BAKER RIVER PROJECT RELICENSE

Economics & Operations Working Group

April 10, 2002

1:00 p.m. – 4:30 p.m.

PSE's Mount Vernon Business Office
1700 E. College Way
Mount Vernon, WA 98273

AGENDA

1.	Lloyd Pernela PSE	Review of group's history and mission
2.	Mark Killgore Louis Berger associates	What FERC wants in models
3.	Joel Molander PSE hydro manager	What are PSE objectives Process used to search model Results Hydrops : modifications to project facilities/ operations
4.	Charles Howard Sr. Consultant	Why need for Hydrops History Hydrops Successful applications
5.	Tung Van Do President CHAL	Calibration Baker Project Fexibility in scenarios

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PSE Office
1700 E. College Way, Mt. Vernon, WA

FINAL MEETING NOTES

"To ensure that alternative project proposals, operations and emergency plans for the Baker River Project and its components provide for:

1. *Public health and safety; and*
2. *Thorough analysis and evaluation of the economic costs and benefits (including non-market) and economic impacts."*

Team Leader: Lloyd Pernela (PSE), 425-462-3507; lperne@puget.com

Note: Please let the team leader know if you are unable to attend a meeting. If something comes up at the last minute, please call Lyn the day of the meeting. Lyn's new cell phone number is ***425-890-3613****.*

PRESENT

Lloyd Pernela, Bob Barnes, Joel Molander, Nick Verreto, (PSE), Bob Helton (Private Citizen), Chris Hansen - Murray (U.S. Forest Service), Mark Killgore (Louis Berger Group), Jim Sinclair (Hydro power consultant), Tom Spicher (Hydro Y.E.S.), Gary Sprague (WA Dept. Fish & Wildlife), Don Wick (Skagit Co. Economic Development Assoc.), Sue Madsen (R-2), Xiaoqing Zeng and Martin Liu (Stetson Engineers, Inc), Chuck Howard, (Senior Consultant and former president of CHAL), Tung Van Do (President, Powel Ltd.), Lyn Wiltse, facilitator (PDSA Consulting Inc.)

NEW ACTION ITEMS

- ALL: Review list of Hydrops Model outputs you receive from Lloyd to look for holes.
- Tung: Email draft of a form that Working Groups would use to submit scenarios. Send to Lloyd to distribute to members to review.
- Tung: Send list of current Hydrops Model outputs to Lloyd to distribute for review.
- Lloyd: Reserve PSE training room for June 12 workshop and include driving directions with the agenda.

DATES OF FUTURE MEETING DATES/LOCATION
Preference of group is to have a morning meeting starting at 9:00 to 12:00 (noon).

No meeting in May 2002

OUR NEXT MEETING, JUNE 12TH 9:00 AM TO 4:00 PM WILL BE AN ALL-DAY WORKSHOP IN PSE'S BELLEVUE OFFICE, 411 108TH AVENUE NE, FIFTH FLOOR. The "hands-on" workshop is designed for participants to gain familiarity with the Hydrops model.

June 12 (**9:00 - 4:00**), September 11 (from 9:00 to noon), at the PSE Office in Mt. Vernon.

AGENDA

April 10, 2002 at PSE Office in Mt. Vernon, WA
1:30 to 4:30

1. Lloyd Pernela PSE, Team Leader	Review of group's history and mission
2. Mark Killgore Louis Berger Associates	What FERC wants in models
3. Joel Molander PSE Hydro Manager	PSE objectives, initial focus operations model. Process used to search model. Results Hydrops.
4. Charles Howard Sr. Consultant	Model development. Why need for Hydrops History Hydrops, Successful applications
5. Tung Van Do President CHAL	Simulation versus Stochastic approach Calibration of Baker Project Model. Flexibility in Scenarios

ANNOUNCEMENTS AND WORKING GROUP HISTORY
Lloyd Pernela announced a calendar of coming events:
May 20 is the date of a FERC/PSE public tour of the Baker River Project from 10:00 AM to 3:00 PM. Relicensing public meetings to review the Initial Scoping Document (ICD) and Scoping Document #1 and gather public input are on May 21 at concrete High School multi-purpose room and 22nd at Cottontree Inn in Mt. Vernon from 9 AM to 3 PM. PSE expects to release the Scoping Document #1 the week of April 15th. FERC allows for a 60-day comment period following the public meeting(s). Comments on both documents are due July 22nd.

He then reviewed the history of the Economics Working Group. June 7, 2000 was our first meeting.

The Economics Working Group Mission Statement:
"To ensure that alternative project proposals, operations and emergency plans for the Baker River Project and its components provide for:
1. *Public health and safety; and*
2. *Thorough analysis and evaluation of the economic costs and benefits (including non-market) And economic impacts."*

Since June 2000, the Working Group has had the following presentations/activities:

- Utility Economics (Ed Schild and Joel Molander of PSE)
- Skagit River Flows (Sue Madsen of R2)
- Emergency Action Plan for the project (Chris Drechsel of PSE)
- Swinomish Tribal Values (Larry Campbell of the Swinomish Tribe)
- Army Corps of Engineers, Flood Control (Wayne Wagner of the Corps)
- Hydro 101, (Bob Barnes PSE hydrologist)
- Review of PSE's environment in Annual reports (Bob Helton, interested citizen)
- Tour of the Baker Project
- Development of relevant issues/interests
- Working group operating norms

HISTORY AND SUBSTANCE OF THE CHARLES HOWARD HYDRO OPERATIONS MODEL
Joel Molander explained that PSE underwent a very rigorous model selection process. The original focus of PSE was to secure a model that optimized their hour by hour operations. He expressed great confidence in the optimization model selected. This Working Group will be using the Study Model, which is essentially the same as the Operations Model. Explained the importance of using the same model for planning and operations. The primary difference in the two models is that the planning model has a static database whereas the operations model uses real time data and is automatically updated for dispatchers.

Charles Howard & Associates, Ltd. (CHAL) has been providing hydrologic and water resource consulting and modeling services since the mid-1970s and has conducted over one hundred twenty analyses and modeling efforts specific to hydroelectric-related projects. HYDROPS™ represents the culmination of CHAL's experience in hydroelectric planning, project optimization and operations modeling and provides a flexible, reliable tool for incorporating real-time operational data into the optimization of the Baker River Project.

WHAT FERC LOOKS FOR IN MODELS
Mark Killgore, consultant (Louis Berger Group) hired by PSE to assist in implementing the Charles Howard Model to ensure it meets FERC requirements. He gave a comprehensive presentation about the application of models and economics to FERC Relicensing. He covered how models are used in relicensing, models that are currently available, characteristics of good models, and an overview of FERC's Economic Evaluation Methodology. He discussed how results from operations models can be linked to other models used in evaluating different resource areas. His presentation is posted on the PSE website at http://www.pse.com/hydro/baker/meetings/2002/economic20020410presentation.pdf. He also distributed relevant FERC regulations from the Section 18.Code of Federal Regulations (CFR) part 4.51 on the contents of a license application. Material on relicensing and links to the CFR are available on the FERC website at www.ferc.gov. The Mead decision, which implemented the current FERC policy on economic analysis, is also on this website under CIPS. Search on Project P-2506 year 1995 for a copy.

HYDROPS HISTORY, APPLICATIONS

- Chuck Howard (retired a year ago from CHAL and is now consulting (clients include BPA, China) and serving on National Academy of Sciences and ASCE committees. He explained that Charles Howard and Associates, LTD has been in the water resources systems analysis business since the

1960's. They started out doing non-point source analysis of water quality issues for the Great Lakes, urban water distribution and drainage, and water management planning studies. In 1986 they put into practice their first hydro operations optimization models and this is still being used to operate two reservoirs in British Columbia. Subsequently these models have been applied to relicensing and planning issues. They have worked on over 150 hydroelectric projects, 129 of which have been modeling assignments. The current Hydrops Model optimizes while incorporating hydrologic uncertainties in long term (seasonal) hydroelectric operations and also provides a deterministic optimization of short term (weekly) operations. He briefly discussed a paper (see handouts) by Beth Faber and Jerry Stedinger that reviews the HYDROPS modeling approach to forecasting, see http://www.pse.com/hydro/baker/meetings/2002/economic20020410handout.pdf .

WATER RESOURCES SYSTEMS PLANNING (CALIBRATION AND FLEXIBILITY)
Tung Van Do walked us through the purposes, limitations, and procedures involved in water resources systems planning. He explained requisite features of a state-of-the-art planning and studies model. Outlined the differences between optimization and simulation models. HYDROPS will be both Puget's real-time operations model and Puget's planning and studies model. Tung presented an overview of the functional interactions in HYDROPS. HYDROPS uses a probabilistic approach to determine ideal reservoir levels and releases for the next seven days and a deterministic method to define hourly schedules. His presentation is posted on the PSE relicensing website at http://www.pse.com/hydro/baker/meetings/2002/economic20020410presentation2.pdf

HANDOUTS
- *Hydro-power Stochastic Forecasting and Optimization* (Tung Van Do and Charles D. D. Howard, M. ASCE)
- *SSDP Reservoir Models Using Ensemble Streamflow Prediction (ESP) Forecasts.* Beth Faber and Jerry Stedinger.
- Mark Killgore, PowerPoint presentation: *The Application of Models and Economics to FERC Relicensing*
- Tung Van Do's PowerPoint presentation: *Water Resources Systems Planning*
- CD: International Workshop on *Sustainable Riverine Fish Habitat* (April 21-24, 1999, Victoria, BC, Canada) (MP3 format)

PARKING LOT
- US Forest Service Watershed Analysis (Jon Vanderheyden)
- Consider who will be the number cruncher for this team: PSE? Other?
- GANNT chart with due dates, etc.
- Presentations:
    - Wild and scenic river 101
    - Flood Plain Values 101
    - Fisheries/Hydraulics 102

EVALUATION OF THE MEETING
Well-Dones:
- Presentations
- Great handouts (will be posted on Web)

- Good participation
- Team Leader on time!

Need to Improve

- Ran out of time
- Warm, stuffy room
- Software still in flux (other than main features)
- Missing some key players
- Some handouts had small print (difficult to read)

TENTATIVE AGENDA FOR NEXT MEETING
June 12, 2002 at PSE Office (One Bellevue Center) in Bellevue, WA
9:00 to 4:00

*****NOTE THAT THIS WILL BE AN ALL-DAY WORKSHOP*****

1. Review/revise minutes and agenda
2. Action items
3. HYDROPS WORKSHOP:
   - Training in AM.
   - "Play" with model in p.m.
   - Discussion
4. Set agenda for next meeting (September 11 at PSE Office in Mt. Vernon)
5. Evaluate meeting

SSDP Reservoir Models Using Ensemble Streamflow Prediction (ESP) Forecasts

Beth A. Faber and Jery R. Stedinger***

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Abstract

The sequential nature of reservoir operating decisions and the variability of streamflow makes Stochastic Dynamic Programming an attractive optimization procedure for reservoir system operations. This paper examines the use of Sampling Stochastic Dynamic Programming (SSDP). SSDP models employing the National Weather Service's (NWS) Ensemble Streamflow Prediction (ESP) forecasts are compared to SSDP models based on historical streamflows and snowmelt volume forecasts. The SSDP optimization algorithm, which is driven by individual streamflow scenarios rather than a Markov description of streamflow probabilities, allows the ESP forecast traces to be employed intact, thus taking full advantage of their rich description of streamflow variability and the temporal and spatial inter-relationships captured within the traces.

1. Introduction

Ensemble streamflow forecasts hold great potential for aiding the operation of multi-purpose reservoir systems. The implicit multi-stage decision process seeks to redistribute water in time, storing inflow as it arrives and releasing the amount in each time period that balances the current benefits with potential future benefits. Stochastic Dynamic Programming (SDP) is well-suited for such multi-stage problems. Sampling SDP is a variation of the traditional SDP algorithm that allows the incorporation of ensemble streamflow forecasts. This paper illustrates the performance of several SSDP reservoir-operation optimization models for a reservoir in a water-supply system that is dominated by the snow-melt hydrology typical of the western United States. This paper extends the work of Faber and Stedinger (2001).

Ensemble streamflow forecasts are currently available from the National Weather Service (NWS) River Forecast Centers. Ensemble Streamflow Prediction (ESP) forecasts for reservoirs in Denver's water system, for example, are generated twice each week throughout that region's snowmelt runoff season, providing multiple daily streamflow traces that are each a possible realization of seasonal streamflow [Day, 1985; Schaake and Larson, 1998]. These sets of hydrographs capture by example the temporal and spatial correlation structure of the streamflow without the need for an explicit probabilistic description. Further processing of these streamflow traces into the familiar probabilistic volume forecasts traditionally provided by the River Forecast Centers eliminates some of this valuable information. Sampling SDP is an optimization technique that can utilize the ESP forecast traces without this post-processing, and perhaps exploit them more effectively.

Sampling Stochastic Dynamic Programming (SSDP) was used by Pacific Gas & Electric in optimizing water system operations on the Feather River in California [Kelman et al., 1990]. (Maceira and Kelman [1991] and Kelman [1992] provide two- and three-reservoir SSDP examples.) The SSDP model uses a collection of historical streamflow time-series as *scenarios* to represent the stochastic streamflow process, rather than a probabilistic Markov description commonly used in SDP. A scenario is defined here as the streamflow hydrograph for one or more locations and the associated volume forecast time-series. The collection of scenarios and their appropriate probabilities represent an *empirical distribution* for the streamflow series.

Faber and Stedinger [2001] described an SSDP model of a single reservoir that employed the National Weather Service's ESP forecast traces as the empirical streamflow description, rather than historical streamflows. Use of ESP forecast traces allowed frequent updating of current decisions by re-solving the SSDP for each new forecast. The ESP hydrographs provided an additional advantage over historical series in that they were each consistent with current streamflows, groundwater and soil moisture levels in the basin. When using historical streamflow scenarios, probabilities conditioned on streamflow volume forecasts as described by Kelman et al. [1990] often indicated that many of those historical scenarios were extremely unlikely, effectively reducing the number of scenarios available to compute the expected future value of water.

Faber and Stedinger [2001]'s study of a single-reservoir SSDP/ESP model in a region with snowmelt hydrology found that: (1) SSDP was an effective framework for employing ESP-type forecasts to derive optimal real-time reservoir operations decisions. (2) When system operations were difficult, use of ensemble forecasts in the SSDP model provided more efficient reservoir operations than use of historical streamflows and runoff season volume forecasts in the SSDP model. (3) Complex transition probabilities were not required in the SSDP model when using ensemble forecasts. (4) A two-stage SSDP decision model generated operation decisions that were as efficient as the full multi-stage SSDP decision model. This fourth result was surprising; essentially, deterministic optimizations of each time series, joined only in a one-stage re-optimization to determine the actual release decision for the current week with the most recent forecast information, generally performed as well as a full SSDP with forecast-based transition probabilities. Because of the significant modeling implications of this result, further study is appropriate to determine how widely this observation was applicable. This paper describes the extension of the previous study to further investigate the properties of the SSDP algorithm. It examines the model's sensitivity to the number of scenarios employed, and how well the model predicts the benefits obtained with actual operation or simulation.

2. Development of the Algorithm

2.1. SSDP Functional Equation

Faber and Stedinger [2001] develop our Sampling SDP algorithm and trace its relationship with the traditional Stochastic Dynamic Programming algorithm and the SSDP model proposed by Kelman et al. [1990], analyzing the purpose of and improvement due to each modification. The final SSDP functional equation for the reservoir problem, solved in each time period for each discrete grid-point of the storage state-space S_t and each scenario i, is:

$$\max_{R_t}\{\, B_t(S_t, Q_t(i), R_t) + \alpha \mathop{E}_{j|i}[\, f_{t+1}(S_{t+1}, j)\,]\,\} \qquad \forall\ S_t, i, \text{ and } t \in \{1, \ldots, T\} \qquad (1)$$

$$f_t(S_t, i) = B_t(S_t, Q_t(i), R_t) + \alpha\, f_{t+1}(S_{t+1}, i) \qquad \forall\ S_t, i, \text{ and } t \in \{1, \ldots, T\} \qquad (2)$$

$$S_{t+1} = S_t + Q_t(i) - R_t \qquad (3)$$

where: t = time period, with T being the final period in the model
$B_t(\bullet)$ = the benefit function for period t
S_t = storage vector for period t
$Q_t(i)$ = inflow vector for scenario i in period t
R_t = optimal release vector for period t
i = scenario i, representing flows of a particular historical year
j = scenario j, representing flows of another historical year that could occur

The use of two equations to calculate the optimal release and update the future value function is significant. In Equation 1, the optimal release decision R_t is determined for each state and scenario i considering the *expected* future value f_{t+1} of the subsequent system state. That expected value is computed over the distribution of future streamflow, described by the probability of each scenario j occurring in the following period given current scenario i (transition probabilities). In Equation 2, that optimal decision is used to compute an updated future value for that stage, assuming that scenario i continues with certainty. In this way, decisions are made considering streamflow uncertainty, but the future values carried through for other decisions are based on intact streamflow sequences that maintain realistic persistence in the streamflow series. Equation 3 describes the transition from the current reservoir state to a subsequent state given a particular decision and is used with Equations 1 and 2.

The output of these equations is a set of optimal decisions and future values for each combination of discrete reservoir states and scenarios, referred to as an optimal policy. As with standard SDP, the reservoir state is unlikely to be exactly at one of those discrete state values when a decision is required, so there must be a method of obtaining the proper decision from the optimal policy. Often, simple interpolation of the table is used. Tejada-Guibert et al. [1993] introduced a method of *re-optimization* in which a new optimal decision is chosen with a one-stage DP, employing the future value function from the correct stage of the original optimization.

With SSDP, there is an additional complication because the optimal policy's decisions are specified for a given scenario as well as state. Usable decisions must be chosen based upon the likelihood of all scenarios, in the fashion of Equation 1. The re-optimization procedure described above can also be used to determine an immediate release for each period. Real-time optimal decisions can be chosen with a single application of Equation 4 in period t, using future values of the optimal policy developed using Equations 1 and 2.

$$\max_{R_t}\{\ \underset{j|H}{E}\ [\ B_t(S_t, Q_t(j), R_t) + f_{t+1}(S_{t+1,}\ j)\ ]\ \} \qquad (4)$$

To summarize, for real-time use of the SSDP algorithm, two steps required for the determination of an optimal decision are:

Step 1 -- a multi-stage optimization using equations 1 and 2 to develop future value functions for each stage and scenario, and

Step 2 -- a single-stage re-optimization to choose an optimal decision using equation 4 and the future value functions from Step 1.

Simulation of this process requires successively performing these tasks with the same frequency required in real-time use. Table 1 describes what is involved in each of the two steps for the various types of streamflow scenarios employed in the study.

Table 1. Summary of SSDP Modeling Procedures

Scenarios:	Step 1 Backward Optimization (Compute $f_t(\vec{S}_t, i)$)	Step 2 Forward Re-optimization (Choice of Optimal Decision)
Historical Streamflow	once only	each week *
Actual ESP Ensemble Forecasts **	each week	each week *
Synthetic ESP Ensemble Forecasts	each month	each week *

* Conditional probabilities used in the Re-optimization were generated once each month from the seasonal runoff volume forecasts available at the beginning of each month
** This model was not implemented because of data limitations

2.2 Transition Probabilities

Use of Equations 1 and 2 to develop future value functions (FVFs) requires transition probabilities defining the probability of the remainder of scenario j starting in stage t+1, given scenario i in stage t, P_t[scenario j | scenario i]. A "scenario" refers to the group or vector of streamflow hydrographs and forecast series (one pair for each reservoir/inflow point being modeled) which represent a particular realization. This definition applies to both historical streamflows and ESP forecasts based on historical weather.

A simple choice for P_t[scenario j | scenario i] would be $P_t[j|i] = 1$ when i = j, and zero otherwise (i.e., the transition matrix is the identity matrix I; this choice is denoted Option I). This choice does not consider uncertainty among scenarios, and is equivalent to performing a deterministic optimization on each scenario in Equations 1 and 2, considering them together only in the Equation 5 re-optimization to obtain real-time decisions.

If instead one envisioned that there is an equal likelihood of moving from a given scenario to any other scenario in the next period, then $P_t[j|i]$ would equal 1/m, where m is the number of scenarios. This choice recognizes streamflow uncertainty throughout the planning horizon, but neglects hydrologic persistence in the decision model by allowing each scenario to be combined with any other, regardless of similarity. (This choice is termed Option m.)

More sophisticated transition probabilities depend on streamflow forecast information. Kelman et al. [1990] and Faber and Stedinger [2001] describe a method of computing P_t[scenario j | scenario i] using empirical streamflow and forecast data. This approach (termed Option F) considers the probability of seeing the remaining volume of scenario j given the volume forecast associated with period t of scenario i. The probability is developed using Bayes Theorem, with prior probability P[j] = 1/m for each scenario and likelihood function $P[QF_t \mid Y_{t+1}]$ developed from regression of $QF_t(j)$ on $Y_{t+1}(i)$ assuming normal regression residuals.

$$P_t\,[\text{scenario j} \mid \text{scenario i}] = P[Y_{t+1}(j) \mid QF_t(i)] \qquad (6)$$

where: $Y_{t+1}(j)$ = remaining streamflow volume of scenario j from periods t+1 to T
$QF_t(i)$ = streamflow forecast associated with scenario i in period t

$$P[Y_{t+1}(j) \mid QF_t] = \frac{P[QF_t \mid Y_{t+1}(j)] * P[j]}{\sum_{i=1}^{m} (P[QF_t \mid Y_{t+1}(i) * P[i])} \qquad (7)$$

$$P[QF_t \mid Y_{t+1}(j)] \sim N(\,qf_t(Y_{t+1}(j)), \sigma_e\,) \qquad (8)$$

$qf_t(Y_{t+1}(j))$ = regression value of forecast given volume
σ_e = standard error of regression

3. Case Study: Williams Fork Reservoir

A single reservoir on a tributary to the Colorado River was modeled using SSDP. Williams Fork Reservoir is a part of the water supply system that serves Denver, Colorado. The Colorado River Forecasting Center of the NWS currently produces ESP forecasts of the seasonal inflows for this reservoir, providing potentially valuable information. Operation of this reservoir, and the water system it is a part of, could benefit from making good use of this forecast information. The availability of ESP forecasts and the growing interest in putting them to good use makes this reservoir a good candidate for this study.

Williams Fork Reservoir experiences the snowmelt runoff cycle common in the Rocky Mountain region. The bulk of the reservoir inflow arrives during the snowmelt period that runs from April to July. The inflow is stored and drawn on throughout the remainder of the year. The ability to forecast seasonal inflow volume based on winter snowpack, and the fact that approximately 80% of the inflow arrives during the snowmelt runoff season, makes the April through July period the focus of operations planning. The R^2 values for snowmelt forecasts of the remainder of the snowmelt season made at the beginning of February, March, April, and May are 0.58, 0.62, 0.71 and 0.72 respectively.

Williams Fork Reservoir has no physical link to the city of Denver, so water in the reservoir cannot be used directly to meet city water demand. Instead, that water is used to "replace for" out-of-priority diversions at other locations which are physically connected to Denver. (When a reservoir or diversion facility is out-of-priority, the inflow it receives actually belongs to downstream users. At that time, a diversion of water is legal if an equal amount is released to the river at an alternate point, as long as that point is above the downstream users.) As long as these replacement needs are met, surplus water can be used for hydropower generation and streamflow maintenance.

It is important that the optimization model reproduce the system priorities accurately. The reservoir's first priority is replacing for out-of-priority diversion, which was represented with constraints that ensure that release. The second priority is to maintain the reliability of supply by meeting a carryover storage target, which was maintained with quadratic penalties for deviation from the ending storage target. The third priority considered in this model, hydropower generation, is valued by its actual economic value. Energy from the turbine below Williams Fork Reservoir define the current benefits $B_t(\bullet)$ in Equations 1 and 2.

The time step for the model is one week, taking advantage of the frequency with which real ESP forecasts are updated. For an initial model horizon of February through September (starting with the date forecasting becomes reasonable and ending at the close of the snowmelt runoff season), there are 35 stages for the first run of the model. Successive runs each week, made as new forecasts become available, are each one stage shorter.

For the model runs which used ESP forecasts rather then historical streamflows and volume forecasts, synthetic ESP forecasts were generated for each month February through September for each simulation year, using the methodology described in Faber and Stedinger [2001]. Using methods also described in that reference and in Faber [2000], to further reduce computational effort, the number of scenarios was reduced from the original 42 scenarios to 19 scenarios by combining similar scenarios and weighting the representative scenario with the total probability.

4. Details of Single-Reservoir Study

4.1 Models to be Compared

Forty years of weekly system operation/optimization was simulated using historical streamflows and volume forecasts, or using ESP traces as the streamflow scenarios in the SSDP models. For each type of scenario, the various transition probability formulations described in section 2.2 were considered:

Option I: no transitioning between scenarios (i.e. the Identity matrix)
Option F: transition probabilities developed using runoff volume forecast information (or ESP remaining-snowpack variable)

For the Step 2 one-stage re-optimization to identify optimal decisions, the options were:
Option m: each scenario equally probable (i.e. probability 1/m for each scenario)
Option F: probabilities conditioned on the current runoff volume forecasts

Models employing ESP scenarios only used Option m for step 2 because the conditional probability of each future ESP trace in the immediate period by construction assigns equal probabilities to all of the ESP traces. Based on all of these options, Table 2 contains a summary of the scenario and probability combinations compared with the reservoir model. Models denoted as Hist use multivariate historical streamflow series in the SSDP models, while those denoted ESP employ ensemble streamflow predictions based upon the current conditions in the week a model is formulated. (See Table 1.) Note that only model Hist I/m contains no forecast information. All other models include some form of forecast information, either in the transition probabilities (Option F) or implicit in the ESP traces. The simulation procedure used to compare the performance of these models is described in Faber and Stedinger [2001] and summarized in Table 1. Use of the model in each week of the snowmelt runoff season, employing the first period decision only, was simulated for each of the 40 historical years.

Table 2. Scenario and Transition Probability Combinations

Source of Scenarios	Step 1 Probability Option	Step 2 Probability Option	Summary Notation
Historical	I	m	Hist I/m
	I	F	Hist I/F
	F	F	Hist F/F
ESP	I	m	ESP I/m
	F	m	ESP F/m

4.2 Sensitivity to Number of Scenarios Employed

4.2.1 Use of Fewer Scenarios

Faber and Stedinger [2001] documented the advantage of SSDP models driven with ESP forecasts over SSDP models driven with historical flows and forecasts. It would seem reasonable to attribute that advantage to the fact that ESP provides a rich, multiple-scenario streamflow description that is consistent with current basin conditions. The 42-year record of historical streamflows provides a good range of probable future flows, but may not include many sequences that are consistent with a given snowmelt season forecast. On the other hand, ESP traces are all generated to represent the volume forecast for each week and its uncertainty. As a result, a small group of ESP scenarios is likely to provide a more adequate representation of future flows.

This section tests the hypothesis that the SSDP/ESP models yield better operational decisions than SSDP/Hist models because of the resolution with which the conditional streamflow distributions are described. Rather than using all of the 42 available years of record to define the historical flows and to compute the ESP traces, the available historical record was limited to eleven years at a time: 1949—1959, 1957—1967, 1965—1975, 1973—1983, 1980—1990. These five sets of historical years, and the corresponding synthetic ESP traces for those years, are denoted as records A, B, C, D and E in Figure 1. (The procedure described in Faber and Stedinger [2001] for the generation of synthetic ESP traces captures the wetness of the particular historical year used to define each trace, as would real ESP traces that used historical precipitation from each year. As a result, when the 1949—1959 synthetic ESP traces were used to construct the ESP/SSDP model, those eleven traces also reflected the relative wetness of each historical year.)

Figure 1 displays the simulated annual benefits (as a percentage of perfect foresight operations) for each set, and for the full 42-scenario model, for realistic operations. Of the models introduced earlier, only models Hist I/F, Hist F/F and ESP I/m are included. It is clear that the efficiency of the SSDP/ESP results was not affected by the use of fewer traces, or the particular set of eleven traces employed. However, the performance of SSDP/Hist models suffered considerably, and clearly depended upon which set was selected. Set A, which contains many dry years, and Set E, which contains several wet years, resulted in less efficient decisions than the other sets which happened to be more representative of the entire record. These results support our hypothesis that the superior performance of SSDP/ESP over SSDP/Hist is due to the fact that the ESP traces provide a better higher-resolution description of the conditional distribution of future flows than can be obtained by with a few historical streamflow sequences.

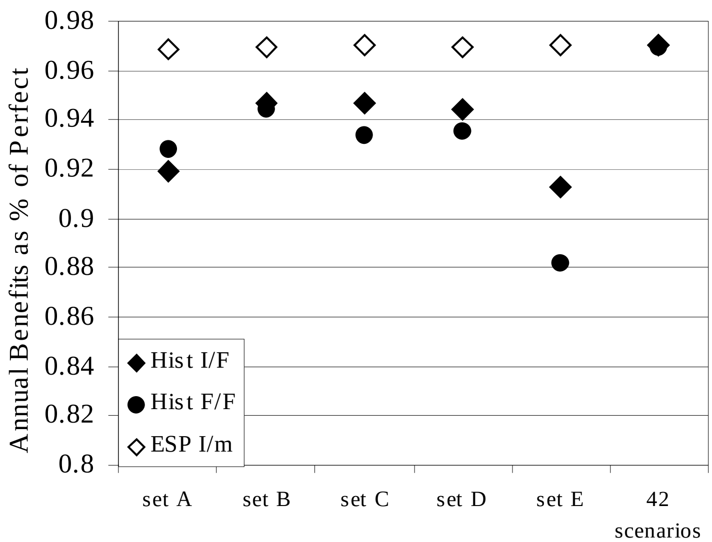

Figure 1. Simulated Average Annual Benefits of SSDP/Hist and SSDP/ESP models using 11 Scenarios

4.2.2 Use of Combined Scenarios

Applications of the single-site SSDP model discussed in Faber and Stedinger [2001] used 19 streamflow scenarios *combined* from the original 42 scenarios so as to retain the resolution of the streamflow description. This section attempts to determine if the combined scenarios do in fact retain the resolution captured in the original 42.

Figure 2 presents the results of the simulations, showing average annual benefits attained with models employing 42, 19, and 10 scenarios, respectively, as a percentage of perfect foresight operations. As in Faber and Stedinger [2001], the increasingly difficult operational cases considered were: case 1 = Normal Demand, case 2 = Increased Demand, case 3 = Varied Energy Pricing, and case 4 = Minimum Flow Target. One-sided paired-Z-tests comparing results

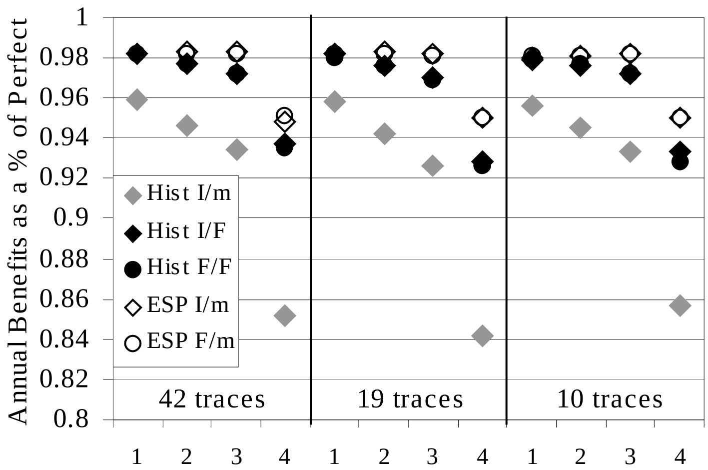

Figure 2. Simulated Annual Benefit from Combining traces , expressed as Percentage of Perfect Operations

using 19 or 10 combined scenarios to results from 42 scenarios were also performed. For cases 1 and 2, the differences were not statistically significant. When we consider varied energy prices and a minimum flow target, the difference between models using 42 and 19 historical scenarios is statistically significant at the 5% level, but remains very small. Overall, the results demonstrate that the algorithm for combining scenarios was able to produce 19 and 10 scenario sets that essentially retained all the information included in the full 42-scenario set.

4.3 Comparison of SSDP Benefits to Simulation Benefits

An important factor in the use of SDP models is how well the models predict the annual benefits their operational decisions can achieve. For any initial state, this prediction is the value of the objective function in the first stage of the SDP. Tejada et al. (1995) showed that SDP models often overestimate the benefits achieved with the optimal policies they produce. One reason for this inaccuracy is that many SDP models employ a simplified, Markov Chain representation of streamflow. Extreme situations are often not considered because they are not encompassed in that discrete representation [Kim and Palmer, 1997]. When decisions based on the simplified streamflow are simulated with actual flows, the performance is often not as successful and benefits are not as high as the model predicts.

With SSDP the representation of streamflow is not simplified. The model estimates future benefits using real or synthetic streamflow time-series. It is anticipated that the models explored here will provide a more accurate prediction of the achievable annual benefits than some SDP models reported in the literature. The objective function value of the SSDP models can be compared to the average annual benefits achieved by the models when their release decisions are simulated.

Figure 3 displays the ratio between the predicted SSDP benefits and the benefits simulated from use of SSDP using 42, 19, and 10 scenarios. The previously evaluated four cases with increasingly challenging operations are presented. Some of the visible trends were expected, and some were surprising. Models using no forecasting, i.e., Hist I/m which uses historical scenarios with probability option I/m, show the greatest overestimation of the average benefits for each case. This is expected. Tejada et al. (1995) showed that as representation of streamflow increases in sophistication, the SDP model predictions become lower and closer to simulated values, while simple representations overestimate those values most severely.

Introduction of forecast information into the Step 2 re-optimization (Hist I/F) reduced the overestimation of the benefits, and inclusion of forecast information into the Step 1 optimization as well (Hist F/F) reduced it even further, though the increment was small. While the actual performance of models Hist I/F and F/F is nearly the same for each case (showing that the added sophistication of a full-scale SSDP with forecast-based probabilities in the Step 1 optimization did not produce better operating decisions than did the 2-stage model), the additional sophistication of F/F did lead to a more accurate estimate of the benefits. This difference is because model I/F employs deterministic DP of each scenario in the Step 1 optimization to compute future value functions, and so overestimates the achievable benefits due to its assumption of perfect foresight. Model F/F incorporates future forecast uncertainty into the development of future value functions, making the expected benefits more accurate.

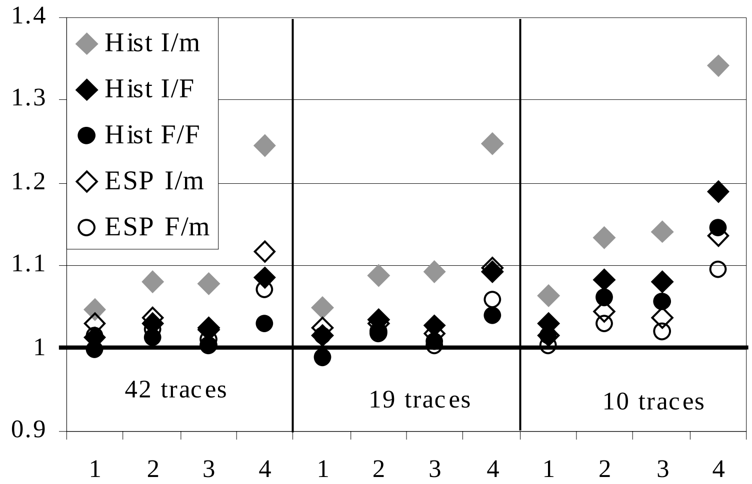

Figure 3. SSDP-Predicted Annual Benefits / Simulated

The two ESP models exhibited the same pattern as the historical models in each case. The full-scale ESP/SSDP model F/m produced the same simulated benefits but more accurate predicted benefits than the 2-stage model ESP I/m. The ESP models produced nearly the same prediction accuracy as the historical models with forecasting.

Generally, as operations are made more challenging, the models' overestimation of the benefits increases. The predicted results of the models operating with normal demand come the closest to the simulated values. The models operating with increased demand, varied energy prices and a minimum release requirement overestimate achievable benefits more. (This pattern is interrupted briefly by the fact that the assumption of varied energy prices reduces rather than increases the overestimation.)

5. Conclusions

1) Fewer ESP scenarios can be used to capture the same streamflow resolution as a larger number of historical scenarios because the ESP scenarios are all consistent with current basin conditions.

2) Similar scenarios (and their transition probabilities) can be combined into groups represented by a single scenario to reduce the number of scenarios included in the models and thus reduce the computational effort. The combination procedure attempts to retain the resolution of the streamflow distribution captured with the 42 scenarios by the choice of groups. Results showed that reduction to 19 scenarios and to 10 scenarios produced nearly the same performance as the model using all 42 scenarios.

3) The SSDP models overestimate achievable benefits only slightly. And while forecast-based transition probabilities used in the Step 1 multistage optimization do not produce more efficient operating decisions, they do provide a better estimate of achievable benefits than a two-stage model that does not consider uncertainty in later stages.

Both this study and Faber and Stedinger [2001] consider a specific circumstance in which the water system operation period being modeled is a finite-length snowmelt runoff season. For this system the results have been exceptional. Generally a two-stage model that combines deterministic optimizations with a one-stage probabilistic optimization does as well as the full multi-stage stochastic optimization. Additional research should extend this analysis to other systems that do not have such a well determined and critical hydrologic period, or that have significant over-year storage operations.

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Water Resources Systems Planning

Purposes:

- Develop a number of reasonable alternatives for decision makers to consider.
- Evaluate the economic, environmental, and social impacts from each alternative.

Tools:

- Mathematical modeling exemplifies the approach and permits an evaluation of the economic and physical consequences.

Water Resources Systems Planning

Limitations:

- Inherent limitation of models as representation of any real problem. Input data, including objectives and other assumptions, may be controversial or uncertain.
- Results of any quantitative analysis of alternatives are often only a small part of the input to the overall planning and decision-making process.

Water Resources Systems Planning

Procedures: How we model any specific water resources problem depends on:

- The objectives of the analysis
- The data required to evaluate the projects
- The time, data, money, and computational facilities available for the analysis
- The modelers' knowledge and skill.

Planning and Studies Model

Features:

- Same model as the one used for operations: to realistically analyze future impacts
- System analysis: versus project-based analysis
- Time steps: as small as practically possible
- Study years: hydrologically representative

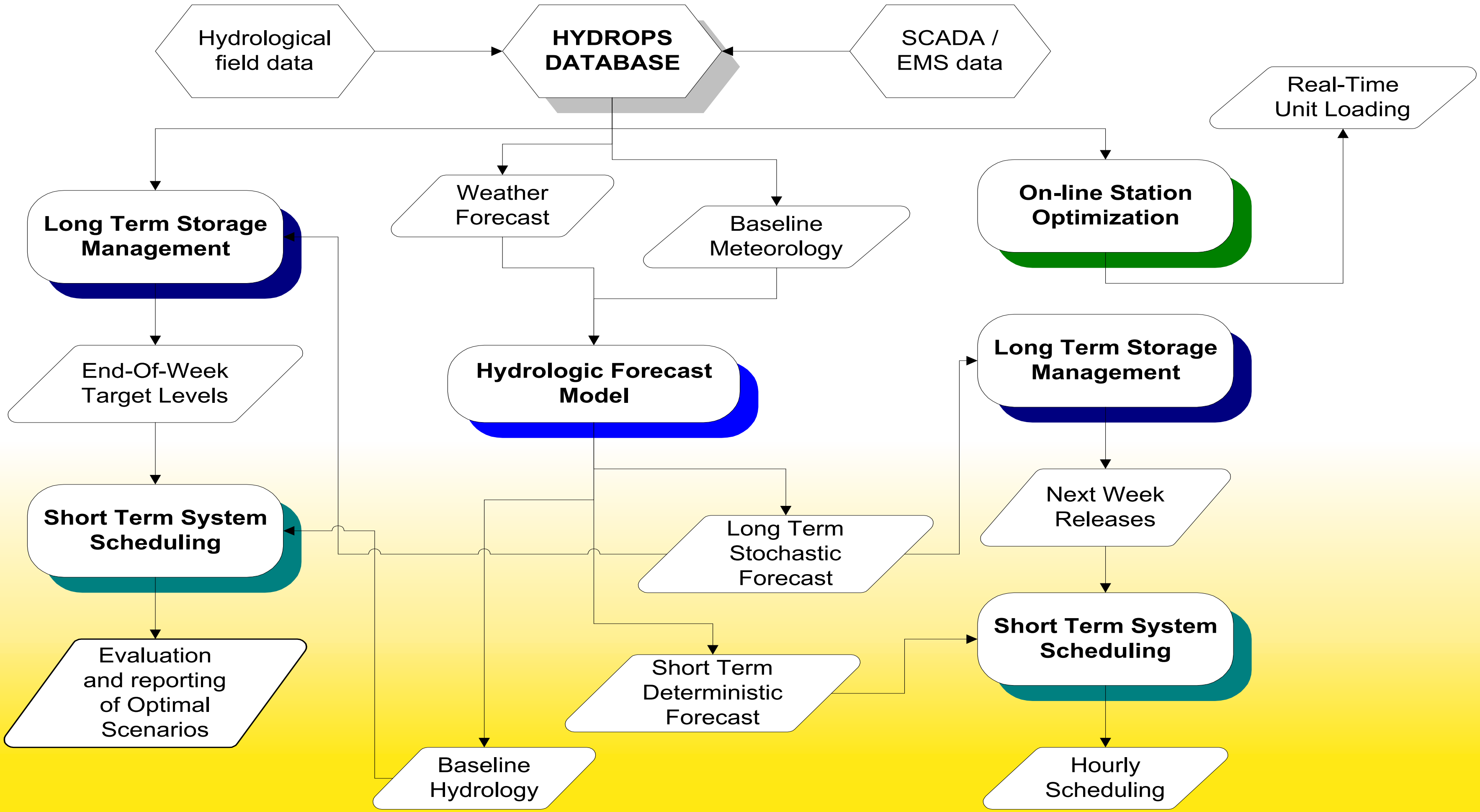
Optimization Model

- **Decision Variables:** engineering design and operating variables.
- **Constraints:** physical, technical, environmental, and other restrictions on the values of the decision variables.
- **Objective function:** a function to be optimized (maximized or minimized).
- **Applications:** small- to medium-scale and mathematically tractable systems. Difficult to model but easy to use.

Simulation Model

- **Decision variables:** engineering design and operating variables.
- **Constraints:** physical, technical, environmental, and other restrictions on the values of the decision variables.
- **Operating procedures:** the rules for storing, releasing and routing water through the system (usually involves a set of priorities).
- **Targets:** level (rule curves), flow, energy, …
- **Applications:** large-scale, complex and not mathematically tractable systems (usually called technique of last resort). Easy to model but difficult to use.

OVERVIEW OF FUNCTIONAL INTERACTIONS IN HYDROPS



Planning Studies | Hydrological Analysis | System Scheduling Operations

OPERATION MODE
Long Term and Short Term Runs

POWEL

Start Current Week

↓

Update Long Term Flow Forecast
(probabilistic, 1-year time horizon, weekly time steps)

↓

Run Long Term Optimization
(probabilistic, 1-year time horizon, weekly time steps)

↓

Model's Output:
How much water should be released from each reservoir for the next 7 days

↓

Update Short Term Forecast
(deterministic, 7-day time horizon, hourly time steps)

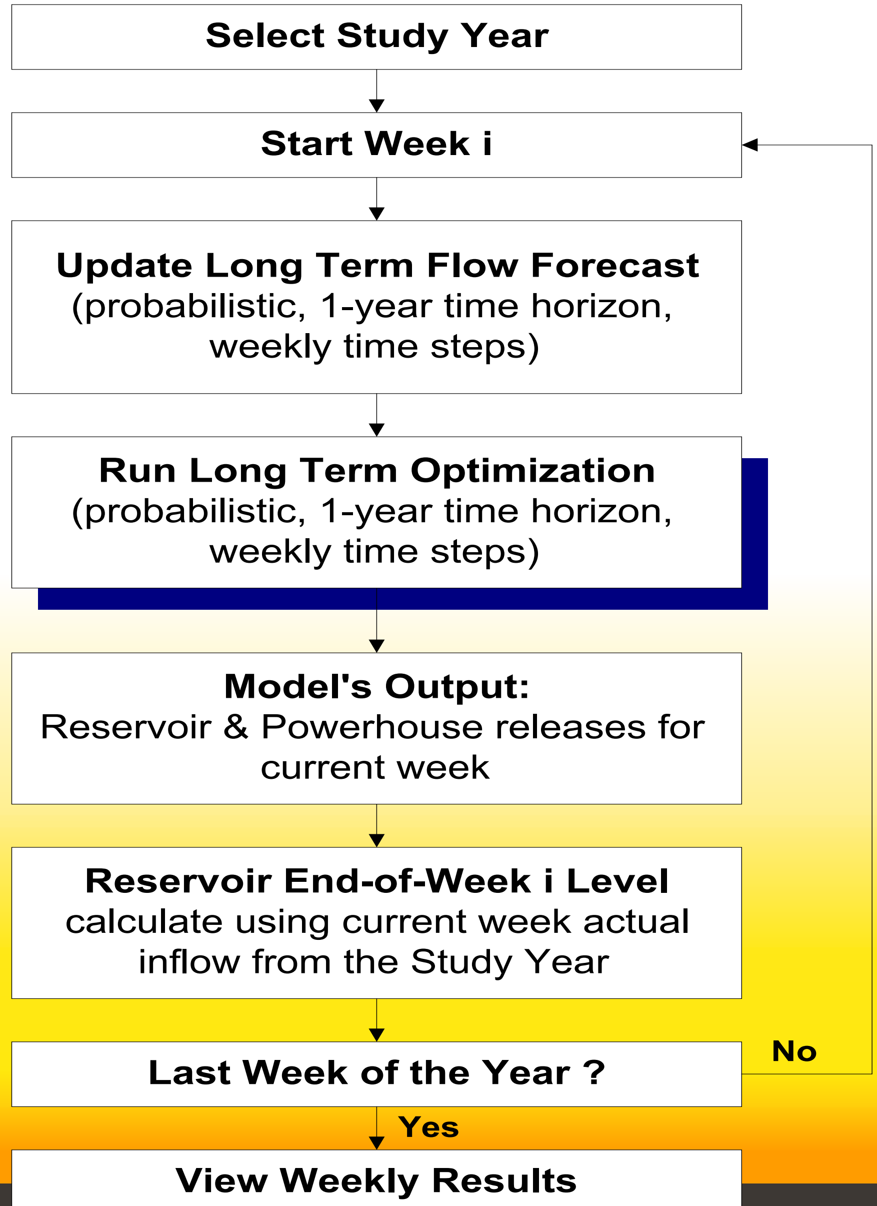
↓

Run Short Term Optimization
(deterministic, 7-day time horizon, hourly time steps)

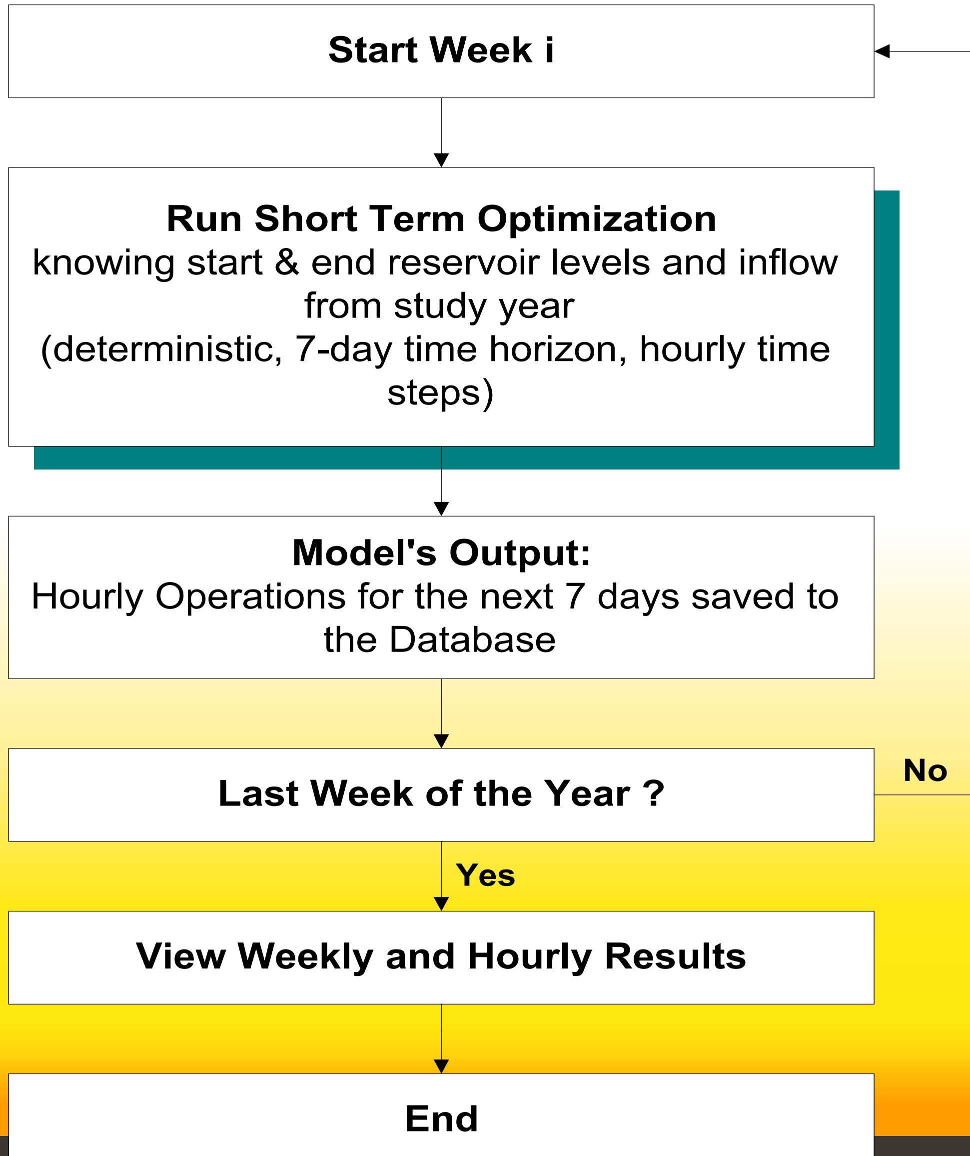
↓

Hourly Schedules for entire System

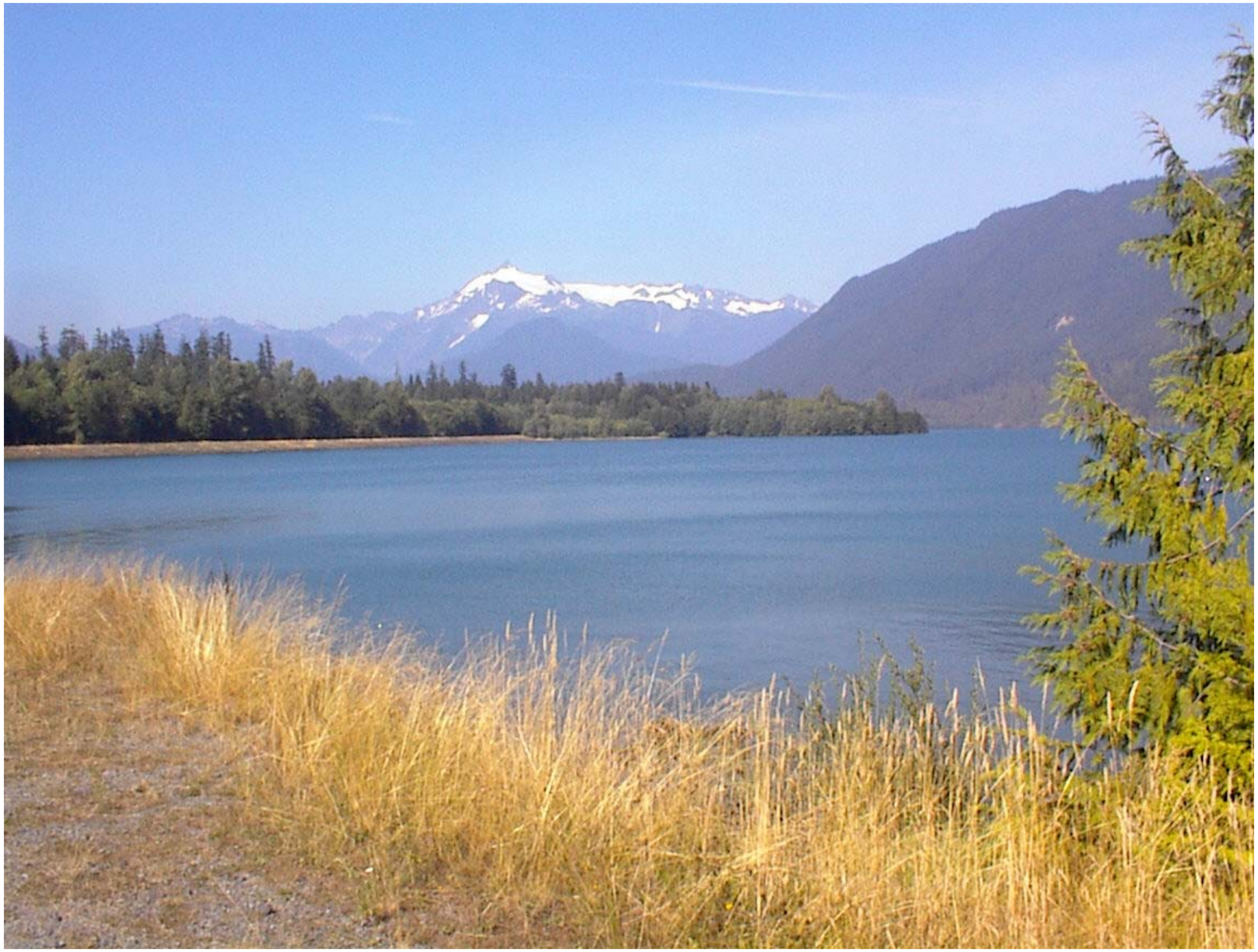
PLANNING STUDY MODE
Long Term Run



PLANNING STUDY MODE
Short Term Run



The Application of Models and Economics in FERC Relicensing



Briefing Purpose

- Promote Understanding of How Models Are Used in FERC Relicensing
- A Variety of Models are Available
- What Is Needed in Models?
- Provide a Background on FERC Economic Evaluation Methodology

Model Applications

- **Provide Flow Data for Fish and Habitat Models**
- **Stage Data below Project on Skagit R. for Ramping**
- **Lake level data for recreation/aesthetic analysis**
- **Operations under wet normal and dry conditions**
- **Input to Economic Models for**
  - **Dependable Capacity**
  - **On-peak to Off-peak Energy**

Characteristics of Good Operations Models

1 Flexible System Configurations

2 Shown to be Calibrated

3 Mass Balance Checks Out (daily and annually)

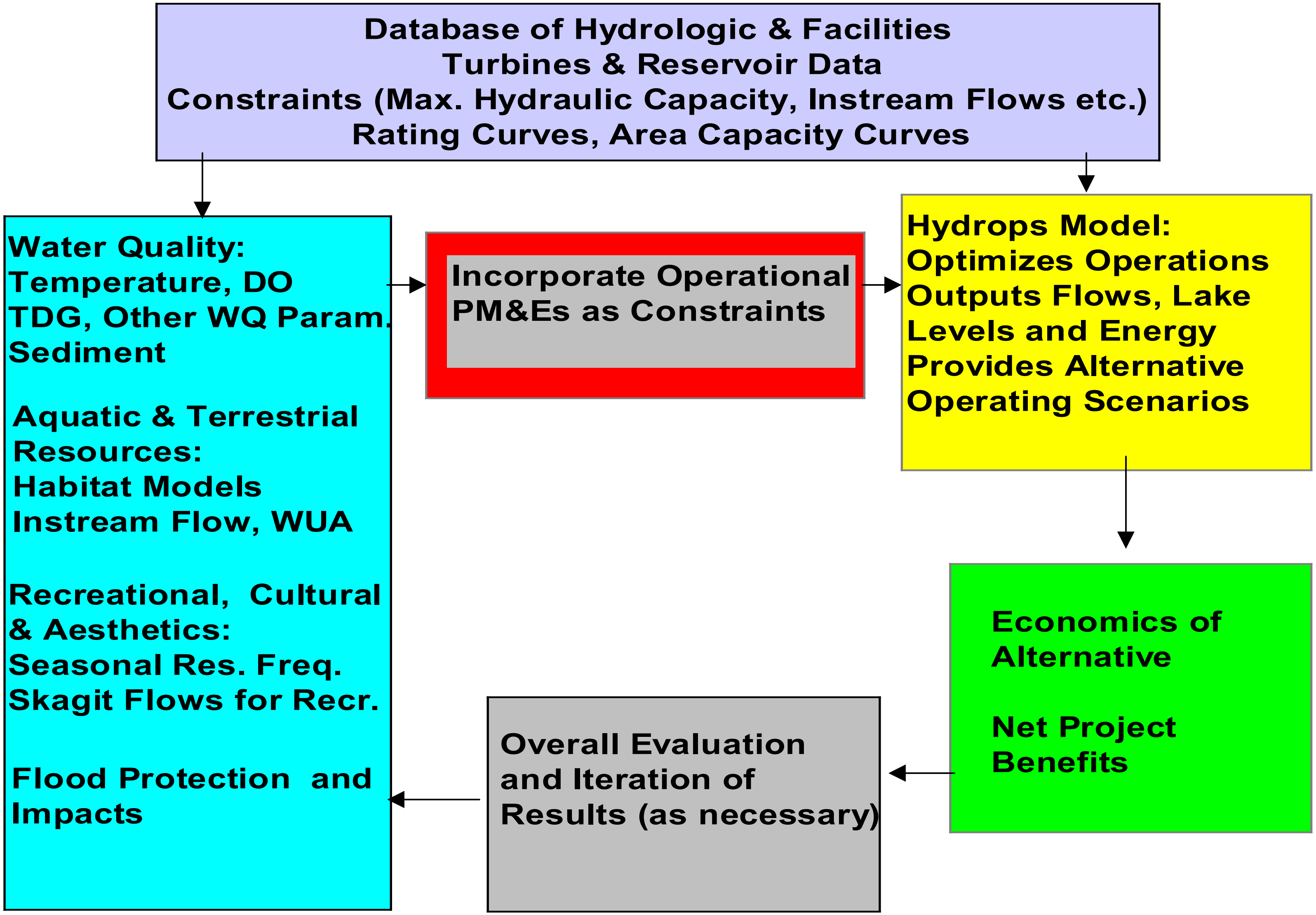
3 Can Optimize Operations under a Variety of Constraints and Objectives

4 Not Totally Perfect Knowledge Models

5 Provide Output Suitable for Other Resource Models and Graphical Interface

6 Facilitate Economic Analysis

Relationship of Operations Model to Other Activities



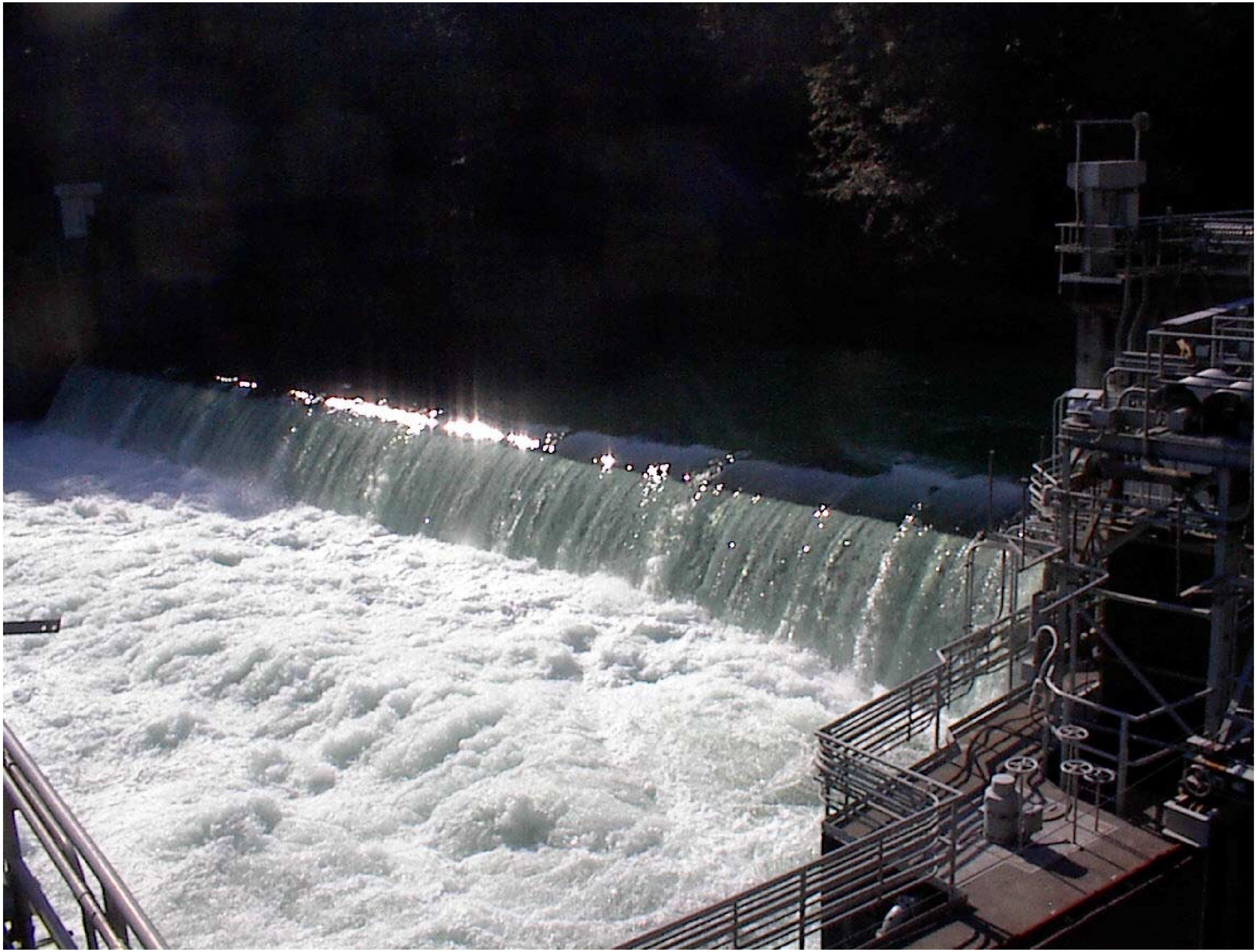
Alternatives Typically Evaluated

1. **Applicant's Proposal**
2. **Agency Proposal***
3. **A Settlement Proposal in Lieu of 1 & 2**
4. **FERC Staff Alternative (may be a modified 1, 2 or 3 or combination thereof)**
5. **No-action Alternative (current license Ts&Cs)**

Collaborative Proposal for Operating the Projects

- **Upper Baker**
  - Reservoir Levels
  - Storage for Floods or other Purposes

- **Lower Baker/Skagit River**
  - Reservoir Levels
  - Minimum Downstream Flow
  - Ramp Rate Limits
  - Storage for Floods or other Purposes



Mandatory Requirements

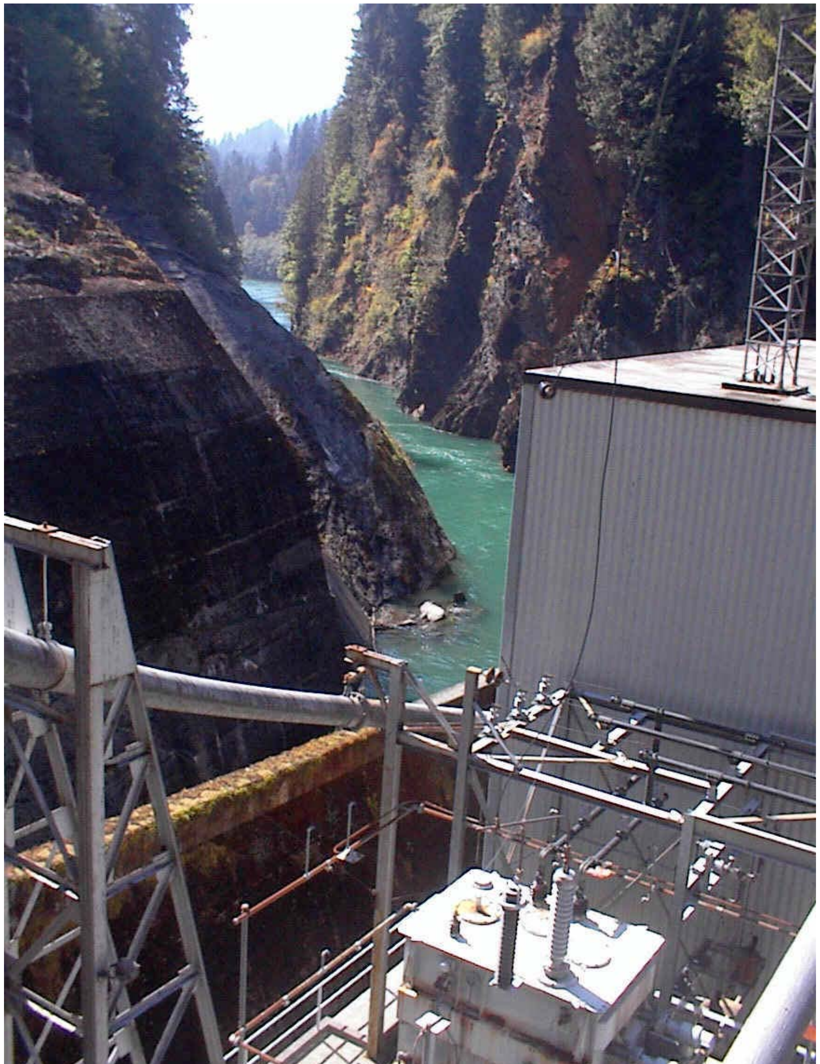
- Water Quality Certification (401)

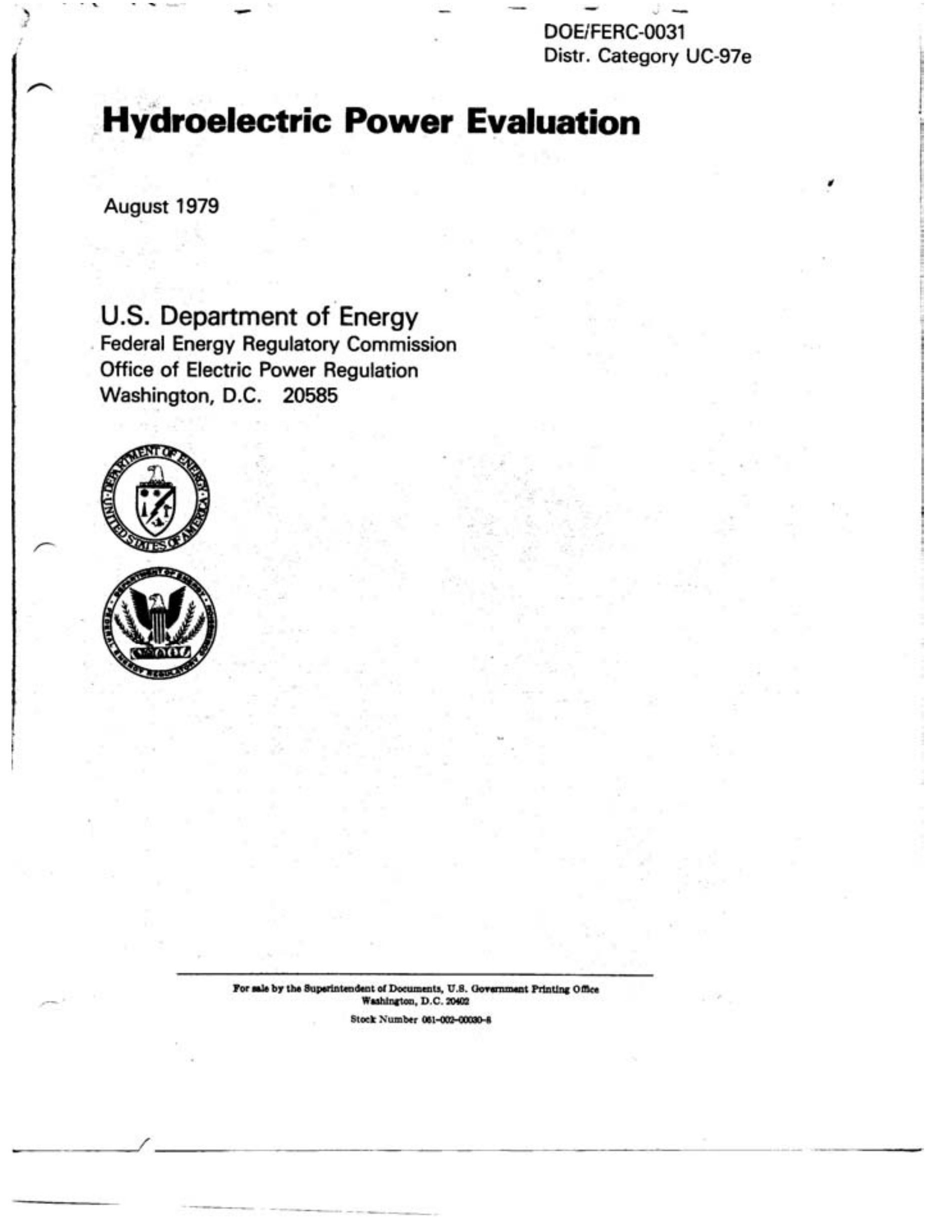
- Reservation of Authority to Prescribe Fishways
  - Interior
  - Commerce

Agency or Tribe Recommendations

- FPA Section 4(e) Terms & Conditions (Ts&Cs)
  - Equal consideration to developmental & non-developmental values
- FPA Section 10(a) Ts & Cs
  - Consider Resource Management Agency Recommendations to Ensure Project is Best Adapted to Comprehensive Plans for Developmental & Non-developmental Resources
- FPA Section 10(j) PM&Es
  - Resource Agency Recommendations Pursuant to Fish & Wildlife Coordination Act to Protect, Mitigate Damages to, and Enhance Fish and Wildlife Resources

FERC Approach





DOE/FERC-0031
Distr. Category UC-97e

Hydroelectric Power Evaluation

August 1979

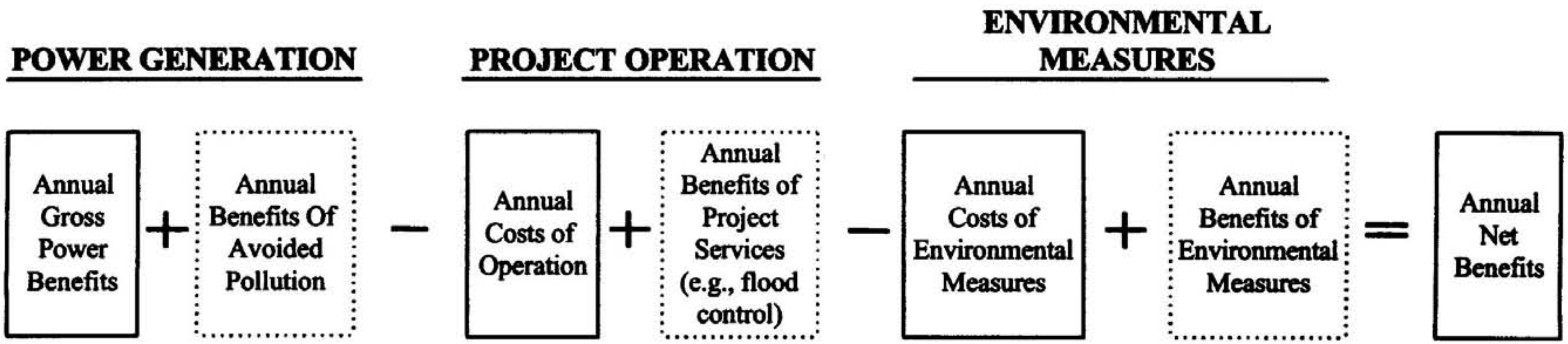
U.S. Department of Energy
Federal Energy Regulatory Commission
Office of Electric Power Regulation
Washington, D.C. 20585

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402

Stock Number 061-002-00030-8

Exhibit 3-1

OVERVIEW OF FERC'S ECONOMIC METHODOLOGY*



* Solid-line box indicates quantified estimate. Dotted-line box indicates items either assessed qualitatively or quantified but left out of FERC's net benefit calcultaion.

Source: Division of Economics, USFWS

UNITED STATES OF AMERICA 72 FERC ¶ 61, 027
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

Mead Corporation, Publishing) Project No. 2506-002
Paper Division)

MEAD

ORDER ISSUING NEW LICENSE

(Issued July 13, 1995)

The Mead Corporation, Publishing Paper Division (Mead), filed an application for new license under Part I of the Federal Power Act (FPA) to continue operation and maintenance of the 9.19 megawatt (MW) Escanaba Project, located on the Escanaba River, near the township of Escanaba in Delta and Marquette Counties, Michigan. [1] Mead proposes no new capacity and no new construction. For the reasons discussed below, we will issue a new license to Mead.

Impact of Mead

- Constant Dollar Method Adopted
- No Escalation for Energy or Capacity Values
- No Inflation of Costs
- FERC No Longer Computes IRR
- Negative Economic Benefit Does Not Preclude License


WELCOME
BAKER RIVER
PROJECT
F.P.C. NO. 2150
RECREATIONAL FACILITIES OPEN TO ALL
INFORMATION
CENTER

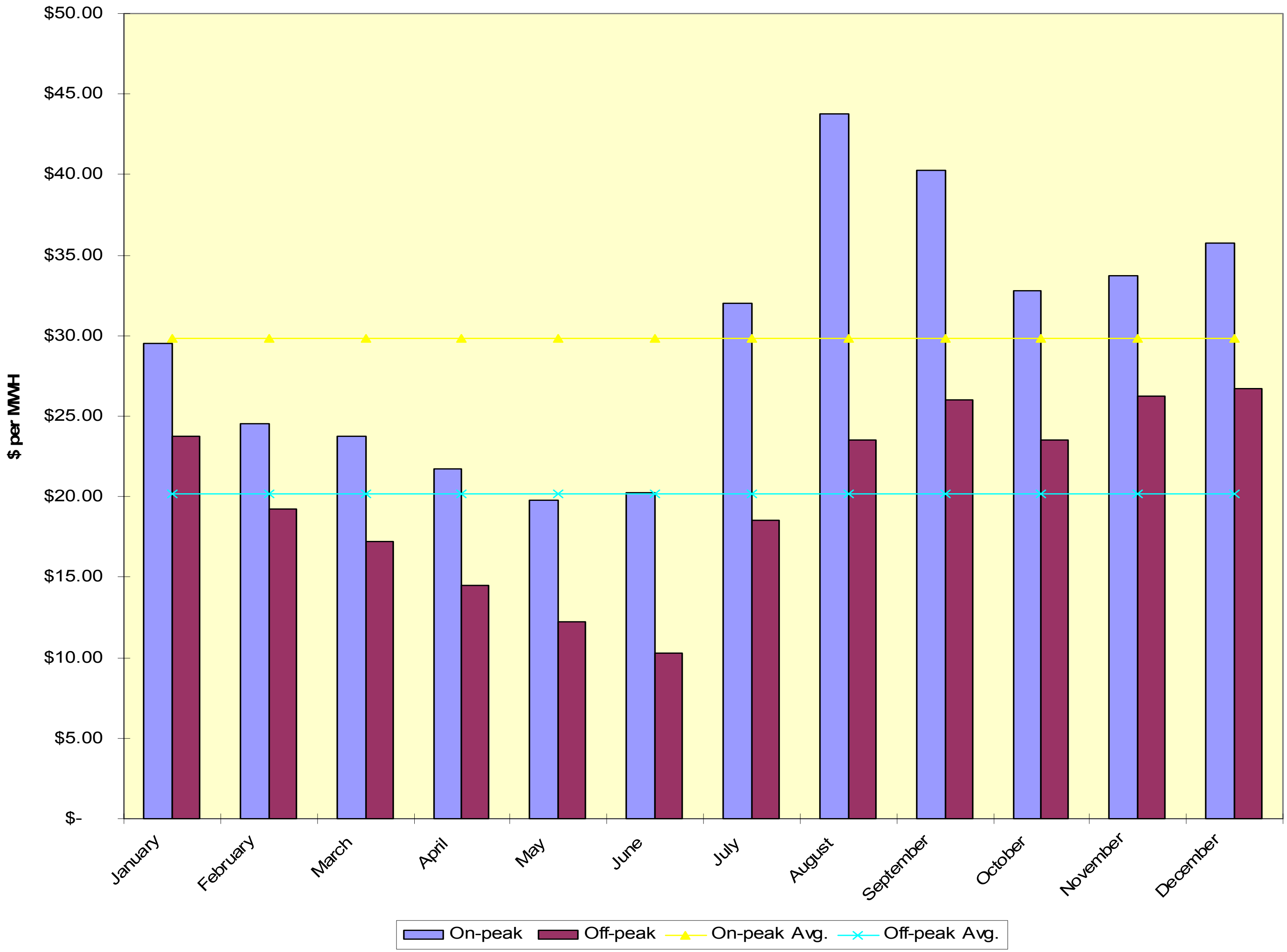
What is Included as a Cost?

- **Capital Costs (levelized over 30 years)**
  - Net Present Value of Project
  - Capital Costs of Plant Improvements
  - Capital Cost New Environmental Measures
  - Costs Expended on Relicensing
- **Annual Costs**
  - Administration, FERC Fees and Insurance
  - Operations and Maintenance (O&M) Costs of Plant
  - O&M Costs of New Measures

What is Included as a Benefit?

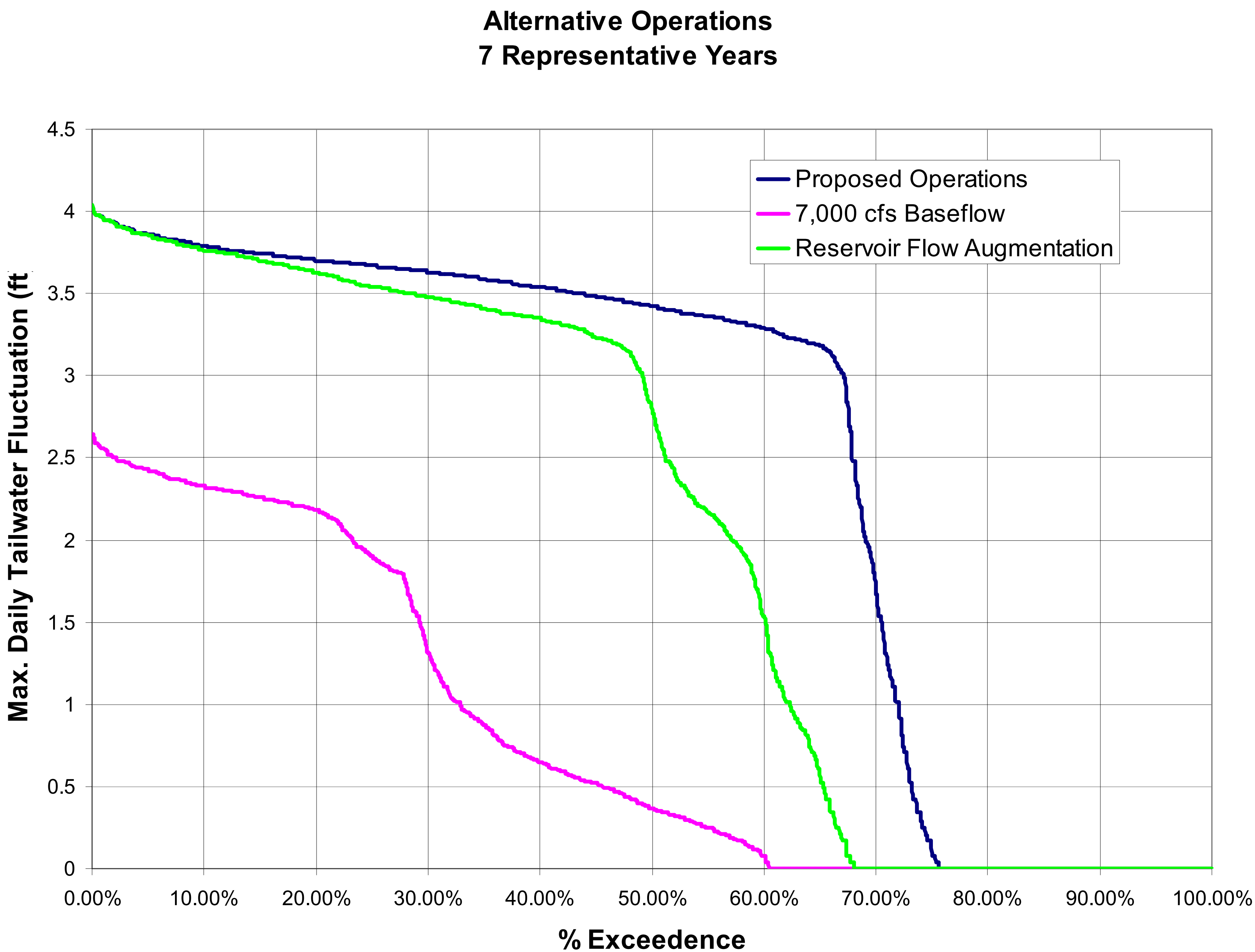
- **Energy Benefits**
  - Seasonal On-peak
  - Seasonal Off-peak
  - Based on Replacement Costs (regional level)
- **Capacity Benefits**
  - Based on Hydrologically Critical Period
  - Based on Replacement Capacity - usually Combustion Turbines
  - Currently $90 to $114 per kW-Year

Sample Energy Price Variation



What Might Impact Capacity Benefit?

- **Tailwater Ramp Rate Restrictions**
- **Reservoir Ramp Rate Restrictions**
- **Pool Elevation Restrictions**
- **Seasonal Reregulation**
- **Minimum Instream Flows**
- **Changes in Turbine Configuration**
- **Redefinition of Critical Period**


Alternative Operations
7 Representative Years
Proposed Operations
7,000 cfs Baseflow
Reservoir Flow Augmentation
Max. Daily Tailwater Fluctuation (ft
% Exceedence
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
0.00%
10.00%
20.00%
30.00%
40.00%
50.00%
60.00%
70.00%
80.00%
90.00%
100.00%

Hypothetical Power Gen. and Economic Impacts at Sample Project X

	No-action Alternative	Applicant's Power's Proposal	Staff Modified Alternative	Agency Alternative
Average annual energy (MWh)	1,204,819	1,201,418	1,199,604	1,203,399
On-peak generation (MWh)	721,521	719,071	714,273	695,356
Off-peak generation (MWh)	483,298	482,348	485,331	508,043
Dependable capacity (MW)	132.4	130	124	109
Annual benefit ($1,000)	46,121	45,932	45,568	44,659
Annual cost ($1,000)	8,790	9,270	9,725	9,297
Net annual benefit ($1,000)	37,331	36,662	35,843	35,361
Net annual benefit effect (%)		-1.8%	-4.0%	-5.3%
Median Tailwater Fluct. (ft)	5.0	3.4	2.4	1.7
Mean Summer Reser. Elev. (ft)	2250	2251	2252	2254

Economics

- Ultimately - It is the Incremental Cost, Benefits and Net Benefits that Must be Evaluated
- The Utility May Have Different Economic Evaluation Needs
- Questions?

HYDROELECTRIC PROJECT LICENSING HANDBOOK

Federal Energy Regulatory Commission
Washington, DC
April 2001

Presented at 3rd Water Resources Operations and Management Workshop
Colorado State University, Fort Collins, Colorado
June 27 - 30th, 1988

HYDRO-POWER STOCHASTIC FORECASTING AND OPTIMIZATION

by Tung Van Do[1]
and Charles D.D. Howard, M. ASCE[1]

ABSTRACT

A micro-computer package was implemented to support real-time decisions for weekly and month-end water management at an industrial complex in the mountains of British Columbia. The rolling one-year look ahead analysis is updated weekly to provide information for on-going management of the reservoirs and for the monthly commitments to purchase supplementary energy from the regional grid. The package of programs is fully integrated into an automatic analysis procedure. Procedures are described and the usefulness of the approach is evaluated.

Introduction

Powell River and Lois River flow into Malaspina Straight about 60 miles Northwest from Vancouver, British Columbia. The prevailing winds drive moist marine air inland across these watersheds and annual precipitation increases dramatically as the air is lifted by the Coast Mountains. At the Town of Powell River near sea level precipitation averages 42 inches and rises to over 100 inches within about 40 miles, where portions of the watersheds reach 6,000 feet in elevation. The extreme topographic relief, coupled with proximity of the weather station to the ocean, introduces a correspondingly high level of complexity in the temperature regimes and consequently in the snow accumulation and melt.

Both of these rivers are dammed to produce hydroelectric power for a pulp and paper complex which is also connected to the regional electrical grid. At Powell the installed capacity is approximately 48 MW; at Lois it is 36 MW.

The purpose of the work described here was to develop and implement a runoff forecasting and reservoir operations optimization procedure which would maximize the resources of water and hydraulic head and minimize the costs of electrical purchases from the grid. Costs are affected by both the total energy and the capacity actually used in each month. The analysis described here provides information for making power purchase commitments for the following month. Figure 1 provides an outline of the system of computer programs and how they are routinely used.

[1]Professional Engineers, Charles Howard & Associates Ltd., Suite 300, 1144 Fort Street, Victoria, B.C., V8V 3K8

Physical Setting

The elevations of the two separate watersheds extend from near sea level to several thousand feet and include areas of permanent snow and ice. Runoff occurs from rainfall and snowmelt and on any given day both sources may be contributing varying amounts from different elevation ranges. Under normal winter conditions rainfall may be running off from the lower elevations, snowmelt may be occurring in the middle range, and at the highest elevations snow may be accumulating.

The Lois Lake watershed has a relatively larger area of low elevation and the reservoir itself has a flatter stage-storage curve. Thus, while the two watersheds may be in almost the same meteorological climate they have different hydrological regimes.

Inflow to the reservoirs is not measured directly. It was estimated daily from reservoir levels and power production. These basic data are subject to errors and there are many days on which the computed inflow is negative. Fortunately, with these large reservoirs, it is not necessary to have precise daily values of inflow for analyzing power operations, Table 1. Five-day moving means eliminated nearly all of the negative daily values.

The smoothed historical time series of Powell Lake inflows covers the period from 1917 to 1974. For Lois Lake the Water Survey of Canada records from 1922 to 1930 was available. From 1931 to 1974, the period since the dam was constructed, the five day moving average analysis was used to smooth the data.

Table 1. Reservoir Characteristics

	LOIS	POWELL
Watershed Area (sq mi)	184 (476 sq km)	580 (1500 sq km)
Reservoir Area at Full Supply Level (sq mi)	11.5 (30 sq km)	45.4 (118 sq km)
Storage Capacity (ac-ft)	450,000 ($555\times10^6 m^3$)	580,000 ($715\times10^6 m^3$)
Maximum Reservoir Elevation (ft)	521 (159 m)	285 (87 m)
Minimum Usable Reservoir Level (ft)	470 (143 m)	265 (81 m)

Two Forecasting Models

At some times of year the future runoff depends on the current inventory of snow on the watersheds. At such times a meteorologically based forecasting approach is appropriate; at other times, historical inflows may provide a more directly usable basis for forecasting. Two alternative forecasting models are therefore included in the package of computer programs.

Probabilistic Streamflow Forecast Model

The procedure adopted in the Probabilistic Streamflow Forecast Model depends entirely on the currently observed hydrological behaviour of the watershed and the streamflow data base of historical inflows. These cover the period 1917 to 1974. Meteorological data are not used in this model.

The forecasting method includes both deterministic and probabilistic components. The deterministic component of the forecast is based on an analysis of the hydrograph recession characteristics which have been observed in the streamflow data base. The hydrographs from this data base were displayed on an interactive graphics terminal and from selected points on the hydrographs a computer program determined exponential decay (alpha) coefficients. These were plotted against time to determine how the hydrograph recession might vary seasonally. For the summer period, recession is governed primarily by residual snowmelt from the highest elevations and by groundwater discharge. A best-fit curve was developed to describe how the recession coefficient varied with time during this season. For the winter months, when the hydrological response of the watershed is more unpredictable, an envelope curve was defined by the hydrograph recession analysis.

The recession coefficients are used to forecast the minimum volume of runoff from the current inflow, including the continuing contributions as it decays for several weeks into the future. This approach provided a deterministic prediction of the minimum runoff to be expected over the twelve month forecast period.

The next step in the procedure is to add information about the probability of additional runoff which cannot be predicted from current conditions. This can be based on historical streamflow by making an adjustment for recession flows from the current date in each year of the period of record. The residual above the recession provides a sample of the additional runoff which might be subsequently expected during the forecast period. Each year provides one such sample for each day of the forecast period and taken together these can be analyzed to estimate the probability distribution of future runoff.

This probabilistic forecast, together with the deterministic forecast developed from the recession flows of the current year, provides one alternative estimate for the overall probability of inflow at each time step during the forecast period. The advantage of this procedure is that it develops the forecast probability distributions directly from streamflow estimates. This avoids the numerous additional complexities introduced by modelling the climatological and hydrological variability of the watershed. The disadvantage of this approach is in failing to recognize the volume of water which is currently stored in the snow inventory and which may runoff at various times during the near future. A meteorologically based approach requires a more complex modelling procedure but offers the possibility of diminishing the level of uncertainty by reducing the variance in the inflow probability distributions.

Probabilistic Snow Resource Inventory Model (PRIM)

The purpose of this alternative forecasting approach is to incorporate an analysis of past meteorological conditions which led to current snow conditions on the watershed with an estimate of when portions of this snow inventory may run off in response to weather conditions during the forecast period. **PRIM** estimates reservoir inflows from current streamflow, current snow conditions, and the probability of future snowmelt/rain, based on the past sixty years of daily temperature and precipitation data recorded at the Town of Powell River.

The deterministic portion of runoff is calculated by this model using a subroutine adapted from the Probabilistic Streamflow Forecast Model and the estimated current inflow. The current snow conditions in ten elevation bands are calculated by a hydrological watershed model using recent weather data and beginning from a snow-free condition two years prior to the forecast date. This analysis provides current initial conditions from which the sixty years of historical weather data are used to estimate the probabilistic portion of runoff during the 12-month forecast period.

In this model calculations of precipitation and snowmelt, and snow accumulation, as a function of elevation and weather data are made each day for the ten different elevation bands. These results are used to develop probability distributions of anticipated inflows from the sixty samples available for each day.

The model was calibrated for each watershed separately by comparing calculated monthly runoff volumes to the estimated monthly reservoir inflow volumes during the sixty year period of record. It was found that the air temperature record obtained in the town close to the ocean is not representative of air temperatures a short distance further inland at the base of the mountains. The temperature record was therefore adjusted based on the results of a comparison between ocean water temperatures and air temperatures at the long term coastal weather station and shorter records from a nearby inland station. Monthly temperature lapse rates were selected from seasonal radiosonde data and adjusted by calibration.

This approach to forecasting recognizes the complexity in modelling atmospheric and hydrological conditions over the topography of the watersheds. Uncertainties in the processes to be modelled and the respective coefficients are somewhat compensated by availability of a long period of record for calibration. Additionally, the model will re-calculate the distribution of the estimated existing snow cover based on snow survey observations from specific points on specific days.

Both the streamflow based and the weather based forecasting procedures are routinely run each time that a forecast is required. For the most part agreement between the two methodologies is close. Differences are resolved through understanding the modelling assumptions and interpreting them in view of the season and the recent runoff experience. However, comparisons are not simple because the forecasts provided by both procedures are time varying probability distribution functions which may converge, diverge, or cross at various percentiles.

Optimization Model

A stochastic, iterative, linear programming model was used to determine optimal reservoir and powerhouse operations for seven different runoff probability levels for each of twelve time steps. A two level hierarchy was used to focus resolution from twelve monthly to twelve weekly intervals.

Results for the first time step are most important because the less pressing future decisions can evolve from future analysis as circumstances actually develop. The model therefore recommends the powerhouse discharge which should be the target during the initial time step if the expected value of future energy production is to be maximized within the constraints. Additional information is provided in the form of probability distributions of future reservoir levels, spills, and powerhouse releases, which could result if the current recommendation is actually followed.

The objective function of the model is expressed mathematically as follows:

$$\text{Max} \left\{ C_{Q1}\, Q_1 + p_j \sum_{j=1}^{7} \left[\sum_{i=2}^{n} C_{Qij}\, Q_{ij} + \sum_{i=1}^{n} C_{Vij}\, V_{ij} \right] \right\}$$

where:

- i = index for time steps (= 1,2,...,12)
- j = index for probability levels (=1,2,...,7)
- V = reservoir storage at the end of time step
- Q = powerhouse release during time step
- S = reservoir spill during time step
- p = probability
- C_V = value of storage
- C_Q = value of powerhouse flow

The capacity of the reservoir and powerhouse and continuity at each level of inflow probability, are handled with the usual bounds and constraints.

Notice that in the first time step there is only one decision variable and that this is the recommended release. At all other times there are numerous variables which describe the ensuing probabilities of releases and storage volumes.

Since the analysis is non-linear, the objective function coefficients are adjusted by an iterative analysis which uses a previous linear solution and the various actual non-linear functions to determine new coefficients for successive iterations.

At a given probability level the reservoir inflow during a time step is the difference between the current and the previous cumulative inflows. This approach avoids dealing with partial correlations that may exist between inflows of consecutive time steps.

Uses of the Models

The weather data file which includes daily minimum and maximum temperature and precipitation is updated every week and the analysis is made at two levels of detail.

First, a monthly time step analysis is made in which the probability distribution of reservoir inflows is forecasted for twelve 28-day periods based on currently estimated inflow and snow conditions. These forecasted inflow probability distributions are then used with the current lake level for optimizing reservoir operations.

The final reservoir storage at the end of the twelfth time step has some effect on the optimal release in the first time step. The optimal final level was found by a special study in which the planning horizon in the optimization model covered a 2-year period. The extended model used the steady-state distribution of historical inflows and produced optimal reservoir storage at the end of one year from each starting month.

Second, a weekly time step analysis provides forecasted inflow probability distributions for twelve 7-day periods. These are used together with current lake level and optimal reservoir level distributions which were determined at the end of the third month by the monthly time step analysis.

In addition to the energy generated from these two hydro plants, the mill can purchase energy from the grid, up to a maximum determined by transmission capacity. The hydro plants must generate at least 40 MW to keep the entire mill in operation. A minimum bound in the LP model is used to keep the results above this minimum and a maximum bound is used for scheduled outages.

The value of the product from the mill is considerably higher than the energy cost, therefore the plant management feels more comfortable if the reservoir level is planned to be maintained above the minimum. This is accommodated in the optimization by setting the lower bound for reservoir level at five ft (1.52 m) above the dead storage level. With this buffer storage of 73,100 cfs-days (2070 cms-days), the minimum generation can be sustained for about one and a half months without inflow. This would provide the minimum energy requirement during any drought which has occurred during the historical record. The optimal return is reduced by about 1% by this buffer storage - a small price to pay compared with the security it provides.

Evaluation

There are many sources of potential uncertainty and error in this type of analysis and these considerations influence the choice of the modelling approach. For example, the basic streamflow data estimated from assumed powerhouse efficiency functions, recorded power output, and estimated stage-storage curves were smoothed by working with a five-day moving average and by the large volumes of storage in the two reservoirs. Runoff routing on the watershed was therefore not included in the models.

It would be useful to directly evaluate the forecasting procedure separately from the optimization methodology. This cannot be done because the three year period during which the method has been in use is too short to estimate the accuracy of the forecasted probability distributions. Instead the overall effectiveness was evaluated in terms of the additional energy which could have been produced in the past if the current system had been in operation. For this purpose five years (1970-1974) from the data base were chosen as a basis for evaluation. Using a monthly time step, three different cases were compared.

1) The historical operations which actually occurred during the 1970 to 1974 period provided a record of reservoir and powerhouse operations.

2) A deterministic optimized operation based on perfect knowledge of the actual reservoir inflows established a standard for comparison in terms of the total water resource energy which was available during the five year period.

3) For each month of the five-year period, the procedures described above were used to develop forecasted inflow probability distributions and the corresponding recommended monthly optimal operations. The analysis provided an estimate of the total energy which could have been generated if the current forecasting and optimization system had been in place.

Comparisons for a specific short period of record cannot be conclusive because of the varying relative importance of hydrological factors, unanticipated outages, and operational decisions which were made in the past. The 1970-1974 period seemed to balance these considerations to provide a reasonable test.

The total runoff for each of the five years, and the long term average, are listed in Table 2. The below average runoff of the first year was followed by four subsequent high runoff years.

Table 2. Powell River, Estimate Annual Total Runoff for the Period 1970-1974

Year	Runoff (cfs-days)	Runoff (cms-days)	Percent of Average %
1970	72,906	2,064	74.4
1971	119,509	3,384	122.0
1972	124,099	3,514	126.6
1973	116,732	3,305	119.1
1974	128,258	3,632	130.9
Long-term average	97,990	2,775	100.0

Table 3 compares the historical operation and the results which could have been realized if the stochastic modelling system had been in place. In this table the deterministic optimization with perfect knowledge of future inflows provides the standard for comparison. The last row is included to illustrate how effective the rolling time horizon optimization can be with a particularly poor set of forecasts.

Figure 2 illustrates reservoir operations for the first three cases in Table 3. It can be seen that the reservoir could have been drawn down to minimum level more frequently if, as the deterministic analysis is aware, it was known that it would be filled later. This perfect operation was approximated nicely by the stochastic optimization based on the forecasting procedure. Historical operations assumed that it would be unwise to draw the reservoir down too much without any knowledge of future inflows.

Table 3. Powell River, Comparative Evaluation, in Percent

	Total Energy	Powerhouse Discharge	Spill
Deterministic optimization based on known inflows	100	100	100
Historical operation	83.4	84.2	356
Stochastic optimization with forecasted inflow probability distributions	95.1	97.1	146
Deterministic optimization Monthly averages used as updated forecasts	92.8	93.8	201

Figure 3 shows powerhouse flows corresponding to the reservoir levels discussed above. The optimal power flow for most of the time was either maximum or minimum, and the historical releases fluctuated in between.

In the first year, which experienced unusually low runoff, the historical total release exceeded the optimum and the reservoir was drawn down more than it should have been by the end of the year. Decisions were then made to fill the reservoir too soon and, as a consequence, there was spill in the ensuing wet seasons of the subsequent years.

Since the 1970-74 period the hydraulic wood chipping equipment at the mill has been retired and the water which that equipment consumed is now used to generate additional hydro-electricity. This change has provided additional flexibility for reservoir operations, and might explain some of the apparent inefficiency of past reservoir operations.

In practice the forecasting and optimization is actually updated each week based on the most recent experience with the weather and the plant operations. To illustrate the reason for the more frequent updating interval, the evaluation described above was applied weekly to the low runoff 1970 situation. For the months in which monthly releases were less than the maximum, the weekly updating interval gave approximately 10 percent more energy than the monthly updating interval.

This can be explained as follows:

1) <u>Optimization:</u> The release in one week is much less in total volume than the release during one month. Therefore, the volume remaining in storage is larger for the weekly optimization.

This can provide more head and more flexibility to adjust later in the month if necessary.

2) Forecasting: Weekly forecasting provides more information about water in snow and in the hydrograph recession than monthly forecasting. This makes it possible to adjust the previous week's forecasts and provides a more finely tuned feed-back process which results in more efficient use of water.

Conclusions

The following conclusions may be made:

1) Results from the stochastic optimization model based on updated, probabilistic runoff forecasts were very close to the deterministic optimal operation based on perfect foresight.

2) A rolling time horizon optimization, using poor forecasts (i.e. steady-state expected values of inflows), would have been a significant improvement over the historical operation.

3) A reserve storage is a good alternative, materially as well as psychologically, to a penalty cost approach. A comparison between deterministic optimization with and without a reserve storage showed that the costs of the added security is less than 1 percent of the overall return.

4) Updating forecasts and optimization frequently is worth the extra effort.

5) For the Powell River generating station the currently used methodology would have increased the energy output by more than 10 percent if it had been in place during the 1970 - 1974 period.

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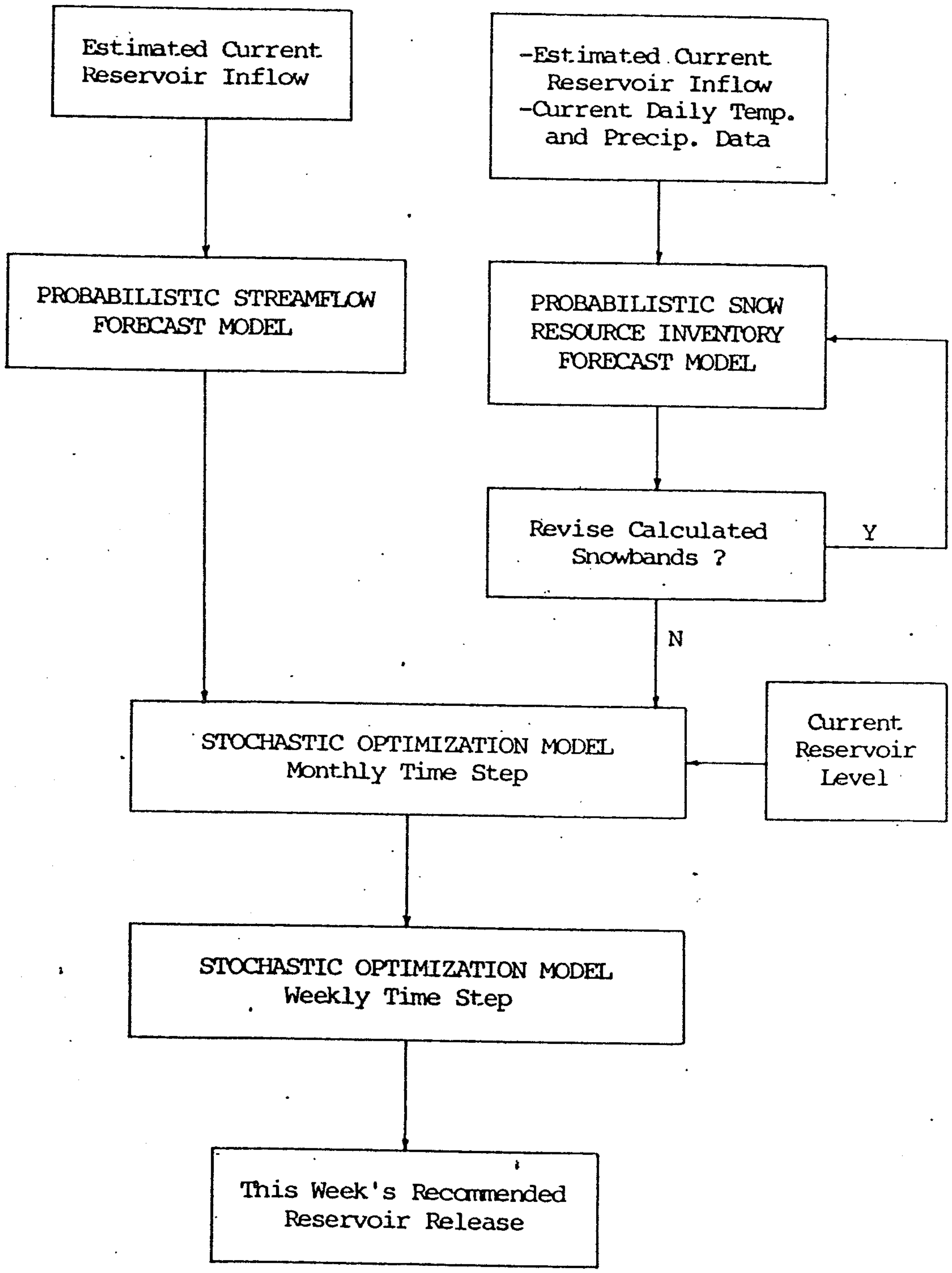

Figure 1. Overview of the System

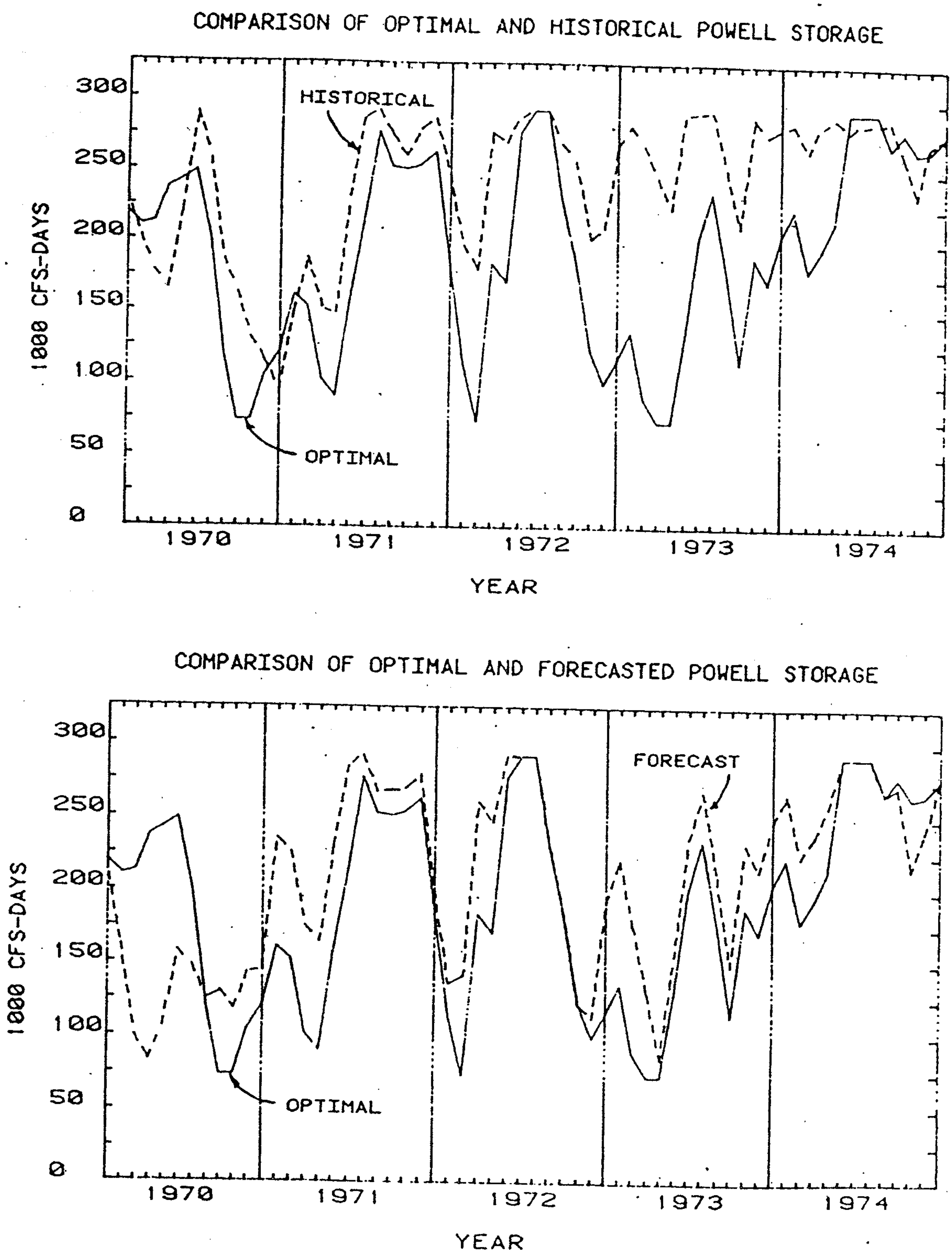

Figure 2. Comparison of Optimal, Historical and Forecasted Powell Storage

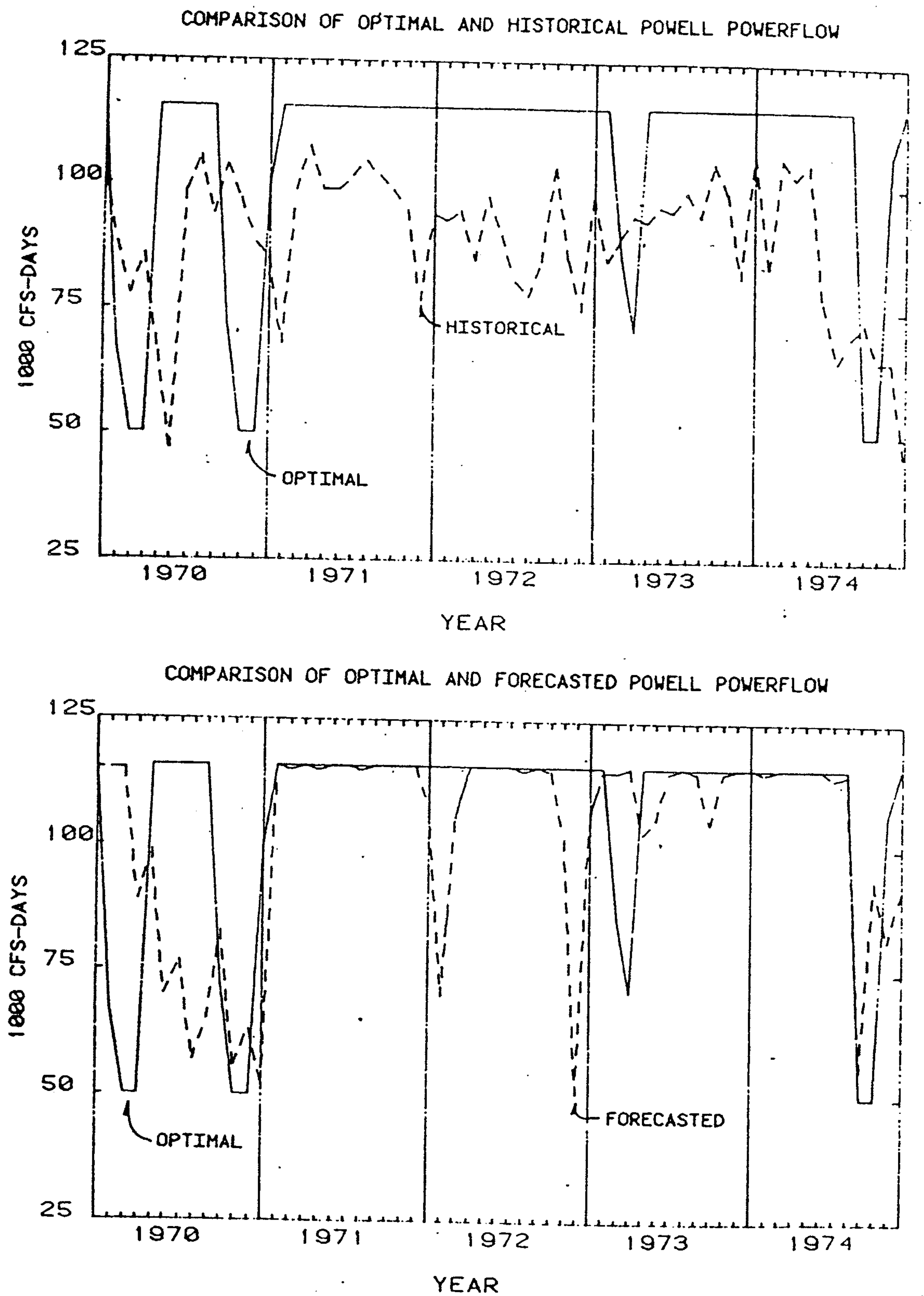

Figure 3. Comparison of Optimal, Historical and Forecasted Powell Powerflow