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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of Southern California Edison Company (U-338-E) for a certificate that the present and future public convenience and necessity require or will require that applicant convert to pumped-storage operation the Balsam Meadow hydroelectric project located in Fresno County, California.	Application 86-07-033 (Filed July 11, 1986)

Carol B. Henningson and Michael D. Mackness, Attorneys at Law, for Southern California Edison, applicant.
John D. Quinley, for Cogeneration Service Bureau, interested party.
James E. Scarff, Attorney at Law, for the Division of Ratepayer Advocates.

I N D E X

OPINION

Summary

By this decision we grant Southern California Edison Company (applicant or SCE) a certificate of public convenience and necessity (CPC&N) to convert and to operate its Balsam Meadow project in a pumped-storage mode. A pumped-storage mode will enable applicant to purchase economy energy during off-peak hours, store that energy in the form of water that has been pumped into a forebay, and use that water during on and mid-peak periods to extend the hours of energy generation of the hydroelectric project.

Background

Before discussing the issue resolved in this decision, we will summarize briefly the nine-year CPC&N process that applicant embarked on for its BMPS project.

In 1981 SCE requested authority to construct and operate a hydroelectric powerhouse of up to 200 megwatts (MW) capacity to be used primarily as a quick-start unit for meeting short daily periods of demand or peaking demand. The project identified as the Balsam Meadow Hydroelectric project, located between Huntington and Shaver Lakes approximately 45 miles northeast of Fresno, included a dam and forebay, underground waterways, an underground powerhouse, a substation at surface level, a 4.5-mile transmission line, and supporting facilities.

Decision (D.) 82-06-051 granted applicant a CPC&N to construct the project. However, the decision ordered that further hearings be held to address the project's optimum generating capacity. Subsequently, by D.83-10-031, applicant was granted a CPC&N for a 200 megawatt hydroelectric peaking facility with a $321 million construction cost cap.

Applicant's civil construction contractor began work on the project November 1, 1983. Civil construction of the forebay dam began in the spring of 1984, and the transmission line in 1986.

The powerhouse, including the unanticipated installation of steel lining in the lower power tunnel, was completed on August 1, 1986. Mechanical, electrical, and instrumentation work commenced on that date.

The project's pre-commercial activities began in the fall of 1986 with the filling of the water-bearing elements. The initial turbine spin occurred in July 1987, and the synchronization to applicant's electrical system occurred in August 1987. Commercial operating criteria were met on December 1, 1987, one month ahead of schedule.

A design feature of the project enables the project to be converted to a pumped-storage operation by installing pumping equipment in the existing underground powerhouse and extending the tailrace tunnel outlet/intake structure in Shaver Lake by 20 feet. However, because SCE had no specific plans to operate the project in a pumped-storage mode, D.83-10-031 did not provide applicant authority to convert the project to a pumped-storage mode. Instead, it required SCE to file a separate application requesting a CPC&N to convert and to operate the project in a pumped-storage mode at the time planned to operate the project in the pumped-storage mode. Applicant was also required to prepare a proponent environmental analysis.

Subsequently, in 1986, applicant firmed-up its plans and filed Application 86-07-033 for a CPC&N to convert and operate the project in the pumped-storage mode. Applicant proposed a two-phase installation/construction schedule in order to minimize interference with the operation of the flow-through portion of the project. First, the outlet/intake structure would be extended. Second, the control equipment would be installed in the powerhouse.

By D.87-07-079 SCE was granted a CPC&N for immediate installation of the outlet/intake structure to the project as well as authority to recover the installation cost as a component of plant held for future use. Because testimony and evidence did not substantiate that the pumped-storage conversion is cost-effective, applicant was not given authority to proceed with the second phase of construction or to operate the project in the pumped-storage mode. The application was kept open so that applicant could submit information justifying the cost effectiveness of the pumped-storage conversion.

D.87-07-079 endorsed the use of the life-cycle cost and first-year cost-effectiveness tests adopted in D.85-07-022 and D.86-07-004, the latter two decisions establish guidelines for identifying avoided resource additions and measuring avoided costs, to determine whether it is cost-effective to operate the project in the pumped-storage mode. The 1987 decision affirmed that these tests are the tests used in the long-run Standard Offer 4 proceeding to define the least-cost resource plan for all electric utilities.

D.87-07-079 also concluded that conversion of the project to a pumped-storage mode would not produce an unreasonable burden on natural resources, community values, aesthetics of the area, public health and safety, air and water quality in the vicinity of park, recreational, and scenic area, historical sites and buildings, or archaeological sites. Accordingly, the negative declaration prepared by DRA was adopted.

<u>Motion</u>

On January 26, 1990 applicant filed a motion for a decision authorizing it to complete construction of the Balsam Meadow pumped-storage facility (BMPS) and for authority to operate the project in the pumped-storage mode. The motion represents that BMPS is an energy efficient enhancement of the existing hydroelectric facility which does not add capacity to applicant's system.

Applicant proposes to begin operating in the pumped-storage mode in 1991. However, to do so, SCE needs to begin its contractor bidding process in August for the installation of a pony motor to reverse the turbine into pumping mode and of certain control equipment so that it may award the contract in the summer of 1990. Applicant estimates that it will cost approximately $4.5 million, less than one and one-half percent (1-1/2%) of the total project cost. Accordingly, applicant requests that a decision be issued as soon as possible. Incorporated as a component of the motion was a report detailing the cost effective analysis of the project.

Protest

On February 23, 1990 the Division of Ratepayer Advocates (DRA) filed a protest to applicant's motion. DRA disputes applicant's claim that the project is cost-effective and requested, among other matters, that evidentiary hearings be held so that DRA could introduce its own economic analysis of the proposed pumped-storage conversion.

Hearings

A prehearing conference (PHC) was held on March 23, 1990 in San Francisco. Discussed at the PHC was the scheduling of evidentiary hearings and a motion filed by DRA on March 21, 1990 regarding applicant's failure to identify in the Biennial Resource Plan Update (BRPU) proceeding any mention of applicant's proposed conversion project. Although interested parties had not yet received their mailed copy of the motion, courtesy copies were available at the PHC. The BRPU proceeding is used to update long-term forecasts and to address generic issues related to utility purchases of electricity from nonutility energy producers, termed "qualifying facilities" or "QFs".

DRA did not recommend that the BMPS project be consolidated with the BRPU now. However, DRA recommended that applicant be required to prepare an analysis of its cost-effectiveness. Applicant and DRA discussed the merits of various production cost models and concluded that the "SERASYM" model was preferred over the "ELFIN" model being used in the BRPU. This is because ELFIN is a load duration curve model which, by its design, cannot easily model generating units which turn on and off on a daily basis or several times a day. SERASYM is a production cost model designed to look at events occurring in chronological sequence during a day. Applicant and DRA agreed that applicant would prepare and introduce into evidence a cost-offectiveness analysis of the project using SERASYM.

Evidentiary hearings were set for the week of June 11, 1990 in San Francisco. However, only two days of hearings were used. Hearings were concluded on June 12, 1990. Mark Minick (Minick), John Ballance (Ballance), and Stephen McKenery (McKenery) testified for applicant. Minick is a supervisor of applicant's planning group in the Engineering, Planning, and Research Department. Ballance is a power resource engineering manager of applicant's system operation organization of the Power Supply Department. McKenery is the project manager for the BMPS project in applicant's power resource engineering organization.

Denise Mann (Mann), a regulatory specialist with DRA's Energy Resources Branch testified for DRA. The proceeding was submitted upon the receipt of concurrent briefs on June 29, 1990.

Issue

The issue in this proceeding is whether BMPS is cost-effective. SCE introduced into evidence two studies to support its claim that BMPS is cost-effective. The first study is based on the first year and projected life tests identified in D.87-07-079. The second study is based on the SERASYM model.

First Year and Projected Life Tests

The first-year cost-effectiveness test adopted in D.85-07-022 and D.86-07-004 determines the first year in which the benefits of a proposed resource exceed the costs of adding a specific resource. The first year that benefits exceed costs is assumed to be the year that the project should commence operation.

Applicant's BMPS first-year test shows that the first-year benefit-to-cost ratio of 2.3 to 1 demonstrates that the project is cost-effective. Applicant's test shows that BMPS will produce a first-year benefit of $0.94 million compared to a first-year cost of $0.40 million. The $0.94 million benefit consists of $0.28 million net energy cost savings, a $0.30 million operation and maintenance (O&M) savings and $0.36 million of other operational cost benefits.

The levelized cost-effectiveness test, also adopted in D.85-07-022 and D.86-07-004, compares the benefits and costs on a levelized basis over the expected life of the project. Applicant evaluated BMPS over its 60-year economical life, analyzing levelized energy benefits and costs, O&M, benefits and costs, other operational benefits, and capital costs.

Applicant's analysis shows that BMPS will produce a $3.37 million total annual levelized benefit compared to a levelized cost of $0.76 million. The levelized benefits consists of a $1.25 million energy benefit, a $0.53 million incremental O&M cost savings, and a $1.59 million operational benefit. This test shows that BMPS has a benefit-to-cost ratio of 4.4 to 1 on a levelized basis.

Applicant also performed a parametric assessment to test the robustness of the first-year and levelized tests calculation by varying the values of certain input assumptions, including gas price and the ratio of applicant's off-peak incremental to off-peak economy purchases. The results were the same: a cost-effective project.

In its first year and levelized analyses, SCE quantified four operational benefits associated with BMPS. These additional benefits are expected to be achieved by purchasing lower cost energy at night and displacing higher cost energy during the day. Applicant's projected additional savings are derived from fixed O&M, ramping, no-load fuel, and spinning reserve.

Fixed O&M Savings

Energy produced by the pumped-storage conversion will displace energy production from primarily oil and gas units thereby reducing thermal stresses on applicant's oil/gas-fired generation plants and reducing system O&M costs. Additional benefits are expected to be realized from reduced O&M costs stemming from emission control associated with energy production from oil/gas-fired generation.

Applicant derived a net O&M benefit of $300,000 in the first year and $530,000 annually over the project life by subtracting BMPS O&M costs from the savings resulting from lower O&M requirements and reduced emission control costs on oil/gas fired units.

Ramping Savings

Ramping is a rapid change in energy load during a short period of time. When water levels are low during the months of October through March the total efficiency of water usage is optimized by using hydro units for peaking purposes only. Low water conditions only allow energy to be produced for two to four hours per weekday through the Big Creek System. Because Balsam Meadow currently has inadequate water to operate all the peak hours additional non-firm energy is purchased to supplement Balsam Meadow production.

Applicant expects to attain a $75,150 cost savings in the first year of BMPS conversion by lessening the purchase of additional non-peak energy. This estimate captures the savings in cost for non-firm energy to assist in controlling energy ramping requirements. It does not include either the cost to pump or the value of energy produced during the mid peak period as these benefits have previously been captured.

No-Load Fuel Savings

Applicant starts and operates sufficient generating capacity on a daily basis to meet its expected baso and peak load requirements and to provide spinning reserve. Since peaking and load capacity is provided by oil/gas fired generation, applicant needs a 215 MW oil/gas fired unit to operate at its minimum during non-peak load hours when its capacity is not needed.

No-load fuel is the amount of fuel needed to heat a unit and to operate the boilers at an idle while not generating electricity. Additional start-up and no-load fuel costs are associated with the oil/gas fired units because they cannot be cycled off at night. Applicant proposes to use BMPS, which can easily be cycled off at night, thereby reducing no-load fuel costs.

Applicant projects that increased generation from BMPS during the on/mid peak period would reduce fuel consumption by approximately $157,000 in the first year of operation.

Spinning Reserve Savings

Balsam Meadow is currently operated at 10MW for spinning reserve approximately two hours each weekday during October through March because of low water levels. Its power efficiency at 10 MW is only 330 kWh per acre-foot of water released compared to full production which produces 1,156 kWh per acre-foot. Therefore, to operate the unit for two hours per day for four months results in energy loss and reduced efficiency.

Spinning reserve results from spinning Balsam Meadow's turbine at full speed, even though it is not generating the maximum amount of additional power, so that electricity may be generated quickly, as demanded.

Applicant explains that by converting Balsam Meadow to pumped-storage capability the unit would be able to run at its maximum load point and increase the efficiency of water release resulting in savings of $120,000.

SERASYM Model

Although applicant prepared an analysis based on SERASYM at the request of DRA, applicant does not recommend the use of this model for small projects such as BMPS, which is designed to produce only 43 gWh in 1991, approximately 0.05 percent of applicant's total energy requirement. This is because the model with an accuracy rate of plus or minus two percent cannot accurately measure the impact of contributing less than one percent of the total energy needs. Nevertheless, applicant used the SERASYM model for the project.

Applicant's analysis using SERASYM production cost model suggests that the BMPS project is cost-effective in every year starting with 1991. The SERASYM analysis predicts production cost benefits from the project that are slightly higher than those estimated by applicant in its first test discussed previously. The O&M benefits of $586,000 is $19,000 more than the previous production cost and O&M benefits test. The first year benefit to cost ratio is 2.0 to 1, and the levelized benefit to cost ratio is 2.1 to 1.

For the purposes of this analysis, applicant introduces two modifications to the SERASYM model. First, QF payment charges were excluded from the model and benefits not captured in the SERASYM model were incorporated as an adjustment outside of the SERASYM model.

Exclusion of QF Payments

The SERASYM model estimates the costs of all resources in the dataset. Applicant demonstrates that if the QF payments remain in the SERASYM model system, efficiency improvements can increase the forecast of payments to a very large block of QFs. This is because the SERASYM model links various QF contract prices directly to the hourly marginal cost.

Applicant does not believe that potential efficiency improvements should be ignored simply because a model shows that QF payments may increase due to efficiency improvements. Since various QF contract prices are linked directly to the hourly marginal cost and since QF payments will not be dotermined or changed as a result of this application, applicant excluded QF payments.

Other Benefits

Applicant testified that the SERASYM model does not capture all the benefits associated with BMPS. To accurately perform the first-year test, applicant added benefits from fixed O&M savings, ramping, reduced no-load fuel, and spinning reserves. These are the same additional benefits that applicant incorporated into its first test previously discussed.

Fixed O&M benefits were added as an adjustment because the SERASYM model is not designed to determine these savings. Minick's prepared testimony incorporated a letter from Sierra Energy and Risk Assessment, Inc. (SERA), developer of SERASYM, confirming that fixed O&M benefits are not captured in the model, Appendix C to Exhibit B.

Minick also explained that SERASYM does capture ramping costs and benefits to the extent that BMPS defers the start-up and/or shutdown of thermal units during ramping periods. However, SERASYM's analysis is limited to turning units on and off only on an hourly basis. Since BMPS ramping decisions are made over a shorter interval, 20 minute intervals, ramping results via the model would not accurately reflect the BMPS project. Therefore, applicant calculated ramping benefits outside of the model.

SERASYM reflects the results of fuel needed to start-up or to maintain a unit at minimum load. Minick testified that the model only reflects 50 Btus of start-up fuel and ignores approximately 600 Btus of no-load fuel. Therefore, applicant calculated no-load fuel benefits outside of the model.

SERASYM cannot operate the project at 10 MW for flow-through at decreased efficiency for a fixed number of hours per day. Since the unit currently operates at 10 MW for approximately two hours each weekday, applicant calculated spinning reserve benefits outside of the model.

Also, at DRA's request, applicant performed a sensitivity for the year 1991 which assumed average precipitation with subnormal runoff, resulting in lower production from all Big Creek generation. The increased production cost benefits resulting from this sensitivity raise the 1991 first year benefit to cost ratio to approximately 2.4 to 1.

<u>DRA's Analysis</u>

DRA supports the tests and standards adopted in D.86-07-004 with regards to proposed utility-owned projects. It believes that the project must be tested for first-year cost-effectiveness using a production cost model. It also believes that a project which passes a first-year test must also pass a life-cycle test, and must then demonstrate a benefit-cost ratio superior to other potential resource additions.

Mann used BRPU proceeding standards for assessing the benefits and costs of the BMPS project. Although DRA used applicant's numbers, DRA neither endorses nor challenges any of applicant's numbers.

Based on its analysis, DRA finds that the project is not cost-effective. The following tabulation prepared by Mann compares the results of DRA's and applicant's SERASYM analysis by comparable categories for the first-year test.

1991 Average Water Year

Item	DRA	Applicant
	(Dollars in Thousands)	
Production Cost Benefit		
Cost Reduction Per SERASYM	$417	$417
Transmission Line Loss	-2	-2
Benefits Per SERASYM	415	415
Benefits Outside SERASYM Model		
Removal of QF payments	0	107
Fixed O&M	0	66
Ramping	0	75
No-Load Fuel	0	157
Spinning Reserve	0	120
Total Benefits Outside SERASYM Model	0	525
Total Benefits	415	940
Project Costs		
New Construction	401	(401
Plant Held For Future Use	75	0
O&M Cost Outside SERASYM	115	50
Total Costs	591	451
NET BENEFITS	$-176	$489

DRA and applicant differ in their calculations of benefits outside the SERASYM model and project costs. Although not reflected in the tabulation, there is also a difference in transmission line loss discussed below.

DRA excluded applicant's alleged benefits outside of the model because it believes that the benefits are captured in the model and that if these benefits are added again the benefits would be double-counted. To the extent that some of these benefits may not be captured in the model, Mann argues that it is nearly impossible to evaluate the net effect of these features based on applicant's analysis.

<u>QF Payment Difference</u>

Mann disagreed with SCE's decision to disregard the impact of the project on QF payments because the operation of BMPS would raise the cost of applicant's payments to QFs under existing contracts which base payments on applicant's marginal cost for off-peak energy.

QF payment formulas are determined in the BRPU proceedings and the payment amounts are set in ECAC (Energy Cost Adjustment Clause) proceedings. Although the authorization of applicant's request will not change the QF formula or QF payments, the operation of BMPS will lead to an increase in QF payments under the current payment formula because the operation of this project in the pumped-storage mode will impact applicant's marginal cost for off-peak energy. As Mann explained, recognition of QF payments was given in applicant's Devers-Palo Verde II proceeding, D.88-12-030. We concur with DRA that QF impacts should be reflected in the cost-effectiveness analysis of BMPS.

<u>Fixed O&M Difference</u>

Although DRA did not allow for any fixed O&M savings, Mann confirmed that such savings are not determinable by SERASYM. Only variable O&M benefits are captured in the model. However, Mann did acknowledge that if there are any fixed benefits that such benefits should be captured as an adjustment outside the model.

Minick explained that fixed O&M savings could be captured in the SERASYM by adding a 3 mill credit to the applicable units as recommended by SERA, Exhibit B, Attachment C. However, Minick chose to calculate fixed O&M savings outside of the model because the applicable generating units were not identified at the time. Minick explained that these additional benefits capture maintenance changes which result from the displacement of oil/gas fired generation facilities having Selective Catalytic Reduction equipment (SCR). Since fixed costs for SCR installation are in addition to the variable cost for operating those resources, Minick separated some of the SCR cost into variable and fixed costs.

Flue gas flowing over the SCR reacts with ammonia, a by-product of UREA injected into the boiler flue downstream from the combustion zone, for NOX reduction. UREA is a water soluble commercial fertilizer. Over time the catalyst will be exhausted requiring replenishment. However, by providing energy from other resources, the cost for the chemical UREA and the replenishment of catalyst can be reduced.

Because BMPS is intended to displace oil/gas fired generation with SCR equipment, it is reasonable to expect that fixed and variable O&M emission control costs associated with the production of these units will decrease. However, Minick also testified that the SCR equipment would not be installed until 1993. It is not reasonable to include fixed cost benefits associated with SCR until the equipment is installed in 1993. Since applicant has not demonstrated that it will defer any additional O&M fixed cost in 1991 or in 1992 no such benefits should be reflected in the cost-benefit analysis until the SCR equipment is installed.

DRA acknowledged in its comments to the ALJ proposed decision that if fixed cost benefits is recognized, at the very least, the 20 gWh of energy produced from SCE's own system gas unity to pump at Balsam Meadow should offset the 43 gWh of Balsam Meadow generation.

We concur with DRA and will adopt a O&M fixed cost benefit of $69,000 (43 gWh - 20 gWh x 3 Mil/kWh) starting in 1993 when the SCR equipment begins operating.

<u>Ramping Difference</u>

Applicant and DRA concur that the model's dispatch logic is restricted to turning units on and off only on an hourly basis by price. However, applicant's Ballance and Minick testified that decisions for BMPS ramping are made over a 20-minute interval of time, ten minutes before the hour and ten minutes after the hour.

Since SERASYM's smallest increment of input is an hour and BMPS ramps over a 20-minute increment of time, the model is not capable of adequately capturing costs or benefits associated with BMPS ramping. Applicant calculated its ramping benefit outside of the model.

DRA finds no justification to credit BMPS with any ramping benefits outside of the SERASYM model becauso the model credits BMPS with the marginal cost of displaced enorgy, and to the extent that the marginal cost of generation is more expensive than average cost during morning and evening ramps, the model credits BMPS with these extra savings.

DRA's conclusion is consistent with SERA's description of ramping cost and benefits reflected in the SERASYM model, Attachment C of Exhibit B. Although ramping benefits are real, and should be considered in a cost-effective analysis, it is not reasonable to include the same ramping benefits applicant calculated for its first study as an additive to applicant's SERASYM model study which does consider ramping costs and benefits within the model. Absent testimony substantiating that the SERASYM model ignored ramping costs and benefits because BMPS ramps on a 20-minute period compared to SERASYM's limited hour increment, there is no basis for adding additional ramping benefits to the results of applicant's SERASYM test.

<u>No-Load Fuel Difference</u>

DRA rejects applicant's no-load fuel benefit adjustment derived outside of the SERASYM model because DRA believes that such savings associated with BMPS are intended to be captured in the model. No-load fuel is the additional amount of fuel needed to bring a unit above the start mode to a minimum load level to keep the unit heated up and boilers operating without generating any electricity.

However, the SERASYM model does not operate units in the no-load state. Instead, it assumes that any no-load charges are included in the fuel needed for start-up or to maintain the unit at minimum load to keep units operating without generating any electricity. Applicant calculated no-load benefits outside of the model because the SERASYM model only captures 50 Btus of the approximate 600 Btus needed to maintain the unit at the no-load state. Once the unit generates energy, the modol has no way of calculating the 600 Btus of no-load fuel. Applicant's adjustment outside of the model is reasonable and should be adopted in determining the cost-effectiveness of BMPS. However, because SCE based its benefit on 87.87 gWh of additional energy instead of the 43 gWh of additional energy used in its SERASYM run, SCE's $157,000 benefit should be reduced by 50% to $79,000 to reflect the lower amount generated energy.

Spinning Reserve Difference

DRA concurs with applicant that efficiency would be achieved by running the project at full power as opposed to running it in a spinning reserve mode. However, DRA disputes whether applicant would stop running the project in the spinning reserve mode. Even if applicant did stop operating the plant in the spinning reserve, DRA argues that applicant's benefit estimate only reflects the gross benefit and that it fails to consider the additional cost that will be incurred because of applicant's need to operate alternate units as spinning reserve during the period of time that Balsam Meadow previously operated in the spinning reserve mode.

Ballance agrees with DRA that other units would need to supply the spinning reserve previously supplied by Balsam Meadow. However, he did not net out any costs associated with the alternate unit because it would result in lowering the output of oil and gas units to the alternate units thereby pushing them to a lower load point. This lower load point would result in a higher heat rate which should be captured in the net production figures in the SERASYM results.

Although DRA did not specifically state its reason for not believing that applicant would operate Balsam Meadow at full power instead of spinning reserve, it is apparent from the line of DRA's questions that DRA was concerned with the fact that the water level at Shaver Lake has been insufficient for applicant to operate Balsam Meadow as a pumped-storage facility since October 1986.

Ballance explained that the water level was insufficient because of four consecutive years of subnormal rainfall and runoff in the Shaver Lake area. Applicant's results are based on six typical precipitation patterns. They assume the first year is an average year, the second a wet year, followed by a subnormal year, followed by a dry year, followed by a subnormal year, and another average year. It is only in those years when a dry year is followed by another subnormal year that the lake levels would be below the 75,000 acre-feet minimum needed to pump.

The SERASYM model cannot simulate the operation of Balsam Meadow at 10 MW for flow-through at decreased efficiency for a fixed number of hours per day. Therefore, to consider the impact of efficiency, which DRA and applicant concur will result, cost benefits applicable to spinning reserve must be captured outside of the model.

The concern of whether the project will be able to operate in the pumped-storage mode is reasonable. However, in this case, as is true of all models and formulas, assumptions must be made. Applicant projected average water availability based on six typical patterns. This is not new. We have accepted the utilization of average water data in prior energy proceedings to set rates and future energy mix, and have also accepted the utilization of average water data to set rates for water utilities. Applicant's cost-efficiency analysis based on six typical precipitation patterns is reasonable. We find the results of applicant's spinning reserve benefit derived outside of the model to be reasonable.

Plant Held For Future Construction Difference

In D.87-07-079, the Commission approved $75,000 of plant held for future use (PHFU) applicable to the construction of the intake/outlet structure. DRA included this amount as an additional cost on the basis that the first-year test, like the levelized test, is designed to test the cost-effectiveness of the incremental resource cost and because PHFU is not a rate base component earning a return until the project is approved.

In its brief, DRA acknowledges that it erred in stating that PHFU was not yet in rate base earning a return. Irrespective, DRA asserts that the presence or absence of plant in rate base does not determine whether plant costs should be included in a cost-effectiveness test. Therefore, since PHFU is a part of the pumped-storage conversion project, DRA included PHFU in its first-year test.

DRA's reasoning for including PHFU cost in its first-year test is flawed. As explained in D.87-12-077, amounts posted to PHFU may be held in that account for up to 15 years prior to the start of any construction. Even if the project is not approved at this time applicant would still be able to earn a return on the PHFU component. If DRA's reasoning is followed further, all associated Balsam Meadow plant costs, such as land and incremental plant facilities to be used for both flow-through and pumped storage purposes should be allocated to the pumped storage conversion. The purpose of the first-year test is to determine whether a project is cost-effective to expend the incremental cost to bring BMPS on line. Applicant is already earning on PHFU and will continue to earn on it irrespective of whether the project is adopted or not. In other words, PHFU is not an additional cost to this project conversion and should not be reflected in the first-year test.

<u>O&M Outside SERASYM Difference</u>

DRA agrees with applicant that conversion of the project to pumped-storage will increase O&M expenses and accepts applicant's projected increased costs of $50,000 for the first year, $80,000 to $90,000 for the subsequent three years, and a $350,000 balloon payment in the fifth year due to a major overhaul of the project. However, DRA levelized the five year additional O&M cost and recommended that a consistent $115,000 O&M charge be applied to the first-year test. DRA utilized the levelized approach because it was not satisfied that applicant demonstrated that BMPS would only be subject to a first-year O&M cost of $50,000.

Applicant explains in Exhibit A, page G-1 that the maintenance cost on new equipment, such as equipment being proposed in the proceeding, is nominal in the early years of operation. This is because new equipment requires minimum maintenance. As the equipment ages, it is necessary to enhance the maintenance program and to perform equipment overhauls to keep the equipment operating and operating efficiently. For example, the project which became operational as a flow-through facility in 1988 incurred $153,000 of O&M cost on $277 million of facility costs. The first nine months of 1989 O&M costs increased to approximately $194,000.

The purpose of the first-year test is to determine whether a project is cost-effective in the first year of operation. Applicant has presented sufficient evidence into the record to demonstrate that O&M costs in the first years of operation will be nominal compared to the later years of operations. Further, it is not reasonable to expect a new facility to require major overhaul in the first year of operation. Should this occur, we would expect applicant to seek reimbursement from its supplier for defective equipment. Therefore, we will adopt applicant's $50,000 of O&M cost as being a reasonable level of O&M costs for the first year test.

The purpose of the life-cycle test is to compare benefits and costs on a levelized basis over the expected life of the project. Therefore, for the life-cycle test, O&M costs applicable to the major overhaul cost expected to occur in the fifth year of operation should be levelized over the five year period that contributes to the need of the overhaul, as recommended by DRA's witness in Exhibit O. DRA's $115,000, $121,000, $128,000, $135,000, and $143,000 of O&M costs for the 1991, 1992, 1993, 1994, and 1995 year, respectively, should be used in the life-cycle test.

<u>Transmission Line Losses</u>

DRA asserts that applicant's SERASYM model has a "fatal flaw," leaving no valid production-cost model results in the record because applicant did not correctly model transmission line losses within SERASYM.

Applicant in its initial testimony used a 1.9% system average line loss factor, calculated by applicant's transmission people, to estimate the cost of additional transmission line losses in transmitting power up to the project's powerhouse for pumping water up to the forebay. Applicant made no adjustment for line losses from the project to the load center. Applicant assumed that such line losses were reflected in the difference between system-wide loads and demand, consistent with the BRPU process.

Subsequently, at the evidentiary hearing, applicant corrected its line loss figures from 1.9% to 5.1% associated with the pumping and to 7.7% associated with the flows of generated energy from the project. These high levels of line loss are due to the distance between the project and applicant's load center and the other flows simultaneously coming south from the rest of applicant's Big Creek system.

Applicant introduced as part of Exhibit E a table showing that with a 5.1% average line loss from transmitting power up to the project's powerhouse, holding all other factors equal, that the project remains cost-effective. Again, consistent with the BRPU proceeding, line losses that may incur from the project to the load center were assumed to be reflected in the difference between system-wide loads and demand.

Although Minick testified that SERASYM is not capable of projecting all line losses, DRA explained that it is possible to incorporate the impact of losses from the project to the load center. DRA asserts that these additional line losses must be reflected in the SERASYM model to derive a reasonable result of the project.

Because line losses are not considered in the evaluation of proposed generation resources in BRPU and because DRA recommends that BRPU tests should be used to evaluate the cost-effectiveness of this project, line losses should not be considered.

Non-Quantifiable Benefits

Applicant identified three non-quantifiable benefits for consideration. These benefits consist of additional savings during times of natural gas curtailment, increased availability of oil and gas units resulting from allowing BMPS to follow load rather than oil and gas units, and value that BMPS would have in allowing the quick shedding of 200 MW of load during emergencies.

Applicant has used several production cost models and calculations outside of the models to quantify benefits associated with BMPS. To the extent that these benefits are found to be reasonable, they should be considered in determining the cost-effectiveness of BMPS. However, since applicant has not quantified these benefits, they should not be considered a project benefit.

Additional Test

In calculating his estimate of the project's potential fuel savings, Minick used historical average gas costs. This is despite the fact that, Minick acknowledged, the interim decision for the BMPS project stated that the Tier 2 gas rate more reasonably serves as the basis for gas transactions in the BMPS project. Minick also acknowledged that the decision concluded that marginal rather than average costs are the proper measure of the project's potential fuel savings.

Conclusion of Law 68 from the most recent BRPU proceeding (D.90-03-060) stated that until we are able to develop long-run marginal gas costs, the full average cost of gas, including transportation-related gas costs, should be used in determining the cost-effectiveness of resource additions.

Minick's Exhibit E which, among other things, recasted applicant's SERASYM model results to reflect the use of average gas price forecasts instead of marginal gas price forecasts shows that the project remains cost-effective.

On one hand DRA argues that the merits of applicant's BMPS project must be judged on the tests and guidelines set forth in the BRPU, and on the other hand DRA states that it is "outrageous" for applicant to submit its study based on the average price of gas. However, Minick has substantiated that this supplemental testimony is consistent with the current BRPU and that it should be considered to the extent that the project is assessed on the merits of BRPU tests.

<u>Alternative Proposals</u>

DRA asserts that applicant must demonstrate a benefit to cost ratio superior to other potential resource additions to conform to cost-effectiveness tests and standards adopted in D.86-07-004. Applicant's filing and testimony relate to the cost-effectiveness of BMPS only in contrast to the no-project alternative. DRA argues that whatever the merits of BMPS may be, without the alternative analysis, it is impossible to determine or to be assured that BMPS is the best project or combination of resources to meet the needs of ratepayers.

Applicant has consistently maintained that the assumptions and methodology adopted in the BRPU do not apply to the analysis of BMPS and points out that the tests now used in BRPU were adopted one year before the Commission's last decision in the

BMPS proceeding. Applicant argues that if the Commission had intended BRPU analysis to apply in evaluating BMPS, it would have so ordered.

D.87-07-079 directed applicant to use specific assumptions in evaluating BMPS such as a 70% ratio of economy energy prices to gas-fired generation costs and marginal gas costs. Ordering Paragraph 3 of that decision precluded applicant from operating the project in the pumped-storage mode until applicant demonstrated that the project is cost-effective. There was no requirement that BMPS needed to be the best alternative source of energy.

Applicant and DRA agreed at the PHC that applicant would prepare and introduce into evidence a cost-effectiveness analysis of the project using SERASYM. Again, there was no requirement that applicant be required to compare the project to other alternative energy resources. It was not until Mann's testimony was introduced that parties became aware of DRA's position that the project must be compared with alternative energy resources.

The purpose of this phase of the proceeding, established by D.87-07-079, is to determine whether the remainder of this project is cost-effective, not to determine whether this project is the best project or combination of resources available.

<u>Conclusion</u>

Applicant introduced substantial testimony with numerous models and studies to justify the cost-effectiveness of its project. Each of these tests demonstrated that the project is cost-effective, based on applicant's data.

First, applicant introduced a first-year test and levelized test, pursuant to an interim decision authorizing the immediate construction of the outlet/intake structure and conditioned the project on a cost-effectiveness analysis. As part of these tests, applicant conducted a parametric assessment and sensitivity test. Also, at DRA's request, applicant analyzed the cost-effectiveness of an alternative economic scenario based on DRA developed dispatch natural gas forecast and PHFU.

Second, pursuant to an ALJ ruling at the PHC, applicant introduced a first-year test and a levelized test based on the SERASYM model. Again, at the request of DRA, applicant prepared a sensitivity test. In this instance applicant assumed that 1991 had average precipitation resulting in subnormal runoff.

DRA's analysis resulting in its recommendation that applicant not be authorized to operate Balsam Meadow in the pumped-storage mode is primarily based on a comparison of DRA's and applicant's SERASYM analyses for the first-year test and its position that applicant's analysis must be consistent with the BRPU.

The comparative analysis showed a $665,000 spread between DRA's $176,000 projected project loss and applicant's $489,000 projected benefit. Based on a careful scrutiny of applicant's and DRA's testimony we conclude that the first-year SERASYM model results in a $165,000 cost benefit discussed in this decision and summarized below. With the additon of average gas cost savings, this benefit will increase $280,000 to $445,000.

	(Thousands of Dollars)
Benefits Per SERASYM	$417
Benefits Outside SERASYM	
No-Load Fuel	79
Spinning Reserve	120
Total Benefits	616
Less: Project Costs	
New Construction	401
O&M Cost Outside SERASYM	50
Total Project Costs	451
NET PROJECT BENEFIT	$165

This $165,000 net project benefit under the SERASYM first-year test adopted results shows that the project is cost-effective. Although modifications may be needed to applicant's other models and test as a result of our discussion adopting specific components of the SERASYM model, similar cost-benefit results will occur. This is substantiated by applying the benefits and costs adopted in this decision to the first five years of the sixty-year project life, as shown in Appendix A, even without considering the impact of average gas cost savings of from $280,000 to $320,000 per year. The project is cost-effective during each of the five years and results in a yearly average benefit of $71,000.

Therefore, we conclude that applicant's BMPS project is cost-effective based on the first-year test and life-cycle test, and that applicant should be authorized a CPC&N to complete construction of its BMPS facility and to operate the facility as a pumped-storage operation.

DRA recommends that if applicant's motion requesting authority to construct and operate the project in pumped-storage operation is not denied, then applicant should be required to submit updated testimony incorporating the current estimate of transmission line losses directly into the SERASYM production-cost model with a sensitivity analysis showing the economies of BMPS if the proposed applicant and San Diego Gas and Electric merger is approved.

The application of transmission line losses have already been addressed. Therefore, no further discussion is necessary. The recommendation that applicant prepare an analysis of the impact of this project if a pending merger is approved is both too late in the proceeding and inappropriate. Any energy impacts resulting from a possible merger should be addressed in the merger proceeding, not in this proceeding which is considering whether a very small energy project is cost-effective.

Section 311 Comments

The Administrative Law Judge's (ALJ) proposed decision on this matter was filed with the Docket Office and mailed to all parties of record on August 13, 1990, pursuant to Rule 77 of the Commission's Rules of Practice and Procedure.

Timely filed comments were received from SCE and DRA, on September 4, 1990. Reply comments were filed by SCE. We have carefully reviewed the comments, but have not summarized them in this order. To the extent that they required discussion, or changes to the proposed decision, the discussion and changes have been incorporated into the body of this order.

Findings of Fact

1. D.83-10-031 required applicant to file a separate application requesting a CPC&N to convert and to operate the project in a pumped-storage mode.

2. D.83-10-030 also required applicant to prepare a proponent's environmental analysis.

3. A.86-07-033 was filed for a CPC&N to convert and operate the project in the pumped-storage mode.

4. D.87-07-079 granted applicant a CPC&N for immediate installation of the outlet/intake structure to the project and granted applicant authority to recover the installation cost as a component of plant held for future use.

5. D.87-07-079 endorsed the use of the life-cycle cost and first-year cost-effectiveness tests adopted in D.85-07-022 and D.86-07-004.

6. D.87-07-079 concluded that conversion of the project to a pumped-storage mode would not produce an unreasonable burden on natural resources, community values, aesthetics of the area, public health and safety, air and water quality in the vicinity of park, recreational, and scenic area, historical sites and buildings, or archaeological sites.

7. DRA filed a protest to applicant's January 26, 1990 motion for authority to operate the project in the pumped-storage mode.

8. Applicant and DRA agreed that applicant would prepare and introduce into evidence a cost-effectiveness analysis of the project using SERASYM.

9. Appicant's BMPS first-year test showing a first-year benefit-to-cost ratio of 2.3 to 1 demonstrates that the project is cost-effective.

10. Applicant's levelized test shows that BMPS has a benefit-to-cost ratio of 4.4 to 1 on a levelized basis.

11. Applicant quantified and included four operational benefits associated with BMPS in its first year and levelized analysis.

12. Applicant's SERASYM cost model shows that the BMPS project is cost-effective in every year starting with 1991. The first year benefit to cost ratio is 2.0 to 1, and the levelized benefit to cost ratio is 2.1 to 1.

13. Applicant incorporated two modifications into its SERASYM model results. Applicant excluded QF payment charges from the SERASYM model and including benefits not captured in the SERASYM model as an adjustment outside of the SERASYM model.

14. At DRA's request, applicant performed a sensitivity for the year 1991 which assumed average precipitation with subnormal runoff. The increased production cost benefits resulting from this sensitivity raise the 1991 first year benefit to cost ratio to approximately 2.4 to 1.

15. Based on DRA's analysis, DRA finds that the project is not cost effective.

16. The operation of BMPS will lead to an increase in QF payments under the current payment formula.

17. Fixed O&M savings are not determinable by SERASYM.

18. SCR equipment will not be installed until 1993.

19. SERASYM's dispatch logic is restricted to turning units on and off only on an hourly basis by price.

20. BMPS rampings are made over a 20-minute interval of time.

21. SERASYM credits BMPS with the marginal cost of displaced energy, and to the extent that the marginal cost of generation is more expensive than average cost during morning and evening ramps, the model credits BMPS with these extra savings.

22. The SERASYM model does not operate units in the no-load state.

23. Efficiency would be achieved by running the project at full power as opposed to running it in a spinning reserve mode.

24. The water level at Shaver Lake has been insufficient for applicant to operate Balsam Meadow as a pumped-storage facility since October 1986.

25 Applicant's spinning reserve results are based on six typical precipitation patterns.

26. The SERASYM model cannot operate Balsam Meadow at 10 MV for flow-through at decreased efficiency for a fixed number of hours per day.

27. We have accepted the utilization of average water data in prior energy proceedings to set rates and future energy mix, and have also accepted the utilization of average water data to set rates for water utilities.

28. Applicant's spinning reserve benefit derived outside of the model should be adopted.

29. PHFU is in rate base earning a return.

30. Even if the project is not approved at this time, applicant would still be able to earn a return on the PHFU component.

31. Maintenance cost on new equipment, such as equipment being proposed in the proceeding, is nominal in the early years of operation.

32. The first-year test determines whether a project is cost-effective in the first year of operation.

33. SERASYM is not capable of projecting all line losses.

34. Line losses are not considered in the evaluation of proposed generation resources in the BRPU.

35. Applicant identified three non-quantifiable benefits for consideration.

36. Applicant has used several production models and calculations outside of the models to quantify benefits associated with BMPS.

37. D.90-03-060 requires that the full average cost of gas, including transportation-related gas costs, be used in determining the cost-effectiveness of resource additions.

38. D.87-07-079 directed applicant to use specific assumptions in evaluating the BMPS project.

39. There was no requirement that applicant be required to compare the project to other alternative energy resources.

40. The total estimated cost of converting the Balsam Meadow hydroelectric facility to pumped-storage operation is approximately $5 million.

<u>Conclusions of Law</u>

1. QF impacts should be reflected in the cost-effectiveness analysis of BMPS.

2. SCR fixed cost benefits should not be reflected in the cost-benefit analysis until the SCR equipment is installed.

3. Since the SERASYM model calculated ramping costs and benefits, additional ramping benefits should not be added outside of the model.

4. Applicant's no-load fuel adjustment desired outside of the model should be adopted.

5. PHFU should not be imputed as an additional cost to this project conversion and should not be reflected in the first-year test.

6. O&M costs in the first years of operation should be nominal compared to the later years of operations.

7. O&M costs should be averaged for the life-cycle test.

8. Transmission line losses should not be considered in assessing the cost-effectiveness of BMPS.

9. Since applicant has not quantified or substantiated non-quantified benefits, they should not be considered a project benefit.

10. Applicant's supplemental testimony which utilizes average gas prices is consistent with the current BRPU and should be considered to the extent that the project is assessed on the merits of BRPU tests.

11. A CPC&N should be granted to applicant to convert and to operate the Balsam Meadow hydroelectric facility as a pumped-storage operation.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company is granted a certificate of public convenience and necessity to convert and to

operate its Balsam Meadow Hydroelectric Powerhouse as a pumped storage operation.

2. This proceeding is closed.

This order is effective today.

Dated SEP 12 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
PATRICIA M. ECKERT
Commissioners

Commissioner John B. Ohanian, being necessarily absent, did not participate.

I will file a written concurring opinion.
/s/ FREDERICK R. DUDA
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

Neal J. Shulman
NEAL J. SHULMAN, Executive Director
pb

APPENDIX A

ADOPTED RESULTS APPLIED TO THE FIRST FIVE YEARS OF OPERATION

	1991	1992	1993	1994	1995
	(Thousands of Dollars)				
Benefits Per SERASYM	$417	$351	$318	$360	$419
Benefits Outside SERASYM					
No-Load Fuel	79	85	90	100	110
Reduced Fixed O&M	NA	NA	69	69	69
Spinning Reserve	120	130	140	150	160
TOTAL BENEFITS	616	566	617	679	758
LESS: Project Costs					
New Construction	401	420	450	470	500
O&M Cost Outside SERASYM	115	121	128	135	143
TOTAL PROJECT COSTS	561	541	578	605	643
NET PROJECT BENEFIT	$100	$ 25	$ 39	$ 74	$115

(END OF APPENDIX A)

FREDERICK R. DUDA, Commissioner, concurring.

The Commission has been and continues to move forward with developing an integrated and comprehensive process for approving future resource needs through the Biennial Resource Plan Update (BRPU) proceedings for each utility's service area. This decision which grants Southern California Edison Company (SCE) a certificate of public convenience and necessity (CPCN) to convert and to operate its Balsam Meadow project in a pumped-storage mode is a unique instance where a new resource addition has been considered outside of the BRPU process.

SCE's efforts to receive regulatory approval for this project date to July 1986, A.86-07-033. In decision D.87-07-079 SCE was authorized a CPCN for the limited purpose of installation of the outlet/intake structure. The Commission in that order did not authorize SCE to proceed with other aspects of the pumped storage unit at that time because SCE had not shown the project to be cost effective. The authority for some limited structural installation was given because of the major cost of retrofitting the facility in the future would have made the pumped storage upgrade less cost-effective. As such, the decision left open A.86-07-033 "for the purpose of receiving Edison's submittal justifying the cost-effectivenss of the pumped storage conversion."[1] It is for this reason that today's decision considers the cost-effectiveness of the pumped storage project at Balsam Meadows in isolation from the BRPU process. I concur with the finding[2] is this decision that there was no requirement to compare the Balsam Meadows Pumped Storage project to other

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1 Ordering paragraph 2 in Decision 87-07-079
2 Finding of Fact #39 in Decison 90-09-048.

alternative energy resources. However, I strongly believe that any future resource additions should be dealt with through the BRPU process. It is only by examining various projects in a side-by-side comparison that ratepayers will be assured of receiving the most cost-effective resource additions.

Although this project was not examined as part of the BRPU process, this did not mean that the Commission was not interested in having the cost effectiveness of this project tested against rigorous analytical procedures. I want to recognize the Division of Ratepayer Advocates' (DRA's) diligence in applying the analytic principles of the BRPU process to its investigation of this project. DRA's effort in this regard resulted in a more exacting and accurate record for the Commission. It is through this type of analysis that the Commission is able to assess the costs and benefits associated with a particular project, such as the pumped storage unit at Balsam Meadows. The "back-of-the-envelope" analysis performed by SCE in its application does a disservice to the Commission in its pursuit of its public responsibilities. In contrast, DRA's insistence that rigorous analytic techniques be used to examine the cost-effectiveness of this project provided the Commission a more complete picture of the costs and benefits, and thereby allowed the Commission to more accurately weigh the risks associated with its decision today. I want to encourage DRA's efforts in this regard in future investigations of plant expansions by the utilities.

One of the risks associated with this project is related to the weather. This decision is based on a typical six year precipitation pattern with an assumed average precipitation in the first year. Given the four consecutive years of drought experienced in California, some reservations have been expressed whether or not average year precipitation was a reasonable assumption to make in this proceeding. However, the Commission in numerous other energy proceedings uses an average weather assumption for rate making purposes. Given the high degree of uncertainty associated with forecasting the weather, I believe it is reasonable that the Commission assume average weather conditions when factoring in its effect on a project's cost-effectiveness. To do otherwise opens the door to both analysts and decision-makers using weather as a factor by which to impose their own biases into the discussion. The facts of a case should not be subjugated to a debate on weather forecasts.

Frederick R. Duda

Frederick R. Duda, Commissioner

September 12, 1990
San Francisco, California