RTP Baseline Use Case

1 Descriptions of Function

All prior work (intellectual property of the company or individual) or proprietary (non-publicly available) work should be so noted.

1.1 Function Name

Name of Function

RTP Baseline Use Case

1.2 Function ID

IECSA identification number of the function

C-4

1.3 Brief Description

Describe briefly the scope, objectives, and rationale of the Function.

This use case (narrative only) describes the traditional methods for calculating the real-time pricing structures and discusses in brief, the process of transmitting those prices to participating customers.

1.4 Narrative

A complete narrative of the Function from a Domain Expert's point of view, describing what occurs when, why, how, and under what conditions. This will be a separate document, but will act as the basis for identifying the Steps in Section 2.

Setting Electricity Usage Prices in a RTP Regime

I. Overview

The RTP price in any hour can be represented as follows:

Price = MEC + MOC + Retail Adjustments

MOC = GOC + TOC

Adjustments = RA + taxes + surcharges + LLF

where:

MEC = marginal energy cost

MOC = marginal outage costs

GOC = marginal generation outage cost

TOC = marginal transmission outage cost

RA = risk adjustment factor

LLF = line loss factor.

In its standard application, all of the cost elements that make up the RTP price, except for the line loss factor, which is specific to the subscriber's delivery point, are the same for all subscribers. But, the elements vary in level each hour to reflect changing system supply conditions and lead to RTP prices that can vary widely throughout the year, and even within a individual day. By posting these prices, instead of average cost-based tariffs, the sponsoring utility can access the inherent variability in the value of electricity among subscriber to better match available system supplies with the value of electricity to users.

Marginal Energy Cost (MEC)

Marginal energy cost is the variable cost of serving, or the cost saved by not serving, another kilowatt-hour of energy. The MEC calculation is straightforward and intuitively appealing. For each hour, the scheduler identifies the unit that will serve the marginal load, identifies the appropriate heat rate, associates that with a fuel cost, and calculates the corresponding $/kwh cost of an incremental load change. Added to this are other costs that vary with the load on the generator, such as lubricants and supervisory and maintenance labor.

Line losses are customer specific in recognition that losses vary according to the delivery voltage at the customer's site. The lower down the transmission and distribution system a customer is served, the higher the loss factor applied. Loss factors are those commonly used for standard rate making purposes.

The risk adder (RA) is a variable factor added in each hour so that RTP prices reflect the value of electricity to customers, and thereby earn margins to offset program costs and reward utility program investments.

In the RTP model, the RA factor provides a revenue stream to cover RTP program costs laid out by the utility. The RA also covers price forecast risks the utility must undertake in setting firm price quotes a day in advance of knowing the actual cost to serve incremental load. The RA serves as a performance incentive for the utility to not only offer RTP, but to operate its units cost effectively at all times. The better the system is operated, the greater the supply availability and therein come opportunities to sell incremental loads and earn incremental returns on the program investment. And as a result all customers realize benefits

Congestion Costs, GOC and TOC

Marginal generation (GOC) and marginal transmission (TOC) costs are somewhat less intuitive at first encounter since they do not represent actual expenditures by the utility as a direct result of changes in the level of incremental load served in each hour. These so-call congestion costs serve a different role--they act as proxies for the usage premiums that a competitive market would impose for consumption during times when capacity is limited and prices would rise to effectively 'ration' available capacity among potential users. First, we will establish the underlying rational and practical application for GOC, and then do the same for TOC.

GOC serves as a proxy for the market clearing price of available capacity in each hour. Imagine a system whose design, development and dispatch is directly overseen by representatives of all customer groups. By agreement, a system reserve margin is set so that marginal capacity investments are made up to the point that customers realize marginal gains in reliability. At that point, any additional investment would not be undertaken because its cost exceeds the value derived by users of the system. Let this reserve margin be R (e.g. 18%).

The system dispatcher's job is to establish merit operating order for units of capacity, and see to it that sufficient capacity is available to meet loads plus R, the reserve margin. He performs an hourly calculation to determine the unit at the margin and sets MEC. And then he checks to see for the hour what system capacity is available to serve loads.

In cases where there is not sufficient capacity to meet loads and cover the reserve margin, the dispatcher convenes the customer group representatives and offers them two choices; either among themselves they must resolve the discrepancy between the load and reserves available so that the reserve margin R is restored, or by default have the dispatcher go ahead with less than promised reserves and risk random outages. If the representatives are to resolve this situation, some must agree to place themselves in the front of the queue for an outage (should it be necessary) so that others can be more secure and enjoy standard reliability. Clearly the negotiations would revolve around those with very high values associated with maintaining service in that hour that would be seeking to buy security at the lowest possible costs, and those with lower service values who for a bribe would take the exposed positions in the dispatch order.

If this market is to work properly, the representatives must come armed with knowledge of their constituency's value of electric service, or more poignantly, their outage costs--the costs they would incur if they suffered an outage and the price they would accept for reduced reliability. And, the representatives must know what the chances for an outage are, so that they can weight the costs of an outage by its probability and come to a price that they should pay for maintaining reliability, or alternatively, to derive the compensation they would accept for increased exposure to an outage.

If such a market could be operated (which is unlikely in a dispatch environment where decisions must be made each 5-10 seconds, but conceivably could exist on a day-ahead basis to conform with system scheduling--the RTP premise), and customers could indeed conduct negotiations and complete transactions each hour to find a market clearing price for capacity, then over time we would observe a stream of marginal electricity values that correspond to the marginal outage costs of customers. And, we would observe people taking different positions relative to average system reliability based on their value of service. The RTP premise, as currently practiced, tries to emulate this market mechanism through the GOC using a more pragmatic means for establishing market clearing prices.

The GOC used in most RTP programs attempts to replicate this idealized market. The value of lost load (VOLL) plays the role of the customer representatives' outage cost used to evaluate the effect of an outage. The loss of load probability serves to weight these costs according to their likelihood of occurring. The basic equation that reflects the principle we evoke to develop a proxy for a true short-run capacity market among end-users is:

***GOC* = (Probability of an outage) * (Value of lost load)**

Engineering calculations can be made each hour to estimate the probability of an outage, commonly referred to as the loss of load probability. It is generally assumed that when system reserves are above the planned level that LOLP is zero, and therefore GOC is also zero. This assumption comes from the notion that if all customers enjoy reliability above that specified in the planning criteria, then there are surpluses available that can be offered without any reliability penalty.

The VOLL is more speculative. But, studies have been undertaken in North America and elsewhere to estimate damage costs and customer willingness-to-pay for greater reliability. These studies find (not surprisingly) that VOLL varies greatly among customer classes and over time. Common practice in RTP programs is to adopt a VOLL value of between $ 5.00 and $ 7.00\kwh. So, for example, if in an hour where the MEC was estimated to be $.020\kwh the LOLP was estimated to be LOLP = .01, then the GOC for that hour if we adopt VOLL = $7.00\kwh would be $.07, and the RTP price, excluding retail adjustment, would be $.09\kwh.

Many utilities have adapted this formulation to accommodate a more common concept used in utility planning and rates circles, marginal capacity cost (MCC). In theory, if capacity investments have been made to satisfy the marginal cost and value equating criteria, then the last unit not yet built is slightly more costly than the marginal outage cost standard for investment. This leads to the “peaker” method often employed to develop a proxy for the marginal cost and value of capacity. Once determined, the marginal capacity cost can be used in place of the VOLL.

One approach for incorporating MCC into the RTP formulation is to calculate the annual carrying cost equivalent of the marginal capacity cost and then convert it to a monthly equivalent that corresponds to a monthly marginal demand charge. This then can be used as the short-run proxy for VOLL and substituted into the equation defined above. If, for example, the annual capacity cost was found to be $72\kw-year, the monthly equivalent would be $6.00, which then serves as the VOLL proxy. Since annual marginal capacity costs generally range from $ 35 to $75/kw, depending on the type of unit assumed as representative of the marginal investment, the equivalent marginal capacity cost proxies for VOLL fall into the range of $3.00 to $ 6.00, which is consistent with the various outage costs data available and used in RTP programs.

TOC is the equivalent to GOC for rationing available transmission capacity. As with GOC, the objective is to let customers know when incremental loads will cause transmission system congestion that imposes upon everyone's service reliability. When transmission capacity is abundant, then TOC is zero. As transmission capacity becomes committed, past standard loading levels, then the likelihood of an outage increases as does the implied outage cost. Parallel construction of TOC to GOC is appropriate, but not generally practical.

The difficulty in practice in estimating TOC values for each hour is finding an equivalent transmission LOLP. Transmission equipment in not generally independently evaluated under probabilistic simulation conditions. Usually, the transmission and distribution systems are evaluated in conjunction with the generation system in power flow models that jointly evaluate different generation availability and line loading conditions.   Identifying a unique transmission LOLP from within this framework is nearly impossible using standard models. So, even though the VOLL concept holds here (after all, customers forego value during outages regardless of whether the cause is generation failure or lack of delivery capacity), there is no easily identifiable analogue to the LOLP used in GOC.

Utilities who include TOC in their RTP prices generally resort to a state variable framework for determining when congestion is a limiting factor and setting a rationing price. Most establish transmission line loading levels for various temperature regimes that they consider to be within the design reliability tolerances, and also establish maximum carrying capacities. Then, using power flow models and experience, a TOC schedule is set that equates higher line loadings with a unique TOC rationing price, so in practice once the transmission loadings have been established for each hour the TOC can be read out directly from the schedule.

The TOC principle is the same as that for GOC--in order to send prices that fully reflect the system and societal costs of usage, some account must be made for the impact of incremental load changes on capacity availability and overall system reliability.

II. Setting Daily RTP prices

In order to offer RTP to customers, the sponsoring utility must develop a pragmatic means for establishing RTP usage prices on a daily basis that correspond to the conceptual principles outlined above. In this section, we will approach the problem functionally. We break the daily RTP price into two elements--wholesale and retail RTP prices--and discuss the various ways that can be adopted to generate the price components of each. This discussion not only addresses procedures and processes, but it also considers how these functional obligations map into routine utility operations. In the next section, we will compare these options and obligations with current operations, identify issues and constraints, and offer recommendations for establishing a smooth and effective process that can be used to support an initial RTP offering.

Offering RTP brings with it the daily responsibility to provide the customer with hourly usage prices. Convention has established 4:00 p.m. as the delivery deadline, although customers appreciate earlier delivery and most utilities send them out when they are ready, which is often soon after 2:00 p.m. This means that those responsible for developing the RTP prices must undertake all data collection, conduct the required analysis, and produce final prices for transmission to customers in that time frame. It is easier to understand and evaluate the needs of this obligation by breaking the RTP prices into two components that correspond to responsibilities that fall to different parts of the utility's organizational structure. Figure 1 displays the various cost elements of the hourly RTP price-marginal energy (MEC), generation (GOC) and transmission (TOC) congestion costs, and retail adjustments, like the adjustment margin (RA).

Wholesale and Retail RTP prices

Wholesale pricing involves estimating the direct costs associated with serving marginal loads in each hour (MEC), and then establishing whether a congestion or reliability fee is applicable and setting the appropriate level of the generation (GOC) and transmission (TOC) cost components.

The retail function is to mark these costs up to reflect losses, to add the appropriate margins to provide product and program returns, and finally to add applicable taxes and surcharges.

Wholesale RTP Prices

Because the wholesale components of the RTP price all relate to the engineering/economics of how generation systems are scheduled and dispatched, this function logically falls to the utility's System Power Operations, particularly the schedulers, who are involved daily in forecasting loads and generation availability for the next day. The scheduler is responsible not only for making a determination of day-ahead capacity availability to fulfill pool and other contractual obligations, his forecasts are vital to wholesale transactions made to either sell generation that will not be needed the next day, or to buy generation to fill capacity voids that are anticipated for the next day. Since schedulers are so fully involved in gathering data and performing analyses that are consistent with establishing RTP cost elements, virtually every utility offering RTP assigns the wholesale RTP pricing function to System Power Operations or its equivalent, and setting daily prices falls to the scheduler.

Schedulers, or their equivalent, are charged with setting marginal energy costs (MECs) for the all hours of the next day, and then establishing hourly measures of reliability and setting corresponding congestion costs.

Marginal Energy Costs (MECs)

A load forecast is developed, the units available for commitment in each hour are ranked by merit order (cost). Then the load forecast for the hour is superimposed to identify the supply unit that will serve the marginal load, and to yield the corresponding MEC fuel cost of that unit. The day-ahead nature of this calculation imposes risks which must be taken into account either by adjustments to the availability of units, or by adding an “uplift” factor to account for erroneous forecasts that result in higher than predicted MECs (most RTP programs quote non-recourse prices, so if it turns out that a more expensive unit serves marginal load, the utility absorbs the loss).

Depending on established practices and the utility’s desire to adopt more extensive procedures, those responsible for setting daily RTP MECs employ one of three methods:

1. **Production simulation**. If the company maintains a production simulation model for scheduling purposes, then it can be easily deployed for establishing MECs. After entering unit availability for each hour along with a sales forecast, which includes purchases and sales transacted on the wholesale power market, the scheduler performs a simulation run and gets as an output the expected hourly MECs. In the simulation, the model identifies the unit at the margin for each of many different levels of forecasted load and unit availability states and, based on its operating level, establishes a heat rate, which is then converted into a cost ($\kwh). The mean of the many samples produces the expected costs, the model output MEC for the hour.

   For RTP, the scheduler needs to make two additional runs, one with a increment of load increase, and one with a load decrease. The size of the increment should correspond to the amount of RTP subscriber load that is presumed to be price responsive. The average cost to serve the increments over these change cases is then the marginal cost of serving RTP load changes, the base MEC. This is then adjusted upward to account for variable O&M costs associated with the unit operating to produce the final hourly MEC.

MECs produced in this way reflect the utility's expectations for the out-of-pocket costs that would be incurred if an RTP customer, in response to the RTP price, elects to modify his load from the CBL, either up or down.

2. Power Flow Models. An alternative method identified in Figure 6 involves the use of a power flow model. Like its simulation counterpart, it takes as inputs hourly load forecasts and unit availability. But, instead of portraying the system as a set of generators set against a total load requirement, the power flow model includes a representation of the operation of the T&D system that delivers electricity to load centers. Thus, it provides a more complete description of the physical process of meeting dispersed loads from concentrations of generation and thereby incorporates transmission constraints. For the purpose of RTP, a power flow model serves equally well as it provides hourly expected MECs. The important difference is the degree of modeling sophistication and data inputs required to run a power flow model, and the fact that the MECs from a power flow model are more accurate of those likely to transpire, especially when transmission constraints are binding and generation dispatch efficiency is compromised as a result.

Marginal Outage Costs (GOC and TOC).

Marginal outage (also referred to as reliability or congestion) costs reflect the impact of incremental load changes on system reliability. In an open market, available capacity would be auctioned off or sold in spot markets, thereby reconciling any discrepancies between demand and supplies. As supplies dwindle, prices would rise as customers with the highest marginal consumption value would bid up the price to secure capacity. Reliability cost are comprised of two components, generation and transmission reliability costs. Each is discussed in turn below

<u>GOCs</u>

The motivating principle for RTP reliability costs is to use intrinsic engineering and economic relationships to produce prices that mimic market clearing spot prices that would characterize an efficient market. This equation amounts to weighting customers' value of electricity, the VOLL, by the probability that an outage will occur and cause such customer inconvenience and losses as the VOLL implies.

The VOLL is not directly observable since it reflects the marginal consumption values of customers. Outage cost studies have been conducted to try and value outage costs, and they generally find that they vary considerable by time of day, by season, and by customer class and usage characteristics. The probability of an outage is a measurable characteristic of the existing capacity situation, the reliability of the constituent units, and the load forecast and its variance. It too however is easier to describe as a theoretical concepts than to capture in practice.

Two basic approaches are used to set generation reliability costs (GOCs)--1). The first employs the use of a set of state variables that characterize supply and demand states as unique, observable situations that can be assigned an outage cost. The second involves the application of engineering/economic models to directly estimate LOLP and applies a proxy for VOLL to it.

1. The State Variable Method. The state variable method involves conducting studies of system capacity states and corresponding demand conditions and sorting them into categories with identifiable characteristics. System data like line loadings and weather can be used to measure system conditions. Summary information such as the expected system send out as percentage of the historic peak, or of the maximum availability capacity can also be used to establish state categories. Once the system states have been identified, each must be associated with a system reliability level and then a corresponding cost.

For example, the states of supply and demand could be represented by forecasted load as a percentage of available supply capacity. The RTP scheduler takes the load forecast and compares it to available supplies, and determines the resulting expected reserve margin. Then, he compares these available reserves with a predetermined reserve level that represents the desired reliability, and determines what level of additional reserves are needed to restore the system to its design state of reserves. Finally, this capacity need, which in the RTP regime translates to a desired load reduction by RTP subscribers, is associated with a demand schedule that shows the GOC that is expected to cause subscribers to reduce demands by that amount.

The CBL marks where the customer would operate under tariffs. The RTP scheduler performs a calculation to determine for each hour system reliability expectations. If reliability is expected to be above the design level, he sets GOC at zero--there is no need for rationing. When reserve shortfalls are forecast, then he uses the need/response schedule to find the GOC that will likely bring about that level of load reduction by RTP subscribers.

The greatest advantage of the state variable approach, simplicity and easy of use, is also its biggest downfall, at least compared to the theoretical notion for which it serves as a proxy. The simplistic representation assumes that the demand curve for subscribers is well known, so that the scheduler has a reliable means of associating needs with a unique price that will realize them. In practice, very little is known about customer response to RTP.

None-the-less, this method has gained favor among utilities who want an easier, more intuitive means of setting GOCs in a pilot RTP program. They believe that this method will produce logical, if not always exactly accurate GOCs, and in doing so at a low cost and with high subscriber acceptance they expedite getting RTP in the field. And, they argue that over time customer price response to RTP prices will reveal the nature of the underlying response curve, the demand for electricity, and that this finding will not only lead to improved RTP program performance, but also provide data of significant strategic value.

Others argue that when the system is characterized by only a few units of nearly equal size and reliability, that there only a few reliability state of interest in setting GOC, and therefore the more elaborate engineering LOLP method is overkill--the state variable approach will accurately capture the important events and provide theoretically correct signals to RTP subscribers. Here, the model’s simplicity is its best asset.

Finally, the state variable approach has appeal to those who see RTP as having two distinct elements, a load growth and a load control aspect. MECs are the load growth signal, since even the highest MEC is seldom much higher than the average usage price under tariffs. GOC serves as a load control device, evoked only when the Scheduler wants to change the RTP signal from "Go ahead and increase usage, capacity is available!" to "Shed all loads of marginal importance because we need load relief." Under this philosophy, the need/response method of setting GOC provides the very price controls the scheduler requires to be able to change the price signal from one state to the other.

The EUE/VOLL Method. The alternative GOC methodology seeks to develop daily forecasts of the elements of the basic GOC equation. This means establishing parameter levels for each hour for the VOLL and the LOLP.

As with the state variable method, the scheduler first develops reserve estimates for each hour, using the load forecast and the level of available capacity. In the EUE/VOLL method, he then compares these not to a need/response curve, but to a schedule that relates reserves to the probability of an outage. The lower the reserves, the greater the probability; when reserves exceed a predetermined "safe" level, LOLP is zero. The LOLP level is then multiplied by the VOLL to arrive at the GOC price for that hour, following the basic GOC formulation.

The elusiveness, some would say arbitrariness, of the VOLL causes skeptics to regard this as little better than arbitrary value-based pricing. They also point to the futility of ever being able to specify the reserves/probability of an outage relationship in any unique and stable manner. But, given that the underlying basis for GOC is defined in terms of probabilities and customer values, and that analogous measures can be developed using established and accepted models, there has been strong support among utilities who offer RTP for the EUE/VOLL method.

Moreover, systems that have converted to pool pricing as the basis for their electricity markets, most notably England, New Zealand, and Victoria, Australia, have adopted this method, legitimizing its use and advancing the methods available to support its application in RTP.

Retail RTP Prices

Retail prices are derived from the wholesale prices quoted for each hour--the wholesale prices represent a floor price that the product manager then uses as the basis for setting usage prices for the various RTP products.

III. Quoting RTP Prices at RTP UTILITY

In order to support a RTP program, the requisite organizational infrastructure and functional processes must be established. Responsible entities must be chartered and provided the resources to chose among the various methods available for preparing hourly wholesale and retail price quotes, develop the necessary procedures and models, supervise their daily application, and review their performance over time.

Functional Elements

The functional elements required for RTP wholesale pricing are reviewed below, followed by recommendations for integrating them under consistent leadership so that wholesale and retail RTP prices can be reliably and accurately quoted on a daily basis.

Load Forecasts. The Systems Operations department issues an hourly load forecast for the next day at about 8:00 a.m. The major client for this forecast is Off-System Sales, who uses it in conjunction with information about unit availability to determine excess capacity that can be sold. The current forecast process is based on high-level temperature relationships that have been established from historic data, and that appear to be quite reliable. System Operations is investigating more sophisticated and intricate forecasting systems, like neural-networks, in order to improve both forecast accuracy and to realize greater automation. These improvements will find great value in forecasting more accurate RTP prices.

Estimating Marginal Energy Cost (MEC). The System Planning department supports a probabilistic simulation model. This model is normally used for longer term planning studies of capacity needs, to estimate system operating costs, and to some extent to evaluate off-system sales opportunities. The simulation is a flexible modeling framework for evaluating not only the utilities capacity situation, but it can also represent the utility system, which is critical to understanding how marginal transactions influence the utility margins and earnings. This is a powerful tool that can serve many roles for the RTP program.

The model could be calibrated regularly to represent the utility's unit availability, and then run each day to provide capacity availability for Off-System Sales, and then rerun later to provide hourly MECs for the RTP program. Early morning load forecasts (available by 9:00 a.m.) could be entered into the model along with updated unit availability data, and information about the larger utility system. With this data bank, a system scheduler could perform standardized simulations to produce an hourly schedule of unit availability for off system sales along with floor prices--the minimum transaction price of such sales. Naturally, these minimum prices would reflect marginal unit operating costs. But other factors might also enter into setting floor prices, such as minimum margins that reflect the value of the unit if dispatched inside of the utility. As RTP matures and more is learned about customer electricity values, utilities may want to set a "reservation" price that reflects the expected price that surplus capacity will bring when offered later in the day for RTP.

Then, after all off-system transactions are completed, the model could be updated with regard to capacity availability. A change-case run that looks at load decrements and increments that reflects the size of the likely RTP price responsive load would then provides the MECs needed for hourly RTP prices. MECs developed in this way would conform to current standard practices of major RTP sponsoring utilities, and would ensure that RTP usage prices are truly reflective of underlying cost to serve incremental load in each hour.

Because RTP prices are subject to subsequent mark-up and other modifications, there is a tendency to assume that MEC forecast accuracy is not so important. And, initially this may be the case. But, as RTP markets mature and competition becomes sharper, winning profitable sales will depend on knowing exact supply costs. A RTP program provides the focus and motivation to first pursue conceptually the notion of MEC, and to adopt pragmatic methods to support the initiation of an RTP program. It should also serve to focus attention on the need to constantly evaluate these methods and to propose and pursue ways to improve them.

Estimating Generation Outage Costs (GOC) and Transmission Outage Costs (TOC). The model discussed above could be used to calibrate a Loss of Load Probability (LOLP)/Reserves schedule, as long as some factor analogous to reserves can be identified and measured. The utility operates within a much larger pool that it does not control, and whose capacity state will be difficult to discern on a day-ahead basis. To ignore the pool capacity would understate, on most days, the true reserve situations and cause congestion costs to be added to the MEC too often, and be too large when evoked. But, capacity availability is not infinite, so to ignore real constraints to serving marginal load invites customers to expand their usage, only to find that the in the short run, on some occasions the RTP price induced load growth causes system shortfalls and outages to other customers that otherwise would not have transpired. Alternatively, load growth so induced may trigger utility pool penalties that are assessed against all customers of the utility.

<u>TOCs</u>

TOC are the equivalent to GOC but they apply to transmission system capacity, constraints, and outage costs. Investigations into these relationships need to be conducted before a methodology to establishing TOCs, when warranted, can be recommended

Overall RTP Program Organization

RTP is a unique product, unlike traditional electric rates and services. The RTP Subscriber becomes connected directly to decisions made every day by system operations. The fundamental language of RTP, the prices set each hour for usage, vary first and foremost according to how the system responds to changing load demands and supply availability. RTP subscribers must be convinced that the prices that are quoted reflect actual system conditions, and are not being manipulated to coerce them to extract greater revenues. Building customer trust is critical, so that they will accept that the price variability is real, invest in understanding these price patterns and how they correspond to the value of electricity to their operations, and devise ways to become price responsive. RTP is only worth the effort and costs if customers become price responsive, thereby generating net benefits to themselves, to other ratepayers, and to shareholders.

The product structure organizes wholesale and retail responsibilities into separate operational units, each reporting to a RTP Program Management Committee. The committee is comprised of representatives of the various departments who are involved in the RTP program, and can include external members who act as advisors. The committee establishes program objectives, sets performance goals, and approves program budgets. Since this is an overlay organization, the committee is responsibility for translating the overall objectives into performance goals that can be exclusively and exhaustively assigned to one or more organizational departments. Where a goal requires that two separate department accept responsibility, the committee must ensure that the proper working arrangements are put in place and accepted by the responsible managers, so that these departments have shared goals consistent with overall program needs and goals.

Two major functions are under the direction of the RTP Committee--Wholesale Pricing and Retail Product Management. We propose that the retail functions be assigned to a Product Manager who is charged with carrying out all activities associated with designing, marketing, supporting, and evaluating the RTP product in the market place. The wholesale functions are assigned to a Wholesale Pricing Manager, whose job is to make sure that the responsible departments and their staff have the resources needed to produce daily RTP wholesale price quotes, and that they meet these obligations routinely and to accepted standards of performance.

Wholesale RTP Pricing

Power Systems Operations

Power Systems Operations (PSO), is responsible for carrying out the daily tasks associated with preparing wholesale RTP prices. PSO manages all unit scheduling functions, both to serve RTP and for other corporate purposes. It is responsible for making off-system sales, and it is responsible for the dispatch and the monitoring and control of the utilities generation units.

Scheduling.

MECs

To serve as the estimator of MECs, the utility establishes a base model configuration that defines existing capacity plans and availability, and links unit operations to variable costs. Those costs should include not only fuel costs, derived from unit heat rates and fuel inventory costs, but also provide for the addition of other variable O&M costs. These latter costs could be established outside the modeling environment and attached to unit marginal costs, once established, from a look-up file. This base case file then serves daily as the basis for performing simulations to determine marginal units and corresponding MECs. The base case requires scrutiny and adjustments as the supply situation changes, as new units or supply sources are added to the generations mix, or as transmission or other operating constraints alter the basic merit order dispatch logic.

The scheduler then daily enters the next day hourly load forecasts, along with any changes in unit availability and operating characteristics into the model. A base run performed early in the morning could then be used by the off system sales agents to determine what capacity is available to sell, and what prices they should seek. Later, when off system transactions have been completed, the scheduler again updates his files and then performs a change case run, by adding and subtracting fixed increment of load to the base forecast. Modifications to the model would facilitate not only setting up the daily runs, but also extracting the required hourly data and preparing an output.

GOC and TOCs

The system model could be used to calibrate a LOLP/Reserves schedule, as long as some factor analogous to reserves can be identified and measured. The utility operates within a much larger pool that it does not control, and whose capacity state will be difficult to discern on a day-ahead basis. To ignore the pool capacity would understate, on most days, the true reserve situations and cause congestion costs to be added to the MEC too often, and be too large when evoked. But, capacity availability is not infinite, so to ignore real constraints to serving marginal load invites customers to expand their usage, only to find that in the short run, on some occasions the RTP price induced load growth causes system shortfalls and outages to other customers that otherwise would not have transpired. Alternatively, load growth so induced may trigger uitily pool penalties that are assessed against all customers of the utility.

TOC are the equivalent to GOC but they apply to transmission system capacity, constraints, and outage costs. Investigations into these relationships need to be conducted before a methodology to establishing TOCs, when warranted, can be recommended

Off-System Sales

Off-System sales are fully integrated with other activities associated with managing scheduling and dispatch, including establishing daily reserve requirements, sales opportunities, and the prices that should be chargde for reserves. Specifically, by integrating off-system sales into an overall wholesale pricing function, the utility will look at the marginal value of its available resources in all markets, and then seek out merchandising opportunities, both wholesale and retail, that maximize the returns for such sales.

Dispatch and SCADA

For the purposed of RTP, the Dispatch and SCADA organization is responsible for acquiring plant operating data and developing up-to-date databases that would serve as inputs to the models operated by the scheduler. Dispatch also would each morning develop hourly load forecasts for the next business day, and several days' forecasts on weekends and holidays, and store them in a database, again so that they can be accessed by the scheduler.

System Planning

Model Development

Since the models and methods that will be deployed for RTP involve intricate programs and databases, we suggest that responsibility for designing, commissioning, testing and supporting these models be given to System Planners. Calibrating these models requires the close coordination with planning activities, as the RTP models used daily will provide reliable and consistent cost estimates only as long as they simulate the system condition. Planners regularly examine large-scale issues that effect system capacity and loads, and therefore they are best equipped to serve the role of establishing model requirements and assisting model users in maintaining well-calibrated models.

Price Quotation Evaluation

System Planning conducts such studies as are required to evaluate the performance of the wholesale price setting models and procedures. This includes conducting comparisons of actual and forecasted RTP prices, decomposing the variances into fundamental elements, diagnosing problems and offering solutions. This charter extends to evaluating not only the RTP prices, but also the process for establishing daily floor prices for off-system sales transactions, so that daily operations can be improved, especially where the sales balance between the off system and RTP market are not well aligned with the relative returns realized in each market.

Daily Flow of Information for RTP Wholesale Pricing

The System Operations department produces early morning forecasts that the Scheduler uses to prepare unit availability and floor prices for off-system sales. The Off System Sales (OSS) department evaluates market opportunities and seeks to maximize the return from sales to other systems. After exercising those contracts that are beneficial, OSS sends back to the Scheduler closed transactions and any other relevant market information. Following this regimen, by noon the Scheduler is ready to set minimum prices for RTP sales, the wholesale RTP prices.

The Scheduler adjusts the simulation model databases to reflect the off-system sales and adds any other relevant data and then performs a routine, specified simulation to generate MECs, by hour, for the next day. Then using an as yet to be determined process, he identifies hours when congestion costs, GOC and TOC, are to be invoked and adds the appropriate values. The result is a set of hourly RTP wholesale prices that are forwarded to the Retail Product Center by 2:00. Wholesale prices are converted to retail prices by the RTP Product Center and transmitted to RTP subscribers via email or fax.

Glossary of Terms and Acronyms

Congestion Cost - also referred to (see) as cost.

Distribution Outage Costs (DOC) - the costs incurred by end-users associated with the failure of the distribution system to carry connected load, resulting in an outage at some customer sites. Unlike MOC and TOC, which are system-level measures, DOCs are localized phenomena and need to reflect the composition of customers served on the part of the distribution system under scrutiny.

Expected Unserved Energy (EUE) - LOLP measures the instance of load being greater than the generation and other dispatchable resources available to meet it. EUE measures at each such occurrence the amount of load that went unserved, the total kilowatt-hours of outages that resulted.

Generation Outage Costs (GOC) - outage costs associated with the insufficiency of generation supply resources to meet connected and demanded loads.

Loss of Load Probability (LOLP) - a measure of the probability of the occurrence of a state where the total load demanded by end-users can not be met by available generation (or transmission) capacity. It is the likelihood of an outage on some part of the system. LOLP is a measure of system reliability. The lower the LOLP, the more reliable the electric service. A conventional standard in utility planning is to add sufficient capacity until the LOLP is one day in ten years. The application of this standard to system load and capacity conditions yields a planned reserve margin, the minimum amount of surplus capacity over peak loads that the utility plans to have available.

Line Losses - marginal energy costs are estimated at the busbar, where the generation unit first connects to the transmission system. Customers take delivery at various points on the transmission and distribution system. Losses reflect energy dissipation as electricity flows through the wires, and through its transformation down to lower delivery levels. Standard rates include loss factors applicable to the various levels of delivery, transmission, subtransmission, and distribution, and for transformation losses when the customer is metered on the low voltage side of a utility owned transformer. These factors are used to mark off wholesale RTP prices to reflect the higher generation output required to delivery energy to the end-use customer.

Marginal Energy Cost (MEC) - the variable generation operating cost incurred to serve an incremental unit of load, or the cost saved from an increment in load reduction. Convention measures energy costs in dollars per kilowatt-hours. As a marginal measure, its level is dependent upon the load level from which the increment is measured, and the size of the increment. In its strictest interpretation, the increment is one kW(h). In practice, the models and methods employed to estimate or measure MEC require a larger increment of load change, often as large as 10 megawatts, more which exceeds the total load of all but a few customers. Therefore, MEC is an illustrative and generic measure that in practice cannot be associated directly with the actions of any one customer. The point on the demand for electricity curve where MEC is measured is a function of the purpose at hand. For RTP, that measurement is taken at the level of wholesale and retail load forecast to be on line in the hour in which prices are being set.

Marginal Capacity Cost (MCC) - measures the cost of capacity associated with the unit that would be added, or the resources rights that would be purchased, to serve incremental load. MCC usually is measured in reference to additions to system peak loads, in terms of dollar per kilowatt of additional capacity added.

Marginal Outage Costs (MOC) - the change in outage costs associated with a change in load, at some specified load level and at a given load increment. For RTP, the increment is usually set at the maximum level of load change that RTP subscribers are likely to undertake in response to RTP prices, although in practice minimum increments required by models used to measure MOC are larger than these increments.

Outage Costs - the costs incurred by customers when electric service is curtailed or interrupted. Curtailments refer to situations where the customer received notice of a pending service outage. Interruptions are no-notice service outages. Outage costs (what?)

Planned Reserve Margin - the level of reserves at the peak load hour that, by design, is available to back up dispatched generation.

Real-Time Pricing (RTP) - a retail electricity pricing system whereby customers are quoted hourly prices for usage. Generally, RTP subscribers receive these price quoted a business-day in advance, by 4:00 p.m. But, in specialized applications, final usage prices are sent to subscribers only an hour in advance of their applicability. RTP services are offered as optional services to utility retail customers under term contract arrangements. Because usage prices are set daily and for each hour individually, RTP requires customers to respond to marginal, not average supply costs and thereby the efficiency of resource utilization increases.

Retail Pricing - the process of setting final consumption prices for RTP subscribers. Wholesale prices set the floor for retail prices, which include mark-ups for margin, taxes, surcharges, line losses, etc.

Risk Adjustment (RA) - is a variable factor added in each hour so that RTP prices reflect the value of electricity to customers, and thereby earn margins to offset program costs and reward utility program investments.

System Control and Data Acquisition System (SCADA) - refers to metering devices, the communication network that ties these meters to a central data base, and the control software and procedures that execute logical tasks based on the data collected. SCADA systems generally refer to meters that measure current, voltage and other aspects of electrical flow at various points on the transmission system, including the output of generators, the flows at major transmission ties, and flows into substations and radial distribution networks.

Transmission Outage Costs (TOC) - The costs incurred by end-users associated with the failure of the transmission system to carry connected load, resulting in an outage at some customer sites.

Value of Lost Load (VOLL) - measures the inconvenience, damage and replacement costs that customers incur when service in curtailed or interrupted.

Wholesale pricing- refers to identifying the underlying variable operating and outage costs associated with serving incremental load.

1.5 Actor (Stakeholder) Roles

Describe all the people (their job), systems, databases, organizations, and devices involved in or affected by the Function (e.g. operators, system administrators, technicians, end users, service personnel, executives, SCADA system, real-time database, RTO, RTU, IED, power system). Typically, these actors are logically grouped by organization or functional boundaries or just for collaboration purpose of this use case. We need to identify these groupings and their relevant roles and understand the constituency. The same actor could play different roles in different Functions, but only one role in one Function. If the same actor (e.g. the same person) does play multiple roles in one Function, list these different actor-roles as separate rows.

Grouping (Community) '		Group Description
Actor Name	**Actor Type (person, device, system etc.)**	**Actor Description**

Replicate this table for each logic group.

1.6 Information exchanged

Describe any information exchanged in this template.

Information Object Name	Information Object Description

1.7 Activities/Services

Describe or list the activities and services involved in this Function (in the context of this Function). An activity or service can be provided by a computer system, a set of applications, or manual procedures. These activities/services should be described at an appropriate level, with the understanding that sub-activities and services should be described if they are important for operational issues, automation needs, and implementation reasons. Other sub-activities/services could be left for later analysis.

Activity/Service Name	*Activities/Services Provided*

1.8 Contracts/Regulations

Identify any overall (human-initiated) contracts, regulations, policies, financial considerations, engineering constraints, pollution constraints, and other environmental quality issues that affect the design and requirements of the Function.

Contract/Regulation	*Impact of Contract/Regulation on Function*

Policy	*From Actor*	*May*	*Shall Not*	*Shall*	*Description (verb)*	*To Actor*

Constraint	***Type***	***Description***	***Applies to***

2 Step by Step Analysis of Function

Describe steps that implement the function. If there is more than one set of steps that are relevant, make a copy of the following section grouping (Preconditions and Assumptions, Steps normal sequence, and Steps alternate or exceptional sequence, Post conditions)

2.1 Steps to implement function

Name of this sequence.

2.1.1 Preconditions and Assumptions

Describe conditions that must exist prior to the initiation of the Function, such as prior state of the actors and activities

Identify any assumptions, such as what systems already exist, what contractual relations exist, and what configurations of systems are probably in place

Identify any initial states of information exchanged in the steps in the next section. For example, if a purchase order is exchanged in an activity, its precondition to the activity might be 'filled in but unapproved'.

Actor/System/Information/Contract	***Preconditions or Assumptions***

2.1.2 Steps – Normal Sequence

Describe the normal sequence of events, focusing on steps that identify new types of information or new information exchanges or new interface issues to address. Should the sequence require detailed steps that are also used by other functions, consider creating a new "sub" function, then referring to that "subroutine" in this function. Remember that the focus should be less on the algorithms of the applications and more on the interactions and information flows between "entities", e.g. people, systems, applications, data bases, etc. There should be a direct link between the narrative and these steps.

The numbering of the sequence steps conveys the order and concurrency and iteration of the steps occur. Using a Dewey Decimal scheme, each level of nested procedure call is separated by a dot '.'. Within a level, the sequence number comprises an optional letter and an integer number. The letter specifies a concurrent sequence within the next higher level; all letter sequences are concurrent with other letter sequences. The number specifies the sequencing of messages in a given letter sequence. The absence of a letter is treated as a default 'main sequence' in parallel with the lettered sequences.

Sequence 1:

```
1.1 - Do step 1
1.2A.1 - In parallel to activity 2 B do step 1
1.2A.2 - In parallel to activity 2 B do step 2
1.2B.1 - In parallel to activity 2 A do step 1
1.2B.2 - In parallel to activity 2 A do step 2
1.3 - Do step 3
1.3.1 - nested step 3.1
1.3.2 - nested step 3.2
```

Sequence 2:

```
2.1 - Do step 1
2.2 – Do step 2
```

#	Event	Primary Actor	Name of Process/Activity	Description of Process/Activity	Information Producer	Information Receiver	Name of Info Exchanged	Additional Notes	IECSA Environments
#	*Triggering event? Identify the name of the event.*[1]	*What other actors are primarily responsible for the Process/Activity? Actors are defined in section1.5.*	*Label that would appear in a process diagram. Use action verbs when naming activity.*	*Describe the actions that take place in active and present tense. The step should be a descriptive noun/verb phrase that portrays an outline summary of the step. "If …Then…Else" scenarios can be captured as multiple Actions or as separate steps.*	*What other actors are primarily responsible for Producing the information? Actors are defined in section1.5.*	*What other actors are primarily responsible for Receiving the information? Actors are defined in section1.5.* *(Note – May leave blank if same as Primary Actor)*	*Name of the information object. Information objects are defined in section 1.6*	*Elaborate architectural issues using attached spreadsheet. Use this column to elaborate details that aren't captured in the spreadsheet.*	*Reference the applicable IECSA Environment containing this data exchange. Only one environment per step.*

2.1.3 Steps – Alternative / Exception Sequences

Describe any alternative or exception sequences that may be required that deviate from the normal course of activities. Note instructions are found in previous table.

#	Event	Primary Actor	Name of Process/Activity	Description of Process/Activity	Information Producer	Information Receiver	Name of Info Exchanged	Additional Notes	IECSA Environments

[1] Note – A triggering event is not necessary if the completion of the prior step – leads to the transition of the following step.

2.1.4 Post-conditions and Significant Results

Describe conditions that must exist at the conclusion of the Function. Identify significant items similar to that in the preconditions section.

Describe any significant results from the Function

Actor/Activity	***Post-conditions Description and Results***

2.2 Architectural Issues in Interactions

Elaborate on all architectural issues in each of the steps outlined in each of the sequences above. Reference the Step by number..

2.3 Diagram

For clarification, draw (by hand, by Power Point, by UML diagram) the interactions, identifying the Steps where possible.

3 Auxiliary Issues

3.1 References and contacts

Documents and individuals or organizations used as background to the function described; other functions referenced by this function, or acting as "sub" functions; or other documentation that clarifies the requirements or activities described. All prior work (intellectual property of the company or individual) or proprietary (non-publicly available) work must be so noted.

ID	Title or contact	Reference or contact information
[1]		
[2]		

3.2 Action Item List

As the function is developed, identify issues that still need clarification, resolution, or other notice taken of them. This can act as an Action Item list.

ID	Description	Status
[1]	Use case to be completed	Will have to picked up by another resource
[2]		

3.3 Revision History

For reference and tracking purposes, indicate who worked on describing this function, and what aspect they undertook.

No	Date	Author	Description
0.1	3/2/04	Jack King	Fomatted initial narrative into Version 27(28) template.

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