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Volume VII: Cost/Benefit Analysis for the ASVT on Operational Applications of Satellite Snow-Cover Observations

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ABSTRACT

The results of the OASSO ASVT's have been used to estimate the benefits accruing from the added information available from satellite snowcover area measurement. Estimates of the improvement in runoff prediction due to addition of SATSCAM have been made by the Colorado ASVT personnel. The improvement estimate is 6-10%.

Data were applied to subregions covering the Western States snow area amended by information from the ASVT and other watershed experts to exclude areas which are not impacted by snowmelt runoff. Benefit models were developed for irrigation and hydroenergy uses. Results of the benefit estimate for these major uses yielded a yearly aggregate of 36.5M.

Cost estimates for the employment of SATSCAM based upon the Colorado ASVT results and expanded to the Western States totalled $505K. The benefit/cost ratio thus formed is 72:1. Since only two major benefit contributors were used and since the forecast improvement estimate does not take into account future satellite capabilities these estimates are considered to be conservative.

The large magnitude of the benefit/cost ratio supports the utility and applicability of SATSCAM. Future development in the use of SATSCAM in computer models specifically tailored or adapted for snow inputs such as those developed by Leaf, Schumann, and Tangborn, and Hannaford will most certainly increase the use and desirability of SATSCAM.

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COST/BENEFIT ANALYSIS FOR THE OPERATIONAL APPLICATIONS OF SATELLITE SNOWCOVER OBSERVATIONS (OASSO)

By Peter A. Castruccio, Harry L. Loats, Jr., Donald Lloyd, Pixie A. Newman

INTRODUCTION

It is almost a decade, dating from the early 1970's, that satellite technology has been capable of providing relatively high quality images on a frequent enough basis to indicate to hydrologists that a possibility for gathering data on snowpack area was practical. Both the techniques for measuring the snowpack area and its applications for improving seasonal runoff predictions have been demonstrated (Reference 1,2,3). As a result, an Application Systems Verification and Transfer (ASVT) program was established by NASA, the major thrust of which was to extend these research efforts into the realm of operational runoff forecasting.

The operational employment of satellite snowcovered area measurement (SATSCAM) to runoff forecasting has been evaluated at four sites strategically located throughout the Western United States. To supplement the ASVT technical evaluations, NASA initiated a study to determine the costs and benefits of operationally applying SATSCAM in this region.

BACKGROUND

An effort to analyze the value of the improvement of water resources operations attributable to satellite data inputs was initiated by the Goddard Space Flight Center in mid-1976. The program was structured around the findings to be obtained from four ASVT (Applications Systems Verification and Test) sites situated within the 11 Western States.

The primary objectives of the investigation carried out at the four ASVT test sites were: 1) to evaluate the operational capability for use of satellite imagery in mapping snowcover area within the test basins; 2) to develop techniques and procedures for systematically monitoring snowcover from remotely sensed imagery; and 3) to perfect methods to incorporate satellite snowcover area measurements into operational streamflow forecasts.

Table 1 lists the ASVT sites for which test data has been collected. These sites/areas include the wide spectrum of geographic and hydrologic diversity necessary to evaluate the general utility of SATSCAM to operational streamflow forecasting. Figure 1 indicates the locations of the Snow ASVT study basins.

The following is a brief summary describing each snow ASVT test site, its activities and results.

Table 1
Snow ASVT Test Sites

ARIZONA	
Cognizant Personnel:	H.H. Schumann - U.S. Geologic Survey (USGS); W. Warskow; E. Kirdar - Salt River Project (SRP)
Key Watersheds:	Salt; Verde
Prinicpal Applications:	Power; irrigation; water supply; flood control
CALIFORNIA	
Cognizant Personnel:	A.J. Brown - California Department of Water Resources (Calif., DWR); J. Hannaford - Sierra Hydrotech
Key Watersheds:	Feather; Upper Sacramento; San Joaquin; Kings; Kern; Kaweah; Tule
Prinicpal Applications:	Power; irrigation; flood control
COLORADO	
Cognizant Personnel:	J. Washicheck, B. Shafer - Soil Conservation Service (SCS); J. Danielson - Colorado Division of Water Resources (CDWR); B. Hansen - Bureau of Recreation (BuRec)
Key Watersheds:	Rio Grande (above Del Norte); Conejos (above Mogote); Culebra (above San Luis); San Juan (above Carracus); Arkansas (above Salida)
Principal Applications:	Power, irrigation
PACIFIC NORTHWEST	
Cognizant Personnel:	J. Dillard - Bonneville Power Administration (BPA) B. Thomas - Corps of Engineers (COE)
Key Watersheds:	Boise; Clearwater; Kootenai; Upper Snake; Flathead
Principal Applications:	Power, flood control, irrigation

Figure 1. Locations of snow ASVT study basins of the Eleven Western States

Arizona ASVT

The Salt and the Verde River basins, located in central Arizona, were evaluated by the Arizona Snow ASVT. The elevation of these basins range from 1,325 to 12,670 feet (400-3,900 m) above sea level. The mean annual precipitation is 10-25 inches (250-650 mm).

The snowpack below 7,000 ft. (2,100 m) is generally thin and transient, energy input for snowmelt is intense, and significant melt is possible throughout the snowmelt season. Since tree cover is sparse and cloudcover recurrence is low, near optimum satellite observing conditions exists over these basins.

Snowcover data were obtained from aerial snow flights, Landsat imagery, SMS/GOES imagery, and NOAA/NESS snowcover maps. The ASVT personnel used these sources in combination in order to obtain the maximum amount of available information. Flight data was of particular value when clouds obscured satellite observation of the snowpack. Aerial observation continued to be a valuable method of assessing snow depth and runoff conditions. However, the availability of frequent satellite snowcover observations has greatly reduced the necessity for frequent aerial reconnaissance flights.

Snowcover data was primarily extracted from Landsat imagery, both Band 5 and Band 7. A density slicing technique was utilized which enabled the operator to select snow reflectance thresholds, thereby distinguishing snowcovered from non-snowcovered areas. Color additive viewing with watershed masks was also employed. The zoom transfer scope was used for the transposing of data from various scale satellite imagery and for scaling of generated snowcover data for forecasting purposes. The Stanford Research Institute Electronic Satellite Image Analysis Console (EISAC) facilitated rapid scanning, registration, storage, analysis and retrieval of satellite imagery.

GOES VISSR data proved to be of great value in coping with the rapidly changing snowcover in Arizona. These data were primarily interpreted via zoom transfer scope which removed the image distortions and permitted registration of the original imagery onto a base map. The snowcovered area thus delineated was then measured by manual and electronic planimetering.

Satellite data collection systems (DCS) were used during the snowmelt runoff season to relay timely hydrologic data, critical to predict runoff from a rapidly changing snowpack. In addition to hydrometeorological data such as temperature, precipitation, and water equivalence from remote portions of the basins, streamflows in response to melt were available within minutes of the actual measurements. Such data proved valuable for short-term runoff predictions. A portable data terminal was recently incorporated into the satellite data system. It was pressed into real-time service for reservoir control purposes by the U.S. Geological Survey upon request of the Salt River Project during the early March 1978 floods. The operational feasibility of using satellite telemetry to relay hydrometeorologic data was clearly demonstrated.

The Arizona test site recently adapted the Hydrometeorological Model (HM) for use on the Salt and Verde Rivers. Modifications to adapt the model to Arizona conditions included the capability to accept daily runoff and the incorporation of temperature. SATSCAM was used primarily for short-term runoff predictions.

California ASVT

Two separate areas were evaluated by the Snow Surveys Branch of the California Department of Water Resources in Sacramento. The southern Sierra experiences cloudcover and snowmelt conditions similar to Arizona; it has slightly denser tree cover and generally much greater accumulation of snow. Up to 75% of the average annual runoff occurs during the snowmelt season. The northern California study areas have even greater tree cover; the incidence of clouds limits the number of usable satellite observations. Roughly 40-50% of the average annual runoff occurs during the snowmelt season. The temperature of the deep snowpack is normally near $0^{o}C$; runoff usually does not occur until after April. The season extends from this date through the month of July.

Snowcovered area was determined directly from the original 1:1,000,000 scale Landsat imagery with the aid of basin boundary overlays and indirectly using the zoom transfer scope (ZTS). In the latter case the data was transferred to 1:500,000 scale. The quality of the results obtained by using Landsat transparencies and the ZTS was found to be better than that obtained by using direct overlays (Reference 4). The ZTS was also used to reduce GOES and NOAA imagery.

The resultant snowcover data were published on a timely basis in the California Department of Water Resources Bulletin No. 120, "Water Condtions in California," which is published on the first of the month in February, March, April and May.

Areal snowcover observations were available for analysis and proved to be a valuable supplemental source of snowcovered area data. Low altitude visual observations over southern California were conducted by the U.S. Army Corp of Engineers, from 1952 to 1973 and the period 1978-1979. Only two years of concurrent aerial and satellite snowcover observations were available for this comparison. Apparently fresh light snowpack as well as patches below the continuous snowline were not mapped by aerial observers. These transient patches did not contribute significantly to runoff. Consequently, the 1973 satellite data consistently showed a greater snowcover area than the aerial data (Reference 3). The California ASVT indicated that the difference between the 1979 aerial and satellite data was roughly 8% on the Kings River and 14% on the Kern. Subsequently, historical aerial data was upgraded accordingly for analysis purposes (Reference 4).

The snowcover area data from aircraft and satellite observations were used in seasonal runoff forecasting on the Kern and Kings River watersheds through incorporation into procedures to update water supply forecasts. The techniques developed at the California ASVT require data turnaround of less than 72 hours, and an update frequency of at least 15 days. Other conventional predictor variables, such as snow-water equivalent and precipitation were also assembled for the snow ASVT period and used in this analysis.

No uniform conclusions could be drawn from the analysis test efforts of the California ASVT. The inclusion of snowcover areas as a parameter in the Kern River test produced a considerable decrease in volumetric error in water supply forecasting over the snowmelt season. In the Kings River test, no significant statistical improvement could be attributed to SATSCAM (Reference 4). Interestingly, unusual snowpack distribution conditions encountered during operational forecasts in 1978 resulted in significant SCA contribution to forecast accuracy on all basins. Hannaford indicated "Snowcover area data was most effective in reducing procedural error at basins characterized by: 1) substantial fraction of area contained within a limited elevation range; 2) erratic precipitation and/or snowpack accumulation pattern, not strictly related to elevation; 3) poor coverage by precipitation stations or snow courses with consequent inadequate indexing of water supply conditions." (Reference 4)

The existing Kings River Hydrologic model was modified by the California ASVT to accept SATSCAM inputs and used to simulate mean daily discharge and snowmelt. Once the basin was fully primed, the rate of snowmelt was mainly dependent upon the area and elevation of the snowcover. Average daily air temperature was used as a measure of energy available for melt. The priming elevation defined the portion of the snowpack available to produce changes in runoff due to energy inputs. Discharge calculations using the observed effective snowline were made. This conceptual models appears to be more consistent with known hydrologic relationships than the Kings River snowmelt submodel without SATSCAM input. Work was also undertaken to further refine the use of snowcover area data in the model by accounting and assessing this area in relation to 500 foot elevation zones. Techniques were developed to extrapolate the depletion of this snowcover, into the future, so the model can be used for predictions.

Results from this analysis indicate that SATSCAM does provide for some potential for improving streamflow forecasting. Comparison of the forecasts made without SATSCAM to those incorporating SATSCAM during the 1978 season indicate that the former generally overestimated spring runoff while the latter did not. However, definite conclusions as to the exact value of this improvement and the total operational application of SCA in conventional water supply forecasting were hampered by such limitations as the short duration of satellite data, the lack of real-time data, and the problems encountered with cloud obscuration.

Colorado ASVT

The two primary basins under study by the Colorado ASVT were the upper portions of the Rio Grande and the Arkansas basins. Snowmelt runoff constitutes roughly 80% and 75% of the mean annual flow of the Rio Grande and the Arkansas, respectively. Participants included the U.S. Soil Conservation Service, the U.S. Bureau of Reclamation, and the Colorado Division of Water Resources in Denver. Moderately dense forest cover and occasionally cloudy conditions prevail throughout the Colorado study area. The snowpack generally remains cold, dry, and of low density until after approximately April 1; afterwards, clear sunny skies can produce wet snow conditions and significant runoff.

Landsat imagery was found to be of adequate resolution and quality for the purpose of evaluating snowcovered area. An alternative method of analysis of partially cloud obscured images was developed by the Colorado Division of Water Resources (CDWR). This method produces estimates of snow area extent in relation to a network of indexed baselines. Baselines are areas free of tree cover and generally visible in Landsat images. The method relies on the assumption that within a watershed the snowline recession follows basically the same pattern year after year, even though the time of recession may change.

Six methods of evaluating satellite derived snowcovered area were tested. Of these six (zoom transfer scope (ZTS); density slicing, color additive viewer, computer assisted classification, grid sampling, and NOAA/NESS basin snowcover maps), the ZTS was found to be the most accurate, least expensive, and least time consuming (Reference 5).

In evaluating the utilization of SCA in runoff prediction, the Colorado ASVT site experimented with graphical techniques, regression analysis, and modeling. Snow depletion curves for each basin were plotted from 1973-1978 data. Simple linear regression analysis indicated that a high degree of correlation between snowcover area on April 1, May 1, and June 1 and the April-September streamflow forecasting. Of the test cases, 66.7% showed a significant increase in forecast accuracy, 15.8% decreased accuracy, and 15.8% were virtually unaffected (Reference 5). Another correlation documented by the Colorado ASVT was that between percent snowcovered area on the date of peak flow and peak discharge.

Estimates of the monthly flows for 1977 on the Conejos River, required to meet the legal obligations under the Rio Grande Compact were based on plots of remaining snowcover area versus time and the remaining runoff throughout the snowmelt season. Landsat data was used for these CDWR water supply forecasts.

The Sub-Alpine Water Balance Model developed by Leaf and Brink (Reference 6) was modified to incorporate Landsat and SNOTEL input data in real time. Control curves relating snowcover area to residual water equivalent were used to update the streamflow forecasts produced by the model. Landsat was first used experimentally to update model predictions of Conejos River runoff in 1977. Operational testing was carried out in 1978. The model was later adapted to other Colorado watersheds, such as the Upper Arkansas River.

Pacific Northwest ASVT

Five basins were under study by this ASVT: the Boise, the Clearwater, the Flathead, the Kootenai, and the Upper Snake. In these basins, forest canopies are extremely dense, broken occasionally by clearcuts and power lines. In two of the five basins, the terrain is extremely rugged. Grey and whitish grey outcrops in the higher elevations are easily confused for snow during the later portion of the snowmelt season. Persistent cloudiness presents a major obstacle to obtaining clear satellite views of the study area, although cloudiness decreases from the northern to the southern watersheds. Snowpacks are deep; in many areas significant snowmelt runoff can occur throughout the winter. Rain or snow is common, resulting in an increased potential for flooding. The Bonneville Power Administration and the U.S. Army Corps of Engineers were the primary participants in this study. Some assistance was provided by NOAA's National Weather Service.

Various methods of obtaining snowcover area data were tested at the Pacific Northwest ASVT. These included Landsat imagery, NOAA imagery, NOAA/NESS interpreted snow maps, and aerial imagery.

The various sources of snowcovered area data compared well with one another. This was particularly true when the individual evaluating the snowpack was familiar with the characteristics such as forest cover, shadows, lakes, terrain and geology, of the basins under study.

In most cases the small difference between satellite snowcovered area data and similar aerial data was due primarily to the inclusion of discontinuous snow patches in SATSCAM. Satellite derived snowcover area measurements for a given day varied by only a few percent. Interpretation of satellite imagery was facilitated by the use of both the zoom transfer scope and electronic interpretation equipment.

Over the study period (1975-1978), a greater than normal variation in annual water supply occured, potentially providing a better than average period over which to investigate the operational applicability of SATSCAM to streamflow forecasting.

One of the data inputs to the Streamflow Synthesis and Reservoir Regulation (SSARR) model conventionally used for forecasting flows in the Columbia River basin is snowcover area. Due to the sporadic availability of satellite data, a mix of Landsat, aerial and ground truth data was used to develop the temporal progression of snowcovered area. Daily forecasts of streamflow were possible, and the model automatically depleted the snowcover area until the next satellite update. Satellite data fixes were used to adjust the computed snowcover area. Results indicated that although the accuracy of streamflow forecasts increased with the utilization of SATSCAM, this increase in accuracy was not statistically significant. However, Pacific Northwest ASVT personnel claim that it is a valuable input for fall and winter forecasting (Reference 7). The additional advantage is that satellite-derived data is potentially more available than aerial snow-flight and ground truth data.

BENEFITS DERIVED FROM IMPROVED INFORMATION

The major benefits of improved snowmelt runoff forecasting are directly related to the major areas of water use.

The major uses of water in the United States, are:

- Hydropower
- Irrigation
- Municipal and Industrial
- Navigation
- Recreation, Land and Wildlife Management

The principal direct and indirect benefits for each use are given in Table 2.

In addition to the benefit areas listed must be added the area of flood damage reduction. The direct benefits are the reduction in losses to public and private property and the increases in net income arising from more extensive use of property. The indirect losses are those caused by the interruption to public and private activities. Major intangible benefits accrue from the prevention of the loss of human life and positive effects on the general welfare and security of the populace.

Hydroelectric energy production is the largest user of water in the 11 Western States and is potentially the largest benefactor of improved streamflow forecasting in terms of energy produced. Approximately 190 terawatt-hours of hydroelectric energy are produced annually in the 11 Western States, requiring over 2 billion acre-feet of water. The annual dollar volume of hydroelectric energy sales at current prices is over $6 Billion.

Irrigation is second to hydropower in quantity of water used and potential physical benefit from improved knowledge of streamflow. Twenty-five percent ($12 Billion) of all crops sold in the United States are produced on irrigated land. Irrigation accounts for approximately 40% of all the water withdrawn annually in the U.S. (with hydropower excluded since it does not withdraw water). Sixty percent of the irrigation water is consumed as evapotranspiration from crops and soil surfaces, making irrigation the largest consumptive user of water. The 11 Western States account for approximately 58% of the nation's irrigation requirement.

The next largest user of water is municipal and industrial water supply. As shown in Table 3 which reports recent annual withdrawal for various uses in the 11 Western States, municipal and industrial uses require only 10% of the water required by irrigation and less than 1% of that required by hydropower. Consequently, the central focus of this study was directed at estimating the benefit of improved streamflow forecasting to hydropower production and to irrigated agriculture.

Table 2
Generic Benefits of Improved Information for Water Management & Utilization

	DIRECT BENEFITS	INDIRECT BENEFITS	INTANGIBLE BENEFITS
HYDROENERGY	• Cost savings due to optimal mix of hydroenergy and thermal energy • Value added by optimal production at upstream/down-stream sites • Improved power production scheduling hence improved overall plant efficiency	• Conservation of fossil energy supplies • Conservation of labor	• Improved level of life due to cheaper energy production
IRRIGATION	• Increase in net farm income due to lower produc-tion costs • Increase in net farm income due to optimal crop selection • Improvements in operational efficiency of in place irrigation projects	• Increases in net income to Ag. industry suppliers • Reduction in food costs to populace • Reduction in energy required to provide irrigation	• Improved community faci-lities and services • Increased level of living
MUNICIPAL/INDUSTRIAL	• Improved surface water withdrawal scheduling hence improved overall waterworks efficiency • Cost saving by reduction of high cost ground water withdrawal	• Reduction of fire insurance rates • Cost savings to populace due to increased avail-ability of water • Expansion of in-dustry due to increased avail-ability of water	• Improved standard of living within area
NAVIGATION	• Reduction in cost of transport through improved scheduled releases of reser-voirs water storage to improve or ex-pand navigable waterways • Increased value of transport services resulting from expanded demand for the improved service	• Increased industrial and commercial activity • Increase utilization/ value of land along waterways	• Enhanced strategic value of inland water-ways
RECREATION, FISH AND WILDLIFE	• Increased revenues from increased utilization of re-creational lands and facilities • Increased popula-tion of higher value fish and wildlife • Reduction of fish embolusm through better control of reservoir re-leases	• Increased revenues from the sale of recreational equip-ment • Improved health of recreationally active populace	• Esthetic value of improved waterways and wildlife habi-tat • Ecological value of improved waterways and wildlife habitat • Scientific value of improved water eco-systems

Table 3
Recent Withdrawals with State and Region
(1,000 Acre/Feet)

STATE	WITHDRAWL YEAR	IRRIGATION	M&I INCLUDING RURAL	MINERALS	THERMAL ELECTRIC	RECREATION FISH & WILDLIFE	OTHER	TOTAL
ARIZONA	1965	7,096	349	102	7	169	78	7,942
CALIFORNIA	1965	29,020	4,131	118	8,220	652	-	38,897
COLORADO	1970	7,826	473	65	19	29	111	9,794
IDAHO	1966	17,668	739	27	-	245	49	25,505
MONTANA	1970	6,292	361	14	67	-	206	8,052
NEVADA	1969	3,301	245	-	63	-	10	4,718
NEW MEXICO	1970	3,206	205	84	66	45	52	3,919
OREGON	1975	7,624	1,581	-	23	36	17	10,878
UTAH	1965	4,803	415	95	7	616	951	7,348
WASHINGTON	1975	6,523	1,934	-	-	-	29	9,886
WYOMING	1968	7,358	134	85	13	-	-	7,977
EVAPORATION		-	-	-	-	-	-	1,862
SUMMARY		100,717	10,567	590	265	1,792	1,503	136,778

[1]Includes both surface and groundwater withdrawls
SOURCE: Westwide State Reports (unpublished)

Estimation of the Upper Bound Value of Snowmelt Water Used for Hydroelectric Energy Production

Table 4 summarizes the results of the computation of the value of snowpack runoff water for hydropower production. Baseline data (Reference 8) from 1968 shows that the average value of alternative energy was 6.8 mills/KWH at a capacity utilization factor of 48%. Data for 1974 (Reference 9) summarizing industry averages, shows that this value has risen by a factor of 1.32 to 9 mills/KWH primarily due to increase in the world price of oil. Applying the yearly growth rate of 9.5% indicated by the price indices of petroleum, yields a combined factor of 1.60 or a current value of energy of 10.9 mills/KWH at 48% capacity utilization. Equivalent adjustment was made for the value of energy at the average capacity utilization factor for each state. Short run values of water for hydropower were computed using the equation [1].

$$V_W = \frac{0.74 \text{ eh y} - 0.08 \left(\frac{\text{eh C}}{\text{f}}\right)}{721.13} \qquad [1]$$

V_W = Value of water used in \$/cfs-yr.

e = Overall plant efficiency

y = Cost of electricity from cheapest alternative source (mills/KWH)

C = Annual capital cost of generation/KWH installed (\$)

f = Annual capacity utilization factor

h = Effective head (ft) (pond elevation minus tailwater elevation)

Data for the quantity of water used for hydropower was determined by trending from current levels, on a state-by-state basis. Average fractions of the total water supply from snowmelt were applied on a state basis to determine the upper bound value of hydropower inputed to snowmelt runoff.

The results shown in Table 4 indicates that the 11 Western States use an average of 2,235 MAF per year for hydropower. At an average alternate energy cost of \$3.20/AF, the total value of the hydropower generated is \$7.15B. This corresponds to a price of 3.8¢/KWH. Adjusting this value by the average snow fraction of 68% (see Appendix E), an upper bound value of \$4.86B for the contribution of snow to hydropower was determined.

Table 4
Upper Bound for the Value of Snow for Hydropower

STATE	AVERAGE HYDROPOWER WATER USE (MAF)	AVERAGE HYDROPOWER GENERATION TERA-WATTS-HR.	VALUE OF WATER FOR HYDROPOWER $/AF	VALUE OF WATER FOR HYDROPOWER ($B)	AVERAGE SNOW FRACTION	CONTRIBUTION $B
WASHINGTON	1,204.1	86.6	2.87	3.46	0.67	2.32
OREGON	617.0	30.0	2.87	1.77	0.67	1.18
IDAHO	112.6	8.4	2.87	0.33	0.66	0.22
MONTANA	82.6	7.5	2.87	0.24	0.70	0.17
WYOMING	18.3	1.3	2.18	0.04	0.73	0.03
NEVADA	15.9	2.0	6.85	0.12	0.65	0.07
UTAH	4.1	1.1	2.187	0.01	0.74	0.01
COLORADO	7.6	1.4	2.18	0.01	0.74	0.01
CALIFORNIA	132.3	40.7	6.85	0.90	0.73	0.66
ARIZONA	39.1	7.8	6.85	0.27	0.74	0.20
NEW MEXICO	1.0	0.1	2.18	0.003	0.71	0.002
TOTAL OR (AVERAGE)	2,234.6	186.0	(3.20)	7.15	(0.68)	4.86

Table 5
Upper Bound Value of Snowmelt for Irrigation

	ARIZONA	CALIFORNIA	COLORADO	IDAHO	MONTANA	NEVADA	NEW MEXICO	OREGON	UTAH	WASHINGTON	WYOMING	TOTAL (AVERAGE)
WATER USE FOR IRRIGATION (MAF)	6.17	36.95	14.56	16.79	8.51	3.36	3.13	5.37	4.03	6.27	6.05	117.2
IRRIGATED AREA (M ACRES)	1.178	7.24	2.895	2.761	1.841	0.753	0.823	1.519	1.025	1.224	1.523	22.8
AVERAGE CROP VALUE PER IRRIGATED ACRE ($/ACRE)	820	766	304	248	130	213	389	260	190	516	199	(453)
REVENUE ADJUSTMENT FACTOR (q)	1.09	1.02	.41	.33	.17	.28	.52	.34	.25	.69	.27	(.36)
(268.9 x q) = MARGINAL $/ACRE	294	275	109	89	46	76	139	93	68	185	71	(163)
AVERAGE WATER USE PER ACRE (AF/ACRE)	5.24	5.1	5.03	6.08	4.625	4.46	3.80	3.53	3.94	5.1	3.97	(5.1)
MARGINAL $/AF	56.2	53.9	22.6	14.64	10.64	17.04	36.58	26.34	17.26	26.27	17.88	(31.8)
TOTAL VALUE OF WATER (M$)	346.5	1992.0	329.06	245.8	90.5	57.25	114.5	141.4	69.55	227.4	108.17	3,722.13
SNOW FRACTION	.74	.73	.74	.67	.70	.65	.71	.67	.74	.67	.73	(.71)*
% SURFACE WATER USE	30	62	60	84	98	84	.50	84	84	88	96	(65)
(M $) VALUE OF SNOWMELT	76.92	901.58	146.10	138.34	62.08	31.26	40.65	79.58	43.23	134.08	75.81	1,729.63

*Note: Weighted by average water usage for irrigation by state

Estimation of the Upper Bound Benefit of Snowmelt Water Used for Irrigation

The value of water used for crop irrigation can be measured by the marginal value inputed to yield increases of existing crops resulting from the use of irrigation water, or from the use of higher valued mixes of crops vis-a-vis non-irrigated areas.

The marginal value per acre-foot of water, from Ruttan (Reference 10), amended by communications with Colorado ASVT personnel, and updated to 1977 dollars, was computed as the ratio of the total marginal value of irrigated crops (acres x $/acre divided by total irrigation water used for each state).

Table 5 summarizes the computation for the upper bound value for snowmelt water to irrigation for the 11 Western States. The tables indicates that the 11 Western States use an average of 117 MAF per year for irrigation purposes. At a net marginal value of $164/acre, the total value of irrigation is $3.72 Billion. Reducing this value by the fraction of water due to snow and that due to groundwater yields an upper bound value of $1.74 Billion for the contribution of snowmelt water for irrigation purposes.

The upper bound values of snowmelt for five major water management activities: hydroelectric energy and irrigation accounted for 65% and 22% of the total value, respectively, while municipal and industrial, average yearly flood damage and navigation accounted for 9%, 4%, and less than 0.5% respectively.

Note that the upper bound serves here only to show that the value of water used for hydropower and irrigation is large and hence an important target for forecast improvement. Estimates for the value of SATSCAM for improving the forecast accuracy were developed by the procedures discussed in the remainder of the paper.

THE ECONOMIC IMPACT OF IMPROVED RUNOFF FORECASTING

The less perfectly the future supply of water (quantity and timing) is known the less efficient are the water supply mangement activities. This is illustrated conceptually in Figure 2.

Curve A, the locus of benefits accruing to perfect forecast reflects optimal management of water dependent activities at each level of water supply. For example, "value" from a perfectly managed volume of water X_o is given by Y_o. Curve B_1, is the locus of the values accruing to water volume lower than the forecasted quantity X_o. Curve B_2 is the analogous locus to water volumes greater than that forecasted.

To illustrate: if the volume X_o is forecast, the lesser volume X is obtained, the corresponding, value is Y_1. Had X been forecasted correctly the benefit would have been Y_1. The benefit loss is the difference between the X intercept of curves B_1 and A.

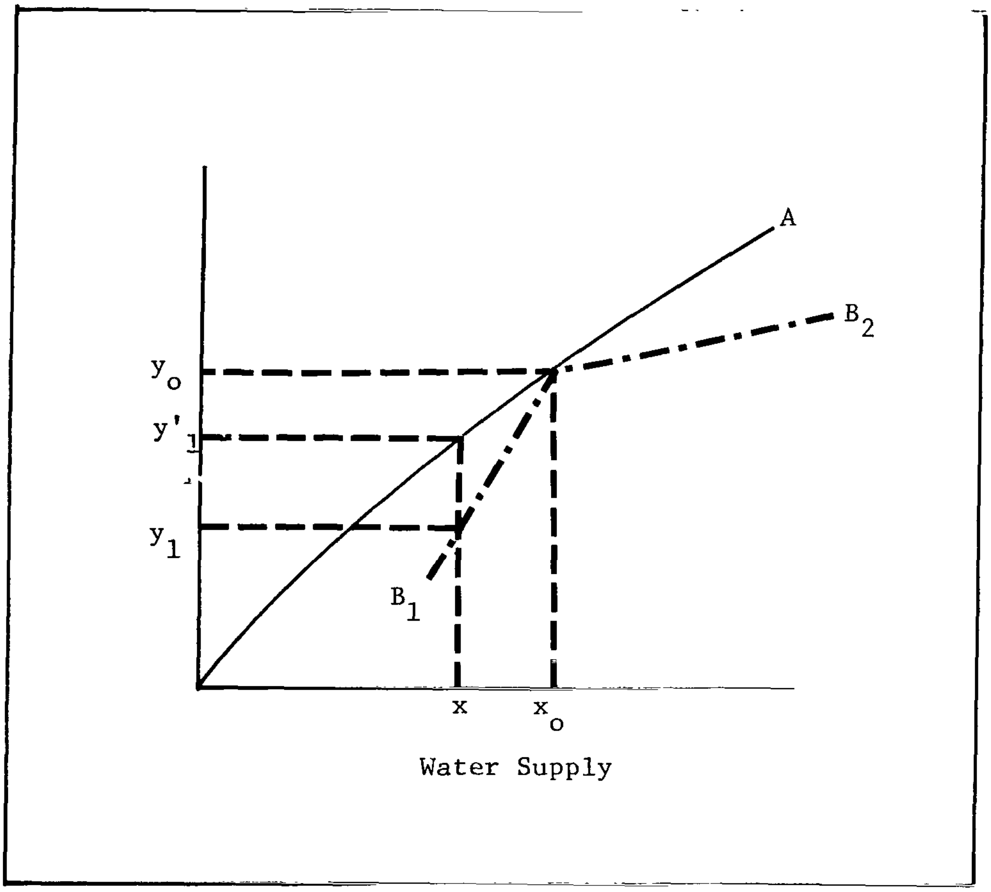

Figure 2. Conceptual description of benefits to improved forecasting

A physical explanation of the disbenefit is that in an attempt to maxmize benefits, activities are planned which will utilize the forecasted quantity of water most efficiently: if subsequently the supply of water actually obtained differs from that forecasted, efficiency suffers, and the results obtained are less than optimal. This conceptual model was adapted to compute the benefits of improved forecasts due to the addition of satellite snow-covered area measurements to irrigated uses and hydroenergy.

DEVELOPMENT OF SNOW FORECAST IMPROVEMENT BENEFIT MODELS

Irrigation Benefit Model

Most existing techniques for estimating benefits employ empirically based linear programming techniques. The Soil Conservation Service (SCS) has developed a linear programming method (Reference 11) which computes the benefits of improved streamflow forecasting to irrigation. The SCS has tested this technique for three key project areas in the Western U.S.: the Salt River Project in Arizona, the Owyhee Project in Oregon-Idaho and the Clarks Fork area in Montana.

A crop-specific linear programming model was generated for each site. Specific inputs included: the water requirements per acre of crop, the levels of irrigation, existing limitations on regional crop acreages, the typical regional crop mix, the dollar value of respective crops, and availability of land. Model outputs are net revenues and optimal acreages for various levels of water availability.

This model is based on three fundamental assumptions; that farm operators are motivated by the goal of profit maximization; that the study area is not so large that it "drives" prices in general in the economy; and that supplies of inputs other than water and irrigable lands are not restricted.

The SCS chose eight representative crops for each project area: it used 1973 prices derived from 1976 U.S. Water Resources Council data. The model estimates potential maximum benefits of improved forecast to irrigation.

The locus of the optimal revenue for 100% accurate forecast is determined by computing an optimal mix and acreage of crops at each indicated water supply level. Families of curves are constructed for various forecast levels. The results of the SCS procedure are illustrated in Figure 3 for the Salt River Project. This Figure is read in the same manner as Figure 2.

ECOsystems adapted the SCS's site specific model to create a more generalized benefit model. The ECOsystems model permits the estimation of irrigation benefits, obviating the need for specific linear programming at each site.

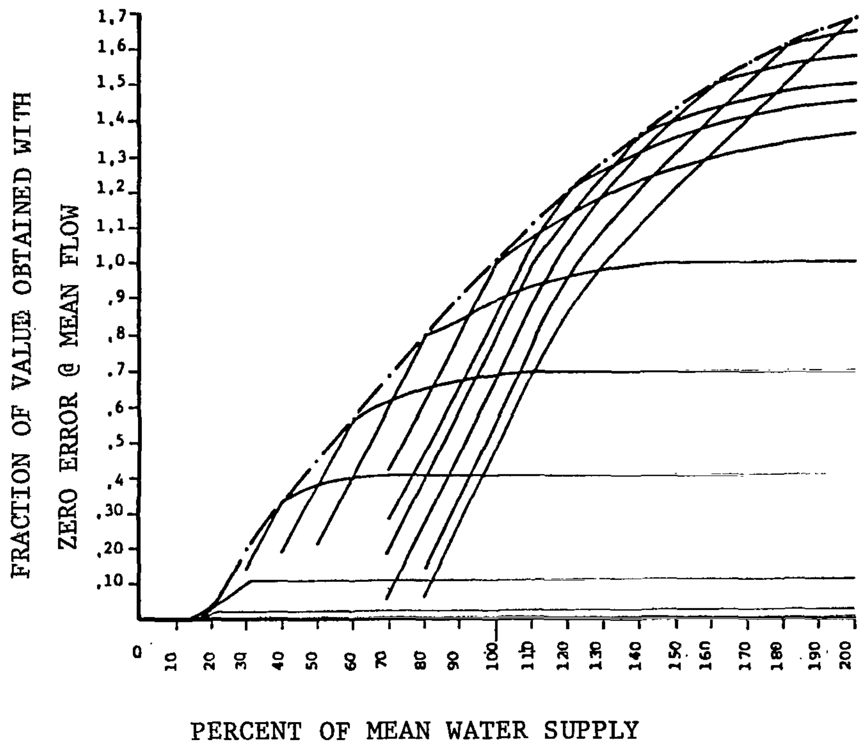

Figure 3. Salt River Project irrigated agriculture value relationship for a stochastic water supply

The SCS technique was generalized by normalizing the results of the SCS Salt River Project simulation. The value of forecast improvement is the difference between the benefit loss calculated for the existing and improved forecast performance level. The benefit loss is given in Figure 4 as the difference of value obtained for a perfect forecast and that obtained for the actual quantities of water experienced. This disbenefit determination assumes optimum response by agricultural managers to water supply forecasts.

The total value of crops produced at mean flow and with perfect forecast was normalized to the total number of irrigated acres for the Salt River Project for the base year 1973 chosen for the SCS simulation. The revenue was normalized by the revenue adjustment factor q, the ratio of the average revenue per irrigated acre for new sites under study to the revenue of Salt River in 1973 = $7.50/acre.

$$q = \frac{I}{B} \qquad [2]$$

where:

I = The average revenue per irrigated acre at new site

B = The average crop revenue per irrigated acre of the Salt River Project in 1973

The value lost due to any level of forecast is computed from equation [3] using the relationship graphically presented in Figure 4.

$$V_L = \alpha\ q\ A\ k \qquad [3]$$

where:

V_L = Value lost due to forecast error

α = Annual fraction of normalized value lost (obtained from Figure 4 for a given forecasted percent of mean flow and realized percent of mean flow).

q = Revenue adjustment factor

A = The irrigated acreage for the geographical location and base year

k = Average added value due to irrigation i.e. for the Salt River Project with a perfect forecast at mean flow as determined by the SCS model = $268.90

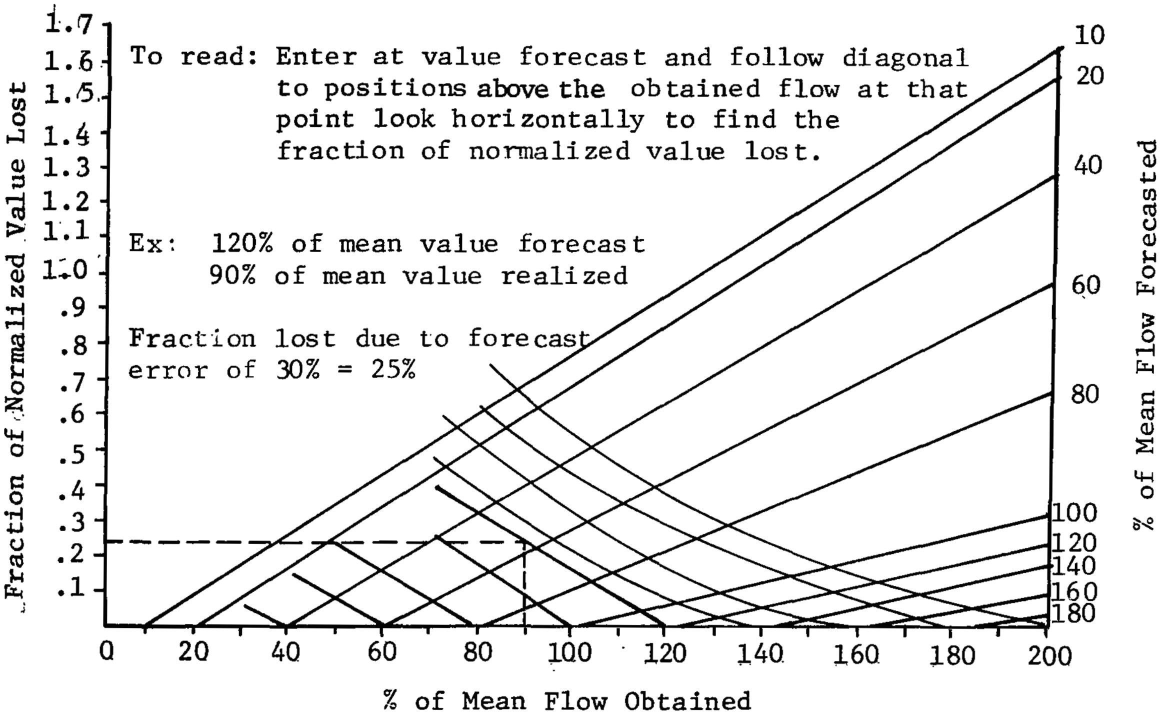

Figure 4. Graph for the calculation of the value lost at the Salt River Project under stochastic water supply conditions

* Note Value lost (expressed as a fraction of the value obtained with zero error @ mean flow)

The aggregation of the benefits to the Western States required a further modification of this technique to permit the use of available data; variability of streamflow, variance of the forecast error and reported per acre revenue for irrigated lands.

Forecasted and realized water quantities were synthesized using available statistics of forecast accuracy and streamflow variability for a significantly long period of record.

The value of improved forecasting, equation [4], is determined by the difference in the average annual value foregone under current accuracies and the average annual value foregone under the improved accuracies.

$$V_{IF} = \frac{\sum_{n=1}^{N} \left[\alpha \left[R_n, F_{n1}\right] - \alpha \left[R_n, F_{n2}\right] \right]}{N} \quad q \quad A \quad (268.9) \qquad [4]$$

where:

V_{IF} = Average annual value of improved forecasting

$\alpha\, [R_n, F_{n1}]$ = Fraction of normalized value lost using a forecast of F_{n1} and a realized water supply of R_n

$\alpha\, [R_n, F_{n2}]$ = Fraction of normalized value lost determined from a forecast of F_{n2} and a realized water supply of R_n.

q = Revenue adjustment factor

A = Irrigated acres

F_{n1} = Forecasted water supply for year n under current accuracy conditions

F_{n2} = Forecasted water supply for year n under projected accuracy conditions, given by

$$F_{n2} = \left[(F_{n1} - R_n) \quad (1 - \beta) \right] + R_n \qquad [5]$$

where:

β = The fractional decrease in forecast error expected from employing SATSCAM

Simulated yearly values of realized and forecast flow are determined by random process using the following:

$$R_n = 100 \left[1 + \left(N_n \bullet \frac{\sigma_{SF}}{\mu_{SF}} \right) \right] \qquad [6]$$

$$F_n = R_n \left[1 + \left(G_n \bullet \frac{\sigma_{FC}}{100} \right) \right] \qquad [7]$$

where:

R_n = The obtained percent of mean flow for year n

F_n = The forecasted percent of mean flow for year n

N_n = A normally distributed random number with mean of zero and σ of 1

G_n = A normally distributed random number with mean of zero and σ of 1

σ_{SF} = Standard deviation of streamflow

μ_{SF} = Mean streamflow

σ_{FC} = Standard deviation of % forecast error

The available data from the Owyhee Project was used as a test case. The mean annual value lost by irrigated agriculture at Owyhee was evaluated using a coefficient of variation of streamflow (standard deviation ÷ mean) of 0.39 and a standard deviation of the forecast % error of 23.6%; where % error is calculated as (Forecast - Obtained) ÷ Obtained, as computed from the SCS data. Table 6 presents the results of a simulation run of 20 years.

The mean yearly value lost computed for the twenty years of synthetic sequence was $950,700: in close agreement with the values calculated from "true" data.

As a further test, the generalized benefit assessment technique was applied to five irrigation projects sited throughout the Western U.S.;

1) Klamath, California
2) Humboldt, Nevada
3) Big Thompson, Colorado
4) Boise, Idaho
5) Lower Yellowstone, Montana

Table 6
Summary of the Calculation of the Mean Value Lost at the Owyhee Project Using the Modified SRP Simulation Results and Synthesized Forecasted and Realized Water Supplies[1]

$q = .45$ $A = 109,884$

n	F_n	R_n	α	Value lost = αqA (268.9 \$/A)
1	127	137	.04	531,860
2	56	75	.12	1,595,581
3	104	107	.01	132,965
4	87	124	.18	2,393,372
5	50	42	.05	664,826
6	86	135	.24	3,191,163
7	58	52	.04	531,860
8	101	99	.01	132,965
9	50	60	.06	797,791
10	111	93	.13	1,728,547
11	189	155	.13	1,728,547
12	30	37	.05	664,826
13	90	117	.13	1,728,547
14	86	85	.01	132,965
15	95	96	0	0
16	126	126	0	0
17	52	43	.04	531,860
18	77	99	.11	1,462,616
19	59	68	.05	664,826
20	127	134	.03	398,895
mean annual value lost = \$950,700				

Initial tests on these five projects indicate that approximately twenty, twenty year simulations are required to assure convergence to a stable average annual value of forecast improvement. This is exemplified in Figure 5 for California's Klamath Irrigation Project. The figure also illustrates that faster and smother convergence can be accomplished by averaging the accumulated averages of individual sequences. In this case 99% convergence is accomplished by sequence 10 at an annual benefit of $162,000 for a 10% forecast improvement.

The program allows the selection of the forecast improvement factor as a fixed value or as a string of parametric values. Required inputs are: 1) average crop value per acre; 2) total acreage covered by the project; 3) CV of the flow; and 4) standard deviation of the % forecast error. Outputs for the five projects indicated are presented in Tables 7 thru 11.

The results of the simulations are summarized in Figure 6, and indicate the percentage in the value of crops per percent increase in forecast accuracy. The relationship is linear over the 0-10% range characteristics of the expected level of improvement of SATSCAM.

A multiple regression and correlation of the percent increase in crop value at the five test sites against the coefficient of variation of streamflow and the standard deviation of forecast error for a 10% increase in forecast accuracy was performed. The results of the analysis are given in the following equation.

% increase in benefit = -0.275 (CV of streamflow) + 2.402 (standard deviation of forecast error) + 0.031

The partial correlation coefficient for the standard deviation of forecast error is 0.992; the partial correlation coefficient for the coefficient of variation of observed streamflow is -0.692.

Strong correlation exists between values generated by the regression equation and simulation results ($r = 0.998$). The standard deviation of the percent forecast error appears to be the dominant parameter for predicting the potential percent increase in crop value that can result from a forecast improvement.

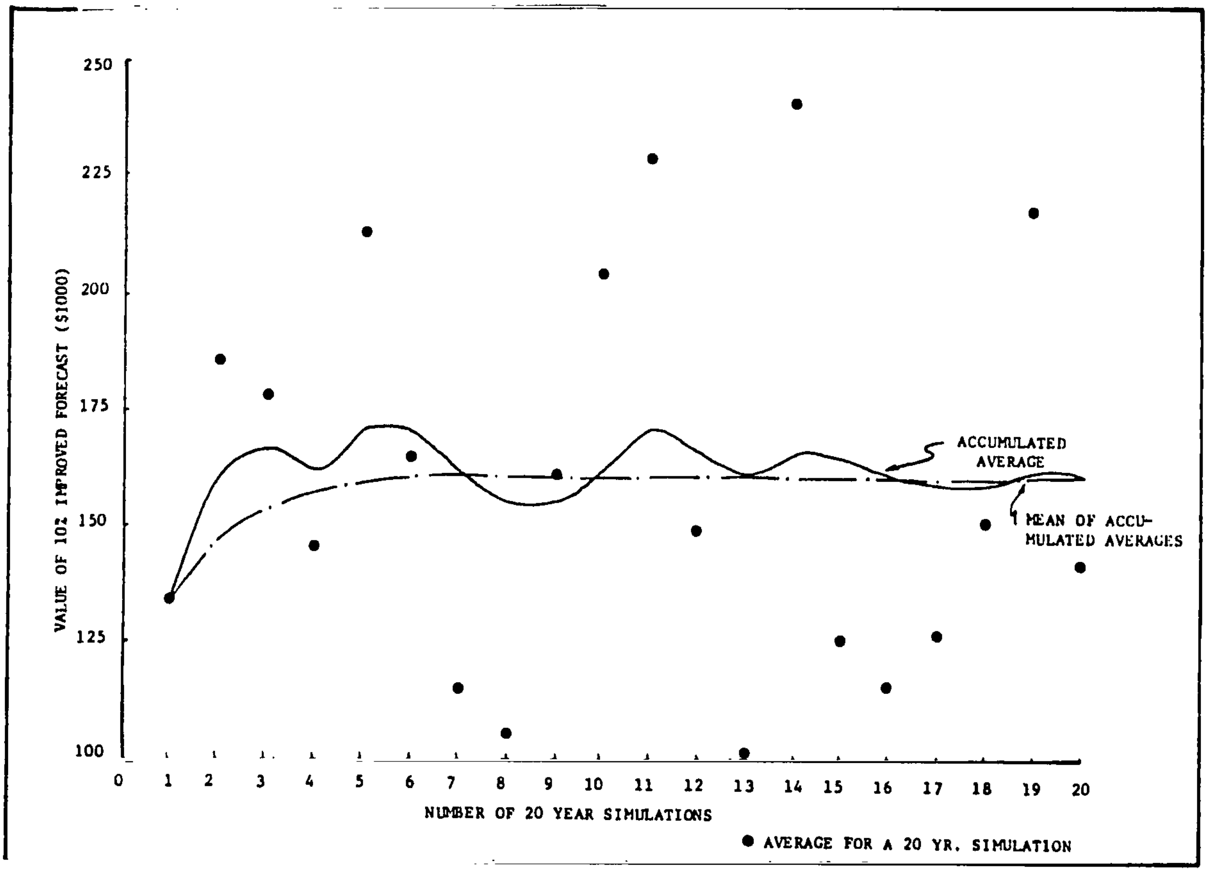

Figure 5. Convergence to the average annual value of a 10% forecast Improvement at the Kalamath Irrigation Project in California

Table 7
Valcon Irrigation Benefit Model Input and Output for
Lower Yellowstone, Montana

```
MONTANA, LOWER YELLOWSTONE

       VALCON
ENTER NUMBER OF SIMULATION STRINGS
□:
       20
ENTER FRACTIONAL IMPROVEMENT
□:
       .02 .04 .06 .08 .1
ENTER SIMULATION LENGTH IN YEARS
□:
       20
ENTER AVE. CROP VALUE PER ACRE
□:
       257.52
ENTER ACREAGE
□:
       29372
ENTER CV OF STREAMFLOW
□:
       .20
ENTER SIGMA OF FORECAST ERROR
□:
       .118
THE AVERAGE VALUE OF 2PERCENT IMPROVEMENT IS
3841.695856
THE AVERAGE VALUE OF 4PERCENT IMPROVEMENT IS
7645.440232
THE AVERAGE VALUE OF 6PERCENT IMPROVEMENT IS
11438.90071
THE AVERAGE VALUE OF 8PERCENT IMPROVEMENT IS
15224.33008
THE AVERAGE VALUE OF 10PERCENT IMPROVEMENT IS
19017.75267
```

Table 8
Valcon Irrigation Benefit Model Input & Output for Humboldt, Nevada

```
NEVADA, HUMBOLT


       VALCON
ENTER NUMBER OF SIMULATION STRINGS
□:
       20
ENTER FRACTIONAL IMPROVEMENT
□:
       .02 .04 .06 .08 .1
ENTER SIMULATION LENGTH IN YEARS
□:
       20
ENTER AVE. CROP VALUE PER ACRE
□:
       221.85
ENTER ACREAGE
□:
       32887
ENTER CV OF STREAMFLOW
□:
       .65
ENTER SIGMA OF FORECAST ERROR
□:
       .524
THE AVERAGE VALUE OF 2PERCENT IMPROVEMENT IS
15678.38937
THE AVERAGE VALUE OF 4PERCENT IMPROVEMENT IS
31471.48873
THE AVERAGE VALUE OF 6PERCENT IMPROVEMENT IS
47315.38752
THE AVERAGE VALUE OF 8PERCENT IMPROVEMENT IS
63436.06404
THE AVERAGE VALUE OF 10PERCENT IMPROVEMENT IS
79389.18667
```

Table 9
Valcon Irrigation Benefit Model Input & Output for Big Thompson, Colorado

```
COLORADO, BIG THOMPSON


          VALCON
ENTER NUMBER OF SIMULATION STRINGS
□:
          20
ENTER FRACTIONAL IMPROVEMENT
□:
          .02 .04 .06 .08 .1
ENTER SIMULATION LENGTH IN YEARS
□:
          20
ENTER AVE. CROP VALUE PER ACRE
□:
          342.92
ENTER ACREAGE
□:
          658720
ENTER CV OF STREAMFLOW
□:
          .32
ENTER SIGMA OF FORECAST ERROR
□:
          .23
THE AVERAGE VALUE OF 2PERCENT IMPROVEMENT IS
225795.453
THE AVERAGE VALUE OF 4PERCENT IMPROVEMENT IS
448872.6957
THE AVERAGE VALUE OF 6PERCENT IMPROVEMENT IS
669118.7319
THE AVERAGE VALUE OF 8PERCENT IMPROVEMENT IS
886563.0713
THE AVERAGE VALUE OF 10PERCENT IMPROVEMENT IS
1102930.928
```

Table 10
Valcon Irrigation Benefit Model Input & Output for Boise, Idaho

```
IDAHO, BOISE


      VALCON
ENTER NUMBER OF SIMULATION STRINGS
⎕:
      20
ENTER FRACTIONAL IMPROVEMENT
⎕:
      .02 .04 .06 .08 .1
ENTER SIMULATION LENGTH IN YEARS
⎕:
      20
ENTER AVE. CROP VALUE PER ACRE
⎕:
      269.67
ENTER ACREAGE
⎕:
      336590
ENTER CV OF STREAMFLOW
⎕:
      .38
ENTER SIGMA OF FORECAST ERROR
⎕:
      .178
THE AVERAGE VALUE OF 2PERCENT IMPROVEMENT IS
69730.10196
THE AVERAGE VALUE OF 4PERCENT IMPROVEMENT IS
139040.0714
THE AVERAGE VALUE OF 6PERCENT IMPROVEMENT IS
207540.2976
THE AVERAGE VALUE OF 8PERCENT IMPROVEMENT IS
275542.3284
THE AVERAGE VALUE OF 10PERCENT IMPROVEMENT IS
343105.6917
```

Table 11
Valcon Irrigation Benefit Model Input and Output for Klamath, California

```
CALIFORNIA, KLAMATH


          VALCON
ENTER NUMBER OF SIMULATION STRINGS
□:
          20
ENTER FRACTIONAL IMPROVEMENT
□:
          .02 .04 .06 .08 .1
ENTER SIMULATION LENGTH IN YEARS
□:
          20
ENTER AVE. CROP VALUE PER ACRE
□:
          280.34
ENTER ACREAGE
□:
          72114
ENTER CV OF STREAMFLOW
□:
          .35
ENTER SIGMA OF FORECAST ERROR
□:
          .35
THE AVERAGE VALUE OF 2PERCENT IMPROVEMENT IS
32744.68379
THE AVERAGE VALUE OF 4PERCENT IMPROVEMENT IS
65269.33954
THE AVERAGE VALUE OF 6PERCENT IMPROVEMENT IS
97729.78416
THE AVERAGE VALUE OF 8PERCENT IMPROVEMENT IS
129888.5819
THE AVERAGE VALUE OF 10PERCENT IMPROVEMENT IS
161856.4659
```

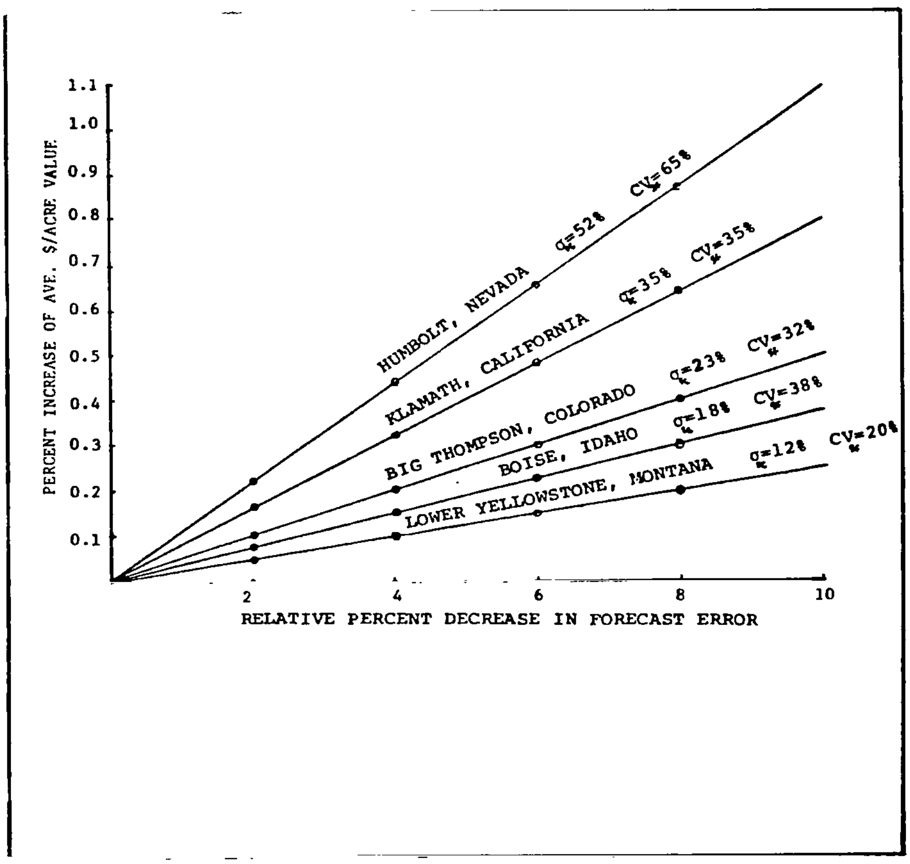

Figure 6. Potential percent increases in the average $/acre value of crops at selected Irrigations Projects in the Western U.S. resulting from increases in forecast accuracy.

Combining the results of the regression and using the linearized relationship of the value of improved forecasting to small forecast improvements the following relationship was developed to determine the value of improvements in forecasting at an irrigation project:

$$V_{IF} = \frac{(-0.275\ CV_{SF} + 2.402\ \sigma_{FC} + 0.31)\ A\ I\ B}{1,000} \qquad [8]$$

where:

V_{IF} = The value of improved forecasting at a project ($)

CV_{SF} = Coefficient of variation of streamflow at the project

σ_{FC} = Standard deviation of percent forecast error at the project

A = Total irrigated area at the project

I = Average revenue per irrigated acre at the project ($/acre)

B = Percent increase in forecasts accuracy (<10%)

To compare the results of the equation with the previous simulation results, the relationship was applied to the Colorado Big Thompson Project for a forecast improvement of 2%. The average annual value of $223,837 obtained differs by less than 1% from the value obtained by simulation.

Computerization of Irrigation Model

A computer model, based on the relationship given in equation [8], was developed to facilitate the analysis of the potential irrigation benefit due to SATSCAM. The APL computer code is listed in Appendix D. The required data inputs include: 1) improvement in forecast accuracy due to SATSCAM; 2) existing forecast accuracy; 3) streamflow variability; 4) irrigated acreage which would potentially benefit from this improvement; and 5) the average annual crop value/acre on these irrigated lands. The model's outputs are estimated current values of improved forecasting.

The computer model was designed to calculate the current benefits to improved forecasting for the irrigated acreage within each subregion and a single aggregate value of the total benefit for all the subregions considered.

Data Base Development

Empirical data were obtained from many sources. The individual ASVT personnel and local hydrologic experts were the primary sources for the collection of accurate, up-to date data required for the exercise of this benefit model.

Estimation of the benefit to irrigation from SATSCAM required the assembly of two extensive data bases: one for the basic characterization of the subregions which are impacted by snow survey forecasting and the second to provide the data inputs for the irrigation simulation model. These data contain geographically specific information at as fine a level of granularity as is presently available and consistent with the total area covered.

The Snow Survey Forecast Unit of The Soil Conservation Service provided data on average streamflow variation, and forecast accuracy for 361 primary snow survey forecast points covering the 11 Western States. Twenty additional forecasts points with the supporting data were obtained from the California Department of Water Resources (CDWR). A listing of this data and regional maps showing the location of these snow survey forecasts points are presented in Appendix A.

Flow weighted values of streamflow CV and 1σ forecast error were calculated for each U.S.G.S. 1974 hydrologic region (Appendix D lists the computer programs used in this analysis). Regional values for these parameters are presented in Figures 7 & 8.

The range in streamflow variability from region to region illustrates the varying hydrologic characteristics of these major basins. The Pacific Northwest hydrologic region shows the smallest variability of streamflow at CV = 0.22 while the Lower Colorado shows the greatest variability of streamflow at CV = 1.15. Streamflow forecast errors also very considerably, with the lowest error (1σ) at 10.0% (California hydrologic region) and the highest error (1σ) at 89.9% (Lower Colorado hydrologic region).

The SCS data, the CDWR data, and other information obtained from hydrologic experts in each of the 11 Western States were used to identify the snow survey forecast impacted basin of the 11 Western States. The snow survey forecast impacted basins are presented in Figure 9. A total of 52 U.S.G.S. 1974 hydrologic subregions are partially or totally impacted by snow survey forecasts. Initially, the analysis of benefit was to be based on the sum of benefits at each individual irrigation project within the 11 Western States. Since there were no consistent, current data available at this granularity, irrigated acreage data were collected on a subregional basis.

According to the U.S.G.S. 1975 Water Use Survey (Reference 12), there are approximately 28M acres of irrigated land in the 11 Western States. Within the 52 subregions which have been identified as being snow survey impacted, approximately 20M irrigated acres can potentially benefit from an improvement in streamflow forecasting. These directly utilize surface water instead of ground water for the purpose of irrigation.

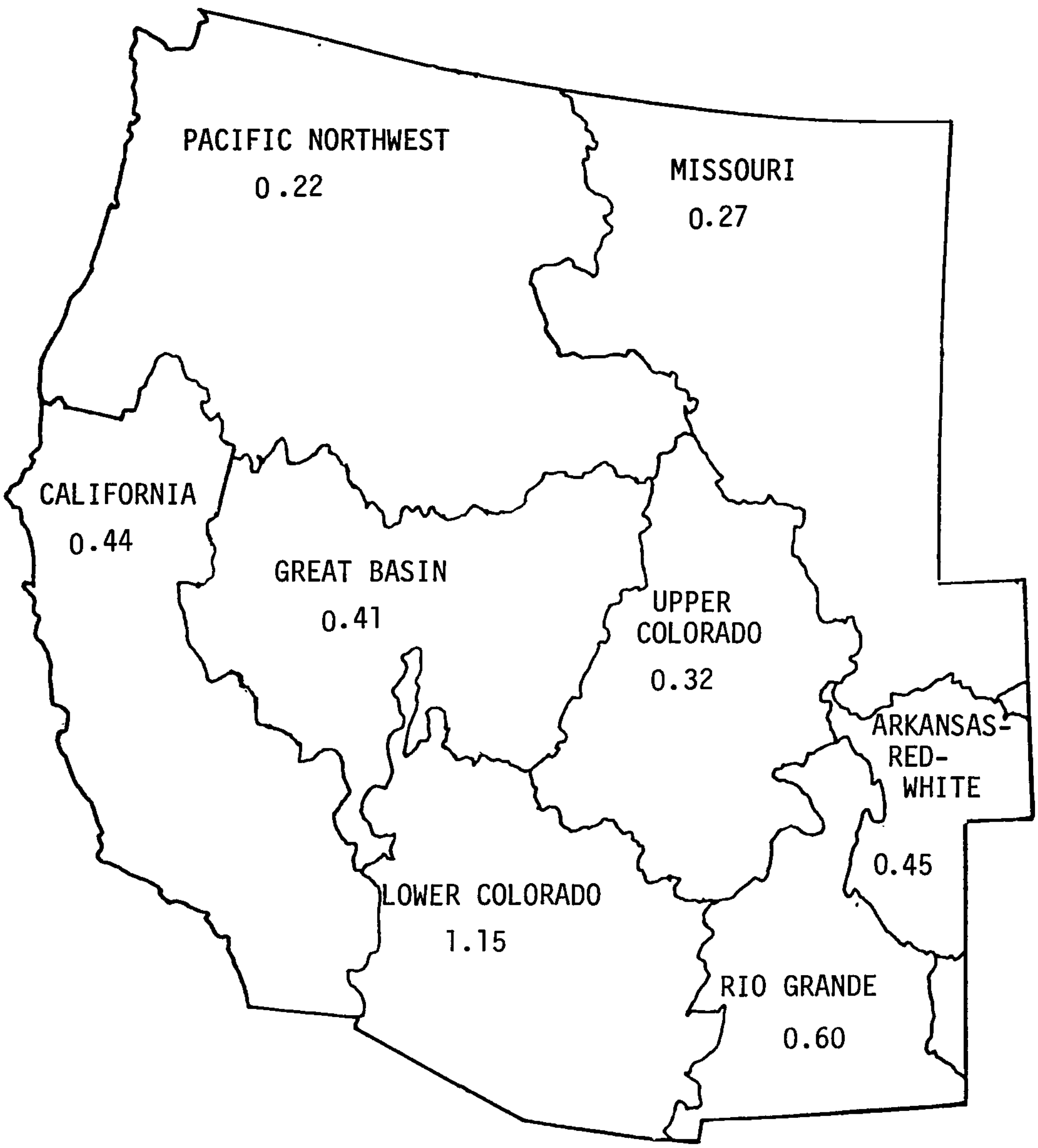

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Figure 7. Weighted coefficient of variation of streamflow, CV in the Eleven Western States by hydrologic region

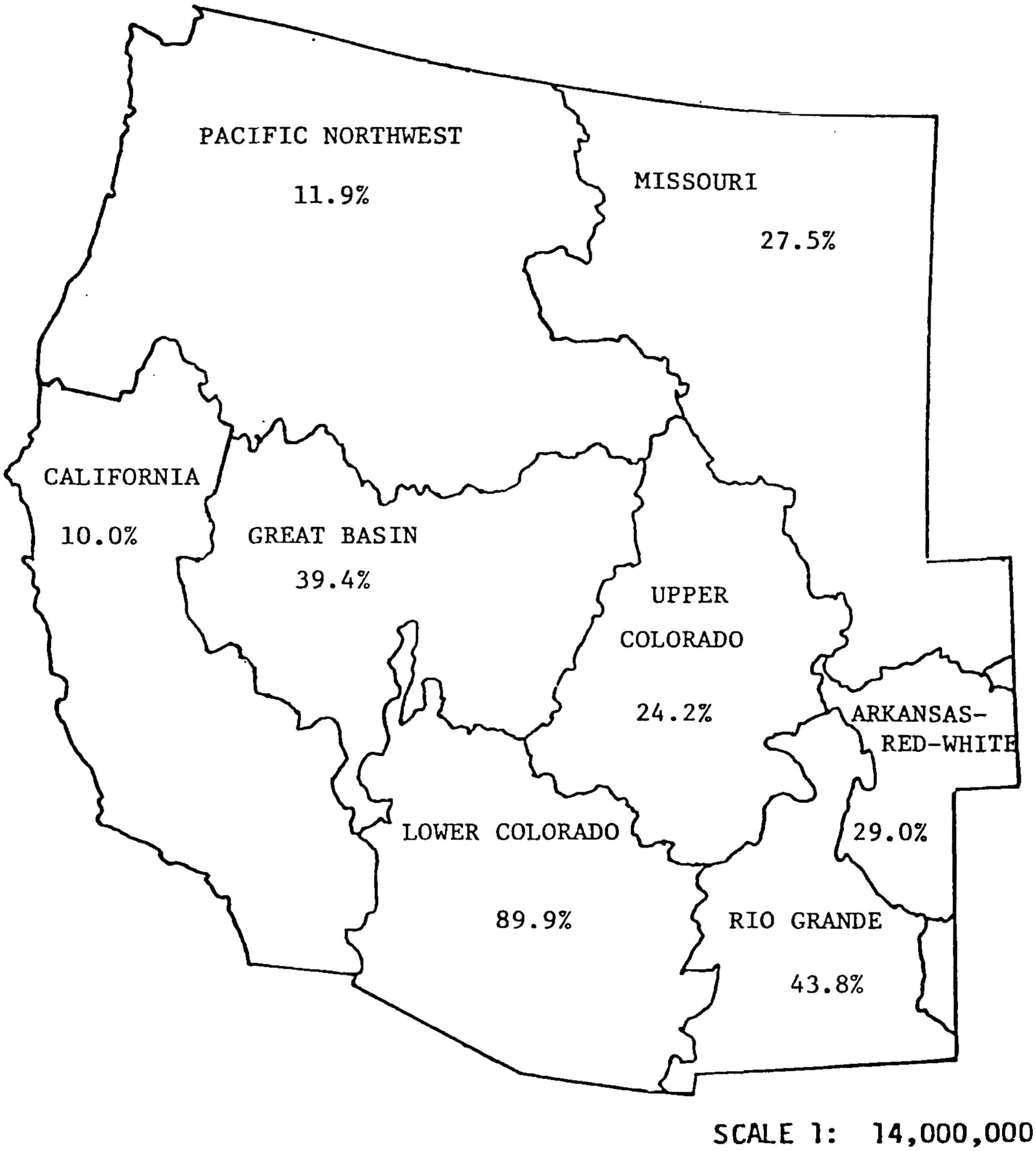


Figure 8. Weighted streamflow forecast error, 1σ (%), in the Eleven Western States by hydrologic region

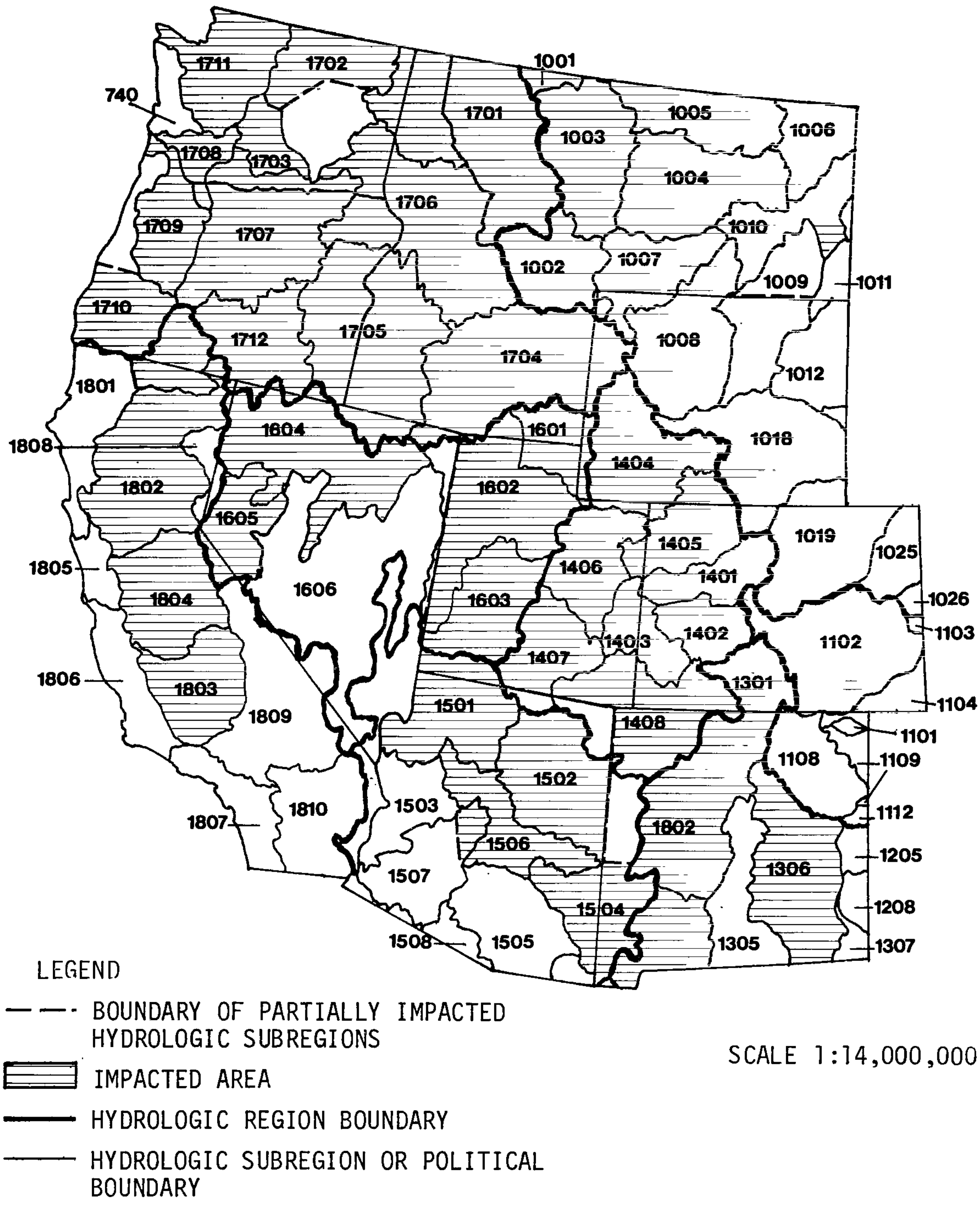


Figure 9. Snow survey forecast impacted areas of the Eleven Western States by U.S.G.S. hydrologic subregion

The total acreage of irrigated lands which could potentially benefit from improvement in forecast accuracy is presented on a regional basis in Figure 10. Three hydrologic regions account for 80.1% of the total 20M acres: the Pacific Northwest (29.5%) the Missouri (30.9%) and the California (19.7) Of the remaining five regions in the Western States, no one region contains more than 1.8M acres of snow survey impacted, surface water-irrigated land.

Appendix B lists irrigation data on a subregional basis. It also graphically illustrates the cumulative distribution of surface water-irrigated acreage in the 11 Western States by snow survey impacted subregions.

The estimated average annual crop values per acre were extrapolated from 1976 crop value/acre statistics (Reference 13) of the Bureau of Reclamation for each of its irrigation projects, and were used to produce an area weighted annual crop value/acre for each snow survey impacted subregion. Figure 10 also shows the area-weighted average crop value/acre for each hydrologic region. Appendix B lists surface water-irrigated acreage and estimated average normal crop value/acre in the 11 Western States on a subregional basis.

The crops grown on approximately 75% of the impacted surface water-irrigated lands were estimated as being valued at less than $300 /acre. In the Lower Colorado hydrologic region, the estimated crop value was as high as $642/acre. The estimated crop values were generally higher on lands located within those hydrologic regions whose relative variability of streamflow was high.

Improvement in Streamflow Forecast Accuracy Due to SATSCAM

An additional data input into the irrigation model is the improvement in streamflow forecast accuracy due to SATSCAM. Mr. Jack Washichek and Mr. Bernard Shafer of the Colorado ASVT site indicated that comparison of forecasts prepared with and without SCAM can eventually quantify improvement attributable to SATSCAM. They indicated that 5 to 10 more years are required to extend the period of record of SATSCAM data and to finalize this evaluation.

At this time, they estimate, based upon years of operational forecasting experience and the currently available record of SATSCAM data, that a 6% to 10% relative improvement in forecasting is reasonable to expect from the operational use of SATSCAM.

In order to obtain a conservative estimate of the benefit due to the operational application of satellite snowcover observations a 6% relative forecast improvement was utilized.

Irrigation Benefits

The above described inputs were used in the computer model analysis of the value of operational application of SATSCAM to irrigation. The computed annual benefit to irrigation from forecast improvements due to SATSCAM was $26.5M/yr. The computed total benefit and benefit per surface water-irrigated acre to each impacted subregion are presented in Table 12. An example of computer printouts used to create Table 12 is illustrated in Appendix D.

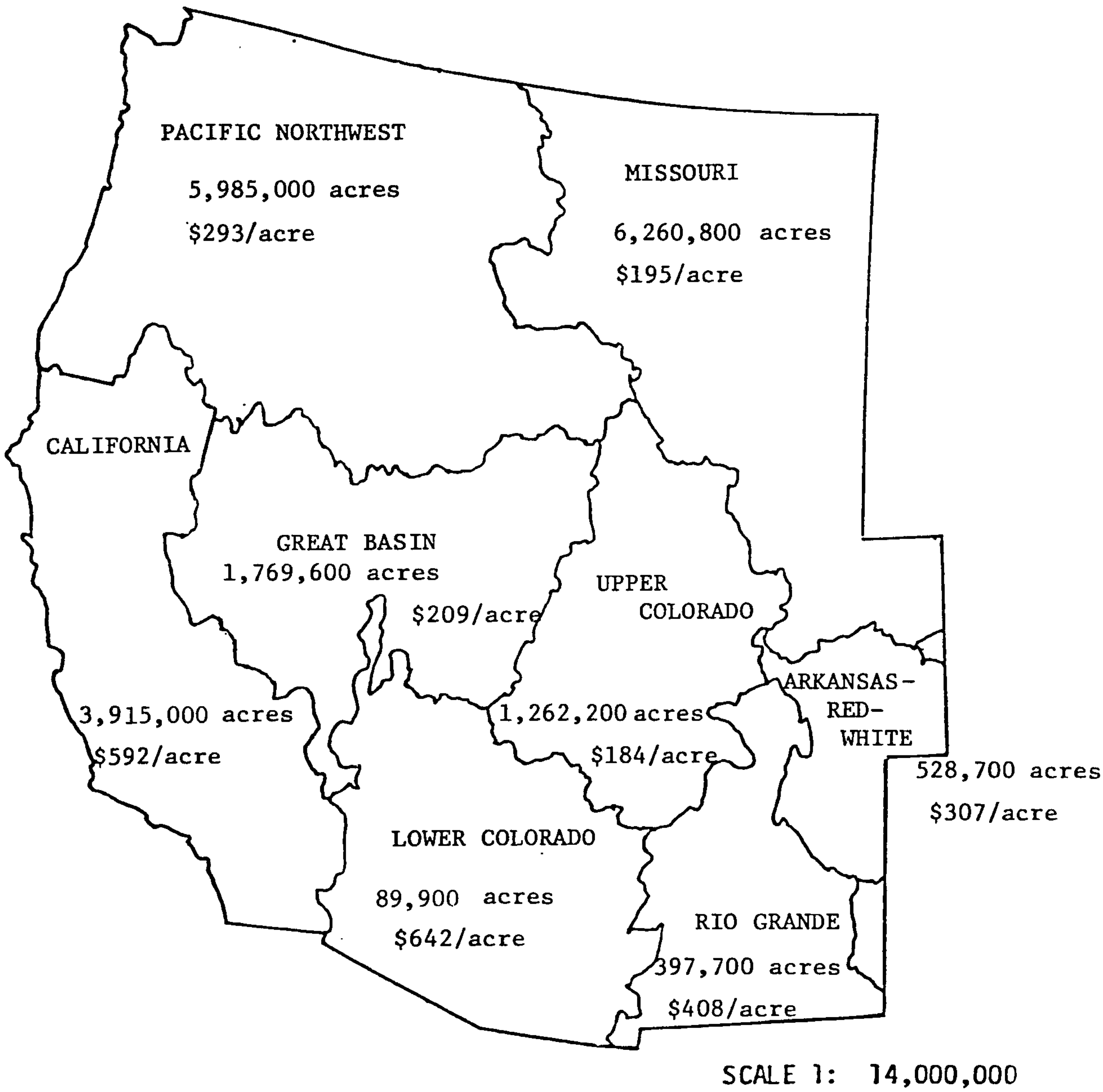


Figure 10. Surface water irrigated acreage and its average crop value ($/acre) in the Eleven Western States by hydrologic region

Table 12
Benefit of Improvement in Snow Survey Forecasting Due to SATSCAM Assessed In Relation to the Economic Value of Irrigated Crops

U.S.G.S. Hydrologic Units				
Region	Subregion		Total Benefit ($)	Benefit/Surface Water Irrigated Acre ($/Acre)
Missouri	1001		0	0
	1002		499,180	0.85
	1003		361,940	0.74
	1004		448,360	0.79
	1005		113,070	0.52
	1006		453,940	0.79
	1007		255,720	0.60
	1008		699,300	1.38
	1009		185,700	1.44
	1010		1,934,700	1.33
	1018		833,770	1.32
	1019		1,326,200	1.96
		Total	7,111,900	1.14
Arkansas Red-White	1102		895,040	1.69
		Total	895,040	1.69
Rio Grande	1301		258,750	1.35
	1302		47,600	2.74
	1303		981,160	8.58
	1306		147,789	1.99
		Total	1,435,299	3.61

Table 12 (Cont'd)
Benefit of Improvement in Snow Survey Forecasting Due to SATSCAM Assessed In Relation to the Economic Value of Irrigated Crops

U.S.G.S. Hydrologic Units: Region	Subregion		Total Benefit ($)	Benefit/Surface Water Irrigated Acre ($/Acre)
Upper Colorado	1401		203,150	1.28
	1402		200,200	1.48
	1403		75,558	1.52
	1404		121,030	0.37
	1405		231,660	1.04
	1406		100,000	0.48
	1407		54,714	1.21
	1408		97,050	0.83
		Total	1,083,400	0.86
Lower Colorado	1501		45,041	2.08
	1502		79,685	9.96
	1504		293,920	10.77
	1506		261,350	12.33
	1507		82,340	7.35
		Total	762,340	8.53
Great Basin	1601		306,210	1.11
	1602		1,164,400	1.53
	1603		254,970	1.35
	1604		785,660	2.84
	1605		242,220	0.90
		Total	2,753,500	1.56
Pacific Northwest	1701		137,600	0.32
	1702		464,780	1.21
	1703		1,016,700	1.91
	1704		2,043,000	1.04
	1705		1,430,700	1.25

Table 12 (cont't)
Benefit of Improvement in Snow Survey Forecasting Due to SATSCAM Assessed In Relation to the Economic Value of Irrigated Crops

U.S.G.S. Hydrologic Units Region	Subregion		Total Benefit ($)	Benefit/Surface Water Irrigated Acre ($/Acre)
Pacific Northwest (con't)	1706		234,660	1.25
	1707		26,995	1.45
	1708		26,995	1.45
	1709		505,670	3.71
	1710		6,669	2.30
	1711		230,780	1.64
	1712		392,230	1.74
		Total	6,979,400	1.17
California	1801		549,660	1.47
	1802		623,540	0.73
	1803		2,619,700	1.65
	1804		1,663,000	1.51
			5,455,860	1.39

Total Benefit over the Eleven Western States $26,476,739

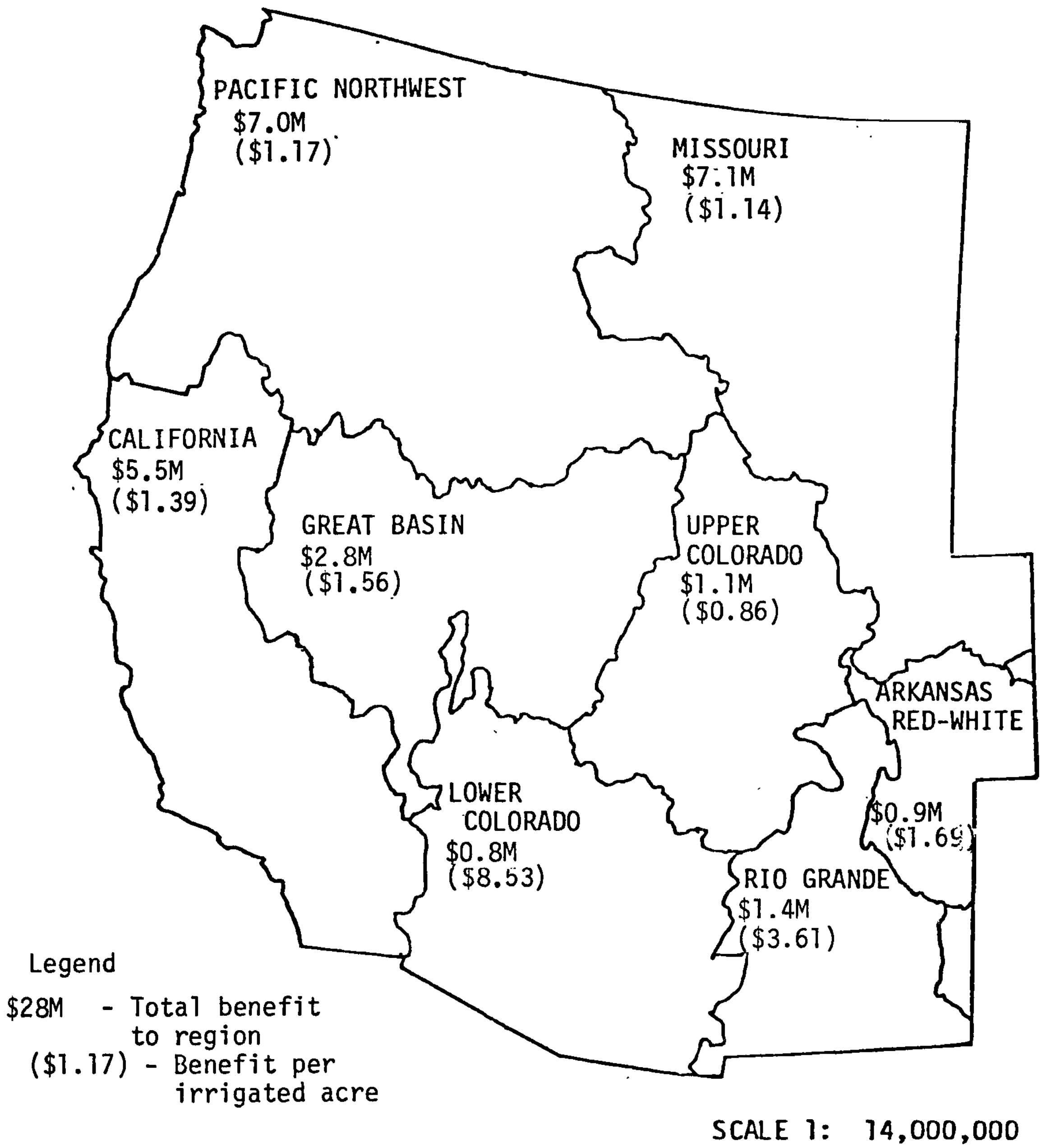


Figure 11. Annual benefit of SATSCAM to irrigated agriculture in the Western U.S. by hydrologic region

Figure 11 illustrates the total benefit and benefit per surface water-irrigated acre summarized for each hydrologic region. The regional irrigation model input data and the resultant regional benefits are presented in Table 13.

Three hydrologic regions account for 74% of the total potential benefit to irrigation. The Pacific Northwest region potentially receives \$7.0M/year, the Missouri region receives \$7.1M/year, and the California region receives \$5.5M/year. These three regions receive this large proportion of the total agricultural benefit because they contain most of the cropland irrigated by surface water. As previously mentioned, 29.5% of this land is located in the Pacific Northwest region, 30.9% is located in the Missouri region, and 19.7 is located in the California region.

The two regions that receive the greatest benefit/acre are the Lower Colorado with \$8.53/acre and the Rio Grande with \$3.61/acre. This high benefit/acre is the combined result of the high average annual value/acre of the crops planted on these lands and the current forecast accuracy in these basins. The estimated average annual crop value/acre is \$642/acre in the Lower Colorado and \$408/acre in the Rio Grande. The current forecast error (1σ) in these two regions is 89.9% and 43.8%, respectively.

Hydroenergy Benefit Model

For a utility which contracts hydroenergy sales at prime rates, excess water results in disbenefits from sales below prime rates; deficit water results in losses because contracted demand must be satsified by alternative generation at higher cost.

The curve of maximum potential revenue versus water supply, shown in Figure 12 as line A, is the locus of sales contracted at prime rates:

$$R = C \quad Q_F \quad G \qquad [9]$$

where:

- R = Value of water at average rate charged for hydroenergy
- Q_F = % of mean annual water supply forecasted
- G = Average annual generation WH per % of mean annual supply
- C = Average price charged for hydroenergy, \$/KWE

For a forecasted % of mean flow Q_F, the expected energy is $E_F = Q_F G$: the corresponding expected revenue is $R_F = C\ E_F$.

Table 13
Summary of the Regional Irrigation Data and Benefit due to the Operational Application of SATSCAM in the Eleven Western States

U.S.G.S. HYDROLOGIC REGION	BENEFIT ($M)	BENEFIT/ ACRE ($/ACRE)	% TOTAL IM-PACTED IRRI-GATED ACREAGE	EST. AVER. ANNUAL CROP VALUE/ACRE ($/ACRE)	STREAMFLOW FORE-CAST ERROR σ (%)	COEFFICIENT OF STREAMFLOW VAR-IATION C_V (%)
Missouri	7.1	1.14	30.9	195	27.5	27.0
Arkansas Red-White	0.9	1.69	2.6	307	29.0	45.0
Rio-Grande	1.4	3.61	2.0	408	43.8	60.0
Upper Colorado	1.1	0.86	6.2	184	24.2	32.0
Lower Colorado	0.8	8.53	0.4	642	89.9	115.3
Great Basin	2.8	1.56	8.7	209	39.4	40.5
Pacific Northwest	7.0	1.17	29.5	293	11.9	22.2
California	5.5	1.39	19.7	592	10.0	44.3

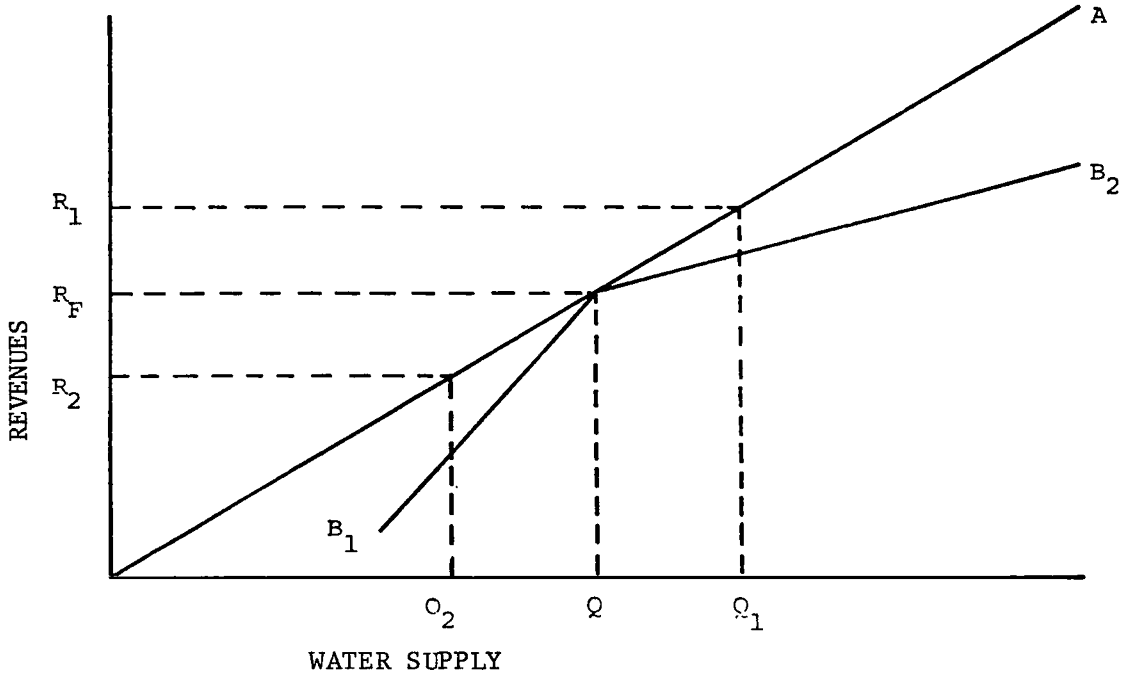


Figure 12. Conceptual model of sales revenues under stochastic water supply conditions

If the forecast is too low, the available water (Q_1) exceeds that expected by $\Delta Q1 = Q_1 - Q_F$. The potential revenue at $Q_1 = R_1 > R_F$. However, the "perfect" utility can only sell the excess energy at a rate $C_1 < C$. Thus, the actual revenue will be $R_F + C1 \; \Delta Q1 \; G$, as per curve B_1 in Figure 2. The corresponding benefit loss (L_B) is:

$$L_B = (C - C_1) \; \Delta Q_1 \; G \qquad [10]$$

If the forecast is too high, the available water is less (Q_2) than that expected by $\Delta Q_2 = Q_F - Q_2$. Total contracted sales cannot be met by hydroenergy production: the deficit must be supplied by higher cost alternate means of generation. The added cost defines the loss of benefit.

With reference to Figure 12, the potential revenue at Q_2 is R_2. The revenue achieved is computed by subtracting from R_2 the added cost of producing the deficit by alternate means:

$$B_2 = C \; Q_F \; G - (C_2 - C) \; \Delta Q_2 \; G \qquad [11]$$

where:

B_2 = Hydroenergy revenue obtained when the forecasting supply of water is greater than the realized supply.

C_2 = Price charged for electric energy generated by alternate means

The annual value of improved forecasting is the difference between the average annual loss of value at current accuracies and the average annual loss of value under the improved accuracies.

The average annual benefit of improved forecast is computed for each site as the average of a simulated sequential record. This is constructed from site-specific values of current forecast accuracy and variability of streamflow. The economic value of the forecast improvement is expressed by:

$$V_{IF} = \frac{\sum_{n=1}^{N} \left[h \; (F_{n1}) - h \; (F_{n2}) \right]}{N} \qquad [12]$$

where:

V_{IF} = Value of improved forecasting to hydropower

$h(F)$ = Value evaluation function given by:

$$h(F) = (R_n - F)\ (P_1 - P_2);\ R_n > F$$

$$h(F) = (F - R_n)\ C_A\ G - P_1;\ R_n < F$$

P_1 = Average rate charged for prime hydroelectric power (guaranteed power)

P_2 = Average rate for secondary hydroelectric power (non-guaranteed power)

C_A = Cost of power production by alternate means (assumed thermal-electric for this study)

G = Average annual generation = average generation percent of mean annual flow

R_n = Simulated observed annual streamflow for year n, in % of mean annual flow given by:

$$R_n = 100\ [1 + (J_n\ \cdot\ CV_{SF})]$$

J_n = A normally distributed random number with mean of zero and σ of 1

F_{n1} = Simulated forecasted annual streamflow for year n under current accuracy conditions, as % of mean annual streamflow given by:

$$F_{n1} = R_n \left[1 + (G_n\ \cdot\ \frac{\sigma_{FE}}{100})\right]$$

G_n = A normally distributed random number with mean of zero and σ of 1

F_{n2} = Forecasted water supply for year n under improved accuracy conditions, given by:

$$F_{n2} = (F_{n1} - R_n)\ (1 - \beta) + R_n$$

β = The fractional decrease in forecast error expected from employing satellite SCAM

CV_{SF} = Coefficient of variation of the streamflow

N = Number of years simulated

σ_{FE} = Standard deviation of the forecast error

The hydroenergy benefit model assumes that the error in forecast is normally distributed with zero mean and standard deviation σ_{FE}. Private discussions with Jack Hannaford of Sierra Hydrotech indicate the normal approximation is a good fit to the data; the frequency of underforecasting approximately equals that of overforecasting.

The standard or typical error of estimation (error with 50% chance of being exceeded) is given by 0.67 x σ_{FC}. Therefore, the value of improved forecast can be simplified to:

$$V_{IF} = 0.67\ \sigma_{FE}\ G\ C\ \beta \qquad [13]$$

where:

V_{IF} = Value of improved forecasting to hydropower

σ_{FE} = Standard deviation of % forecast error

G = Average annual generation

C = Mean of the difference in prime and secondary hydropower tariffs and the difference in hydroelectric and steam-electric production costs given by:

$$C = (P_1 - P_2) - (C_S - C_H)$$

P_1 = Tariffs charged for prime energy

P_2 = Tariffs charged for secondary energy

C_S = Cost of producing steam-electric

C_H = Cost of producing hydroelectric energy

β = The fractional decrease in forecast error expected from employing satellite SCAM

Available data for each site can be used in an analogous manner to the stochastic simulations described in the section for irrigation benefits. The expected potential value of the benefit of forecast error improvement for hydroelectric energy production can be determined for specific or representative sites.

The method's advantage is threefold: it speeds the evaluation of the benefits; it exploits available empirical parameters; it is consistent with planning and marketing operations currently practiced in the Western States.

Computerization of Hydroenergy Model

The relationship, summarized in equation [13] forms the basis of the hydroelectric energy benefit computer model. This model is interactive, requiring input information on the level of forecast improvement, existing forecast accuracy, and streamflow variability. Other required inputs are average annual hydroelectric energy generation, hydroelectric and steam-electric production expenses, and the revenues obtained from the sale of prime and secondary energy. The model's outputs are estimated values of improved forecasting to hydroenergy for each subregion and the aggregate benefit to each region. The computer model is presented in Appendix D.

Data Base Development

In addition to the streamflow and forecast data for each snow survey impacted subregion, the analysis of the benefit of SATSCAM to hydroelectric energy required the development of another data base to provide the data inputs for the hydroelectric energy simulation model.

Electric energy data were acquired for the plants located within the 11 Western States as listed by the Federal Energy regulatory Commission (FERC), the Energy Information Administration (EIA) and the former Federal Power Commission (FPC). These data reorganized to a subregion basis, included: 1) 1978 average annual hydroelectric energy generation (MWH) (Reference 14); 2) current estimates of hydroelectric expenses (mills/KWH); and 3) current estimates of the revenues obtained from the sale of prime and secondary energy (mills/KWH). Production expenses, initially based on 1976 figures (References 15 & 16) and the energy sales revenue, initially based on 1975 figures (Reference 17), were adjusted for inflation. Data on the average annual hydroelectric energy generated within the 11 Western States, listed on a plant-by-plant basis, is presented in Appendix C. Also included in this appendix are hydroelectric and steam-electric production expenses on a plant-by-plant basis and revenues obtained from the sale of prime energy on a regional basis.

Approximately 180 terawatt-hrs of hydroelectric energy are generated annually by plants located within the 52 snow survey impacted subregions of the 11 Western States. The total average annual hydroelectric energy generation by hydrologic region is illustrated in Figure 13. The Pacific Northwest hydrologic region generates 73% of this hydroelectric energy. The 2nd largest hydroelectric energy producing region is California which accounts for 18% of the total annual generation. The Missouri and the Upper Colorado hydrologic regions generate approximately 3% and 2%, respectively.

According to the Energy Information Administration (EIA) data, the cost of producing hydroelectric energy varies considerably across the Western States. It is most expensive in those basins whose streamflow variability is relatively large compared to those whose streamflow variability is relatively small. In 1976 hydroelectric energy production costs of Lower Colorado were 2.23 mills/KWH, while those of the Pacific Northwest were 0.39 mills/KWH. The coefficient of variation of streamflow, CV, in the Lower Colorado is roughly 1.15 while that of the Pacific Northwest is roughly 0.22. Regional energy production expense data are presented in Figure 14.

The cost of producing steam-electric energy similarly varies. Data (1976) obtained from the EIA indicates that production expenses were least in the Upper Colorado (5.95 mills/KWH) and the Pacific Northwest (6.65 mills/KWH) regions and greatest in the California region (22.67 mills/KWH).

The mean difference between these expenses was 11.43 mills/KWH (1976) over the 11 Western States. The minimum difference between these expenses was 5.45 mills/KWH in the Upper Colorado and the maximum difference between these expenses was 21.55 mills/KWH in the California Region. Adjusted for inflation in production expenses since 1976, the corresponding mean difference was 13.83 mills/KWH.

The revenues obtained from the sale of prime energy were obtained from statistics collected by the former Federal Power Commission on publicly owned electric utilities in the United States. Since this data was last published for 1975; the values were upgraded in relation to relative increases in the consumer price index (1.26) in order to reflect "current" values. These values are also presented in Figure 13.

Similar data for secondary energy were not available. Conversation with FERC personnel indicated that revenue for this are legally set at 85% of the cost of producing steam-electric energy.

Hydroelectric Energy Benefits

These inputs and the estimated 6% forecast improvement from the Colorado ASVT personnel were used in the computerized hydroelectric benefit model. The resulting computed average annual SATSCAM benefit was $10M/year for hydroenergy. This value is the sum of hydroenergy benefit calculated for each snow survey impacted subregion in the 11 Western States. The computed hydroelectric value of improved forecasting due to SATSCAM for each subregion is presented in

LEGEND

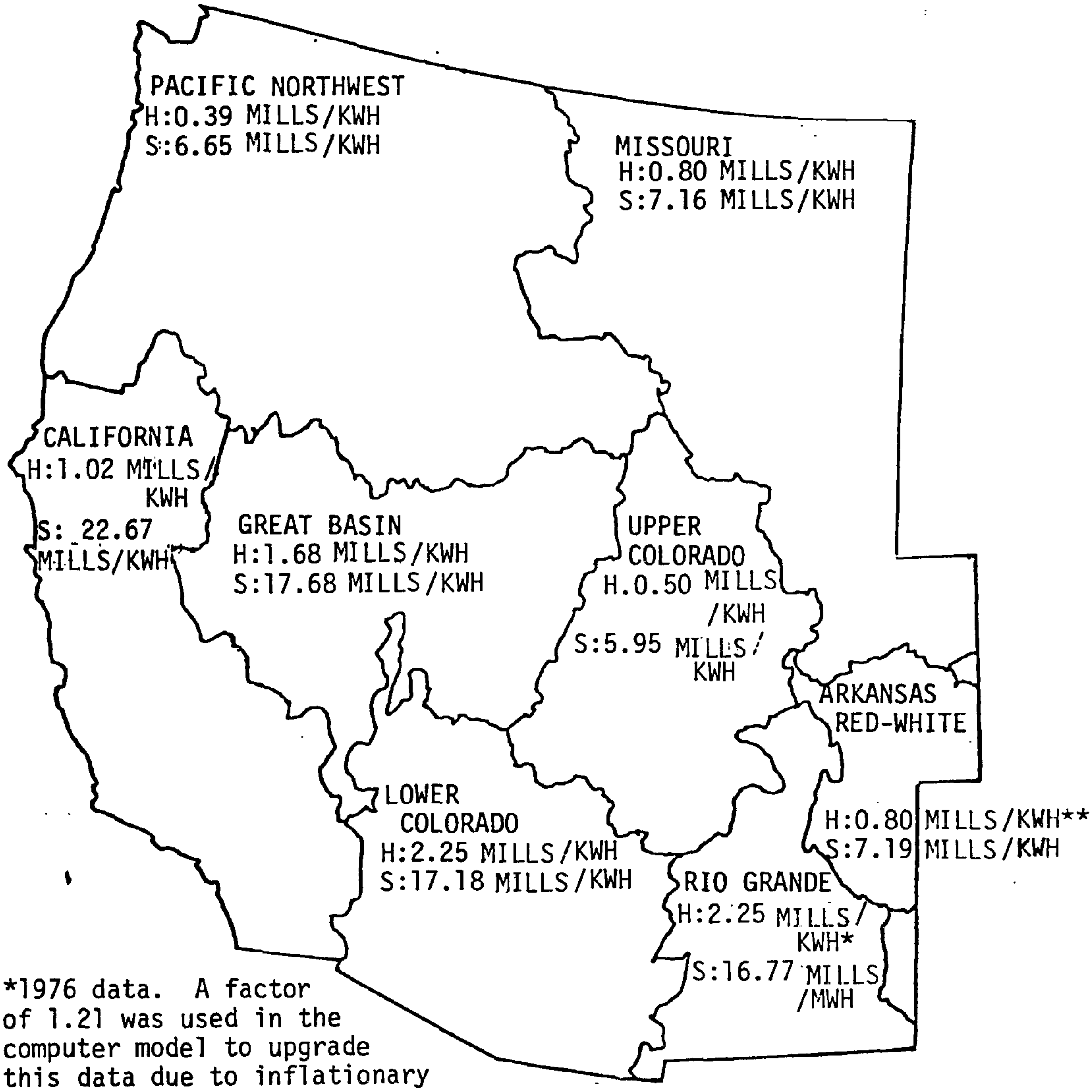
SCALE 1: 14,000,000

96,000 MWH - Total 1978 Average Annual Hydroelectric Energy Generation

28.9 mills/KWH - 1975 Revenues Obtained From The Sale of Prime Hydroenergy

(36.4 mills/KWH) - Current Revenues Inflationary Adjust Revenues Using an Inflationary Factor of 1.26

Figure 13. Average annual hydroelectric energy and revenues obtained from the sale of prime hydroelectric energy in the Eleven Western States by hydrologic region.



*1976 data. A factor of 1.21 was used in the computer model to upgrade this data due to inflationary rises in production expenses.

SCALE 1: 14,000,000

**These are rough indicies of hydro electric energy production expenses since no data was available for plant in these regions.

H = Unit hydrologic energy expenses S = Unit steam-electric energy expenses

Figure 14. Hydroelectric and steam-energy production expenses in the Eleven Western States by hydrologic region

Table 14. An example of the computer results used to generate Table 14 for one region are presented in Appendix D.

The annual benefit of SATSCAM to hydroelectric energy by region is presented in Figure 15. Also provided in this figure is the benefit/MWH of hydroelectric energy generated annually.

Table 15 presents the benefit of SATSCAM to hydroelectric energy, the benefit/MWH of energy generated, the percent of hydroelectric energy generated within each region, the current differences between prime and secondary hydroenergy tariffs and between hydroelectric and steam-electric production expenses, and the streamflow 1σ forecast error on a regional basis.

The Pacific Northwest with its heavy concentration of hydropower (132 terawatt-hours of generation annually or 73% of the total generation in the Western U.S.) receives the largest portion of the benefit (38% of the total), roughly twice that of California, the second largest energy producing region.

The Pacific Northwest also exhibits the smallest benefit per KWH of generation, 0.03 mills/KWH. This is primarily the result of the small difference between the revenues obtained for prime and secondary hydroelectric energy (3.62 mills/KWH). Other factors which cause the benefit per MWH to be low are the relatively small difference between hydroelectric and steam-electric production expenses (7.57 mills/KWH) and the relatively low forecast error in this region (11.9%).

The second highest beneficiary is the Lower Colorado, which has an average annual benefit of $2.1M. In this region, the difference between prime and secondary hydroelectric energy tariffs (18.07 mills/KWH, adjusted for inflation) and the difference between hydroelectric and steam-electric production expenses (15.33 mills/KWH, adjusted for inflation) are relatively high. This combined with the strong influence of a very high 1σ forecast error (89.9%) drives up the benefit/KWH of SATSCAM to 0.46 mills/KWH. Since the average annual hydroelectric energy generated in the Lower Colorado is on the order of 4.5 terawatt-hours, the computed annual benefit is relatively high.

Although the market of hydroelectric energy in the Rio Grande region is influenced by similar conditions, its computed total benefits differs significantly from that computed for the Lower Colorado. The Rio Grande's 1σ forecast error is relatively high and consequently the benefit/KWH value is also high (0.50 mills/KWH). Yet, the amount of hydroelectric energy generated in this region is very low (96,000 MWH/year); the total hydroelectric energy benefit potentially derived from the use of SATSCAM is low at 0.05M/year.

Table 14
Value of Improvement in Snow Survey Forecasting Due to SATSCAM Assessed In Relation to the Hdroelectric Energy Economic Market

U.S.G.S. Hydrologic Units Region	Subregion		Total Benefit ($)	Benefit/MWH Hydroelectric Energy ($/MWH)
Missouri	1001		0	0
	1002		7,446	0.15
	1003		337,114	0.16
	1004		158,519	0.18
	1005		0	0
	1006		0	0
	1007		5,012	0.09
	1008		237,083	0.21
	1009		0	0
	1010		0	0
	1018		122,546	0.17
	1019		143,213	0.18
		Total	1,010,933	0.17
Arkansas Red-White	1102		3,641	0.17
		Total	3,641	0.17
Rio Grande	1301		0	0
	1302		48,395	0.50
	1303		0	0
	1306		0	0
		Total	48,395	0.50

Table 14 (cont'd)
Value of Improvement in Snow Survey Forecasting Due to SATSCAM Assessed In Relation to the Hydroelectric Energy Economic Market

U.S.G.S. Hydrologic Units				
Region	Subregion		Total Benefit ($)	Benefit/MWH Hydroelectric Energy ($/MWH)
Upper Colorado	1401		26,531	0.10
	1402		143,956	0.20
	1403		1,879	0.17
	1404		106,615	0.16
	1405		0	0
	1406		1,611	0.12
	1407		834,527	0.21
	1408		4,542	0.21
		Total	1,119,661	0.20
Lower Colorado	1501		2,071,269	0.50
	1502		0	0
	1504		4,673	0.71
	1506		20,997	0.05
	1507		0	0
		Total	2,096,939	0.46
Great Basin	1601		63,598	0.19
	1602		29,255	0.14
	1603		11,203	0.42
	1604		0	0
	1605		8,737	0.11
		Total	112,793	0.24
Pacific Northwest	1701		342,960	0.03
	1702		1,247,451	0.02
	1703		5,040	0.03
	1704		102,180	0.04
	1705		325,356	0.05
	1706		474,569	0.04

Table 14 (cont'd)
Value of Improvement in Snow Survey Forecasting Due to SATSCAM Assessed In Relation to the Hydroelectric Energy Economic Market

U.S.G.S. Hydrologic Units Region	Subregion		Total Benefit ($)	Benefit/MWH Hydroelectric Energy ($/MWH)
Pacific Northwest (con't)	1707		779,217	0.02
	1708		102,436	0.03
	1709		143,796	0.05
	1710		104,222	0.06
	1711		132,923	0.03
	1712		0	0
		Total	3,760,150	0.03
California	1801		191,002	0.24
	1802		1,188,731	0.06
	1803		102,133	0.05
	1804		398,420	0.04
		Total	1,880,286	0.06

Total benefit over the Eleven Western States = 10,032,798

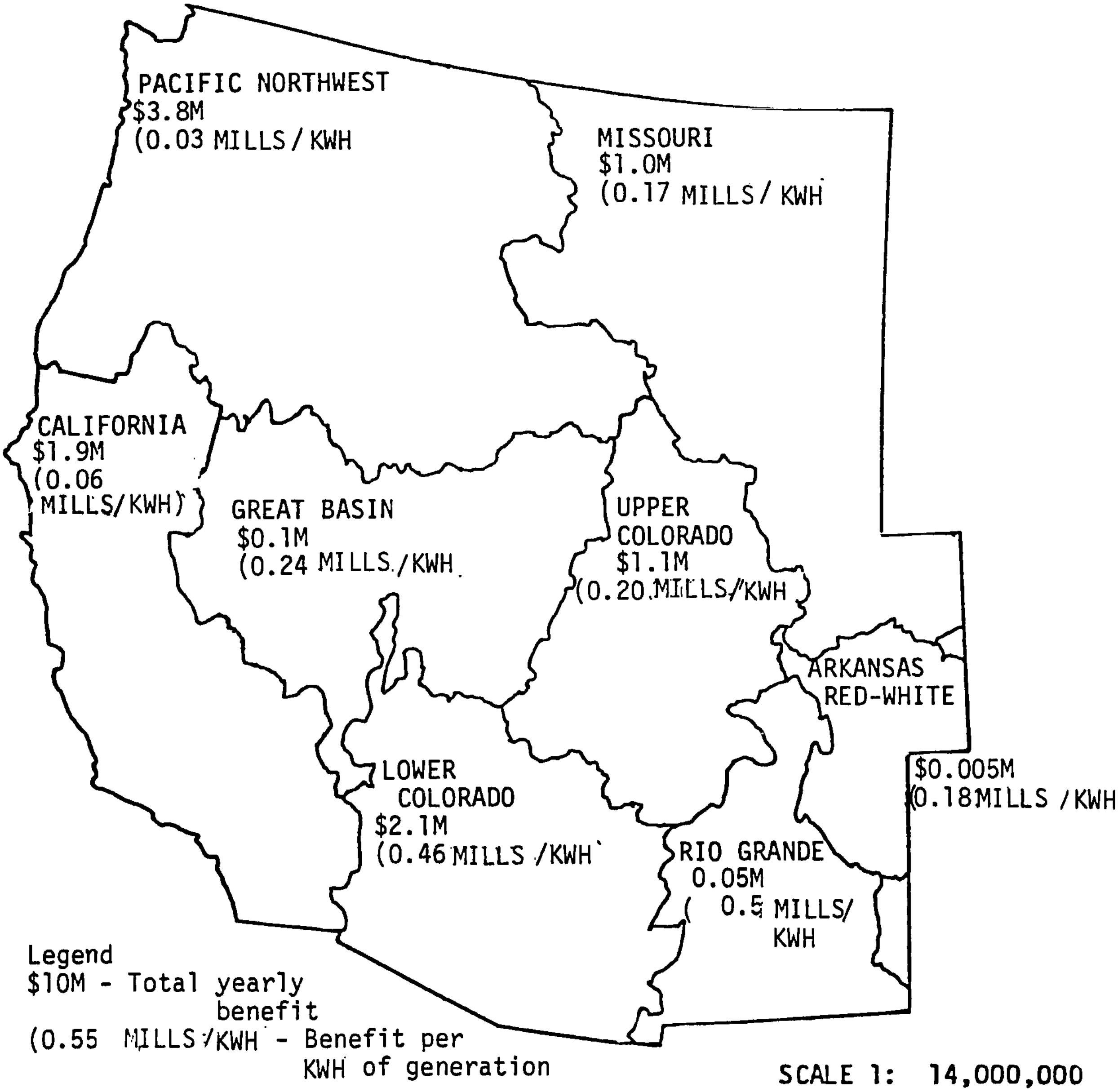


Figure 15. Annual benefit of SATSCAM to hydroelectric energy in the Western U.S. by hydrologic region

Table 15
Summary of Computed Hydroelectric Energy Benefit and Other Relevant Date By U.S.G.S. Hydrologic Region

U.S.G.S. Hydrologic Region	Benefit (V_{IF}) \$M	Benefit/MWH (\$/MWH)	1978 % of Total Hydroelectric Energy Production (%)	*Current Difference Between Hydroelectric & Steamelectric Energy Production Expense (Mills/KWH)	*Current Difference Between 1° & 2° Revenues From The SALE OF ENERGY (MILLS/KWH)	Streamflow Forecast Error 1σ (%)
Missouri	1.0	0.17	3.2	7.70	21.43	27.5
Arkansas-Red-White	0.05	0.18	<0.1	7.73	21.41	29.0
Rio Grande	0.1	1.03	0.1	17.57	19.16	43.8
Upper Colorado	1.1	0.2	3.2	6.50	23.89	24.2
Lower Colorado	2.1	0.46	2.5	18.07	15.33	89.9
Great Basin	0.1	0.24	0.3	19.36	4.36	39.4
Pacific Northwest	3.8	0.03	73.1	7.57	3.63	11.9
California	1.9	0.06	17.7	26.08	6.69	10.0

*Values shown have been adjusted for inflationary rises on production expenses (inflationary factor = 1.21) and sales revenues (inflationary factor = 1.26).

SATSCAM IMPLEMENTATION COSTS

The cost associated with operationally employing SATSCAM consists of four components: satellite data products, image interpretation, data implementation, and equipment. Costs associated with satellite research and development and with operational SATSCAM "start up" in a forecasting scheme have been considered sunk for purposes of these estimates.

The total cost for a given area of operationally employing SATSCAM in a forecasting scheme is given by the sum of the non-sunk components as:

$$C = C_{SDP} + C_{A} + C_{AP} + C_{E}$$

C = Total cost of operationally employing SATSCAM

C_{SDP} = Cost of satellite data products used

C_{A} = Cost of satellite data analysis

C_{AP} = Cost of incorporation analysis results into the forecasting scheme

C_{E} = Cost of equipment needed for analysis

An analysis of the magnitude of this cost was derived from data supplied by the Colorado ASVT.

The Colorado ASVT effort focused on six study watersheds covering a total area of 8876 km^2. Five Landsat frames were required to provide adequate basin coverage for each date. The forecast period during which SATSCAM was used extended from mid-March to mid-June. Eight observations (image dates) were used during this period. Using a Landsat per frame cost of $10, the total cost of image procurement was $400. Image interpretation for the six basins required 16 man-days per season and resulted in a total cost of $800. Implementing the data into the forecasting scheme required an additional 8 man-days/season of effort at a cost of $600. The total seasonal cost, exclusive of equipment was $1,800 or $0.20/$km^2$.

ASVT experience has shown the stereo viewing zoom transfer scope to be the most widely used and generally accepted basic piece of equipment required for performing operation snowcover mapping. This instrument was identified by Colorado ASVT personnel as being the primary piece of equipment utilized at their site. It provides the necessary scaling and distortion elimination capabilities required for the task. Bausch and Lomb, Inc., a leading company in the manufacturing and sale of zoom transfer scopes, indicates that the current market price of a zoom transfer scope is approximately $10,000. This price is indicative of a zoom transfer scope, with stereo viewing capability, which permits optical overlay of imagery onto a base map, and possessing a scaling capability from 0.6x to about 16x.

Marketing specialists at Bausch and Lomb were requested by ECOsystems to determine a reasonable equipment turnover or replacement rate upon which to base the period of amortization. It was indicated that while optical equipment such as the zoom transfer scope is designed to last 25 or more years without need of major reapir or replacement, a reasonable turnover rate would be on the order of 10 years. Equipment turnover sooner than 10 years was not considered to be cost effective. Hence, assuming an equipment utilization factor for the Colorado ASVT of 25% and amortizing the cost over 10 years, the annual equipment cost was computed as $250.

Adding the equipment cost to the $1,800 seasonal operations cost indicated by the Colorado ASVT brings the total annual cost of employing SATSCAM at the Colorado ASVT to $2050 or $0.23/km^2$.

Extrapolating to the 2,195,250 km^2 area impacted by snow-survey forecasting in the Western U.S., the total yearly cost of employing SATSCAM is approximately $505K.

SUMMARY AND CONCLUSIONS

The on-going Applications System Verification Study on the Operational Applications of Satellite Snowcover Observations covering the Western U.S. offered NASA the possibility of developing credible cost benefits derived from data supplied by operationally cognizant experts.

Under continuous interaction with and guidance by the ASVT experts ECOsystems developed an empirically-based benefit assessment technique which estimated the major benefit and cost drivers for 52 snow runoff impacted subregions over the Western States.

During the benefit model development process ECOsystems, with significant input and direction from the ASVT's, also accumulated and validated an up-to-date data base containing runoff, forecast accuracy, irrigation, and hydroelectric energy related data at a granularity sufficient to permit distributed modeling of benefits for the major uses of improved forecasts.

Over the life of this project, multiple ASVT site visits and some 80-100 phone conversations were held with ASVT personnel or with area experts identified by them to acquire the necessary data.

Under the assumption that the greater the gross value the greater the potential return from improved information, the concentration upon the two primary water use benefit areas of irrigation and hydroelectric energy stemmed from an upper bound analysis of the following major water uses:

- Hydroelectric Energy
- Irrigation
- Flood Control
- Navigation
- Recreation
- Fish and Wildlife

The gross value upper bound analysis showed that almost 87% of the total value inputed to water use from snow runoff can be assessed by addressing two major driver uses - hydroelectric energy and irrigation. The other uses, for example, municipal and industrial account for roughly 9%, flood damage accounts for roughly 4%, and the balance of the other uses are of the order <1% of the gross.

Since the result of improved snowcover area measurement is improved information, the bottom line technical question to be answered by the ASVT effort was the level of improvement in the forecast inputed to the addition of this new information.

Mr. Jack Washichek and Mr. Bernard Shafer of the Colorado ASVT projected a 6-10% relative improvement in forecasting based upon the Colorado ASVT operational forecasting experience. Since only limited results from the performance of present satellites are available specifying the improvement attributable to SATSCAM, they may not represent the full potential of near-future SATSCAM systems.

Limitations of the Use of SATSCAM Indicated by the ASVT's

Operational application of SATSCAM as an input into streamflow forecasting was limited by the lack of cloud-free, real-time, accurate data.

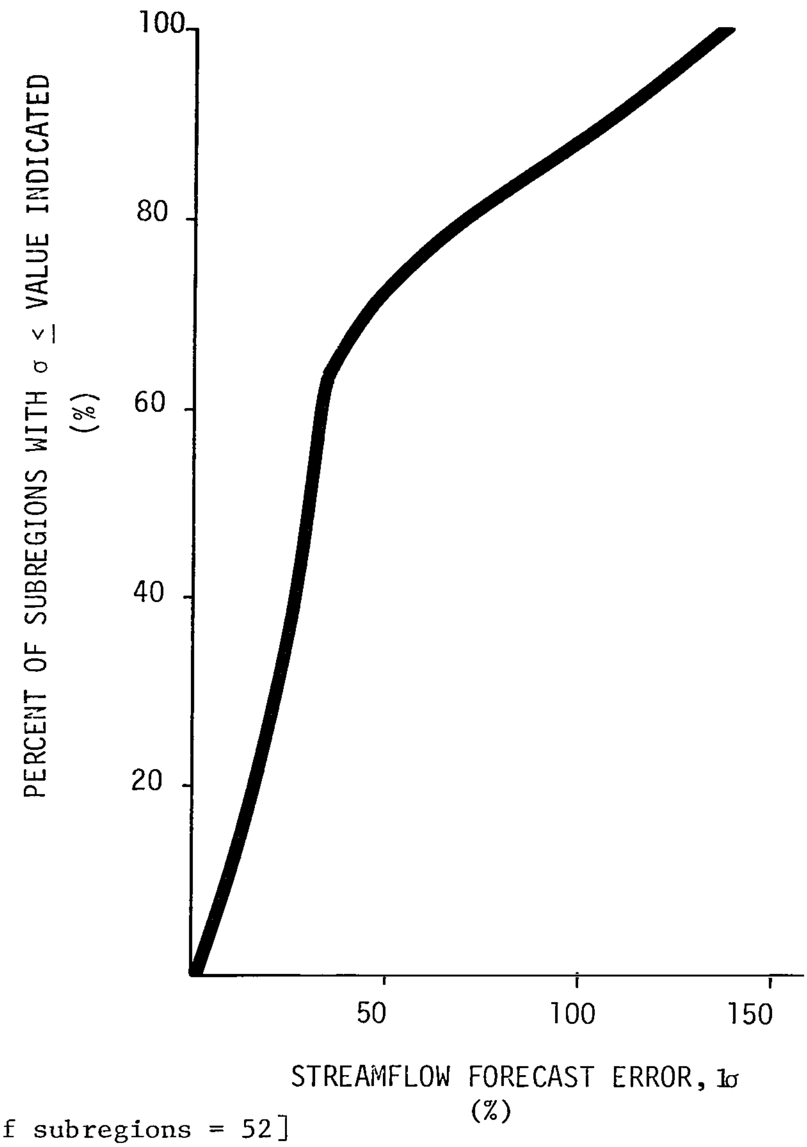
Standard Landsat imagery was not available in sufficient time. The average turnaround time for NASA was 10 days. Even the Canadian quick look imagery was not rapidly available due to delivery delays. Delays were as great as 5 days during the 1977 snowmelt season. Operational use as indicated by the ASVT's requires a turnaround time of three days.

Cloud obscuration presented a major problem, particulary in the Pacific Northwest. The cloud cover over the Upper Snake basin was so extensive during 1974 that it limited the number of usable Landsat images to 1 for a period of 54 days. This impact was magnified due to the return frequency of Landsat. Even with the frequent coverage afforded by the NOAA data, acquisition of usable data through cloud cover still remains a significant problem. During the snowmelt seasons of 1976 and 1977, 39 and 42 consecutive days respectively elapsed without a break in the cloud cover over the Upper Snake basin.

Although a method of analysis of partially cloud obscured images was developed by the Colorado Division of Water Resources and implemented by the Colorado ASVT, roughly 40% of the imagery received for the snowmelt periods under study were too cloud obscured to be evaluated by this or any other method.

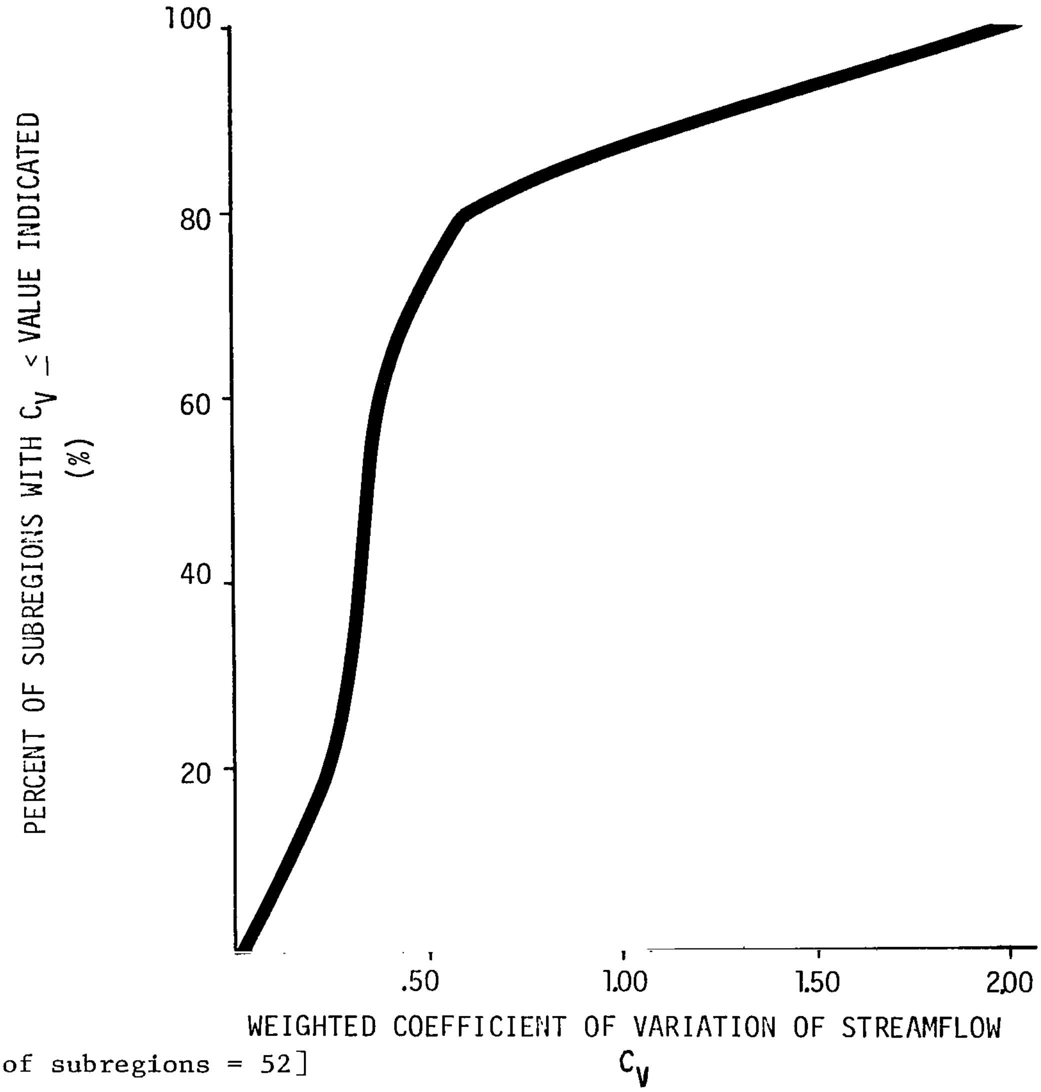
Summary of the Assessment of Irrigation Benefit

Figures 16 and 17 summarize the runoff variation and forecast errors for the 52 snow survey impacted subregions. Generally, the greater the streamflow variability and the greater the forecast error, the greater the relative impact on improvement from new information. The median coefficient of variation of streamflow was approximately 0.37; however, the upper percentile



[No. of subregions = 52]

Figure 16. Cumulative distribution of streamflow forecast error, 1σ (%) in the Eleven Western States by snow survey impacted subregions



[No. of subregions = 52]

Figure 17. Cumulative distribution of weighted coefficient of observation of streamflow, C_V, in the Eleven Western States by hydrologic region

displayed variabilities as high as 1.96. The regions whose rivers exhibited the greater variability of streamflow were the Lower Colorado (CV = 1.15), the Rio Grande (CV = 0.60), the California (CV = 0.44), and the Great Basin (CV = 0.41). The median of the 1σ forecast error for the 52 subregions was 30%; However, the upper percentile exhibited 1σ error of 140%. The regions which exhibit 1σ streamflow forecast errors greater than the mean of the Western U.S. were the Lower Colorado (89.9%), the Rio Grande (43.8%), and the Great Basin (39.4%).

The irrigation data base was developed from site specific evaluation made by local experts from the U.S.G.S. A total of approximately 20M acres of surface water-irrigated land was identified as potentially benefiting from improvement in streamflow forecasting.

The irrigated lands are distributed across the Western U.S. The cumulative frequency distribution of surface water-irrigated acreage by subregions is presented in Figure 18. The median acreage was roughly 260,000. The Pacific Northwest region, with 29.5% of the total 20M potentially affected acres, and the Missouri, with 30.9% of the total 20M acres, accounted for the largest benefit from an improvement in streamflow forecasting.

Figure 19 presents the cumulative distribution of the estimated average annual crop value/acre in the Western U.S. by snow survey impacted subregion. The median crop value was \$380/acre. The maximum crop values were \$895/acre in subregion 1506, \$915/acre in subregion 1504, and \$767/acre in subregion 1803. The minimum crop values were as low as \$71/acre in subregion 1404, \$76/acre in subregion 1005, and \$95/acre in subregion 1701. Those regions which grow the most highly valued crops are the Lower Colorado with \$642/acre, the California with \$592/acre, and the Rio Grande with \$408/acre.

The irrigation benefit was computed for each snow survey impacted subregion. The total yearly irrigation benefit for all 52 subregions was approximately \$26.5M. The subregion results are presented in Table 12; similar regional values are presented in Table 13. The three regions which would most benefit from this increase in forecast accuracy were the Pacific Northwest with 7.0M, the Missouri with \$7.1M and the California with \$5.5M.

The calculation of benefit per surface water-irrigated acre eliminates the effect of the uneven distribution of irrigated land. The largest benefit/irrigated acre accrued to the Lower Colorado (\$8.53/acre) and the Rio Grande (\$3.61/acre) regions. Intermediate unit benefit accrued to the irrigated lands in the Arkansas-Red-White (\$1.69/acre), the Great Basin (\$1.56/acre), the California (1.39/acre). The lowest per acre benefit accrued to the Pacific Northwest (\$1.17/acre), the Missouri (\$1.14/acre) and the Upper Colorado (\$0.86/acre) Regions.

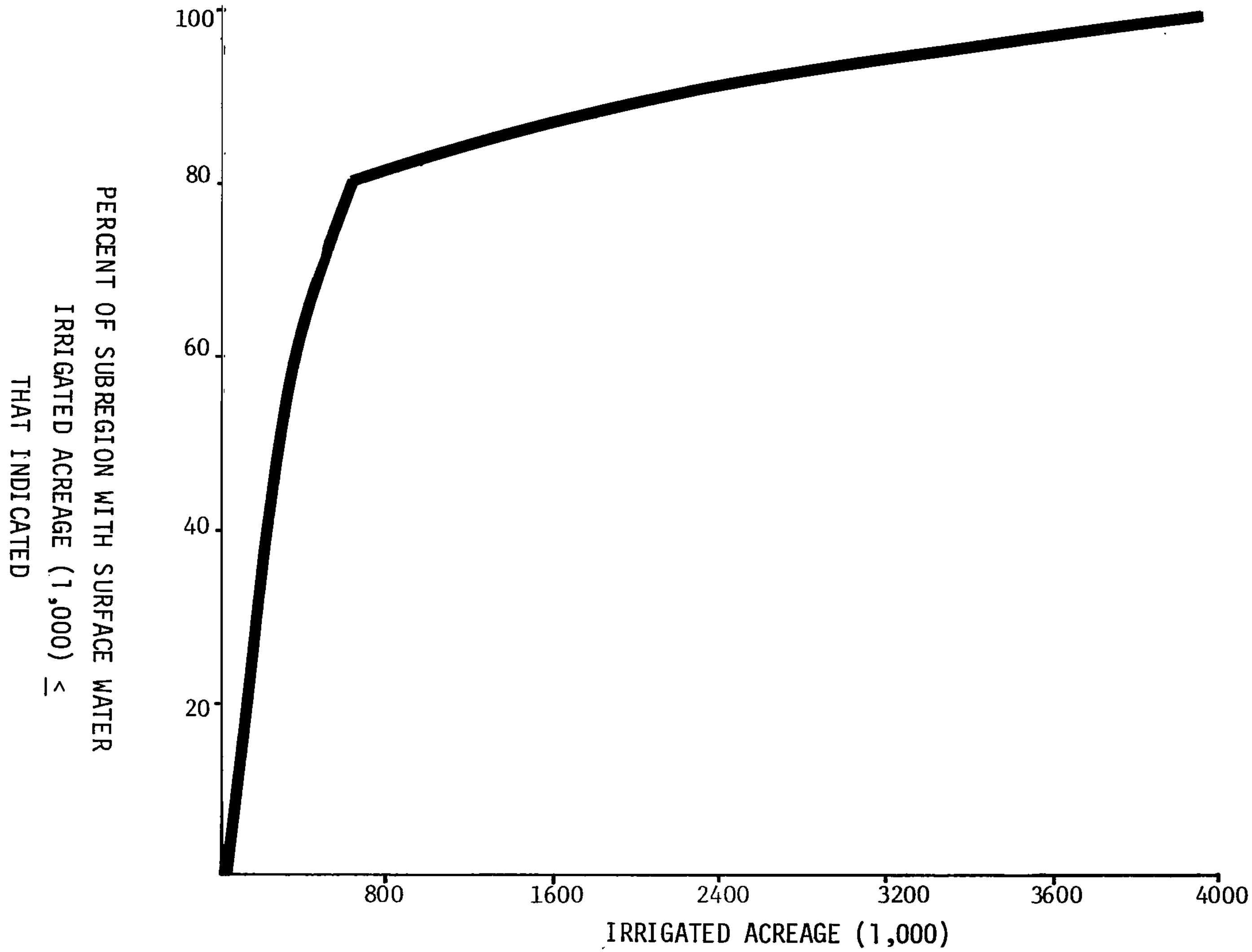


Figure 18. Cumulative distribution of surface water irrigated acreage (1,000) in the Eleven Western States by snow survey impacted subregions

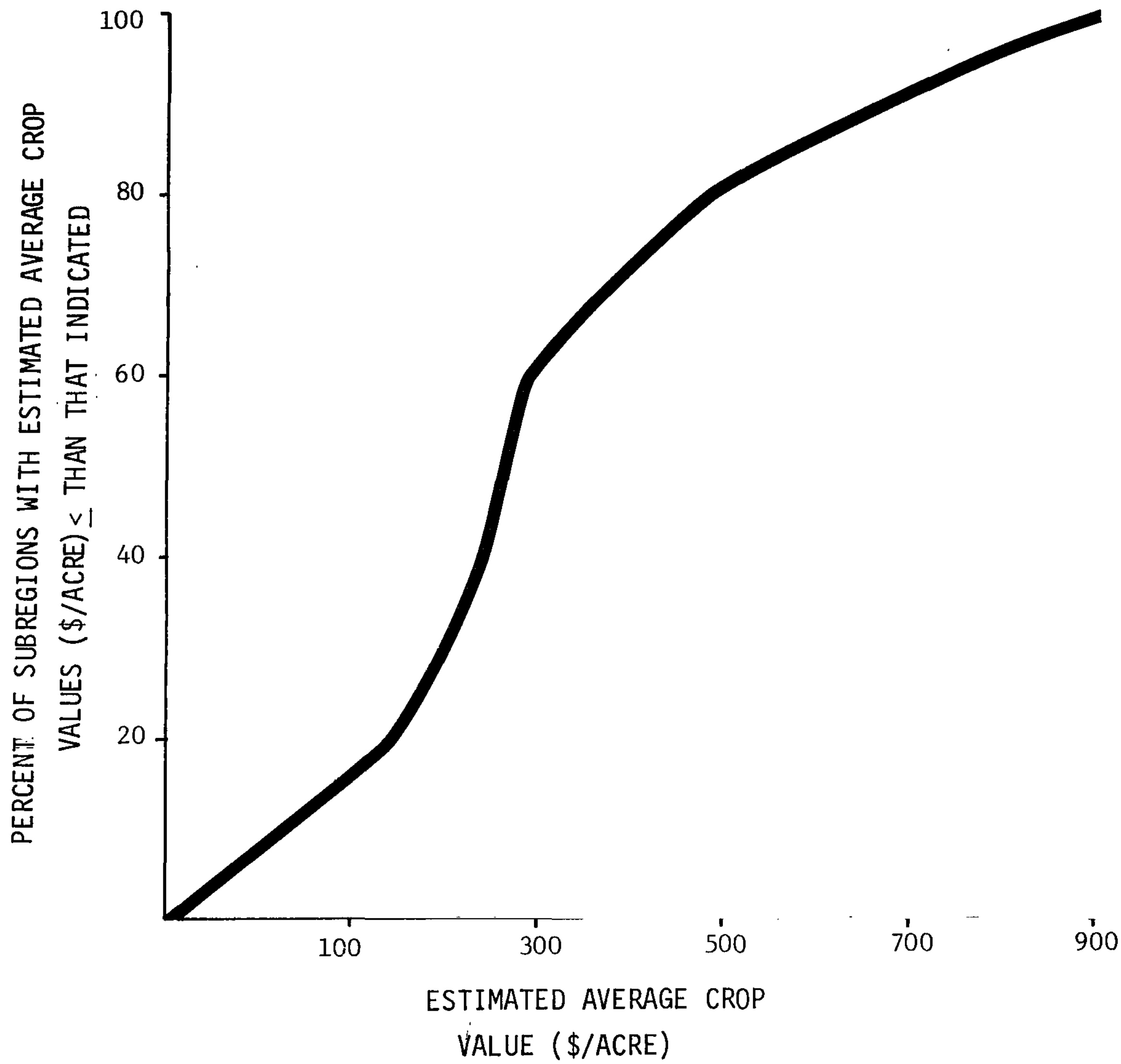


Figure 19. Cumulative distribution of estimated average crop value/acre in the Eleven Western States by snow survey impacted subregions

It should be noted that the two regions would experience the greatest benefit/acre were those which grew high valued irrigated crops, along rivers which showed high streamflow variability and for which flow forecasts were of relatively low accuracy.

Summary of Assessment of Hydroelectric Energy Benefit

Electric energy data were collected for all plants listed by the federal government as generating electric energy. The total 1978 hydroelectric energy generated in the snow survey impacted subregions was roughly 180 terawatt-hrs. Figure 20 illustrates the cumulative distribution of hydroelectric energy generation for snowmelt impacted subregion. Twenty-five percent of these subregions do not contain hydroelectric energy generating plants, fifty percent contain plants that generate less than 201,900 kilowatt-hrs. annually. However, twenty-five percent contain plants that generate anywhere from ten to twenty-six times the median subregional generation (201,900 KWH).

Figures 21 and 22 present the cumulative frequency distribution of the hydroelectric and steam-electric energy production expenses of the Eleven Western States by snow survey impacted subregions, respectively. The median hydroelectric energy production cost was 0.87 mills/KWH while that for steam-electric energy was 7.000 mills/KWH.

The difference between hydroelectric and steam-electric energy production expenses is presented on a regional basis in Table 15. The difference was as great as 26.08 mills/KWH for California and small as 6.40 mills/KWH in the Upper Colorado. The Missouri, the Arkansas-Red-White, the Upper Colorado, and the Pacific Northwest regions had differences well below the mean.

The regional revenues obtained from the sale of prime energy were compared with the calculated values of revenues obtained from the sale of secondary energy (see Table 15). The average current difference between these revenues was 14.49 mills/KWH. The Great Basin, the Pacific Northwest, and the California region all had differences well below the mean.

The potential hydroelectric benefit due to the operational application of SAT-SCAM was computed for each snow survey impacted subregion. The total benefit for the Western U.S. was estimated at $10M annually. Regional benefit estimates are presented in Table 14. The regions which showed the largest total benefit were the Pacific Northwest with $3.8M, the Lower Colorado with $2.1M, and the California with $1.9M.

The benefit/MWH in the Pacific Northwest and that in California were computed at $0.03/MWH and $0.06/MWH, respectively. Since unit benefit is a function of three other parameters: the mean difference between hydroelectric and steam-electric production expenses, the mean difference between prime and secondary energy tariffs, and streamflow 1σ forecast error, it is reasonable that the benefit/MWH would be relatively low in these two regions. The Pacific Northwest had the lowest differences between hydroelectric and steam-electric production expenses and between prime and secondary energy tariffs;

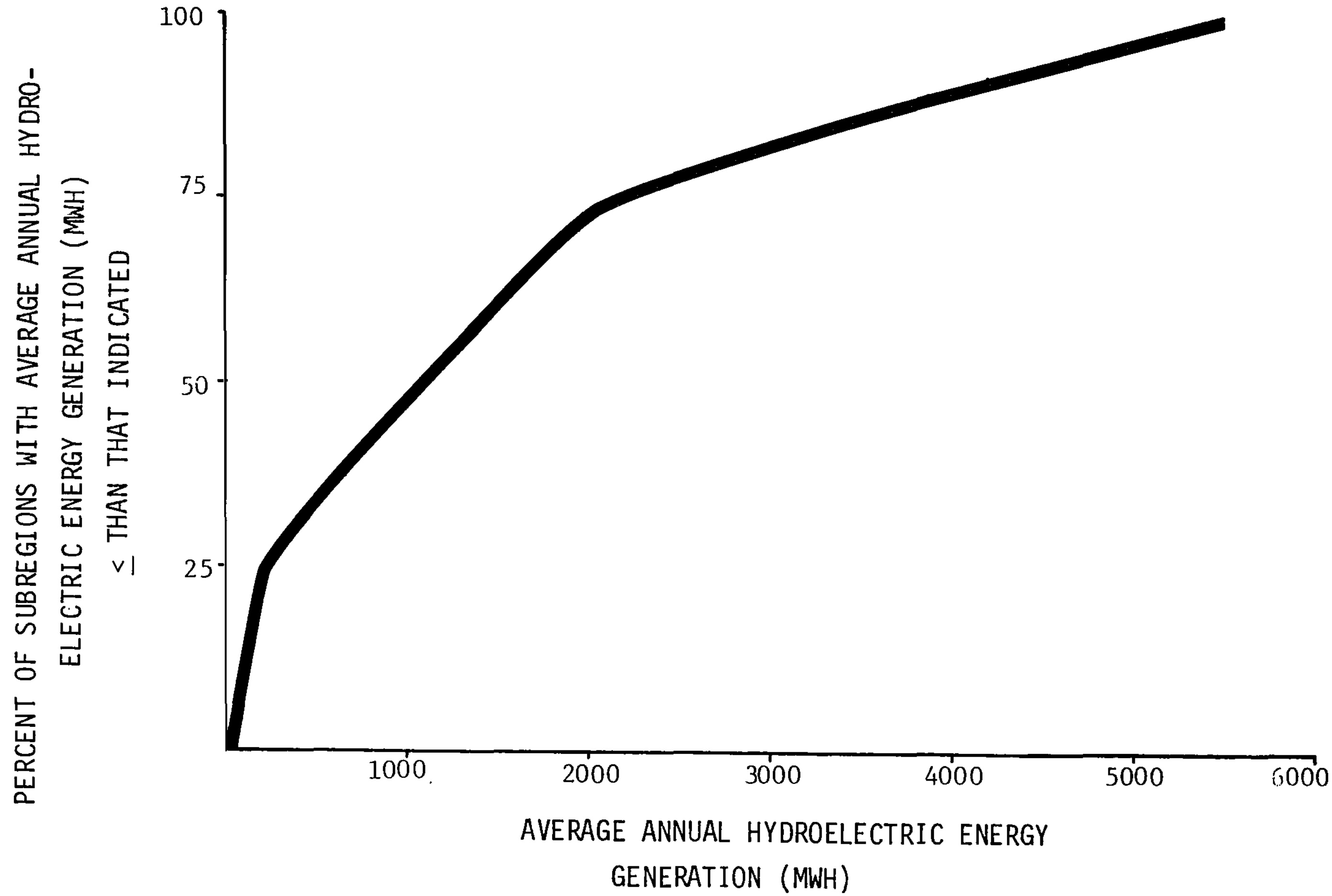


Figure 20. Cumulative distribution of average annual hydroelectric energy generation (MHW) in the Eleven Western States by snow survey impacted subregions

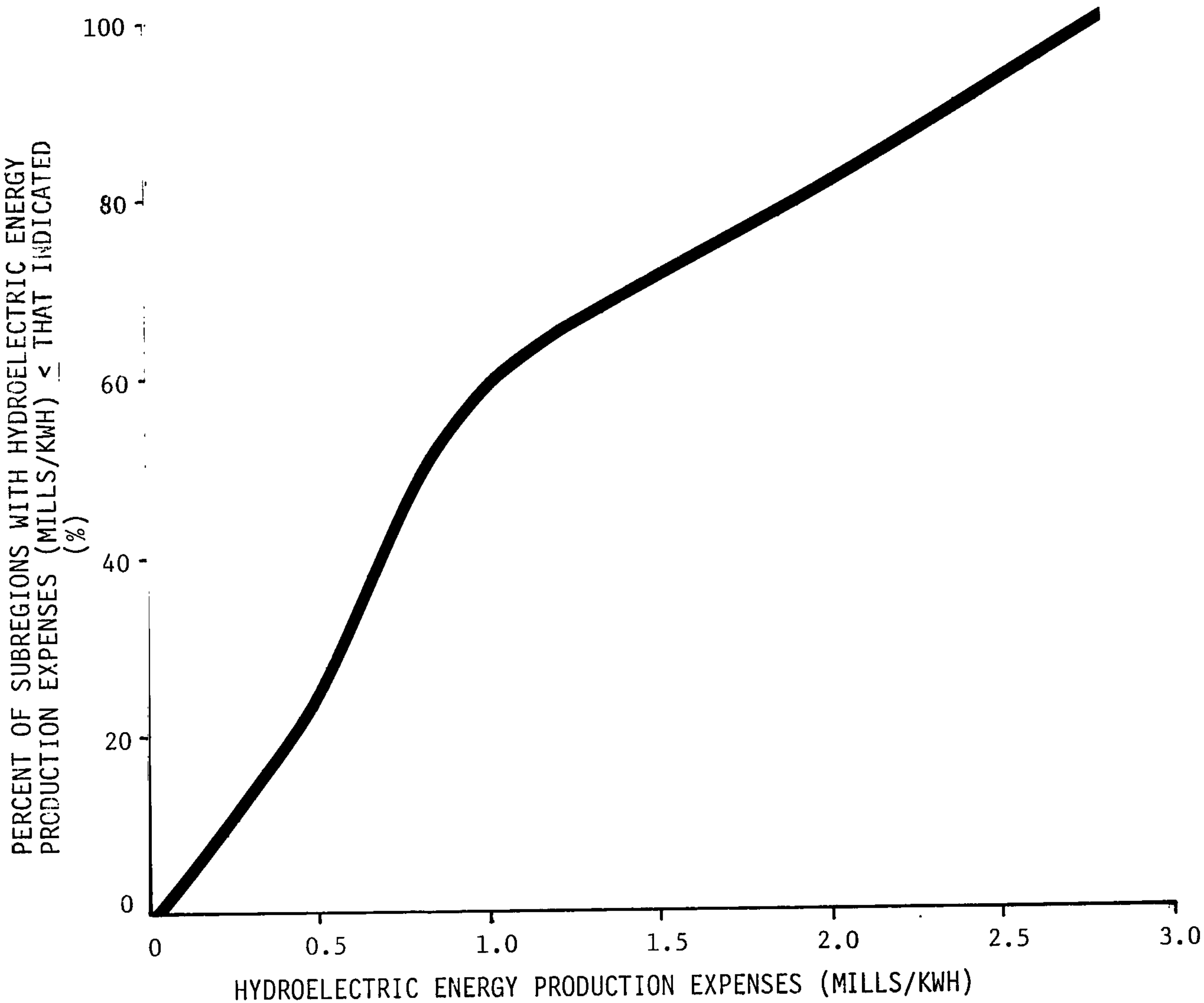


Figure 21. Cumulative distribution of hydroelectric energy production expenses (Mills/KWH) in the Eleven Western States by snow survey impacted subregions

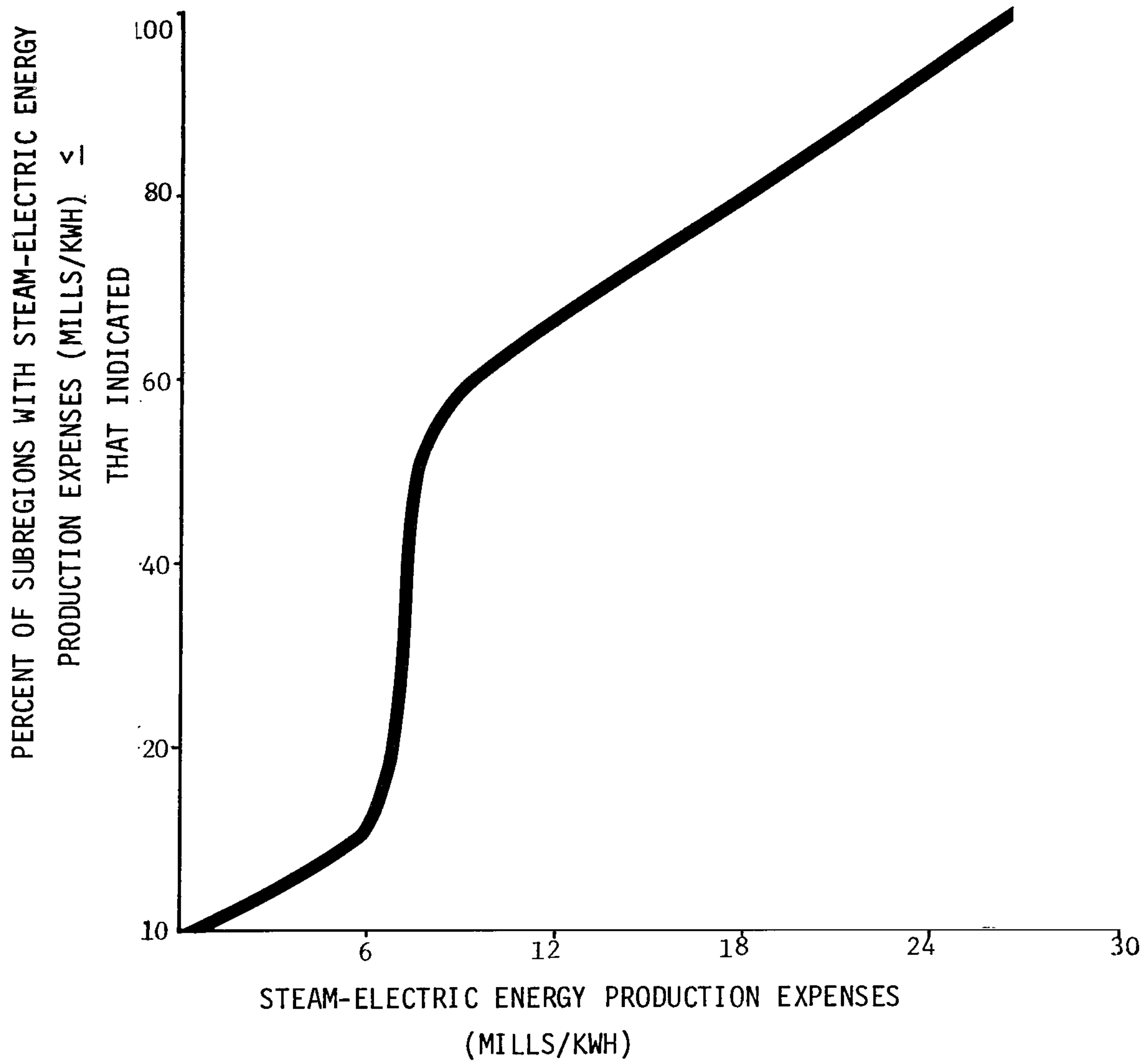


Figure 22. Cumulative distribution of steam-electric energy production expenses (Mills/KWH) in the Eleven Western States by snow survey impacted subregions

the California had a relatively low mean difference between hydroelectric and steam-electric production expenses and above average mean difference between energy tariffs.

The regions with the greatest unit benefit ($/MWH) were the Rio Grande ($0.50/MWH) and the Lower Colorado ($0.46/MWH). For both of these regions the driver parameters were well above the average for the Western U.S.

The aggregate total benefit which could potentially accrue to irrigation and hydroenergy was ($36.5M) yearly. Cost estimates for the employment of SATSCAM based upon the Colorado ASVT results and expanded to the Western States totalled $505K. The resultant benefit/cost ratio is 72:1.

Since only two major benefit contributors were evaluated and since the forecast improvement estimate does not take into account future satellite capabilitites, these estimates are considered to be conservative.

The large magnitude of the benefit/cost ratio supports the utility and applicability of SATSCAM. Future development in the use of SATSCAM in computer models specifically tailored or adapted for snow input such as those developed by Leaf, Schumann, and Tangborn, and Hannaford will most certainly increase the use and desirability of SATSCAM.

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CREDITS AND ACKNOWLEDGEMENT

This estimate of cost/benefit derived from the operational applications of satellite snowcover observations could not have been carried out without the significant inputs and guidance provided by the ASVT's.

Particular thanks go to the ASVT leaders: Jack Washichek and his successor, Bernie Shafer, John Dillard, Jean Brown, and Herb Schumann for the patience and courtesy they extended to us throughout the length of the project. Their constructive criticism and expert guidance coupled with their unstinting efforts to provide data have permitted the completion of the difficult task of projecting the benefits of this new technique.

Thanks are also extended to: Jeris Danielson, Chuck Leaf, Jack Hannaford, Chuck Howard, Billy Thomas, Bill Warskow, Ed Kirdar, Manes Barton, Dick Murray and Pat Jefferson for their significant inputs and their expert knowledge and advice throughout the project.

A special thanks goes to Dr. Albert Rango for his pioneering work in organizing the entire snow ASVT program, his help in coordinating all facets of the application of a new technology and his expert guidance throughout this effort.

APPENDIX A

APPENDIX A

Description of the Hydrologic Regions and Related Snow Survey Forecast Points

The 11 Western States contain 9 major basins, in "U.S.G.S." hydrologic regions; the Missouri, the Arkansas-Red-White, the Texas-Gulf, the Rio Grande, The Upper Colorado, the Lower Colorado, the Great Basin, the Pacific Northwest, and the California. The small portion of the Texas-Gulf hydrologic region which is contained within the 11 Western States is not snow survey impacted, and consequently, is not included within this analysis.

The nine hydrologic regions are divided into subregions. Of these, 52 were identified by local experts as being at least partially impacted by snow survey forecasting. Table A1 lists the names and agencies of those who assisted in the identification of impacted areas within their individual state. Figure 9 in the body of the text distinguishes the snow survey impacted subregions from the non-impacted subregions. The total area of the Eleven Western States impacted by snow forecast points is approximately 2,185,250km^2. Table A2 presents the snow impacted area for each region on a subregional basis.

Data characterizing the flow and forecast at snow survey forecast points were provided by the Snow Forecast Unit of S.C.S. and the California Division of Water Resources. These data were augmented via conversations with persons listed in Table A1. Table A3 lists the average runoff (KAF); the coefficient of variations of streamflow, CV; streamflow forecast error, 1σ (%), the principal forecast period, and the name of each of the snow survey forecast points.

Figures A1 through A8 depict the approximate location of the snow survey forecast points within each subregion.

Subregional data on flow weighted streamflow CV are summarized graphically in Figures A9 through A16. Twenty percent of the impacted subregions had streamflow CV's of $\leq$ .24, forty percent had streamflow CV's $\leq$ .30, sixty percent had CV's of $\leq$ .35, eighty percent had streamflow CV's of $\leq$ .58, and a hundred percent of the impacted subregions had streamflow CV's $\leq$ .196.

Subregional data on flow weighted 1σ of forecast error, (%), are also presented graphically in Figures A17 through A24. Twenty percent of the impacted subregions had streamflow 1σ's of $\leq$ 16%, forty percent had streamflow 1σ's of $\leq$ 25%, sixty percent had streamflow 1σ's of $\leq$ 31%, eighty percent had streamflow 1σ's of $\leq$ 70%, and a hundred percent of the impacted subregions had streamflow 1σ's of $\leq$ 136%.

Table A1
Contacts With Local Agencies Who Assisted in the Identification of Snow Survey Impacted Subregions and/or the Development of the Irrigation Data Base by State

STATE	INDIVIDUALS	ASSOCIATED AGENCIES
Arizona	Larry Linser	Water Commission
	Chris Williams	State Conservation Service
	Herb Schumann	Phoenix Office, U.S.G.S.
	Joe Falbo	Maricopa Water Conservation District
California	Ralph Allison	Statewide Planning Dept. of Water Resources
	Leonard Jorgensen	District Office, U.S.G.S.
Colorado	Fred Daubert	Water Conservation Board
	Mr. DeBrine	Water Rights Division, Dept. of Water Resources
	Ted Hurr	District Office, U.S.G.S.
Idaho	Ralph Mellin	Dept. of Water Resources
	Herman Ray, Cecil Thomas	District Office, U.S.G.S.
Montana	Rick Bondy	Water Resources Division, DNRC
	Philip Farne	Snow Survey, Soil Conservation Service
	Glenn Smith	Water Resources Division, DNRC
	Kathy Wilkie	District Office, U.S.G.S.
Nevada	Vic Hill	Division of Water Resources, DCNR
New Mexico	Dennis Cooper	Water Rights State Engineers Office
	Dennis Bond, Jean Kunkler, Walt Morant	District Office, U.S.G.S.
Oregon	Gene Kunkle	Dept. of Agriculture
	Jim Sexson	Dept. of Water Resources
	Larry Hubbard	District Office, U.S.G.S.
	Tom Winn	Oregon Dept. of Agriculture
Utah	Ronald Jibson	Division of Water Resources, DNR
	Barry Saunders	Planning, Division of Water Resources, DNR
	Russ Kruff	District Office, U.S.G.S.
Washington	Ed Garling	Dept. of Ecology
	Norman Dion	District Office, U.S.G.S.
Wyoming	John Jackson	Planning Dept. of Water Resources
	Bill Long	State Engineers Office
	John Warner	Soil Conservation Service
	Gordon Craig	District Office, U.S.G.S.

TABLE A2

Area of the U.S.G.S. 1974 Hydrologic Subregions in the Eleven Western States

U.S.G.S. HYDROLOGIC UNITS: REGION	U.S.G.S. HYDROLOGIC UNITS: SUBREGION	BASIN NAME	AREA (SQUARE KM)	SNOW SURVEY IMPACTED AREA (SQUARE KM)
Missouri	1001	Saskatchewan	1810	1810
	1002	Missouri Headwaters	36260	36260
	1003	Upper Missouri; Marias	51460	51460
	1004	Fort Peck Lake; Musselshell	60480	60480
	1005	Milk	39110	39110
	1006	Missouri-Poplar	26600*	26600
	1007	Upper Yellowstone	37300	37300
	1008	Big Horn	59050	59050
	1009	Tongue; Powder	48670	28310
	1010	Lower Yellowstone	34400*	34400
	1011	Lake Sakakawea; Little Missouri	8910*	-
	1012	Cheyenne: Belle Fourche	28700*	-
	1015	Niobrara	1350*	-
	1018	North Platte	56410*	56410
	1019	South Platte	53640*	48446
	1025	Republican	20070*	-
	1026	Smokey Hill	2490*	-
			Total Impacted Area in Region:	431180
Arkansas Red-White	1102	Upper Arkansas	63460	63460
	1103	Middle Arkansas	1040	-
	1104	Upper Cimarron	10390	-
	1108	Upper Canadian	32890	-

*See notes at end of Table

TABLE A2 (continued)
Area of the U.S.G.S. 1974 Hydrologic Subregions in the Eleven Western States

U.S.G.S. HYDROLOGIC UNITS REGION	SUBREGION	BASIN NAME	AREA (SQUARE KM)	SNOW SURVEY IMPACTED AREA (SQUARE KM)
Arkansas Red-White	1109	Middle Canadian	6530	-
	1110	Upper Beaver	1920	-
	1112	Brave Fork Tom Fork Red	1740	-
		Total Impacted Area in Region:		63460
Texas-Gulf	1205	Brazos Headwaters	6860*	-
	1208	Upper Colorado	6810*	-
		Total Impacted Area in Region:		0
Rio Grande	1301	Rio Grande Headwaters	19760	19760
	1302	Upper Rio Grande; Elephante Butte Reservoir	70140	70140
	1303	Rio Grande-Caballo; Nimbres	29030	29030
	1305	Rio Grande Closed Basins	30770*	-
	1306	Upper Pecos	61130	61130
	1307	Lower Pecos	4840*	-
		Total Impacted Area in Region:		180060
Upper Colorado	1401	Colorado Headwaters	25330	25330
	1402	Gunnison	20640	20640
	1403	Middle Upper Colorado	21600	21600
	1404	Upper Green; Great Divide Closed Basin	53720	53720

*See notes at end of Table

TABLE A2 (continued)
Area of the U.S.G.S. 1974 Hydrologic Subregions in the Eleven Western States

U.S.G.S. HYDROLOGIC UNITS: REGION	SUBREGION	BASIN NAME	AREA (SQUARE KM)	SNOW SURVEY IMPACTED AREA (SQUARE KM)
Upper Colorado	1405	White Yampa	34710	34710
	1406	Lower Green	38070	38070
	1407	Lower Upper Colorado	34970	31130
	1408	San Juan	64491	29030
			Total Impacted Area in Region:	254230
Lower Colorado	1501	Colorado - Lake Mead	78740	49600
	1502	Little Colorado	70450	57060
	1503	Lower Colorado; Bill Williams	44810	-
	1504	Upper Gila	39630	39630
	1505	Middle Gila; San Pedro-Willcox; Santa Cruz	43540	-
	1506	Salt; Verde	35690	35690
	1507	Lower Gila	38670	6290
	1508	Rio Sonoyta; Rio dela Concepcio; Rio de Bavispe	12540	-
			Total Impacted Area in Region:	188270
Great Basin	1601	Bear	19300	19300
	1602	Weber; Jordon; Great Salt Lake Basin	81790	64620
	1603	Escallante Desert - Sevier Lake	42740	42740
	1604	Humboldt; Black Rock Desert	74070	74070
	1605	Truckee; Carson; Walker	33070	33070
	1606	Tonopah Desert	123280	-
			Total Impacted Area in Region:	233900

TABLE A2 (continued)

Area of the U.S.G.S. 1974 Hydrologic Subregions in the Eleven Western States

U.S.G.S. HYDROLOGIC UNITS		BASIN NAME	AREA (SQUARE KM)	SNOW SURVEY IMPACTED AREA (SQUARE KM)
REGION	SUBREGION			
Pacific Northwest	1701	Kootenai; Pend Oreille Spokane	94300	94300
	1702	Upper Columbia	57760	19090
	1703	Yakima	16400	16400
	1704	Upper Snake	94200	94200
	1705	Middle Snake	96010	96010
	1706	Lower Snake; Salmon; Clearwater	91010	91010
	1707	Middle Columbia; John Day; Deschuttes	73950	73950
	1708	Lower Columbia	16210	16210
	1709	Williamette	29530	29530
	1710	Washington Coastal; Oregon Coastal	60370	32890
	1711	Puget Sound	42990	42990
	1712	Oregon Closed Basin	45580	45580
		Total Impacted Area in Basin:		652160
California	1801	Northern California Coastal; Klamath	64900	14920
	1802	Sacramento	72000	72000
	1803	Tulare Lake	36780	36780
	1804	San Joaquin	46620	46620
	1805	San Francisco Bay	11500	-
	1806	Central California Coastal	29270	-
	1807	Southern California Coastal	28490	-

TABLE A2 (continued)
Area of the U.S.G.S. 1974 Hydrologic Subregions in the Eleven Western States

U.S.G.S. HYDROLOGIC UNITS REGION	SUBREGION	BASIN NAME	AREA (SQUARE KM)	SNOW SURVEY IMPACTED AREA (SQUARE KM)
California	1808	North Lahontan	11760	11760
	1809	Mono-Owens Lakes; South Lahontan	73170	-
	1810	Southern Mojave Desert; Salton Trough	41910	-
		Total Impacted Area in Region:		182080

TOTAL IMPACTED AREA IN THE ELEVEN WESTERN STATES: 2,185,250 square km

*Figures include only that portion of the basin contained within the political boundaries of the Eleven Western States.

Table A3
Snow Survey Forecast Points and Associated Data For U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW C_V (%)	FORECAST ERROR -1σ (%)
Missouri	1001	1 St Mary River near Babb, MT.	Apr. - July	421.0	14	12.99
	1002	1 Red Rock River near Monida, MT.	Apr. - July	74.2	43	32.54
		2 Ruby River above Reservoir near Alder, MT.	Apr. - July	79.4	15	27.01
		3 Big Hole River near Melrose, MT.	Apr. - July	694.0	37	24.18
		4 Birch Creek near Glen, MT.	Apr. - July	11.5	29	34.48
		5 Boulder River near Boulder, MT.	Apr. - July	85.3	30	52.54
		6 Willow Creek near Harrison, MT.	Apr. - July	17.1	39	53.08
		7 Jefferson River at Sappington, MT.	Apr. - July	857.0	31	35.22
		8 Madison River near Grayling, MT.	Apr. - July	374.0	17	14.63
		9 Madison River near McAllister, MT.	Apr. - July	652.0	13	16.57
		10 Gallatin River near Gallatin Gateway, MT.	Apr. - July	451.0	17	14.63
		11 Bridger Creek near Bozeman, MT.	Apr. - July	19.3	29	46.42
		12 Inflow to Hyalite Reservoir, MT.	Apr. - July	38.2	19	26.87
	1002	13 Gallatin River at Logan, MT	Apr. - July	487.0	24	24.33
	1003	1 Missouri River at Toston, MT.	Apr. - July	2100.0	27	20.90
		2 Sheep Creek near White Sulphur Springs, MT.	Apr. - July	18.0	31	40.60
		3 Sun River at Gibson Dam, MT.	Apr. - July	541.0	30	21.19
		4 Belt Creek near Monarch, MT.	Apr. - July	113.0	46	75.82
		5 Missouri River at Ft. Benton, MT	Apr. - July	3123.0	28	30.00
		6 Two Medicine River near Browning, MT	Apr. - July	240.0	27	14.03
		7 Badger Creek near Browning, MT.	Apr. - July	113.0	23	17.01
		8 Cut Bank Creek near Cut Bank, MT.	Apr. - July	111.0	29	20.30
		9 Marias River near Selby, MT.	Apr. - July	538.0	46	42.69
	1004	1 Missouri River at Virgelle, MT.	Apr. - July	3742.0	29	27.46
		2 South Fork Judith River near Utica, MT.	Apr. - July	13.7	36	52.84
		3 Judith River near Utica, MT.	Apr. - July	31.1	57	44.18
		4 Missouri River near Landusky, MT.	Apr. - July	4068.0	30	28.81

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR −1σ (%)
Missouri (cont'd)	1004	5 North Fork Musselshell River near Delpine, MT.	Apr. - July	5.4	38	34.03
		6 South Fork Musselshell River above Martindale, MT.	Apr. - July	47.3	42	35.82
	1005	1 Milk River at Eastern Crossing, MT.	March - Sept.	286.0	21	35.07
	1006	1 Missouri River below Fort Peck Dam, MT.	Apr. - July	4069.0	31	27.61
		2 Missouri River near Wolf Point, MT.	Apr. - July	4361.0	34	29.85
		3 Missouri River at Williston, ND.	Apr. - July	10437.0	28	29.55
	1007	1 Yellowstone River at Corwin Springs, MT.	Apr. - July	1662.0	20	10.30
		2 Yellowstone River near Livingston, MT.	Apr. - July	1926.0	20	11.79
		3 Shields River at Clyde Park, MT.	Apr. - July	92.2	40	41.79
		4 Boulder River at Big Timber, MT.	Apr. - July	350.0	22	15.97
		5 Stillwater River near Absarokee, MT.	Apr. - July	494.0	18	26.27
		6 Clarks Fork Yellowstone River near Belfry, MT.	Apr. - July	546.0	23	17.01
		7 Rock Creek near Red Lodge, MT.	Apr. - July	84.0	17	22.69
		8 Yellowstone River at Billings, MT.	Apr. - July	3613.0	20	16.42
	1008	1 Bighorn River at St. Xavier, MT.	Apr. - July	1706.0	38	40.30
		2 Wind River near Dubois, WY.	Apr. - Sept.	102.0	28	26.57
		3 Wind River at Riverton, WY.	Apr. - Sept.	664.0	47	45.37
		4 Bull Lake Creek near Lenore, above Bull Lake, WY.	Apr. - Sept.	182.0	18	17.46
		5 Little Popo Agie near Lander, WY.	Apr. - Sept.	47.0	25	43.58
		6 Tensleep Creek near Tensleep, WY.	Apr. - Sept.	79.0	23	41.79
		7 Medicine Lodge Creek near Hyattsville, WY.	Apr. - Sept.	21.2	25	55.67
		8 Shell Creek near Shell, WY.	Apr. - Sept.	73.0	32	51.64
		9 Shoshone River below Buffalo Bill Dam, WY.	Apr. - Sept.	827.0	26	18.51

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

MISSOURI REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Missouri (cont'd)	1019	4 Clear Creek near Golden, CO.	Apr. - Sept.	119.0	41	31.34
		5 St Vain at Lyons, CO.	Apr. - Sept.	70.0	40	29.85
	1009	1 Tongue River near Dayton, WY.	Apr. - Sept.	113.0	19	37.91
		2 North Fork Powder River near Hazelton	Apr. - Sept.	10.0	31	32.24
	1010	1 Yellowstone River at Miles City, MT.	Apr. - July	5555.0	23	29.25
		2 Yellowstone River near Sidney, MT.	Apr. - July	5895.0	26	32.69
	1018	1 North Platte River above Semino Res. near Sinclair, WY.	Apr. - Sept.	648.0	23	24.93
		2 Encampment River, above Hog Park Creek Encampment, WY.	Apr. - Sept.	141.0	25	17.16
		3 Rock Creek above King Canyon Canal, near Arlington, WY.	Apr. - Sept.	55.0	26	42.39
		4 Deer Creek at Glen Rock, WY.	Apr. - Sept.	26.3	54	174.93
		5 Little Laramie River near Filmore, WY.	Apr. - Sept.	62.0	29	14.78
		6 North Platte River near Northgate, CO.	Apr. - Sept.	240.0	39	31.79
	1019	1 Big Thompson at Canyon Mouth near Drake, CO.	Apr. - Sept.	100.0	32	23.88
		2 Boulder Creek near Orodell, CO.	Apr. - Sept.	49.0	39	32.84
		3 Cache La Poudre at Canyon Mouth near Ft. Collins, CO.	Apr. - Sept.	215.0	34	29.85
Arkansas Red-White	1102	1 Arkansas near Pueblo, CO.	Apr. - Sept.	290.0	54	34.33
		2 Arkansas at Salida, CO.	Apr. - Sept.	309.0	34	19.40
		3 Cuchara near La Veta, CO.	Apr. - Sept.	10.0	56	46.27
		4 Purgatoire at Trinidad, CO.	Apr. - Sept.	46.0	60	56.72

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

RIO GRANDE REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Rio Grande	1301	1 Alamosa Creek above Terrace, CO.	Apr. - Sept.	62.0	41	23.88
		2 Conejos River near Mogote, CO.	Apr. - Sept.	182.0	37	23.88
		3 Culebra Creek at San Luis, CO.	Apr. - Sept.	19.0	54	47.76
		4 Rio Grande near Del Norte, CO.	Apr. - Sept.	438.0	42	19.40
		5 Rio Grande at 30 mile Bridge near Creed, CO.	Apr. - Sept.	121.0	32	13.43
		6 South Fork at South Fork, CO.	Apr. - Sept.	110.0	39	23.88
	1302	1 Rio Grande at San Marcial, NM	Apr. - July	379.9	94	94.00
		2 Rio Grande at Otowi Bridge, NM.	Apr. - July	532.0	68	47.40
	1303	1 Nimbres near Nimbres, NM.	March - May	3.1	196	91.34
	1306	1 Pecos River at Pecos, NM.	Apr. - July	40.0	76	47.50
Upper Colorado	1401	1 Gunnison near Grand Junction, CO.	Apr. - Sept.	1137.0	48	28.36
		2 Blue River Inflow to Green Mountain, CO.	Apr. - Sept.	297.0	32	26.87
		3 Colorado River near Cameo, CO.	Apr. - Sept.	2370.0	29	11.94
		4 Colorado River near Dotsero, CO.	Apr. - Sept.	1434.0	31	14.93
		5 Colorado River Inflow to Granby, CO.	Apr. - Sept.	228.0	24	10.45
		6 Roaring Fork at Glenwood Springs, CO.	Apr. - Sept.	692.0	27	14.93
		7 Williams Fork near Parshall, CO.	Apr. - Sept.	63.0	47	31.34
		8 Willow Creek Inflow to Willow Creek Reservoir, CO.	Apr. - Sept.	47.0	32	17.91
	1402	1 Surface Creek near Cedaridge, CO.	Apr. - Sept.	16.0	21	11.94
		2 Uncompahgre at Colona, CO.	Apr. - Sept.	129.0	36	34.33
	1403	1 Delores River at Delores, CO.	Apr. - Sept.	231.0	34	23.88
		2 Colorado near Cisco, UT.	Apr. - July	2835.0	31	25.97

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

UPPER COLORADO REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Upper Colorado (cont'd)	1404	1 Green River at Warren Bridge near Daniel, WY.	Apr. - Sept.	327.0	20	9.40
		2 Green River near La Barge, WY.	Apr. - Sept.	931.0	27	21.34
		3 Green River near Green River, WY.	Apr. - Sept.	989.0	35	19.40
		4 Big Sandy near Big Sandy, WY.	Apr. - Sept.	57.0	22	36.27
		5 Inflow to Flaming Gorge Reservoir, UT	Apr. - July	1174.0	36	35.97
	1405	1 Little Snake near Dixon, WY	Apr. - Sept.	301.0	24	31.19
		2 Elk River at Clark, CO.	Apr. - Sept.	191.0	22	13.43
		3 Little Snake near Lily, CO.	Apr. - Sept.	277.0	36	23.88
		4 White River near Meeker, CO.	Apr. - Sept.	293.0	25	10.45
		5 Yampa near Maybell, CO.	Apr. - Sept.	905.0	31	14.93
		6 Yampa at Steamboat Springs, CO.	Apr. - Sept.	260.0	31	19.40
	1406	1 Ashley Creek near Vernal, UT.	Apr. - July	50.0	28	31.49
		2 Green near Green River, UT.	Apr. - July	2839.0	10	13.43
		3 Duchesne River near Tabiona, UT.	Apr. - July	104.0	16	15.97
		4 Rock Creek near Mountain Home, UT.	Apr. - July	94.0	14	17.76
		5 Strawberry River near Duchesne, UT.	Apr. - July	56.0	43	43.58
		6 Lakefork River below Moon Lake near Mountain, UT.	Apr. - July	69.0	16	14.33
		7 Yellowstone River near Altonah, UT.	Apr. - July	65.0	24	14.63
		8 Duchesne River near Myton, UT.	Apr. - July	205.0	33	25.37
		9 Uinta River near Neola, UT.	Apr. - July	88.0	30	14.03
		10 Whiterocks River near Whiterocks, UT.	Apr. - July	58.0	29	29.10
		11 Duchesne River near Randlett, UT.	Apr. - July	220.0	51	54.78
		12 Gooseberry Creek near Scofield, UT.	Apr. - July	10.0	33	23.88

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

UPPER COLORADO

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Upper Colorado (cont'd)	1406	13 Inflow to Scofield Reservoir, UT.	Apr. - July	34.0	42	18.66
		14 Huntington Creek near Huntington, UT.	Apr. - July	45.0	30	30.45
		15 Ferron Creek near Emery, UT.	Apr. - July	35.0	29	13.28
		16 Inflow to Strawberry Reservoir, UT.	Apr. - July	45.0	30	21.34
	1407	1 Muddy Creek near Emery, UT.	Apr. - July	17.0	32	22.69
		2 Inflow to Lake Powell, UT	Apr. - July	6881.0	32	32.24
	1408	1 San Juan near Bluff, UT.	Apr. - July	853.0	83	47.01
		2 Animas River at Durango, CO.	Apr. - Sept.	409.0	35	19.40
		3 La Plata at Hesperus, CO.	Apr. - Sept.	24.0	43	20.90
		4 Los Pinos near Bayfield, CO.	Apr. - Sept.	194.0	33	23.88
		5 Piedra Creek near Arboles, CO.	Apr. - Sept.	163.0	40	17.91
		6 San Juan near Carracus, CO.	Apr. - Sept.	354.0	48	32.84
		7 Inflow to Navajo, CO.	Apr. - July	597.0	58	26.87
Lower Colorado	1501	1 Virgin River at Littlefield, AZ	Apr. - June	43.2	125	99.40
		2 Virgin River near Virgin, UT	Apr. - June	48.0	68	44.33
	1502	1 Little Colorado River above Lyman Reservoir, AZ	Apr. - June	7.8	135	84.03
	1504	1 Gila near Solomon, AZ	March - May	90.5	133	98.96
		2 San Francisco River at Glenwood, NM	March - May	20.6	145	131.49
		3 Gila River below Blue Creek, NM	March - May	46.0	125	91.64
		4 At Clifton, AZ	March - May	46.9	133	91.19
	1506	1 Salt near Roosevelt, AZ	March - May	224.6	104	69.70
		2 Tonto above Gun Creek near Roosevelt, AZ	March - May	23.1	144	137.16
		3 Verde below Tangle Creek above Horseshoe Dam, AZ	March - May	114.4	117	125.37
	1507	1 Gila near Gila Bend, AZ	March - May	38.3	112	73.73

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S.
1974 Hydrologic Subregions

GREAT BASIN REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Great Basin	1603	1 Sevier River at Hatch, UT	Apr. - July	41.0	86	51.64
		2 Sevier River near Kingston, UT	Apr. - July	21.0	129	141.19
		3 Inflow Sevier near Kingston to Vermillion Dam, UT	Apr. - June	50.0	74	78.51
		4 Antimony Creek near Antimony, UT	Apr. - July	7.3	32	47.31
		5 East Fork Sevier near Kingston, UT	Apr. - July	14.4	108	139.85
		6 Sevier River below Piute Dam near Marysvale, UT	Apr. - July	33.0	110	123.28
		7 Clear Creek above Diversions near Sevier, UT	Apr. - July	15.0	68	90.15
		8 Salina Creek near Salina, UT	Apr. - June	8.1	75	123.73
		9 Pleasant Creek near Mt. Pleasant, UT	Apr. - July	7.8	27	41.19
		10 Inflow Vermillion Dam to Sevier near Gunnison, UT	March - June	39.0	30	18.06
		11 Sevier River below San Pitch River near Gunnison, UT	Apr. - July	39.0	68	140.0
		12 Beaver River near Beaver, UT	Apr. - July	20.0	51	31.04
		13 Inflow to Minersville Reservoir near Minersville, UT	Apr. - June	5.8	113	145.07
		14 Coal Creek near Cedar City, UT	Apr. - July	16.1	84	60.30
	1604	1 Humboldt River at Palisades, NV	Apr. - Aug.	193.0	62	84.33
		2 South Fork Humboldt near Dixie Creek, NV	Apr. - Aug.	-	36	67.46
		3 North Fork Humboldt at Devils Gate, NV	Apr. - Aug.	32.0	65	52.39
		4 Martin Creek near Paradise Valley, NV	Apr. - Aug.	16.0	54	37.46
		5 Lamoille Creek at Lamoille, NV	Apr. - Aug.	28.0	25	38.21
		6 Mary's River above Hot Springs, NV	Apr. - Aug.	34.0	49	47.31
		7 Humboldt River at Comus, NV	Apr. - Aug.	149.0	70	98.21

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

GREAT BASIN REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Great Basin	1601	1 Smiths Fork near Border, WY	Apr. - Sept.	116.0	31	18.66
		2 Thomas near Wyo. ID Stateline, WY	Apr. - Sept.	32.2	46	26.42
		3 Montpelier Creek near Montpelier, ID	Apr. - Sept.	12.4	39	33.58
		4 Cub River near Preston, ID	Apr. - Sept.	50.0	27	25.67
		5 Bear River at Harer, ID	Apr. - Sept.	297.0	32	49.25
		6 Bear River near Utah-Wyoming State Line, UT	Apr. - July	112.0	11	14.48
		7 Bear River above Reservoir near Woodruff, UT	Apr. - July	131.0	16	49.40
		8 Woodruff Creek near Woodruff, UT	Apr. - July	15.4	29	25.52
		9 Bear River near Randolph, UT	Apr. - July	102.0	27	61.79
		10 Little Bear near Paradise, UT	Apr. - June	34.0	36	42.54
		11 Logan River above State Dam near Logan, UT	Apr. - July	113.0	31	28.06
		12 Blacksmith Fork above UPL Dam near Hyrum, UT	Apr. - July	48.0	38	49.10
	1602	1 Weber River near Oakley, UT	Apr. - June	100.0	15	23.28
		2 Inflow to Pineview Reservoir, UT	Apr. - June	110.0	7	29.55
		3 Spanish Fork at Thistle, UT	Apr. - July	32.0	40	42.84
		4 Hobble Creek near Springville, UT	Apr. - July	16.0	44	46.57
		5 Provo River near Hailstone, UT	Apr. - July	102.0	12	21.64
		6 Provo River below Deer Creek Dam, UT	Apr. - July	110.0	10	28.96
		7 American Fork above Upper Plant near American Fork	Apr. - July	29.0	37	18.96
		8 Utah Lake Inflow, UT	Apr. - July	208.0	28	41.64
		9 Little Cottonwood Creek near Salt Lake City, UT	Apr. - July	35.0	9	17.76
		10 Mill Creek near Salt Lake City, UT	Apr. - July	36.0	7	14.48

Table A3 (cont'd)
Snow Survey Forecast Points and Aossicated Data for U.S.G.S. 1974 Hydrologic Subregions

GREAT BASIN REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Great Basin	1605	1 Lake Tahoe Rise, NV	Apr. - Aug.	14.6	51	29.70
		2 E. Carson River near Gardenville, NV	Apr. - Aug.	182.0	40	17.01
		3 Carson River near Carson City, NV	Apr. - Aug.	178.0	51	24.18
		4 Carson River near Fort Churchill, NV	Apr. - Aug.	159.0	58	22.54
		5 Truckee River at Farad, CA	Apr. - Aug.	267.0	50	23.28
		6 W. Walker River near Coleville, CA	Apr. - Aug.	145.0	38	12.69
		7 W. Carson River near Bridgeport, CA	Apr. - Aug.	52.0	34	11.04
		8 E. Walker River near Bridgeport, CA	Apr. - Sept.	68.0	72	48.21
		9 Little Truckee River above Boca Reservoir, CA	Apr. - Aug.	89.0	52	32.84
		10 East Carson River Gardnerville, CA	Apr. - Aug.	179	45	10.6
Pacific Northwest	1701	1 Pend Oreille River below Box Canyon, WA.	Apr. - Sept.	15950.0	24	12.84
		2 Priest River at Priest River, ID.	Apr. - July	879.0	17	15.07
		3 Spokane River at Post Falls	Apr. - Sept.	3008.0	29	17.16
		4 St. Joe River at Calder, ID.	Apr. - Sept.	1345.0	25	15.22
		5 Kootenai River at Leonia	Apr. - July	7957.0	23	14.33
		6 Clark Fork River at White Horse Rapids near Cabinet, ID.	Apr. - July	13086.0	25	9.55
		7 Fisher River near Libby, MT.	Apr. - July	269.0	43	18.06
		8 Kootenai River at Libby, MT.	Apr. - July	6956.0	20	11.34
		9 Yaak River near Troy, MT.	Apr. - July	544.0	32	19.10
		10 Flint Creek at Maxville, MT.	Apr. - July	56.1	29	24.33
		11 Middle Fork Rock Creek near Philipsburg, MT.	Apr. - July	68.6	29	19.55
		12 Nevada Creek near Finn, MT.	Apr. - July	20.1	44	47.31

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Pacific Northwest (cont'd)	1702	1 Columbia River at Grand Coulee, WA	Apr. - Sept.	69020.0	18	10.15
		2 Columbia River below Rock Island Dam, WA	Apr. - Sept.	75290.0	20	8.36
		3 Kettle River near Laurier, WA	Apr. - Sept.	1873.0	29	16.57
		4 Colville River at Kettle Falls, WA	Apr. - Sept.	148.0	57	46.87
		5 Similkameen River near Nighthawk, WA	Apr. - Sept.	1516.0	48	28.06
		6 Okanogan River near Tonasket, WA	Apr. - Sept.	1723.0	52	37.61
		7 Methow River near Pateros, WA	Apr. - Sept	1031.0	43	27.91
		8 Chelan River at Chelan, WA	Apr. - Sept.	1253.0	27	8.66
		9 Stehekin River at Stehekin, WA	Apr. - Sept.	904.0	25	9.55
		10 Wenatchee River at Plain, WA	Apr. - Sept.	1312.0	27	9.25
		11 Wenatchee River at Peshastin, WA	Apr. - Sept.	1786.0	29	7.31
		12 Columbia River at Birchbank, BC	Apr. - Sept.	46410.0	15	8.51
	1703	1 Yakima River near Martin, WA.	Apr. - Sept.	142.0	32	10.15
		2 Yakima River at Cle Elum, WA.	Apr. - Sept.	968.0	31	7.46
		3 Yakima River near Parker, WA.	Apr. - Sept.	1730.0	43	16.12
		4 Yakima River near Easton, WA.	Apr. - Sept.	125.0	36	13.88
		5 Cle Elum River near Roslyn, WA.	Apr. - Sept.	477.0	31	9.25
		6 Bumping River near Nile, WA.	Apr. - Sept.	146.0	33	8.21
		7 American River near Nile, WA.	Apr. - Sept.	128.0	29	11.34
		8 Tieton River at Tieton Dam, WA	Apr. - Sept.	247.0	32	11.64
		9 Naches River near Naches, WA	Apr. - Sept.	889.0	35	9.70
		10 Ahtanum Creek near Tampico, WA	Apr. - Sept.	48.0	37	21.64

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR −1σ (%)
Pacific Northwest (cont'd)	1701	13 Clark Fork River Milltown, MT.	Apr. - July	690.0	32	24.93
		14 Blackfoot River near Bonner, MT.	Apr. - July	934.0	33	13.43
		15 Clark Fork River above Missoula, MT.	Apr. - July	1624.0	32	15.97
		16 West Fork Bitterroot River near Conner, MT.	Apr. - July	156.0	36	20.75
		17 Bitterroot River near Darby, MT.	Apr. - July	542.0	33	17.31
		18 Skalkaho Creek near Hamilton, MT.	Apr. - July	49.6	29	14.78
		19 Burnt Fork Creek near Stevensville, MT.	Apr. - July	31.0	35	12.09
		20 Bitterroot River at Missoula, MT.	Apr. - July	1412.0	34	15.07
		21 Clark Fork River below Missoula, MT.	Apr. - July	3036.0	32	12.54
		22 St. Regis River near St. Regis, MT.	Apr. - July	308.0	41	20.15
		23 Clark Fork River at St Regis, MT.	Apr. - July	4087.0	32	13.58
		24 North Fork Flathead River near Columbia Falls, MT.	Apr. - July	1813.0	23	15.52
		25 Middle Fork Flathead River near West Glacier, MT.	Apr. - July	1768.0	20	10.30
		26 South Fork Flathead River near Columbia Falls, MT.	Apr. - July	2240.0	22	14.48
		27 Flathead River at Columbia Falls, MT.	Apr. - July	5942.0	21	12.84
		28 Swan River near Big Fork, MT.	Apr. - July	630.0	20	11.79
		29 Flathead River near Polson, MT.	Apr. - July	7082.0	22	13.28
		30 Clark Fork River near Plains, MT.	Apr. - July	11523.0	25	11.19
		31 Thompson River near Thompson Falls, MT.	Apr. - July	248.0	41	19.25
		32 Prospect Creek at Thompson Falls, MT.	Apr. - July	137.0	36	15.52

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS: REGION	SUBREGION	FORECAST POINT DATA: NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Pacific Northwest (cont'd)	1704	1 Salmon Falls Creek near San Jacinto, NV.	Mar. - Sept.	10.0	33	23.88
		2 Snake River near Moran, WY.	Apr. - Sept.	858.0	22	9.10
		3 Snake River above Palisades, WY	Apr. - Sept.	2621.0	25	9.55
		4 Pacific Creek at Moran, WY.	Apr. - Sept.	169.0	30	13.73
		5 Greys River above Palisades Res. near Alpine, WY.	Apr. - Sept.	388.0	28	21.34
		6 Salt River near Etna, WY.	Apr. - Sept.	365.0	33	29.25
		7 Swift Creek near Afton, WY.	Apr. - Spet.	45.7	30	19.10
		8 Palisades Reservoir Inflow near Irwin, ID.	Apr. - Sept.	3714.0	25	11.04
		9 Snake River near Heise, ID.	Apr. - Spet.	3946.0	24	17.61
		10 Snake River near Blackfoot, ID.	Apr. - July	4173.0	27	24.48
		11 Henrys Fork River near Ashton, ID.	Apr. - Sept.	671.0	16	22.09
		12 Henrys Fork River Rexburg, ID.	Apr. - Sept.	1364.0	20	29.40
		13 Teton River near St. Anthony, ID.	Apr. - Sept.	442.0	22	34.33
		14 Portneuf River at Topaz, ID.	March - Sept.	93.0	33	31.49
		15 Big Lost River at Howell Ranch, ID.	Apr. - Sept.	208.0	32	39.10
		16 Big Lost River near Mackay, ID	Apr. - Sept.	183.0	34	41.79
		17 Little Wood River High Five Creek, ID.	Apr. - Sept.	94.0	51	28.36
		18 Big Wood River Magic Res. Inflow (Combined Flow Big Wood River near Bellevue & Camas Creek near Blaine, ID.	March - July	310.0	61	32.99
		19 Oakley Res. Inflow (Combined Flow Goose Creek near Oakley), ID. &Trapper Creek near Oakley	March - Sept.	29.5	46	37.76
	1705	1 Owyhee River near Owyhee, NV.	Apr. - Sept.	68.0	50	37.46
		2 Snake River at Weiser, ID	Apr. - Sept	6524.0	33	22.09

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS REGION	SUBREGION	FORECAST POINT DATA NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Pacific Northwest (cont'd)	1705	3 Bruneau River near Hot Springs, ID.	March - Sept.	226.0	44	45.82
		4 Boise River near Twin Springs, ID.	Apr. - Sept.	720.0	32	19.40
		5 Boise River near Boise River, ID.	Apr. - Sept.	1612.0	38	17.76
		6 Boise River South Fork at Anderson Dam, ID.	Apr. - Sept.	603.0	42	21.34
		7 Payette River near Horseshoe Bend, ID.	Apr. - Sept.	1850.0	31	19.40
		8 Payette River North Fork at Cascade, ID.	Apr. - Sept.	562.0	28	19.70
		9 Payette River North Fork near Banks, ID	Apr. - Sept.	730.0	32	20.75
		10 Owyhee Net Inflow, OR.	Apr. - Sept.	332.0	62	35.82
		11 Bully Creek at Warmsprings, OR.	March - May	13.1	86	59.70
		12 Malheur near Drewsey, OR.	Apr. - Sept.	72.0	61	38.81
		13 North Fork Malheur at Beulah, OR.	Apr. - Sept.	64.0	49	44.78
		14 Burnt near Hereford, OR.	Apr. - Sept.	33.0	58	41.79
		15 Powder near Sumpter, OR.	Apr. - Sept.	56.0	45	25.37
		16 Eagle Creek above Skull Creek, OR.	Apr. - Sept.	190.0	21	13.28
		17 Owyhee River near Gold Creek, NV.	Apr. - Aug.	18.0	60	50.60
	1706	1 Salmon River at Whitebird, ID.	Apr. - Sept.	6959.0	26	21.49
		2 Clearwater River at Spalding, ID.	Apr. - Sept.	8605.0	22	16.27
		3 Bear Creek near Wallowa, OR.	Apr. - Sept.	66.0	22	26.87
		4 Catherine Creek near Union, OR.	Apr. - Sept.	65.0	26	22.39
		5 Imnaha at Imnaha, OR.	Apr. - Sept.	307.0	22	25.37
		6 East Fork Wallowa near Joseph, OR.	Apr. - Sept.	11.4	19	23.88
		7 Hurricane Creek near Joesph, OR.	Apr. - Sept.	47.0	17	14.93
		8 Lostine near Lostine, OR.	Apr. - Sept.	125.0	19	16.42
		9 Grande Ronde at La Grande, OR.	Apr. - Sept.	158.0	36	32.84

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Pacific Northwest (cont'd)	1707	1 Columbia River at the Dallas, WA	Apr. - Sept.	104600.0	22	10.00
		2 Mill Creek near Walla Walla, WA	Apr. - Sept.	27.0	41	26.42
		3 Umatilla near Gibbon, OR.	Apr. - Sept.	75.0	25	23.88
		4 Umatilla near Pendleton, OR.	Apr. - Sept.	144.0	32	27.76
		5 McKay near Pilot Rock, OR.	Apr. - Sept.	24.0	55	53.73
		6 Birch Creek near Rieth, OR.	Apr. - July	15.9	52	46.27
		7 Butter Creek near Pine City, OR.	Apr. - Sept.	7.6	48	49.25
		8 South Fork Walla Walla near Milton Freewater, OR.	Apr. - Sept.	66.0	17	20.90
		9 Strawberry Creek near Prairie City, OR	Apr. - Sept.	7.6	26	23.88
		10 Middle Fork John Day River near Ritter, OR.	Apr. - Sept.	108.0	37	29.85
		11 Crooked River near Post, OR.	Apr. - Sept.	91.0	52	34.33
		12 Ochoco Net Inflow, OR.	Apr. - Sept.	18.8	53	47.76
		13 Cresent Creek near Cresent Lake, OR.	Apr. - Sept.	22.0	44	62.69
		14 Little Deschutes near Lapine, OR.	Apr. - Sept.	82.0	40	32.84
		15 Odell Creek near Cresent, OR.	Apr. - Sept.	28.0	24	22.39
		16 Deschutes below Snow Creek, OR.	Apr. - Sept.	62.0	37	35.82
		17 Crane Prairie Net Inflow, OR.	Apr. - Sept.	119.0	31	28.36
		18 Deschutes at Benham Falls, OR.	Apr. - Sept.	550.0	14	23.88
		19 Tumalo Creek near Bend	Apr. - Sept.	44.0	18	19.40
		20 Squaw Creek near Sisters, OR.	Apr.- Sept.	50.0	22	11.34
		21 West Fork Hood River near Dee, OR	Apr. - Sept.	154.0	23	25.37
		22 White River below Tygh Valley, OR.	Apr. - Sept.	133.0	27	22.39
	1708	1 Lewis River at Aerial, WA	Apr. - Sept.	1341.0	28	16.87
		2 Cowlitz River at Castle Rock, WA	Apr. - Sept.	2773.0	28	11.04

Table A3 (cont'd)
Snow Survey Forecast Points and Assoicated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
Pacific Northwest (cont'd)	1709	1 Row River above Pitcher Creek near Dorena, OR.	Apr. - Sept.	102.0	36	38.81
		2 Middle Fork of Willamette River below North Fork near Oakridge, OR.	Apr. - Sept.	779.0	24	22.39
		3 McKenzie at McKenzie Bridge, OR	Apr. - Sept.	598.0	16	14.93
		4 McKenzie near Vida, OR.	Apr. - Sept.	1262.0	19	19.40
		5 South Santiam at Waterloo, OR.	Apr. - Sept.	623.0	26	32.84
		6 North Santiam at Mehama, OR.	Apr. - Sept.	872.0	21	24.48
		7 Willamette at Salem, OR.	Apr. - Sept.	4943.0	25	25.37
		8 Oak Grove Fork above Power Intake, OR.	Apr. - Sept.	162.0	23	19.40
		9 Clackamas above Three Lynx, OR.	Apr. - Sept.	604.0	21	19.40
		10 Clackamas at Estacada, OR.	Apr. - Sept	789.0	22	19.40
		11 McKenzie River at Inflow of Clear Lake, OR.	Apr. - Sept.		71	41.79
	1710	1 Clearwater above Trap Creek near Tobette Falls, OR.	Apr. - Sept.	69.0	13	23.88
		2 North Umpqua near Tokette Falls	Apr. - Sept.	166.0	19	17.91
		3 North Fork Little Butte near Lake Creek, OR.	Apr. - Sept.	13.7	40	29.85
		4 South Fork Little Butte near Lake Creek, OR.	Apr. - Sept.	28.0	41	40.30
		5 Rogue above Prospect, OR	Apr. - Sept.	311.0	21	19.40
		6 South Fork Rogue near Prospect, OR	Apr. - Sept.	72.0	29	17.91
		7 Rogue at Raygold near Central Point	Apr. - Sept.	890.0	23	20.90
		8 Rogue at Grants Pass, OR	Apr. - Sept.	890.0	25	25.37
		9 Applegate near Copper, OR	Apr. - Sept.	133.0	32	32.84
		10 Illinois near Kerby, OR	Apr. - Sept.	197.0	43	53.73
	1711	1 Dungeness River near Sequim. WA	Apr. - Sept.	165.0	21	11.79

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

PACIFIC NORTHWEST REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW C_V (%)	FORECAST ERROR -1σ (%)
Pacific Northwest (cont'd)	1712	1 Twentymile near Adel, OR	Apr. - Sept.	19.0	67	34.33
		2 Deep Creek near Adel, OR	Apr. - Sept.	68.0	49	34.33
		3 Honey Creek near Plush, OR	Apr. - Sept.	17.2	62	32.84
		4 Silver Creek near Silver Lake, OR	Apr. - July	14.1	71	50.75
		5 Chewaucan near Paisley, OR	Apr. - Sept.	79.0	46	31.34
		6 Donner and Blitzen River near Frenchglen, OR	Apr. - Sept.	53.0	35	26.87
		7 Silvies near Burns, OR	Apr. - Sept.	74.0	59	50.75
		8 Silver Creek near Riley, OR	Apr. - July	15.6	58	49.25
		9 Trout Creek, OR	Apr. - July	7.5	52	43.28
California	1801	1 Fourmile Lake Net Inflow, OR	Apr. - June	4.3	38	44.78
		2 Spague near Chiloquin, OR	Apr. - June	242.0	41	37.31
		3 Williamson near Chiloquin, OR	Apr. - June	414.0	33	29.85
		4 Upper Klamath Lake Net Inflow, OR	Apr. - June	536.0	35	35.82
		5 Gerber Reservoir Net Inflow, OR	Apr. - June	-	8	52.24
	1802	1 Drews Reservoir Net Inflow, OR	Apr. - June	27.0	20	58.21
		2 Pit River above Shasta, CA	Apr. - June	1004	30	8.8
		3 McCloud River above Shasta, CA	Apr. - June	420	32	11.0
		4 Sacramento River above Shasta, CA	Apr. - June	285	45	10.2
		5 Total inflow to Shasta, CA	Apr. - June	1772	35	6.4
		6 Feather River at River, CA	Apr. - June	1864	50	10.3
		7 Yuba River at Smartville, CA	Apr. - June	1081	45	8.4
		8 American River at Folsom, CA	Apr. - June	1322	46	6.8
	1803	1 Kings River at Pine Flat, CA	Apr. - June	1157	50	6.6

Table A3 (cont'd)
Snow Survey Forecast Points and Associated Data for U.S.G.S. 1974 Hydrologic Subregions

CALIFORNIA REGION

U.S.G.S. HYDROLOGIC UNITS		FORECAST POINT DATA				
REGION	SUBREGION	NAME	PRINCIPAL FORECAST PERIOD (PFP)	AVER RUNOFF (KAF)	STREAMFLOW CV (%)	FORECAST ERROR -1σ (%)
California (cont'd)	1803	2 Kaweah River at Terminus, CA	Apr. - June	269	50	9.3
		3 Tule River at Success, CA	Apr. - June	62	81	17.7
		4 Kern River at Isabella, CA	Apr. - June	432	72	9.7
	1804	1 Cosumnes River at Michigan Bar, CA	Apr. - June	131	64	18.3
		2 Mokelumne River at Pardee, CA	Apr. - June	466	43	4.5
		3 Stanislaus River at Melones, CA	Apr. - June	717	45	7.0
		4 Tuolumne River at Don Pedro, CA	Apr. - June	1192	42	5.0
		5 Merced River at Exchequer, CA	Apr. - June	608	48	7.4
		6 San Joaquin River at Millerton, CA	Apr. - June	1193	49	6.5
	1808	1 Bidwell Creek near Ft. Bidwell, CA	Apr. - June	11.5	-	-
		2 Eagle Creek near Eagleville, CA	Apr. - June	4.4	-	-
		3 Mill Creek near Cedarville, CA	Apr. - June	4.7	-	-
		4 Deep Creek near Cedarville, CA	Apr. - June	3.3	-	-

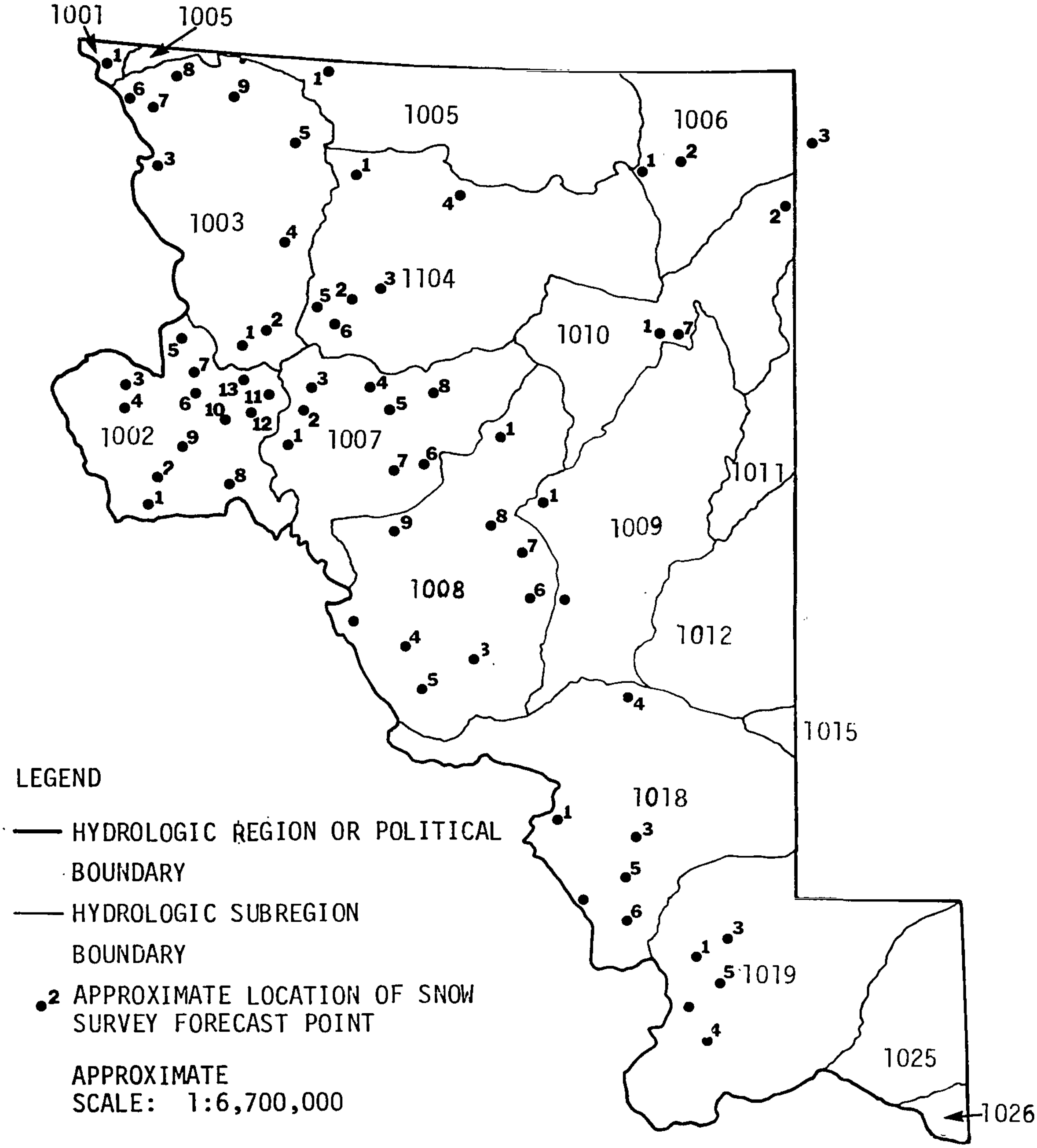


Figure A1. Locations of snow survey forecast points in the Missouri hydrologic region

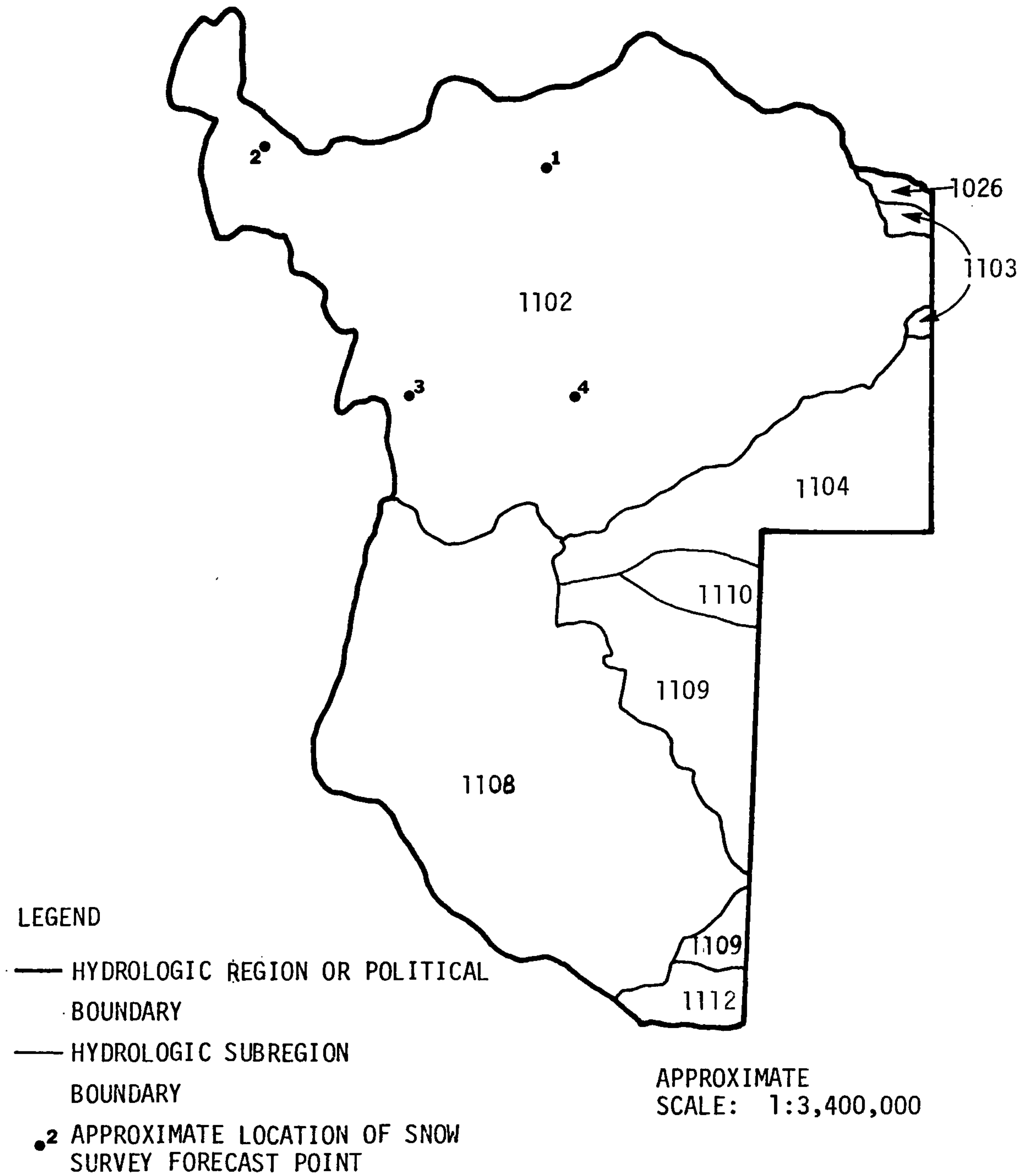
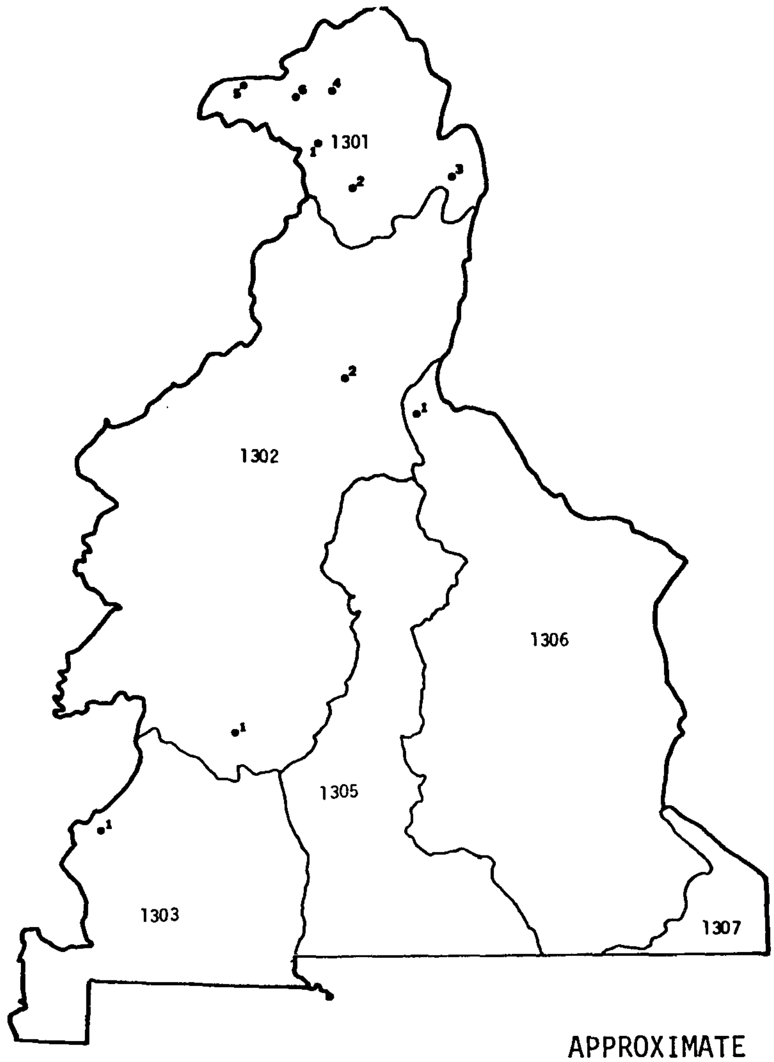


Figure A2. Locations of snow survey forecast points in the Arkansas-Red-White hydrologic region



LEGEND

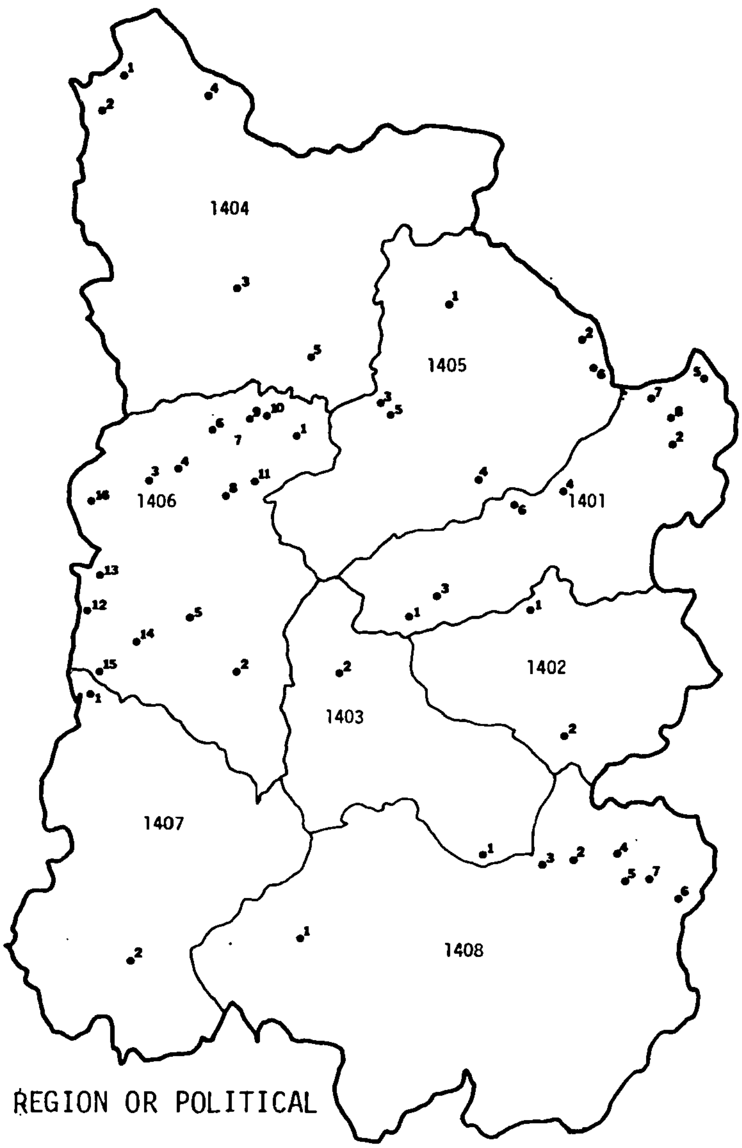
— HYDROLOGIC REGION OR POLITICAL BOUNDARY

— HYDROLOGIC SUBREGION BOUNDARY

•2 APPROXIMATE LOCATION OF SNOW SURVEY FORECAST POINT

APPROXIMATE
SCALE: 1:5,500,000

Figure A3. Locations of snow survey forecast points in the Rio Grande hydrologic region



LEGEND

—— HYDROLOGIC REGION OR POLITICAL BOUNDARY

—— HYDROLOGIC SUBREGION BOUNDARY

•2 APPROXIMATE LOCATION OF SNOW SURVEY FORECAST POINT

APPROXIMATE
SCALE: 1:5,500,000

Figure A4. Locations of snow survey forecast points in the Upper Colorado hydrologic region

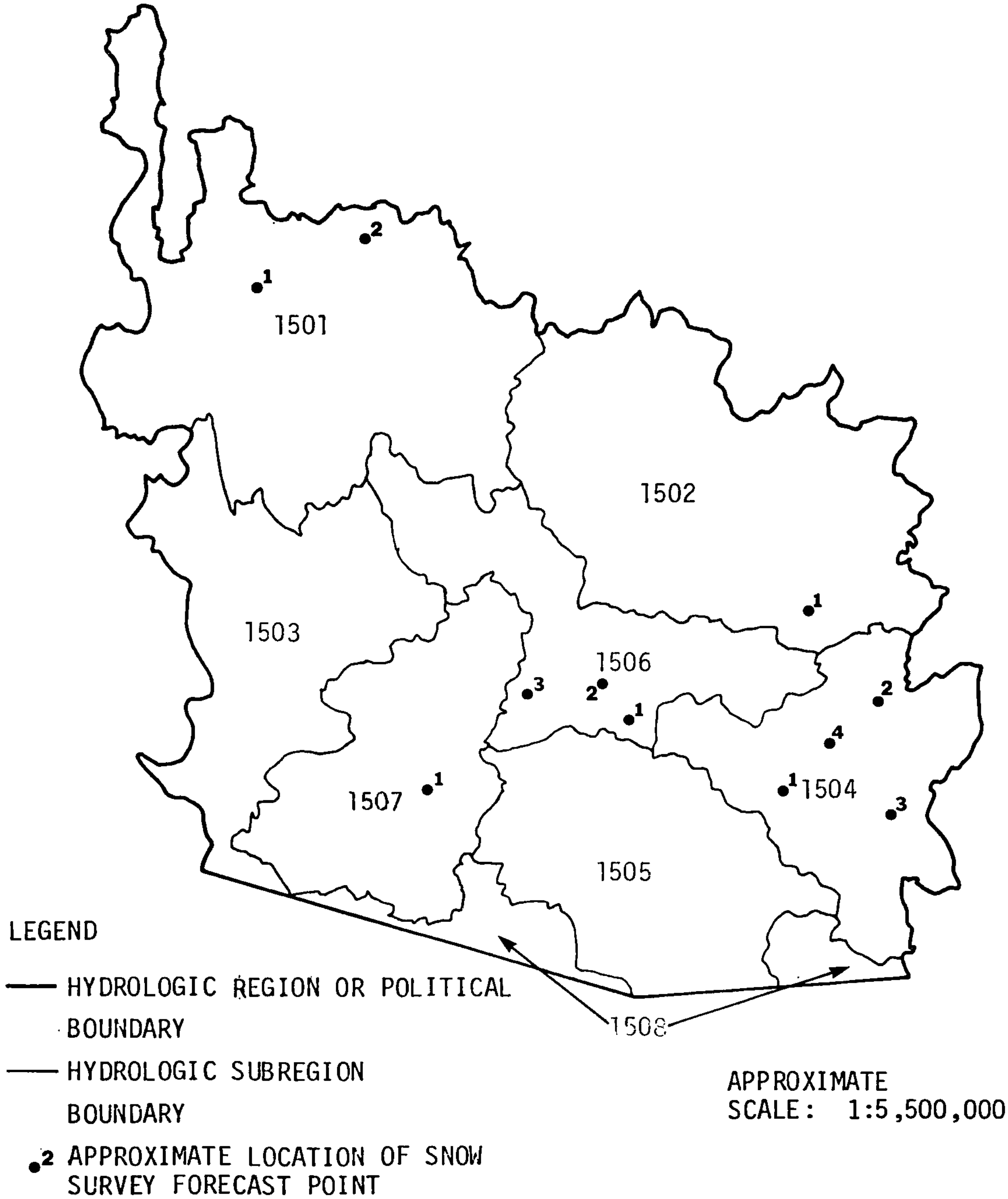


Figure A5. Locations of snow survey forecast points in the Lower Colorado hydrologic region

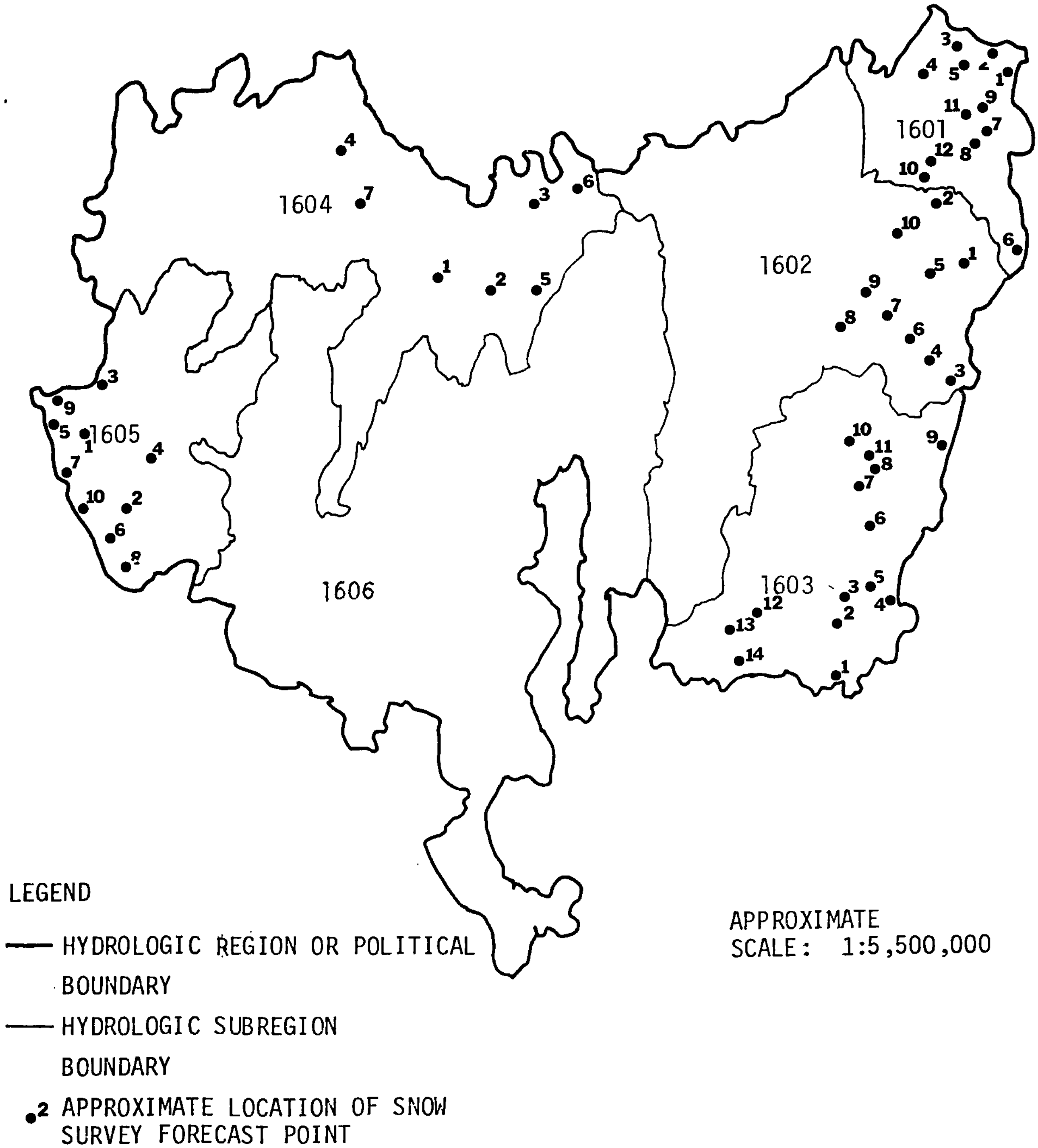
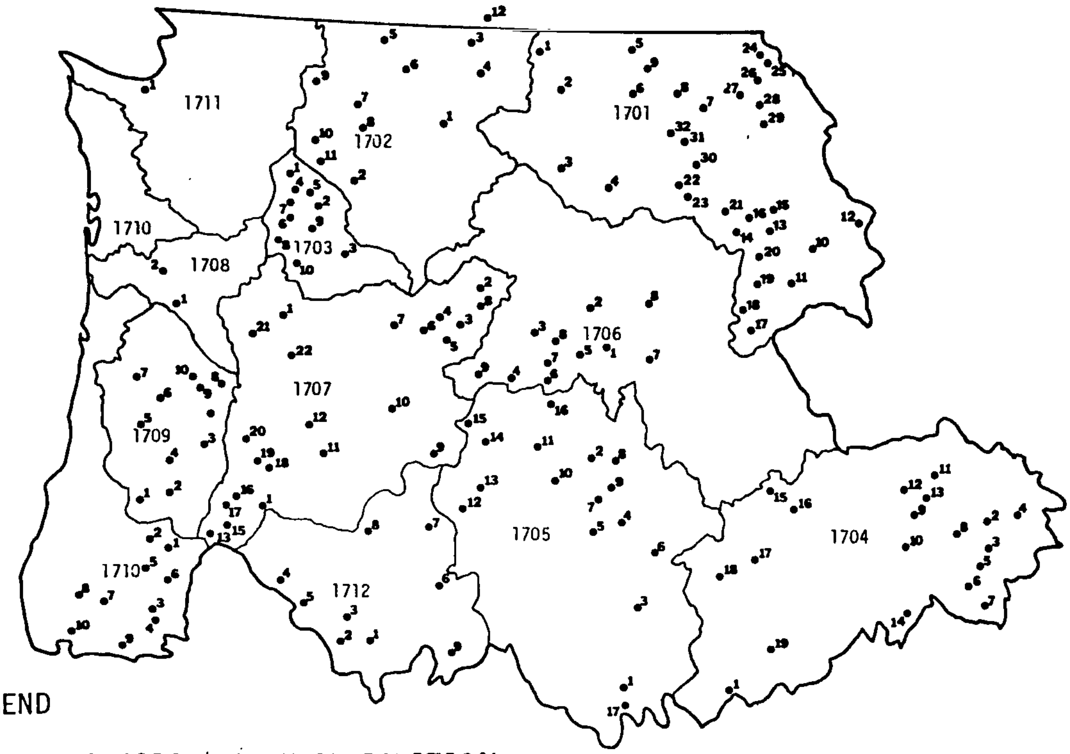


Figure A6. Locations of snow survey forecast points in the Great Basin hydrologic region



LEGEND

HYDROLOGIC REGION OR POLITICAL BOUNDARY

HYDROLOGIC SUBREGION BOUNDARY

●2 APPROXIMATE LOCATION OF SNOW SURVEY FORECAST POINT

APPROXIMATE SCALE: 1:8,800,000

Figure A7. Locations of snow survey forecast points in the Pacific Northwest hydrologic region

LEGEND

—— HYDROLOGIC REGION OR POLITICAL BOUNDARY

—— HYDROLOGIC SUBREGION BOUNDARY

•2 APPROXIMATE LOCATION OF SNOW SURVEY FORECAST POINT

APPROXIMATE
SCALE: 1:7,300,000

Figure A8. Locations of snow survey forecast points in the California hydrologic region

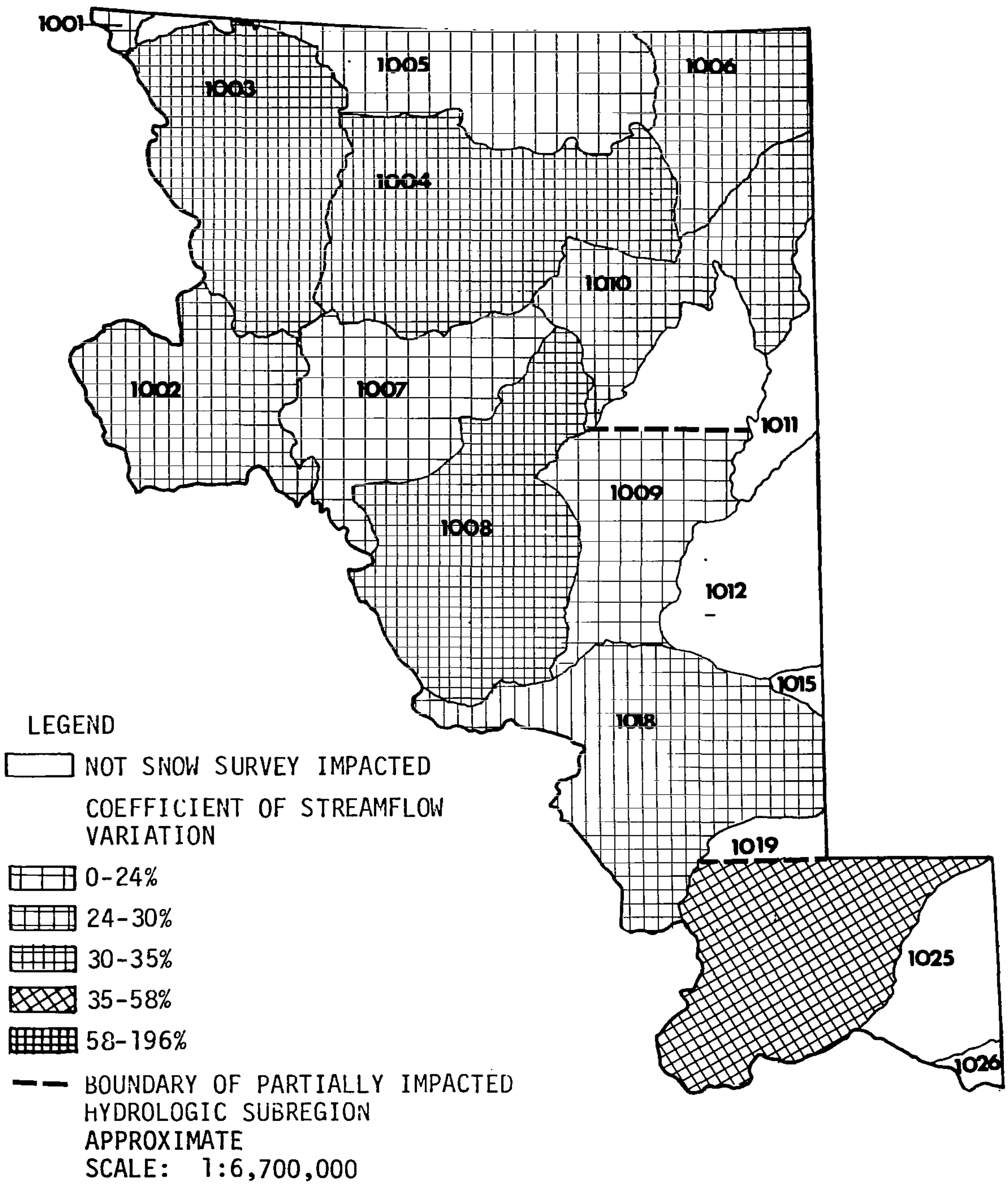


Figure A9. Weighted coefficient of streamflow variation, CV(%), in the snow survey impacted subregions of the Missouri hydrologic region

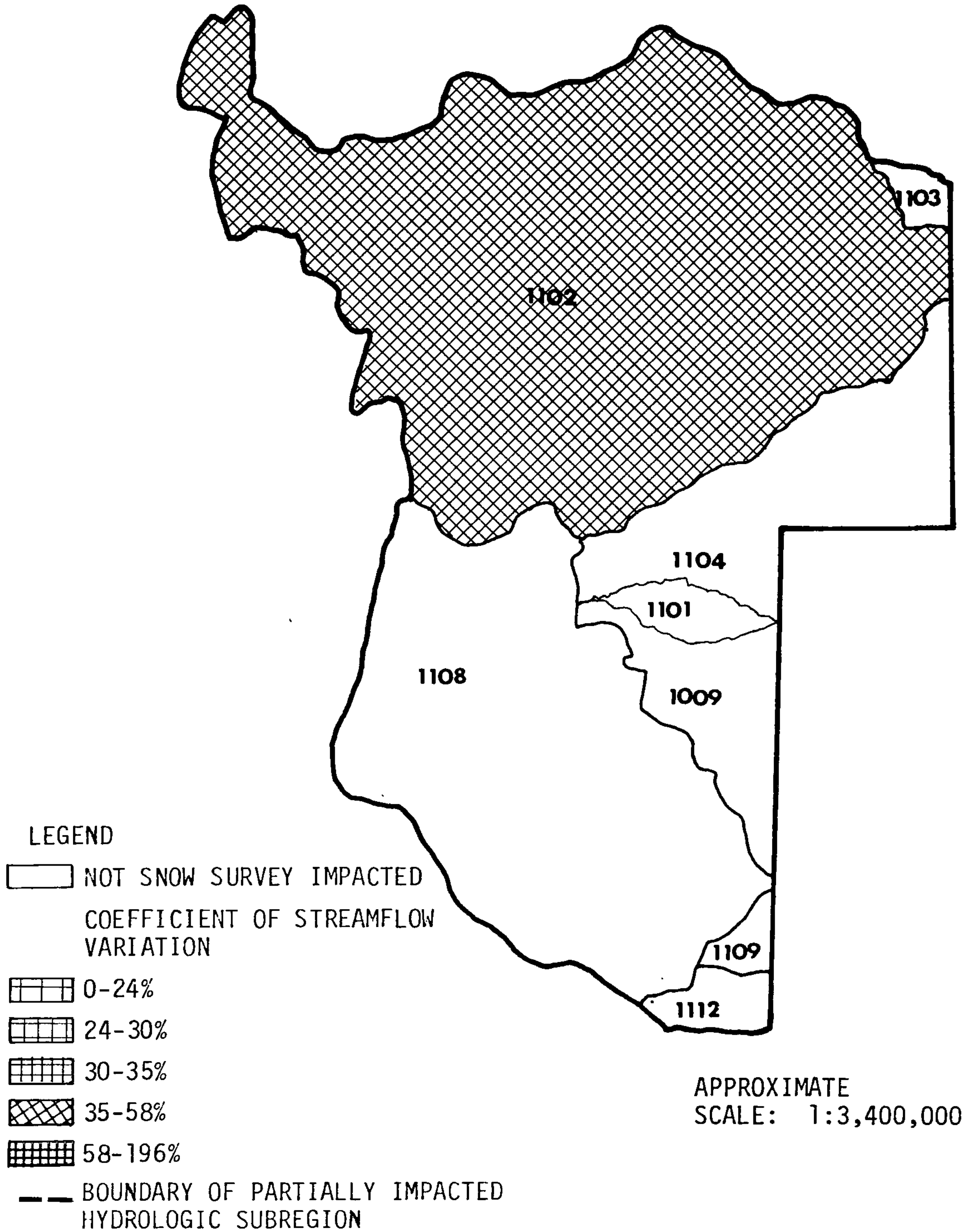


Figure A10. Weighted coefficient of streamflow variation, CV (%), in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region

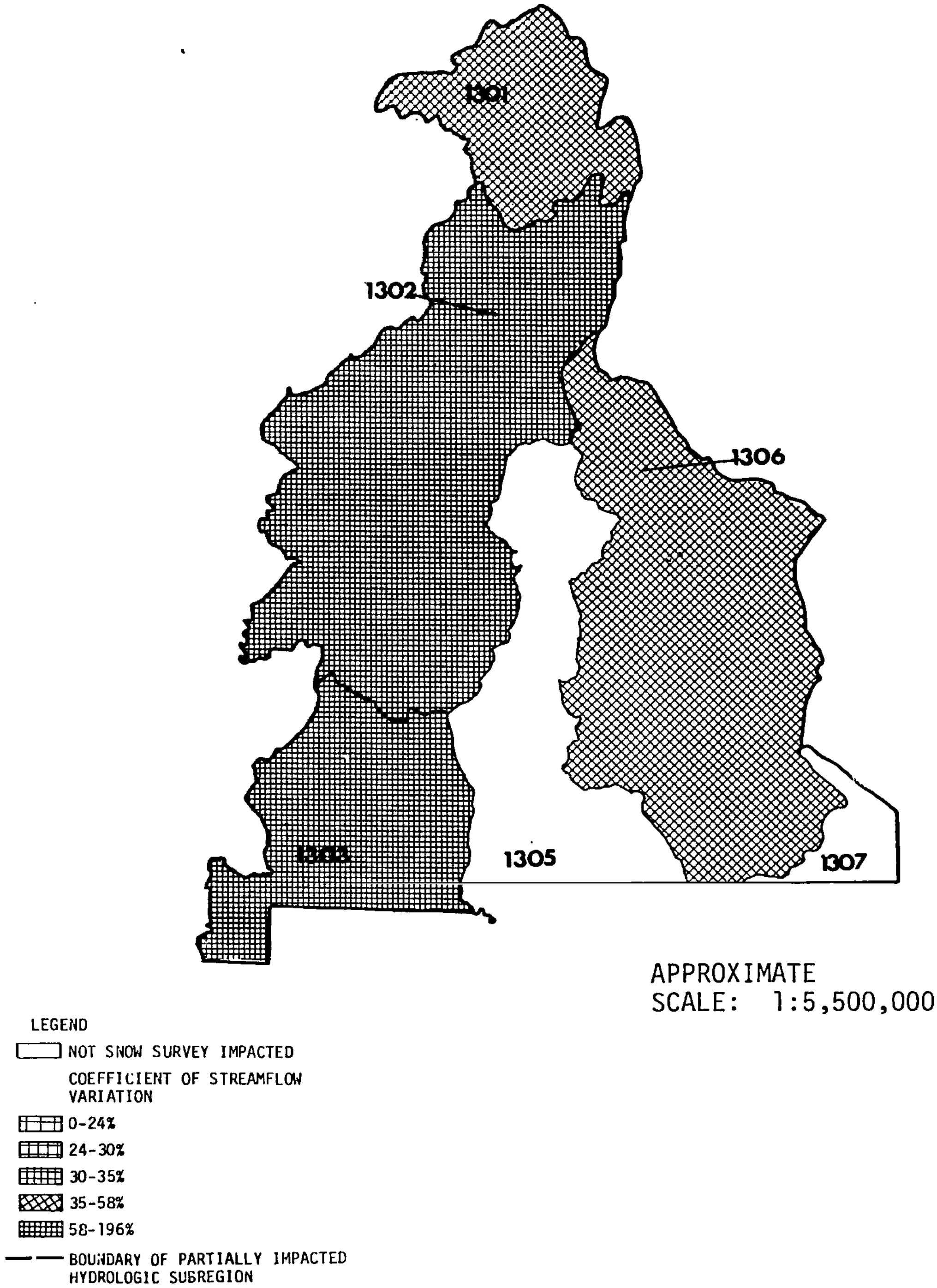


Figure A11. Weighted coefficient of streamflow variation CV (%), in the snow survey impacted subregions of the Rio Grande hydrologic region

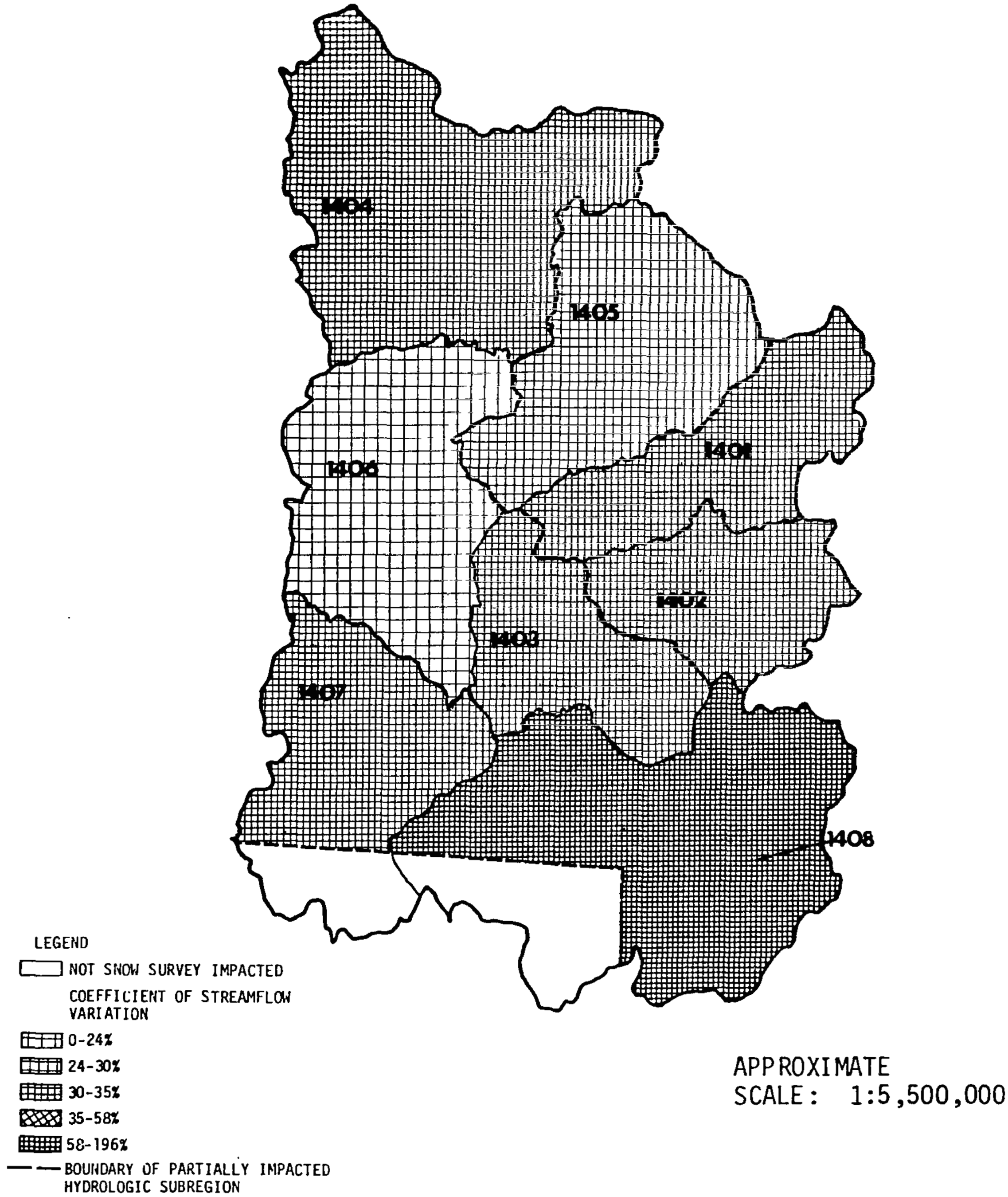


Figure A12. Weighted coefficient of streamflow variation, CV (%) in the snow survey impacted subregions of the Upper Colorado hydrologic region

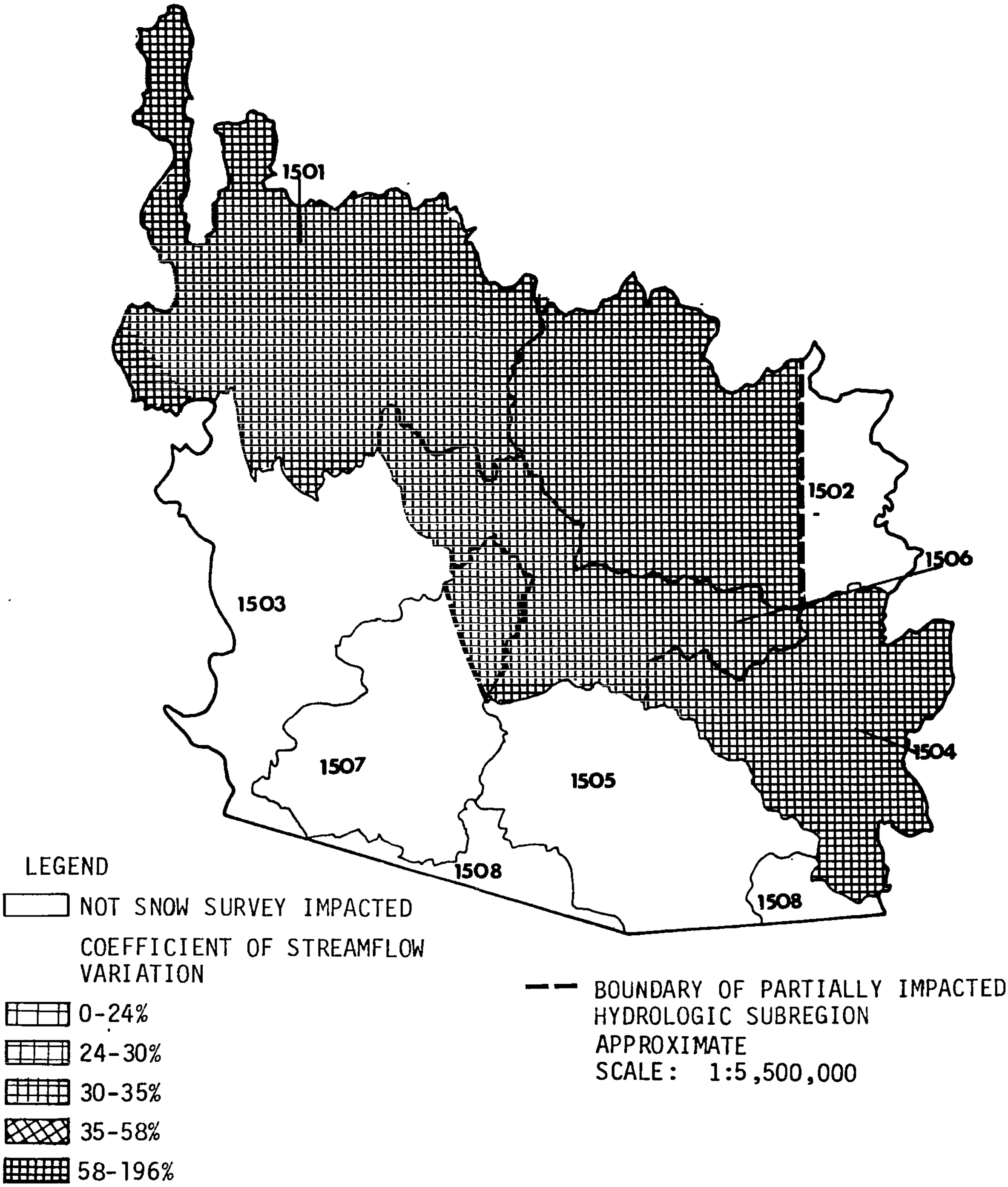


Figure A13. Weighted coefficient of streamflow variation, CV (%) in the snow survey impacted subregions of the Lower Colorado hydrologic region

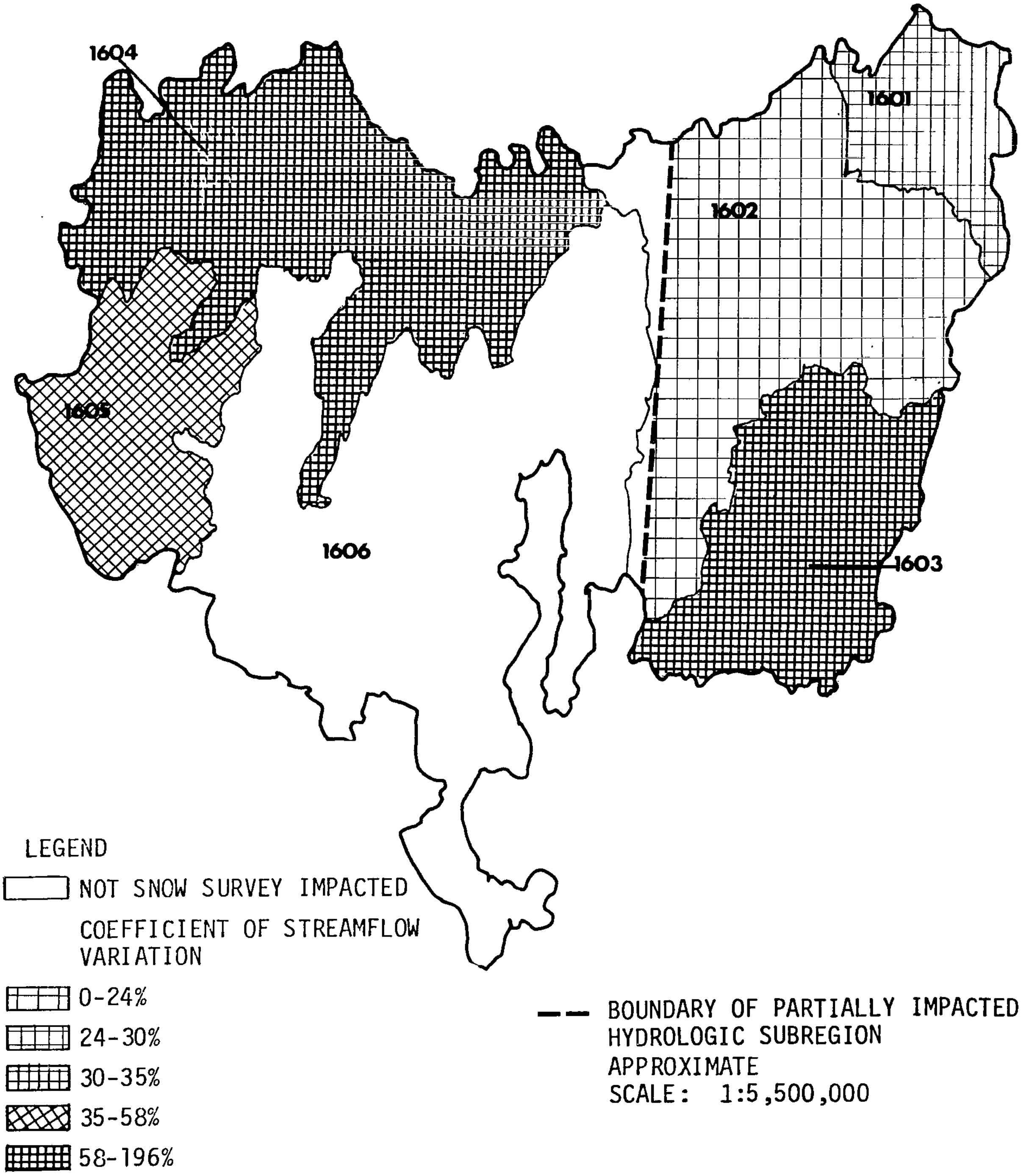


Figure A14. Weighted coefficient of streamflow variation, CV (%), in the snow survey impacted subregions of the Great Basin hydrological region

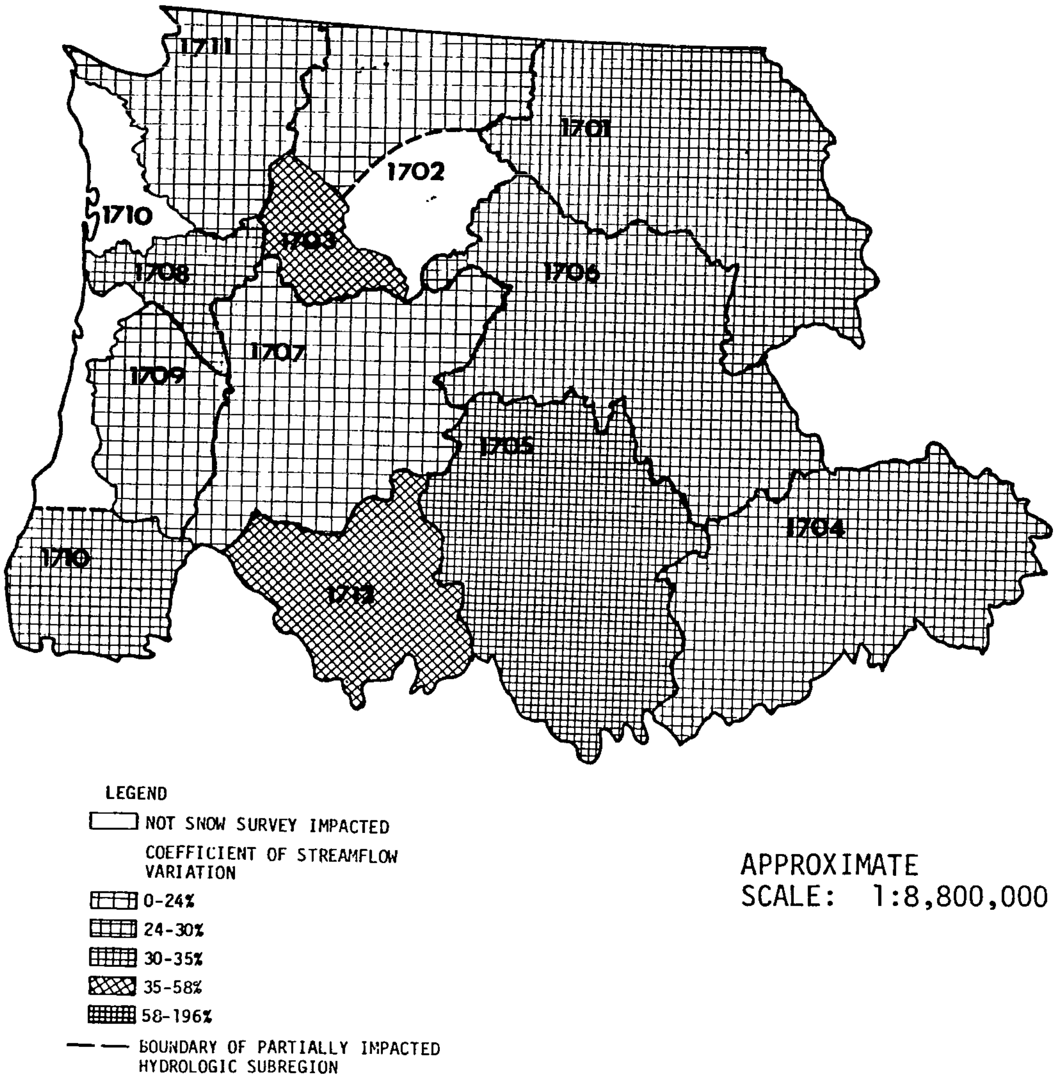


Figure A15. Weighted coefficient of streamflow variation, CV (%), in the snow survey impacted subregions of the Pacific Northwest hydrologic règion

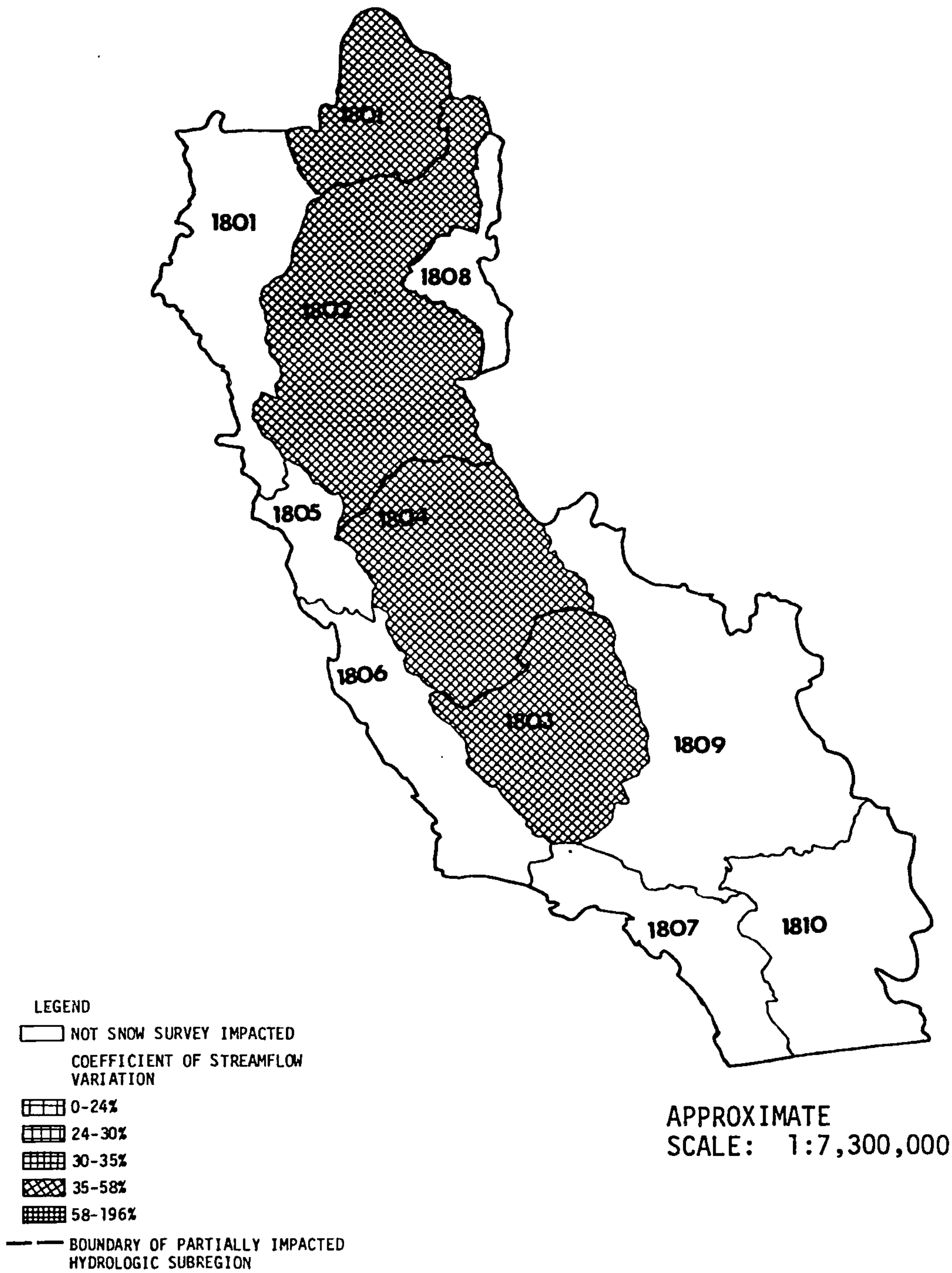


Figure A16. Weighted coefficient of streamflow variation, CV (%) in the snow survey impacted subregions of the California hydrologic region.

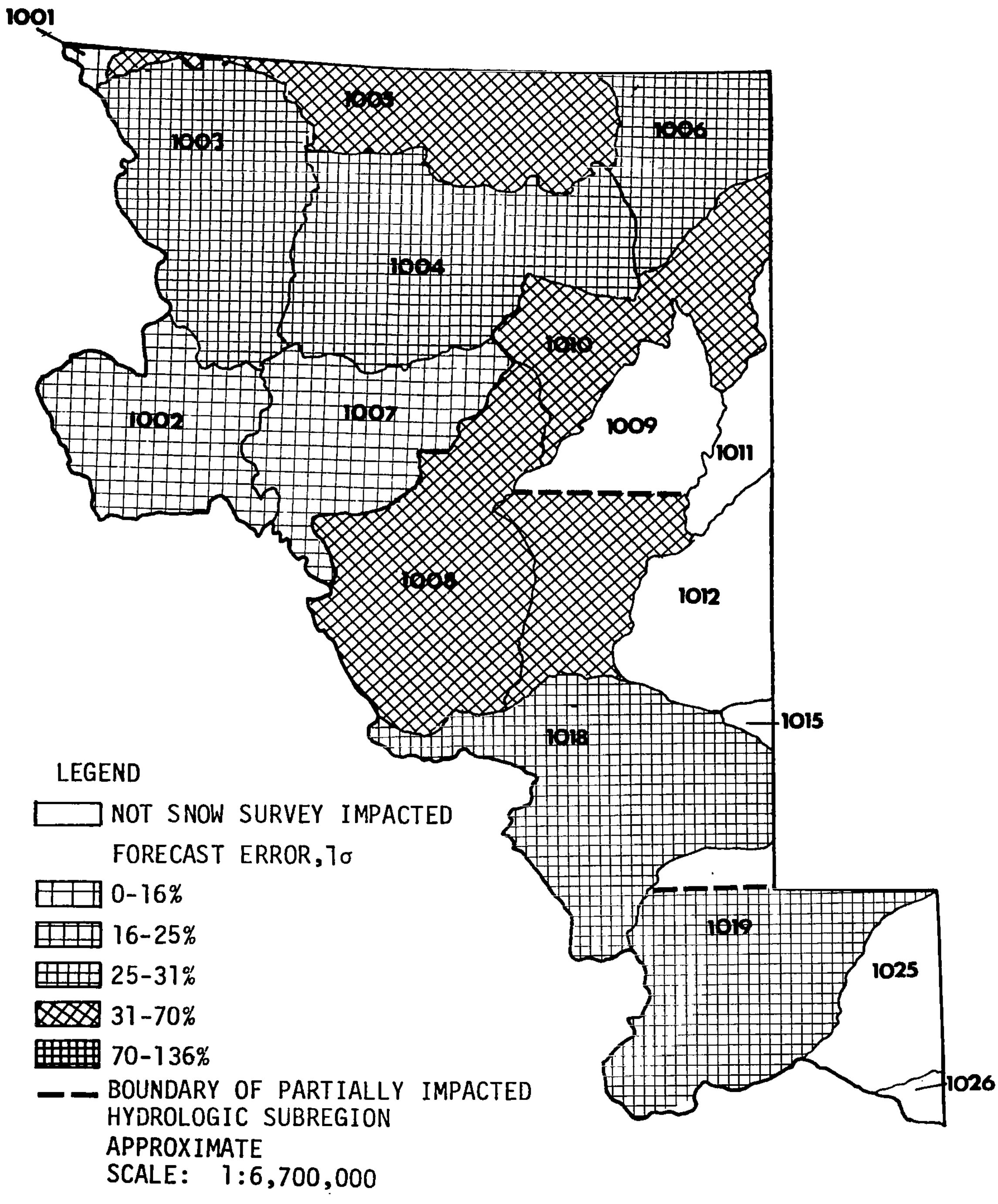


Figure A17. Streamflow forecast error, 1σ (%), in the snow survey impacted subregions of the Missouri hydrologic region

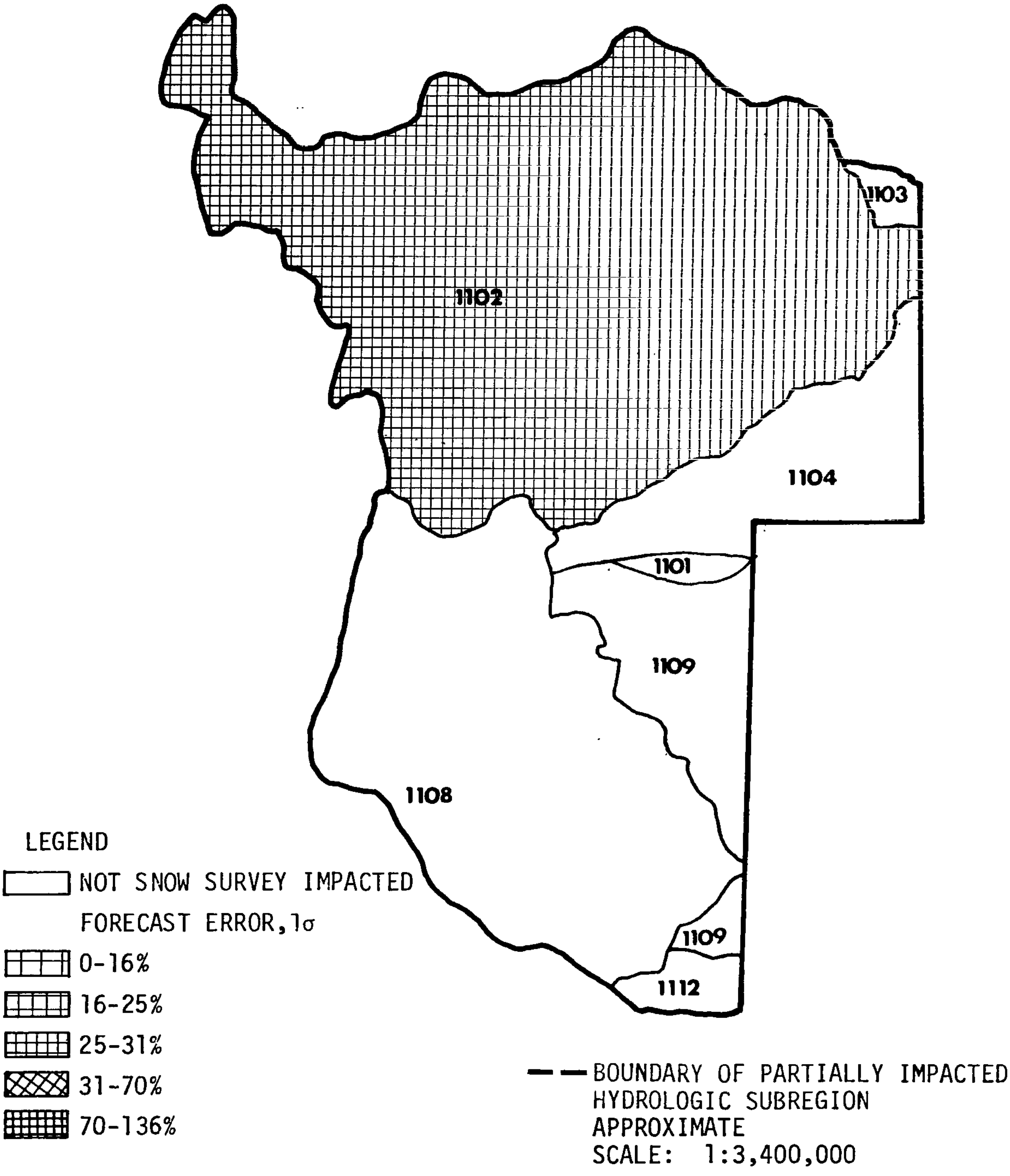


Figure A18. Streamflow forecast error 1σ (%), in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region

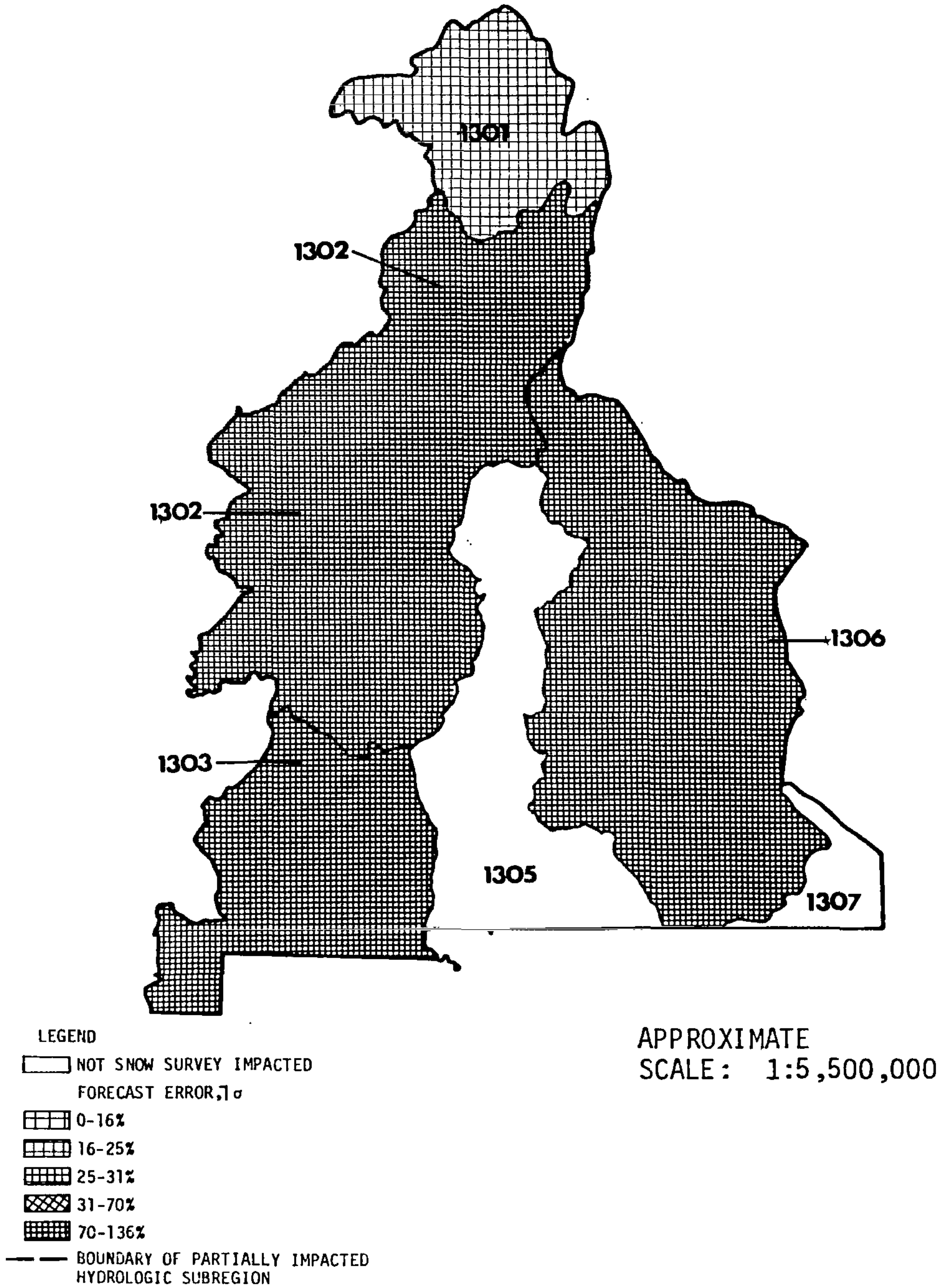


Figure A19. Streamflow forecast error, 1σ (%), in the snow survey impacted subregions of the Rio Grande hydrologic region

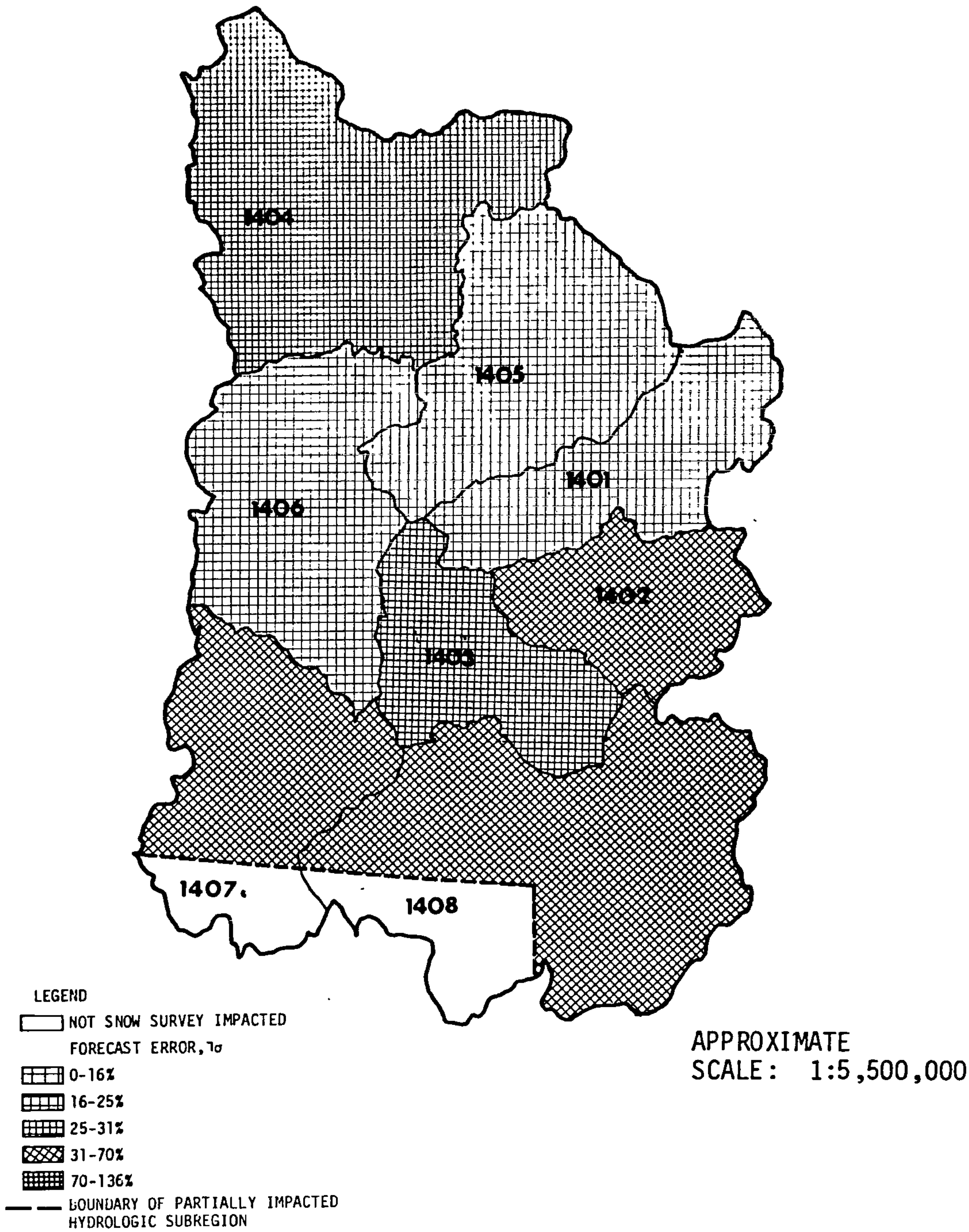


Figure A20. Streamflow forecast error 1σ (%), in the snow survey impacted subregions of the Upper Colorado hydrologic region

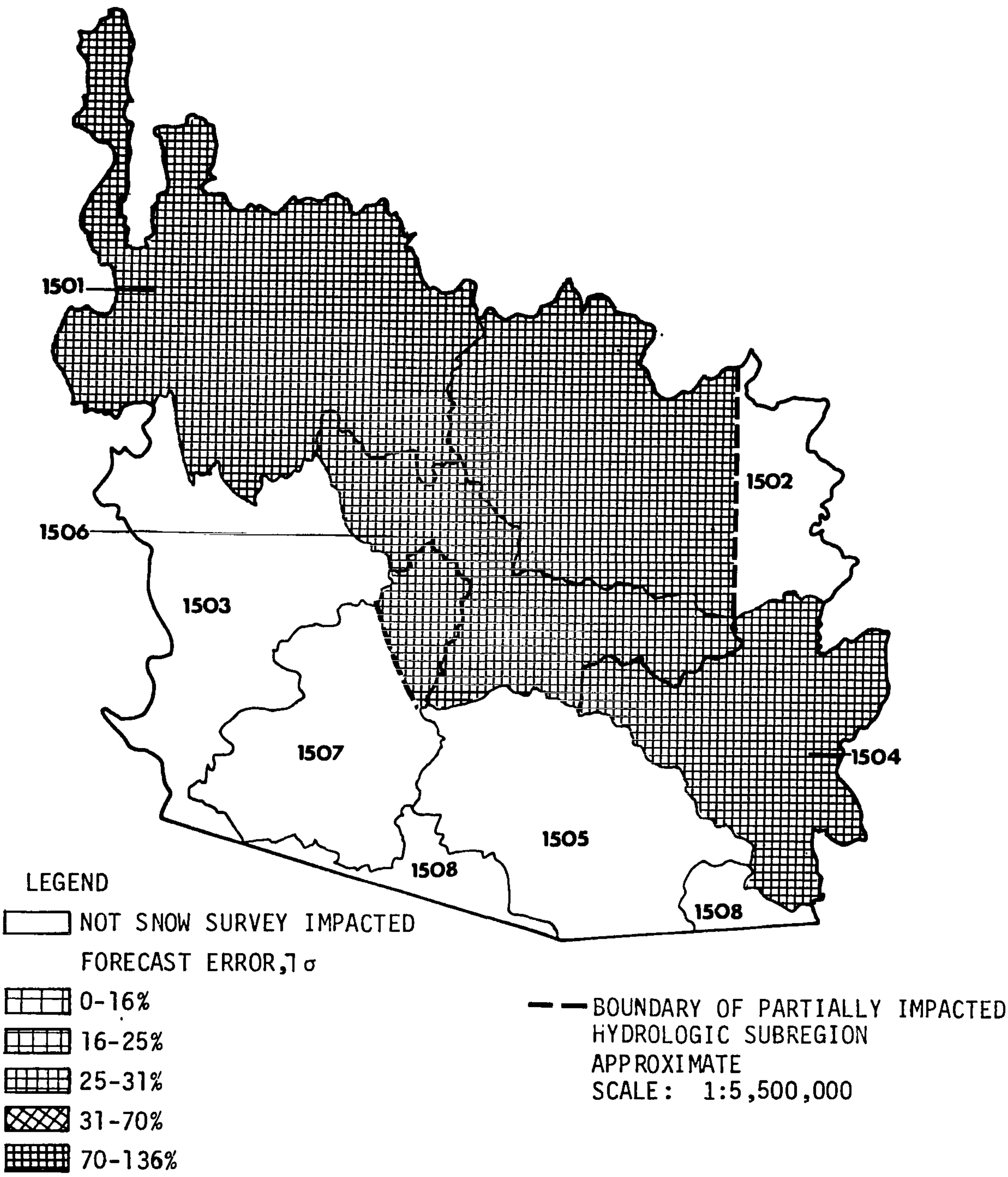


Figure A21. Streamflow forecast error, 1σ (%), in the snow survey impacted subregions of the Lower Colorado hydrologic region

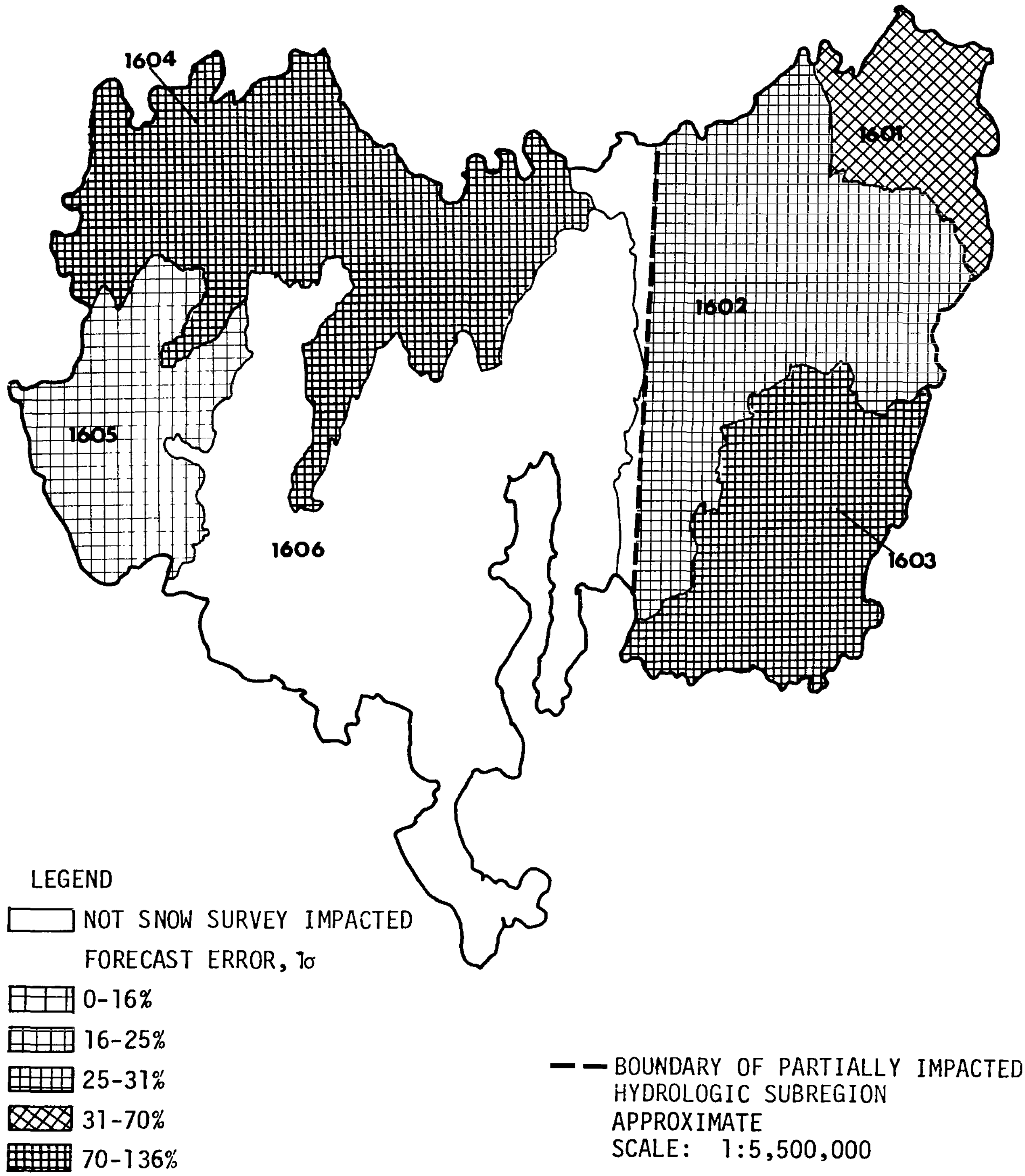


Figure A22. Streamflow forecast error, 1σ (%), in the snow survey impacted subregions of the Great Basin hydrologic region

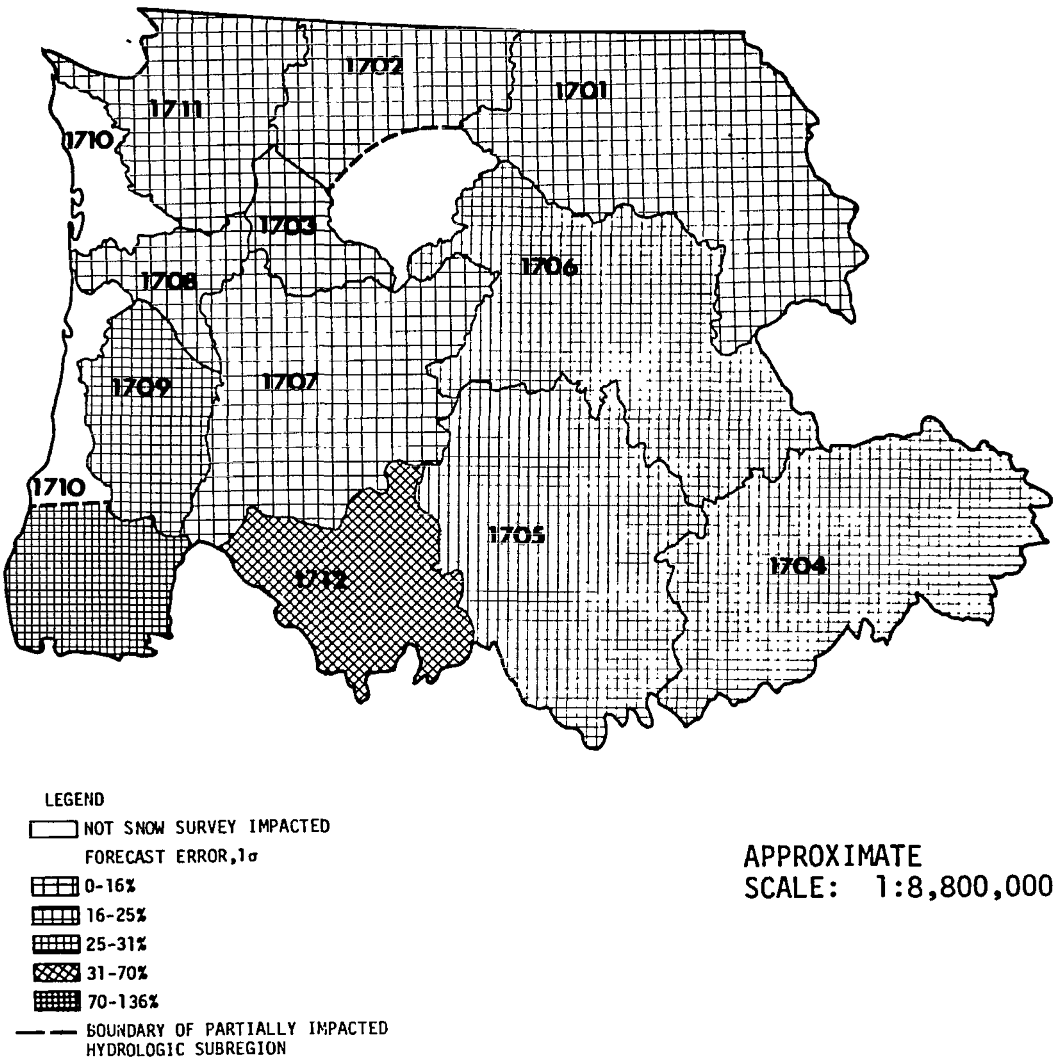


Figure A23. Streamflow forecast error, 1σ (%), in the snow survey impacted subregions of the Pacific Northwest hydrologic region

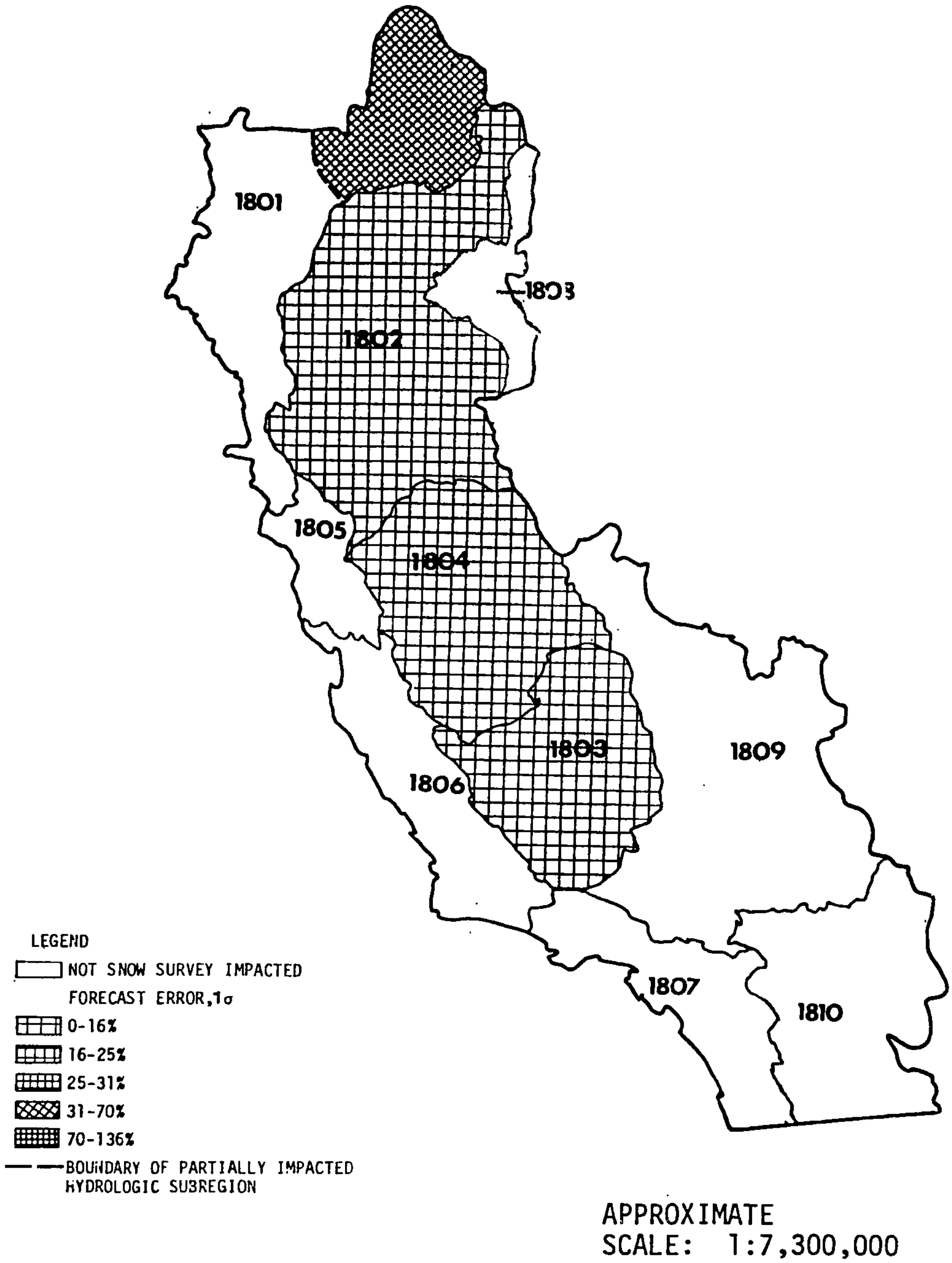


Figure A24. Streamflow forecast error, 1σ (%), in the snow survey impacted subregions of the California hydrologic region

APPENDIX B

APPENDIX B

Description of Surface Water-Irrigated Areas In The Western U.S. (1975) and Estimated Crop Value Per Acre (1976)

According to 1975 U.S.G.S. data[1], approximately 28,812,300 acres of land are irrigated in the Eleven Western States. Of these, roughly 20,208,800 are located within snow survey impacted subregions and use surface water for irrigation. Table B1 lists the surface water-irrigated acreage by snow survey impacted subregion.

Also included in Table B1 is the estimated annual crop value of that irrigated land. These values are based on similar estimates[2] provided by the Bureau of Reclamation for their projects located within each impacted subregion. In those instances where no federal project was located within a given impacted subregion, the regional area-weighted value was substituted.

Figures B1 through B8 graphically present the cumulative distribution of this acreage. The first twenty percent of the subregions contain less than 45,000 acres of surface water-irrigated land; the second twenty percent contain between 45,000 and 188,000 acres of surface water-irrigated land; the third contain between 188,000 and 328,000 acres; the fourth contain between 328,000 and 589,000 acres; and the fifth twenty percent contain between 589,000 and 4,310,000 acres of surface water-irrigated land.

The cumulative distributions of estimated 1976 crop value/acre is presented in Figures B9 through B16. Twenty percent of the impacted subregions had irrigated crops valued at less than or equal to $145/acres, forty percent had crops valued at less than or equal to $225/acre, sixty percent had crops valued at less than or equal to $275/acre, eight percent had crops valued at less than or equal to $490/acre, and one hundred percent had crops valued at less than or equal to $895/acre.

[1] U.S.G.S., 1975 Estimates of Water Use in the United States in 1975; U.S.G.S. Water Use Circular #765.

[2] Bureau of Reclamation, 1976, 1976 Project Data Statistical Appendix III.

TABLE B1

Surface Water - Irrigated Acreage and its Estimated Value Located Within Snow Survey Impacted Areas Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. HYDROLOGIC UNITS REGION	SUBREGION	STATES LOCATED IN THIS SUBREGION	SURFACE WATER/IRRIGATED ACREAGE IN IMPACTED AREAS (1,000)	EST. VALUE OF IRRIGATED LAND ($/ACRE)
Missouri	1001	Montana	d.n.a.	137
	1002	Montana, Wyoming	589.0	164
	1003	Montana	490.5	142
	1004	Montana	566.5	137
	1005	Montana	217.6	76
	1006	Montana	572.0	137
	1007	Montana	430.1	148
	1008	Montana, Wyoming	508.2	208
	1009*	Wyoming	129.4	199
	1010	Montana	1452.0	216
	1018	Colorado, Wyoming	629.5	227
	1019	Colorado	676.6	343
		Total	6260.8	
Arkansas - Red-White	1102	Colorado, New Mexico	528.7	307
		Total	528.7	
Rio Grande	1301	Colorado, New Mexico	191.7	307
	1302	Colorado, New Mexico	17.4	259
	1303	New Mexico	114.4	669
	1306	New Mexico	74.2	257
		Total	397.7	
Upper Colorado	1401	Colorado	158.5	329
	1402	Colorado	135.6	241
	1403	Colorado	49.6	289

TABLE B1 (continued)
Surface Water - Irrigated Acreage and its Estimated Value Located Within Snow Survey Impacted Areas Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. HYDROLOGIC UNITS: REGION	SUBREGION	STATES LOCATED IN THIS SUBREGION	SURFACE WATER/IRRIGATED ACREAGE IN IMPACTED AREAS (1,000)	EST. VALUE OF IRRIGATED LAND ($/ACRE)
Upper Colorado (cont'd)	1404	Colorado, Utah, Wyoming	328.1	71
	1405	Colorado, Utah, Wyoming	222.2	273
	1406	Utah, Colorado	206.8	112
	1407*	Utah	45.1	195
	1408	Colorado, New Mexico, Utah	116.3	144
		Total	1262.2	
Lower Colorado	1501*	Arizona, Utah	21.7	191
	1502*	Arizona, New Mexico	8.0	815
	1504	Arizona, New Mexico	27.3	743
	1506	Arizona	21.2	895
	1507*	Arizona	11.2	664
		Total	89.9	
Great Basin	1601	Idaho, Utah	275.3	153
	1602	Utah	760.8	249
	1603	Utah	188.6	102
	1604	Nevada	276.8	222
	1605	California, Nevada	268.0	212
		Total	1769.5	
Pacific Northwest	1701	Idaho, Montana	430.0	94
	1702*	Washington	383.7	397
	1703	Washington	533.0	618
	1704	Idaho, Nevada, Utah, Wyoming	1969.5	240
	1705	Idaho, Nevada, Oregon	1147.6	270
	1706	Idaho, Oregon, Washington	248.8	216

TABLE B1 (continued)

Surface Water - Irrigated Acreage and its Estimated Value Located Within Snow Survey Impacted Areas Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. HYDROLOGIC UNITS REGION	SUBREGION	STATES LOCATED IN THIS SUBREGION	SURFACE WATER/IRRIGATED ACREAGE IN IMPACTED AREAS (1,000)	EST. VALUE OF IRRIGATED LAND ($/ACRE)
Pacific Northwest (continued)	1707	Oregon, Washington	568.3	278
	1708	Oregon, Washington	18.6	427
	1709	Oregon	136.2	733
	1710*	Oregon	2.9	436
	1711	Washington	140.8	490
	1712	Nevada, Oregon	225.6	261
		Total	5985.0	
California	1801*	California, Oregon	375.0	227
	1802	California, Oregon	860.0	289
	1803	California	1580.0	767
	1804	California	1100.0	716
		Total	3915.0	
	Total for the Eleven Western States		20208.8	

*Only part of this subregion is impacted by snow survey forecasting.

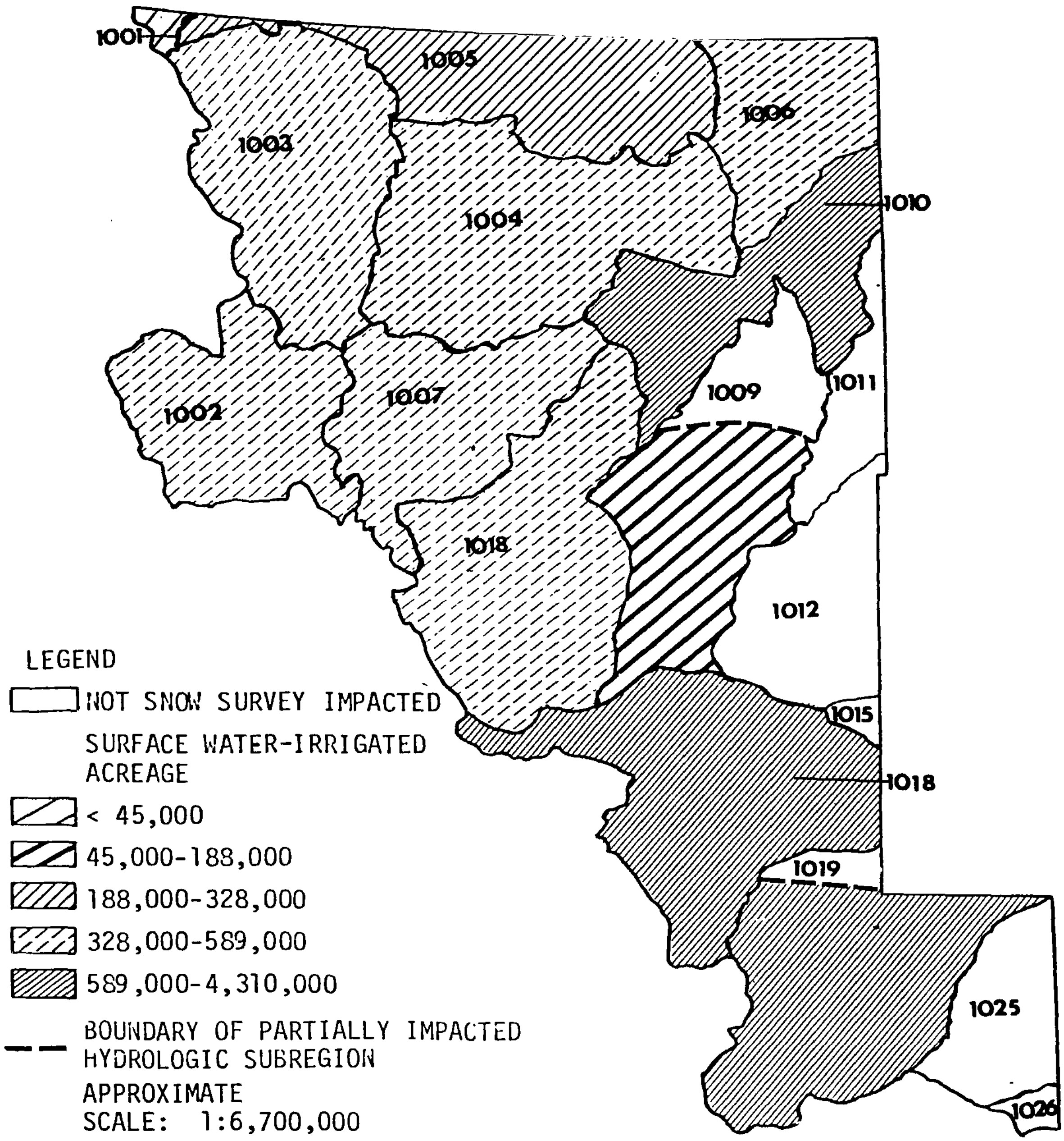


Figure B1. Irrigated acreage in the snow survey impacted subregions of the Missouri hydrologic region

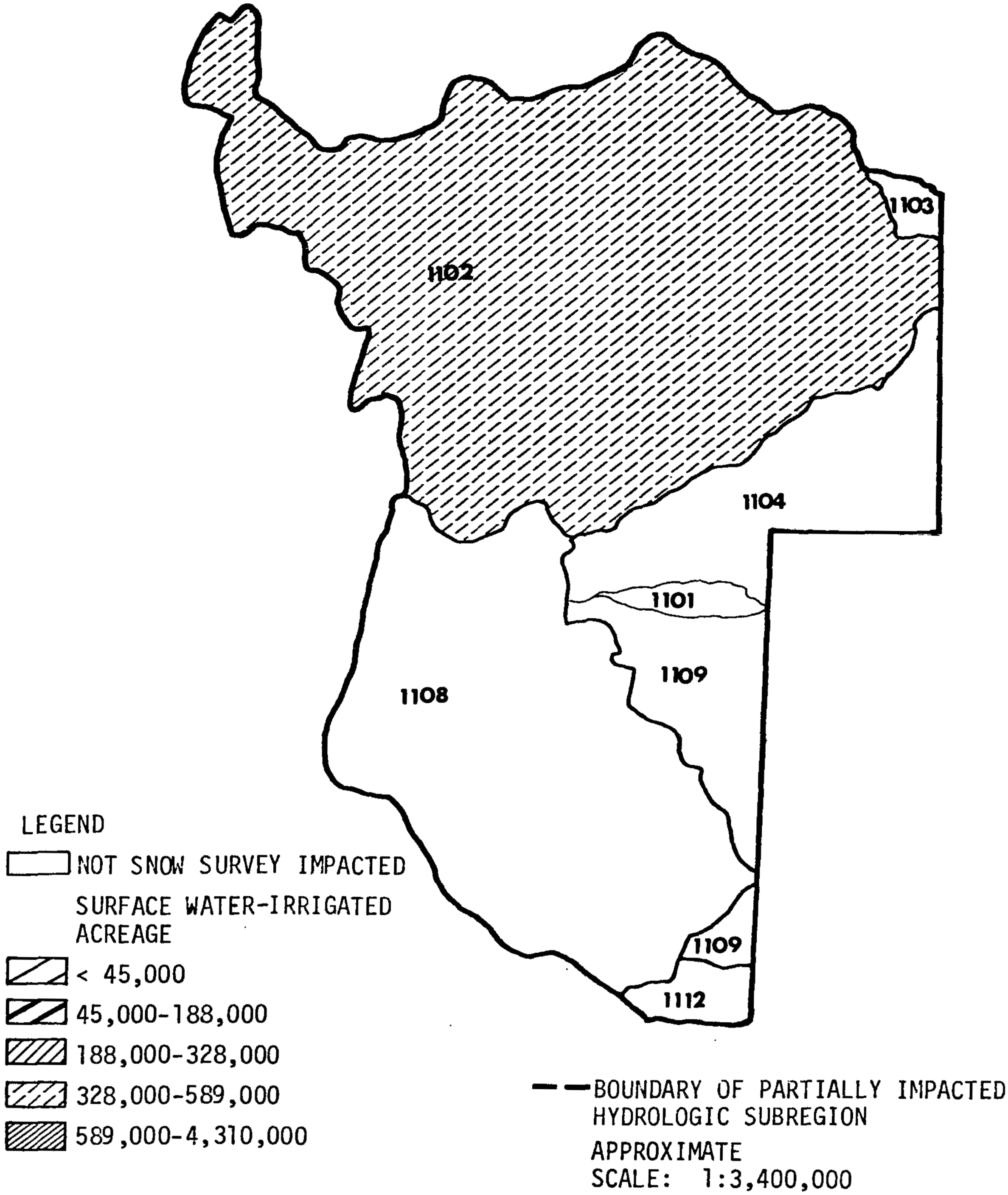


Figure B2. Irrigated acreage in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region

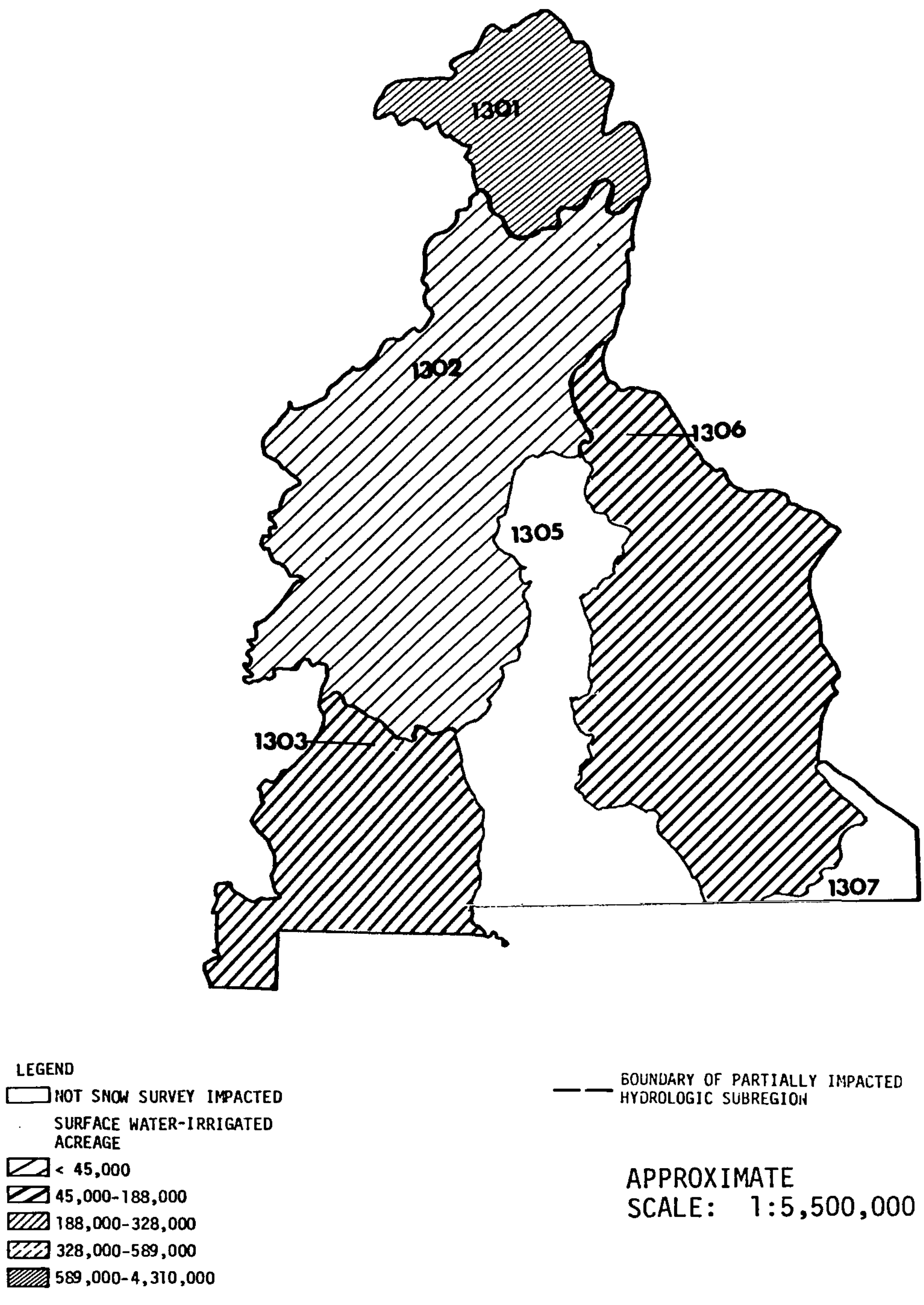


Figure B3. Irrigated acreage in the snow survey impacted subregions of the Rio Grande hydrologic region

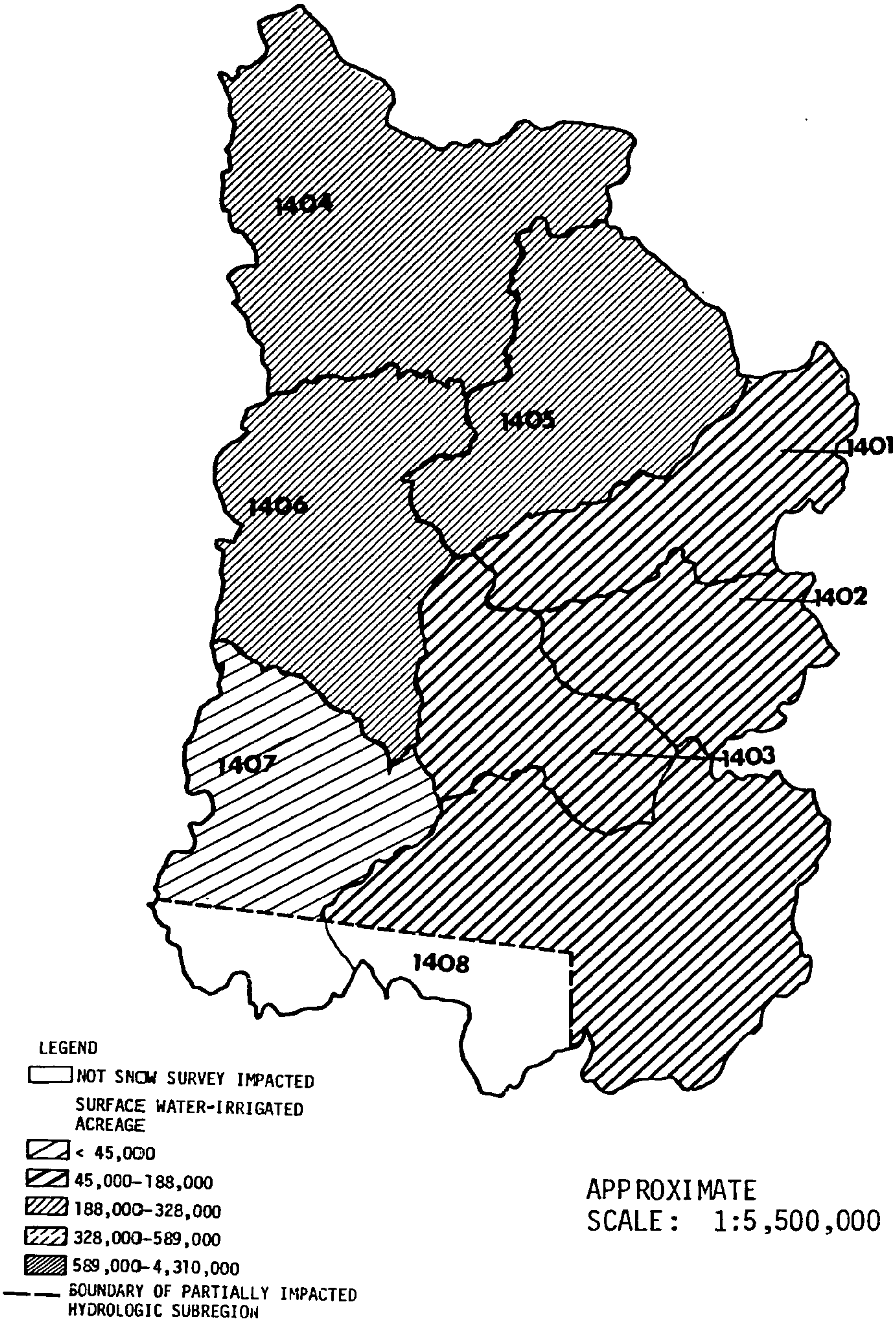


Figure B4. Irrigated acreage in the snow survey impacted subregions of the Upper Colorado hydrologic region

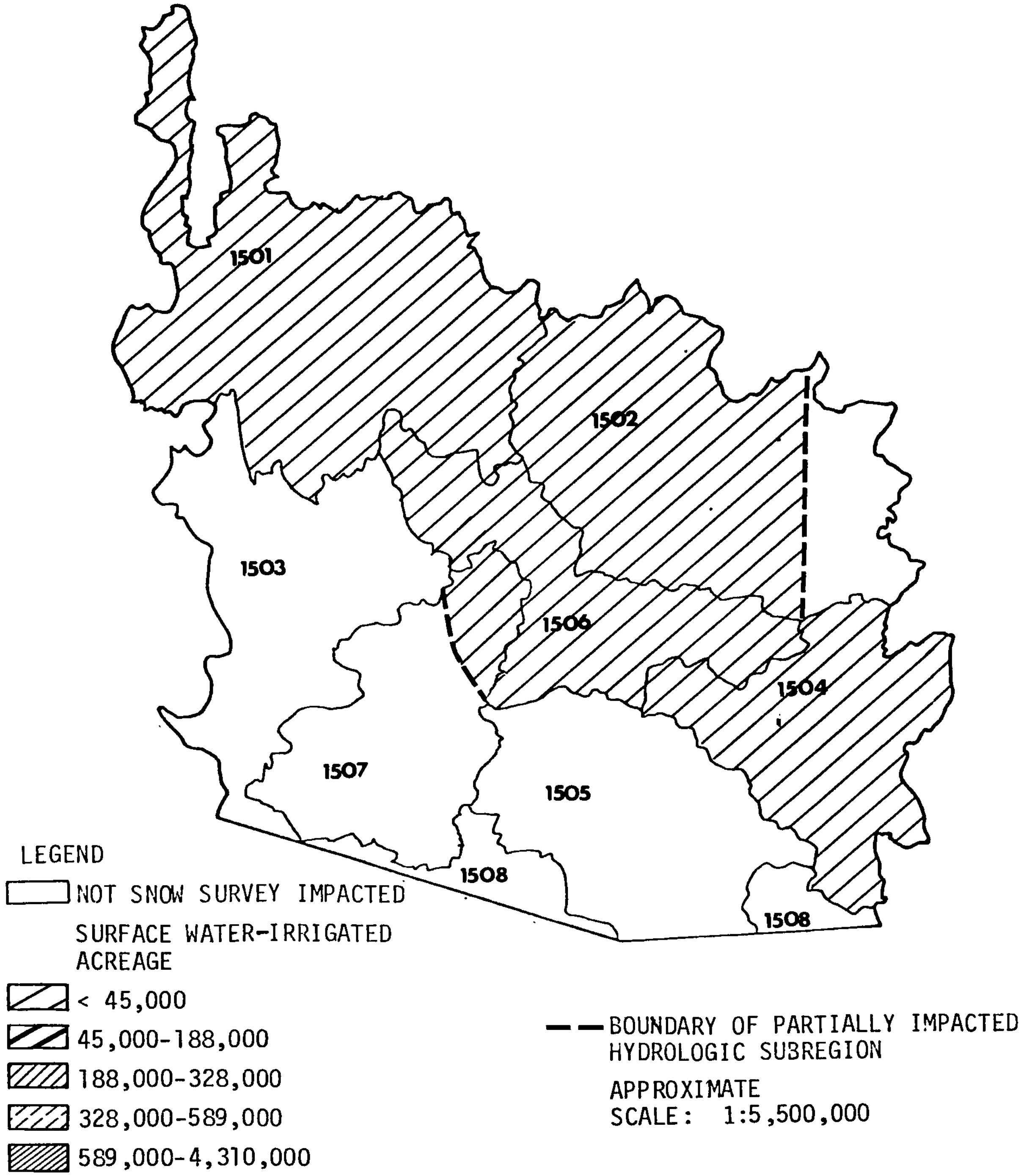


Figure B5. Irrigated acreage in the snow survey impacted subregions of the Lower Colorado hydrologic region

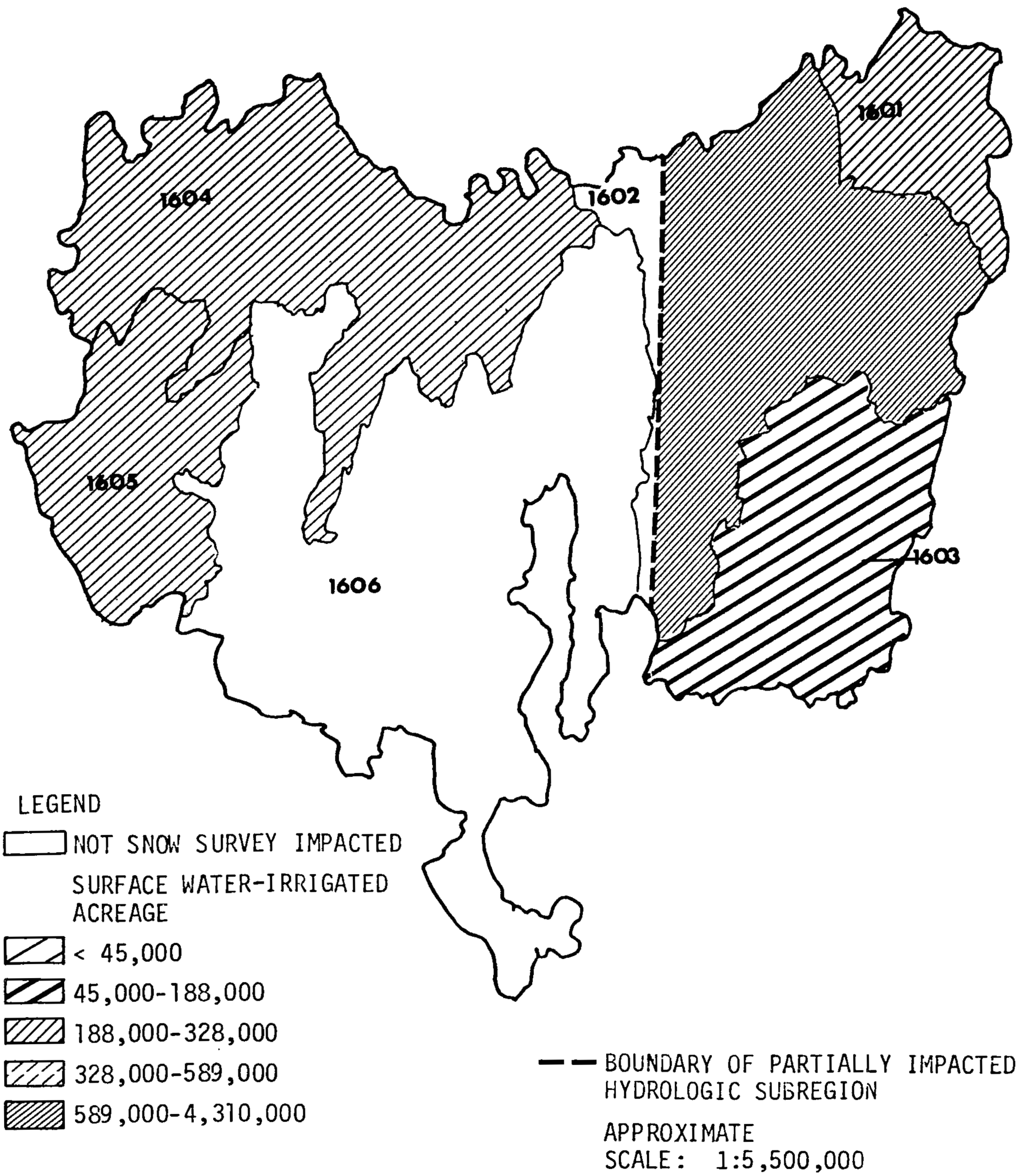


Figure B6: Irrigated acreage in the snow survey impacted subregions of the Great Basin hydrologic region

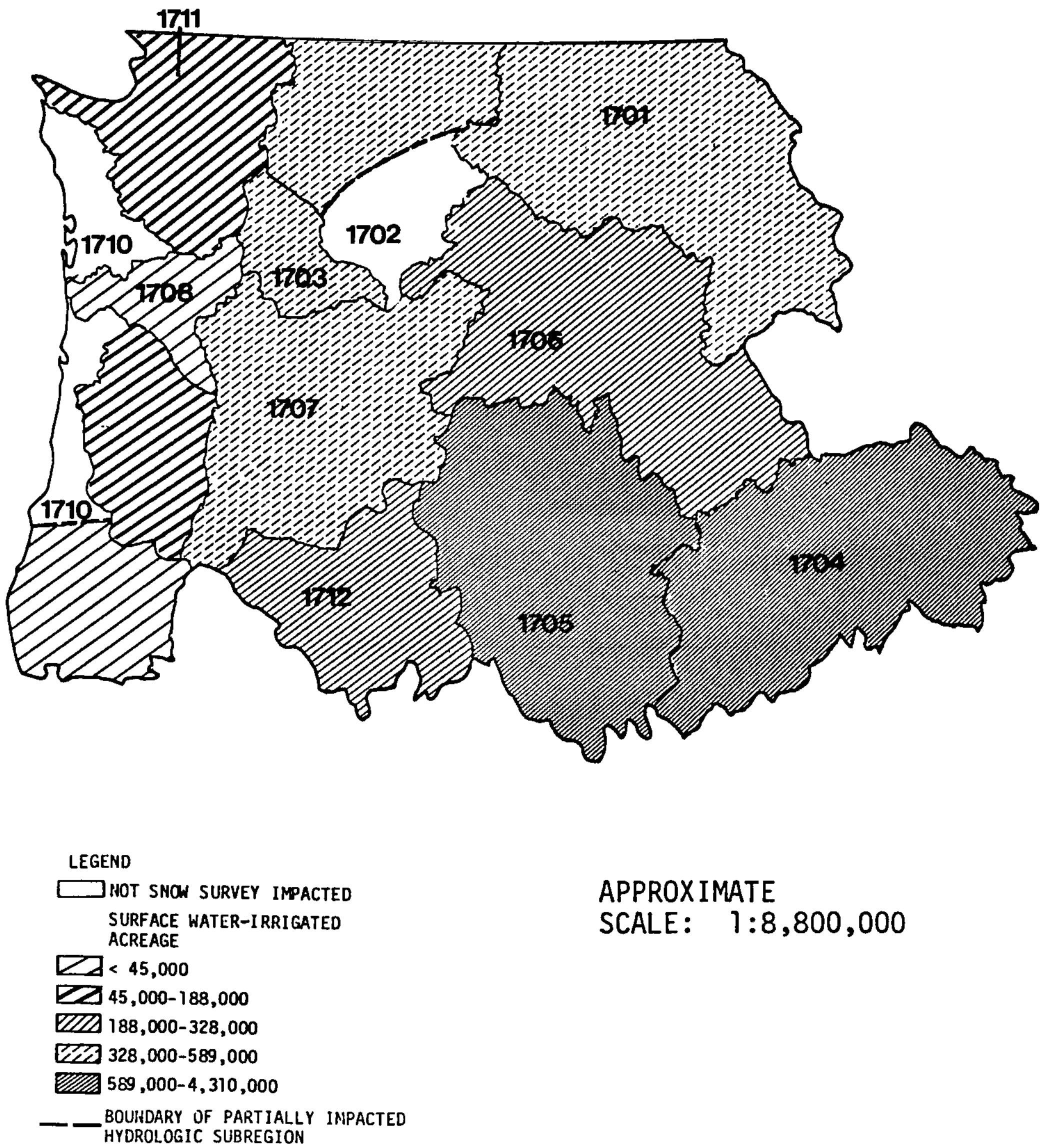


Figure B7: Irrigated acreage in the snow survey impacted subregions of the Pacific Northwest hydrologic region

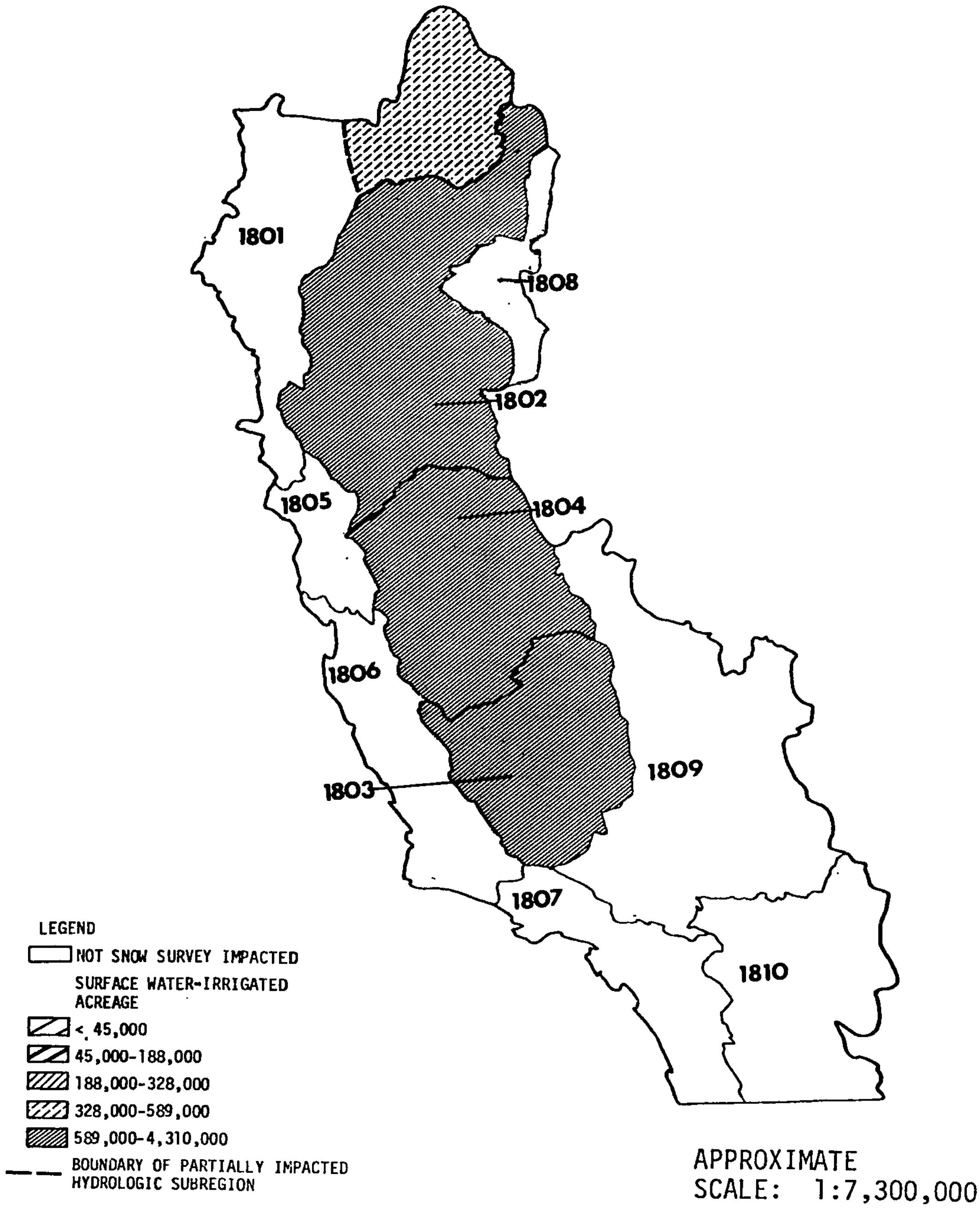


Figure B8: Irrigated acreage in the snow survey impacted subregions of the California hydrologic region

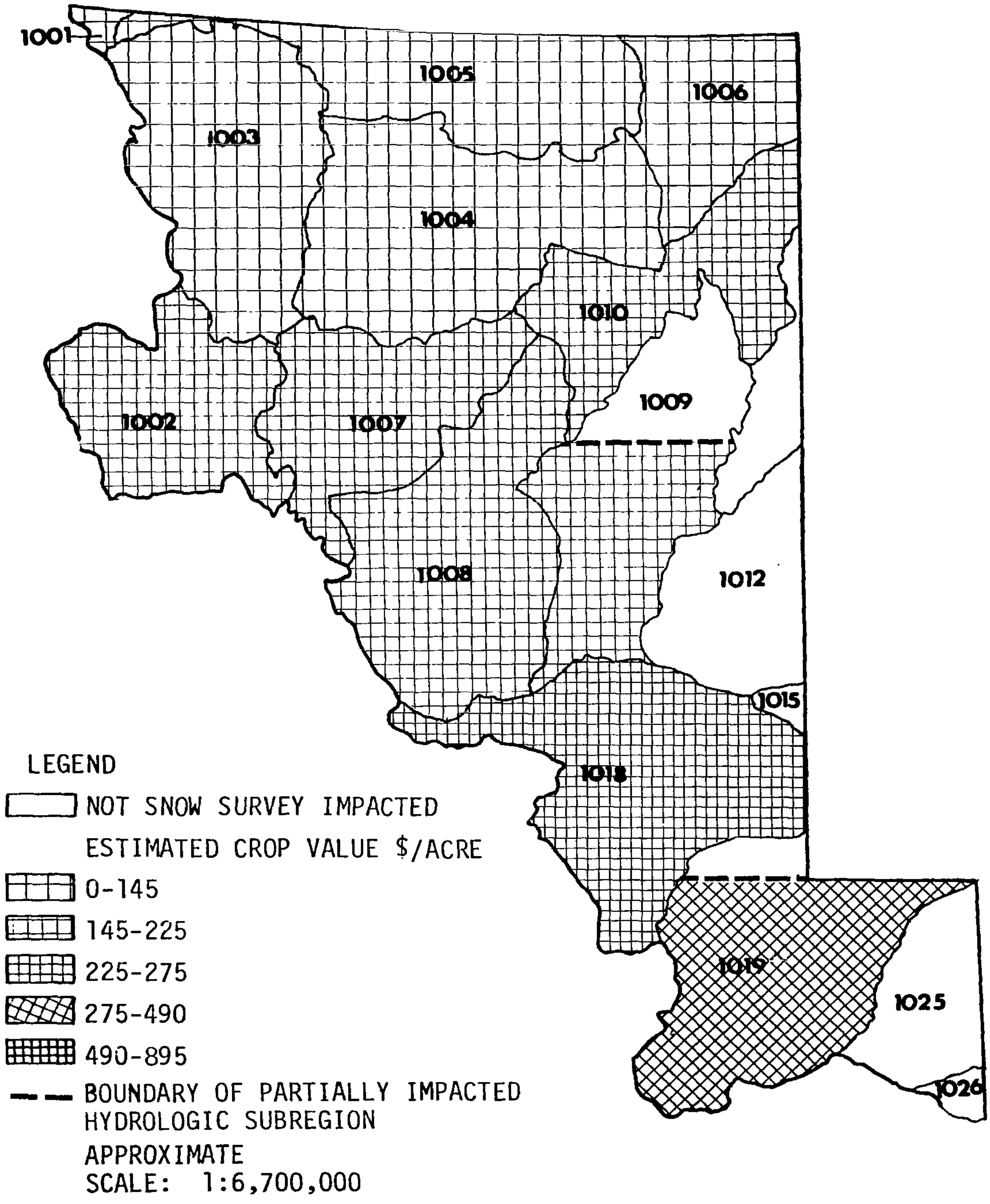


Figure B9: Estimated average crop value ($/acre) value of irrigated land in the snow survey impacted subregions of the Missouri hydrologic region

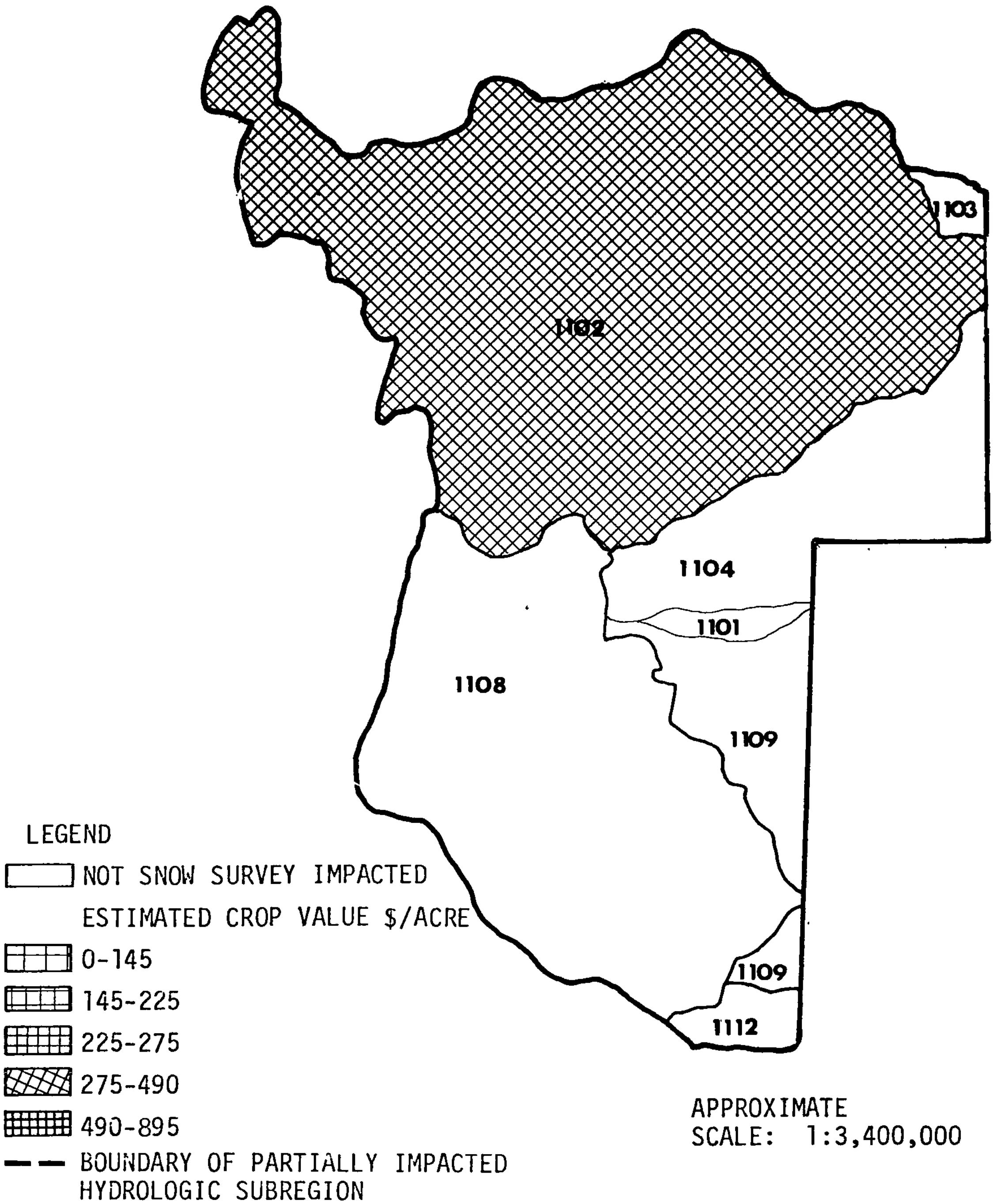


Figure 10B: Estimated average crop value ($/acre) value of irrigated land in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region

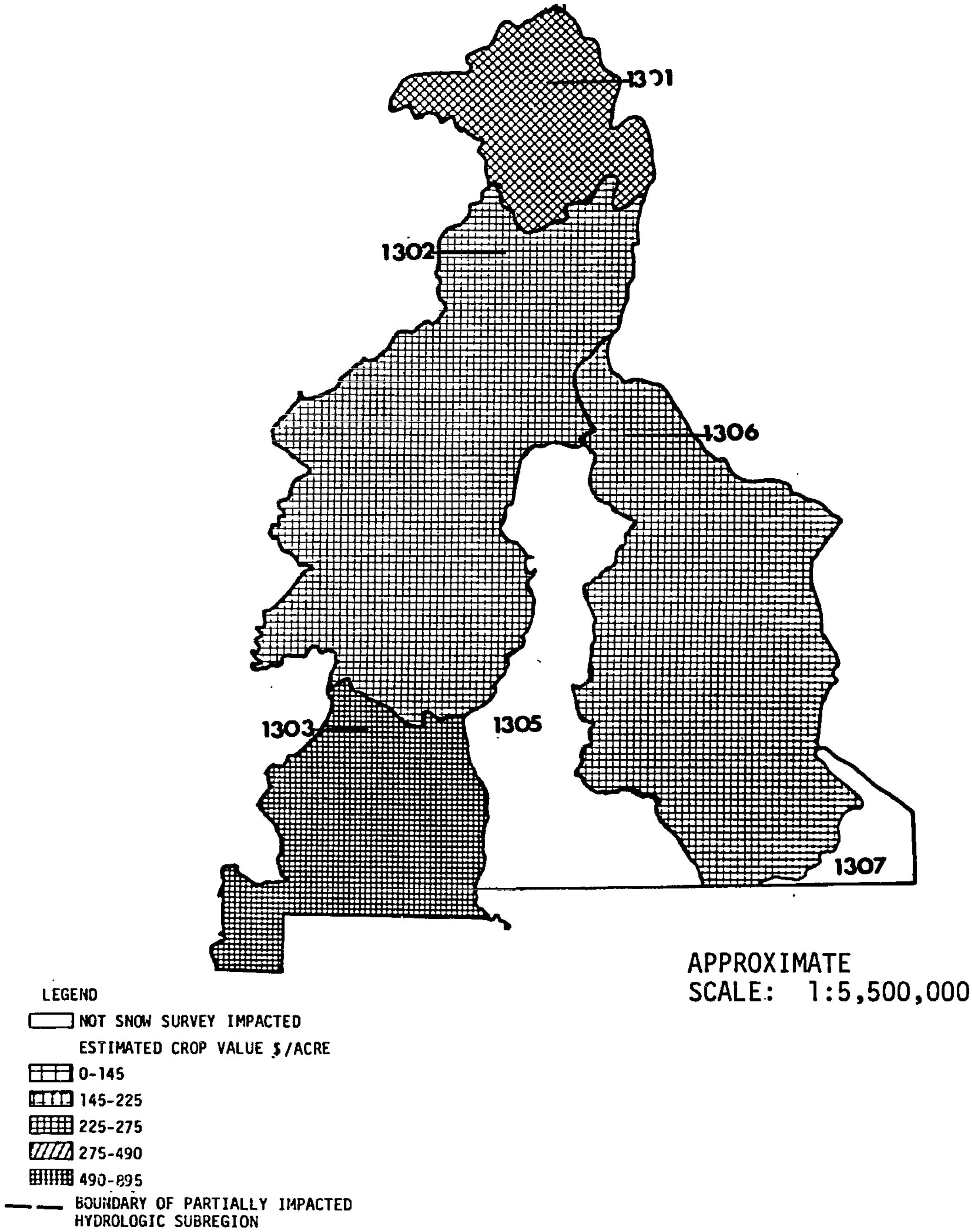


Figure B11: Estimated average crop value of irrigated land in the snow survey impacted subregions of the Rio Grande hydrologic region.

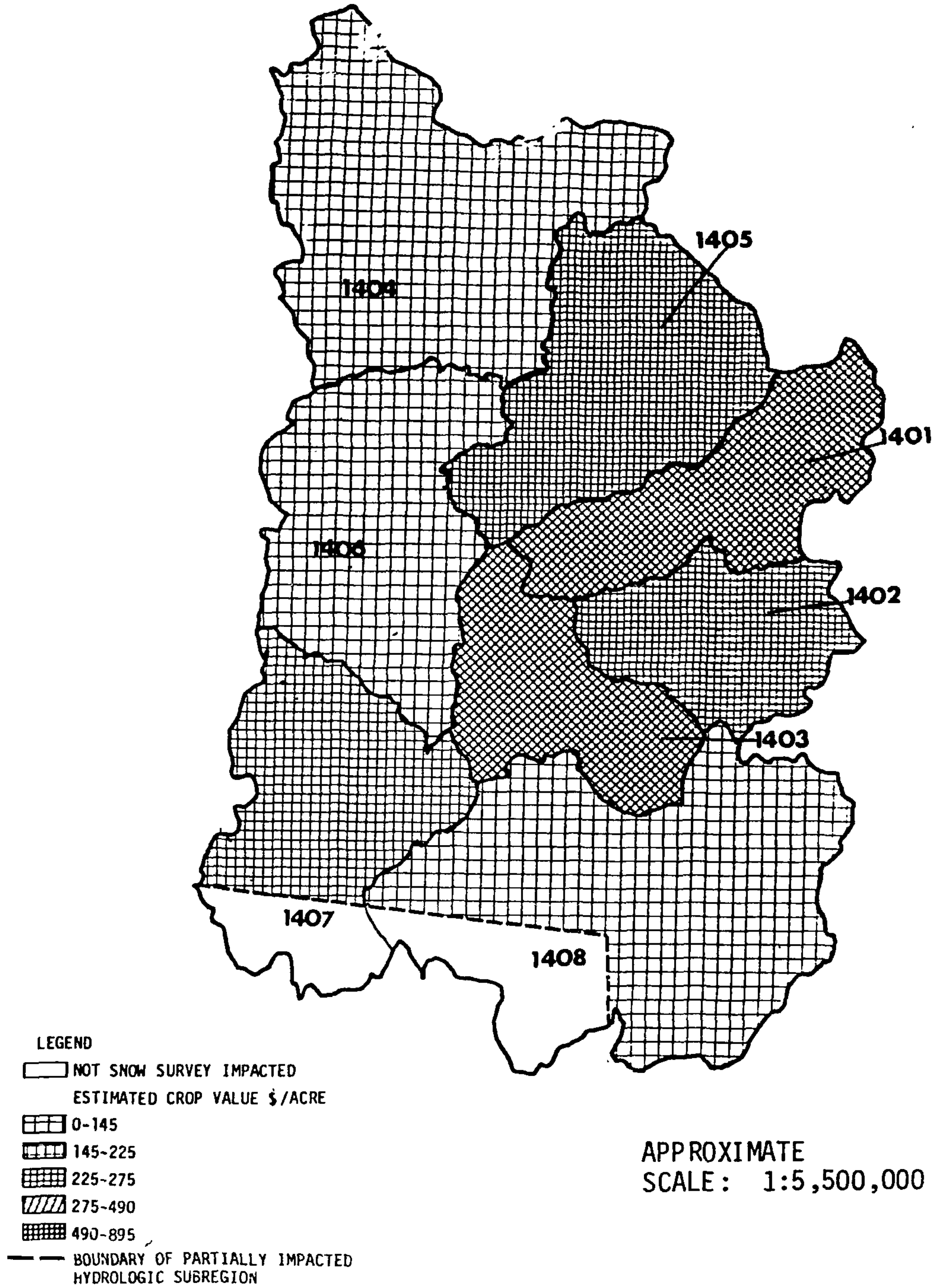


Figure B12: Estimated average crop value ($/acre) value of irrigated land in the snow survey impacted subregions of the Upper Colorado hydrologic region

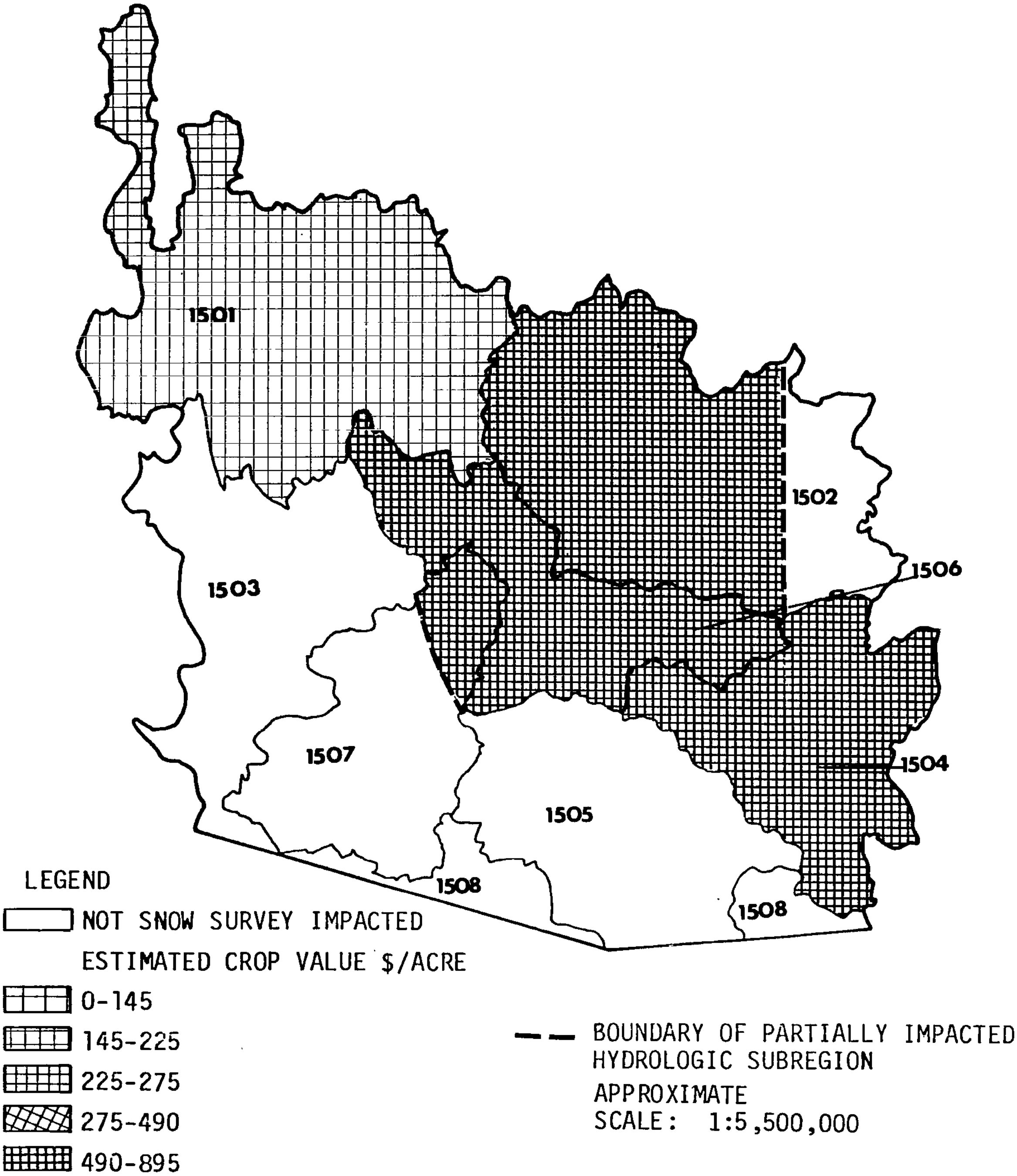


Figure B13: Estimated average crop value ($/acre) value of irrigated land in the snow survey impacted subregions of the Lower Colorado hydrologic region.

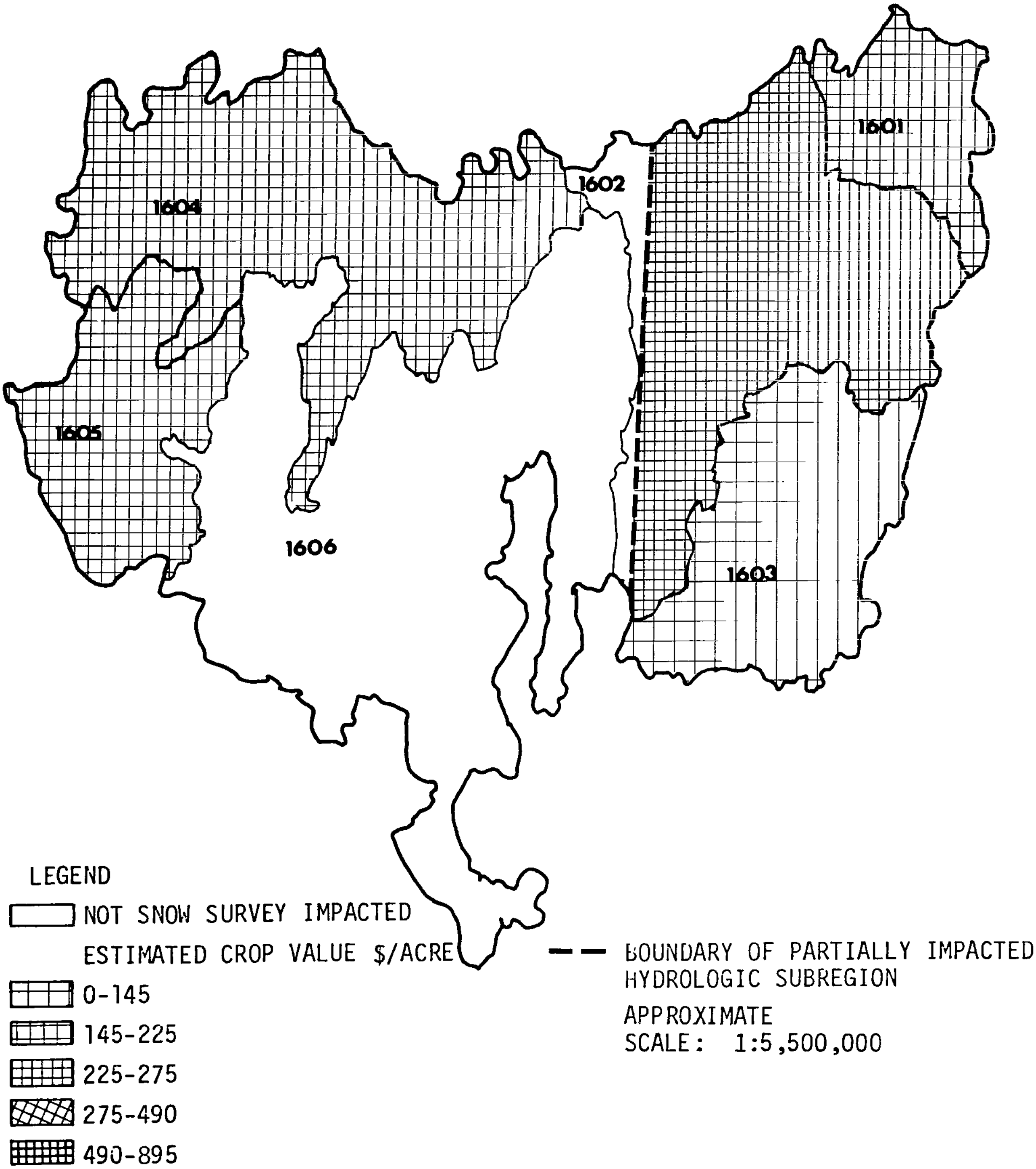


Figure B14: Estimated average crop value ($/acre) value of irregated land in the snow survey impacted subregions of the Great Basin hydrologic region.

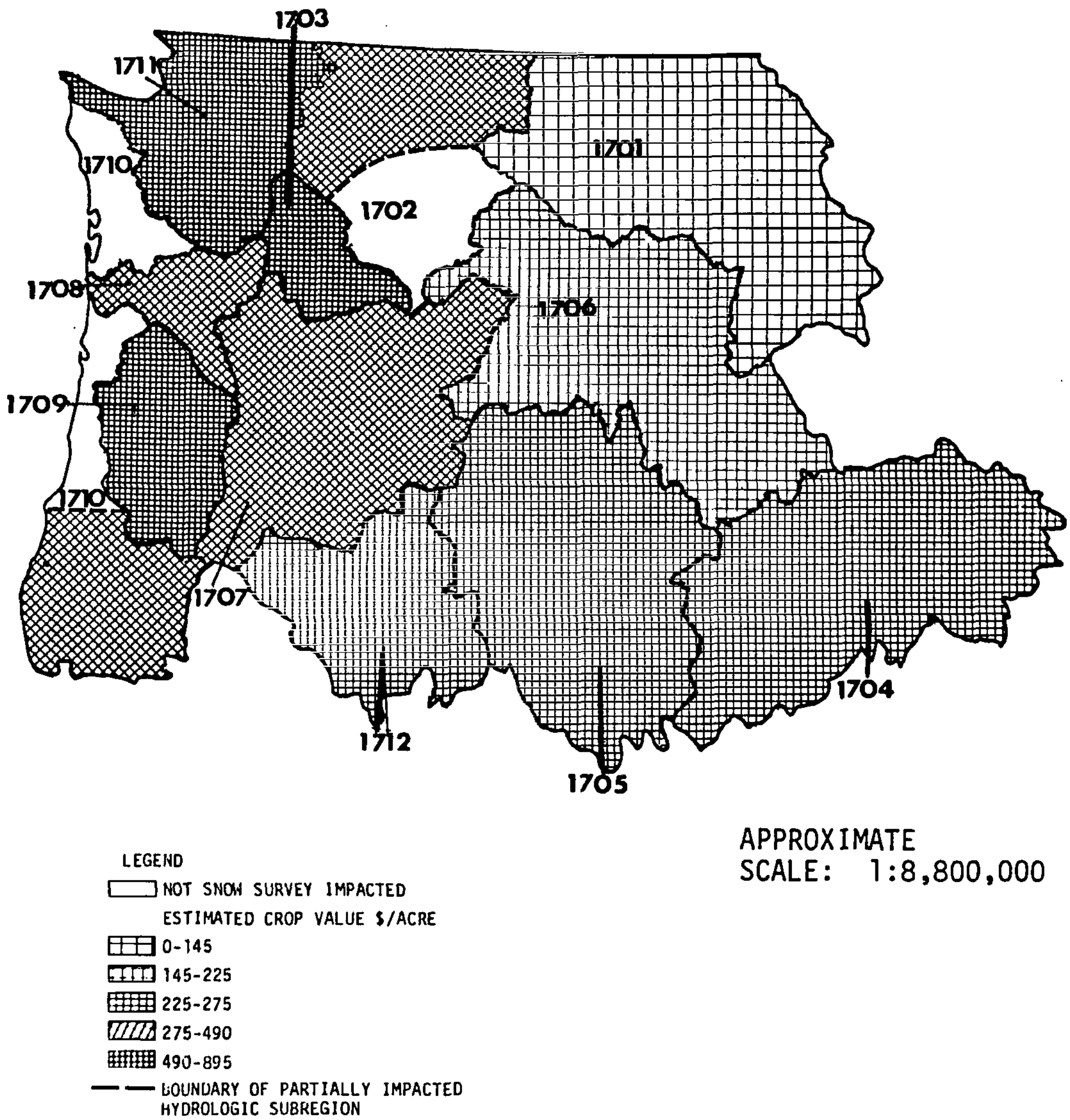


Figure B15: Estimated average crop value ($/acre) value of irrigated land in the snow survey impacted subregions of the Pacific Northwest hydrologic region.

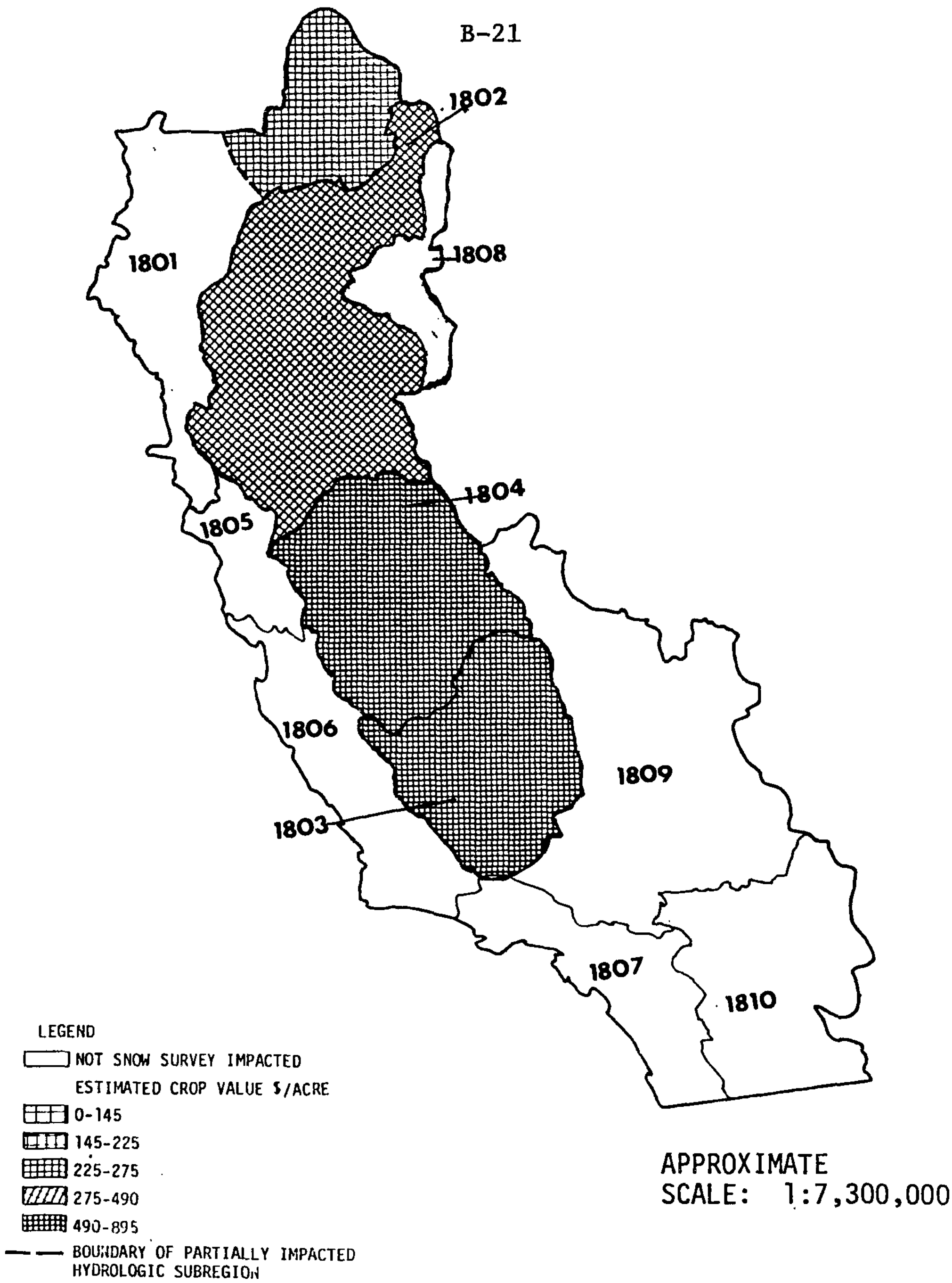


Figure B16: Estimated average crop value ($/acre) value of irrigated land in the snow survey impacted subregions of the California hydrologic region.

APPENDIX C

APPENDIX C

Hydroelectric Energy Data Base:

Average Annual Hydroelectric Energy Generation

Unit Production Costs

Average Unit Revenue for Sale of Prime and Secondary Energy

The 1978 average annual hydroelectric energy generated at each plant[1] located within the impacted subregions is presented in Table C1. Also listed are the unit values of plant and subregional hydroelectric energy production (1976)[2] and regional revenues obtained from the sale of prime energy (1975)[3].

Twenty-seven percent of these subregions do not contain any hydroelectric energy generating plants, twenty-three percent contain plants which generate less than 201.9 MWH/yr., twenty-five percent contain plants which generate between 201.9 and 2,174.0 MWH/yr., and the remaining twenty-five percent contain plants which generate between 2,174.0 and 5,538.4 MWH/yr. This information is presented graphically in Figures C1 through C8. Figures C9 through C17 graphically present the hydroelectric energy production expense data listed in Table C1.

Figures C18 through C25 graphically present steam-electric energy production expenses data[4] listed in Table C2. Thirteen percent of the impacted subregions had generation weighted steam-electric production expenses less than 6.65 mills/KWH, fifty-two percent had expenses of less than 7.20 mills/KWH, sixty percent had expenses of less than 9.20 mills/KWH, eighty percent had expenses of less than 18.10 mills/KWH, and one hundred percent of the impacted subregions had generation-weighted steam-electric production expenses of less than 25.90 mills/KWH.

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[1] FERC, 1978, Two line River Basin Listing of January 1, 1978 thru May 31, 1978 (unpublished)

[2] EIA, 1978, Hydroelectric Plant Construction & Annual Production Expenses 1976

[3] Federal Power Commission, 1975, Statistics of Publically Owned Electric Utilities in the United States

[4] EIA, 1978, Steam-electric Plant Construction Cost & Annual Production Expenses 1976

Table C1
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Missouri	1001[3]	-	Missouri	Montana	-	-	-
	1002	Madison #2	Madison	Montana	50,000	0.80	22.80
	1003	Morony	Missouri	Montana	310,000	-	-
		Ryan	Missouri	Montana	450,000	-	-
		Cochrane	Missouri	Montana	245,000	-	-
		Rainbow	Missouri	Montana	292,000	-	-
		Black Eagle	Missouri	Montana	156,000	-	-
		Holter	Missouri	Montana	226,000	-	-
		Hauser Lake	Missouri	Montana	111,000	-	-
		Canyon Ferry	Missouri	Montana	384,000	-	-
			Total 1003		2,174,000	0.56	22.80
	1004	Fort Peck	Missouri	Montana	896,000	0.80	22.80
	1005[3]	-	-	-	-	-	-
	1006[3]	-	-	-	-	-	-
	1007	Mystic Lake	Rosebud Creek	Montana	52,500	-	-
		Mammoth	Gardiner	Wyoming	1,500	-	-
			Total 1007		54,000	1.86	22.80
	1008	Yellowtail	Bighorn	Montana	1,000,000	-	-
		Heart Mt.	Shoshone	Wyoming	55,800	-	-
		Shoshone	Shoshone	Wyoming	28,800	-	-
		Boysen	Bighorn	Wyoming	8,800		
			Total 1008		1,093,400	0.52	22.80

See notes at end of table

Table C1 (cont'd)

Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Missouri	1009[3]	-	-	-	-	-	-
(con't)	1010[3]	-	-	-	-	-	-
	1018	Gurnsey	No. Platte	Wyoming	27,000	-	-
		Glendo	No. Platte	Wyoming	82,000	-	-
		Alcova	No. Platte	Wyoming	124,000	-	-
		Fremont Canyon	No. Platte	Wyoming	203,600		
		Kortes	No. Platte	Wyoming	147,500	-	-
		Seminole	No. Platte	Wyoming	130,700		
			Total 1018		714,800	1.21	22.80
	1019	Big Thompson	Thompson	Colorado	15,000	-	-
		Flat Iron 1&2	Co-Big Thompson	Colorado	261,100	-	-
		Flat Iron 3	Co-Big Thompson	Colorado	4,200	-	-
		Pole Hill	Co-Big Thompson	Colorado	207,300	-	-
		Estes	Co-Big Thompson	Colorado	107,800	-	-
		Mary's Lake	Co-Big Thompson	Colorado	40,400	-	-
		Fall River	Fall	Colorado	2,300	-	-
		Longmont	St. Vrain Creek	Colorado	3,000	-	-
		Boulder Canyon	Boulder	Colorado	33,000	-	-
		Georgetown	Clear Creek	Colorado	6,800	-	-
		Cabin Creek	So. Clear Creek	Colorado	126,000	-	-
			Total 1019		806,900	1.32	22.80
		Total Missouri Region			5,789,100		

See notes at end of Table

Table C1 (cont'd)

Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units: Region	U.S.G.S. Hydrologic Units: Subregion	Plant Name	Location: River	Location: State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Arkansas Red-White	1102	Manitou Springs	Ruxton Creek	Colorado	10,000	-	-
		Ruxton Park	Ruxton Creek	Colorado	2,600	-	-
		Salida Hydro #2	Arkansas	Colorado	3,900	-	-
		Salida Hydro #1	Arkansas	Colorado	4,100	-	-
			Total 1102		20,600	0.80	22.80
		Total Arkansas-Red-White Region			20,600		
Rio Grande	1301[3]	-	-	-	-	-	-
	1302	Elephant Butte	Rio Grande	-	96,000	2.25	28.90
	1303[3]	-	-	-	-	-	-
	1306[3]	-	-	-	-	-	-
		Total Rio Grande Region			96,000		
Upper Colorado	1401	Palisades (Grand Valley)	Colorado	Colorado	21,000	-	-
		Lower Molina	Pipeline Plateau	Colorado	25,100	-	-
		Upper Molina	Pipeline Plateau	Colorado	42,700	-	-
		Shoshone	Colorado	Colorado	105,000	-	-
		Fall Creek	No. Fall Creek	Colorado	980	-	-
		Green Mt.	Blue	Colorado	69,800	-	-
		William Fk.	Williams Fork	Colorado	12,000	-	-
			Total 1401		276,580	3.51	23.80

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Upper Colorado (con't)	1402	Redlands	Gunnison	Colorado	9,000	-	-
		Duray	Uncompahgre	Colorado	2,700	-	-
		Marrow Point	Gunnison	Colorado	410,500	-	-
		Blue Mesa	Gunnison	Colorado	300,000	-	-
			Total 1402		722,200	0.98	23.80
	1403	Ames	Lake Fork	Colorado	10,800	0.50	23.80
	1404	Flaming Gorge	Green	Colorado	600,000	-	-
		Fontelle	Green	Colorado	70,000	-	-
		Pinedale	Pine Creek	Colorado	200	-	-
			Total 1404		670,200	0.79	23.80
	1405[3]	-	-	-	-	-	-
	1406	Uinta (Poole Creek)	Uinta	Utah	7,500	-	-
		Yellowstone 5	Yellowstone Creek	Utah	6,500	-	-
			Total 1406		14,000	0.50	23.80
	1407	Glen Canyon	Colorado	Arizona	4,000,000	-	-
		Boulder Ck.	Boulder Creek	Utah	23,000	-	-
			Total 1407		4,023,000	0.35	23.80
	1408	Tacoma	Animas				
	1408	Tacoma	Animas	Colorado	21,650	-	-
		Pagosa Springs	San Jaun	Colorado	400	-	-
			Total 1408		22,050	0.50	23.80
		Total Upper Colorado Region			5,738,830		

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location		Average Annual Generation	1976 Production Expenses[1]	1975 Average Revenues Obtained for Primed Energy[2]
Regions	Subregion	Plant Name	River	State	'78 (MWH)	(Mills/KWH)	(Mills/KWH)
Lower Colorado	1501	Cedar #1	Santa Clara	Utah	2,100	-	-
		Cedar #2	Santa Clara	Utah	1,000	-	-
		Cedar #3	Santa Clara	Utah	1,300	-	-
		Cedar #4	Virgin	Utah	2,900	-	-
		Hoover	Colorado	Arizona	2,055,500	-	-
		Hoover	Colorado	Nevada	2,055,500	-	-
			Total 1501		4,118,300	1.06	26.20
	1502[3]	-	-	-	-	-	-
	1504	Coolidge	Gila	Arizona	6,600	2.25	26.20
	1506	Cross Cut	Cross Cut Canal	Arizona	11,500	-	-
		Blue Ridge	East Verde	Arizona	9,800	-	-
		Childs	Fossil Creek Div.	Arizona	24,000	-	-
		Irving	Fossil Creek	Arizona	11,000	-	-
		Stewart Mt.	Salt	Arizona	43,000	-	-
		Morman Flat 3/	Salt	Arizona	46,000	-	-
		Morman Flat	Salt	Arizona	50,000	-	-
		Horse Mesa 3/	Salt	Arizona	25,000	-	-
		Horse Mesa	Salt	Arizona	73,000	-	-
		Roosevelt	Salt	Arizona	96,100	-	-
			Total 1506		389,400	28,56	26,20
	1507[3]	-	-	-	-	-	-
		Total Lower Colorado Region			4,514,300		

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Primed Energy[2] (Mills/KWH)
Great Basin	1601	Cutler	Bear	Utah	74,500	-	-
		Hyrum	Blacksmith Fork	Utah	3,000	-	-
		Logan-Agriculture	Logan	Utah	1,300	-	-
		Logan City	Logan	Utah	6,000	-	-
		Oneida	Bear	Idaho	53,000	-	-
		Cove	Bear	Idaho	25,600	-	-
		Grace	Bear	Idaho	128,500	-	-
		Soda	Bear	Idaho	26,000	-	-
		Soda Springs #1	Soda Creek	Idaho	1,200	-	-
		Soda Springs #4	Soda Creek	Idaho	1,600	-	-
		Paris	Paris	Idaho	2,900	-	-
		Brighman City	Box Elder Creek	Utah	3,100	-	-
		Brigham	Box Elder Creek	Utah	4,200	-	-
			Total 1601		330,900	1.68	17.90
	1602	Pioneer	Ogden	Utah	25,700	-	-
		Weber	Weber	Utah	19,300	-	-
		Wanship	Weber	Utah	5,700	-	-
		Salt Lake City 1	City Creek	Utah	2,700	-	-
		Granite	Big Cottonwood	Utah	6,100	-	-
		Stairs	Big Cottonwood	Utah	5,000	-	-
		Hydro (City of Muray)	Little Cottonwood	Utah	4,700	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units Region	Subregion	Plant Name	Location River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Great Basin (con't)	1602	American Fork	No. American Fork	Utah	6,500	-	-
		Olmsted	Provo	Utah	59,300	-	-
		Deer Creek	Provo	Utah	26,800	-	-
		Snake Creek	Snake Creek	Utah	3,200	-	-
		Snake Creek	Snake Creek	Utah	4,500	-	-
		Herber	Provo	Utah	4,500	-	-
		Spring Creek	Spring Creek	Utah	700	-	-
		Hobble Creek	Hobble Creek	Utah	1,600	-	-
		Bartholomew	Bartholomew Creek	Utah	2,000	-	-
		Lower Straw-berry	Spanish Fork	Utah	1,100	-	-
		Upper Straw-berry	Spanish Fork	Utah	5,200	-	-
		Payson	Peteetneet Creek	Utah	1,900	-	-
			Total 1602		201,900	1.68	17.90
	1603	Center Creek (Parowan City)	Parowan	Utah	2,000	-	-
		Paragonah (Parowan City)	Red Creek	Utah	1,600	-	-
		Beaver Lower	Beaver	Utah	1,400	-	-
		Beaver Upper	Beaver	Utah	3,100	-	-
		Beaver Upper	Beaver	Utah	11,000	-	-
		Manti	Manti Creek	Utah	800	-	-
		Mt. Springs	Manti Creek	Utah	2,400	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location		Average Annual Generation	1976 Production Expenses[1]	1975 Average Revenues Obtained for Prime Energy[2]
Region	Subregion	Plant Name	River	State	'78 (MWH)	(Mills/KWH)	(Mills/KWH)
Great Basin (con't)	1603	Ephraim #1	City Creek	Utah	800	-	-
		Spring City	Oak Creek	Utah	1,000	-	-
		Lower (City of Mt. Pleasant)	Pleasant Creek	Utah	100	-	-
		Upper (City of Mt. Pleasant	Pleasant Creek	Utah	100	-	-
		Lower Fairview	Cottonwood Creek	Utah	300	-	-
		Fountain Green	Big Springs	Utah	1,300	-	-
		Lower Monroe	Monroe Creek	Utah	400	-	-
			Total 1603		26,800	1.68	17.90
	1604[3]	-	-	-	-	-	-
	1605	Washoe	Truckee	Nevada	14,000	-	-
		Verdi	Truckee	Nevada	16,000	-	-
		Fleish	Truckee	Nevada	20,000	-	-
		Farad	Truckee	Nevada	14,000	-	-
		26 Foot Drop	Carson	Nevada	5,000	-	-
		Lahontan	Carson	Nevada	13,000	-	-
			Total 1605		82,000	1.68	17.90
		Total Great Basin Region			641,600		

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975 Average Revenues Obtained for Prime Energy[2]
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	(Mills/KWH)
Pacific Northwest	1701	Little Falls	Spokane	Washington	217,000	-	-
		Long Lake	Spokane	Washington	444,100	-	-
		Nine Mile	Spokane	Washington	109,200	-	-
		Monroe Street	Spokane	Washington	58,000	-	-
		Upper Falls	Spokane	Washington	73,700	-	-
		Upper River	Spokane	Washington	31,000	-	-
		Post Falls	Spokane	Idaho	79,000	-	-
		Boundry	Pend Oreille	Washington	3,997,000	-	-
		Box Canyon	Pend Oreille	Washington	508,500	-	-
		Albeni Falls	Pend Oreille	Idaho	210,000	-	-
		Calispell	Calispell Creek	Washington	2,300	-	-
		Cabinet Gorge	Clarks Fork	Idaho	1,088,500	-	-
		Noxon Rapids	Clarks Fork	Montana	1,776,300	-	-
		Thompson Falls	Clarks Fork	Montana	310,000	-	-
		Kerr	Flathead	Montana	1,060,000	-	-
		Big Creek	Big Creek	Montana	2,040	-	-
		Big Fork	Swan	Montana	31,000	-	-
		Hungary Horse	S. Fk.	Montana	820,000	-	-
		Milltown	Clarks	Montana	20,000	-	-
		Flint Creek	Flint	Montana	8,000	-	-
		Moyie #1	Moyie	Idaho	2,000	-	-
		Moyie #2	Moyie	Idaho	10,000	-	-
		Lake Creek #1	Lake Creek	Montana	5,600	-	-
		Lake Creek #2	Lake Creek	Montana	19,400	-	-
		Libby	Kootenai	Montana	858,000	-	-
			Total 1701		11,740,640	0.64	8.30

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Pacific Northwest (con't)	1702	Priest Rapids	Columbia	Washington	5,256,000	-	-
		Wanapum	Columbia	Washington	5,580,000	-	-
		Rock Island	Columbia	Washington	1,304,000	-	-
		Trinity	Phelps Creek	Washington	300	-	-
		Rocky Reach	Columbia	Washington	5,744,000	-	-
		Chelan (Lake)	Chelan	Washington	361,000	-	-
		Stehekin	Stehekin, Chelan	Washington	600	-	-
		Wells	Columbia	Washington	5,870,000	-	-
		Chief Joseph	Columbia	Washington	9,850,000	-	-
		Grand Coulee	Columbia	Washington	20,935,000	-	-
		Grand Coulee P/G	Columbia	Washington	88,000	-	-
		Meyers Falls	Colville	Washington	9,000	-	-
			Total 1702		54,997,900	-	-
	1703	Chandler	Yakima offstream	Washington	80,000	-	-
		Drop #2	Yakima	Washington	6,000	-	-
		Drop #3	Yakima	Washington	3,000	-	-
		Naches	Naches	Washington	33,500	-	-
		Naches Drop	Naches	Washington	9,600	-	-
		Roza	Yakima offstream	Washington	50,000	-	-
			Total 1703		182,100	0.39	8.30

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975 Average Revenues Obtained for Prime Energy[2]
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	(Mills/KWH)
Pacific Northwest (con't)	1704	Swift Upper	Swift Creek	Wyoming	2,700	-	-
		Thousand Springs	Springs	Idaho	62,000	-	-
		Clear Lake 5/	Springs	Idaho	18,000	-	-
		Shoshone Falls 5/	Snake	Idaho	99,660	-	-
		Bliss	Snake	Idaho	395,400	-	-
		Twin Falls	Snake	Idaho	70,700	-	-
		Minidoka	Snake	Idaho	90,000	-	-
		American Falls	Snake	Idaho	138,300	-	-
		Lower New Idaho Falls	Snake	Idaho	24,000	-	-
		City of Idaho Falls	Snake	Idaho	14,000	-	-
		Upper Idaho Falls	Snake	Idaho	16,000	-	-
		St. Anthony	Henrys Fork	Idaho	3,900	-	-
		Ashton 5/	Henrys Fork	Idaho	33,000	-	-
		Pond Lodge	Buffalo	Idaho	400	-	-
		Palisades	Snake	Idaho	610,000	-	-
		Strawberry	Strawberry Creek	Wyoming	8,000	-	-
		Malad, Lower	Malad	Idaho	102,000	-	-
		Malad, Upper	Malad	Idaho	61,500	-	-
		Lower Salmon	Snake	Idaho	270,000	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Pacific Northwest (con't)	1704	Upper Salmon A	Snake	Idaho	167,000	-	-
		Upper Salmon B	Snake	Idaho	141,600	-	-
		Total 1704			2,328,160	0.44	8.30
	1705	Hells Canyon	Snake	Oregon	1,995,600	-	-
		Oxbow	Snake	Oregon	1,044,300	-	-
		Brownlee	Snake	Idaho	2,308,300	-	-
		Rock Creek	Rock Creek	Oregon	4,900	-	-
		Baker (City of)	Goodrich Lk.	Oregon	1,300	-	-
		Black Canyon	Payette	Idaho	78,000	-	-
		Cascade	*N. Fk. Payette*	*Idaho*	2,700	-	-
		Boise River Division	Boise	Idaho	4,700	-	-
		Atlanta	M. Fk. Boise	Idaho	100	-	-
		Anderson Ranch	S. Fk. Boise	Idaho	149,000	-	-
		Swan Falls 5/	Snake	Idaho	96,100	-	-
		Strike C.J.	Snake	Idaho	513,700	-	-
		Total 1705			6,198,700	0.17	8.30

See notes at end of Table

Table C1 (cont'd)

Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hyrdologic Subregions

U.S.G.S. Hydrologic Units			Location		Average Annual Generation	1976 Production Expenses[1]	1975 Average Revenues Obtained for Prime Energy[2]
Regions	Subregion	Plant Name	River	State	'78 (MWH)	(Mills/KWH)	(Mills/KWH)
Pacific Northwest (Con't)	1706	Ice Harbor	Snake	Washington	2,574,000	-	-
		Lower Monumental	Snake	Washington	2,410,000	-	-
		Little Goose	Snake	Washington	2,360,000	-	-
		Lower Granite	Snake	Washington	1,424,500	-	-
		Dworshak	N. Fk. Clearwater	Idaho	1,9000,00	-	-
		Wallowa Falls	Wallowa	Oregon	8,000	-	-
			Total 1706		10,676,500	0.35	8.30
	1707	The Dalles	Columbia	Washington	8,431,000	-	-
		Pelton	Deschutes	Oregon	400,000	-	-
		Round Butte	Deschutes	Oregon	946,000	-	-
		Cline Falls	Deschutes	Oregon	5,300	-	-
		Bend	Deschutes	Oregon	6,300	-	-
		John Day	Columbia	Oregon	9,430,000	-	-
		John Day	Columbia	Washington	970,000	-	-
		McNary	Columbia	Oregon	6,720,000	-	-
		Powerdale	Hood	Oregon	47,500	-	-
		Condit	White Salmon	Washington	95,200	-	-
		Bonneville	Columbia	Oregon	4,780,000	-	-
			Total 1707		31,831,500	0.25	8.30

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				
Regions	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KHW)
Pacific Northwest (con't)	1708	Bull Rum	Bull Run	Oregon	141,000	-	-
		Mayfield	Cowlitz	Washington	650,000	-	-
		Mossyrock	Cowlitz	Washington	736,000	-	-
		Packwood Lake	Lake Creek, Cowlitz	Washington	101,000	-	-
		Merwin (Ariel)	Lewis	Washington	539,500	-	-
		Yale	Lewis	Washington	528,600	-	-
		Swift #1	Lewis	Washington	642,000	-	-
		Swift #2	Lewis	Washington	240,000	-	-
			Total 1708		3,758,100	0.91	8.30
	1709	Lake Oswego	Willamette	Oregon	1,700	-	-
		River Mill	Clackamas	Oregon	104,500	-	-
		Faraday	Clackamas	Oregon	180,000	-	-
		North Fork	Clackamas	Oregon	213,000	-	-
		Oak Grove	Clackamas	Oregon	245,000	-	-
		West Linn	Williamette	Oregon	30,000	-	-
		Sullivan	Williamette	Oregon	80,000	-	-
		Oregon City	Williamette	Oregon	6,900	-	-
		Baker Creek	Baker Creek	Oregon	400	-	-
		Stayton	N. Santiam	Oregon	4,000	-	-
		Big Cliff RRG	N. Santiam	Oregon	100,000	-	-
		Detroit	N. Santiam	Oregon	380,000	-	-
		Foster RRG	S. Santiam	Oregon	110,000	-	-
		Green Peter	M. Santiam	Oregon	230,000	-	-
		Albany	Williamette	Oregon	3,700	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975 Average Revenues Obtained for Prime Energy[2]
Regions	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	(Mills/KWH)
Pacific Northwest (con't)	1709	Waterville	McKenzie	Oregon	70,900	-	-
		Leaburg	McKenzie	Oregon	108,900	-	-
		Cougar	S. Fk. McKenzie	Oregon	150,000	-	-
		Trail Bridge	McKenzie	Oregon	46,000	-	-
		Carmen-Smith	McKenzie	Oregon	203,000	-	-
		Dexter RRG	M. Fk. Williamette	Oregon	80,000	-	-
		Lookout Point	M. Fk. Williamette	Oregon	300,000	-	-
		Hills Creek	M. Fk. Williamette	Oregon	170,000	-	-
			Total 1709		2,848,000	1.6	8.30
	1710	Soda Sprinks	N. Umpqua	Oregon	71,900	-	-
		Slide Creek	N. Umpqua	Oregon	105,700	-	-
		Fish Creek	N. Umpqua	Oregon	62,300	-	-
		Toketee	N. Umpqua	Oregon	261,000	-	-
		Clearwater #1	Clearwater	Oregon	56,800	-	-
		Clearwater #2	Clearwater	Oregon	67,000	-	-
		Lemolo #1	N. Umpqua	Oregon	181,000	-	-
		Lemolo #2	N. Umpqua	Oregon	237,000	-	-
		Gold Hill	Rogue	Oregon	11,000	-	-
		Green Springs	Emigrant Creek	Oregon	63,000	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units: Region	U.S.G.S. Hydrologic Units: Subregion	Plant Name	Location: River	Location: State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Pacific Northwest (con't)	1710	Eagle Point	Little Butte Creek	Oregon	20,000	-	-
		Lost Creek	Rogue	Oregon	303,000	-	-
		Prospect #1	N.&M. Fk. Rogue	Oregon	25,000	-	-
		Prospect #2	N.&M. Fk. Rogue	Oregon	282,000	-	-
		Prospect #3	N.&M. Fk. Rogue	Oregon	50,000	-	-
		Prospect #4	N.&M. Fk. Rogue	Oregon	8,200	-	-
			Total 1710		1,804,900	0.57	8.30
	1711	Nooksack	Nooksack	Washington	2,600	-	-
		Lower Baker	Baker	Washington	381,200	-	-
		Bear Creek #1	Bear Creek	Washington	12,400	-	-
		Bear Creek #2	N. Fk. Bear Creek	Washington	1,600	-	-
		Upper Baker	Baker	Washington	336,400	-	-
		Newhalem Creek	Newhalem Creek	Washington	12,500	-	-
		Gorge	Skagit	Washington	894,000	-	-
		Diablo	Skagit	Washington	752,000	-	-
		Ross	Skagit	Washington	792,000	-	-
		Snoqualmie FLS1	Snoqualmie	Washington	73,600	-	-
		Snoqualmie FLS1	Snoqualmie	Washington	200,000	-	-
		Cedar Falls	Cedar	Washington	96,200	-	-
		White River	White	Washington	322,200	-	-
		Electron	Puyallup	Washington	172,300	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
Pacific Northwest (con't)	1711	Centralia (Yelm)	Nisqually	Washington	85,000	-	-
		La Grande	Nisqually	Washington	330,000	-	-
		Alder	Nisqually	Washington	220,000	-	-
		Cushman #1	Hood Canal	Washington	110,000	-	-
		Cushman #2	Hood Canal	Washington	220,000	-	-
		Elwha	Elwha	Washington	60,000	-	-
		Glines Canyon	Elwha	Washington	80,000	-	-
			Total 1711		5,177,500	1.05	8.30
	1712[3]	-	-	-	-	-	-
		Total Pacific Northwest Region			131,543,900		
California	1801	Iron Gate	Klamath	California	153,500	-	-
		Fall Gate	Fall Gate	California	12,800	-	-
		Copco #1	Klamath	California	120,000	-	-
		Copco #2	Klamath	California	141,200	-	-
		John C. Boyle	Klamath	Oregon	369,000	-	-
			Total 1801		796,500	0.7	23.70
	1802	Nimbus	American	California	91,100	-	-
		Folsom	American	California	702,700	-	-
		Chili Bar	American	California	37,000	-	-
		White Rock	S. Fk. American	California	618,600	-	-
		Camino	S. Fk. American	California	441,600	-	-
		El Dorado	S. Fk. American	California	97,900	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
California (con't)	1802	Jaybird	Silver Creek	California	575,000	-	-
		Union Valley	Silver Creek	California	115,000	-	-
		Robbs Peak	Tells Creek	California	55,000	-	-
		Oxbow	M. Fk. American	California	36,500	-	-
		Ralston	Rubicon	California	476,300	-	-
		Loon Lake	Gerle Creek	California	117,000	-	-
		French Meadows	Rubicon	California	75,300		
		L.J. Stephensen	M. Fk. American	California	650,000	-	-
		Wise	Auburn Ravine	California	75,000	-	-
		Halsey	Dry Creek	California	66,600	-	-
		Chicago Park	Bear	California	140,000	-	-
		Dutch Flat #1	Bear	California	54,800	-	-
		Dutch Flat #2	Bear	California	120,000	-	-
		Alta	Lower Boardman	California	6,400	-	-
		Drum #1	S. Yuba Div. & Bear	California	245,000	-	-
		Drum #2	S. Yuba Div. & Bear	California	35,000	-	-
		Deer Creek	Deek Creek	California	30,600	-	-
		Narrows	Yuba	California	72,000	-	-
		Narrows-2	Yuba	California	210,000	-	-
		Spaulding #1	Drum Canal	California	38,000	-	-
		Spaulding #2	S. Yuba Canal	California	20,000	-	-
		Spaulding #3	S. Yuba	California	25,100	-	-
		New Gate	N. Yuba	California	2,160,000	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units Region	U.S.G.S. Hydrologic Units Subregion	Plant Name	Location River	Location State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
California (con't)	1802	Thermalito 3/	Feather Div.	California	270,000	-	-
		Thermalito	Feather Div.	California	65,000	-	-
		Kelly Ridge	S. Fk. Feather	California	79,100	-	-
		Edward G. Hyatt 3/ Oroville	Feather	California	1,934,000	-	-
		Edward G. Hyatt Oroville	Feather	California	306,000	-	-
		Forbestown	S. Fk. Feather	California	183,100	-	-
		Woodleaf	S. Fk. Feather	California	297,100	-	-
		Lime Saddle	W. Br. N. Fk. Feather	California	11,000	-	-
		Poe	N. Fk. Feather	California	512,000	-	-
		Cresta	N. Fk. Feather	California	330,500	-	-
		Rock Creek	N. Fk. Feather	California	482,500	-	-
		Bucks Creek	N. Fk. Feather	California	241,300	-	-
		Belden	N. Fk. Feather	California	245,300	-	-
		Caribou #1	N. Fk. Feather	California	145,000	-	-
		Caribou #2	N. Fk. Feather	California	210,900	-	-
		Butt Valley	Butt Creek	California	84,200	-	-
		Hamilton Branch	Lake Almanor	California	15,800	-	-
		Coal Canyon	Miocene Canal	California	7,500	-	-
		Centerville 5/	Butte Creek	California	43,800	-	-
		De Sabla	W. Fk., N. Fk. Feather	California	120,000	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975 Average Revenues Obtained for Prime Energy[2]
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	(Mills/KWH)
California (con't)	1802	Coleman 5/	Battle Creek	California	56,800	-	-
		Inskip	S. Fk. Battle Creek	California	37,900	-	-
		South	S. Fk. Battle Creek	California	36,000	-	-
		Volta	Milseat Creek	California	39,600	-	-
		Cow Creek	S. Fk. Cow Creek	California	12,000	-	-
		Kilare	N. Fk. Cow Creek	California	22,000	-	-
		Judge Francais Carr	Clear Creek	California	491,500	-	-
		Keswick	Sacramento	California	477,500	-	-
		Spring Creek PH	Spring Creek, Sacramento	California	543,600	-	-
		Shasta	Sacramento	California	2,021,600	-	-
		Pit #1	Pit (from Fall Creek)	California	264,100	-	-
		Pit #3	Pit	California	385,400	-	-
		Pit #4	Pit	California	422,200	-	-
		Pit #5	Pit	California	836,000	-	-
		Pit #6	Pit	California	335,000	-	-
		Pit #7	Pit	California	495,000	-	-
		James B. Black	Pit	California	540,000	-	-
		Hat Creek #1	Hat Creek	California	19,300	-	-
		Hat Creek #2	Hat Creek	California	39,300	-	-
			Total 1802		20,047,000	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975 Average Revenues Obtained for Prime Energy[2]
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	(Mills/KWH)
California (con't)	1803	Kings River	N. Fk. Kings	California	207,900	-	-
		Balch #1	N. Fk. Kings	California	61,400	-	-
		Balch #2	N. Fk. Kings	California	552,200	-	-
		Haas	H. Fk. Kings	California	517,500	-	-
		Kaweah #1	Kaweah	California	16,000	-	-
		Kaweah #2	Kaweah	California	13,000	-	-
		Kaweah #3	Kaweah	California	25,000	-	-
		Tule River	N. Fk./M. Fk. Tule	California	26,500	-	-
		Lower Tule	Tule	California	19,000	-	-
		Kern Canyon	Kern	California	47,200	-	-
		Kern River #1	Kern	California	173,000	-	-
		Kern River #3	Kern	California	197,500	-	-
		Borel	Kern	California	64,000	-	-
			Total 1803		1,920,200	1.95	23.70
	1804	O'Neil	Delta Mendota Canal	California	41,500	-	-
		San Luis	California Aqueduct	California	321,000	-	-
		Pardee	Mokelumne	California	105,000	-	-
		Edectra	Mokelumne	California	347,200	-	-
		West Point	N. Fk. Mokelumne	California	87,600	-	-
		Tiger Creek	N. Fk. Mokelumne	California	353,200	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				1975 Average Revenues Obtained for Prime Energy[2]
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	(Mills/KWH)
California (con't)	1804	Salt Springs 1	N. Fk. Mokelumne	California	50,000	-	-
		Salt Springs 2	N. Fk. Mokelumne	California	125,600	-	-
		Tulloch	Stanislaus	California	70,200	-	-
		Melones 5/	Stanislaus	California	102,300	-	-
		Angels	Angels Creek	Calfiornia	6,200	-	-
		Murphy's	Angels Creek	California	16,000	-	-
		Stanislaus	M. Fk. Stanislaus	California	406,000	-	-
		Spring Gap	M. Fk. Stanislaus	California	48,500	-	-
		Beardsley	M. Fk. Stanislaus	California	51,500	-	-
		Donnells	M. Fk. Stanislaus	California	279,000	-	-
		La Grange	Tuolumne	California	18,000	-	-
		Don Pedro	Tuolumne	California	598,400	-	-
		Phoeniz	Sullivan Creek	California	10,000	-	-
		Moccasin Creek	Hetch Hetchy Aqueduct	California	548,000	-	-
		D.R. Holm	Cherry Creek	California	772,000	-	-
		R. Kirkwood	Tuolumne	California	622,000	-	-
		Merced Falls	Merced	California	19,100	-	-
		McSwain	Merced	California	45,000	-	-
		Exchequer	Merced	California	316,100	-	-
		Cascades	Merced	California	13,200	-	-
		Kerckhoff	San Joaquin	California	253,000	-	-
		A.G. Wishon	N. Fk. Willow Creek	California	94,200	-	-

See notes at end of Table

Table C1 (cont'd)
Hydroelectric Production Plants and Associated Data Locations Within Snow Survey Impacted Areas
Organized by U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. Hydrologic Units			Location				
Region	Subregion	Plant Name	River	State	Average Annual Generation '78 (MWH)	1976 Production Expenses[1] (Mills/KWH)	1975 Average Revenues Obtained for Prime Energy[2] (Mills/KWH)
California (con't)	1804	A.G. Wishon	N. Fk. Willow Creek	California	94,200	-	-
		San Joaquin #1A	Willow Creek	California	1,700	-	-
		San Joaquin #2	Ditch #1	California	22,000	-	-
		San Joaquin #3	Mauezanita Lake	California	17,500	-	-
		Crane Valley	Ditch #3	California	5,100	-	-
		Big Creek #1	Big Creek	California	521,000	-	-
		Big Creek #2A	Big Creek	California	387,000	-	-
		Big Creek #2	Big Creek	California	451,000	-	-
		Big Creek #3	Redinger Lake	California	783,000	-	-
		Big Creek #4	San Joaquin	California	428,000	-	-
		Big Creek #8	San Joaquin	California	337,000	-	-
		Portal	Big Creek	California	51,000	-	-
		Mammoth Pool	San Joaquin	California	546,000	-	-
			Total 1804		9,270,400	1.73	23.70
	1808[3]	-	-	-	-	-	-
		Total California Region			22,034,100	-	-
		Total 11 Western States			180,378,400		

Notes:

[1]One value has been calculated for each subregion, weighted by the average annual generation of plants located within that subregion (1976 data). Where no data were available for a given subregion, the regional weighted average was substituted.

[2]One average value has been calculated for each region. It is the average, generated-weighted revenue obtained from the sale of prime energy publically owned utilities (1975 data[4]).

[3]According to the Federal listing of "Hydroelectric Power Resources Inventory" no hydroelectric energy was being generated in this subregion.

[4]These figures have been upgraded to take into account the inflationary trend in market values.

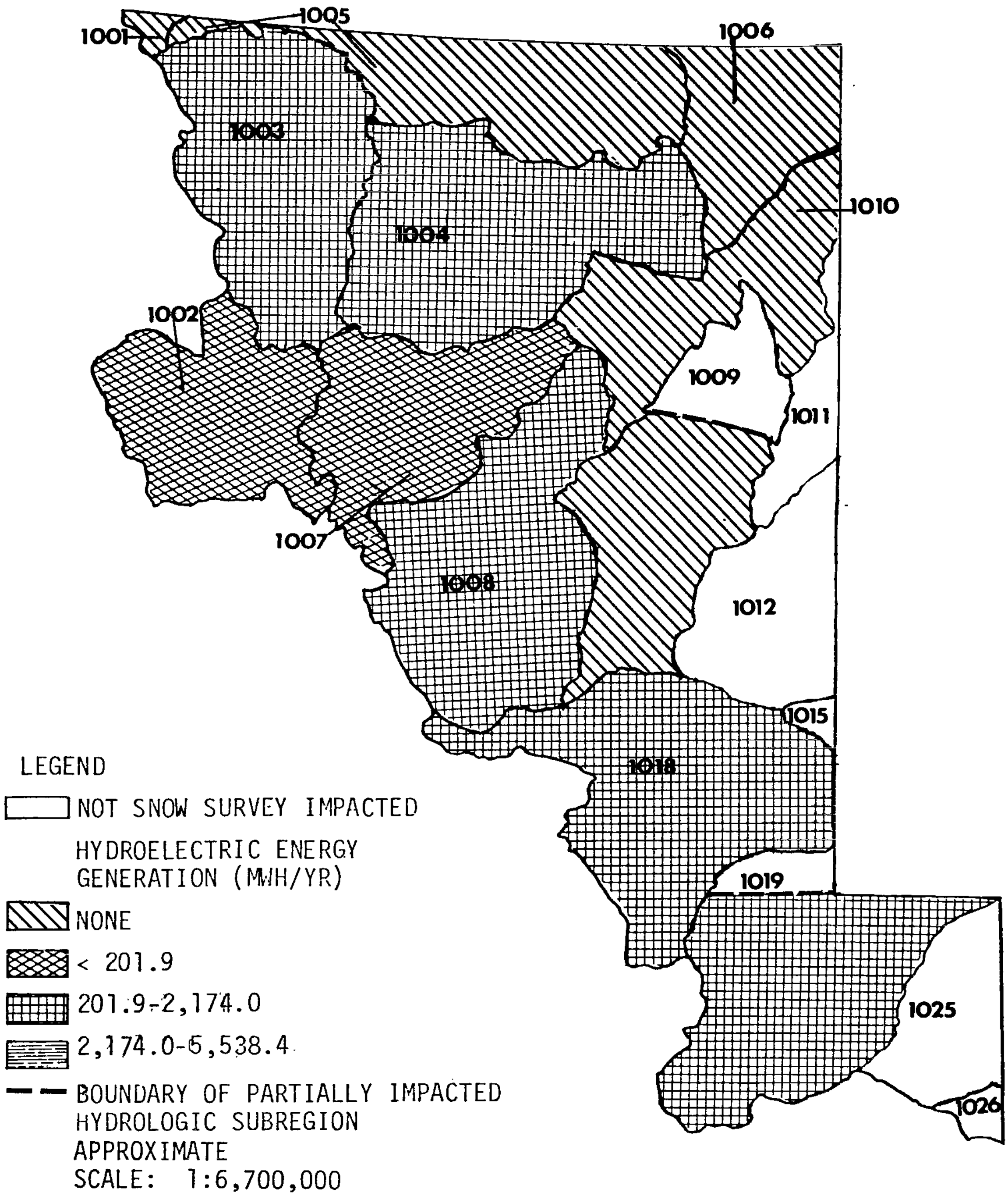


Figure C1: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregions of the Missouri hydrologic region.

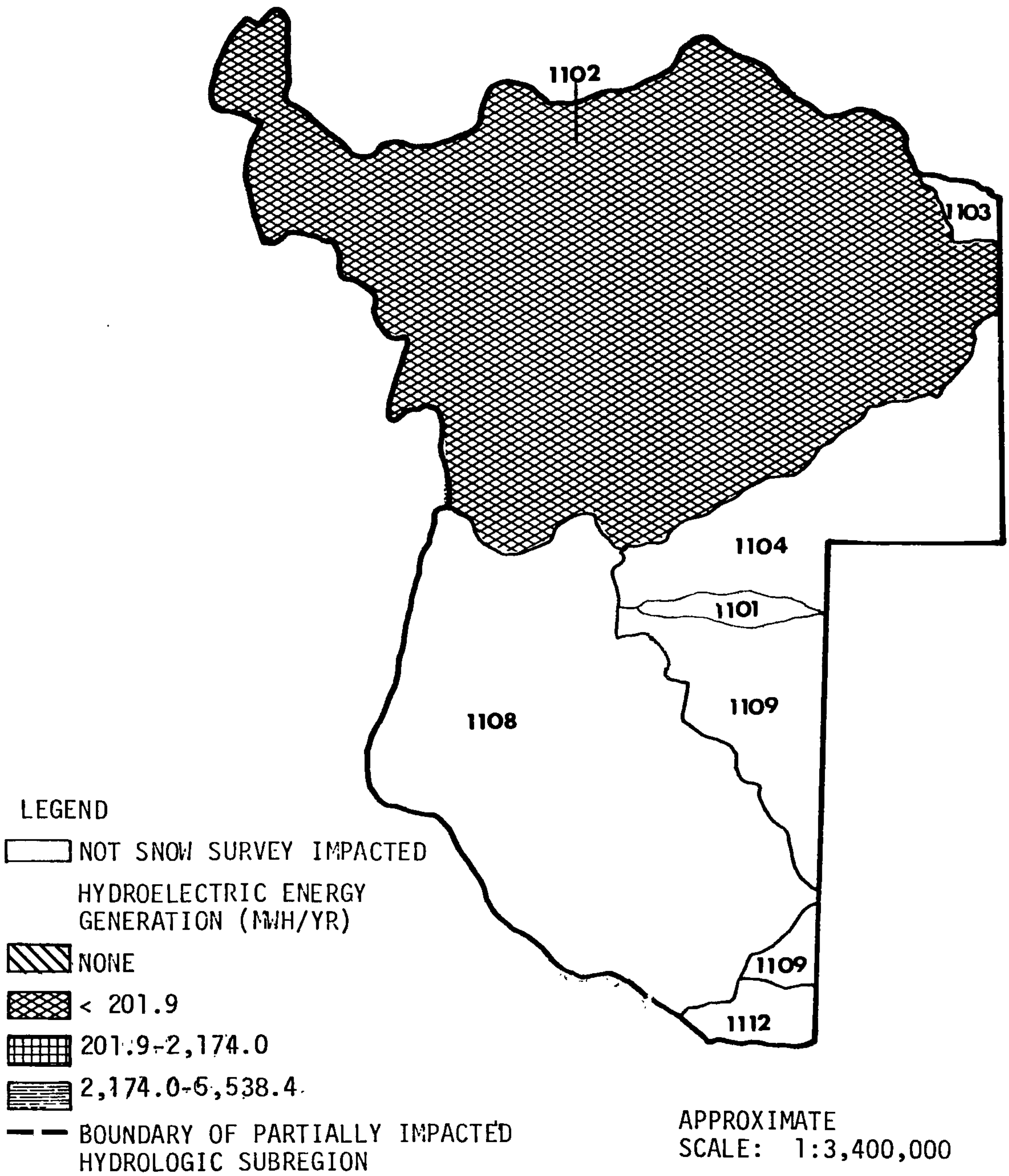


Figure C2: Average annual Hydroelectric energy generation (MWH) in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region.

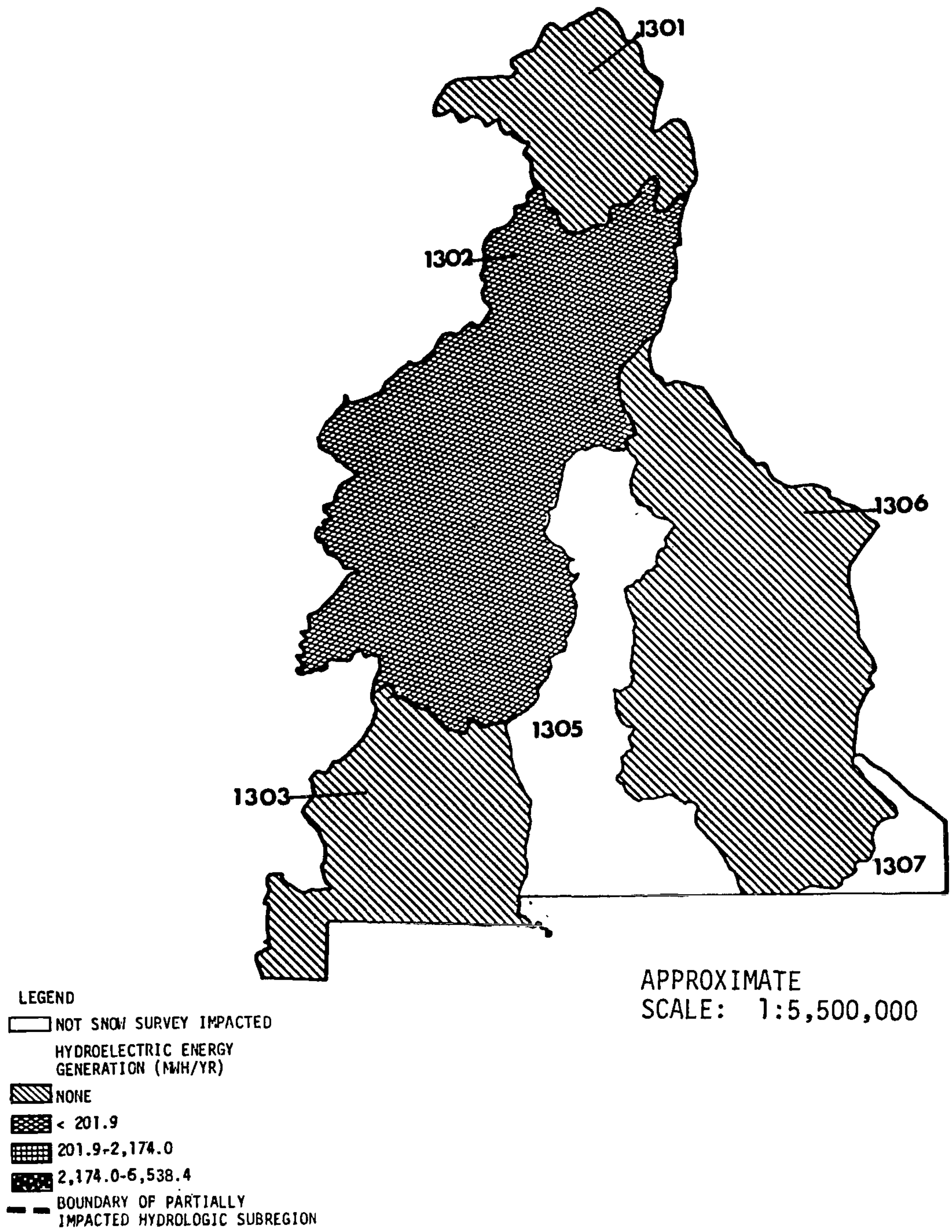


Figure C3: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregions of the Rio Grande hydrologic region.

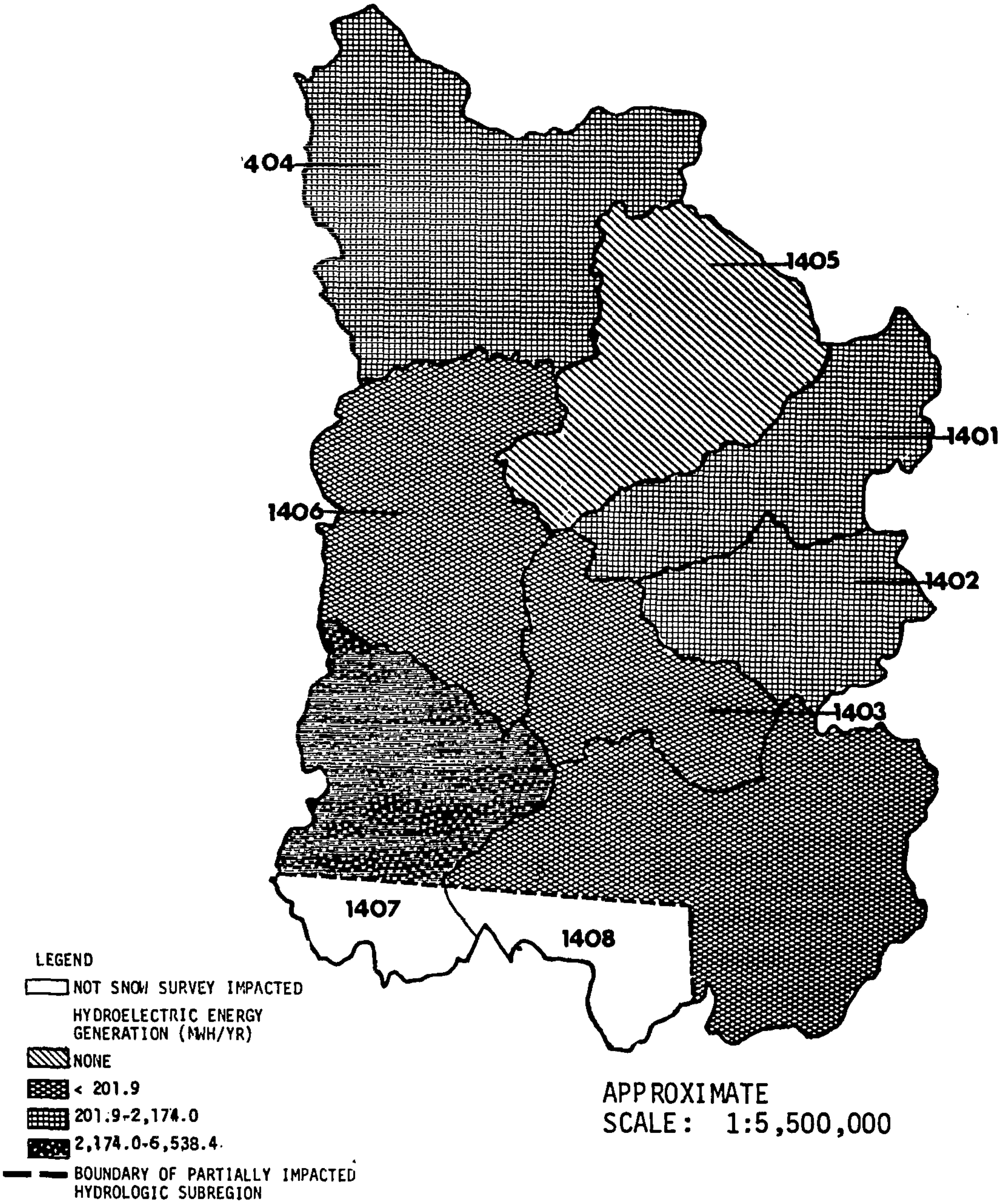


Figure C4: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregions of the Upper Colorado hydrologic region.

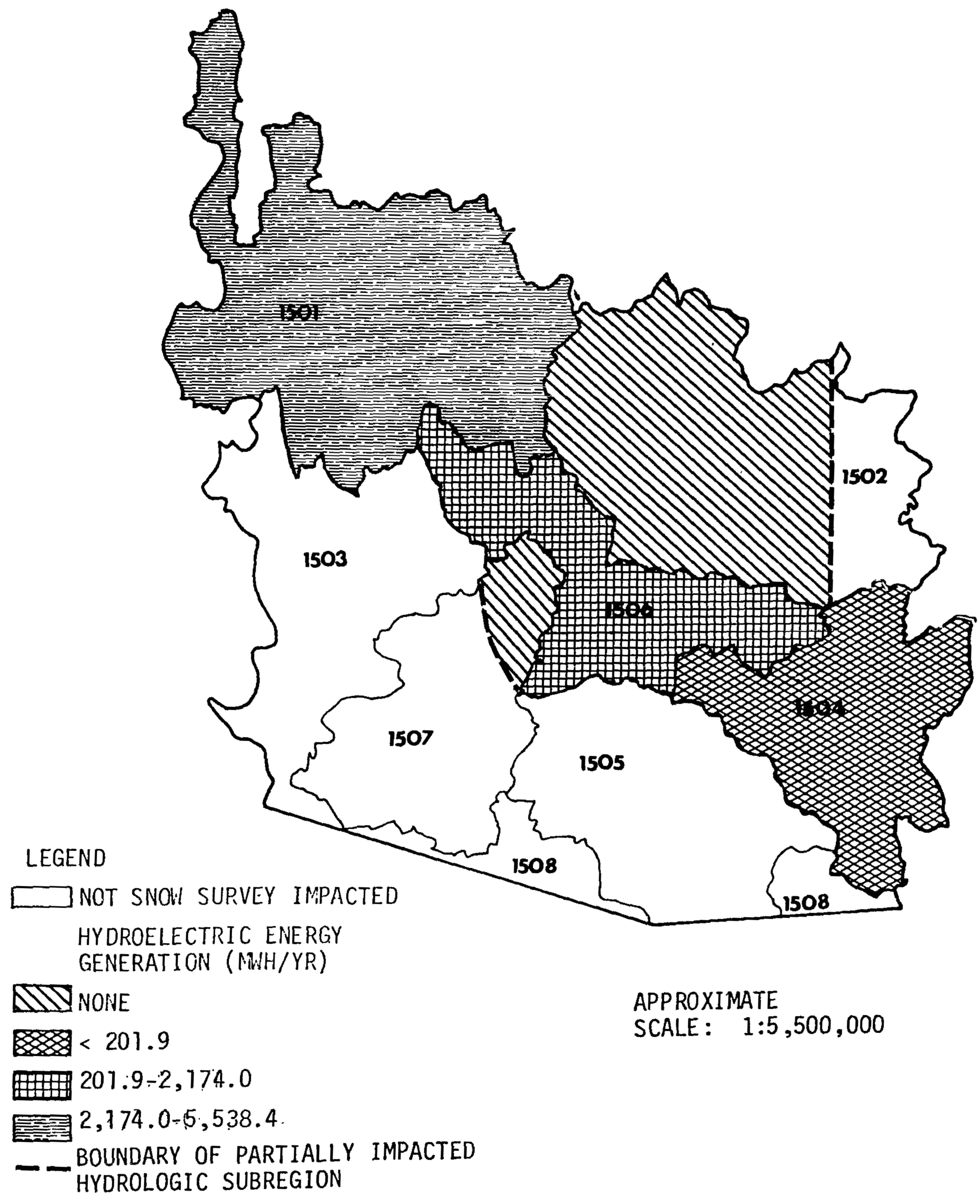


Figure C5: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregion of the Lower Colorado hydroelectric region.

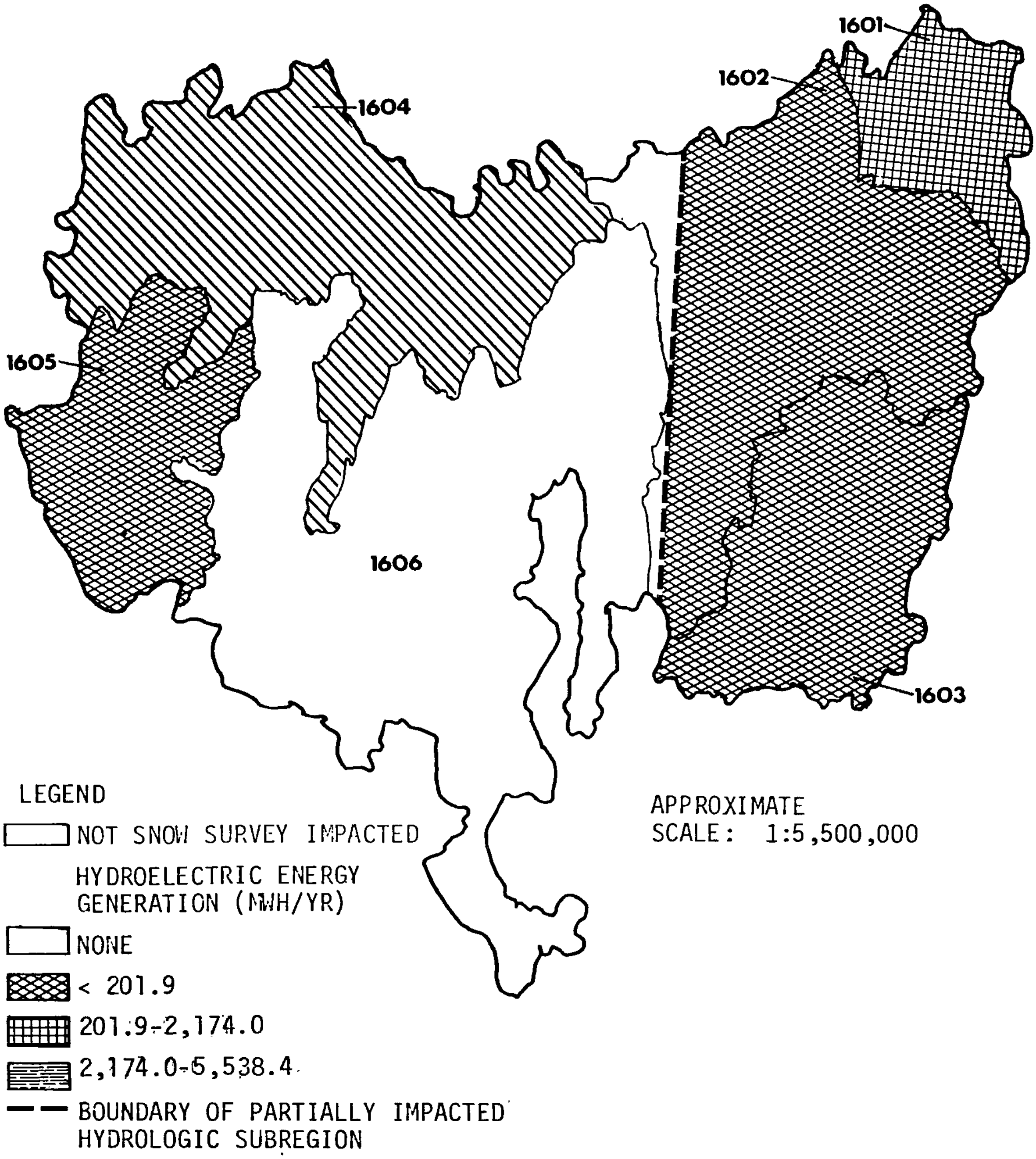


Figure C6: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregions of the Great Basin hydrologic region.

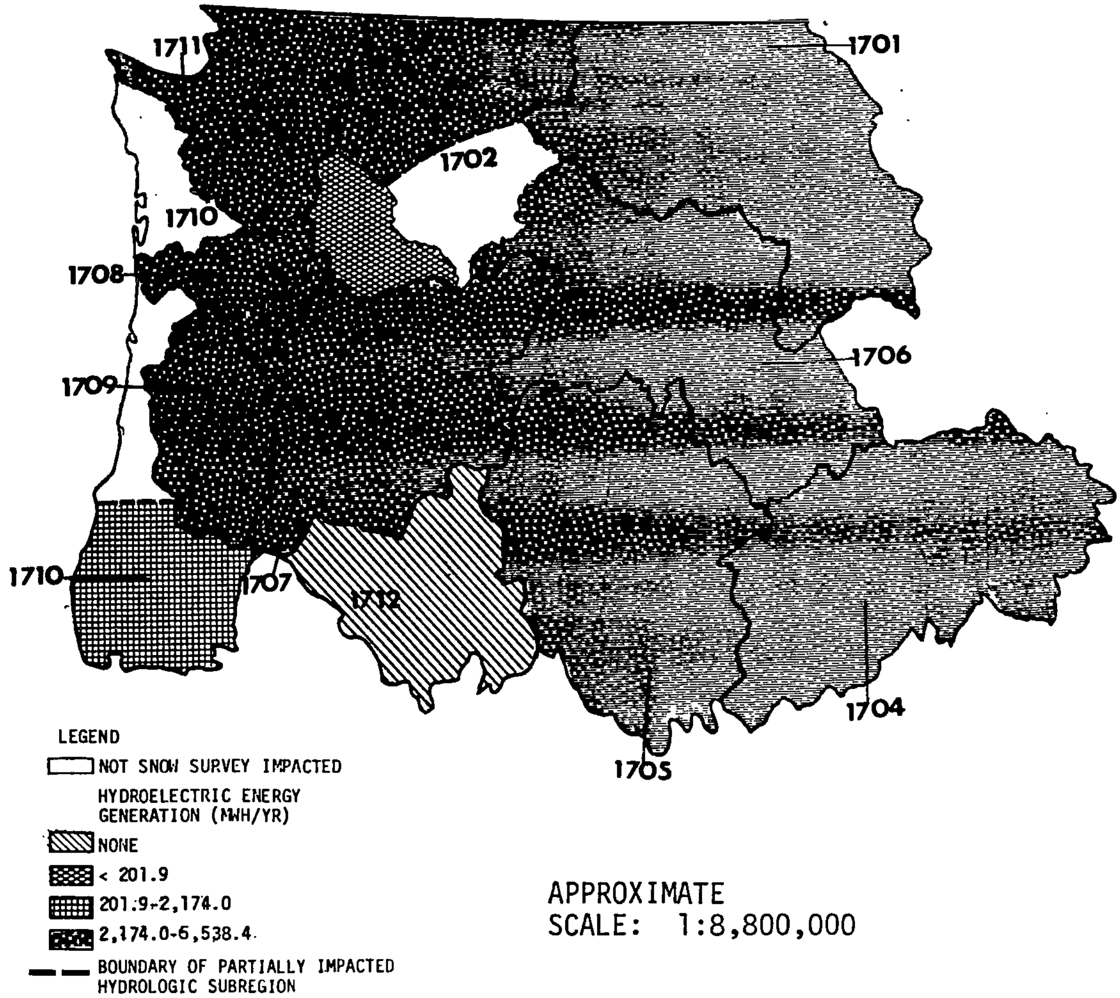


Figure C7: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregions of the Pacific Northwest hydrologic region.

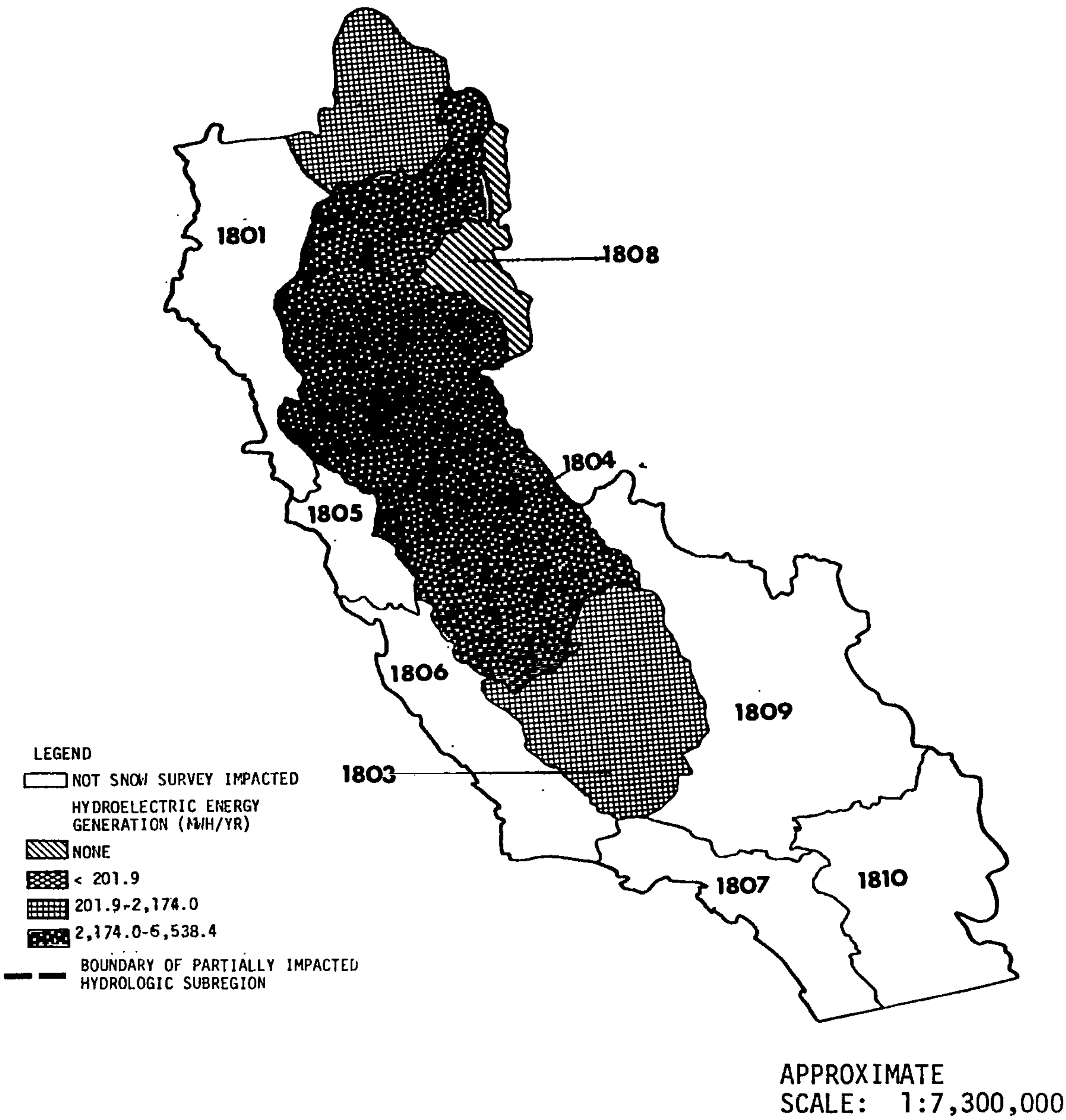


Figure C8: Average annual hydroelectric energy generation (MWH) in the snow survey impacted subregions of the California hydrologic region.

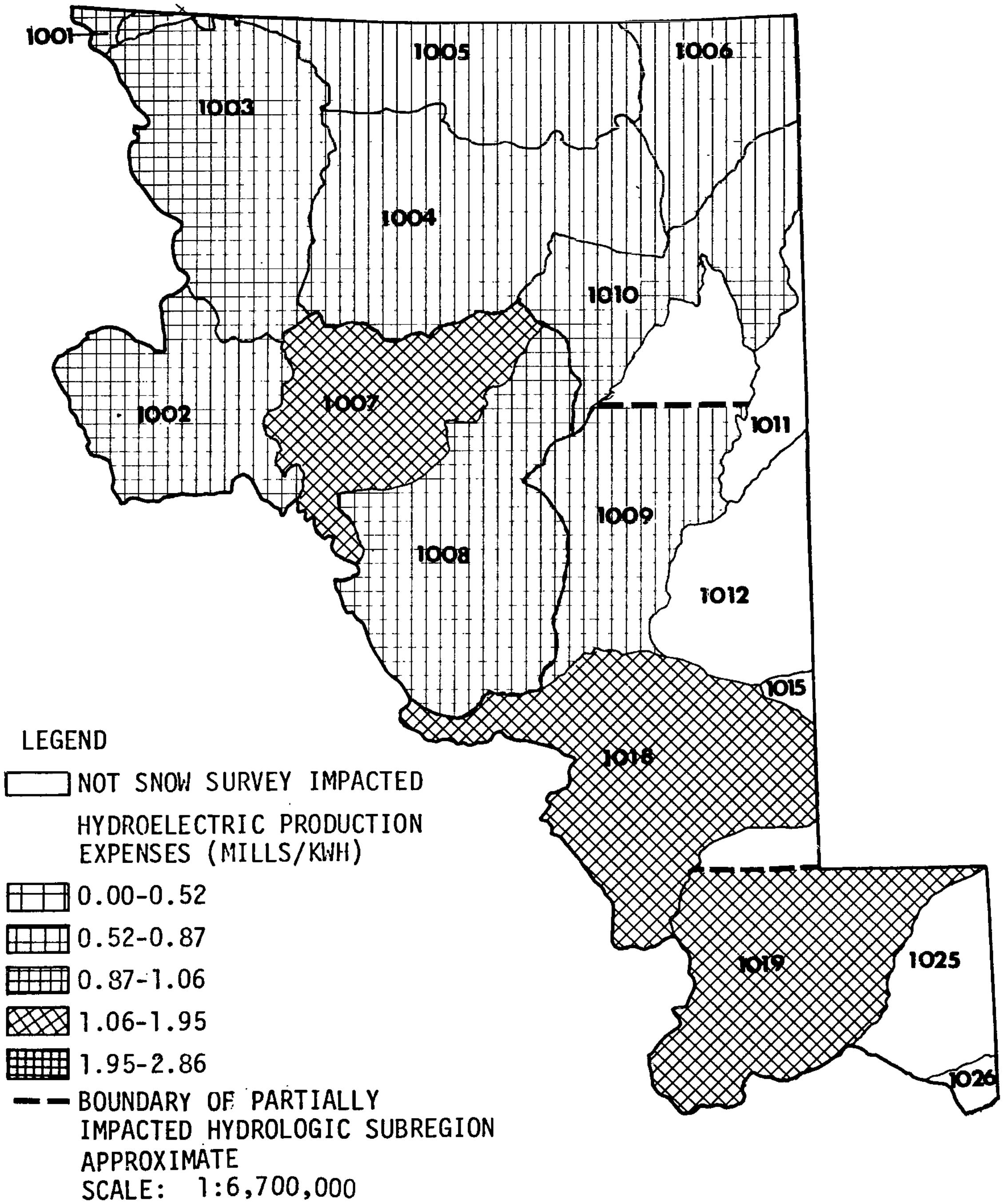


Figure C9: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Missouri hydrologic region.

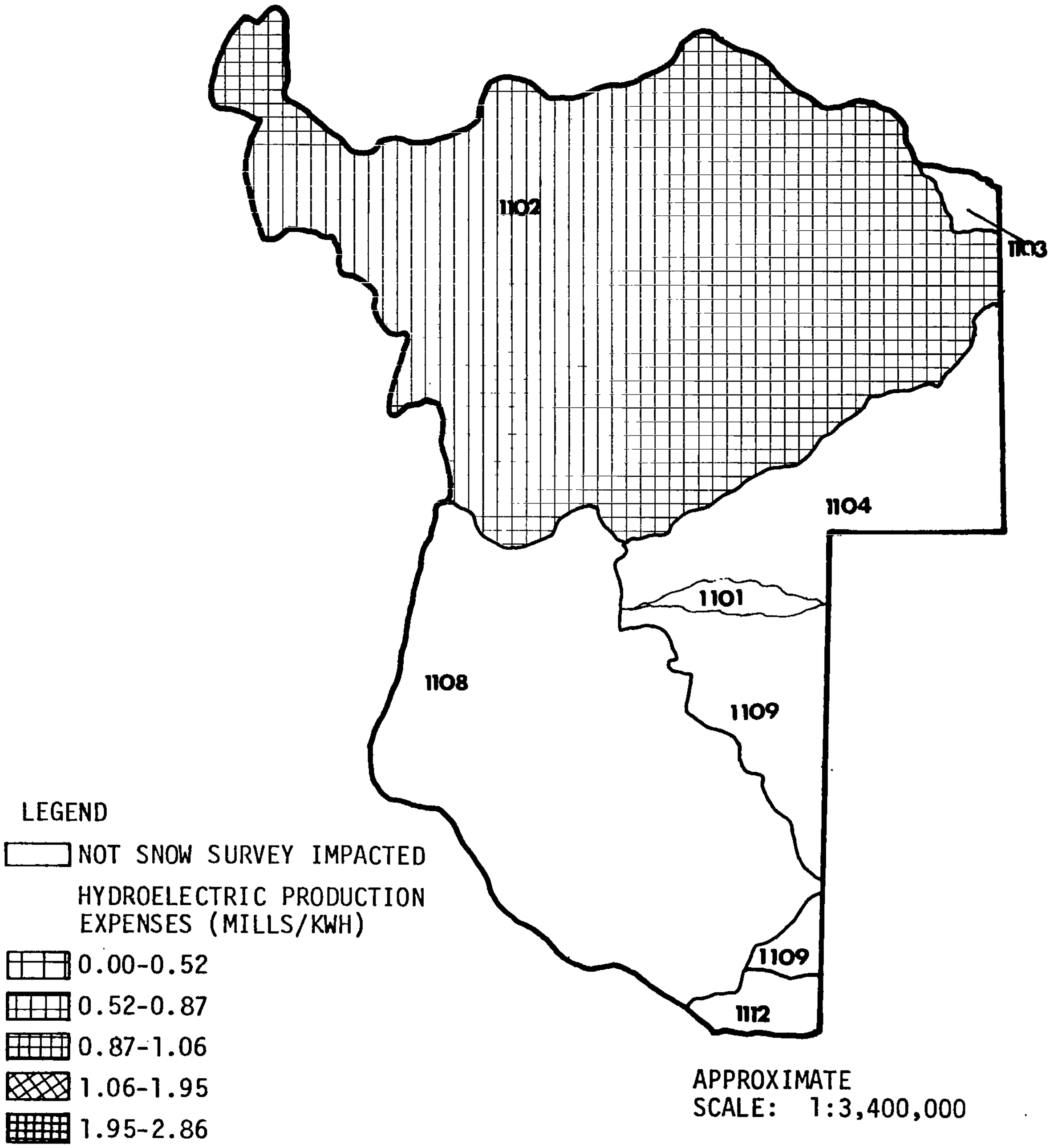


Figure C10: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region.

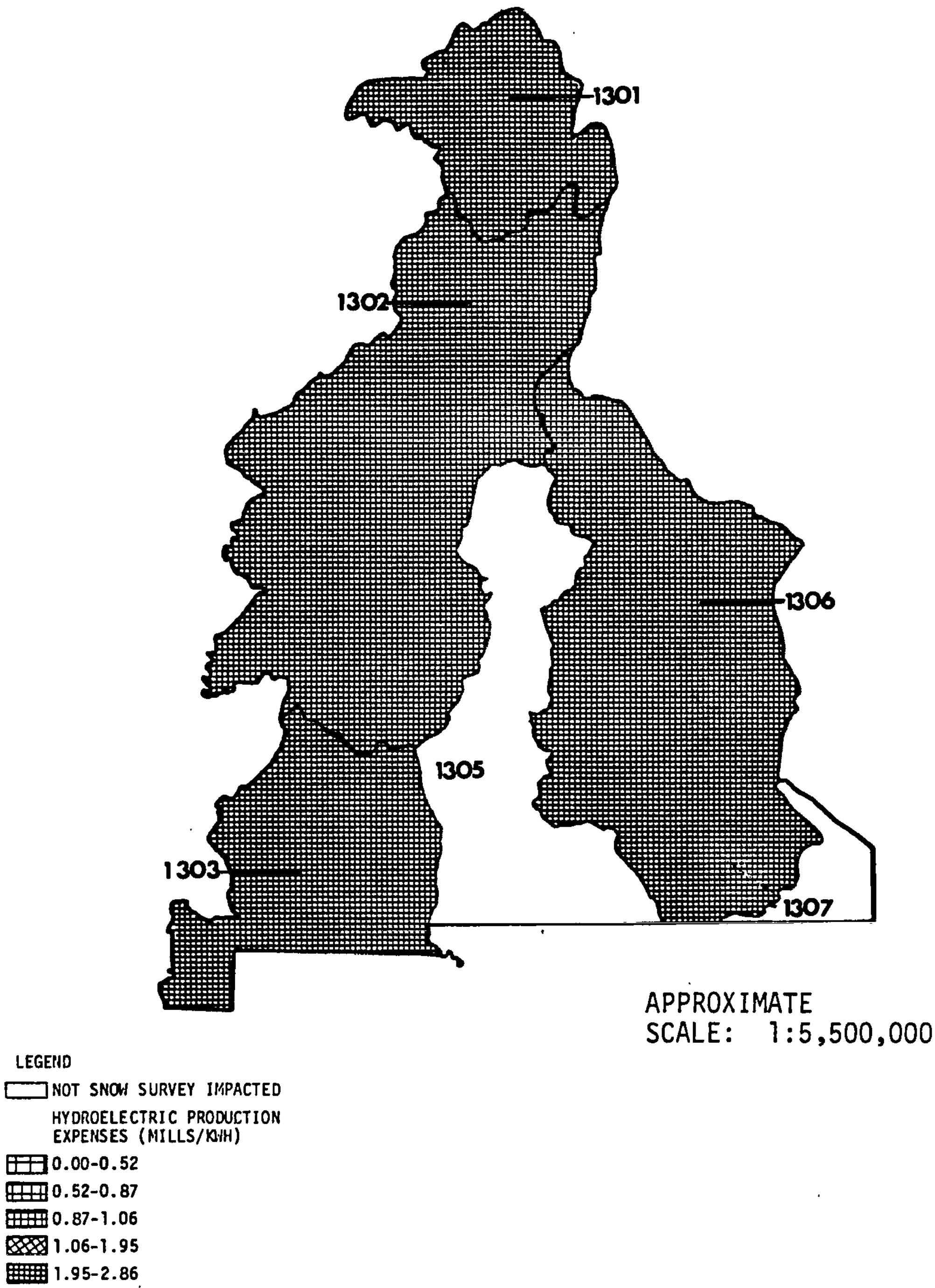


Figure C11: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Rio Grande hydrologic region.

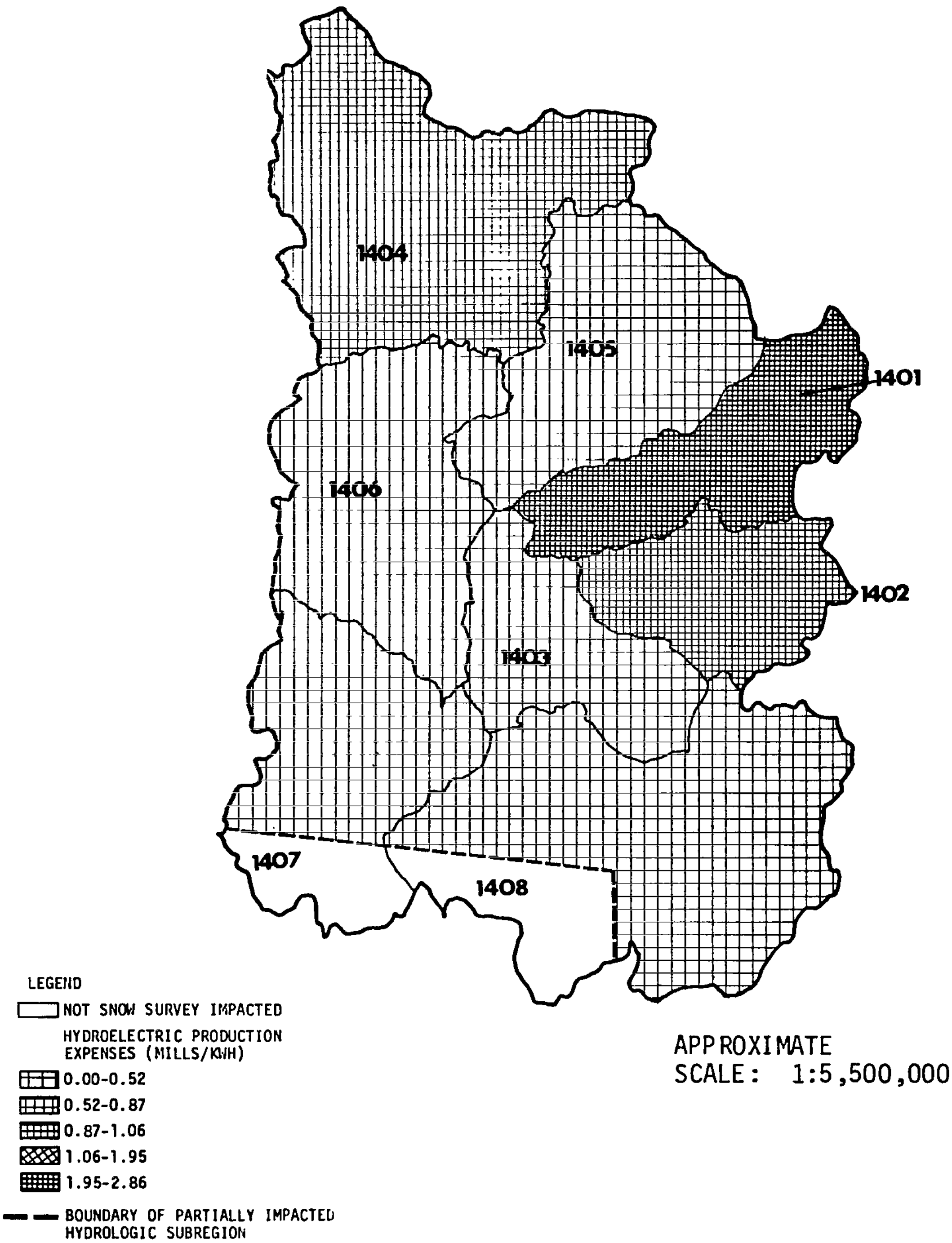


Figure C12: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Upper Colorado hydrologic region.

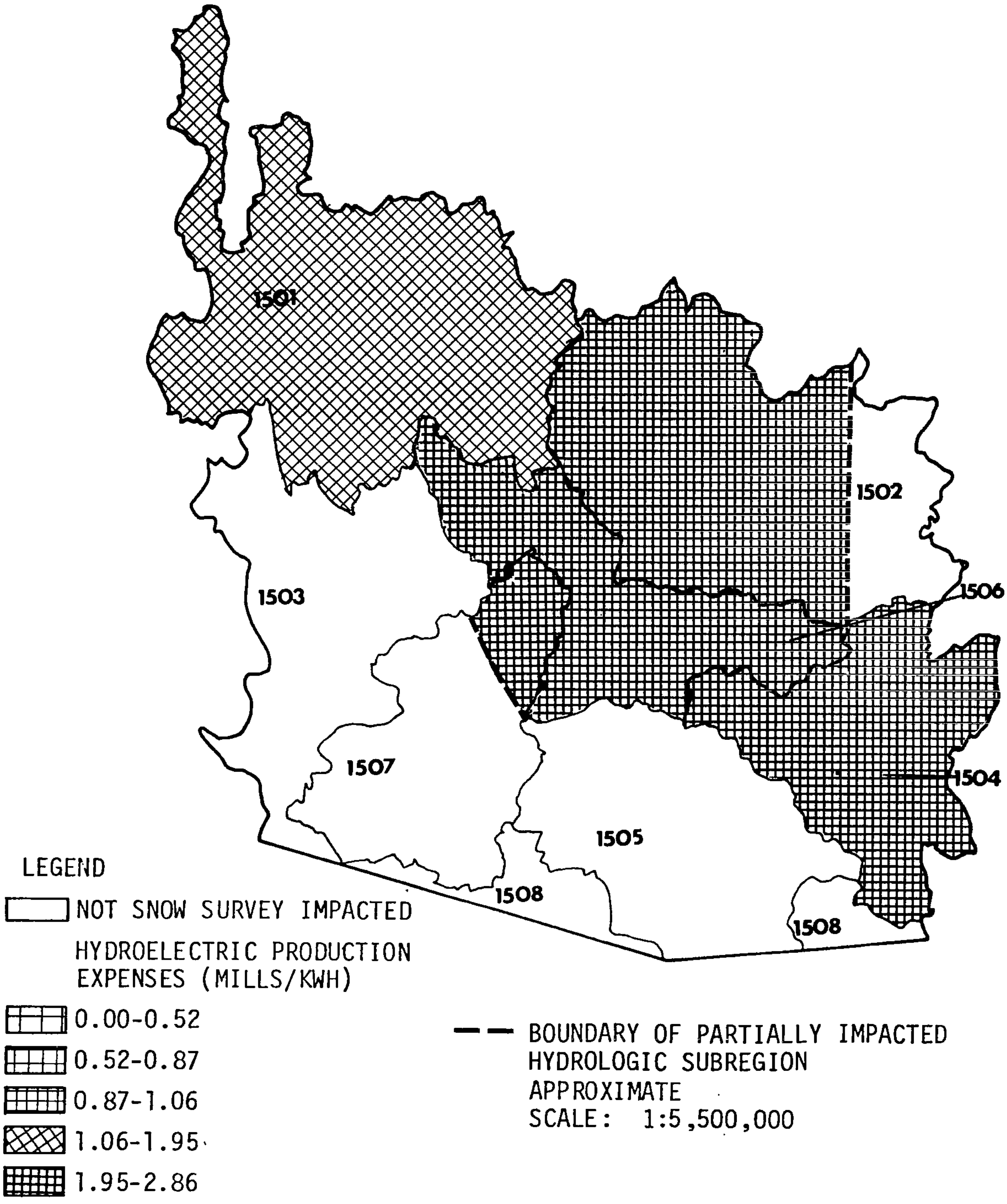


Figure C13: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Lower Colorado hydrologic region.

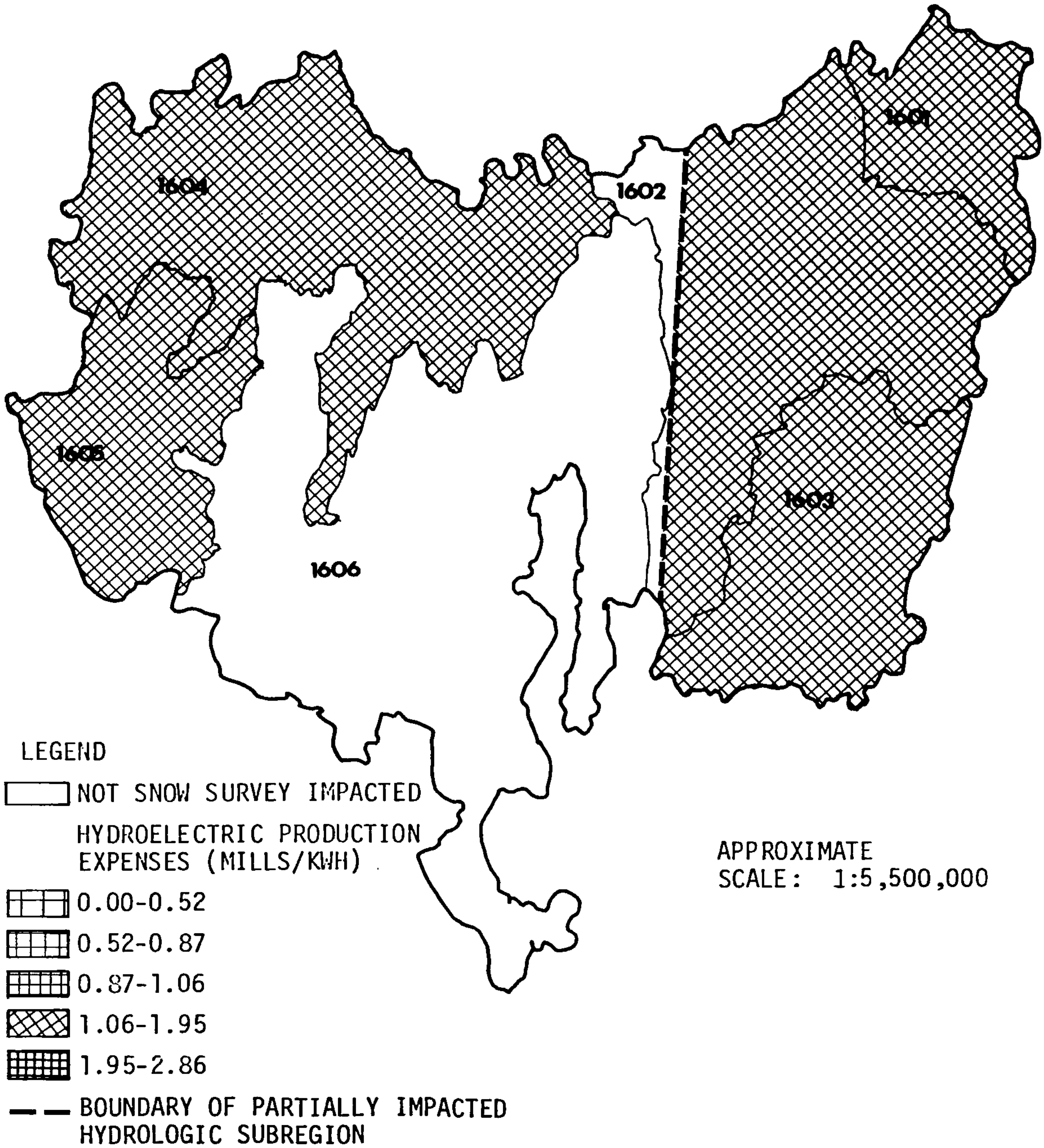


Figure C14: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Great Basin hydrologic region.

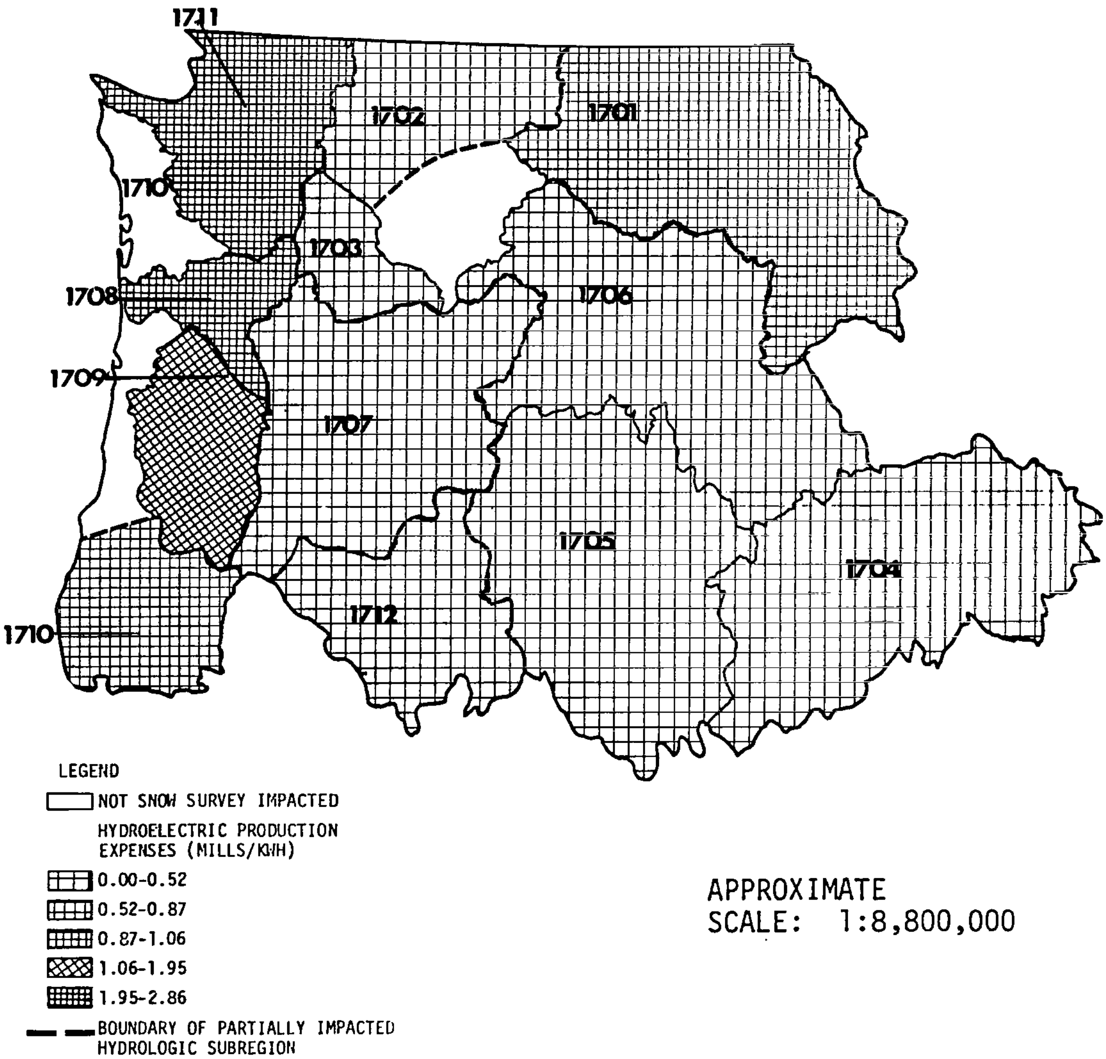


Figure C15: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Pacific Northwest hydrologic region.

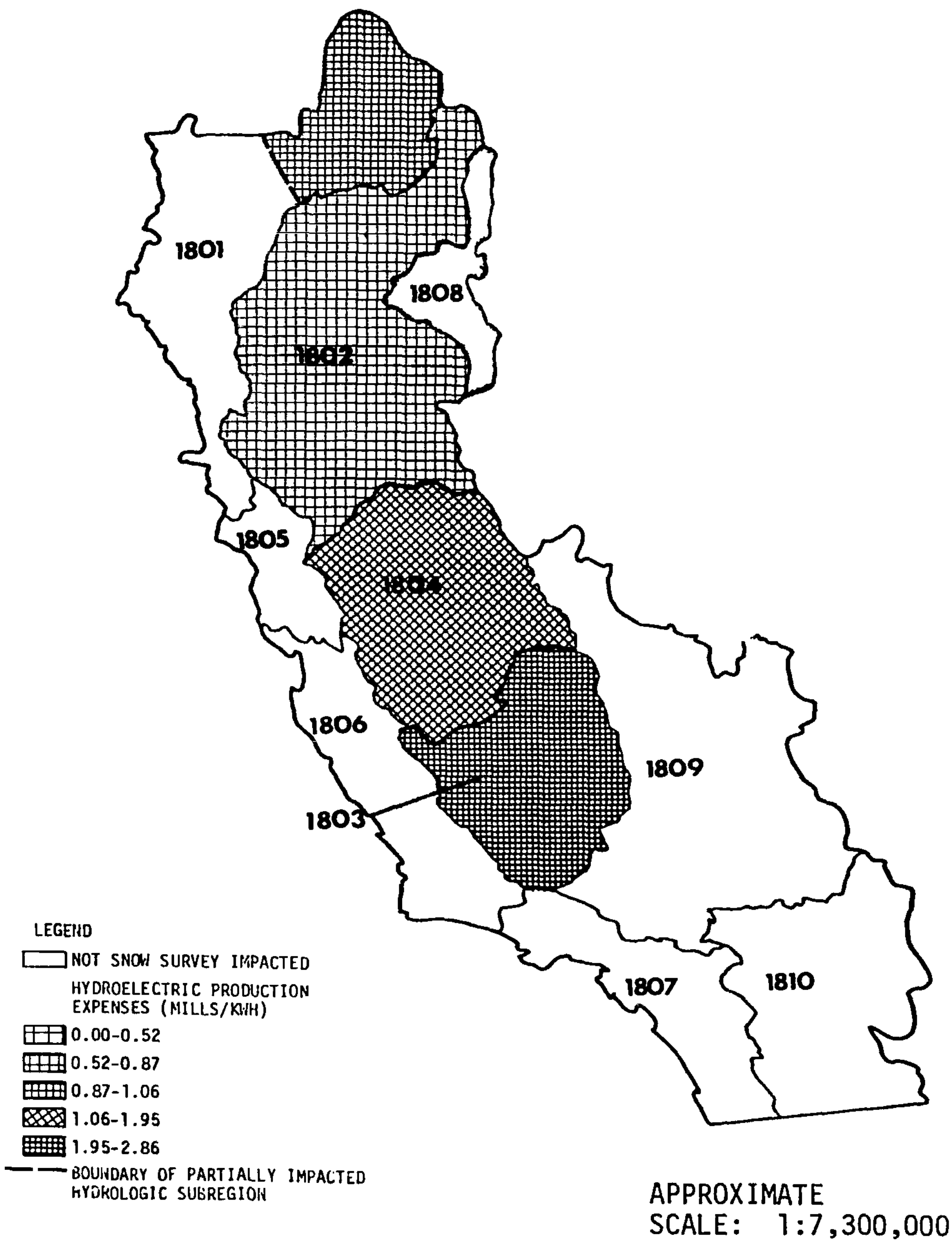


Figure C16: Hydroelectric energy production expenses (mills/KWH) in the snow survey impacted subregions of the California hydrologic region.

Table C2

Sample Summary of Steam-Electric Net Annual Generation and Production Expenses (1976) Organized By U.S.G.S. 1974 Hydrologic Subregions

U.S.G.S. HYDROLOGIC UNITS		STEAM-ELECTRIC PRODUCTION DATA			
REGION	SUBREGION	PLANT NAME	LOCATION: CITY, STATE	NET ANNUAL GENERATION (MWH)	PRODUCTION EXPENSES (MILLS/KWH)
Missouri	1007	J.E. Corette	Billings, Montana	1,029,300	3.65
		Colstrip #1	Billings, Montana	2,182,100	4.60
	1010	Lewis & Clark	Sidney, Montana	314,000	9.19
	1012	Osage	Osage, Wyoming	243,000	6.70
	1018	Dave Johnston	Glen Rock, Wyoming	3,893,300	4.81
	1019	Cherokee	Denver, Colorado	4,074,300	8.17
		Arapahoe	Denver, Colorado	1,474,900	10.61
		Zuni	Denver, Colorado	673,100	19.96
			REGIONAL AVERAGE PRODUCTION EXPENSE:		7.16
Arkansas Red-White	1102	Comanche	Pueblo, Colorado	3,967,000	6.78
		Valmont	Boulder, Colorado	1,383,400	8.36
			REGIONAL AVERAGE PRODUCTION EXPENSE:		7.19
Rio Grande	1302	Person	Albuquerque, New Mexico	488,000	15.22
		Reeves	Albuquerque, New Mexico	1,077,700	12.47
		Algodomes	Albuquerque, New Mexico	204,200	10.18
	1303	Rio Grande	New Mexico, N.W. of El Paso, Texas	916,400	19,48
	1306	Carlsbad	Carlsbad, New Mexico	283,200	11.67
			REGIONAL AVERAGE PRODUCTION EXPENSE:		16.76
Upper Colo-rado	1401	Cameo	Cameo, Colorado	509,500	8.20
	1403	Nucla	Nucla, Colorado	142,400	15.46

Table C2 (cont'd)

U.S.G.S HYDROLOGIC UNITS		STEAM ELECTRIC PRODUCTION DATA			
REGION	SUBREGION	PLANT NAME	LOCATION: CITY, STATE	NET ANNUAL GENERATION (MWH)	PRODUCTION EXPENSES MILLS (KWH)
Upper Colorado	1404	Jim Bridar	Rock Springs, Wyoming	5,900,700	4.81
		Naughton #1	Kemmerer, Wyoming	1,005,100	5.80
		Naughton #2	Kemmerer, Wyoming	1,230,000	5.60
		Naughton #3	Kemmerer, Wyoming	1,893,200	5.39
	1405	Hayden #1	Hayden, Colorado	1,318,800	3.78
		Hayden #2	Hayden, Colorado	387,800	4.35
	1406	Carbon County #1	Castle Gate, Utah	347,000	9.96
		Carbon County #2	Castle Gate, Utah	574,300	8.05
		Huntington #2	Huntington, Utah	969,500	10.50
	1407	Navajo	Page, Arizona	9,832,900	6.14
	1408	Four Corners 1-3	Farmington, New Mexico	3,537,700	7.10
		Four Corners 4-5	Farmington, New Mexico	7,982,100	3.46
		San Juan	Fruitland, New Mexico	1,843,800	6.20
			REGIONAL AVERAGE PRODUCTION EXPENSE:		5.95
Lower Colorado	1501	Reid Gardner	Moapa, Nevada	1,557,200	12.80
		Sunrise	Las Vegas, Nevada	384,100	14.49
	1502	Cholla	Joseph City, Arizona	861,800	8.60
	1504	Lordsburg	Lordsburg, New Mexico	152,200	21.70

Table C2 (cont'd)

U.S.G.S. HYDROLOGIC UNITS		STEAM ELECTRIC PRODUCTION DATA			
REGION	SUBREGION	PLANT NAME	LOCATION: CITY, STATE	NET ANNUAL GENERATION (MWH)	PRODUCTION EXPENSES MILLS(KWH)
Lower Colorado	1505	Apache	Cochise, Arizona	330,700	13.71
		Irvington	Tucson, Arizona	1,523,700	20.44
		Sautan	Gilbert, Arizona	459,200	27.79
	1506	Kyrene	Tempe, Arizona	16,600	63.68
		Octillo	Tempe, Arizona	492,600	22.57
		Phoenix	Phoenix, Arizona	189,100	24.27
	1507	Agua Fria	Glendale, Arizona	1,165,600	18.10
			REGIONAL AVERAGE PRODUCTION EXPENSE:		20.66
Great Basin	1602	Gadsby #1	Salt Lake City, Utah	102,000	28.29
		Gadsby #2	Salt Lake City, Utah	319,500	11.93
		Gadsby #3	Salt Lake City, Utah	401,700	10.93
	1605	Churchill Forest	Yerlington, Nevada	1,135,600	18.95
		Tracey	Sparks, Nevada	523,800	21.54
			REGIONAL AVERAGE PRODUCTION EXPENSE:		1.77
Pacific Northwest	1710	Centralia	Centralia, Washington	6,127,200	8.92
	1710	Jim Bridger	Centralia, Washington	5,900,700	4.29
			REGIONAL AVERAGE PRODUCTION EXPENSE:		6.65
California	1801	Humboldt Bay	Eureka, California	349,100	25.87
		Contra Costa	Antioch, California	6,127,400	21.63
		Hunters Point	San Francisco, California	1,675,100	23.24
		Potero	San Francisco, California	1,630,000	21.51
		Pittsburg	Contra Costa, California	10,426,300	22.63

Table C2 (cont'd)

U.S.G.S. HYDROLOGIC UNITS		STEAM ELECTRIC PRODUCTION DATA			
REGION	SUBREGION	PLANT NAME	LOCATION: CITY, STATE	NET ANNUAL GENERATION (MWH)	PRODUCTION EXPENSES MILLS (KWH)
California	1806	Morro Bay	Morro Bay, California	5,860,800	19.92
		Moss Landing	Moss Landing, California	10,452,700	20.19
	1807	Grayson	Glendale California	368,400	31.80
		Olive Avenue	Burbank, California	382,600	28.14
		Glenarm/Broadway	Pasadena, California	455.700	33.07
		Haynes	Seal Beach, California	7,017,100	24.10
		Valley	Sun Valley, California	714,400	23.06
		Encina	Carlsbad, California	3,383,600	25.05
		South Bay	San Diego, California	3,720,500	23.04
		(Los) Alamitos	(Los) Alamitos, California	7,807,800	23.33
		El Segundo	El Segundo, California	4,046,700	23.19
		Etinando	Fontaine, California	3,998,500	23.70
		Huntington Beach	Huntington Beach, California	3,224,900	22.38
		Mandalay	Oxnard, California	1,800,800	21.90
		Ormond Beach	Oxnard, California	5,947,400	24.00
		Redondo Beach	Redondo Beach, California	5,672,400	25.06
		San Bernardino	San Bernardino, California	758,800	19.98
		Scattergood	Plays Del Ray, California	1,662,200	15.68
		Harber	Wittington, California	102.800	50.85
	1809	Coal Water	Daggett, California	724,000	22.68
	1810	El Centro	El Centro, California	586,200	20.43
			REGIONAL AVERAGE PRODUCTION EXPENSE:		2.27

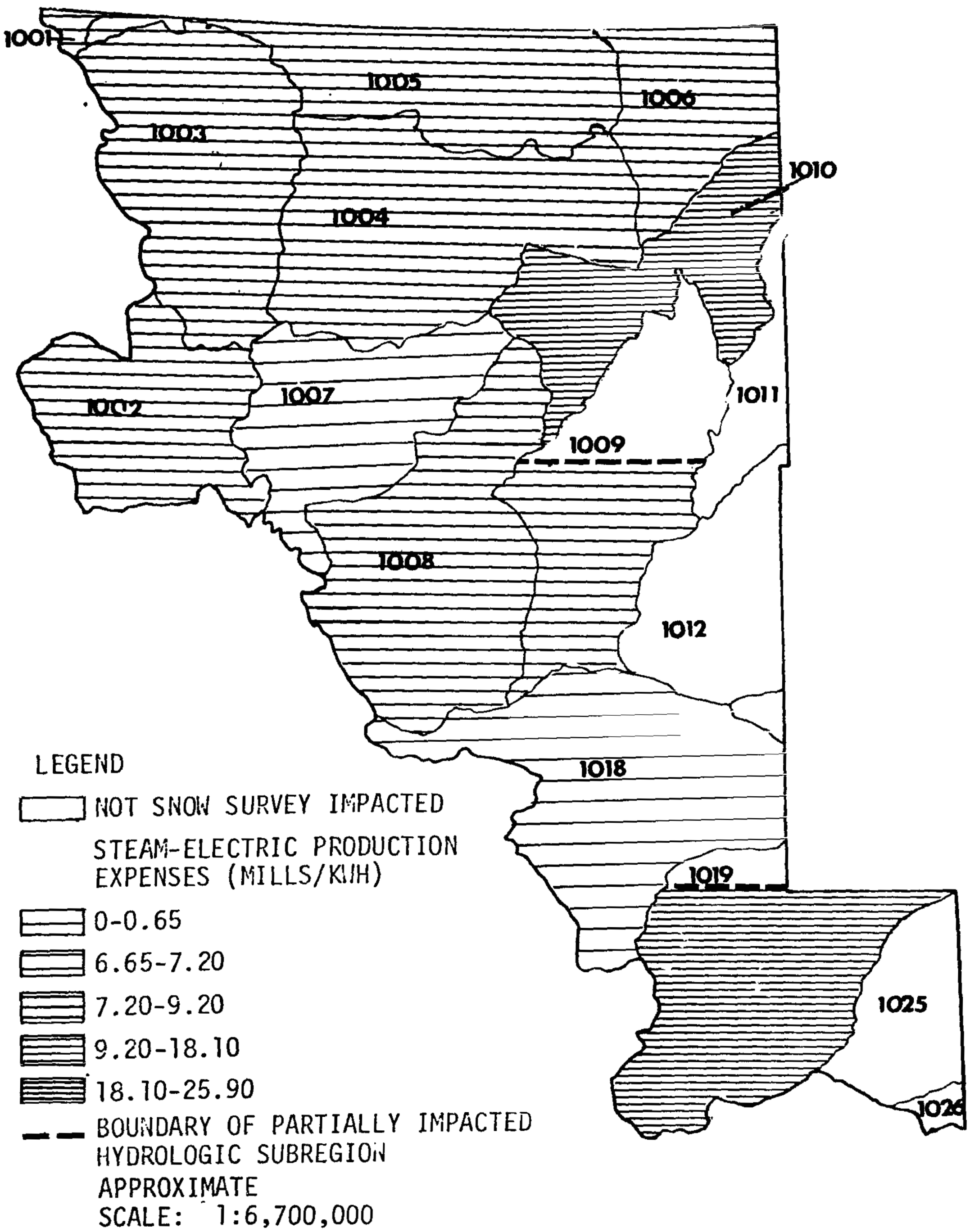


Figure C17: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Missouri hydrologic region.

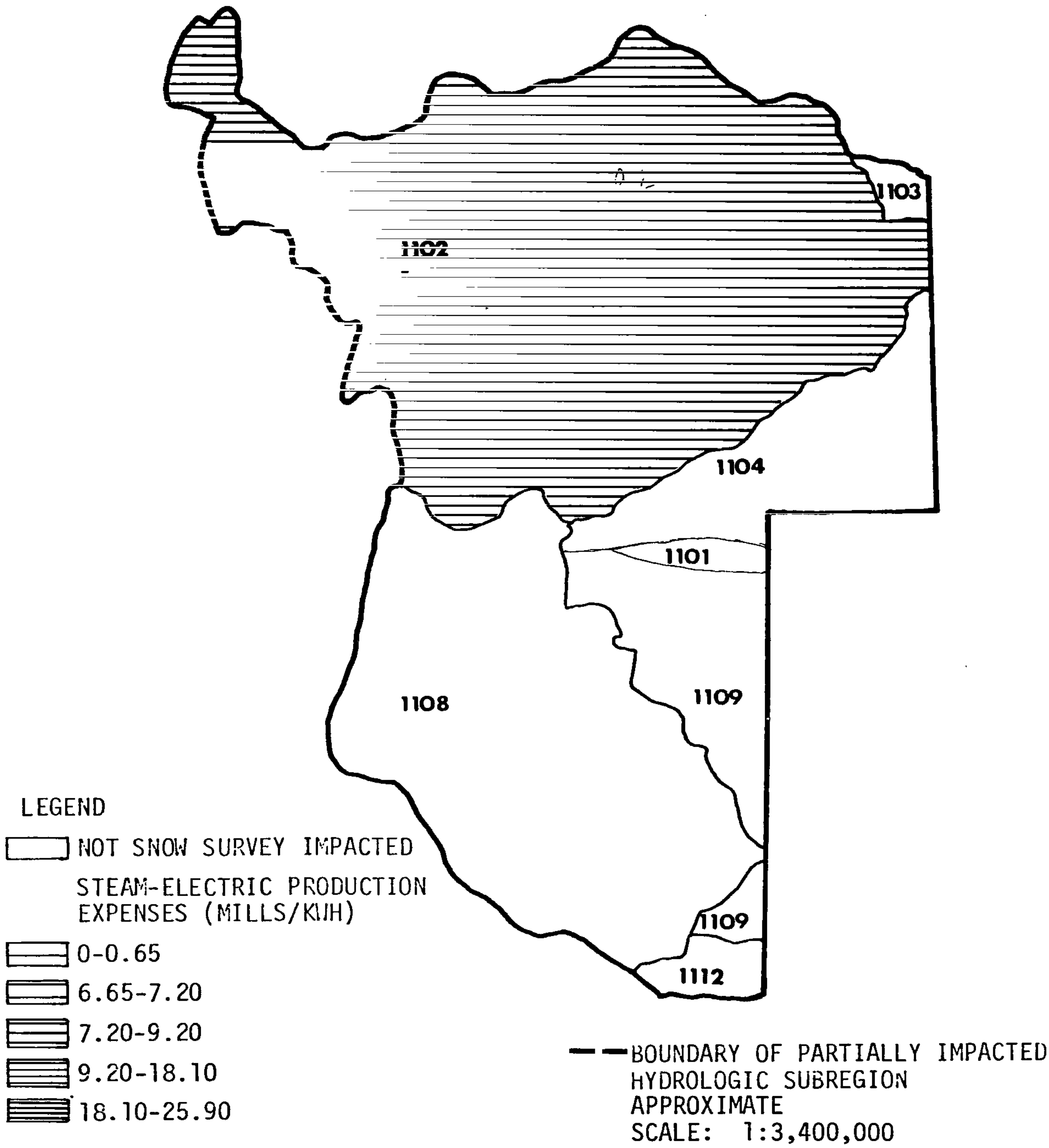


Figure C18: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Arkansas-Red-White hydrologic region.

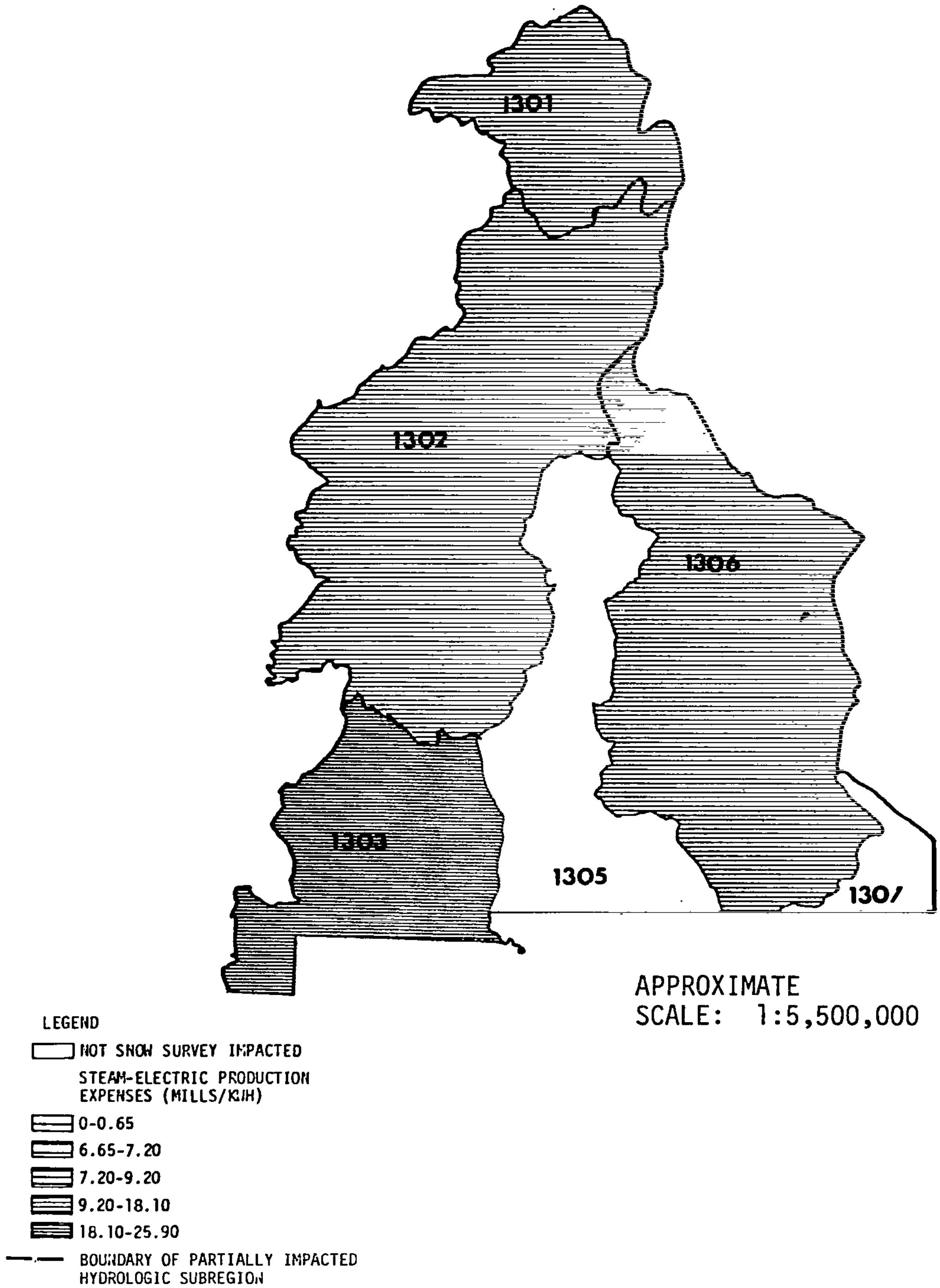


Figure C19: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Rio Grande hydrologic region.

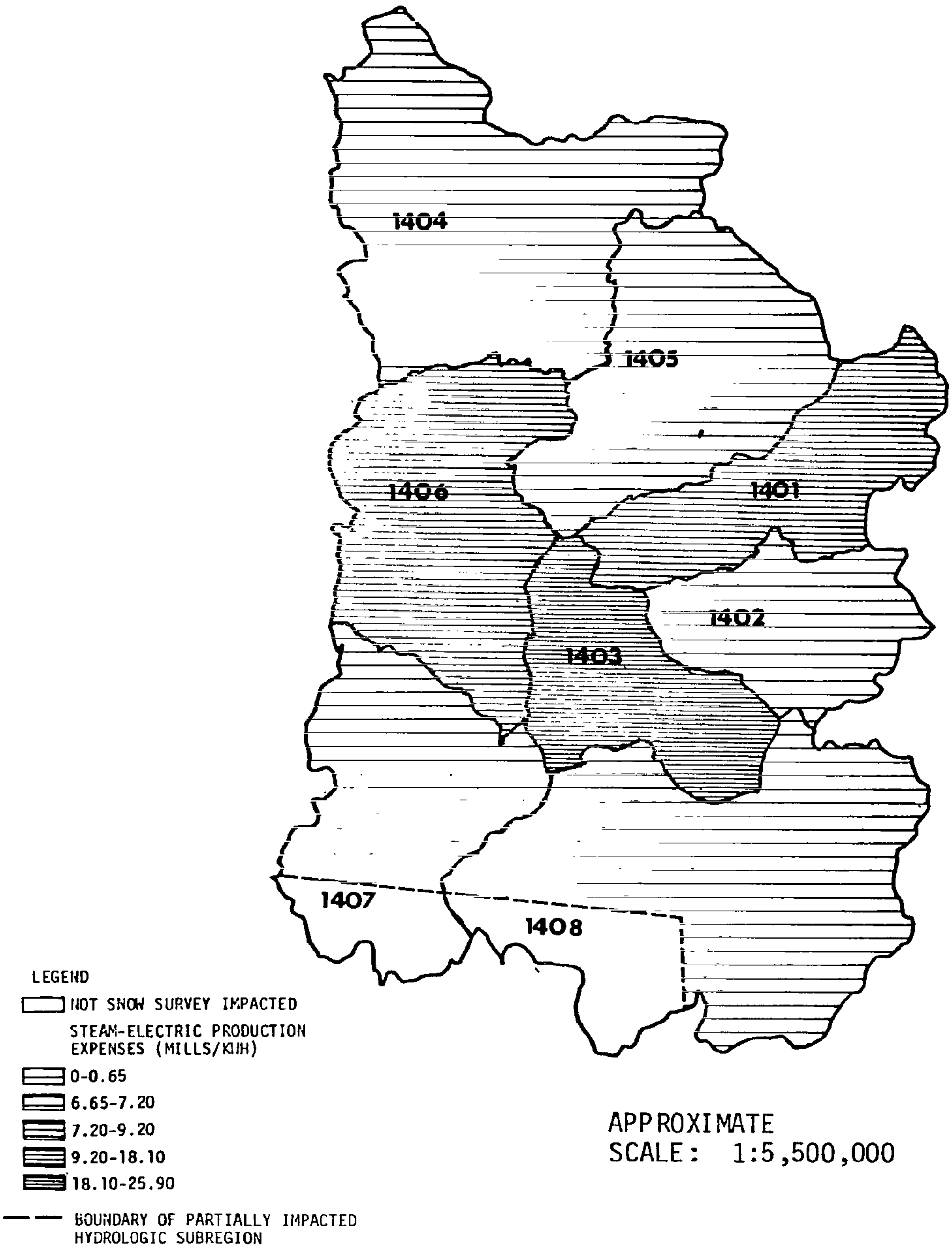


Figure C20: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Upper Colorado hydrologic region.

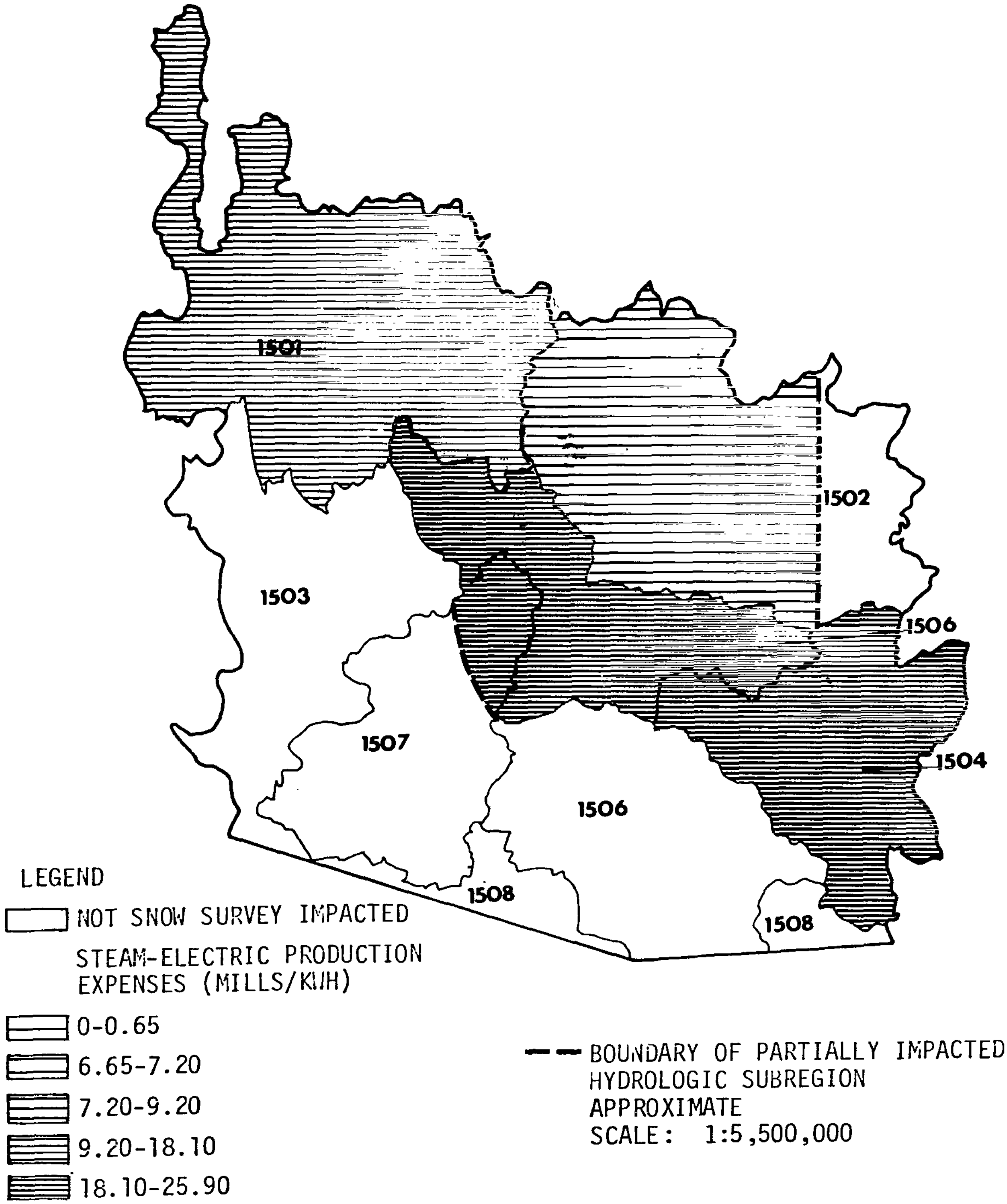


Figure C21: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Lower Colorado hydrologic region.

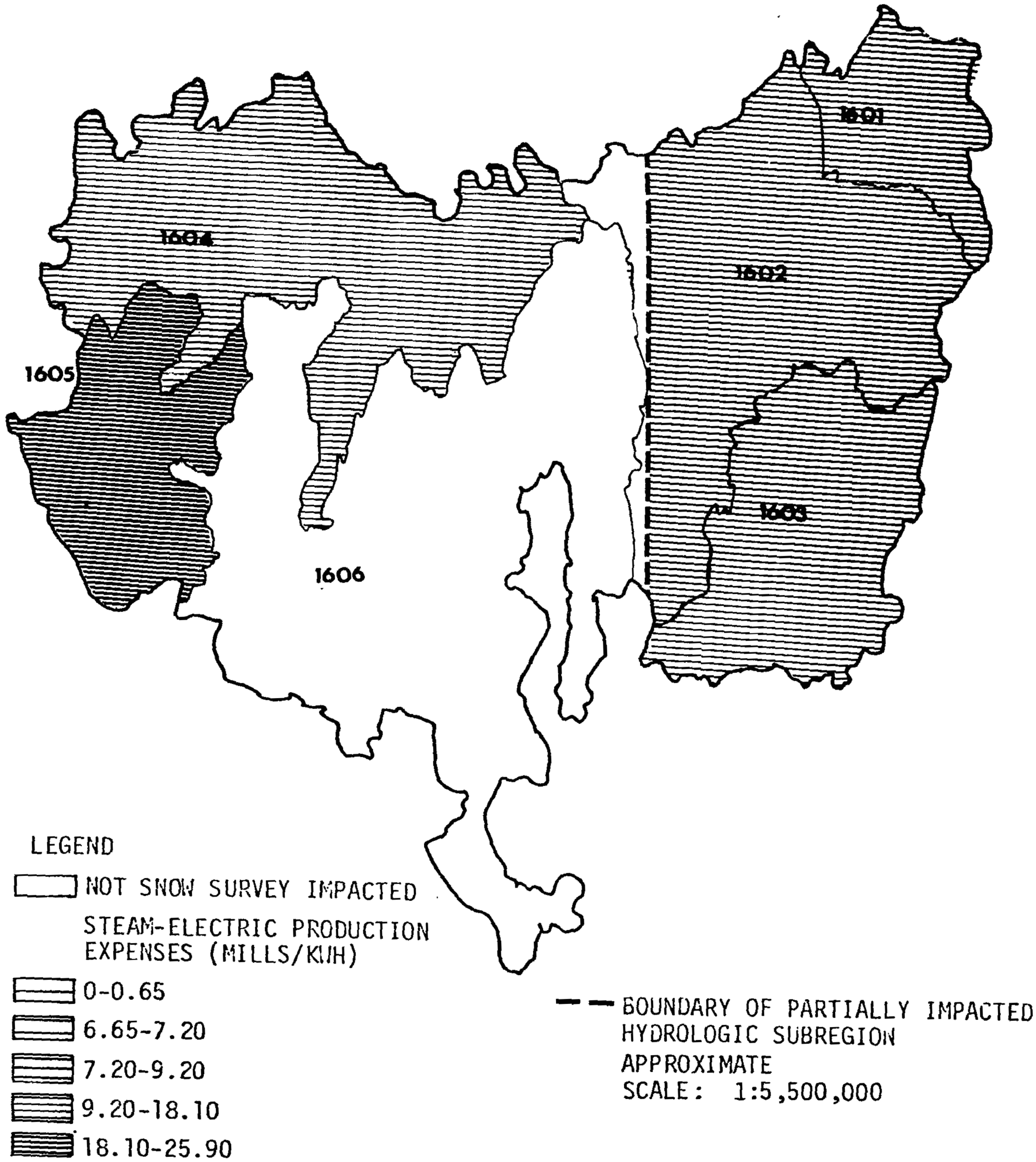
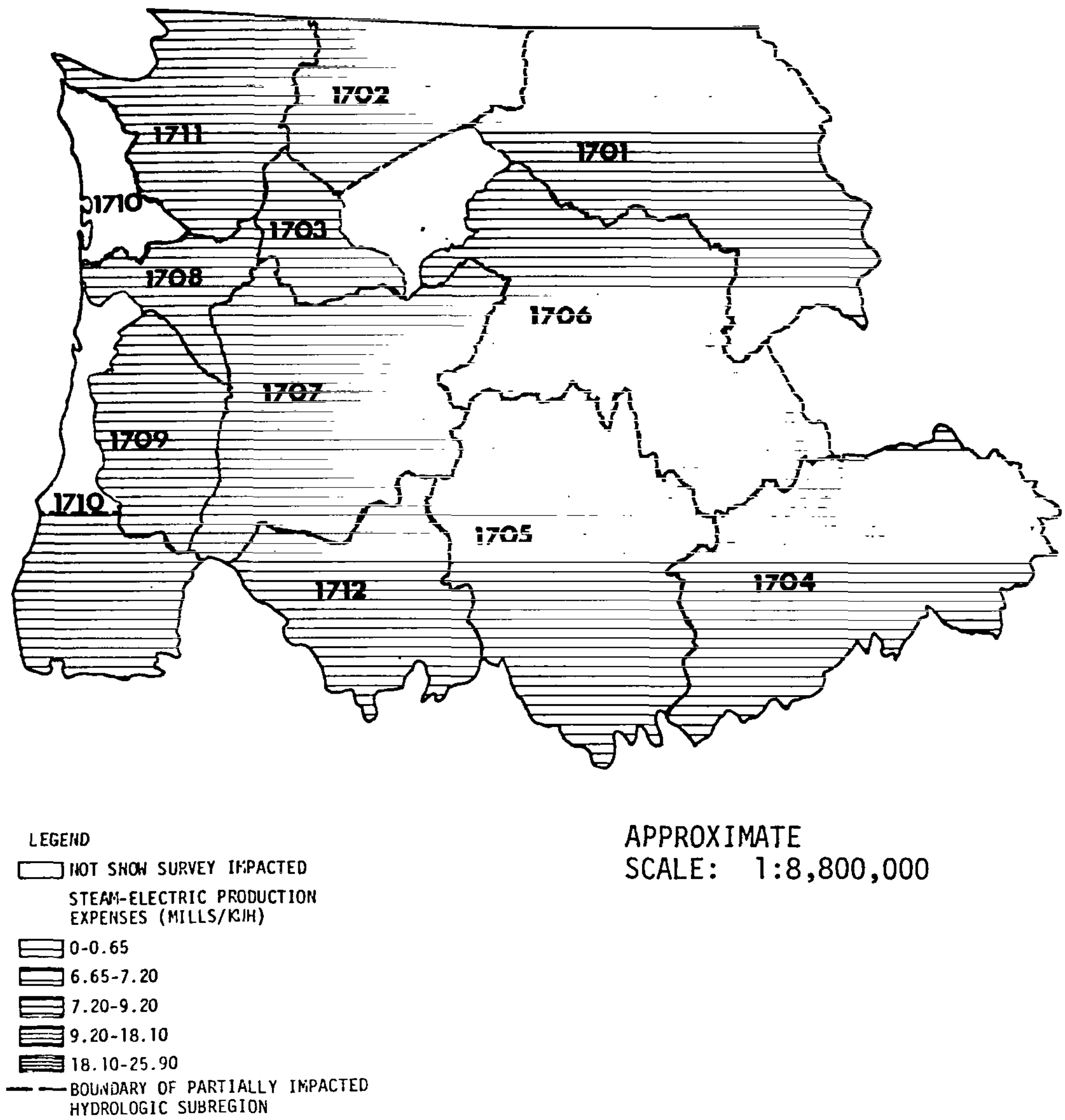


Figure C22: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Great Basin hydrologic region.



APPROXIMATE
SCALE: 1:8,800,000

Figure C23: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the Pacific Northwest hydrologic region.

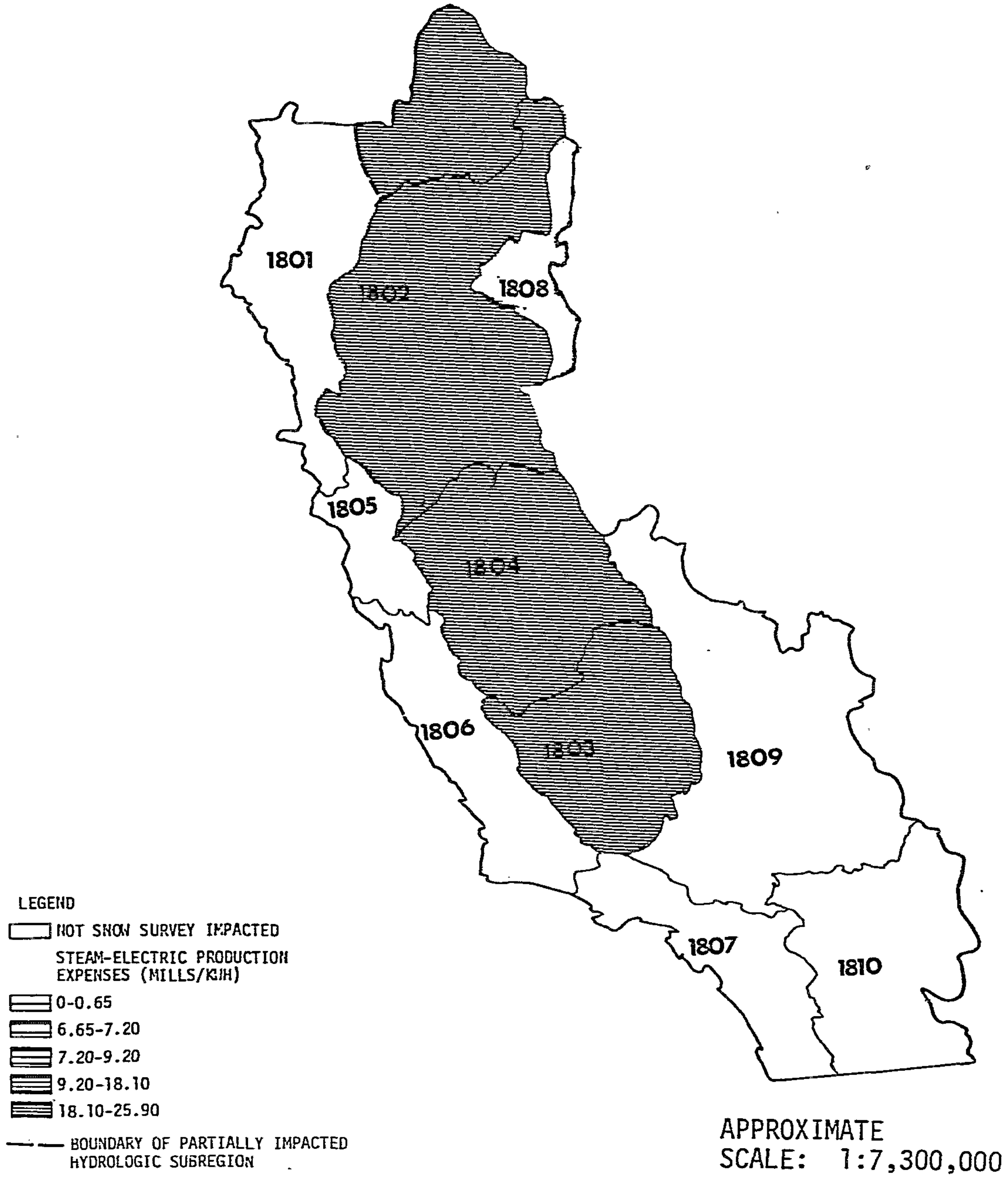


Figure C24: Steam-electric energy production expenses (mills/KWH) in the snow survey impacted subregions of the California hydrologic region.

APPENDIX D

APPENDIX D

Computer Programs Used For Data Storage and Data Reduction/Analysis

The use of computers greatly facilitated the analysis of the potential benefit of the operational application of satellite snowcover observation to the Eleven Western States. It was used for two primary purposes: data storage and data reduction/analysis.

The three extensive data bases required for the analysis of this benefit were divided into numerous working files. Forecast site data organized in a subregional basis were stored in 8 files: FPSR1 through FPSR8. Irrigated acreage and estimated crop value/acre data organized on a state divided subregion basis were stored in 8 work files: IRR1 through IRR8. Similarily, average annual hydroelectric energy generation, hydroelectric energy production expenses, and steam-electric energy expenses were stored in HYD1 through HYD8, HYX1 through HYX8, and STM1 through STM8, respectively.

Three primary programs were written which allowed for the reduction/reorganization of the above data files and the calculation of irrigation and hydroelectric energy benefit due to SATSCAM. The first, referred to as WEIGH, was used to:

1) Obtain subregional values for the coefficient of streamflow variation and the streamflow forecast error by weighting these by the associated streamflow at each forecast point.

2) Obtain subregional values of hydroelectric energy production expenses by weighting these by the associated hydroelectric energy generated at each plant.

3) Obtain subregional values of average annual crop value/acre by weighting these by the associated irrigated acreage.

WEIGH is presented in Table D1.

This reorganized data was temporarily stored in SREG1 through SREG8 and POW1 through POW8, one for each of the 8 regions. Data files AREG1 through SREG8 were 52 row by 5 column matrices. Column 1 listed the number of the subregion; column 2 listed the 1978 surface water irrigated acreage (1,000 acres); column 3 listed the estimated crop values/acres (8/acre); column 4 listed the coefficient of streamflow variation, CV; and column 5 listed the streamflow 1σ forecast error, (%). Data files POW1 through POW8 were 52 row by 6 column matrices. Column 1 listed the average annual hydroelectric energy generation (MWH); column 2 listed the hydroelectric energy production expenses; column 3 listed the 1976 steam-electric energy production expenses; column 4 listed the 1975 revenues obtained from the sale of prime hydroelectric energy; column 5 listed the coefficient of streamflow variation, CV and column 6 listed the streamflow 1σ forecast error, (%). Each row corresponds to one of the 52 snow survey impacted subregions.

Table D1
The Computer Program: Weight

```
      .∇WEIGH[⎕]∇
      ∇ WEIGH
[1]    'ENTER THE WEIGHING VECTOR'
[2]    WV←⎕
[3]    'ENTER THE VECTOR TO BE WEIGHTED'
[4]    W←⎕
[5]    'ENTER A VECTOR OF INDEXES WHOSE ELEMENTS SPECIFY
THE STARTING POINT FOR EACH WEIGHTING AND WHOSE LAST
ELEMENT IS THE INDEX OF THE LAST ELEMENT IN THE WEIGHING
VECTOR'
[6]    IN←⎕
[7]    RHO←(⍴IN)−1
[8]    WSUM←ANS←RHO ⍴0
[9]    NO←((¯1×RHO)↑IN)−(RHO↑IN)
[10]   NO←(NO+(NO=0))−1
[11]   J←0
[12]  LOOP: J←J+1
[13]   KO←IN[J]
[14]   V←KO
[15]   K←(KO−1)
[16]  LOOP1: K←K+1
[17]   V←V,K
[18]   →(K<KO+NO[J])/LOOP1
[19]   V←(⍳(⍴WV))∊V
[20]   D1←(V/WV)÷(+/(V/WV))
[21]   ANS[J]←+/((V/W)×D1)
[22]   WSUM[J]←+/(V/WV)
[23]   →(J<RHO)/LOOP
[24]   'THE WEIGHTED VECTOR IS STORED AS ANS'
[25]   'THE CORRESPONDING SUMS OF THE WEIGHTING FACTORS ARE
STORED AS A VECTOR CALLED WSUM'
      ∇
```

Table D2
The Computer Program: IRRFIN

```
      ∇IRRFIN[⎕]∇
     ∇ IRRFIN
[1]   'ENTER THE NAME OF THE DATA MATRIX'
[2]   NAME←⎕
[3]   'ENTER THE IMPROVEMENT IN THE FORECAST'
[4]   IMP←⎕
[5]   'ENTER THE NAME OF THE REGION'
[6]   NAME1←⍞
[7]   RHO←1↑(⍴NAME)
[8]   V←RHO⍴0
[9]   I←0 .
[10] LOOP: I←I+1
[11]  V[I]←((¯0.00275×NAME[I;4])+(0.024×NAME[I;5])+0.31)×IMP
[12]  V[I]←V[I]×NAME[I;2]×NAME[I;3]
[13]  →(I<RHO)/LOOP
[14]  NAME←NAME,(RHO,1)⍴V
[15]  '******************************************************************
***'
[16]  '          IRRIGATION DATA SUMMARY FOR THE ';NAME1;' REGION'
[17]  '   '
[18]  '   '
[19]  'EACH ROW OF THE MATRIX REPRESENTS A SUBREGION'
[20]  'THE COLUMNS ARE;NO, IRR ACREAGE(1000) AVG DOLLARS PER ACRE'
[21]  'CV STREAMFLOW  SIGMA OF FORECAST ERROR BENEFIT IN DOLLARS'
[22]  '   '
[23]  '   '
[24]  'THE AVERAGE FORECAST IMPROVEMENT FOR THE REGION IS: ';IMP
[25]  '  '
[26]  '******************************************************************
****'
[27]  NAME
[28]  '******************************************************************
****'
[29]  'THE TOTAL IRRIGATION BENEFIT IS ';+/NAME[;6];' DOLLARS'
[30]  '******************************************************************
```

The two computed simulation models developed and presented in the body of this report constitute the other two primary programs utilized (IRRFIN and POWVAL). IRRFIN, given in Table D2 computes, stores, and prints the benefit for each subregion in the region being run. It also prints the total irrigation benefit for the region. The required inputs for IRRFIN are the region's name, the improvement in forecast accuracy, and the data matrix (SERGI through SERG8). IRRFIN was run 8 times, thereby calculating and storing the irrigation benefit for each region.

IRRPRT, a secondary program written to print the benefit calculated by IRRFIN is presented in Table D3. An example of this printout is presented in Table D4.

POWAL, presented in Table D5, computes and prints the potential hydroelectric energy benefit for each subregion. The required inputs are the region's name, the improvement in forecast accuracy, and the data matrix (POW1 through POW8). Eight runs out of POWVAL were carried out in order to obtain the values of SATSCAM's benefit for each region. An example of the POWVAL printout is presented in Table D6.

The results from these computer simulation runs were combined with the data contained in the original SREG1 through SREG8 and POW1 through POW8 to form one comprehensive storage file of subregional data. This file was referred to as ALDATA.

An additional storage file of subregional data was created for analytical purposes. Its file name is BENSR. It is a 52 by 2 matrix. The first column lists the benefit of SATSCAM per surface water-irrigated acre and the second column lists the benefit of SATSCAM per MWH of hydroelectric energy for each subregion.

Numerous regional values were similarly calculated. Those stored in computer files are the coefficient of streamflow variation and forecast error, stored as CVS; steam-electric production expenses, stored as STMR; and hydroelectric production expenses, stored as HYDR.

Table D3

The Computer Program: IRRPRT

```
      ∇ IRRPRT
[1]    'ENTER THE NAME FOR THE REGION BEING RUN'
[2]    REGION←⍞
[3]    'ENTER THE NAME OF THE DATA MATRIX'
[4]    NAME←⍞
[5]    ⍎')ASSIGN 1 ',NAME,';APL'
[6]    ⍎')READ 1'
[7]    ⍎')CLOSE 1'
[8]    DM←⍎NAME
[9]    VALUE←DM[;6]
[10]   ⍎')ERASE ',NAME
[11]   VM←((⍴VALUE),2)⍴0
[12]   VM[;1]←⍳(⍴VALUE)
[13]   VM[;2]←VALUE
[14]   ' '
[15]   'THE FOLLOWING VALUES ARE GIVEN IN DOLLARS'
[16]   ' '
[17]   'VALUES FOR THE ',REGION,' REGION'
[18]   ' '
[19]   '================================================================'
[20]   'THE VALUE OF IMPROVED FORECASTING TO EACH OF THE SUBREGIONS IS'
[21]   '================================================================'
[22]   ' '
[23]   VM
[24]   ' '
[25]   'THE TOTAL VALUE TO THE ENTIRE REGION IS ';+/VALUE
      ∇
```

Table D4
Example of IRRPRT Printout: Irrigation Benefit for the Missouri Region by Snow Survey Impacted Subregions

```
THE FOLLOWING VALUES ARE GIVEN IN DOLLARS

VALUES FOR THE MISSOURI REGION, 10

=================================================================
THE VALUE OF IMPROVED FORECASTING TO EACH OF THE SUBREGIONS IS
=================================================================

   1001         0.0000
   1002         4.9918E+5
   1003         3.6194E+5
   1004         4.4836E+5
   1005         1.1307E+5
   1006         4.5394E+5
   1007         2.5572E+5
   1008         6.9930E+5
   1009         1.8570E+5
   1010         1.9347E+6
   1018         8.3377E+5
   1019         1.3262E+6

THE TOTAL VALUE TO THE ENTIRE REGION IS 7.1119E+6
```

Table D5
The Computer Program: POWVAL

```
      ∇POWVAL[⎕]∇
     ∇ POWVAL
[1]   'ENTER THE PERCENT IMPROVEMENT EXPECTED'
[2]   IMP←⎕
[3]   'ENTER THE NAME FOR THE REGION BEING RUN'
[4]   REGION←⍞
[5]   'ENTER THE NAME OF THE DATA MATRIX'
[6]   NAME←⍞
[7]   ⍎')ASSIGN 1 ',NAME,'.APL'
[8]   ⍎')READ 1'
[9]   ⍎')CLOSE 1'
[10]  DM←⍎NAME
[11]  ⍎')ERASE ',NAME
[12]  V1←(DM[;3]-DM[;2])×1.21
[13]  V2←(DM[;4]×1.26)-(0.85×DM[;3]×1.21)
[14]  C←(V1+V2)÷2000
[15]  VALUE←(0.67×DM[;1]×DM[;6]×C×IMP)÷10
[16]  VM←((⍴VALUE),2)⍴0
[17]  VM[;1]←⍳(⍴VALUE)
[18]  VM[;2]←VALUE
[19]  ' '
[20]  'THE FOLLOWING VALUES ARE GIVEN IN DOLLARS'
[21]  ' '
[22]  'VALUES FOR THE ',REGION, ' REGION'
[23]  ' '
[24]  '================================================================'
[25]  'THE VALUE OF IMPROVED FORECASTING TO EACH OF THE SUBREGIONS IS'
[26]  '================================================================'
[27]  ' '
[28]  VM
[29]  ' '
[30]  'THE TOTAL VALUE TO THE ENTIRE REGION IS ';+/VALUE
     ∇
```

Table D6
Example of POWVAL Printout: Hydroelectric Energy Benefit for the Missouri Region by Snow Survey Impacted Subregions

THE FOLLOWING VALUES ARE GIVEN IN DOLLARS

VALUES FOR THE MISSOURI REGION, 10

==
THE VALUE OF IMPROVED FORECASTING TO EACH OF THE SUBREGIONS IS
==

1001	0
1002	7445.962993
1003	337114.2712
1004	158518.7256
1005	0
1006	0
1007	5011.647122
1008	237082.5892
1009	0
1010	0
1018	122545.5434
1019	143213.3381

THE TOTAL VALUE TO THE ENTIRE REGION IS 1010932.078

APPENDIX E

APPENDIX E

Assessment of Relative Importance of Snowmelt (The Snow Fraction)

The value of water usage attributable to snowmelt runoff depends upon the magnitude of total runoff utilized and the portion of that runoff which is contributed by snowmelt (Snow Fraction). To estimate the snow fraction, the monthly contribution of rain to the runoff is determined from the ratio between the runoff for months which do not exhibit significant snow contribution and the corresponding precipitation due to rain (rainfall to runoff transfer function). The initialization date of months exhibiting insignificant snow contribution to runoff is determined by allowing a snowmelt lag period following the last month exhibiting a snowfall event.

The snow fraction is computed by the following water balance equation:

$$F_s = \frac{\sum_{1}^{12} (RO)_s}{\sum_{1}^{12} (RO)_t} \qquad [E1]$$

Where:

F_s = Fraction of total runoff attributed to snow

$(RO)_s$ = Monthly runoff due to snowmelt

$(RO)_t$ = Monthly total runoff due to total precipitation (combined snowmelt and rainfall)

The above values are averages over the period of record; in this study, a 10-year period was used.

The average monthly runoff due to snowmelt is expressed by the formulation:

$$(RO)_s = (RO)_t - (RO)_r \qquad [E2]$$

Where:

$(RO)_r$ = 10-year average monthly contribution of runoff due to rainfall.

The monthly contribution (10-year average) of rain to the runoff is determined from the ratio between the precipitation due to rain and the corresponding runoff for months which do not exhibit significant snow contribution. It is given by the following expression:

$$(RO)_r = (P_r)\ C \qquad [E3]$$

Where:

(P_r) = Mean monthly precipitation occurring as rainfall

C = Rainfall-to-runoff transfer function of the watershed

This method of computation determines the snow fraction for a homogeneous watershed whose outlet feeds a reservoir either directly or indirectly, without intermediate withdrawals.

The snow fraction was calculated for 21 watersheds distributed throughout the 11 Western States. Selection of these watersheds was based upon: 1) the availability of adequate watershed climatic records; and 2) the proximity of local watershed specialist's estimates of snow fractions for comparison. The following procedure was used for each watershed:

1. Each selected watershed was precisely located on the USGS Hydrologic Unit maps;
2. Precipitation records for gages located within each sub-watershed were obtained from NOAA's "Climatic Summary of the U.S.;"
3. Monthly averages of total precipitation for at least 10 years of record were computed;
4. Average monthly temperatures were computed, from the same source. The resulting average yearly temperature profile permitted estimating the period of zero contribution of snowmelt to runoff. Beginning at the time when the average monthly temperature rose sufficiently for snowmelt to occur, and snowfall events ceased, a lag period was introduced to account for all of the accumulated snow to melt. The time interval between the end of this lag and the occurrence of the next snowfall event was the assumed period when snowmelt did not contribute to runoff. It is during this period that the sub-watershed's rainfall-to-runoff transfer function was calculated from the average monthly precipitation and monthly average runoff records.

The actual value of the lag varies with local conditions. The method selected to assess its best value was to compute the snow fraction of each watershed using synthetic one-month and two-month lags: and then to compare the computed values with the estimates by the local experts. The calculations for the Black River Basin are exemplified in Table E1. Table E1 indicates that approximately 80% of the total water from the Black River Basin derives from the snowpack.

Table E1
Snow Fraction Calculation Summary for Black River Basin, Arizona

Month	Precipitation (in.)			Runoff (in.)			
	Total	Rain	Snow	Total	Rain	Snow	Temp. (F^{O})
Oct.	2.26	2.06	0.2	0.049	0.049	0.000	45.2
Nov.	1.21	0.43	0.78	0.078	0.024	0.054	34.9
Dec.	1.77	0.07	1.70	0.515	0.004	0.511	29.0
Jan.	3.19	0.77	2.42	0.382	0.042	0.34	27.8
Feb.	1.91	0.16	1.75	0.338	0.009	0.329	28.1
Mar.	2.80	1.32	1.48	0.781	0.073	0.708	32.8
Apr.	1.54	0.83	0.71	0.917	0.046	0.871	39.8
May	0.64	0.37	0.27	0.303	0.020	0.283	46.3
June	1.13	1.13	0.00	0.64	0.062	0.002	55.7
July	4.38	4.38	0.00	0.60	0.060	0.000	60.1
August*	5.53	5.53	0.00	0.218	0.218	0.000	59.0
Sept.*	1.33	1.33	0.00	0.159	0.159	0.000	54.0
Total	27.69	18.38	9.31	3.864	0.766	3.098	
C= .055				f_s = 80.2%			

*Months utilized for calculation of Basin's Rainfall to runoff transfer function, c.

Table E2 presents the results of the snow fraction computations for the 21 selected watersheds assuming one-month and two-month lag periods respectively. On the average, the hypothesis of a two-month lag period produces snow-fraction estimates which are 5.1 ± 7.1% higher than those derived from the one-month lag period. The relationship is shown in Figure E1.

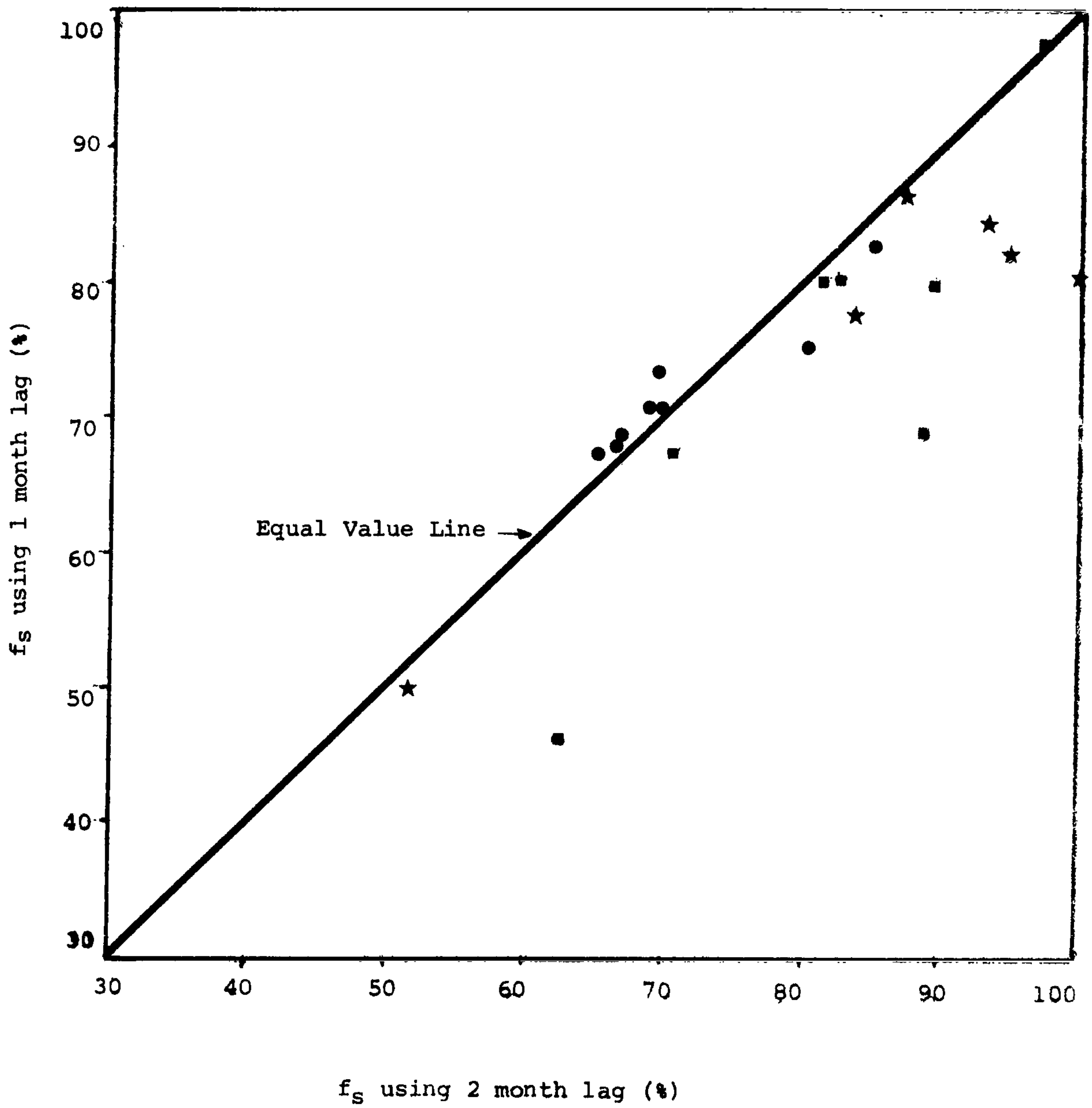
Table E3 presents estimates of snow fractions supplied by local experts. The estimates calculated using a two-month snowmelt lag period differed fron the expert estimates by + 6.4%; those which employed a one-month snowmelt lag period differed by +0.2%. This comparison is summarized in Table E4.

It should be noted from Table E4 that most of the points where there was pronounced error were those points for which the local experts did not give specific values. A visual comparison of the expert values with the computed values when amended by physiographic partitioning suggested by the ASVT personnel gives a sufficient basis for assessing the fractional contribution of snow to the total water resource of the Western States.

Figure E2 illustrates such a partitioning for the Pacific Northwest which was provided to ECOsystems by Mr. John Dillard, Head of Hydrology at the Bonneville Power Authority. The assessed fractional contributions of snowmelt for a one month lag are presented in Table E5 by state.

Table E2
Comparison of Snow Fraction Calculation Results Using a One and Two Month Snowmelt Lag Period

SUBWATERSHED	SNOW FRACTION (%) 2 MONTH LAG	1 MONTH LAG
Black River Basin, Arizona	80.2	75.0
Chevelon Creek Basin, Arizona	85.0	82.6
Gila River Basin, Arizona	68.9	70.6
Little Colorado River Basin, Arizona	69.8	70.3
Salt River Basin, Arizona	66.8	67.8
Tonto Creek Basin, Arizona	69.7	73.0
White River Basin, Arizona	66.9	68.4
Castle Creek Basin, California	87.6	86.0
Pit River Basin, California	94.5	81.9
Sacramento River Basin, California	51.8	50.0
San Joaquin River Basin, California	100.0	80.0
San Joaquin River Basin, California	83.3	77.3
Upper Colorado River Basin, Colorado	65.3	67.3
Bigwood River Basin, Idaho	70.9	67.0
Crooked River Basin, Oregon	88.7	68.3
Donner & Blitzen Basin, Oregon	97.2	97.6
Marias River Basin, Montana	81.3	79.9
Skyland Creek Basin, Montana	82.7	79.7
Carson River Basin, Nevada	93.3	84.0
Nisqually River Basin, Washington	62.7	46.0
North Platte River Basin, Wyoming	89.7	79.2



● Arizona & Colorado subwatersheds

★ California & Nevada subwatersheds

■ Pacific Northwest subwatersheds

Figure E1: Comparison of snow fraction calculation results.

Table E3
Snow Fraction Estimates by Local Watershed Specialists

BASIN	SPECIALISTS	SNOW FRACTION
Willamette River Basin	Gary Flightner, Hydraulics Engineer, Corps of Engineers	50%
Castle Creek	Gary Flightner, Hydraulics Engineer, Corps of Engineers	80%
Oregon Basin	Tom George, Snow Survey Supervisor, SCS, USDS, Portland, Oregon	60-90%
Sacremento River Basin	Jack Hannaford, Sierra-Hydrotech	45%
Pit River Basin	" " " "	32%
San Joaquin	" " " "	70%
Salt River	Bill Warskow, Darrell Jordan, Salt River Project	75%
Colorado	Richard Enz, Snow Survey Supervisor	80-85%
St. Louis Creek	Charles F. Leaf, Consulting Hydrologists, Colorado	67%
	Bob Whaley, Snow Survey Supervisor, Utah	75-80%
Carson River	Ron Moreland, Snow Survey Supervisor, Nevada	82%
Skyland Creek	Jerry Beard, SCS, USDA	80%
Marias Creek	Montana	80%

Table E4

Comparison of Computed Snow Fractions for a One and Two Month Lag and Expert Estimates

BASIN	EXPERT ESTIMATES	ONE MONTH LAG	TWO MONTH LAG	DIFFERENCE BETWEEN ONE MONTH LAG AND EXPERT	DIFFERENCE BETWEEN TWO MONTH LAG AND EXPERT
Washington Basins	50	46	63	-4	+13
Oregon Basins	60-90 (75 aver.)	68	89	-7	+14
	60-90 (75 aver.)	98	97	+23	+22
Sacramento Basin	45	50	52	+5	+7
San Joaquin	70	77	84	+7	+14
Upper Colorado	(80-85) (82.5 aver.)	67	65	-15.5	-17.5
Salt River	75	68	67	-7	-8
				MEAN +0.2	+6.4

Note: By using the actual difference, as opposed to the absolute difference which would result in average differences of 9.8 for the one month lag and 13.6 for the two month lag, any bias associated with the method of calculation can be determined. The one month lag exhibits negligible bias whereas the bias of the two month lag results appears quite significant. At any rate, the one month lag calculations appear to be the more valid of the two methods regardless of the means of comparison.

Table E5
Estimates of Average State Snow Fractions Calculated Using A One Month Snowmelt Lag Period

ESTIMATES OF AVERAGE STATE SNOW FRACTIONS CALCULATED USING A ONE MONTH SNOWMELT LAG PERIOD

STATE	SNOW FRACTION
Arizona	.74
California	.73
Colorado	.73
Idaho	.67
Montana	.70
Nevada	.65
New Mexico	.71
Oregon	.67
Utah	.74
Washington	.67
Wyoming	.74

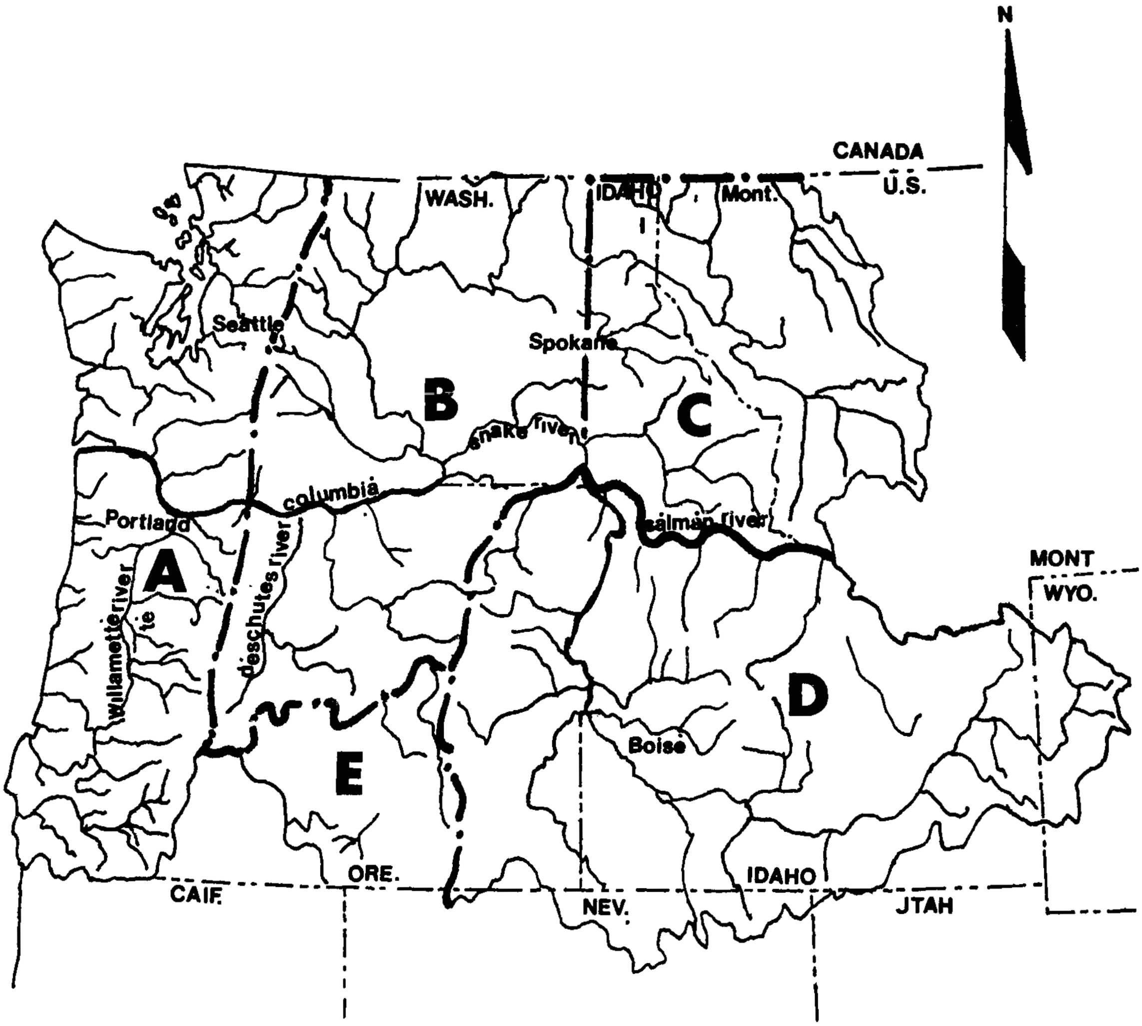


Figure E2: Suggested division of the Pacific Northwest Region.

APPENDIX F

APPENDIX F

Optimizing Size and Cost of Future Reservoirs

Benefits from satellite snowcover measurement can accrue to the design and operation of future reservoirs by providing adequate information to permit the optimization of the facilities size and cost and selection of the facilities optimal operating procedures.

Design Criteria

Conventional design procedures for hydropower facilities can be divided into two types:

1. Those that begin with an assumed project capacity (or other output specification) and provide criteria for designing other components so as to minimize some measure of cost.

2. Those that employ some measure of project output value and provide criteria for choosing capacity and designing components so as to maximize the excess of output value over cost.

Both procedures utilize simplifying assumptions regarding the nature of the market for electric energy. Typically, the market is divided into three sectors:

1. The market for firm power -- this may be energy available 24 hours per day, 365 days per year; or it may be energy available during specified periods or specified seasons; but its availability is guaranteed, regardless of hydrologic conditions.

2. The market for secondary power -- this is energy which cannot be guaranteed, but which is available with some known probability and for which a definite market exists; it may be provided on an interruptible basis to industrial customers.

3. The market for dump power -- energy available on terms which preclude the existence of a consistent market; dump power may be sold at extremely low rates to industries with an application for temporary blocks of energy, or it may be transferred to another distribution system, even at otherwise uneconomic transmission costs.

The first, cost minimizing, type of design procedure can be illustrated using the following example:

Project Description:	Run-of-the-river, 0.75 overall efficiency, maximum available head = 50 feet
Capacity requirements:	Total installed capacity = 200,000 kw
Market sector definitions:	Firm power -- available 24 hrs./day, 365 days/year
	Secondary power -- available at least fifty percent of the time
	Dump power -- available less than fifty percent of the time

The design procedure begins with the selection of the design hydrology. This is a particular sequence of streamflow having known statistical properties. Since the purpose is to insure that a certain amount of generating capacity will be available on a firm basis, the design hydrology would cover a period of critically low flows -- either an historical period having a low probability of recurrence, or a synthetic sequence of generated streamflows having a chosen low level of probability of occurrence.

The design hydrology is reduced to a flow-duration curve, where streamflow is plotted against the percent of the time that such a streamflow is equalled or exceeded in the design streamflow sequence. Such a curve appears as in Figure F1. It can be seen that in the design sequence of flows chosen, no flows were less than 20,000 cfs: this level of streamflow can evidently be relied upon to produce firm power. It is also evident that streamflows of 53,000 cfs are exceeded not more than fifty percent of the time, thus establishing the level for firm plus secondary power.

The dump power limit is determined by solving the following:

$$P_{design} = \frac{\nu}{737.6} e\, Q\, H$$

where:

P_{design} = Total design capacity, 200,000 kw

e = Overall efficiency, 0.75

H = Available head, 50 feet.

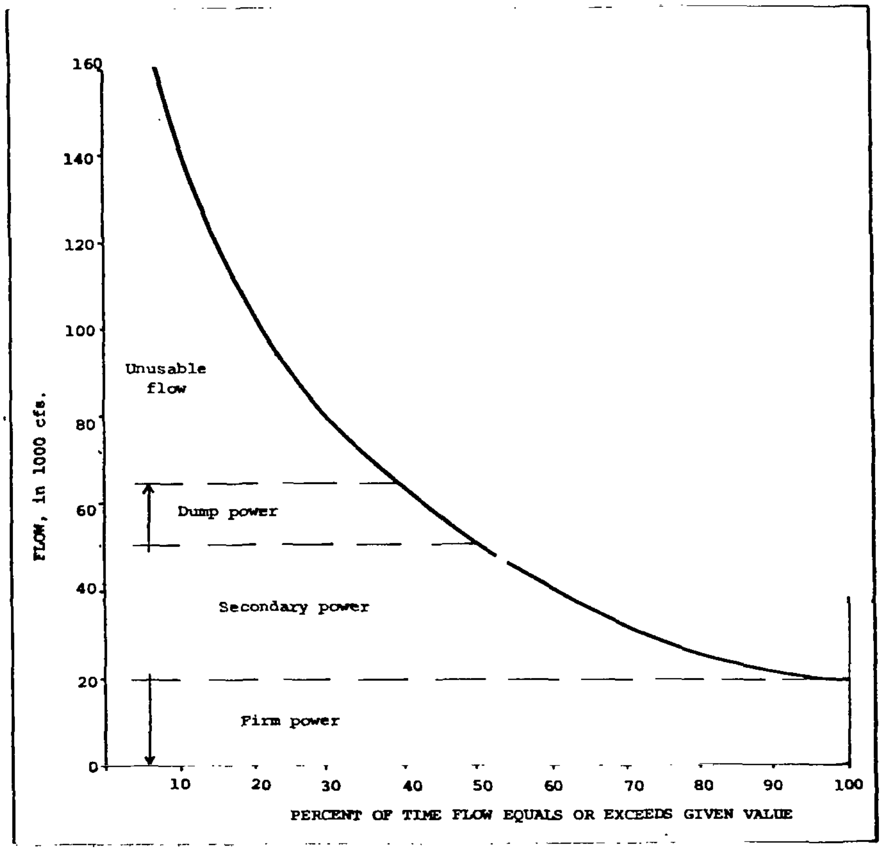


Figure F1: Flow duration curve for run-of-the river plant design.

Solved for Q, this expression indicates that full design output (200,000 kw) would be achieved when streamflow is equal to approximately 63,000 cfs. By solving (19) for streamflow equal to 53,000 cfs (firm plus secondary level), the project output at this level can be computed as 168,000 kw. Similarly, equation (19) shows that the project output at the firm power level (20,000 cfs) is equal to approximately 63,500 kw.

Extending this analysis to hydropower projects with a storage reservoir requires the incorporation of some type of operations analysis into the design procedure. In its simplest form, such an analysis consists of a tabulation of reservoir contents for each of the periods of the design streamflow sequence, accounting for evaporation and seepage losses, releases to the hydropower plant, other releases, and involuntary spills. The periods used may be days, weeks, months, ètc., but months are frequently employed. Upper and lower bounds are established for storage contents: when the upper bound is reached inflows in excess of releases are assumed to spill; when the lower bound is reached releases cannot exceed inflows.

The effect of storage is to increase the firm power level for a given hydrology; the greater the storage provided, the greater the increase. Design may proceed by using the reservoir operations study to calculate the firm energy available for each of a number of possible storage capacities. The relationships between firm energy and storage capacity would be similar to that of Figure F2 with the intercept on the horizontal axis corresponding to the firm energy obtainable from a run-of-the-river plant. The figure also shows that, for a given hydrology, firm energy asymptotically approaches an upper bound with increasing storage capacity. It should also be evident that secondary energy approaches zero as firm energy approaches its maximum, when maximum generating capacity is constant.

In designing hydropower storage facilities, it is customary to fix the firm energy requirements on the basis of anticipated electric loads, although the definition of firm energy need not be the same as that adopted above. If the plant is to be used as a peaking facility, for example, firm energy may be required during specified periods of each day, at levels which vary from season to season. For example, 300,000 kw of firm power may be required during the period 10:00 a.m. to 6:00 p.m. in May, June, July, August and September; 150,000 kw of firm power may be required during the period 10:00 a.m. to 3:00 p.m. for other months. This pattern of generation can be incorporated into the reservoir operation analysis and the minimum size reservoir which will guarantee such a pattern of releases, assuming designing hydrology, determined.

A further design factor relates to the choice of "dead storage" capacity. Since hydropower capacity is a function of both flow and head, additional energy can be obtained from the same flow by increasing head. One means of accomplishing this is to increase the height of the dam, so as to cause the water surface elevation to be derived from a point further upstream. The lower bound for storage is also raised by an equivalent amount, resulting in a certain amount of reservoir storage remaining unused ("dead") since it lies

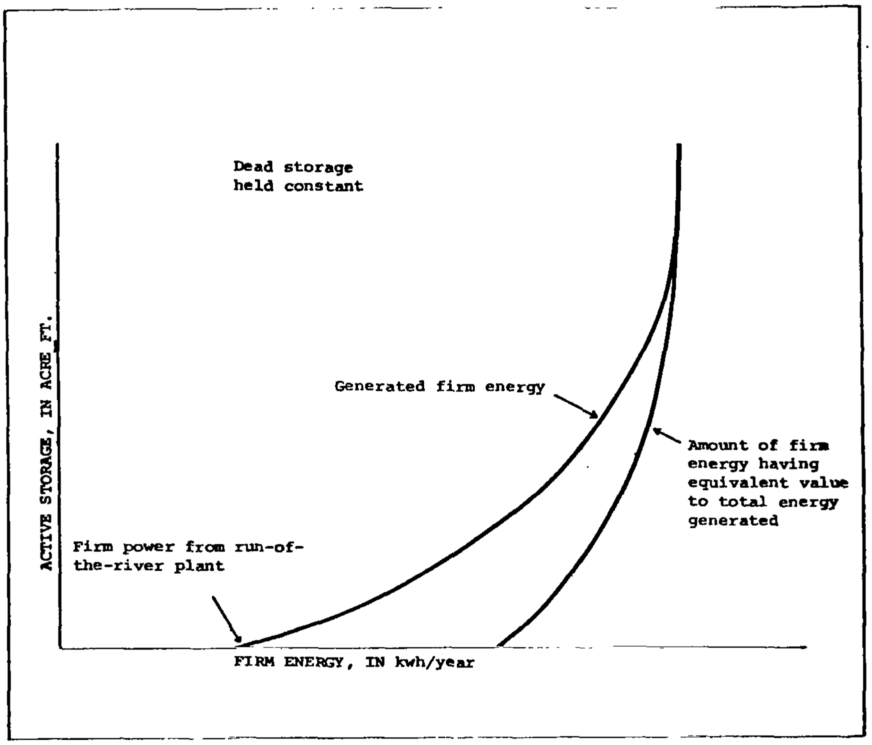


Figure F2: Active reservoir storage vs. firm energy.

below the operating ("active") range. Increasing dead storage increases output for any given release. As a result, it permits a specified level of firm energy production to be achieved with smaller releases, hence lower capital and operating cost for power facilities. On the other hand, increasing dead storage increases dam and reservoir costs. Part of the cost-minimizing problem is to determine the optimal level of dead storage for the firm energy level selected. This process is illustrated by Figure F3, which shows that the total cost of providing a specified level of firm energy each year reaches a minimum for a particular value of dead storage, when the calculations are performed for a particular site and design hydrology.

The first type of design procedure, then, begins with a specified output characteristics (such as maximum generating capacity, or minimum firm energy output) and develops the particular project which would minimize the cost of achieving the required output. Such design approaches stem from an objective of matching generating facilities to perceived "requirements" derived from anticpitated loads. Another approach which takes a somewhat broader view of the design problem, attempts to maximize the difference between the value of the output of the hydroelectric facility and the total cost of construction and operation.

The more conventional of the various techniques employs fixed estimates of unit value for each of the classes of energy. Firm energy (however defined) is assigned a value per kwh, secondary energy is assigned a lower value, and dump energy a still lower value. For a given site and design hydrology, the maximum sum of firm plus secondary plus dump power is determined by the capacity of the generating plant; the sum of firm plus secondary power is determined by reservoir capacity and operating mode; and the level of firm power is determined by active storage provided. The design problem is one of choosing that combination of generating capacity and storage configuration which maximizes the difference between the aggregate value (as assumed) of firm, secondary, and dump energy, and the total cost of the project.

The major shortcoming of this method of design is the same as for the simple cost-minimizing approach: the fluctuation in the value of output and the resulting dependence of output value on the time sequence of generation, are ignored. Operating a hydropower facility round-the-clock in order to meet a firm power commitment may, when other generating options are available, result in unnecessarily high total costs for the overall electric utility system. If the hydroelectric energy output is confined to those periods when alternate costs are highest, high-cost thermal generation during peak periods would be replaced by energy-efficient, low-cost generations at off-peak times.

To reflect this mode of operation in the design process, so as to insure the proper sizing of generating facilities and the proper storage configuration for this type of use, a much more complex design procedure is required. The operation of the reservoir must be simulated in parallel with assumed electric system load changes, and an explicit operating rule must be assumed and simulated. Past system load patterns are statistically analyzed and used to predict output value as a function of time-of-day and time-of-year; the results

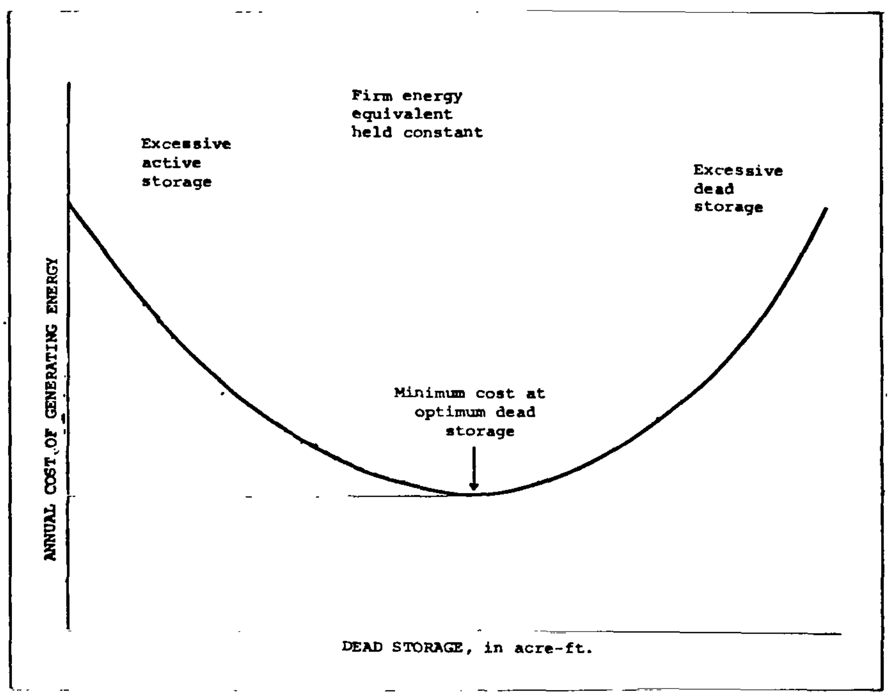


Figure F3: Annual cost of energy production vs. dead storage.

of this analysis form the basis of operating rule development. Several approaches may be used: the rule may be strictly time-based, where the plant is operating preferentially at certain times, and at other specified times when water is already available; the rule may employ anticipated streamflows to predict the optimal pattern of operation in each period.

Whatever assumptions are employed, the simulation is conducted so as to maximize the difference between output value and cost. Since the various periods of operation can no longer be treated as independent, more advanced optimizing procedures are required. These include dynamic programming and optimal control theory* (see Hall and Roefs, "Hydropower Project Output Optimization."

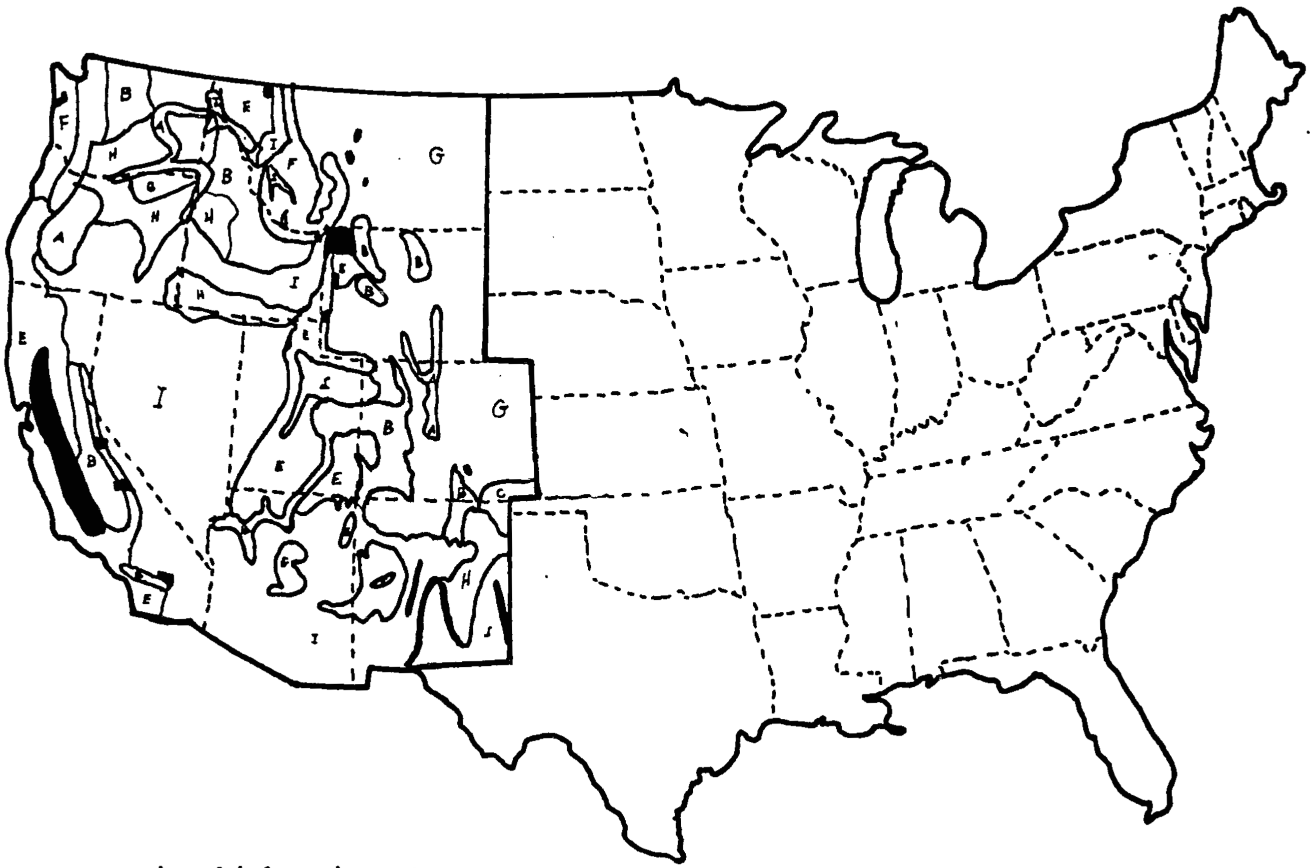
Table F1 gives the reservoir costs in dollars of reservoir storage per acre-feet for the regions of U.S. are given for the physiographic region shown in Figure F4 and serve as an indication of the marginal value. The costs referred in hereafter are capital (construction) costs per limit volume of storage. The costs per unit of storage capacity vary with the size of the reservoir and the physiographic region in which the reservoir is situated. These cost data are given for each region. To determine cost data for each state the composition of the physiographic region is computed by calculating the fraction contributes to the state. This is shown in Table F2. Then from the costs curves for the regions (Figure F5) using the average useable reservoir storage from Table F3, the weighted average cost/unit of reservoir storage is computed. For each state the average costs in $/acre-ft. is computed and the results are given in Table F3.

Although it is clear that improved information regarding future streamflows can lead, in many cases, to more efficient project operation, it is less obvious how this improved information produces benefits in the initial design of the project. Where reservoir size, active storage boundaries, generating capacity, and other parameters have been chosen as a consequence of a full operations study, excess capacity has almost certainly been provided. The design procedure includes the development of the operating procedures which are simulated against some historical or synthetic sequence of streamflow, using the chosen design parameters. The overall design is adjusted so that output value less input cost in minimized, an adjustment that includes, among other things, providing additional capacity over and above what would be required if future streamflows were known with certainty. This additional storage minimizes the spilling of unanticipated deficits. If it were known at the outset that more accurate streamflow forecasts would be available, and that operating procedures which consider such information would be used, the overall investment in the project could be reduced for the same stream of outputs.

Table F1
Capital Costs of Reservoirs in the Physiographic Regions of the United States
(1977 Prices)
(Source: Corps of Engineers, U.S. Army, 1960)

	PHYSIOGRAPHIC REGION									
SIZE CLASS	A	B	C	D	E	F	G	H	I	J
10	515.2	448.0	403.2	358.4	347.2	324.8	313.6	268.8	212.8	145.6
30	425.6	358.4	302.4	268.8	257.6	237.4	230.7	192.6	145.6	96.3
50	392.0	324.8	268.8	235.2	219.5	201.6	194.9	163.5	123.2	82.9
80	362.9	295.7	246.6	208.3	190.4	179.2	168.0	138.9	103.0	71.7
150	324.8	257.6	212.8	174.7	163.5	145.6	134.4	112.0	85.1	56.0
300	291.2	224.0	179.2	145.6	134.4	123.2	112.0	89.6	67.2	44.8
700	253.1	190.4	147.8	116.5	105.3	96.3	85.1	67.2	49.3	33.6
1,500	226.0	168.0	125.4	94.1	85.1	76.2	67.2	53.8	40.3	26.4
3,000	197.1	143.4	109.8	78.4	71.7	62.7	56.0	40.3	33.6	22.4
7,000	172.5	123.2	89.6	62.7	56.0	47.0	42.6	31.4	22.4	17.9
30,000	134.4	89.6	62.7	40.3	35.8	31.4	26.9	22.4	17.9	13.4

(Values are costs in dollars of reservoir storage per acre-feet. Size class in thousand acre-feet. Physigraphic regions are shown in Figure 1).



■ Areas in which major storage reservoirs cannot be constructed or are not likely to be needed.

Figure F4: Map of physiographic regions in the Western United States (Source: Corps of Engineers, U.S. Army, 1960)

Table F2
Tables of Weights for States in Western U.S.

Tables of Weights for States in Western U.S.										
	WEIGHT IN EACH PHYSIOGRAPHIC REGION									
STATE	A	B	C	D	E	F	G	H	I	J
Arizona	-	.15	-	-	-	-	.15	.3	.4	-
Colorado	.10	.25	-	-	-	-	.65	-	-	-
Idaho	-	.4	-	-	.05	-	-	.3	.25	-
Montana	-	-	-	-	-	.20	.75	-	.05	-
New Mexico	-	-	-	-	-	-	.40	.15	.45	-
Utah	-	.15	-	-	.45	-	-	-	.40	-
Washington	.05	-	-	-	.30	.10	-	.55	-	-
California	-	.10	-	-	.60	-	-	.3	-	-
Oregon	.15	.30	-	.10	-	-	.15	.30	-	-
Wyoming	-	.20	-	-	-	-	.80	-	-	-

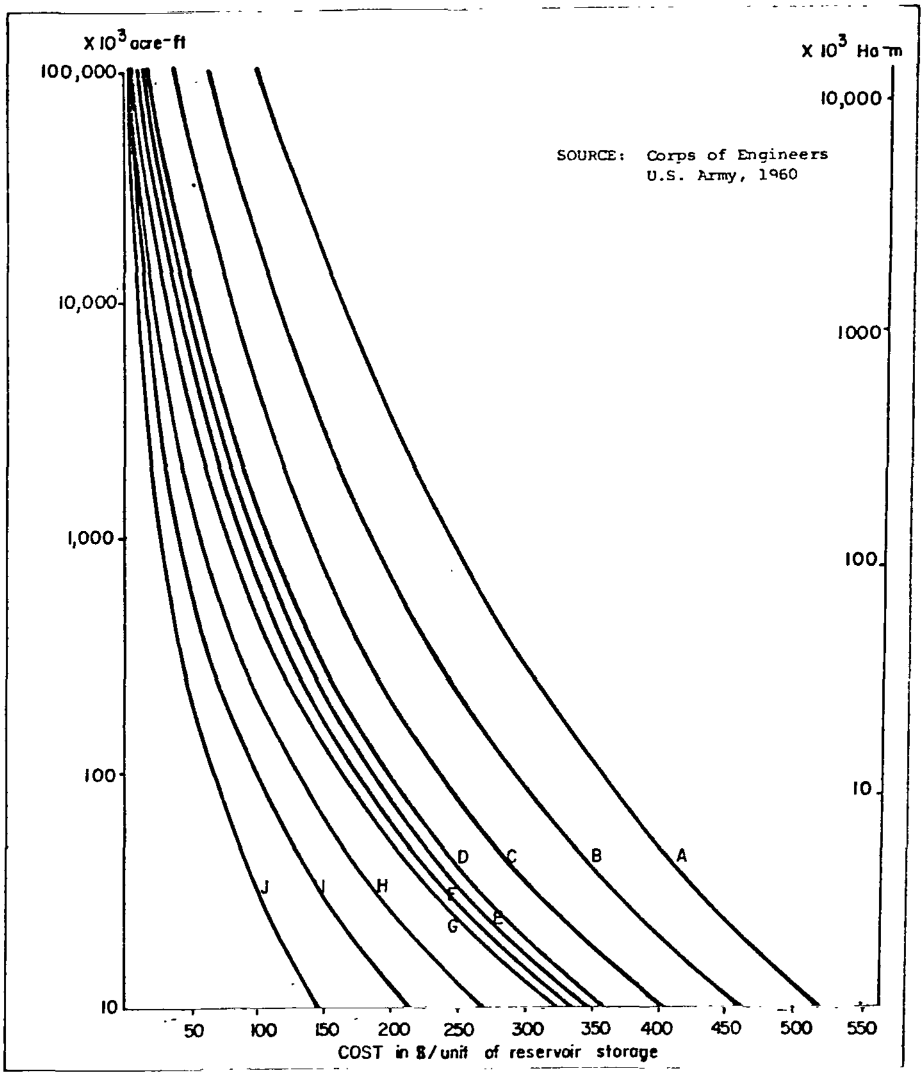


Figure F5: Potential in the capital costs due to reduction of reservoir storage in the physiographic regions of the U.S. (in 1977 $).

Table F3
The Average Usable Storage for each State and the Corresponding Cost

	AVERAGE USABLE STORAGE (M acre/ft,	COST/ACRE. FT. (IN $1977)
Arizona	2,47	58
Colorado	0,04	260
Idaho	0,207	152
Montana	0.39	129
Nevada	0,072	108
New Mexico	0,236	92
Utah	0,154	159
Washington	0,284	119
California	0,138	155
Oregon	0,094	204
Wyoming	0,178	155

Obviously, if design is based on rule-of-thumb rather than full analysis, such benefits do not appear. Rule-of-thumb design, however, has evolved from past experience with design and later operation, and incorporates implicitly additional capacity as a result of uncertainty concerning future streamflows. The availability of improved forecasting techniques may provide an additional incentive for full analysis, by increasing the benefits available thereby.

The benefits obtainable from the use of better information in forecasting future streamflows, then, are seen to depend upon two conditions:

1. That operating procedures be employed which make explicit use of streamflow forecasts; or

2. That design procedures be based on full operational analysis, assuming operating procedures which use streamflow forecasts, and that such procedures actually be used in operation.

Where these conditions are already satisfied, better estimates of snowpack data, combined with appropriate streamflow forecasting techniques, will lead directly to benefits. More frequently, however, the availability of better snowpack data can provide the incentive necessary to cause the installation of the necessary operating procedures, or design procedures in the case of planned projects. The result would be measurable improvements in the efficiency with which such projects are constructed and operated.

GLOSSARY OF IMPORTANT TERMS FOR HYDROPOWER

Average Megawatt - A unit of average energy output over a specified time period (total energy in megawatt-hours divided by the number of hours in the time period.

Capability - The maximum load which a generator, turbine, power plant, transmission circuit, or power system can supply under specified conditions for a given time interval without exceeding approved limits of temperature and stress.

Maximum Plant Capability (Hydro) - The maximum load which a hydroelectric plant can supply under optimum head and flow conditions without exceeding approved limits of temperature and stress. This may be less than the overload rating of the generators due to encroachment of tailwater on head at high discharges.

Peaking Capability - The maximum peak load that can be supplied by a generating unit, station, or system in a stated time period. For a hydro project the peaking capability would be equal to the maximum plant capability only under favorable pool and flow conditions, often the peaking capability may be less due to reservoir drawdown or tailwater encroachment.

Ultimate Plant Capability (Hydro) - The maximum plant capability of a hydroelectric plant when all contemplated generating units have been installed.

Dependable Capacity - The load-carrying ability of a station or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. For hydro projects the term refers to the capability in the most adverse month in the critical period -- January 1932 in the case of the 1928-32 critical period.

Firm Capacity - Capacity which has assured availability to the customer on a demand basis. System firm capacity consists essentially of hydro system dependable capacity plus thermal plant installed capacity plus firm imports minus maintenance and forced outrage reserves.

Hydraulic Capacity - The maximum flow which a hydroelectric plant can utilize for power generation.

Installed Capacity - Same as nameplate capacity unless otherwise specified.

Nameplate Capacity - The nominal rated capacity of a generating unit or other similar apparatus. The term gives an indication of the approximate generating capability of the unit, but in many cases the unit is capable of generating on a continuous basis substantially more than the nameplate capacity (See Overload Capacity, below).

Interruptible Power - Nonfirm power; power made available under agreements which permit curtailment or cessation of delivery by the supplier.

Pumped Storage Plant - A hydroelectric power plant which generates electric energy for peak load use by utilizing water pumped into a storage reservoir during off-peak periods.

Reregulating Reservoir - A reservoir located downstream from a hydroelectric peaking plant having sufficient pondage to store the widely fluctuating discharges from the peaking plant and release them in a relatively uniform manner downstream.

System Reserve Capacity - The difference between the available dependable capacity of the system, including net firm power purchases, and the actual or anticipated peak load for a specified period.

Rule Curve - A seasonal guide to the use of reservoir storage.

Run-of-River Plant - A hydroelectric plant which depends chiefly on the flow of a stream as it occurs for generation, as opposed to a storage project, which has sufficient storage capacity to carry water from one season to another. Some run-of-river projects have a limited storage capacity (pondage) which permits them to regulate streamflow on a dialy or weekly basis.

Storage

Dead Storage - The volume of water remaining in a reservoir after all of the usable storage has been withdrawn.

Gross (Total) - The total volume of water in a reservoir at normal full pool.

Seasonal Storage - Water held over from the annual high-water season to the following low-water season.

Usable Storage - The volume of storage in a reservoir which can be withdrawn for various conservation purposes (gross storage minus dead storage).

Storage Project - A project with a reservoir of sufficient size to carryover from the high-flow season to the low-flow season and thus to develop a firm flow substantially more than the minimum natural flow. A storage project may have its own power plant or may be used only for increasing generation at downstream plants.

Tailwater - The water surface immediately downstream from a dam or hydroelectric power plant.

Usable Energy - All hydroelectric energy which can be used in meeting system firm and secondary loads. In the early years of this study, it is possible that there may be a market for all of the secondary energy which could be generated in years of abundant water supply and some of the water may have to be diverted over project spillways and the energy wasted.

Energy Content Curve - A seasonal guide to the use of reservoir storage for at-site and downstream power generation. It is based on the following constraints: 1) During drawdown sufficient storage shall remain in the reservoir to insure meeting its share of the system firm energy requirements in the event of critical period water conditions, 2) Draft of storage for secondary energy production is permitted only to the extent that it will not jeopardize reservoir refill by the end of the coming July. Drafting below the assured refill level is permitted only if required to meet firm energy loads or if such draft is secured by commitment to return energy equivalent to the drafted water if refill is not otherwise accomplished.

Firm Load Carrying Capability (FLCC) - The firm load that a system could carry under coordinated operation under critical period streamflow conditions with the use of all reservoir storage.

Forebay - The impoundment immediately above a dam or hydroelectric plant intake structure.

Head

Gross Head - The difference of elevation between water surfaces of the forebay and tailrace under specified conditions.

Net Head (Effective Head) - The gross head less all hydraulic losses except those chargeable to the turbine.

Load Factor - The ratio of the average load over a designated period to the peak load occurring in that period.

Normal Full Pool - The maximum forebay water surface elevation within the reservoir's normal operating range.

Peaking Plant - A power plant which is normally operated to provide all or most of its generation during maximum load periods.

Penstock - A conduit to carry water to the turbines of a hydroelectric plant (usually refers only to conduits which are under pressure).

Pondage - Reservoir power storage capacity of limited magnitude that provides only daily or weekly regulation of streamflow.

Firm Power - Power which is considered to have assured availability to the customer to meet all or any agreed upon portion of his load requirements. It is firm energy supported by sufficient capacity to fit the load pattern.

The availability of firm power is based on the same probability consideration as is firm energy.

Overload Capacity - The maximum load that a machine, apparatus, or device can carry for a specified period of time under specified conditions when operating beyond its nameplate rating but within the limits of the manufacturer's guarantee or, in the case of expiration of the guarantee, within safe limits as determined by the owner. For example, most of the generators installed in the region's newer hydroelectric plants have a continuous overload capacity of 115 percent of the nameplate capacity.

Peaking Capacity - Same as Peaking Capability.

Reserve Capacity - Extra generating capacity available to meet unanticipated demands for power or to generate power in the event of loss of generation resulting from scheduled or unscheduled outages of regularly used generating capacity.

Capacity Factor - The ratio of the average load in the generating plant for the period of time considered to the capacity rating of the plant. Unless otherwise identified, capacity factor is computed on an annual base.

Conventional Hydroelectric Plant - A hydroelectric power plant which utilizes streamflow only once as it passes downstream, as opposed to a pumped-storage plant which recirculates all or a portion of the streamflow in the production of power.

Critical Period - Period when the limitations of hydroelectric power supply due to water conditions are most critical with respect to system energy requirements.

Critical Water Year - A term sometimes used interchangeably with Critical Period when the critical period falls within one operating year.

Drawdown - The distance that the water surface of a reservoir is lowered from a given elevation as the result of the withdrawal of water.

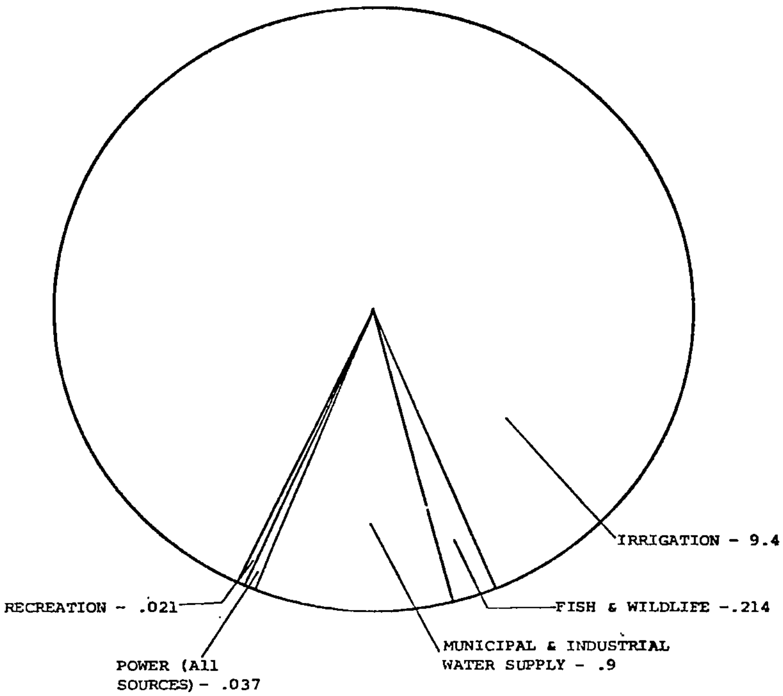
Average Annual Energy - Average annual energy generated by a hydroelectric project or system over a specified period.

Firm Energy - Electric energy which is considered to have assured availability to the customer to meet all or any agreed upon portion of his load requirements. Firm energy is based on certain specified probability considerations.

Prime Energy - Hydroelectric energy which is assumed to be available 100 percent of the time: specifically, the average energy generated during the critical period.

Secondary Energy - All hydroelectric energy other than prime energy: specifically, the difference between average annual energy and prime energy.

Ultimate Development - The maximum contemplated generating installation at a power plant.



SOURCE: "Lower Colorado Region - Comprehensive Framework Study of Water and Land Resources," Lower Colorado Region State-Federal Interagency Group for the Pacific Southwest Inter-agency Committee, June, 1971, Summary Report

Figure F6: Lower Colorado region water withdrawal projection for 1980. (All units in Million Acre-Feet)

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15. Supplementary Notes
This report is designed to supplement the technical work of four NASA initiated ASVT's which are currently evaluating and improving the operational runoff techniques using satellite snowcovered area.

16. Abstract

The results of the OASSO ASVT's have been used to estimate the benefits accruing from the added information available from satellite snowcover area measurement. Estimates of the improvement in runoff prediction due to addition of SATSCAM have been by the Colorado ASVT personnel. The improvement estimate is 6-10%.

Data were applied to subregions covering the Western States snow area amended by information from the ASVT and other watershed experts to exclude areas which are not impacted by snowmelt runoff. Benefit models were developed for irrigation and hydroenergy uses. Results of the benefit estimate for these major uses yielded a yearly aggregate of 36.5M.

Cost estimates for the employment of SATSCAM based upon the Colorado ASVT results and expanded to the Western States totalled $505K. The benefit/cost ratio thus formed is 72:1. Since only two major benefit contributors were used and since the forecast improvement estimate does not take into account future satellite capabilities these estimates are considered to be conservative.

The large magnitude of the benefit/cost ratio supports the utility and applicability of SATSCAM. Future development in the use of SATSCAM in computer models specifically tailored or adapted for snow inputs such as those developed by Leaf, Schumann, and Tangborn, and Hannaford will most certainly increase the use and desirability of SATSCAM.

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