A multi-attribute evaluation framework for electric resource acquisition in California

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In the competitive environment in which US utilities operate, auctions are becoming an accepted means for procuring resources to meet utilities' projected needs. The rationale for instituting auctions is to effectively harness the competitive forces in electricity resource markets in order to implement least-cost planning objectives. PG&E, in cooperation with the other California investor-owned utilities, Southern California Edison and San Diego Gas and Electric, has developed a multi-attribute auction framework for the procurement of future resources. The framework uses the attributes of capacity and energy price, dispatchability, location, start date flexibility, price diversity, project viability and environmental impacts to evaluate customer benefits. This allows comparability between and tradeoffs among attributes. Other key features include the use of multiple scenarios to explicitly account for fuel price and load growth uncertainty, the explicit evaluation of long-term impacts and dynamic operating benefits of dispatchability, and the use of portfolio theory for the evaluation of price diversity. The bidding evaluation also uses optimal power flow derived loss adjustment factors and incremental network reinforcement costs and takes into account uncertainty in determining start-date flexibility. The framework is sufficiently general to be usable not only for auctions, but also for utility evaluation of maintenance, power contracts and other investment decisions. This paper describes the framework and its implementation into a PC spreadsheet software package.

Keywords: resource acquisition, resource bidding, multi-attribute bidding, dispatchability

I. Introduction

The Public Utilities Regulatory Policies Act (PURPA) of 1978 was largely responsible for the introduction of cogenerators and small power producers, the so-called qualifying facilities (QF) as a new group of players in the US electricity supply markets. Through favourable policies promulgated by state utility commissions, which were given jurisdiction for the implementation of PURPA, the once-fledgling private power enterprises have become a multi-billion dollar industry. Private power producers or non-utility generators (NUG) have become important players in electricity supply. The advent of still another class of non-QF third-party generators – independent power producers (IPP) – has brought about widespread agreement that private power will be a major source of new supply for meeting the future demand of utility customers. Hence, the need is paramount for utilities to put an effective procurement system in place that provides reliable and competitively priced electricity.

One key consideration is how to effectively and efficiently harness the increasing competition in electricity supply markets. Both utilities and their regulators are recognizing that competitive bidding is the best approach for the acquisition of private power[1–4]. Several state jurisdictions have implemented power purchase auctions and several auctions have already taken place[1,3]. However, the development and implementation of electricity bidding systems is a somewhat complicated undertaking. It is important to explicitly recognize that electricity is not a commodity, but rather a product/service with multiple attributes. In particular, when several projects are competing to meet a utility's resource needs, it is important to take into account that

- varying project characteristics determine a project's ability to meet the utility's resource needs
- project viability can differ
- price variability may be expected

Clearly, factors other than price of capacity and energy are critical to implementing least-cost planning. The incorporation of these factors as well as the results of the utility's least-cost planning into a bidding system adds

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to the complexity of the process. Thus, a key challenge in the design of auctions aimed at effectively capturing the benefits of increasing competition, is the development of a bidding system that is capable of emulating the utility's planning process. In particular, an appropriate bidding framework should explicitly include all key planning considerations and all relevant resource attributes, and have the ability to properly assess the interrelationships between various attributes.

Several utilities have implemented multi-attribute bidding systems using an evaluation framework based on point systems. In such a framework, judgement is used to allocate the total number of points into specific categories aimed at measuring each project's offering of a particular attribute. The pre-determined number of points is the maximum score that can be assigned to assess a project's ability to meet a specified requirement. A major drawback of these point-based systems is the inability to directly relate points to actual dollar impacts. In addition, such frameworks cannot adequately capture trade-offs and interrelationships among the attributes.

This paper describes a multi-attribute bidding framework for procuring future resources that was developed by PG&E in cooperation with the state's two other major investor-owned utilities, Southern California Edison and San Diego Gas and Electric. A salient characteristic of the framework is the evaluation of all attributes in monetary terms. In particular, the framework has the capability to evaluate hard-to-quantify attributes in addition to the usual price attributes. This allows the consistent evaluation of dissimilar projects and the proper accounting for trade-offs among values of the various attributes. The objective of the bidding system is to select the bidders that maximize customer benefits per MW of capacity. The customer benefits measure the reduction in revenue requirements if a project is added to the system.

The framework is comprehensive in its incorporation of important resource attributes, factors pertaining to project operations such as performance and controllability and the impacts on the utility's ability to manage uncertainty and environmental impacts. The key resource attributes – capacity and energy price, controllability and location – are used to evaluate the customer benefits associated with a project's impacts on utility fixed and variable costs. The attributes of start date flexibility, price diversity and project viability are incorporated to quantify the customer benefits associated with reduction of risks to be borne by them. In addition, the attribute of environmental impacts is included to allow the quantification of environmental benefits for the customers. The structure of the framework is given in Figure 1. This structure is modular to allow straightforward addition or deletion of attributes.

To attain the maximum customer benefits, while at the same time allow for bidder flexibility in structuring bids, we designed the framework with a 'maximum information/minimum specification' orientation. Rather than giving strict specification of the requirements of the utility's need for resources, the idea is to give bidders sufficient information for them to understand the value of each attribute and to tailor their bids accordingly. For example, the utility does not prescribe the capacity factor at which a project should operate. Instead, it provides sufficient data for the bidder to understand inter-relationships between controllability and energy price so as to tailor a bid which will be responsibe to utility needs

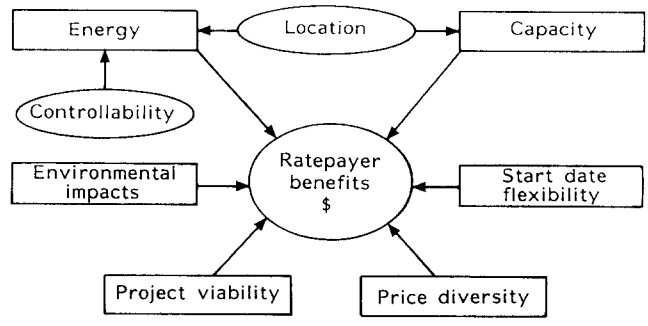

Figure 1. Evaluation framework

while, at the same time, ensuring profitability to the developer. Moreover, the framework provides the capability for the utility to send out appropriate economic signals to bidders: explicit price incentives for valued attributes.

A key aspect of the framework is the explicit consideration of uncertainty, an inherent characteristic of planning. The evaluation of customer benefits is done under a number of scenarios which are selected to capture possible futures that the utility may face. In particular, sources of uncertainty in load growth and fuel price are key elements in the formulation of scenarios. The expected value of the customer benefits is evaluated under the various scenarios. The utility's flexibility in managing uncertainty can be exercised through the ability to defer or accelerate projects in response to actual conditions differing from those forecast. The start date flexibility attribute explicitly evaluates this uncertainty effect. In addition, the evaluation of price diversity captures the variance of the benefits. The uncertainty associated with the availability of resources and the constraints of energy limited plants (e.g., hydro units) are incorporated in the evaluation of customer benefits of each scenario.

Transparency of the bidding process is currently a political necessity in California. As such, we designed the framework to be fair by providing all bidders with the identical information and a self-scoring evaluation system. The data provided by the utility allow bidders to optimize their bids by selecting appropriate options. For example, a bidder may decide to site a plant at a specific location from the information provided on transmission losses and reinforcement adjustments and the bidder's own cost data. One may note that the winning projects may not necessarily represent the optimal expansion decisions since the utility does not have pre-bid information of all the possible projects. In practice, however, this suboptimality impact is mitigated by the size of anticipated capacity additions relative to the large size of the California utility systems.

A LOTUS 1-2-3® implementation of the framework contains and bases the evaluation on information derived from probabilistic production costing, reliability, optimal power flow and other studies. The single package, incorporating the results of such key planning models, is an effective tool for making multi-attribute bid evaluation a practical reality. In fact, due to the comprehensiveness of the framework, this tool is so powerful that it can be used for serving the needs of the utility in all investment decision and contract analyses. Typical applications in addition to auctions include screening studies to evaluate utility-to-utility power contracts and utility investments

to construct new resources or upgrade or maintain existing ones.

II. Overview of the evaluation framework

The evaluation framework sets up the mechanism for the quantification and evaluation of customer benefits. In general terms, the economic benefits of a project measure the amount by which revenue requirements (total utility costs) decrease due to the project's addition to the system. Thus, to evaluate the benefits of a project, two costing studies are required: one with and one without the particular project. Standard utility benefit evaluations rely on tools such as probabilistic production costing, reliability and optimal power flow. However, in practice, such model runs are not possible within a transparent framework. Instead, approximation techniques based on utility marginal cost information are used to evaluate project impacts.

The per MW-period capacity and per MWh energy benefits of a project to customers are defined as the difference between 'reference cost' and 'price'. The price is the utility payment for the project's capacity and energy generation, i.e., the capacity and energy bid price. The reference cost is the cost the utility would otherwise incur for the capacity and generation that the project would provide, in \$/MW-period and \$/MWh, respectively. The utility's marginal capacity costs may be used for the reference capacity costs, as they are not generally a function of a project's loading and output. However, a utility's marginal energy costs vary significantly between peak and off-peak periods. Therefore, the reference energy cost, i.e., the cost the utility would otherwise incur for a project's energy generation, is a function of the project's forecast hours of operation. The reference energy cost may be calculated as the average of the hourly marginal costs during the forecasted hours of the project's operation. The per MW-period energy benefits may then be calculated by multiplying the difference between reference energy cost and energy price by the forecasted number of hours of operation per period. Sections III and IV describe the benefit calculations.

The evaluation of economic capacity and energy benefits based on reference cost and price also accounts for controllability and location impacts. It results in expected benefit values over different scenarios. The evaluation of the three attributes related to minimizing risks, price diversity, start date flexibility and project viability, is based on the variation of benefits between scenarios. The total customer benefits for a given project are obtained by summing the benefits associated with each attribute. The per MW benefits B is calculated as

$$\begin{aligned} B = {} & \bar{B}_c(P_c, L) + \bar{B}_e(P_e, P_{e,m}, L, \delta) + \\ & B_s(as, ds, \bar{B}_c, \bar{B}_s) + B_d(\bar{B}_c, \bar{B}_e) + \\ & B_v(P_e, P_{e,m}, L, \delta, \tau) - B_p(\bar{B}_c, \bar{B}_e, B_s, B_d, B_v, \gamma) \end{aligned} \tag{1}$$

where

- $\bar{B}_c$ expected value of capacity benefits per MW
- $\bar{B}_e$ expected value of energy benefits per MW
- B_s start date flexibility benefits per MW
- B_d price diversity benefits per MW
- B_v environmental benefits per MW
- B_p project viability benefits per MW
- P_c capacity price in \$/MW-period
- P_e energy price for generation at maximum efficiency in \$/MWh
- $P_{e,m}$ energy price for generation at minimum efficiency in \$/MWh
- L location of project's interconnection to the system
- δ project's controllability option
- $as(ds)$ project's earliest advanced (latest deferred) start date
- τ project technology and fuel type
- γ vector of project's development status parameters

A superbar is used to denote net present value of a particular variable over all periods of the project contract life.

Once each project's expected net present value customer benefits are assessed, competing bids are ranked in the order of decreasing customer benefits per MW capacity.

III. Capacity benefits

The capacity benefits compare the utility's marginal capacity costs against the project's capacity price. Marginal capacity costs based either on the combustion turbine proxy or value-of-service studies[5], are used as reference capacity costs. Since according to the power purchase contract capacity payments are a function of actual availability, the latter need not be considered in the evaluation of customer benefits. The basic calculation for capacity benefits is given by

$$B'_c = P_c^0 - P_c \tag{2}$$

where

- B'_c capacity benefits in \$/MW-period for one scenario, with ′ denoting a formula unadjusted for location impacts
- P_c^0 reference capacity cost in \$/MW-period

The capacity benefits are adjusted for transmission losses and transmission system reinforcement costs, which are dependent on the bid project's location. When the location considerations are incorporated, B'_c is changed to B_c, where

$$B_c = P_c^{0e}\eta_{cL} - \alpha_L - P_c \tag{3}$$

where

- η_{cL} capacity loss adjustment factor for location L
- α_L transmission system reinforcement adjustment cost for location L in \$/MW-period.

IV. Energy and controllability benefits

By controllability we refer to the level of control the utility can exercise over a project's operation. Examples of controllability options include automatic or manual dispatchability, prescheduled dispatchability, and curtailability, as well as factors such as coordinated maintenance scheduling and project responsiveness under normal and emergency conditions. The utility has control over the hours of operation of a dispatchable project which it can use to follow load economically. A more restrictive

controllability is available with a curtailable project whose operation may be reduced to a specified capacity for up to a contractually determined number of hours in a given period. The utility has no controllability for a nondispatchable project. Such a project may operate at all times regardless of the utility's resource needs.

A project's controllability impacts directly its energy benefits. As discussed in Section II, we may express the energy benefits B_e''' as a function of reference energy costs, energy bid price and forecast hours of operation:

$$B_e''' = (P_e^0 - P_e)*F \tag{4}$$

where,

B_e''' energy benefits in \$/MW-period for one scenario, with the primes denoting formulae unadjusted for tranmission impacts and operational constraints

P_e^0 reference energy cost in \$/MWh

F forecast number of hours per period for which project operates.

The reference energy costs and forecast number of hours of operation are derived from the utility's marginal costs information. These quantities depend on the level of controllability of the project. As a power system's loads change over the course of a day and period, the marginal energy cost also changes. A typical chronological marginal cost curve is shown in Figure 2. Figure 2(a) shows that a fully dispatchable project would be operated only when system marginal costs exceed the project's energy price, P_e. The project would provide energy benefits per unit of capacity to the customers equal to the sum of the areas denoted by X. A nondispatchable project, on the other hand, would operate during all hours including periods when its price exceeds marginal costs, as shown in Figure 2b. Energy benefits per unit of capacity could be calculated as the sum of the areas denoted by X minus the sum of the areas denoted by Y. For a given project and a specified energy price, the benefits with dispatchability are always greater than or equal to those without dispatchability.

This analysis may be further simplified by rearranging the marginal costs in order of decreasing value. This creation of a marginal cost duration curve[6] is analogous to the creation of a load duration curve from hourly loads. As illustrated in Figure 3, the marginal cost duration curve specifies the number of hours F for which the marginal cost is greater than or equal to a specified level P_e.

This curve is well suited as a basis for the evaluation of energy benefits for both dispatchable and nondispatchable projects. For nondispatchable projects, the hours of operation F are by definition all hours in the period. Fully dispatchable projects will only generate during hours in which the utility's marginal costs exceed P_e: therefore, F is calculated from the marginal cost duration curve M such that

$$P_e = M(F) \tag{5}$$

For both types of projects, the reference energy costs, i.e., the value of the project's generation to the utility, is determined as the average of the utility's marginal costs during the hours of operation:

$$P_e^0 = \int_0^F M(x)\mathrm{d}x/F \tag{6}$$

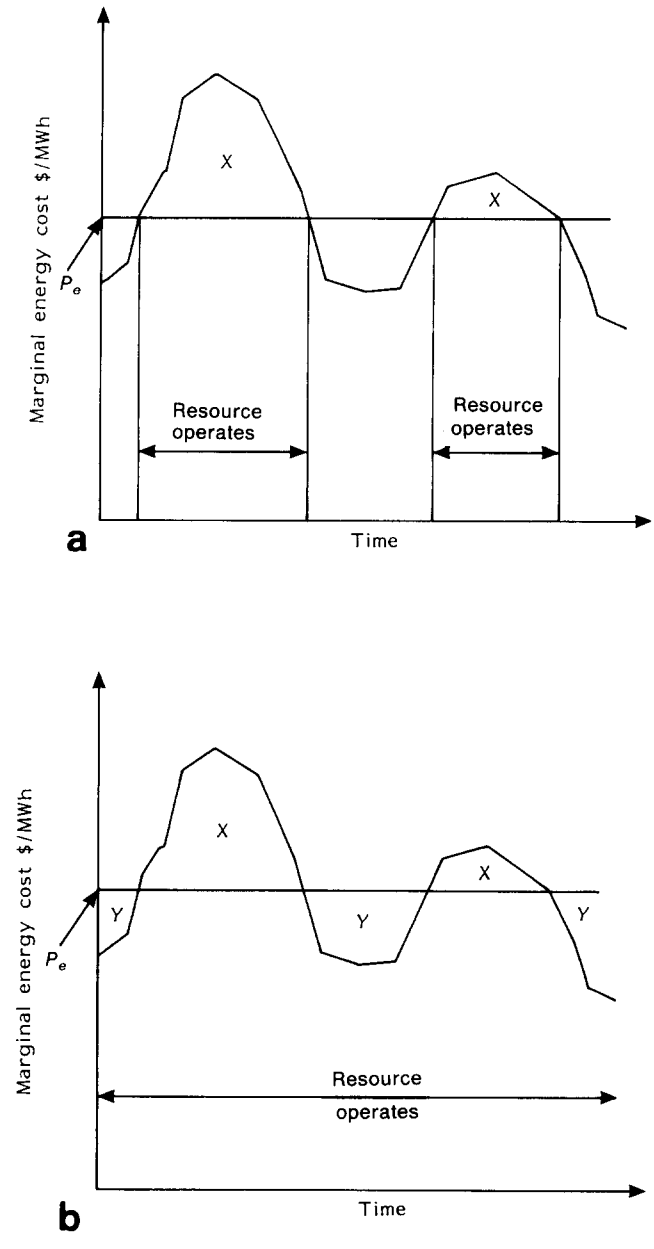

Figure 2. Chronological marginal cost and its relation to energy price. (a), dispatchable project; (b), non-dispatchable project

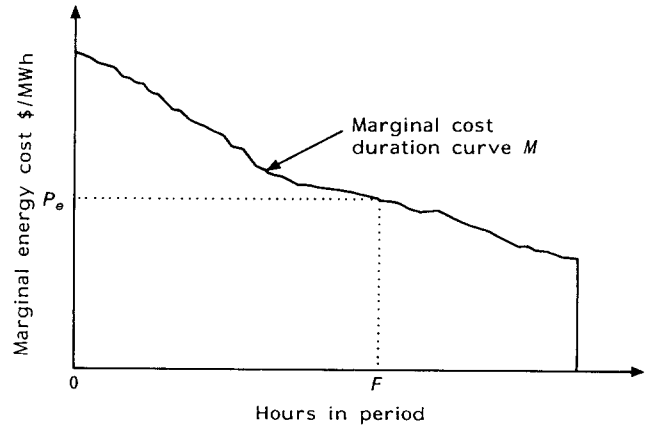

Figure 3. Marginal cost duration curve

When the energy benefits are further adjusted to incorporate location impacts and the project's availability, we obtain B''_e, where,

$$B''_e = (P^0_e * \eta_{s,L} - P_e) * A * F \quad (7)$$

where

$\eta_{s,L}$ the energy loss adjustment factor for location L
A availability factor

Equation (7) ignores some basic operational constraints. We may include the effects of minimum up and down times, which may lead to uneconomic generation at minimum capacity, by computing the adjusted benefits term B'_e, where

$$B'_e = (P^0_e * \eta_{s,L} - P_e) * A * F + (P^0_{e,m} * \eta_{s,L} - P_{e,m}) * C_m * A * F_m \quad (8)$$

In this expression

$P^0_{e,m}$ reference energy cost for (uneconomic) generation at minimum operating capacity in \$/MWh
$P_{s,m}$ energy bid price at minimum operating capacity in \$/MWh
C_m ratio of the minimum operating capacity to the project capacity
forecast of number of hours in period during which project operates (uneconomically) at minimum operating capacity

F_m, and therefore $P^0_{e,m}$, depend on the hours of economic operation F, and on the project's minimum up and down times. Details on the calculation of P^0_e, $P^0_{e,m}$, F and F_m can be found elsewhere[7]. The effects of the remaining operational considerations, such as ramp rates, notice period, commitment, reserve and regulation requirements are captured through the introduction of the dynamic dispatchability adjustment factor D[8,9]. When these effects are incorporated, we obtain the benefits B_e, where

$$B_e = (P^0_e * \eta_{s,L} * D - P_e) * A * F + (P^0_{e,m} * \eta_{s,L} - P_{e,m}) * C_m * A * F_m \quad (9)$$

The quantification of dynamic benefits represented by D is the subject of on-going research.

V. Location

The transmission impacts due to project location are incorporated via three sets of quantities: capacity loss adjustment factor η_{cL}; energy loss adjustment factor η_{cL}; and system reinforcement adjustment cost α_L. The subscript L denotes the location of interconnection of the project to the utility system. The pre-bid information provided by the utility includes system reinforcement adjustment costs can either increase, decrease, or leave unchanged the benefits of a project. The methodology for computing loss adjustment factors and system reinforcement adjustment costs is based on marginal losses and associated costs. The applicability of these data is consequently limited to a location-specific size cap. We briefly describe the derivation of the three sets of data. Complete details can be found elsewhere[10].

V.1 *Loss adjustment factors*

η_{cL} measures the capacity losses associated with a generation addition at location L at the time of system peak demand. η_{cL} captures the marginal transmission losses associated with a generation addition for a location L and the subsequent optimal redispatch of existing generation in the system using an Optimal Power Flow (OPF) model. If η_{cL} for a bus is greater than one, a project added at bus L reduces system losses. Conversely, if η_{cL} is less than one, a project connected to bus L would increase losses in the system. In a similar way, η_{eL} measures the energy losses associated with a project connected at location L. η_{eL} is the time weighted average of the η_{cL}'s for location L evaluated for various system load levels.

V.2 *System reinforcement adjustment costs*

Project additions to a network may aggravate or alleviate potential thermal loading and voltage problems on network facilities. Hence, the need for system reinforcements can be made more or less pressing by addition of a project at a given location. The total expenditure incurred or deferred at location L is measured by the system reinforcement adjustment cost α_L. α_L's are evaluated by computing the constituent components, the cost of loading impact and the cost of voltage impact. α_L is positive (negative) if a resource addition at L exacerbates (alleviates) loading and voltage problems.

The cost of loading impact for location L is defined as the product of the marginal reinforcement costs of relevant network facilities and the change in the loading of those facilities due to a marginal generation addition at that location. The relevant facilities are those that are loaded close to their ratings. The cost of loading impact is calculated from OPF results.

The cost of voltage impact for location L is defined as the product of the marginal voltage control equipment cost at relevant buses and the change in voltage at those buses due to a marginal generation addition at L. The relevant buses are those buses that operate close to their operationally allowable voltage limits. The cost of voltage impact is also calculated from OPF studies.

VI. Price diversity

The multi-attribute framework incorporates uncertainty in evaluating a project by considering its impact on both the overall level and variability, or, more precisely, the expected value and variance of the utility's revenue requirements. The expected value of the capacity and energy benefits provided by a project quantifies its impact on the expected value of revenue requirements. The impact of a project on the variance of revenue requirements is measured by the price diversity benefit. The evaluation of price diversity benefits is based on the concepts of risk aversion in decision analysis[11] and of diversity in financial portfolio theory[12]. Largely due to fuel price uncertainty, electricity bills are uncertain over the long term, and customers might be willing to pay a so-called price diversity premium to reduce the variability of electric rates. This concept is analogous to the portfolio theory notion that financial markets exhibit a premium in the prices of assets that diversify or offset the variance in overall market return. We may think of the price diversity premium in our framework as an insurance premium against large increases in customer rates or equivalently in revenue requirements. This insurance becomes particularly critical when a limited number of fuel types comprises the utility's generation mix. Since a resource's variable costs are based on the forecast price

of the fuel used, fuel diversity is a large part of price diversity.

If a project provides greater benefits in scenarios in which revenue requirements are high, variability in the benefits from the project will partially offset variability in revenue requirements and the price diversity benefits would be positive. This would be the case, for example, for a utility whose revenue requirements are heavily dependent on oil and gas prices and a project whose energy price is not tied to oil and gas prices. Conversely, a project whose benefits are uniform in every scenario, or even lower in high fuel price scenarios, would receive zero or negative price diversity benefit.

Conceptually, the price diversity attribute is defined as follows. The extent to which customers in the aggregate are adverse to risk in revenue requirements is represented by a von Neumann–Morgenstern utility function which translates each possible value of revenue requirements into a utility measure[11]. The utility function is constructed on the basis of customer surveys, observed behaviour in financial and energy markets, and policy considerations. The expected utility of revenue requirements over all scenarios is calculated from this utility function. The certain equivalent of revenue requirements is the dollar value of revenue requirements at which the utility equals the expected utility of revenue requirements. The difference between the certain equivalent and the expected value of revenue requirements is called the risk premium. The price diversity benefits of a project are then defined as the impact of the project on the risk premium of revenue requirements.

To implement the evaluation of the price diversity benefits two common approximations are used. First, the risk premium is approximated by the product of the variance of revenue requirements and the risk aversion coefficient, which is defined as the ratio of the second to the first derivative of the utility function evaluated at a point near the expected value of total revenue requirements. Therefore, the change in risk premium is approximately the product of the change in variance and the risk aversion coefficient. Second, the change in variance of revenue requirements is approximately the covariance of total revenue requirements and the capacity and energy benefits of the project. With these approximations, the price diversity benefits B_d are computed to be

$$B_d = R^* \sigma \tag{10}$$

where

R aggregate customers' risk aversion coefficient
σ covariance of capacity and energy benefit of the project with the utility's revenue requirements over all scenarios

In practical applications, R is derived from customer surveys and economic studies of financial and energy markets[13]. σ is computed directly from each scenario's capacity and energy benefits and revenue requirements.

VII. Start date flexibility

Start date flexibility is the ability to accelerate or defer the start date of a project. It affects the utility's capability to manage the inherent planning uncertainty. If loads grow more rapidly than anticipated, the acceleration of a project's start date would alleviate potential capacity shortage problems. Conversely, if loads grow more slowly than anticipated, project deferral would prevent the utility from paying for capacity that is not needed.

The benefits of start date accelerability B_{as} may be calculated as the difference in capacity and energy benefits of the project with the earliest possible start date and the planned start date in scenarios with higher than expected load growth. Benefits are gained in the years before the planned start date, and lost in years after the planned end date, since the contract life is constant. Thus we have (omitting net present value operations for clarity)

$$B_{as} = \max\left[0, \sum_{y=as}^{ps-1} (B_{c,y,h} + B_{e,y,h}) - \sum_{y=ps+T+1}^{ps+T} (B_{c,y,h} + B_{e,y,h})\right] \tag{11}$$

where

h index for high load growth scenario
y year index
as accelerated start date
ps planned start date
T contract life minus one in years

Similarly, the value of start date deferrability B_{ds} is calculated as the net present value of the difference in its capacity and energy benefits with the planned start date and the latest possible start date in scenarios with lower than expected load growth. Benefits are gained in the years after the planned end date and lost in years after the planned start date. Thus

$$B_{ds} = \max\left[0, \sum_{y=ps+T+1}^{ds+T} (B_{c,y,l}) - \sum_{y=ps}^{ds-1} (B_{c,y,l} + B_{e,y,l})\right] \tag{12}$$

where,

l index for low load growth scenario
ds deferred start date (year)

The start date flexibility benefits are the sum of the accelerability and deferrability values multiplied by the appropriate probability $\Pi_h(\Pi_l)$ of the high (low) load-growth scenarios:

$$B_s = \Pi_h^* B_{as} + \Pi_l^* B_{ds} \tag{13}$$

Thus, through the extension of capacity and energy calculations to years before and after the planned contract life, start-date flexibility benefits can be calculated without any further assumptions or additional studies.

VIII. Project viability

Project viability is an important attribute to help utilities determine each project's likelihood and impact of not coming or staying on-line. If a project does not come or stay on line, the customers lose all or a portion of its benefits. Therefore, project viability benefits B_p may be calculated as a function of the other project benefits that are at risk, and of the project's development status parameters that influence the probability Π_p that is comes and stays on line.

The probability Π_p of a project delivering to the utility the forecast benefits can be estimated as a function of how far project development has been advanced. The

following resource development factors have been selected to represent a project's development status: status of permits and licenses: site control/thermal host agreement; security of fuel supply; developer experience; financing; and economic viability. The computation of Π_p is based on experience and judgement. Work on deriving Π_p from statistical analysis of prior bids' success factors will be undertaken. The product of $(1-\Pi_p)$ and the net present value of all project benefits is the maximum loss that could occur if the project failed to materialize. This amount may be mitigated by posting a security S to cover any potential loss of benefits. Consequently,we may express

$$B_p = (\bar{B}_c + \bar{B}_e + B_s + B_d + B_v - S)(1-\Pi_p) \qquad (14)$$

The customer benefits are reduced by the amount B_p which fully measures project viability considerations.

IV. Environmental impacts

The quantification of environmental impacts is a controversial issue. There is no universally accepted methodology for quantifying the social costs of externalities such as pollutant and greenhouse gas emissions, hazardous waste and wildlife effects[14]. Nevertheless, utilities and their regulators recognize the importance of reflecting these impacts in resource planning. Consequently, we have designed the multi-attribute bidding system to incorporate environmental impacts once they have been quantified. For example, if a social cost is ascribed to CO_2 emissions in \$/lb, the framework computes the net benefits associated with a project due to the reduction of system-wide CO_2 emissions. The quantification of externalities is a topic of on-going research.

X. Implementation

The bid evaluation framework has been implemented in a LOTUS 1-2-3® spreadsheet software package. The nature of the information provided by the utility and the inputs of the bidders are shown in Figure 4. Fast turnaround time of the order of minutes enables bidders to evaluate various options in tailoring their bids.

The software accommodates four resource types: dispatchable; curtailable; hydro; and solar/wind. The only part of the framework which requires slight modifications to accommodate the different resource types is the energy benefit evaluation. For curtailable units, the calculation of F using Equation (5) has to consider the project's chosen upper limit on curtailment hours, which translates into a lower limit on F. For hydro and wind or solar resources, the hours of operation are not decision variables, but input variables. For hydro projects, net seasonal hours of operation for at least three different streamflow scenarios are required to represent the seasonality and variability of streamflows. Run-of-river hydro projects may be evaluated with P_e^0 equal to the average of all marginal costs in each season. Hydro projects with storage reservoirs may be evaluated with P_e^0 calculated as in Equation (6). For wind or solar resources, at least eight different values of F may be required, corresponding to four seasons with on- and off-peak periods each. The periods should be chosen such that during each period the project's generation can be assumed to be uncorrelated with loads. They can be evaluated with P_e^0 equal to the baseloaded energy costs in each period. This evaluation method may also be applied to cogeneration projects with rigid operation schedules.

Linear or piecewise linear approximations to the functions $F(P_s)$ and $P_e^0(P_e)$ are used bypassing the need for the marginal cost duration curves.

XI. Conclusions

We have described the development of a comprehensive framework and its implementation into a powerful resource planning and acquisition tool. The tool provides the capability of evaluating bids in auctions. In addition, it has useful applications for power contract and utility investment decisions. The framework captures all the important factors in resource planning by incorporating information from many complex models and explicitly considers uncertainty. Since all attributes are evaluated in dollars, the tool provides bidders with an understanding of the value of each attribute and its impacts on the various components of the customer benefits. Bidders' decisions and their impacts are summarized in Figure 5.

The self-scoring feature allows bidders to tailor their bids so as to maximize customer benefits while at the same time ensuring the profitability of their projects. This makes

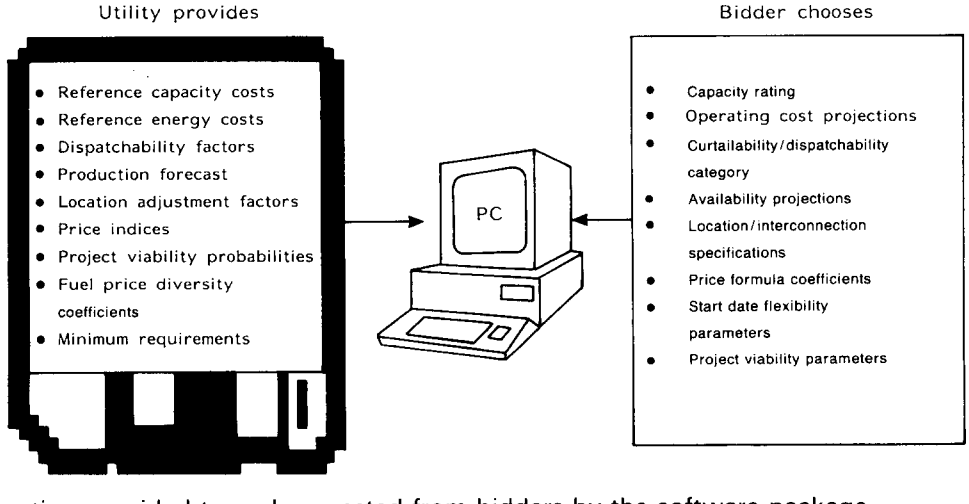

Figure 4. Information provided to and requested from bidders by the software package

Bidder Decision / Component of benefits	Capacity	Energy	Start date flexibility	Price diversity	Project viability	Environmental impacts
Change capacity price	X		X	X	X	
Change energy price		X	X	X	X	X
Change location[1]	X	X	X	X	X	X
Change controllability option[1]		X	X	X	X	X
Offer start date flexibility			X		X	
Advance project development					X	
Offer project failure security					X	
Select technology/fuel					X	X

Figure 5. Typical decisions and their impacts on benefit components

the tool a highly practical vehicle for moving from least cost planning to least cost resource acquisition.

XII. Acknowledgements

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