TECHNICAL FEASIBILITY ASSESSMENT AND DEVELOPMENT OF A PROOF-OF-CONCEPT ELECTRIC UTILITY RATE SCHEDULE EVALUATION TOOL (RATE SET)

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June 1995

Presented at the
Competitive Power Congress 1995 Conference
June 21-22, 1995
Philadelphia, Pennsylvania

Prepared for
the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

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Technical Feasibility Assessment and Development
of a Proof-of-Concept
Electric Utility Rate Schedule Evaluation Tool
(RateSET)

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1.0 INTRODUCTION

Federal military installations often receive electric utility service under "special" rate schedules designed for large government and institutional facilities. These schedules are intended to be financially beneficial to the government when compared with rates offered to large non-federal customers. Past experience, however, indicates that this may not always be the case. Determining the applicability and cost-effectiveness of alternative rate schedules is a complicated process requiring the analysis of utility bills and computer simulation of diurnal load data and utility rate structures. A layer of complexity is added if the federal installation receives service from more than one electric utility and is considering consolidated billing.

In 1993, under a project with the Air Force, Pacific Northwest Laboratory (PNL) examined the possibility of developing a methodology to facilitate the evaluation of alternative rate schedules. To meet the objectives of this project, PNL performed two tasks as follows:

**Task 1.** PNL developed a proof-of-concept prototype computer program (RateSET) that compares the costs under a government rate schedule to those back-calculated under an alternative rate schedule. The program was used to recreate the structure of both rate schedules and then to process 24 monthly billing statements and the associated 30-minute demand data for the two year period. For the initial test case, actual data were used from a large U.S. Army Forces Command (FORSCOM) installation located in Georgia.

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¹ Pacific Northwest Laboratory is operated by Battelle Memorial Institute for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830.
After inputting the data and debugging the program, PNL experimented with a plausible load management what-if scenario to determine the impact under both schedules. This additional exercise was performed to provide an indication of the potential breadth and value of the RateSET program.

**Task 2.** PNL then reviewed the tariff packages for each of the major electric utilities providing service to Shaw Air Force Base in Sumter, South Carolina. The primary objective of this alternative rate schedule screening and evaluation process was to characterize the process itself, identify problem areas, and develop a workable approach to use in future similar evaluations.

The remainder of this paper presents the findings from Task 1 and Task 2.

### 2.0 FINDINGS FROM TASK 1 - DEVELOPMENT OF THE RateSET PROGRAM

The government schedule used in the proof-of-concept program is Georgia Power Company’s (GPC) G-10 rate. The G-10 schedule is classified as a Wright Demand rate where the energy charge is based directly on the number of kWhs used and indirectly on the monthly demand (kW). The alternative rate, GPC’s Schedule TOU-4, is a seasonal time-of-use rate.

GPC’s schedule G-10 is for Federal, State, and Municipal agencies and institutions taking service at a single delivery point through a single meter. This schedule is not applicable to agencies or institutions that are predominantly residential, nor for customers with more than one meter. The G-10 schedule is a rate form that combines demand and energy costs into a blocked cost per kWh, which is based on the equivalent time maximum demand is used each month. The "hours use" component is computed by dividing the total kilowatt-hours by the peak demand. The first 300 hours’ use is charged on a four-tier declining block and the remaining usage is billed on a flat rate. There is a demand ratchet -- 95% for the eleven preceding months for the summer period (June through September) and 60% of the highest winter months (October through May, including the current month). There is also a power factor penalty with the excess reactive demand billed at $0.27 per excess kVAR.
Along with GPC's schedule G-10 comes the company's Revenue Adjustment Rider, Schedule "RA-1." The rider decreases the bill after all adjustments excluding state and local taxes. The rider is updated monthly based on the amount of return established by the Georgia Public Service Commission.

Georgia Power Company's TOU-4 rate schedule has a monthly Base Charge of $475. Demand charges are in a declining block based on summer and winter "on-peak" and economy demand "off-peak" periods. Economy demand only comes into play when the off-peak demand exceeds the on-peak demand. Energy charges vary by time of day and by season. The highest cost period for energy is similar, but not identical, to the on-peak demand period. Energy costs in the winter period are significantly lower than in the summer. Like the G-10, the TOU-4 has a fuel cost recovery adjustment schedule, and power factor charges are also identical to the G10's.

The structures of the G-10 and TOU-4 rate schedules were programmed into RateSET. For the proof-of-concept we compared two rate schedules, however, it is possible that a utility could have more than one alternative rate schedule. In a fully functional program, the user would select underlying rate structures that best describe the schedules to be analyzed and could compare as many different structures as applicable. The RateSET program would "prompt" the user to build an accurate facsimile of the original rate structure using current costs.

Twenty-four (24) months of thirty-minute (30-minute) interval demand readings from Fort Stewart were placed in a spreadsheet program. Using these data, RateSET recalculated the utility bills. The recalculated G-10 data were validated by comparing the results to the actual bills (calculated costs were within pennies of actual billing charges). The demand data were also processed using the alternative rate, GPC's TOU-4 rate, and the results were validated by performing hand calculations for a number of months.

A data-processing system was developed to "manage" the diurnal demand data to account for variations in the billing period (from 28 - 34 days). Impacts of rate changes or rider changes that occurred during a monthly period also had to be programmed. If the billing period and rider clauses were more consistent every month, bill calculation would be simplified, but unfortunately this is not the case. These factors need to be accounted for to accurately compare different rate structures.
When compared head-to-head using actual data, the time-of-use rate, GPC's TOU-4, saved Fort Stewart $72,806 over a period of one year compared with use of the G-10.

Another simulation was run with the peak demand limited to a plausible level of 25,000 kW (31,629 kW was the high peak demand for the year). A view of the aggregate demand profile shows a peak during the summer months. This peak impacts the G-10 through the 95% ratchet but also corresponds to the on-peak periods in the TOU-4 rate -- the highest-priced tier. The RateSET program was run to find out how costs would change under both rate schedules using the load management scenario (peak shaving to 25,000 kW). The comparison after peak shaving indicated that Fort Stewart would save $131,649.90 on the G-10 rate schedule compared with use of the TOU-4.

The trade-off between rate structures resulted from savings across the entire year on the Wright Demand rate because of the ratchet clause, whereas, peak shaving only affects a time-of-use rate structure during the peak periods.

3.0 FINDINGS FROM TASK 2 - SCREENING AND EVALUATION

This section provides a description of the information requested and received from the electric utilities providing service to Shaw AFB: Carolina Power & Light (CP&L) and Black River Electric Cooperative (Black River). Rate schedules and energy usage data were evaluated to determine the value of further analysis using the RateSET program.

Carolina Power & Light

Information was obtained from CP&L through two phone calls to CP&L's Account Representative to Shaw.

The account representative provided PNL with the following information:

- a summary billing statement covering 20 months for each of the four accounts
- one sample monthly statement for the "Main Meter" covering all accounts and providing the monthly total
- microfilm containing 15-minute demand readings for both a summer and winter month for both Wherry Housing and the Main Meter,
- copies of six rate schedules and three riders
In the one-year period from August 18, 1992 to August 20, 1993 Shaw paid CP&L a total of $4,320,273 for 79,619,298 kWh at a unit cost of $0.0543/kWh. Demand charges accounted for approximately 38% of the total cost (inferred from the one billing statement provided for October 1993). The high peak demand came in the summer at 16,703 kW and the winter high registered at 12,978 kW.

CP&L has a 115kV line into a step-down transformer (115kV/23kV) at Shaw AFB. CP&L meters the power and energy on the high side of the transformer. Power is distributed on the base by a 12kV feeder owned by Shaw. CP&L also has a submeter at Wherry Housing that measures total kW and kWhs. Street light energy use is registered under the Main Meter account but then subtracted for billing purposes and is rebilled under CP&L "Area Lighting Service - Schedule ALS-79." ALS-79 is a schedule that uses monthly charges per fixture based on the fixture type (HPS, Metal Halide, and Mercury Vapor).

Shaw currently takes service under the "Large General Service - Schedule LGS-79". LGS-79 is for nonresidential customers with a contract demand or load of greater than 1,000 kW. This is a Hopkinson-type rate schedule characterized by a demand and energy component. The kW demand is billed on a three-tier declining block. The energy component is a flat block with the fuel adjustment built-in to the kWh charge that appears on the rate schedule. There is a demand ratchet - 80% for the eleven previous months for the summer period (July through October), 60% of the preceding eleven billing months for the winter period (November through June), or 75% of the Contract Demand. (The CP&L account representative could not supply exact information on the Contract Demand level for Shaw, but indicated that it would only come up if CP&L had to put in new facilities to meet new load). Power factor charges are levied if the power factor for the month is less than 85%. There is a "Transformation Discount" with both transmission and distribution components. This element of the rate currently does not come into play at Shaw.

Along with schedule LGS-79 comes the "Military Service Rider No. 28k." The purpose of the Rider is not entirely apparent, however, it is likely that the Rider gives Shaw the right to redistribute or extend distribution to various points of use should the need arise. Furthermore, the Rider indicates that CP&L "may continue to provide distribution facilities where the customer is required by Federal Government regulations to supply electric service."
Alternative Rates

CP&L's Medium and Small General Service rate schedules can be quickly eliminated as direct alternatives because their "Availability" criteria requires less than 1,000 kW and 30 kW of demand respectively.

The "Large General Service" (Time-of-Use) Schedule LGS-TOU-79 is a possible alternative. The CP&L account representative indicated that the potential beneficial use of TOU-79 is monitored by CP&L and that their general rule-of-thumb to determine applicability is a minimum load factor of 82%.

Similar to the LGS-79, the TOU rate has a monthly "Basic Facilities Charge" of $425, power factor charges, fuel adjustments, and T&D discounts. Demand charges are on a declining block and vary in cost from the summer to the winter period and from on-peak to off-peak. Both the summer and the winter season on-peak demand charges are higher on the TOU rate relative to the LGS-79 rate and energy charges are lower.

On-peak is defined as between the hours of 10:00 a.m. and 10:00 p.m., Monday through Friday (excluding holidays considered as off-peak), from April 1st through September 30th, and between 6:00 a.m. and 1:00 p.m., plus 4:00 p.m. through 9:00 p.m., Monday through Friday from October 1st through March 31st. Off-peak are all other hours, Saturdays, Sundays, and holidays.

Off-peak excess billing demand is defined as "the maximum demand registered or computed by or from Company’s metering facilities used during any 15-minute interval in the off-peak hours of the current month less the on-peak billing demand."

Copies of two additional riders were also provided by CP&L: Dispatched Power (Experimental) Rider NO. 68C and Curtailable Load Rider NO. 58W. Apparently the Dispatched Power rider was designed for textile manufacturing companies and is only good through January 31, 1994. The Curtailable Load Rider is complex. Further clarification is required from the CP&L account representative before this Rider could be considered as a viable alternative.

Black River Electric Cooperative

Information from Black River was obtained through phone calls to Black River's General Manager.

The General Manager provided PNL with the following information:

- summary billing statements (15 months of data from September 1992 through November 1993) for four accounts - (capital credit data was hand written on the statement)
copies of two rate schedules and one rider.

In the one-year period from December 1992 to November 1993 Shaw paid Black River a total of $962,826 (and received capital credits totalling $54,375) for 15,690,200 kWh at a unit cost of $0.0579/kWh (after capital credits). Demand charges accounted for approximately 23% of the total cost. The high peak demand came in July at 4501 kW.

Black River has several feeders into Shaw AFB and services the 500 Housing Unit, the 1980 Building, the Exchange Building, and the Gunnary Range. The 500 Housing Unit, 1980 Building, and Exchange Building are provided service under "Large Power - Schedule LP", and the Gunnary Range under "Small Commercial - Schedule B."

Schedule LP appears to be straightforward with all demand billed at $6.00/kW and all energy billed at $0.05/kWh. There is a demand ratchet set at 90% of the billing demand during the preceding six billing months (data on the utility bills indicate that this ratchet mechanism may not be enforced). A power factor correction clause allows Black River to adjust the "integrated demand" -- by multiplying by 85% and dividing by the average power factor in percent for that month." This would have the effect of increasing the "integrated demand" as the denominator is by definition smaller than 0.85. The rate schedule also includes a Wholesale Power Adjustment Charge that allows Black River to pass through increases in purchased power costs.

Applicability of a RateSET Analysis of Shaw AFB Using CP&L Schedule LGS-TOU-79

CP&L mentioned that at one point Shaw AFB was on the TOU rate but reverted to the LGS-79 rate. The account representative pointed out that an 82% load factor is needed to reap the benefits of the TOU rate. The 10-weeks of diurnal data provided for the Main Meter indicate that Shaw's load factor is consistently near or above 82% (a full year of data is needed to confirm). Graphing selected days of the diurnal data gives visual support to this finding, showing a relatively flat profile. In addition, the summer demand ratchet is 80%, considerably less severe than GPC's G-10 95% ratchet, for example. Given these considerations, running the RateSET program with the TOU schedule as the alternate rate is recommended. Realistic load management, cogeneration, or energy efficiency scenarios could then be used to "sensitize" the results.
The CP&L account representative indicated that the utility "does not" retain historic 30-minute demand readings electronically. She stated that CP&L does keep the data on hardcopy and microfilm. However, CP&L can provide Shaw with an IBM-compatible electronic version of the demand data on a monthly basis for a nominal charge of $20/month. It is recommended that Shaw immediately request the demand data electronically. In fact, we suggest that all federal installations advised to request the monthly demand data from their electric utilities. Although they may not be able to use the information immediately, they may be able to in the near future.

4.0 CONCLUSIONS

The concept of a computer program that uses real-time demand data to evaluate the impact of alternative rates (as well as load management and energy efficiency activities, standby generation, and cogeneration) is proven feasible. The output from the RateSET program is much more accurate than savings data generated by less dynamic methods of energy study that do not consider actual rate characteristics and diurnal demand data on an integrated basis. More accurate savings projections usually lead to better decisions on capital investment.

Results of the preliminary research indicate that the RateSET computer program can be developed to encompass the range of rate schedules currently in use and the input data formats anticipated from utilities. Because of the variety of rate schedule permutations, however, it is possible that the major generic categoric rates (Hopkinson, Wright, seasonal TOU, Block, etc.) may not capture all of the rate schedules currently in use. In addition, new approaches to rate design may be introduced in the future. Therefore, the ideal approach to the continued development of RateSET is to structure the program to allow "easy-to-perform" alterations by the end-user as well as to provide modularity in the program to allow introduction of contemporary structures as they become applicable.
Data Collection from Utilities

To perform an effective rate comparison analysis, the following information should be obtained from each servicing electric utility:

1. Copies of all potentially applicable rate schedules and riders.

2. A summary printout of the most recent 24 months' billing data accompanied by at least several representative samples of the actual monthly billing statements. (Often the actual billing statement provides important additional information, such as specific rate changes.) Ideally, all 24 months' bills should be obtained.

3. Electronic data on 24 months of 15- or 30-minute demand readings accompanied by hard copy or microfilm versions, (The hardcopy or microfilm is used to clarify any glitches that may occur in the transfer of electronic data into a usable format.)

4. The utility's most recent Annual Report and Integrated Resource Plan (gives indication of utility's capacity and energy disposition in the near and long-term).