Real-time pricing for purchased electricity: an innovative pricing option for electricity as used by the pulp and paper industry

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ABSTRACT

The pulp and paper industry relies heavily on electricity as an energy source. Although a major share of the pulp and paper industry's electrical needs are met by cogeneration, a substantial quantity of utility-generated electricity is purchased. The cost of purchased electricity can have a significant "bottom line" impact on mill production costs. Some utilities now have a new and innovative pricing methodology that provides cost benefits to their pulp and paper customers while also allowing utilities to achieve their own load management goals. This pricing concept is based on a utility's marginal cost structure, and is generally known as real-time pricing (RTP).

Application:

This paper provides an explanation of the RTP concept for purchased electricity. An actual pulp and paper mill's perspectives and experiences with RTP are presented from the standpoint of mill operations and the economic benefit of this innovative rate structure.

ELECTRICITY WILL BE AN INCREASingly vital energy source for the pulp and paper industry. Although benefits of the real-time pricing (RTP) concept are not limited to the real-time pricing pulp and paper industry, many mills will have the option to obtain a lower cost supply of purchased electricity in accordance with their process requirements while using operational capabilities in conjunction with the utilities load management programs. Through the development and use of RTP programs, electric utilities can achieve load management objectives, better use generation resources, and be prepared to compete in an emerging open market place.

Energy bills account for about 8% of the overall manufacturing costs in the U.S. pulp and paper industry (see **Table I**).[1] This percentage makes this industry one of the most energy-intensive. Over the past decade, with ever-increasing energy costs, the industry has turned to generating more of its own supply which now provides over half of the industry's needs through cogeneration and on-site power plants that burn self-generated fuel sources such as bark and spent pulping liquors. This move has kept overall energy costs fairly steady despite price fluctuations in individual energy sources.

Self-generated energy by the pulp and paper industry accounted for 55.3% (**Table II**)[2] of the industry's total energy needs in 1993, based on data compiled by the American Forest & Paper Association (AF&PA). The use of residue sources such as spent pulping liquors, hogged wood, and bark represented a savings of more than 230 million barrels of oil according to the association. However, the cost of upgrading and/or replacing outdated or inefficient power generation equipment can be high, and companies are looking to other sources and opportunities to bring down the cost of energy.

Among external factors that will continue to point the pulp and paper industry in the direction of alternatives and greater efficiencies in the energy markets will be legislation to promote and force cleaner and more cost-efficient energy methods. The deregulation of the natural gas and fuel oil industries has led to lower energy prices for these energy sources. The electrical utilities must also prepare for deregulation. One response was from Georgia Power management, who knew the company had to become more customer-oriented and become a low cost provider of energy to compete in a deregulated world and to keep customers on its system in the event of open access. Georgia Power Co. decided to ask some of its large industrial customers what type of rate could best suit their needs. Federal Paper Board became instrumental in the advent of a new rate that could be used by many customers in the state of Georgia.

BACKGROUND OF THE UTILITY

Georgia Power Co. (GPC) is the largest member of the Southern Co., one of the nation's largest investor-owned electric utility groups. In 1994, Georgia Power's electric sales topped 70 billion kWh and had a territorial peak of almost 18,000 MW.

[1] *Pulp & Paper 1995 North American Factbook—North America: Energy Use & Conservation,* Miller Freeman, San Francisco.

[2] American Forest & Paper Association, Fact Sheet on 1993 Energy Use in the U.S. Pulp & Paper Industry, Washington, DC.

This is 46% of the Southern Co.'s total electric sales. Georgia Power serves almost 1.5 million residential customers, 195,000 commercial customers and 11,000 industrial customers.

Georgia state law places Georgia Power in a competitive situation that is unique from other investor-owned utilities (IOUs). Since 1973, GPC has operated under a legislative act that allows customers with new or expansion load of 900 kW connected or greater to be served by any electric utility in the state. As a result, GPC must compete for this load against close to 100 unregulated rural electric cooperatives (EMCs) and municipal (Munis) utilities. All of the utilities are part of a fully integrated transmission system in the state.

GPC did not encounter the full competitive nature of the act until the late 1980s and early 1990s when excess capacity owned by the EMCs and the Munis led to intensified intrastate price competition. At the same time, other large utilities in the Southeast were also aggressively competing with the GPC for new loads moving to the South.

One of the first responses by GPC was to introduce a curtailable rider known as supplemental energy (SE). This rider allowed the customer to purchase energy above a specified demand threshold at a set unit price without incurring additional demand charges. GPC retained the right to curtail customer's usage under certain conditions (when the cost of producing the electricity exceeded the price charged, under capacity constraints and/or when the GPC system was approaching a system peak). If a customer did not curtail the usage back to the demand threshold, a new demand threshold was set and the customer had to pay for the additional demand charges for the next 12 months due to the demand ratchets in the customer's

Year	Purchased energy cost[a], $	Value of shipments, $	% Of shipments
1992	4.5	53.4	8.4
1991	4.4	53.7	8.2
1990	4.5	56.6	8.0
1989	4.2	57.5	7.3
1988	4.0	54.1	7.4
1987	4.1	46.2	8.9
1986	4.3	41.1	10.5
1985	4.8	39.1	12.3
1984	5.1	41.3	12.3
1983	4.8	35.9	13.4
1982	4.7	33.8	13.9
1981	4.8	35.1	13.6
1980	4.0	31.8	12.7
1979	3.3	28.0	11.7
1978	2.7	24.0	11.3
1977	2.6	22.3	11.4
1976	2.2	21.0	10.5
1974	1.7	18.5	8.9
1973	0.9	13.7	6.8
1972	0.8	11.7	6.9

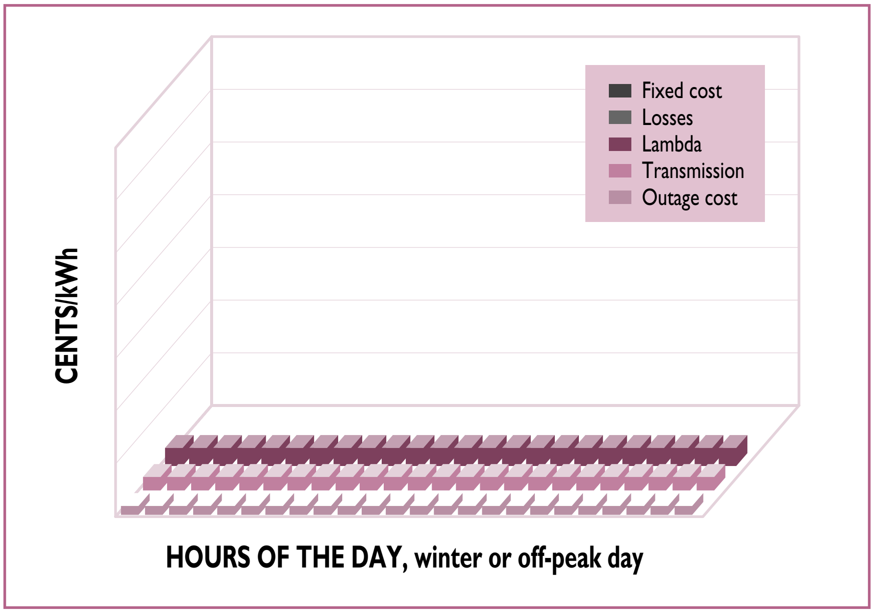
[a] Includes electric energy, fuel oil, natural gas, and other fossil fuels.
Source: American Forest & Paper Association

I. U. S. pulp and paper industry purchased energy costs as a percentage of shipments (billion $)

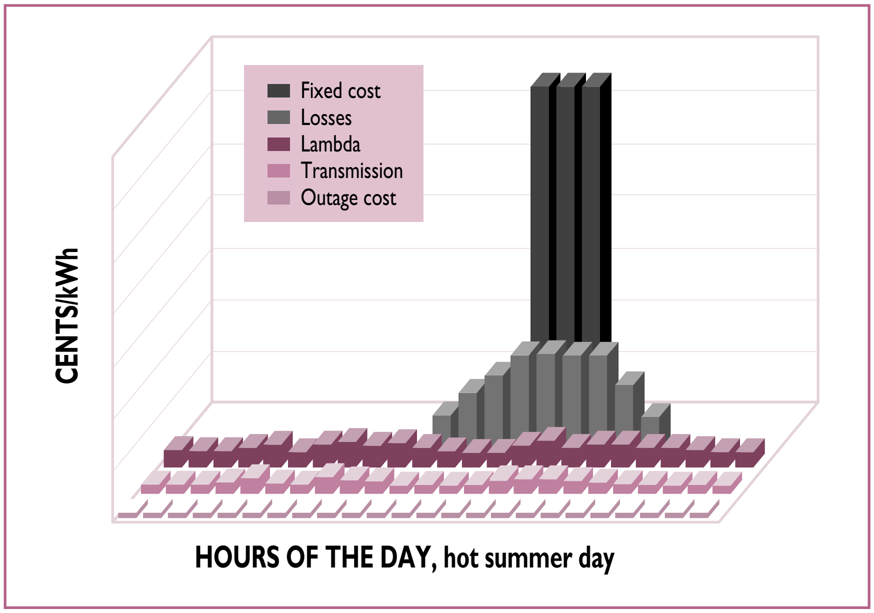
	1993, %	1992, %	1972, %
Purchased fuel			
Purchased electricity	6.5	6.4	4.4
Coal	12.9	12.7	10.7
Residual fuel oil	6.7	6.1	21.2
Distillate fuel oil	0.2	0.2	1.0
Natural gas	16.6	17.2	21.1
Other	1.8	1.8	1.3
Total	44.7	44.4	59.7
Self-generated fuel			
Wood residues	8.4	9.1	2.0
Bark	6.1	5.7	4.5
Spent pulping liquors	39.5	39.6	33.3
Self-generated hydro	0.5	0.6	0.4
Other	0.8	0.6	0.1
Total	55.3	55.6	40.3

Source: American Forest & Paper Association Fact Sheet on 1993 Energy Usage in the U. S. Pulp and Paper Industry

II. Fuel and energy consumption percentages in the U. S. pulp and paper industry



1. Cumulative hourly price components



2. Cumulative hourly price components

rate. This rider worked for many years until the number of hours of curtailment increased.

A pulp and paper facility in southeast Georgia installed a monitor to ensure that the threshold was not exceeded during curtailments. This company could get up to a US$ 300,000 increase in demand costs if *any* half-hour average demand consumption exceeded the limit during a curtailment.

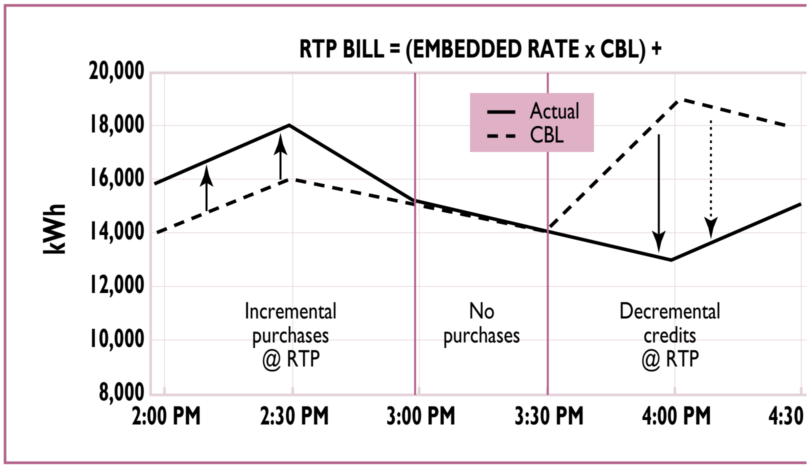
THE RESPONSE

In the early 1990s, several large industrial customers approached Georgia Power and asked what could be done to avoid the increasing number and duration of curtailment calls. The customers basically said "why not sell us electricity at your cost during these curtailments if we are willing to pay for your cost to produce the electricity?" An industrial customer referred to a utility and its rates as the only restaurant in town and that it had only one or two items on the menu. You could take it or leave it. Here the customers suggested a buffet line in which there are many items and customers can pick and choose what they want and at what price they are willing to pay. Under this situation, both parties have maximized their goals—both have increased their customer satisfaction and profits.

Faced with ever-increasing competition from other utilities and other fuel sources and increasing hours of curtailment, GPC sought to develop a more competitive rate built on the company's strengths. With adequate generation facilities and plans to add additional combustion turbine peaking units in the mid to late 1990s, Georgia Power had good base load capacity and low marginal costs. GPC sought to combine both strengths into a single rate. And GPC wanted to develop a rate that would produce a WIN–WIN–WIN situation for it and its stakeholders, the customers, and the state of Georgia.

The GPC staff examined several types of rates offered by other utilities. Most of the rate options were based on embedded revenue requirements and could not take advantage of the company's competitive strengths. The team decided that the rate that would satisfy the company's objectives and build on its strengths was a real-time pricing (RTP) rate. RTP would provide customers with a lower-cost (per kWh) cost-based option and more control over their electric bill while helping GPC to manage system peaks.

The following is an explanation of the RTP concept for purchased electricity. We will compare and contrast the RTP pricing concepts to more traditional electric rates and describe the potential benefits to the utility's load management strategy. An actual pulp and paper mill's perspectives and experiences with RTP are presented from the standpoint of mill operations and the economic impact of this innovative rate structure.



3. Calculation of RTP bill

WHAT IS RTP?

Electric utilities have historically priced electricity using filed, approved tariffs, and the tariffs were designed to collect embedded revenue requirements. Embedded revenue requirements, sometimes referred to as embedded costs (EC), reflected the accounting cost (i.e., the balance sheet and income statement) as authorized by the governing regulatory authority. These accounting costs contain items which vary with kWh consumption as well as fixed cost requirements which may not vary with energy usage (kWh) over the planning horizon in question. (In the long run all costs are deemed to be variable in nature.)

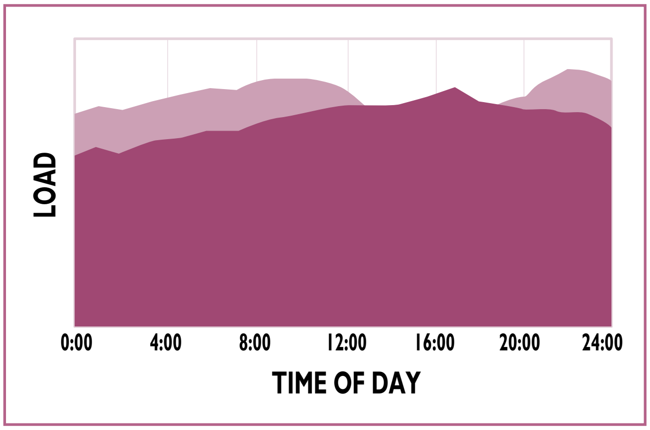
In a RTP program, there are no set prices for electricity as in standard utility rates. Instead the price is normally set by using a formula to establish the price. The price of the electricity varies by hour according to the marginal cost of producing the next kWh of electricity. Under RTP, the price changes frequently to reflect the constantly changing, or real-time, costs of supplying electricity.

A cousin to what in the EC vernacular has been referred to as variable cost is referred to by economists as marginal cost (MC). Marginal costs are those costs normally connected with a specific time interval which vary directly with a specific, relatively small change in electricity usage. The distinction between variable cost in the embedded cost sense and marginal cost in an economic sense can be exemplified by the difference in a fuel clause and lambda. Lambda (l) is a utility term referring to a utility's marginal fuel and variable operating and maintenance (O&M) cost in a specific hour. A utility's fuel clause is normally the average of all fuel costs over the time period, and therefore includes the averaging effect of all lambdas. For example, let's say that there are only 2 hours in a year, and the marginal fuel cost in hour 1 is 2 cents/kWh and the marginal fuel cost in hour 2 is 3 cents/kWh. Presuming that kWh usage was forecast to be equal across both hours, a fuel clause might be set at 2.5 cents/kWh to be recovered evenly across all hours of the period, while the marginal cost for hours 1 and 2 could be 2 cents/kWh and 3 cents/kWh, respectively.

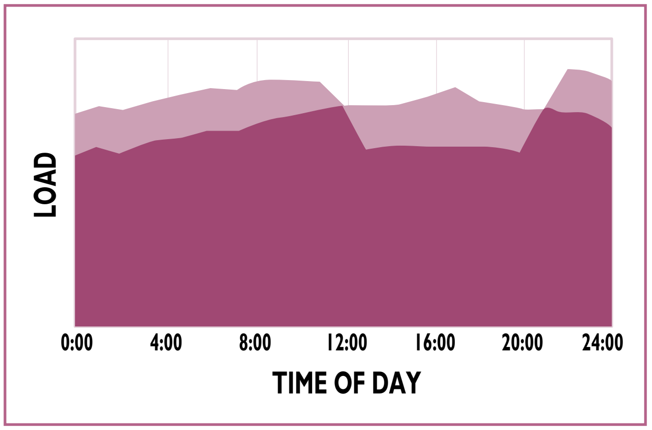
The difference in an embedded cost practitioner's use of variable cost versus an economist's use of marginal cost can be insignificant as long as the forecast of kWh sales and cost are predicted with 100% accuracy. But, let's assume that sales, which were forecast to occur evenly across both hours, actually are twice as common in hour 1 as hour 2, and let's assume that incremental fuel costs were indeed forecast accurately at 2 cents/kWh and 3 cents/kWh, respectively. Obviously, a pre-set fuel clause will not collect the fuel cost incurred over the test period.

A further challenge with embedded rate design is the need to collect fixed costs which by definition do not change with kWh consumption. Normally, embedded cost rate designers will take the required fixed cost revenue requirement, divide the requirement by the anticipated billing units, and add this to the variable cost per billing unit to produce a final rate. For example, let's suppose that variable cost per kWh is 2.5 cents/kWh, while the calculation of embedded fixed cost per kWh is 1.5 cents/kWh. A final rate could be 4 cents/kWh across all hours of the planning period.

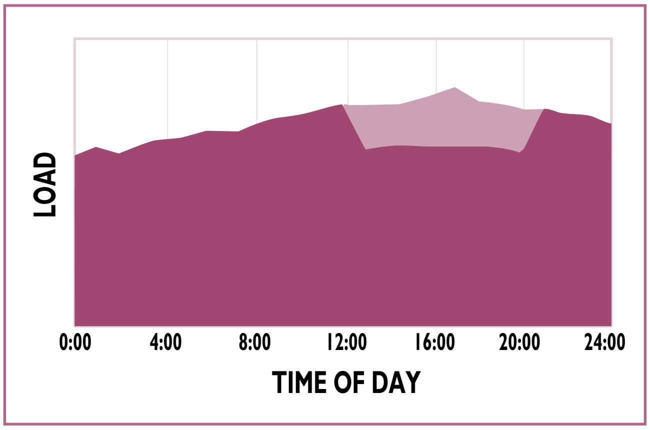
Now, let's return to incremental costing which indicated marginal cost of 2 cents/kWh and 3 cents/kWh. Obviously, if we charged these prices alone, we would cover our incremental cost but fail to receive enough contribution to



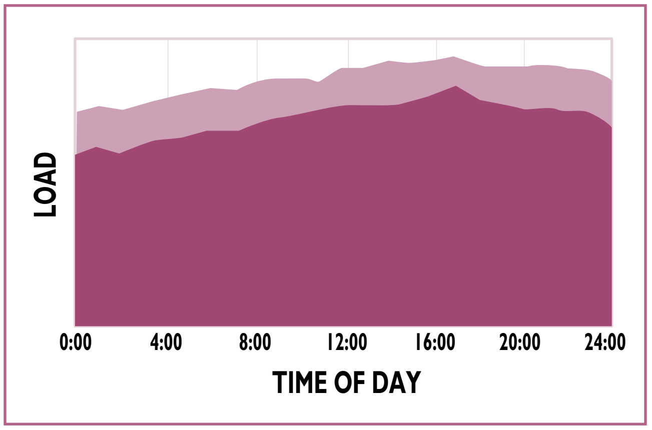
4. Typical load responses (increase usage in low cost hours)



5. Typical load responses (increase in low cost, decrease in high cost)



6. Typical load responses (decrease usage in high cost hours)



7. Typical load responses (increase usage in all hours)

cover our fixed cost. How do we bridge the gap between the coverage of 4 cents/kWh across all hours to the hourly incremental costs of 2 cents/kWh and 3 cents/kWh, respectively? Using real-time pricing, which reflects the forecasted "real-time" marginal cost of providing electricity, many utilities have chosen to bridge this gap in one of two methods.

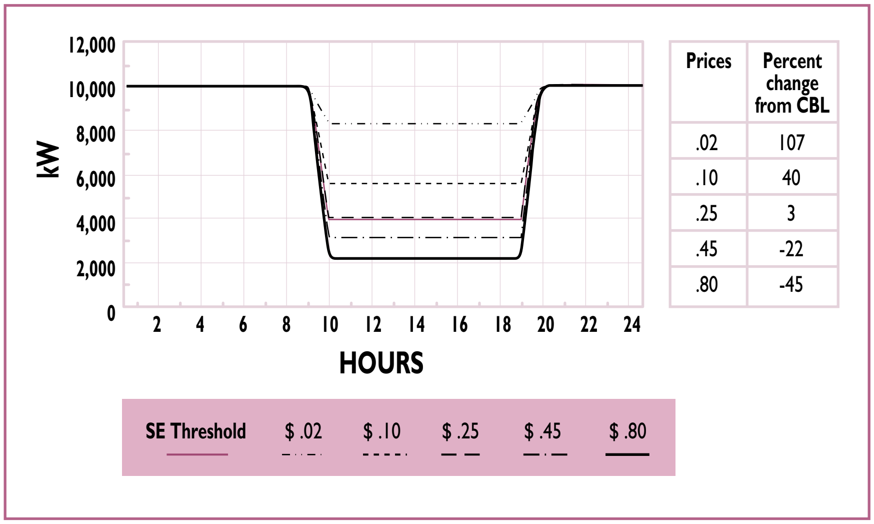
In 1991, there were two models for an RTP rate. The first model was a one-part tariff that set marginal cost higher than true marginal cost. Under this model, embedded costs were recovered by either a factor added to the marginal cost or applying a multiplier to the marginal cost. Experimenting with the one-part rate model were several utilities, including Pacific Gas & Electric, Connecticut Light & Power, and Consolidated Edison. Under a one-part design, you can simply divide the average embedded revenue requirement by the average marginal cost weighted for hourly sales, and multiply this factor by the hourly marginal cost. In our example, assuming equal sales across both hours, the hourly RTP prices would be:

Hour 1: (4 cents/2.5 cents) x 2 cents = 3.2 cents/kWh

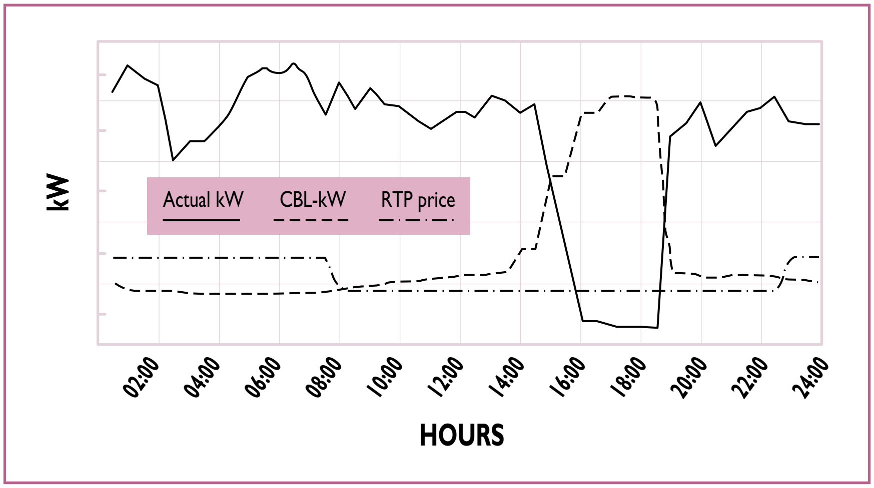
Hour 2: (4 cents/2.5 cents) x 3 cents = 4.8 cents/kWh

All kWh consumption during hour 1 would be billed at 3.2 cents, and all kWh consumption during hour 2 would be billed at 4.8 cents/kWh. This model, however, did not build off of GPC's strengths. Once you have sold the expected kWh, any additional sales would continue to collect the embedded revenue requirement. Price elasticity would seem to indicate that if you could sell any additional kWh at marginal cost, society as a whole would be better.

The second model was a two-part tariff that Niagara Mohawk was field testing. The first part of this rate is a customer baseline load-shape (CBL) which represents the historical usage patterns of the customer. This CBL is used to recover the embedded costs of the utility. The second part of this rate is the hourly incremental (both positive and negative) deviations from the CBL are priced at marginal costs. For example, take a historical representation of kWh usage and multiply it by the standard embedded rate, in this case 4 cents/kWh. (The link here is that it is the historical load shape upon which the fixed cost is recovered.) From this point forward, however, any changes in kWh usage on an hourly basis will be billed at each hour's respective marginal cost—in this case, 2 cents/kWh and 3 cents/kWh, respectively. The two-part rate model was chosen by Georgia Power. (Note that, if kWh consumption does not change from historical patterns, the two different RTP design procedures produce the same result.)



8. Predicted customer response to price (based upon RTP-X experimental results)



9. Federal Paper Board—RTP performance (relatively mild summer weekday)

DEVELOPMENT OF RTP AT GEORGIA POWER

In Georgia, as in most states, the rate adjudication process requires utilities to file a tariff which is then approved, perhaps with modification after input from all the parties, or disapproved by the Public Service Commission (PSC). Since an RTP rate is a formula for calculating rates rather than a tariff with specified prices, GPC requested to file the formula approach instead of a stated rate.

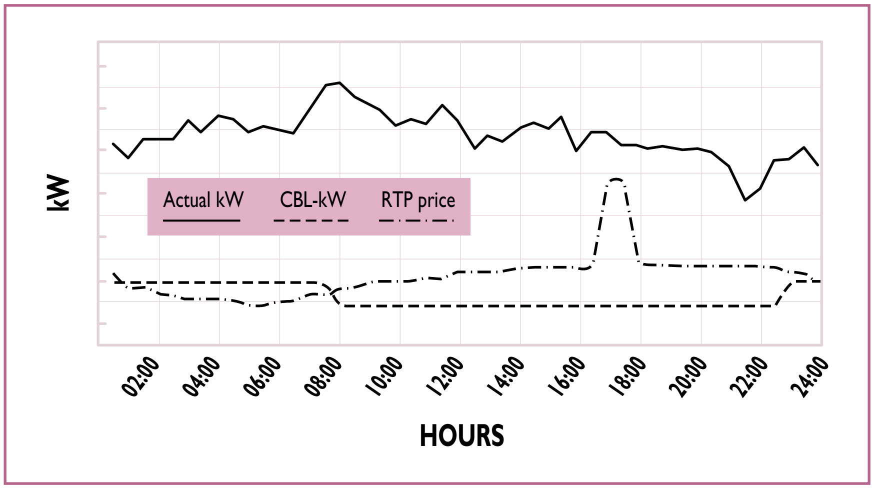
Given the uncertainty surrounding the customer response, the proposed rate was set forth as an experiment. In June 1992, PSC approved a two-year experiment.

Prior to gaining approval for the tariff, GPC contacted around 100 of its largest customers in terms of demand. These companies and Georgia Power were involved in a dialogue to create a design for a day-ahead RTP rate that would meet the customer needs and also the utility needs. After incorporating the customer's inputs, a final design was submitted to the PSC in the form of a two-year experiment in which a test group of 25 customers was allowed on the rate for the first year and a control group of 25 was also created in order to determine how customers would react to the new tariff. After one year, the control group customers were allowed on the rate.

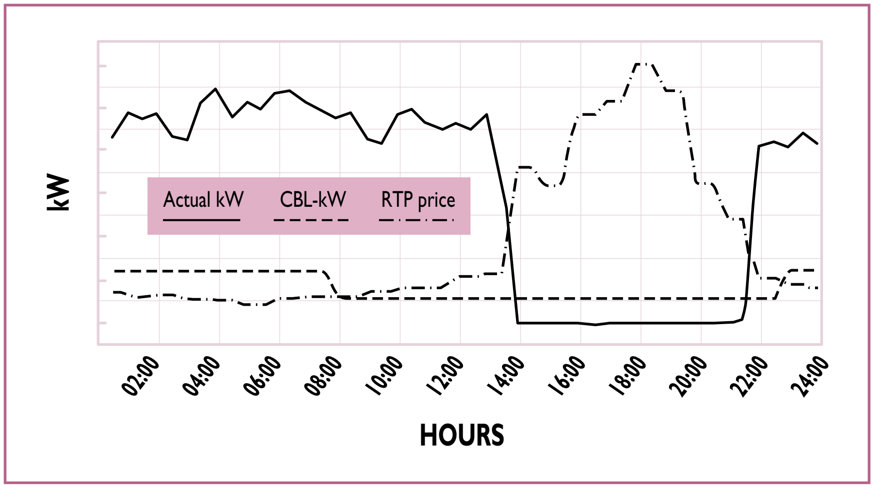
Examination of the reactions of the customers to the rate design indicated the experiment was an immediate success. GPC filed for a permanent rate even before the second year was finished. Test group customers, in total, moved blocks of load off of the peak and added additional load off-peak.

DESIGN OF THE RTP RATE

Georgia Power's RTP rate has two components: a fixed, customer-specific charge, known as the standard bill, and a variable component known as the hourly marginal price.



10. Federal Paper Board—RTP performance (summer weekday without large price spikes)



11. Federal Paper Board—RTP performance (hot, high system load, summer weekday)

Customer's standard bill

The standard bill is based on the customer's historical hourly load shape which is referred to as the customer baseline load, or CBL. The CBL is used to calculate what the customer would have paid on the previous firm (non-RTP) rate for that historical usage. This CBL and standard bill are what allow Georgia Power to collect embedded revenue requirements while ensuring the customer against large increases in marginal costs resulting from unexpected capacity disruptions (i.e., if the customer reduces consumption down to its CBL, the customer is no longer purchasing marginal priced energy or the customer can reduce consumption below its CBL and receive hourly credits at the respective RTP price).

Hourly marginal price

The hourly marginal price is the price RTP customers pay for energy consumption above their CBL or the value they receive as a *credit* for consumption reduction to levels below their CBL. Under the two-part tariff, only the incremental usage from the CBL is priced at the RTP price; whereas, under a one-part RTP rate, *all* usage is priced at the RTP rate. If an RTP price were 20 cents/kWh, under the two-part rate, only *usage above* the CBL is priced at this rate (or usage below the CBL is *credited* at this price). But under the one-part rate, *all usage* is priced at this rate (*plus* usually some multiplier to recover embedded revenue requirements).

The marginal price at any given hour reflects several factors. In the original RTP rate, the RTP price components are calculated and set the day before the prices are to be in effect. These prices are then communicated electronically to the customer. Below are some examples of prices that could be experienced under RTP:

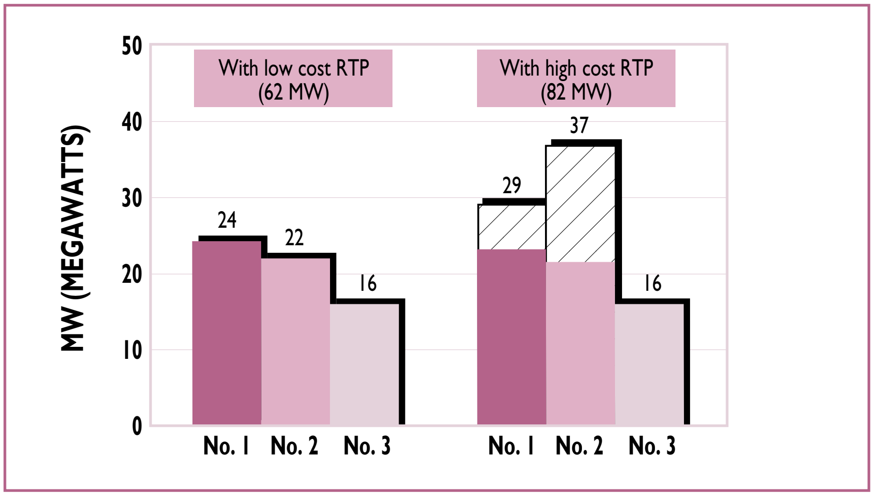
As illustrated in **Fig. 1,** the first three components are used in all hours of the year and are typical of days in October through May and low cost or off-peak days in June through September.

Figure 2 shows an example of when all five components of the RTP rate appear. All five components appear in only a small percentage of hours during the year and are typical of hot days, high load conditions, and/or system emergency conditions.

RTP BILLS

A bill under RTP is calculated by taking the CBL and pricing it under standard rates. Then each hour's actual usage is compared to the historical CBL usage in that hour. If the actual usage in the hour is greater than the CBL in that hour, the incremental usage is multiplied by the RTP price for that hour and added to the standard bill. If the actual usage is less than the historical usage in that hour, the decremental usage is multiplied by the RTP price for that hour and is subtracted from the standard bill.

KEYWORDS
Electric utilities, electricity, energy consumption, forest products industry, Georgia, paper industry, prices, public utilities, southeastern USA, southern USA.



12. Federal Paper Board in-plant generation

This is done for each hour in the billing period (**Fig. 3**).

RTP RATE PROGRAMS

In the initial experiment, the customers had to have at least one megawatt of load. In the latest version of the rate, this has been lowered to 250 kW. The original experiment provided the RTP prices to customers the day before the prices were to go into effect. This original rate was initially known as RTP-X (for experimental) and is now known as RTP-DA (for day ahead pricing). These prices are firm and communicated to the customer by 4 p.m. the day before the prices go into effect.

During the first year of the experiment, GPC and several other larger industrial customers were working on a variation of the RTP rate. These customers indicated they could react more quickly to changing RTP prices than most other customers. These customers had processes in which they could shut down with one-hour notice. Responding to customer needs, another version of RTP was introduced and became known as RTP-HA (for hour ahead pricing). Under this rate, the customers must be at least 10 megawatts, be on GPC's interruptible service (IS) schedule, and be able to react to prices that are provided 1 hour before they become effective. Under this option, the customers are provided a *forecast* of RTP prices for the next 24 hours, but the final price will be available to them 1 hour before the final price goes into effect. Under extreme system reliability conditions, GPC also has the right to interrupt the HA customers down to a contract threshold. Customers are paid up to US$ 45/kW for the amount of kW contracted for between the peak in the CBL and this threshold. If during an interruption the customer does not come to this level, the customer pays the going RTP-HA price and a penalty as stated in the IS rate.

The RTP price components under RTP-DA and RTP-HA are the same except for the risk recovery factor. Under the RTP-DA rate, the factor is 5 mils/kWh and for RTP-HA the factor is 4.5 mils/kWh. The difference is that the HA customers are shouldering more of the risk of price fluctuations since the magnitude of their price components are calculated as firm merely 1 hour ahead as opposed to the RTP-DA customers whose prices are firm the day ahead.

HOW DID CUSTOMERS REACT?

Based on the experiment, customers reacted in a variety of ways based on their individual needs and the RTP price in effect:

- Customers who were growing and were price-sensitive added usage in the off-peak hours and came down to their CBL during higher priced hours (**Fig. 4**).
- Customers who were not growing shifted usage from the higher cost hours to the lower cost hours, thereby using the same amount of electricity but lowering their energy bill overall (**Fig. 5**).
- Customers who were not growing and could shut down operations or run cogenerators decreased usage in the higher cost hours (**Fig. 6**).
- Customers who were not price-sensitive and/or had to get production finished did not respond to prices and in many cases added usage in all hours. This was especially true of those customers who were increasing production (**Fig. 7**).

Those customers who had been on the supplemental energy (SE) rate now could use energy as they decided, not as the utility decided. The customers were more satisfied in that they had more control over their energy bills, and the utility was more satisfied in that, while their customers were more satisfied, they were recovering their costs. The RTP rates also allowed customers who were growing and had not been on the SE rate a chance to grow without incurring additional demand charges and not having to curtail usage by having to go on the SE rate for this increased usage. Experience acquired during the pilot did reveal some "buy-through" in what would have otherwise been curtailment hours but, during critical high priced hours, the customers actually curtailed more than they would have had they remained on SE.

ACTUAL RESULTS

The experimental RTP rate became effective on July 1, 1992. By the end of the year, there were 22 customers on the rate. The kWh growth of those customers was about twice the growth of non-RTP customers, and the growth was primarily in the off-peak periods.

In 1993, the weather was extremely hot and there were long periods when there was no rain to cool the temperatures. Customers reacted more to the prices than ever. On many days, there was as much as a 2500% increase in prices. However, customers did react to these prices. Based on the analysis of the usage by the customers, there is price elasticity and the customers do react to the different levels of prices.

In June 1993, the hour ahead RTP rate was introduced. By the end of 1993, there were 57 customers on the RTP rates. Again the growth in kWh usage was about twice that of non-RTP customers and the growth was still occurring off-peak. The RTP rates generated about US$ 7.6 million of additional incremental revenue to the utility but, while the average bill per RTP customer was up about 7%, the average cents per kWh was down about 5%.

In 1994, the weather was not as hot as in 1993 and there was ample rainfall to cool temperatures. In 1994, both the RTP-DA and RTP-HA rates were made permanent and opened to all customers who met the eligibility requirements. The minimum load requirements were lowered to 250 kW in December 1994. By the end of 1994, there were 291 RTP customers on the RTP rates. Again the growth in usage for RTP customers as a whole was about twice that of non-RTP customers. Prices were relatively mild and growth in usage was even all across all periods. Incremental revenue for the utility was up by about US$ 20.7 million. The average bill per RTP customer was up by approximately 9%, but the customer's average cost per kWh (including usage under their CBL) was down about 9%.

One additional outcome of the experiment is the development of a price response model. This model takes the historical reactions of customers to prices (**Fig. 8**) and uses the responses along with the current models to enhance the forecast of the marginal cost component of the RTP price. If we know how customers will react to prices above or below certain levels, we can incorporate this information to better reflect what the system costs and conditions will be for the next day.

By also increasing sales in the off-peak period, the utility's load factor is increased and therefore the utility is running more efficiently and can pass these savings onto the customers.

The state of Georgia has also been a winner under the RTP rate. By mid 1994, there had been an increase of 3000 new jobs and an increase of US$ 0.5 billion of new investment in the state. GPC and the Georgia Department of Industry and Trade work closely together to make economic development happen.

ONE MILL'S EXPERIENCES

Federal Paper Board's involvement with Georgia Power's RTP program dates back to 1991 when this new rate concept was under development. Federal was involved in the dialogue between the Georgia Industrial Group and Georgia Power. This involvement helped Georgia Power create an offering that would match customer needs and capabilities.

In order to foster an atmosphere and to possibly allow flexibility to incorporate changes based on experience, the suggestion was made for this to be named an experimental rate initially. Federal believes the recognition by Georgia Power, its customers, and the regulators, that RTP was an experiment was a key factor in the progress of the RTP program from 1992 to 1994 when it became permanent.

Federal's Augusta, GA, operations (a large bleached paperboard mill) subscribed to RTP-X (the name of the experimental rate) in January 1993. The mill's response to the rate's price signals has been extremely successful. Federal had been on PLL (Power and Light—Large) with SE (supplemental energy). Federal is now on RTP-DA since its approval as a permanent rate. The following are some examples of how the plant responded to Georgia Power's price signals.

The first example (**Fig. 9**) is for a relatively mild summer weekday, Wednesday, July 20, 1994. The RTP price spike duration was about 4 hours. During that time, Federal increased generation to reduce purchases to a minimum level. This was done in accordance with a previously developed operational procedure. The cost basis for generating electricity in the condensing mode is coal as the marginal fuel.

On days, such as Tuesday, Aug. 30, 1994, when the RTP price spike is not very significant (**Fig. 10**), RTP purchases are not displaced.

However, on hot, high system load, summer weekdays, such as in **Fig. 11** for Monday, July 18, 1994, RTP prices can peak for an extended period. This spike was for 8 hours. With actual purchases less than the customer baseline (CBL), not only is the high price RTP purchase avoided, but credit is received at RTP rates for the amount of energy not used below the CBL.

Operationally (**Fig. 12**), some 90 psig extraction is shifted to the No. 1 turbine generator, raising its output by 5 MW to a maximum capacity of about 29 MW. The No. 2 turbine generator is run with a higher condensing flow, with output increasing by 15 MW to 37 MW. The output of the No. 3 turbine generator remains constant at 16 MW. Some of the extra capacity in Nos. 1 and 2 turbine generators results from a rebuild of No. 3 during a recent capital program.

The plant's load is around 84 MW with the plant making 62 MW with minimum condensing and the plant buying an average of about 22 MW during lower RTP prices:

24 + 22 + 16 = 62; 62 + 22 = 84

During higher RTP pricing, only 2 MW is purchased:

29 + 37 + 16 = 82; 82 + 2 = 84

RTP has helped Federal reduce overall energy costs and provide a cost-effective incentive to add future load at this facility.

Federal has recently subscribed to RTP at its sawmill, which is adjacent to the paperboard mill. The sawmill increased operations to three shifts, from two, due to increased demand for lumber. RTP was the most cost-effective option for supplying the additional energy requirements. Now that the facility is on RTP, opportunities for reducing load during high-priced periods will be explored.

Basically, a customer can optimize the use of energy by using RTP through either a supply-side method or a demand-side response. If the customer possesses supply side resources such as self-generation, the customer can choose to rely upon his own generation when it is cheaper than the RTP price offered by the utility for that time period. The customer can later back down on generation and rely on the utility when the RTP prices are less than the cost of the customer's self-generation. Using demand side resources, a customer can select certain production processes for interruption whenever the RTP price rises above predetermined threshold levels. Customers oftentimes build up inventory levels of certain products or ingredients in anticipation of selected product interruption so that if selective interruption is necessary, major production processes can sail through without interruption. Georgia Power has customers using both methods on RTP.

With the changes forthcoming in the purchased power marketplace, it is increasingly important for customers to have a stronger technical understanding of the utility's rate offerings. This is true not only so the customer can achieve the optimum economics with the present rates in effect, but also to facilitate proactive interface with the utility toward the development of new rate offerings which have mutual benefit.

WHAT NEXT?

Utilities will continue to look at various future options for the customer. Georgia Power has instituted three new time-of-use rates. The company is also looking at other alternatives such as price insurance for customers to protect themselves during high-priced periods and rates that treat a customer's separate accounts across the state as one account.

With the likelihood of open access, the customer wanting more options, and the competitive nature of alternative fuel sources, utilities must be prepared to enter a new competitive environment. The utility must be willing to take risks because "you cannot discover new oceans unless you have the courage to lose sight of the shore."

Electricity will be an increasing vital energy source for the pulp and paper industry. Although benefits of the RTP concept are not limited to this industry, many mills will have the option to obtain a lower cost supply of purchased electricity in accordance with their process requirements while using operational capabilities in conjunction with the utility's load management programs. Through the development and use of RTP programs, electric utilities can achieve load management objectives, better use generation resources, and be prepared to compete in an open marketplace, all with concomitant benefit to the customer. **TJ**

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