

VALUE OF SERVICE RELIABILITY

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Abstract—This paper presents the value of service (VOS) reliability evaluation approach that explicitly incorporates into the planning process customer choices regarding reliability “worth” and service costs. Using the least-cost planning framework, and taking advantage of the recent advances in the quantification of outage costs, our approach determines the optimal level of reliability for the utility and its customers. The approach considers system operational measures—the so-called emergency actions—that the operators invoke in times of dwindling reserves. Information on customer outage costs associated with such actions is incorporated using a probabilistic framework. This approach permits utilities to plan for levels of reliability commensurate with the customers’ willingness to pay. The application of this methodology to planning problems is discussed. Numerical results for a large utility are presented.

Keywords—value-based planning, power system generation reliability, customer outage costs, least-cost planning.

INTRODUCTION

As the electric utility industry enters an increasingly competitive environment, utilities must concern themselves with the market value of the services they provide and the cost of providing those services. At the same time, utilities are still burdened with the obligation to serve their customers’ loads with adequate reliability. Utilities must undertake new investments in demand-side and supply-side resources to meet this obligation. In light of the economic pressures facing utilities, these investments must be evaluated in terms of their reliability “worth” as well as costs. Consequently, appropriate reliability planning criteria must be used to fully account for the cost-effectiveness of these investments in resources. This paper discusses the development of such a criterion and its practical implementation into a methodology for the economic evaluation of reliability. This approach permits utilities to plan for levels of reliability commensurate with the consumers’ willingness to pay.

Historically, reliability planning criteria have been based on engineering judgment. The earliest criteria used purely deterministic measures such as the single largest contingency and percentage reserve margin. Probabilistic reserve criteria subsequently based on the evaluation of the loss of load probability (LOLP) and, in certain cases, the expected unserved energy (EUE) were developed. Probabilistic criteria have become

widely adopted in recent years by the utility industry. A common industry yardstick is the 1 day in 10 years LOLP. As a linkage to the past, the probabilistic reliability measures are generally expressed in terms of the reserve margin.

Traditional deterministic and probabilistic criteria have failed to consider within an integrated framework the utility’s costs of providing a particular level of service reliability on the one side, and the customers’ costs associated with that reliability level on the other side. The methodologies used in these reliability criteria cannot evaluate the economic impacts of changing levels of reliability for the utility and its customers. Consequently, they cannot determine the optimal level of reliability. There is much arbitrariness to the criteria currently in use. For example, it is difficult to determine from a societal point of view whether a 1 day in 10 years LOLP is more appropriate than 1 day in 5 years or 1 day in 20 years.

The economic evaluation of reliability requires the determination of reliability “worth” from the customers’ point of view and its explicit incorporation into the planning process. The basic approach to measuring reliability “worth” is in terms of customer outage costs. There is a growing body of work concerned with the value of outages throughout the world. [1],[5],[6],[8],[9]. However, the integration of this information into the resource planning framework has yet to be widely adopted in the utility industry.

An early attempt at incorporating reliability “worth” in planning is in [2]. The EPRI Over/Under Model [4] implemented the concepts into a production grade program. However, adoption of these concepts was hindered due to a lack of utility-specific data on customers’ outage costs.

This paper presents an approach to reliability evaluation that explicitly incorporates into the planning process customer choices regarding reliability “worth” and service costs. We refer to this approach as value of service (VOS) reliability. Using the least cost planning framework and taking advantage of the recent advances in the quantification of outage costs, our approach determines the optimal level of reliability for the utility and its customers. A basic building block of the VOS reliability concept is the EUE. Our approach considers system operational measures—the so-called emergency actions—that the operators invoke in times of dwindling reserves. Information on customer outages costs associated with such actions is incorporated to determine optimal cost-effective reliability levels. Although a probabilistic framework is used, we can express the system requirements to meet the VOS reliability criterion in terms of the deterministic measure reserve margin. This allows the comparison of VOS reliability with traditional approaches.

The paper has six additional sections. We start with a section describing the derivation of the VOS reliability criterion using the least-cost planning framework. The next section provides details on the VOS reliability evaluation techniques. We continue with a section discussing data requirements and acquisition for VOS reliability. Typical applications of the VOS reliability approach are then given. We devote a section to

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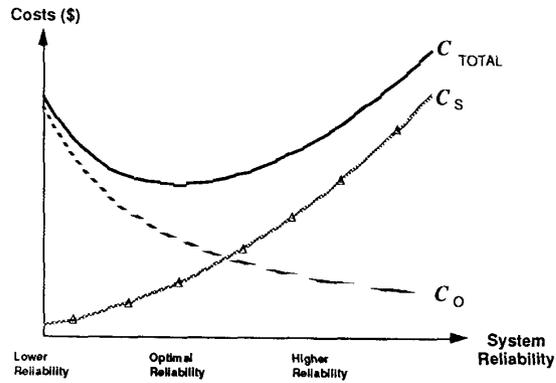


Figure 1. The variation of costs as a function of reliability.

discussing the implementation of the VOS reliability approach and present numerical results. In the final section, we discuss the strengths and limitations of the approach and extensions to possible future applications.

VOS RELIABILITY IN THE LEAST COST PLANNING FRAMEWORK

Least-cost planning requires the joint consideration of reliability and economics within the framework of constraints under which the utility operates [15]. The least cost plan is the resources plan that minimizes the total costs of electric service over the planning horizon. From a societal perspective, the total costs of electric service are given by

$$C_{TOTAL} = C_S + C_O$$

The first term C_S represents the costs associated with serving the load, such as capital investment expenditures and production costs to supply energy. They include the fixed and variable costs for both demand-side and supply-side generation. The customer sees supply costs in the form of electric rates for services received. The second term C_O represents the costs incurred by customers when the utility is unable to meet their demand. Typical examples include food spoilage, loss of leisure activities for residential customers or lost production for industrial customers. Figure 1 illustrates the nature of the two component costs C_S and C_O as a function of reliability. If the utility reduces its supply costs by reducing reliability (e.g., by lowering reserve margins, or allowing a deterioration in the availability of its existing units) expected customer outage costs increase. On the other hand, the utility can increase reliability and reduce expected customer outage costs. However, this improvement requires new investment expenditures, thereby increasing C_S .

In broad terms, it follows from the necessary conditions for optimality that at the optimal reliability level the least cost plan has the attributes that

- Any additional investment in reliability should not be made because reductions in outage costs and operating expenses are less than the investment cost.
- Any lesser investment should not be made because

savings in investment costs are outweighed by benefits in reduced outage costs and operating expenses.

Typical resources such as gas turbines that are added to improve reliability generally provide very small, if any savings in operating costs. If we neglect the term related to savings in operating costs, we obtain a simpler expression. Thus, at optimal reliability levels, the cost associated with adding an additional unit of a resource to improve reliability equals the benefit associated with reducing the outage costs due to that unit. In other words, at optimal reliability we have the important relation,

$$\text{Marginal costs of additional reserves at the margin.} = \text{Marginal benefit of additional reserves at the margin.}$$

This relation is the basis for establishing the VOS reliability criterion.

VOS EVALUATION TECHNIQUES

The evaluation of VOS reliability uses the usual probabilistic framework of traditional reliability criteria. In addition, however, the VOS reliability approach explicitly incorporates customer outage cost information.

We present the development in terms of the available reserve denoted by \underline{R} . For the period under consideration, we define the random variable

$$\underline{R} = \underline{A}_{TOTAL} - \underline{L}$$

where \underline{A}_{TOTAL} is the total available capacity of the resources serving load and \underline{L} is the system load. The random variables \underline{A}_{TOTAL} and \underline{L} take into account the maintenance schedule, the forced outages and partial forced outages of the generating units, and the availability of demand-side management programs. A loss of load event occurs whenever \underline{R} becomes negative, and we define the loss of load probability to be

$$LOLP = \text{Probability} \{ \underline{R} < 0 \}$$

VOS reliability uses the expected unserved energy \underline{U} as the basic building block. In terms of \underline{R} we define \underline{U} as

$$\underline{U} = E \{ \underline{R} | \underline{R} < 0 \}$$

It has become customary to express reliability in terms of the deterministic quantity reserve margin. For a given period, we define the reserve margin

$$m = c_{TOTAL} - I_{PEAK}$$

Here, for the period under consideration, c_{TOTAL} is the total installed capacity of the resources and I_{PEAK} is the maximum value of the load random variable \underline{L} . \underline{U} is clearly a function of m . Any addition of capacity or reduction of peak load increases the reserve margin. As m increases the corresponding $\underline{U}(m)$ decreases. To determine the optimal value m^* of reserve margin, the cost of outages must be explicitly considered.

Increasing the reserve margin makes sense as long as the marginal cost of the increase is less than the marginal benefits

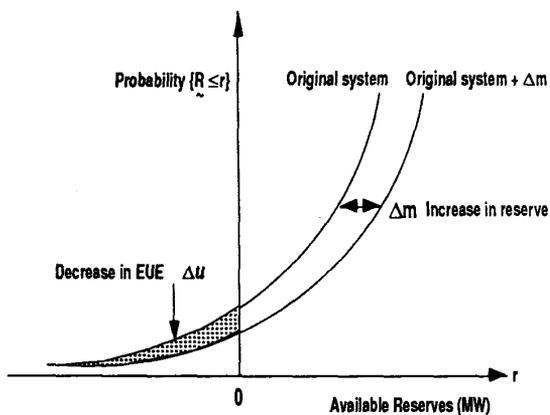


Figure 2. The evaluation of $\frac{\partial \mu}{\partial m}$ using differencing.

associated with the reduction in unserved energy. Let s denote the marginal cost of capacity per MW for the period under consideration. Let q denote the cost of a unit (MWh) of outage.

We define

$$d(m) = \left. \frac{\partial \mu}{\partial m} \right|_m$$

The marginal change in μ with respect to m may be analytically computed. It can also be evaluated by differencing with a small block size Δm , as illustrated in Figure 2. As discussed in the previous section, the least cost planning framework determines the optimal value to be the point m^* such that

$$s = d(m^*)q$$

In actual operation, a utility invokes emergency actions before the operating reserves fall to zero. Typical actions include shedding of interruptible customers, voltage reductions, and customer appeals for load reduction. These actions are applied in order of increasing severity, i.e., in order of decreasing operating reserves. The final and most severe emergency action is the implementation of rotating outages. With each action i we associate a corresponding expected unserved energy μ_i . μ_i may

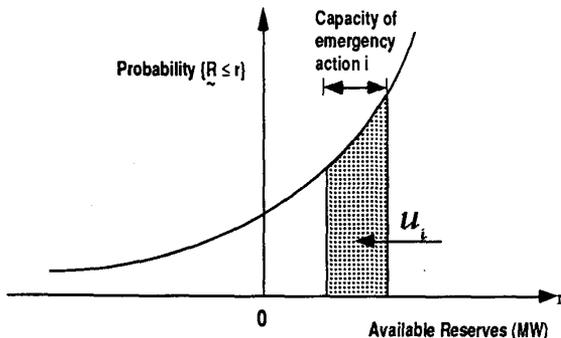


Figure 3. Unserved energy resulting from invoking emergency action i .

be interpreted as the energy "supplied" by the emergency action i . Figure 3 illustrates μ_i for the load relief associated with a particular emergency action i . If there are a total of I emergency actions with the i th being rotating outages, then

$$\mu = \sum_{i=1}^I \mu_i$$

Consequently,

$$d(m) = \left. \frac{\partial \mu}{\partial m} \right|_m = \sum_{i=1}^I \left. \frac{\partial \mu_i}{\partial m} \right|_m = \sum_{i=1}^I d_i(m)$$

where, we define $d_i(m) = \frac{\partial \mu_i}{\partial m}$. The marginal change in μ_i with respect to m can be evaluated analytically, or with the differencing approach as illustrated in Figure 4.

The costs per unit q_i of unserved energy resulting from each emergency action i are required. Then, at the optimal value m^*

$$s = \sum_{i=1}^I q_i d_i(m^*)$$

The evaluation of $d_i(m^*)$ can be easily incorporated in the probabilistic framework of reliability or production costing models. The acquisition of the outage costs is described in the next section.

DATA REQUIREMENTS AND ACQUISITION

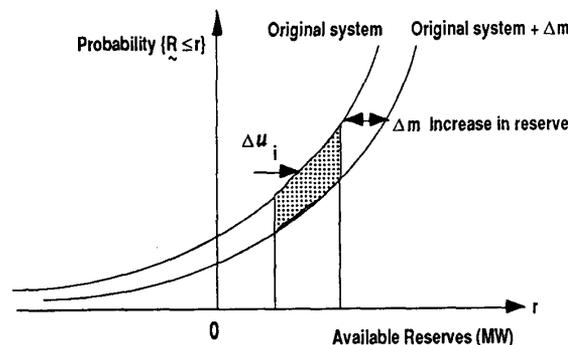


Figure 4. The evaluation of $\frac{\partial \mu_i}{\partial m}$ using differencing

The VOS reliability evaluation requires all the data used in the conventional probabilistic reliability approaches. In addition, quantification of the "worth" of reliability information is needed. It is common to express such information in terms of the customer costs incurred when electric service is unavailable, i.e., customer outage costs. The principal methods used to measure customer outage costs can be classified into four categories:

- Proxy methods use some measure of electricity service or the impact of such service to indirectly measure outage costs; examples include the ratio of area output to electricity [2] and the marginal value of lost leisure evaluated at wage rates [7].

- Market-based methods examine actual customer behavior in response to various service options or investments in reliability to infer customer outage costs; historical data on customers who sign up for non-firm service rates or install backup generation can be used to infer the costs of differentially reliable service.
- After-the-Fact-Measurement methods measure the impacts of outages that have actually occurred; an example is the New York Blackout [3].
- Survey methods use customer responses to postulated outage scenarios to measure outage costs.

Recent reviews [14], [16] present a more detailed discussion of these methods.

Utility efforts in the evaluation of customer outage costs have concentrated on survey techniques. Surveys can be designed around four basic types of questions:

- Direct costs: what cost would the customer incur due to an outage of specified duration with a specified warning time?
- Willingness to pay: how much would the customer pay to avoid an outage of specified duration with a specified warning time?
- Willingness to accept: how much would the utility have to pay the customer to accept an outage of specified duration with a specified warning time?
- Revealed preference: would the customer prefer a given level of service reliability, say n outages per year, at a given price, or a higher level of reliability, say $n-k$ outages per year, with $0 < k < n$, at a higher price?

Outage attributes such as magnitude, timing, duration, advance notice, etc., affect customers' estimates of outage costs. Though more costly than other methods, surveys have gained favor because they allow the utility to focus on the particular needs of their customers and the unique outage and operating characteristics of their utility system.

The various methods for obtaining customers' outage costs are instrumental in allowing the incorporation of customer choice information in the utility's planning process.

VOS RELIABILITY APPLICATIONS

The VOS reliability evaluation provides a powerful tool for utility planners to study resource planning and rate issues. The value of VOS reliability lies in directly linking utility investment decisions to customer costs. Typical resource planning applications include:

- determination of reliability requirements
- analysis of demand-side management programs
- analysis of utility-owned supply-side projects
- optimal scheduling of maintenance
- evaluation of bulk power transactions
- analysis of resource acquisition issues

A major advantage in the application of the VOS reliability supply-side resources. A particularly appropriate application is in the evaluation of capacity payments for non-utility owned generation. Additional applications include the evaluation of transmission and distribution investments, and fuel inventory decisions.

In the rates area, VOS reliability evaluation provides relevant information on marginal costs that may be used for rate design and revenue allocation. Specific applications include setting of demand charges and the design of interruptible/curtailable rates.

NUMERICAL EXAMPLE

To illustrate the application of the VOS reliability approach, we used the results of determining reserve requirements for the PG&E system. PG&E currently uses customer surveys to measure outage costs [10],[11]. PG&E initially conducted separate surveys of the residential, commercial, industrial and agricultural customer classes in 1983. These studies are periodically updated. For example, the latest survey of residential customers was completed in 1986, while the commercial customers were surveyed in 1988-89. The industrial customer class survey is expected to be completed in November 1989. PG&E's latest surveys utilize both direct cost and willingness-to-pay measures.

For PG&E, a summer peaking utility, responses to survey questions focusing on outages experienced on a peak summer day are particularly relevant. Table 1 presents the latest survey results for this type of question.

Table 1: Direct cost of a summer afternoon outage with 1 hour notice

Customer Class	Average Outage Cost* (1988 \$/kwh)
Residential	4.05
Commercial	39.69
Industrial	6.78
Agricultural	3.53
System Weighted Average	18.63

As all customers are treated uniformly due to insufficient generation, the system weighted average is the value used for planning purposes.

Additional questions on the most recent surveys also address the issue of partial curtailments—in particular, those resulting from voluntary appeals for load curtailment. Survey results indicated that the system weighted average cost for a voluntary partial outage is approximately \$3/kWh.*

PG&E uses these results to determine appropriate planning reserve requirements. Figure 5 presents a comparison of reliability reserve requirements using the VOS reliability approach and the more traditional LOLP based methods. Two versions of the 1 day in 10 years LOLP criterion are used. The first uses hourly loads and translates the criterion to 2.4 hours in 1 year LOLP. The second uses daily peak loads and translates

*PG&E surveys measure outage costs in dollars per event. The dollars per event are divided by an expected energy use to arrive at a \$/kWh outage cost.

the criterion to 1 day in 120 months LOLP. VOS reliability evaluation results in somewhat lower reserve requirements than those obtained with either version of the 1 day in 10 years LOLP criterion.

It is clear from the discussion on VOS reliability that the optimal reliability level is strongly dependent on the value of outage costs used in the analysis. The variation of reserve requirements as a function of the outage costs used in the analysis is given in Figure 6. This diagram presents the values of the reserve requirements when multiples of the survey-derived results are used. The value 1 on the horizontal axis corresponds to the survey-derived outage costs (the value used in Figure 5). Additional studies on the sensitivity of reserve requirements to planning assumptions can be found in [13].

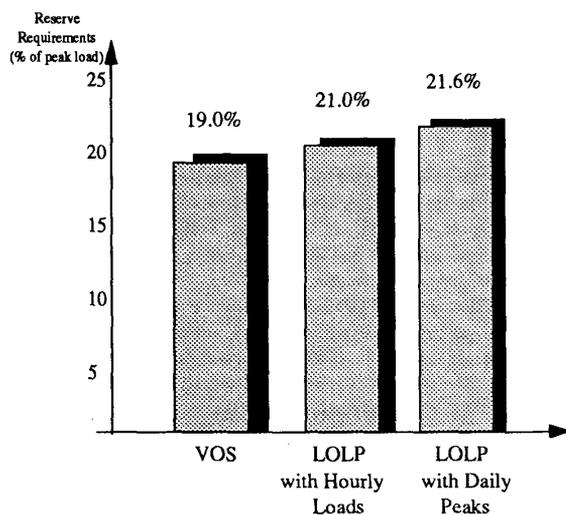


Figure 5. Comparison of reserve requirements obtained with COS and LOLP based approaches.

FUTURE DIRECTIONS

The methodology described in this paper is based on the use of an average customer outage cost. All customers receive and pay for the same level of system reliability. The least-cost plan minimizes the costs for the average consumer. However, due to the fact that customers have distinct needs, a system with uniform power supply reliability is not the most economic way to meet the individual needs. The full power of the value of service reliability approach will be realized only when utilities go beyond optimizing for the average consumer. Information on customer outage costs can be used by the utility to design a menu of reliability service options at different prices. This "unbundling" of electric supply services would allow each customer to benefit by selecting the individual's preferred service option. In an increasingly competitive environment, the utility benefits by better satisfying their customers and avoiding investment in excessive supply- or demand-side resources. In this context, VOS reliability will become an excellent tool for utility marketing.

A certain amount of unbundling has occurred for some customers already. Interruptible/curtailable rates for industrial

customers and residential air conditioner controls are examples of this unbundling. However, there are technical limitations restricting the utilities' ability to provide reliability differentiated services on an individual customer basis. Moreover, the available technology is too expensive for widespread application. Nevertheless, unbundling will become an important tool in marketing utility services in the future.

Reserve Requirements (% of peak load)

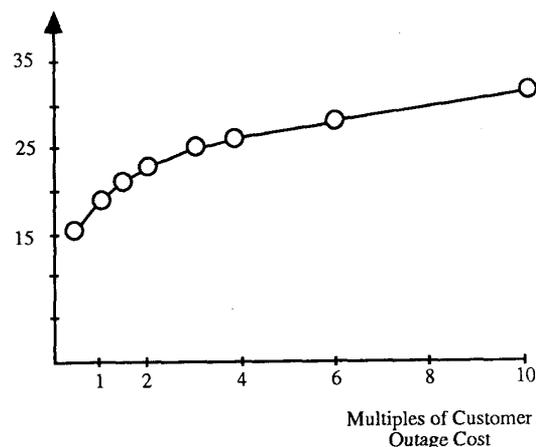


Figure 6. Variation of reserve requirements with respect to customer outage costs.

CONCLUSION

This paper has focused on the development and implementation of a practical tool for evaluating the reliability of a power system with explicit consideration of customer outage costs. The VOS reliability approach incorporates the consideration of emergency actions invoked by operators whenever reserves fall below specified target levels. The contribution of this paper is the development of a useful tool for utility planners that enables them to incorporate customer choice in their work. Results for a large utility are given to illustrate the effective application of VOS reliability.

A major obstacle to the wider adoption of economic evaluation of reliability has been the lack of confidence in outage cost estimates [12]. Although customer outage cost measurement is still an evolving science, utility experience has shown that it is possible to develop reasonably good estimates. Based on the success to date with the application of VOS reliability, and as the improvements in measurement techniques come to the fore, there are encouraging signs that the VOS reliability approach will become widely adopted by the utility industry and accepted by regulators.

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Biographies

Sandra J. Burns, a native of Brookline, MA, received her A.B. degree in Economics and an M.S. degree in Operations Research from Stanford University, Stanford, CA.

Subsequently, she joined Pacific Gas and Electric Company, San Francisco, CA, as a resource planning engineer. She was responsible for production cost studies and reliability assessment. Ms. Burns was instrumental in the development and implementation of the value of service reliability at PG&E. She is currently working on methods and techniques for estimating the marginal cost of gas transportation.

George Gross earned his undergraduate degree in Electrical Engineering at McGill University in Montreal. He continued his studies at the University of California, Berkeley, where he obtained his Master's and Ph.D. degrees in Electrical Engineering and Computer Sciences.

Dr. Gross joined PG&E as a Computer Applications Engineer in 1974. In 1977, he established the Company's Systems Engineering Group. In 1985, he founded the first Management Sciences Department at a utility and served as its Manager. In May 1987, Dr. Gross became a Manager of the Electric Resources Planning Department. He is in charge of charting the Company's long-term electric resource plans, formulating strategic directions for its electric supply business activities, developing tactical plans for electric resource development and presenting these plans to regulatory agencies.

Dr. Gross has been invited as a lecturer on diverse power system topics at leading universities, research institutions and utilities throughout the world. He has organized and served on the faculty of short courses given annually in the areas of utility resource planning and modern power system control centers at the University of California, Berkeley. In 1986 he was invited to undertake a technical mission to Chile under the auspices of the United Nations Industrial Development Organization to assist Chilean engineers in the solution of power system problems.

Dr. Gross is the author of a large number of papers appearing in various IEEE and management science publications. Dr. Gross was awarded the IEEE Power Engineering Society Power System Engineering Committee Award for the Prize Winning Paper in 1980. He is a recipient of the Franz Edelman Management Science Award from the Institute of Management Sciences. He was elected a Fellow of the IEEE in recognition for "contributions to computer applications for power system engineering."

George Gross is an active member of the IEEE Power Engineering Society. He has served in several capacities in the organization of the PICA Conferences. He was Executive Chairman of PICA in 1985. He is currently Chairman of the Computer and Analytical Methods Subcommittee of the Power System Engineering Committee. He is also currently a member of the EPRI Task Force on Power System Planning and Operation.

DISCUSSION

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This paper introduces a useful concept to calculate the system risk due to generation outages. The authors are to be commended for using the costs of interruption to compute the reserve requirements. We would appreciate authors' comments on the following questions:

1. It is true that, using the VOS method, the optimal reliability level is strongly dependent on the value of outage costs. However, can one infer that, for a practical network, the proposed VOS method would provide lower reserve requirements compared to those calculated by LOLP methods. Have the authors tested their method on other test systems?
2. It seems that only direct costs of outages are considered in the computation of reserve requirements. What about considering indirect costs, such as losses resulting from looting or damage suits brought against a power company during widespread outages. Undoubtedly, the computation of indirect costs is a very difficult task, but in our opinion, these costs should also be included when calculating the cost of an outage. If indirect costs are considered then the proposed VOS method may not provide lower reserve requirements as compared to LOLP methods.
3. The authors have correctly recognized the need of supplying power to a customer at a reliability level that is in commensurate with what he/she is willing to pay. This kind of analysis can be done rather easily at each consumer load point. But it is not yet clear how one can extend this analysis to the generation level. This is further complicated by the fact that an electric system is a non-linear system and that the transmission, the sub-transmission and the distribution systems can also fail. It should be noted, however, that it may not be necessary and practical to calculate the generation system reliability requirements precisely based on such an exhaustive VOS approach. A better place would be a major bulk load center. It is possible to calculate the reliability of a major load center by considering both generation and/or transmission outages in the system. The reliability then can be compared with the reliability expectation of the customers supplied from that point. The VOS approach would help a power utility in budgeting their funds among various facilities based on the reliability requirements. Would the authors care to comment on this concept? Have they given consideration to using probabilistic reliability measures at the distribution supply points?
4. Would the authors elaborate more on how can they incorporate the evaluation of $d_i(m^*)$ in the production costing models? There seems to be an error in the definition of the expected unserved energy $u = E(R|R < 0)$. The expected value (operator E) of the negative reserve margin should be multiplied by the time to obtain the expected unserved energy.

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Hung-Po Chao, Electric Power Research Institute, Palo Alto, California. I would like to congratulate the authors for making a valuable and timely contribution to electric resource planning. They have provided an up-to-date review of major issues concerning the VOS approach and demonstrates its application at a large utility. In the 1990's, electricity demand growth is likely to continue to outpace capacity additions, and energy supply options

will become increasingly expensive and scarce. Therefore, it is apt for a responsible utility planner to ask the question, "What is the worth of reliability?" This question has received increasingly serious attention among a growing number of utilities. Indeed, many utilities in California, New York, Massachusetts, Florida, Washington, Oregon, and other states are stepping up their efforts in estimating customer outage costs.

This paper logically leads to another related question: "During a power shortage, how can a utility allocate the available power supply efficiently and equitably among users so that outage costs can be minimized?" In an integrated planning environment, these two questions are closely inter-linked, because the outage cost estimates depend critically on how a power shortage would be managed. For instance, curtailable/interruptible rates, an option which is quickly gaining acceptance among utilities for meeting reliability needs, would definitely lower the marginal outage cost and therefore the marginal benefit of additional reserves. In this context, what is important to know is the marginal outage cost rather than the average outage cost. This suggests that in the future, outage cost studies should place a greater emphasis on the marginal cost measures than in the past.

I fully agree with the authors' assessment of the prospects for "unbundling" electric services and differentiated service offerings. Emerging competition in the electric power business and recent advances in computer, communications, and metering technologies have presented to utilities unprecedented pressures as well as opportunities to expand product and service offerings that meet diverse customer needs. Serious research effort is urgently needed in this area to help utilities exploit these opportunities.

As a final note, the following formula, which shows the relationship between the marginal change in the expected unserved energy with respect to m , $d(m)$, and the LOLP, should prove useful to the reader for gaining a deeper insight into the results of the paper:

$$U(m) = E\{\min [R, 0]\}$$

$$d(m) = \partial U / \partial m$$

$$= a \Pr \{R < 0\} = a \text{ LOLP},$$

where a is the availability factor of the marginal generation unit. This formula can be established by using results in Chao [1].

Reference

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ED WOJCZYNSKI, (Manitoba Hydro, Winnipeg, Canada)
 The authors are to be congratulated on advancing the state of the art in optimum power system reliability determination. While the fundamental theoretical concepts employed are not new in themselves, the authors present a coherent approach and practical example which represent an advancement in the application of the concepts. The application successfully combines information on cost of customer interruptions, cost of additional supply, and system reliability to determine optimum generation reserve levels.

A particularly interesting aspect is that such an approach can be a rational and consistent means to simultaneously making decisions on required reserve levels and establishing capacity payments for non-utility generators (in effect, avoided cost = worth of reliability). This linkage has the potential to be another step in obtaining an overall optimum power system. Another comment on this aspect is that the approach may be quite suitable for utilities whose plant additions are determined by requirements only for capacity; it would be less suitable or at least more difficult to apply for utilities whose additions are driven by requirements for both capacity and energy (such as Manitoba Hydro).

A small clarification relates to the authors speaking of neglecting the savings in operating costs to obtain a simpler relation which is then given as the

basis for their reliability criterion:

Marginal cost of additional reserves at the margin	=	Marginal benefit of additional reserves at the margin
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I expect that the authors did not intend to imply that this simplification is required to apply the approach. Such a simplification only makes the work of estimating costs easier.

I have the following questions:

1. Since the optimum reserve level is quite sensitive to customer interruption cost and since the customer interruption cost estimates likely tend to reflect costs of small scale independent interruptions rather than large scale interruptions, do the authors believe there is any need to incorporate adjustments for macro-economic or synergistic effects for the lower reliability levels? I ask this question with the idea in mind that these effects may be non-linearly related to reliability.
2. Is the application example provided a theoretical example or is PG&E using the results to assist in decisions on reserves and nonutility generator payments?
3. What is the reaction of the local regulators?

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The Burns and Gross paper observes that, for electric power resource investment to be optimal, the marginal benefits of additional power system reserves should equal their marginal costs. The key theoretical finding concerns the definition of marginal benefits. During emergencies, power system operators undertake various load-shedding actions, each of which has an associated outage cost per unit of load shed. Additional reserves reduce the expected quantities of load shed under each of these emergency actions. The marginal benefit of additional reserves is measured by the sum, over load-shedding actions, of the marginal effects of reserves on the values of load shed.

The theoretical framework is based upon two explicit simplifications. First, the effects of additional reserves on operating costs are neglected. Second, the marginal benefits of additional reserves are assumed to depend solely upon expected unserved energy, and not to depend upon various other outage attributes such as magnitude, timing, duration, and notification. More complete treatment of these attributes is reasonably left for future consideration.

The empirical study examines optimal reserve requirements for the Pacific Gas and Electric Company (PG&E) over a 20-year horizon. It considers three emergency actions: voluntary curtailments at 5% spinning reserves; voluntary curtailments at 3% spinning reserves; and rotating blackouts. The study depends upon detailed customer survey data regarding outage costs, upon rate case data on investment costs, and upon estimated marginal effects of reserves upon load shedding. The latter are provided by a load-duration-curve model that considers uncertainties in temperature-related demand, in long-term demand growth, in generating unit forced outage rates, and in outages of the Northwest intertie; but the model does not consider uncertainties in the dates that new generators begin service, in generator

maintenance schedules, or in the availability of any transmission system components other than the Northwest intertie.

The empirical results indicate that, for PG&E, the authors' value of service (VOS) method yields estimates of optimal generating reserves that are fairly sensitive to the uncertain measurement of customer outage costs: at the best estimate of outage costs, optimal reserves are 19% of peak load; at half the best estimate, 15%; at double the best estimate, 23%. Furthermore, these results are also inevitably sensitive to the assumed mix of generating plant types. Since the traditional one-day-in-ten-year loss-of-load-probability (LOLP) method indicates optimal reserves of 21%, the VOS and LOLP methods seem to imply virtually the same level of reserve requirements.

The paper correctly asserts that its methodology has several important intermediate- to long-term applications in scheduling and planning. These should be pursued further. Additionally, those with interests in ratemaking would like to see future application of similar methodologies to the problem of determining the short-term reliability (security) effects of unit commitment decisions and load changes.

* The discussants are presently involved in research that aims to incorporate power system reliability considerations, at both the generation and transmission levels, into the development of real-time prices. This research is being funded by the Electric Power Research Institute and the National Science Foundation through a grant to the University of Wisconsin.

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SANDRA BURNS and GEORGE GROSS: We appreciate very much the interest of the discussers in our work. We thank them for their thoughtful and pertinent comments which add considerably to the value of the paper. Also, we welcome the opportunity to provide further clarification on our work. In view of some of the common threads of the discussions, we have structured our closure in four principal areas so as to cover the various issues raised by the discussers.

OUTAGE COST ESTIMATES

Several discussers commented on the sensitivity of the optimal reserve level to the outage cost estimate. As Messrs. Caves and Kirsch correctly noted, the conclusion drawn from the plot in Figure 6 is that for the system under consideration, a doubling (halving) of the outage cost results in an increase (decrease) of approximately 4% in the reserve levels. On the other hand, the optimal reserve level is directly a function of the EUE term. Consequently, the uncertainty in the inputs used to evaluate the EUE, such as that in the load forecast and of the resource availability, is propagated into the VOS results. The impact of the uncertainty in the input variables and parameters used for evaluating the EUE may be more marked than that of the outage cost uncertainty. In addition, the marginal cost of capacity will directly impact the optimal reserve level. Typically, this term has much less uncertainty associated with it than the EUE and outage cost estimates. As a result, one cannot conclude in general that VOS reserve requirements will be higher, or lower, than LOLP-based requirements.

We note that the outage costs employed in the VOS reliability evaluation are determined from surveys that consider conditions that are expected to occur in the event of a generation shortage. For the PG&E system, a typical event would occur on a peak summer day and would consist of voluntary curtailments followed by controlled, rotating outages with advance warning. Specific attributes of outages such as magnitude, timing, duration and notification are thus implicitly incorporated in the data from which the outage cost estimates are derived. In response to Mr. Wojczynski's question, there is no need to include additional macroeconomic effects because the rotating outages would be limited to specific geographic areas. We have not considered indirect costs such as looting or damage suits, the issue raised by Drs. Agarwal and Anderson. Under the conditions of the postulated outages used for the surveys, we expect such indirect costs to have negligible contributions.

CALCULATION OF $d(m^*)$

Drs. Agarwal and Anderson requested elaboration of the evaluation of the $d_j(m^*)$ terms. Dr. Chao's discussion gives the relationship we use in the evaluation of d , i.e.,

$$\frac{\partial u}{\partial m} = \text{LOLP}(m)$$

Here, $\text{LOLP}(m)$ is evaluated at the load level corresponding to reserve margin m . The Chao expression is more general since it incorporates explicitly the availability of the reserve margin capacity as expressed by the factor a . However, if we introduce the simplifying assumption that the reserve margin capacity has "perfect" availability, as we do in our calculation, then $a = 1$. Thus, the Chao expression reduces the above equation. The Agarwal and Anderson discussion also correctly points out that the expression for u needs to be multiplied by the duration of the (simulation) period. To simplify the notation, we presented our formulation using implicitly the customary per unit basis for the time variable with 1 p.u. equal to the number of hours in the simulation period.

GENERILITY OF THE APPROACH

Several questions were raised concerning the limitations of the VOS reliability framework and the approach. Mr. Wojczynski and Messrs. Caves and Kirsch commented on the simplification introduced by neglecting the operational costs of additional reserves. This assumption is quite reasonable because these operational costs are much smaller than the other terms. However, these costs may be accommodated within the framework in a straightforward way at the cost of a more complex expression. In response to Messrs. Caves and Kirsch, we note that outage attributes such as duration, frequency and magnitude are captured in the outage costs, as discussed above, rather than in the EUE.

We may have a slight disagreement with Mr. Wojczynski because we believe that the VOS approach can be applied to energy deficient systems just as well as capacity deficient ones. The key issue is the correct evaluation of EUE for such systems. Since the loss of load in such systems occurs due to insufficient energy to serve the load rather than insufficient capacity, consequently, the optimal reserve levels are determined from marginal costs of adding energy as opposed to adding capacity. The application of the VOS approach for energy deficient systems would allow the

explicit incorporation of customer choices in the planning of such systems.

PG&E has employed VOS reliability for generation planning for several years. VOS planning criteria have been applied to multiple PG&E planning scenarios. In response to the question raised by Drs. Agarwal and Anderson, we have not tested the application of VOS on resource plans for utilities outside the PG&E planning area. Of course, the methodology is very general and it should be no problem to apply it to any utility for which the appropriate data are available.

Our paper focused on the application of customer value of service to resource planning. Marginal improvements of the resource reliability have been quantified in terms of marginal benefits to customers in reducing outages. Results for all customers have been aggregated to derive average customer outage costs. The average customer outage cost is appropriate, since all customers will share curtailments equally during resource-related outages.

Drs. Agarwal and Anderson also raised the issue of the utilization of specific outage data with the VOS approach and its extension to transmission and distribution planning. The VOS approach can be applied to transmission and distribution systems, by weighting the cost of improvements against the benefits of reducing transmission/distribution related outage costs. If the circumstances under which transmission/distribution outages occur differ from those under which generation outages occur, then the appropriate outage costs should be used. For example, at PG&E, distribution outages are more likely to occur during the winter and be weather related. Outage cost estimates may be calculated for the customer mix on the portion of the transmission/distribution system in question rather than the system average. The VOS reliability approach values allows generation, transmission and distribution investments to be compared on a consistent basis, resulting in an optimal allocation of the limited capital investment budgets.

REGULATOR RESPONSE

Mr. Wojczynski inquired about the responses of the California regulators. In general, the response has been encouraging even though formal VOS-based planning criteria have not yet been adopted. PG&E has presented VOS planning reserve requirements to both the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). Both regulatory agencies have indicated a long run goal of adopting VOS-based planning criteria, and have commended PG&E on their work to date. Much of the initial reluctance to adopt VOS stemmed from concern over the outage cost estimates. However, in light of the CPUC's enthusiastic reaction calling PG&E's value-of-service study "a distinguished ground-breaking effort" [A] and urging PG&E to continue work on it, PG&E has updated its outage cost estimates recently. The ER-90 Committee of the California Energy Commission has found the VOS methodology to be the "most innovative" of the various probabilistic approaches filed for consideration in the proceedings. [B] In fact, the Committee decision [B] concluded that:

"In concept, reliability criteria are preferable if they add the judgments of customers regarding acceptable costs to the judgments of system operators regarding prudent management of the physical system... The Committee finds the value-of-service method to be based on solid theoretical foundation in the economic literature. PG&E's

method is preferable to older approaches and urges other parties to initiate the necessary research to develop value-of-service estimates for their own planning areas. While there is always room for refinement, this method is sound."

We expect the VOS-based planning criteria will be adopted by the commissions in the near future. At that point, VOS-based marginal capacity costs may be used to calculate non-utility generator payments and for other ratemaking applications.

REFERENCES

- [A] California Public Utilities Commission, San Francisco, CA, Decision No. 86-11-071, November 1986.
- [B] ER-90 Committee Final Decision on Resource Assumptions, California Energy Commission, Sacramento, CA, Docket No. 88-34-8, March 23, 1990.

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