year in the PNW). The average temperature forecast and therefore peak demand for CA in the current summer is biased towards higher peak demands (and a somewhat higher risk of capacity limitations). The exceedance probability distribution for transferable surplus hydropower generation in the PNW is biased towards higher surplus hydropower in the coming spring and summer (Figure 9). Hamlet et al. (2002) have shown that increased transfers from the PNW to CA in late summer would benefit the PNW because the price of power is higher then (and would remain so assuming these transfers are fairly small—as in the Hamlet et al. 2002 study). CA would benefit by hedging against the potential risks of a capacity constraint in late summer. A simple market-based approach could probably be used to facilitate these transfers. Based on an ensemble streamflow forecast for the coming spring, the PNW would determine how much energy can be safely delivered in late summer with a low probability of jeopardizing system refill in the following summer (see Hamlet et al. 2002). Based on their real-time capacity needs, CA (or other spot market) wholesale customers could then purchase energy from this available pool as market forces or capacity constraints dictated. In some cases the available energy pool might not be used. Medium-term contracts specifying transfer amounts and/or prices might benefit both parties as well under certain circumstances.

Although CA would typically benefit in terms of marginal cost from power transfers from the PNW to CA in late summer, it is also clear that there would be little incentive for CA to propose such an arrangement under “normal” conditions, since the price differential between natural gas based generation and PNW hydropower rates is greater in spring. This suggests that the potential value to CA of transfers from the PNW to CA in late summer is much more dependent on potential savings associated with meeting extreme peak demands at shorter time scales than in meeting average demands on monthly time scales.

b. Natural gas planning applications

ENSO and PDO forecasts probably have their clearest energy related applications for forecasting natural gas markets in CA since in warm ENSO and/or warm PDO years there is typically little surplus electric power available from the PNW and the CA would have to rely largely on conventional resources to meet spring and summer power demands. Conversely in cool ENSO and/or cool PDO years, CA can be expected to use less natural gas. The simple power transfer model described above, for example, suggests a simple way of relating changes in natural gas consumption in spring and summer in CA to long-range ENSO and PDO forecasts. Another energy-related application is economic assessment of future capacity increases for the PNW-CA intertie, using the long time series of electric power transfers in spring constructed above as driving data for the analysis. The apparent changes in variability and timing of spring streamflow in the last 30 years of the record have important implications for such assessments.

6. Conclusions

Hydropower generation in the PNW is (primarily) a function of total annual stream discharge which is strongly correlated with winter climate. Hydropower generation in CA is affected by winter climate (which primarily determines streamflows) and by irrigation demand (which as represented here is primarily a function of overall water availability). Simulations of hydropower generation performed for 1917-2002 reveal correlations ranging from -0.24 to -0.34 between ENSO and PDO signals and average April-July PNW hydropower production. The correlation coefficient between the time series of hydropower production in the PNW and CA is 0.52, which indicates that annual hydropower resources in the two regions are frequently in phase.

Monthly daily average and peak hour power demands are also sensitive to climatic variations and are well correlated to daily average temperatures in the winter in the PNW and in summer in

CA. PNW and CA power demands are out of phase on a seasonal time scale as PNW power demand peaks in winter time whereas CA demand peaks in summer time. At the regional aggregations examined here, demand variations are relatively small at monthly time scale, and we were unable to demonstrate large predictable signals in either the PNW in winter and spring (using the Niño3.4 or PDO indices) or in CA in summer (using the PDO index) (Section 3.c).

Because predictable demand signals are relatively small, the predictability of potential transfers from the PNW to CA is shown to be primarily a function of water availability, which determines surplus power availability in the PNW. The probability of exceedance of the power transfers can be predicted with long lead times via ENSO and PDO forecasts. A simple transfer model and associated economic analysis over the 1917-2002 period shows that April-July power transfers between the PNW and CA would produce an average economic benefit of $136 million for CA and $79 million for the PNW. This benefit is on average 11 to 27% larger during cold ENSO and/or PDO events and 16 to 30% lower during warm ENSO and/or PDO events.

Winter climate predictions are available with a lead time of about six months (mid summer for the next winter). While the use of long-range climate forecasts is not required to facilitate the power transfers in the spring/summer months, it could complement current short term PNW water resources operations to provide access to more power in late summer, with potential benefits to both CA (hedging against late summer capacity constraints) and the PNW (increased hydropower revenues).

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FIGURES

Figure 1: Hydrographs of observed and simulated streamflow in the Sacramento River at Bend Bridge, CA.

Figure 2: Regression of detrended FERC power demand from 1993-2000 with population weighted daily average temperatures in the PNW and CA a) Average daily demand (in average GW over 24 hours) for the PNW for January, February and March b) Daily peak demand (GW) for CA for June, July, and August. (Correlations are significant using t statistics at the 95% confidence level with the null hypothesis being that the demand is not dependent on Tavg.)

Figure 3: a) 1993-2000 adjusted and detrended FERC observed and simulated daily average power loads in the PNW in January, February, and March (in average GW over 24 h) and b) 1993-2000 detrended FERC observed and simulated daily peak hour power demands in CA in June, July, and August (in GW).

Figure 4: Simulated monthly hydropower production in million MWh in the PNW during 1917-2002.

Figure 5: 1917-2002 annual (water year) hydropower generation (GWh) as a function of annual mean flow upstream of several dams in the Columbia River Basin.

Figure 6: Covariability of standardized annual hydropower generation in the PNW, CA and surplus hydropower in the PNW. Annual hydropower generation mean and standard deviation are 14 462 and 2586 aMW for the PNW, 497 and 387 aMW for PNW surplus power, and 976 and 319 aMW for CA.

Figure 7: Predictability of June-August average temperatures in CA based on a regression of 1917-2002 observed average temperatures with March, April and May PDO temperature

anomalies. Correlations are significant using t statistics at the 95% confidence level with the null hypothesis being that CA Tavg is not dependent on March, April and May PDO temperature anomalies.

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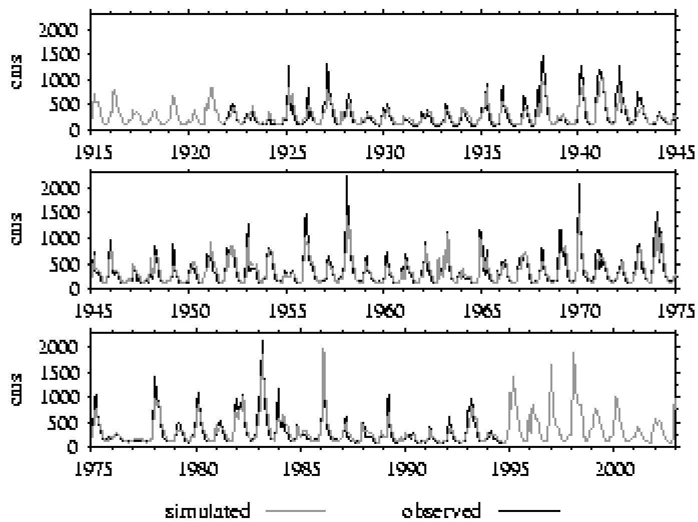

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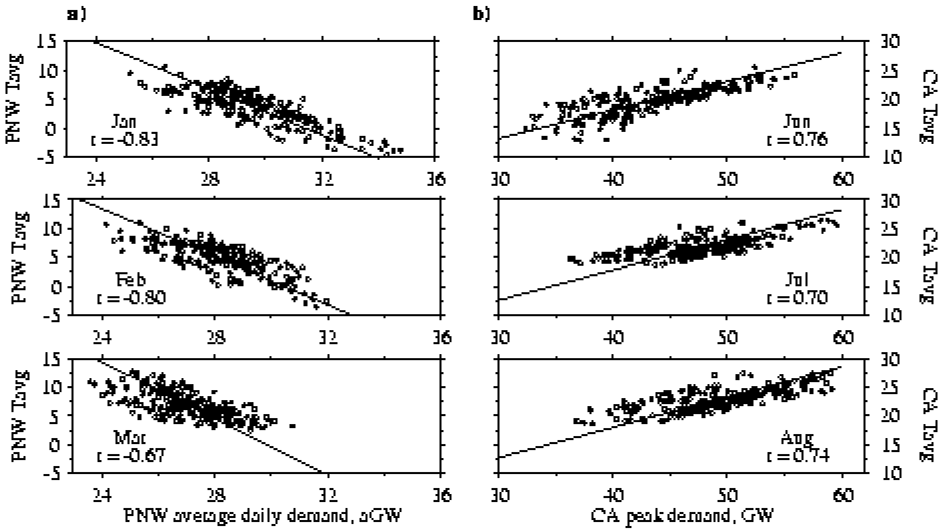

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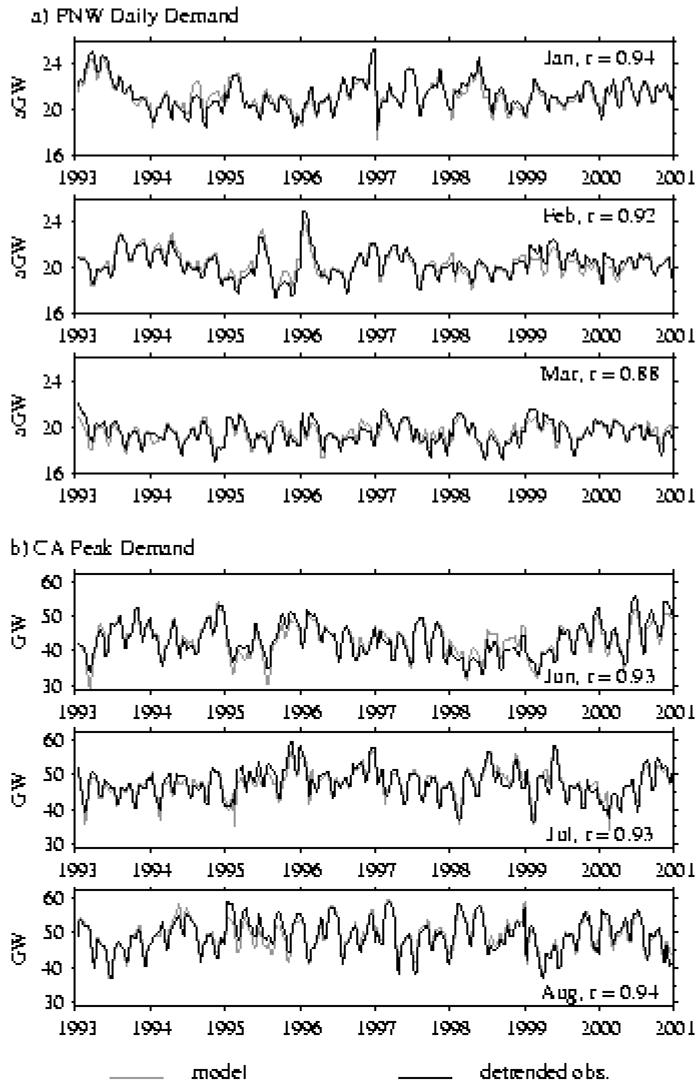

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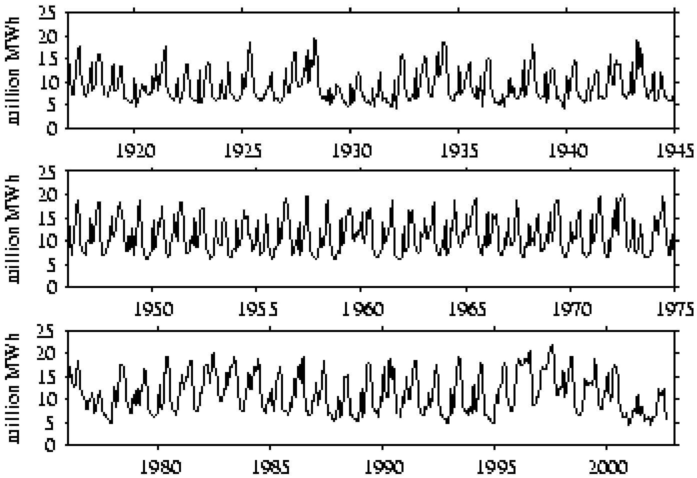

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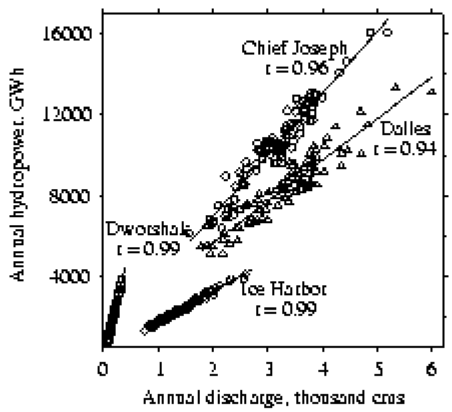

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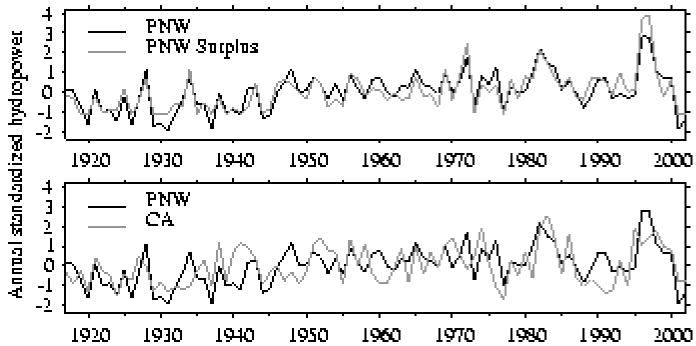

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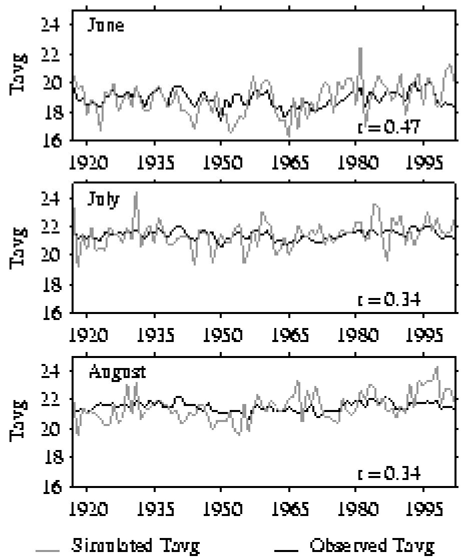

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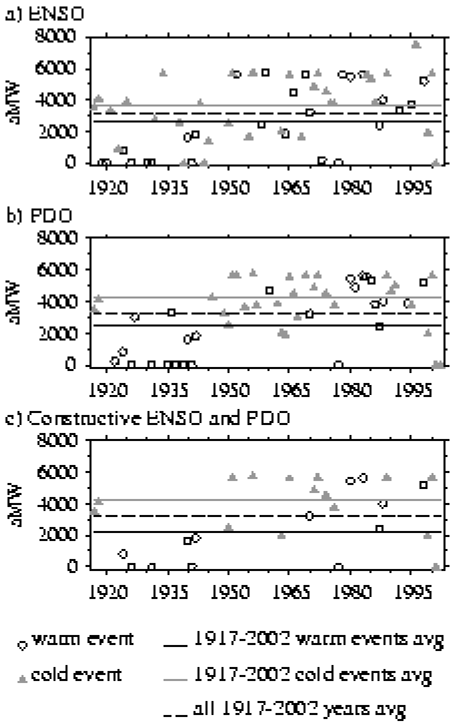

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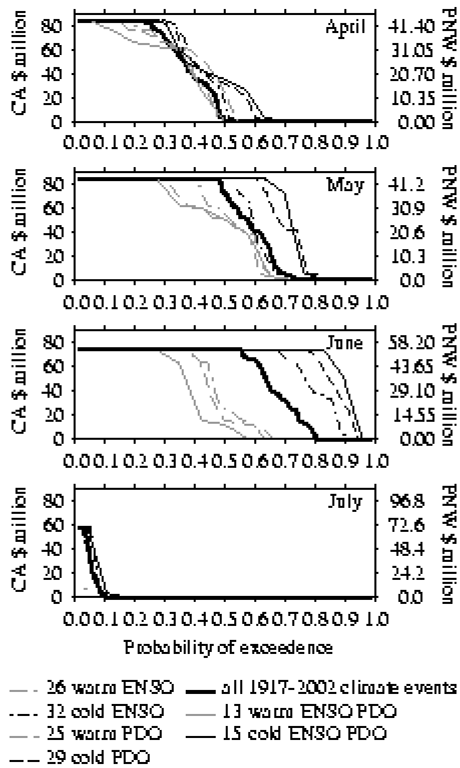

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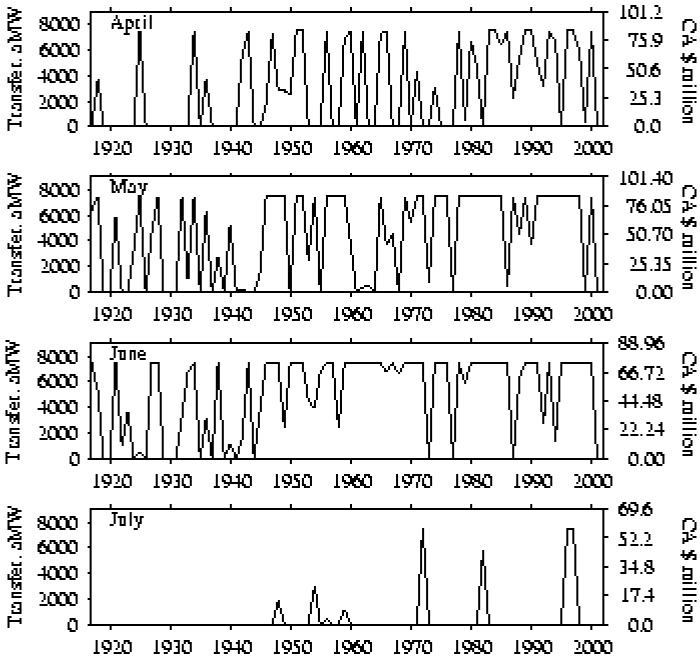

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TABLES

TABLE 1. Columbia River simulated discharge (cms) at the Dalles, OR, in the April-July period and annually (water year) over the 1917-2002 period, and fraction of the long term average in each climate category.

	WARM ENSO	WARM PDO	WARM ENSO PDO	COLD ENSO	COLD PDO	COLD ENSO PDO	1917-2002 avg
Apr-Jul							
Flow	9051*	8906*	8469*	10 563	11 107*	11 247*	10 035
Fraction	0.90*	0.89*	0.84*	1.05	1.11*	1.12*	1.00
Annual							
Flow	4885*	4873*	4685*	5597	5783*	5934*	5332
Fraction	0.92*	0.91*	0.88*	1.05	1.08*	1.11*	1.00

* satisfies one-tail Student t test with p=0.05. Null hypothesis is that the mean equals the long term average.

TABLE 2. Simulated discharge (cms) of the Sacramento River at Shasta, North CA during March-July and of the San Joaquin River at Millerton, South CA during May-September and annually (water year) over the 1917-2002 period, and fraction of the long term average in each climate category.

	WARM ENSO	WARM PDO	WARM ENSO PDO	COLD ENSO	COLD PDO	COLD ENSO PDO	1917-2002 avg
North CA,	Mar-Jul						
Flow	376	374	374	310	336	302	342
Fraction	1.10	1.10	1.09	0.91	0.98	0.88	1.00
South CA,	Mar-Sep						
Flow	91	110	100	90	80	76	93
Fraction	0.98	1.19	1.08	0.97	0.86	0.82	1.00
North CA,	annual						
Flow	240	241	241	205	219	203	225
Fraction	1.07	1.07	1.07	0.91	0.98	0.90	1.00
South CA,	annual						
Flow	69	74	73	64	61	57	67
Fraction	1.02	1.11	1.09	0.96	0.91	0.85	1.00

* satisfies one-tail Student t test with p=0.05. Null hypothesis is that the mean equals the long term average.

TABLE 3. Summary of the effects of climate variability on hydropower production, regional power demand, and power transfers. Rows 1-7 show a summary of April-July PNW hydropower production (PNW Hydro), electric power demand (PNW Dem), and surplus hydropower production available for transfer (PNW Transfer). Rows 8-12 show a summary of CA April-July hydropower production (CA Hydro), and peak power demand (CA PkDem). Rows 13-18 summarize the ratio of power transfers from the PNW to CA power demand and economic benefits to the PNW (PNW Bnft) and CA (CA Bnft). Frac is the fraction of the long term average.

Apr-Jul monthly avg	WARM ENSO	WARM PDO	WARM ENSO PDO	COLD ENSO	COLD PDO	COLD ENSO PDO	1917-2002 avg
PNW							
Hydro (aMW over 24 h)	17 477	17 353*	16 630	19 543	20 452*	20 402	18 834
Frac of Hydro	0.93*	0.92*	0.88*	1.04	1.09*	1.08*	1.00
Dem (aMW)	19 035	19 040	19 018	19 046	19 038	19 048	19 044
Ratio of Hydro to Dem	0.92	0.92*	0.87	1.02	1.07*	1.07	0.99
Transfer (aMW)	2655	2605	2329	3578	3917*	4062	3215
Frac of Transfer	0.83	0.81	0.72	1.11	1.22*	1.26	1.00
CA							
Hydro (aMW over 10 h)	3543	3365	3411	3456	3606	3558	3542
Frac of Hydro	1.00	0.95	0.96	0.98	1.02	1.00	1.00
PkDem (MW)	40 829	41 155*	41 014	40 621	40 577	40 643	40 749
Ratio of Hydro to PkDem	0.07	0.07	0.06	0.09	0.10	0.10	0.08
Economic Value							
Ratio of PNW Transfer to CA PkDem	0.07	0.06	0.06	0.09	0.10*	0.10	0.08
CA Benft ($ million)	114	112	101	151	166*	172	136

Frac of CA Benft	0.84	0.82	0.74	1.11	1.22*	1.26	1.00
PNW Benft ($ million)	63	62	55	88	96*	100	79
Frac of PNW Bnft	0.80	0.79	0.70	1.12	1.22*	1.27	1.00

* satisfies one-tail Student t test with p=0.05. Null hypothesis is that the mean equals the long term average.

TABLE 4. Annual hydropower production in CA for the 1917-2002 water year period as simulated by CVmod as fraction of the long term average.

	warm ENSO	neutral ENSO	cold ENSO	all ENSO
warm PDO	1.05	0.87	1.15	1.01
neutral PDO	0.91	0.98	0.94	0.95
cold PDO	1.20	0.89	1.09	1.05
all PDO	1.04	0.92	1.04	1026 (aMW)

* satisfies one-tail Student t test with p=0.05. Null hypothesis is that the mean equals the long term average.

TABLE 5. Electric power rates in spring and summer in CA and PNW.

Power rates ($ MWh^{-1})	April	May	June	July	August
CA cost of gas turbine power generation	59.52	59.52	59.52	59.52	59.52
PNW hydropower sale (HHL + load variance)	19.15	19.08	23.63	30.71	44.94
PNW transmission	3.39	3.39	3.39	3.39	3.39
PNW HHL sale, PNW benefit	18.05	17.98	22.53	29.61	43.84

HHL = high hour load