Utilizing Load Research Data for Direct Access Forecasting and Reconciliation

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ABSTRACT

This paper introduces a key problem created by direct access programs: how can monthly-read electricity consumption data be allocated and spread across all hours of the monthly billing cycle to identify the hourly load scheduling requirements for each Energy Service Provider (ESP). A utility's existing load research data is a critical resource in determining how to allocate loads across all hours of each billing cycle.

Alternative methods to allocate monthly-read consumption data across each billing cycle are reviewed. The specific methodology used by one utility to both forecast each ESP's load scheduling requirements and reconcile their hourly load schedules to customers' actual electricity consumption (including line losses) is described. Preliminary observations are provided on the accuracy of using historic load profiles and weather-adjusted daily consumption data to estimate both the actual utility system load and the load of each ESP. Several lessons learned are presented on how to further improve the accuracy of forecasts and reconciliation of ESP load requirements using load research data.

Introduction

This paper considers a key problem created by direct access programs: how can monthly-read electricity consumption data be allocated and spread across all hours of the monthly billing cycle to identify the hourly load scheduling requirements for each Energy Services Provider (ESP). Hourly data is needed to both forecast ESP load requirements and to reconcile their customers' actual electricity consumption to the power that was scheduled and shipped to the utility.

Portland General Electric (PGE) identified this problem as they prepared for a direct access pilot involving approximately 50,000 customers. Utilities have traditionally forecast the total system load on an hourly basis for planning purposes and for managing the power supply needed to meet customers' demand. They have used a variety of macro-level techniques that are based on the historical relationship of total system load to weather, day of week, hour of the day, holidays and other causal variables. Such forecasts, referred to here as "top-down" due to their macro-level techniques, are insufficient to allocate monthly-read meter loads to the supplying ESP by hour.

PGE considered a variety of methods to allocate monthly-read load data across all hours of each billing cycle. The possible solutions ranged from using only the total system load shape as a basis for allocating all customer loads to recommending the installation of telemetry based hourly-interval metering for collecting near real time actual hourly usage data for building empirical meter segment load models.

There is no consensus on the best methods to use to allocate monthly read meter data across all hours of the billing cycle (Farley 1997, Goldberg 1997). Rochester Gas & Electric utilized the simplest approach possible - allocating customer loads using the total system load adjusted for selected large interval metered loads. Several utilities have used "deemed" methods to allocate flat loads like streetlights or traffic signals across a billing cycle. The major California utilities have utilized static load profiles during the early introduction of California's open electricity market. NEES adopted a "proxy-day" methodology to allocate loads across a billing cycle (Laccetti 1997). Finally, the installation of AMR technology on a random sample of residences and businesses to perform dynamic profiling has been proposed by the California Public Utilities Commission for the major utilities in California (PG&E 1997, SCE 1997, SDG&E 1997).

This paper will review alternative methods to allocate monthly-read consumption data across each billing cycle. The specific methodology adopted by PGE to both forecast each ESP's load scheduling requirements and reconcile their hourly load schedules to customers' actual electricity consumption (including line losses) is described. Preliminary observations are reported on the accuracy of using load profiling methods to estimate the load of each ESP. Several lessons learned are presented on how to further improve the accuracy of forecasts and reconciliation of ESP load requirements using load research data.

Alternative Methods to Allocate Monthly-Read Consumption Data

The methods considered by PGE ranged from the simple to the complex. At the time the evaluation began, only New Hampshire had extensive experience with direct access pilots. The California Direct Access workshops were just being initiated. PGE considered a wide range of theoretical, practical, economic and political issues. The requirements established by PGE to select a load profiling methodology included: a) simplicity of implementation, b) transparency of approach, c) accuracy, and d) fairness to ESP's. The methods explored are listed in Table 1.

The first method to be considered was also the simplest and least expensive - the system load profile. The system load proxy is comprised of simply subtracting known load research meters that have telemetry from the daily system load and assigning the remaining shape to all other customers. While the approach met several of our criteria, it is not necessarily fair to ESP's. PGE considered whether to subtract current residential load research estimates from the system load, and use that remainder as the commercial and industrial profile. Since our entire residential hourly interval meters were read on a 60-to-90 day basis, this method would overly protract the reconciliation process.

The deemed approach uses simple variables like times for sunrise and sunset to estimate load shape pattern. This approach can be used where a load has a very predictable flat or patterned load shape. Examples include predictable loads like traffic lights, streetlights, or telephone booths. This approach is not an accurate or fair method for allocating most other variable loads.

The static estimation approach utilizes same day historical load profile data to allocate monthly-read data. This data is often collected to set pricing for a utility's existing tariff schedules. PGE's load research sample was designed to support marketing efforts and not rate making. Business activity types provided the basis for the stratification method instituted by PGE's Marketing Intelligence Group. This data can not accurately represent daily variability caused by weather conditions nor was it applicable to highly variable commercial and industrial loads.

PGE also considered the most complex method - dynamic profiling. This would involve replacing existing load research meters that did not have telemetry with ones that did. In addition, this proposal included metering every meter with a load over 500 kW. While this approach may be the preferred model of the future, it was neither practical nor cost-effective to implement within the six-month time frame required by the introductory launch. Further, the relatively recent installation of new load research meters discouraged writing-off the prior meter capital investment. PGE explored the cost of this wide scale change out. It was prohibitive to the budget for the initial launch. Existing system requirements such as download times, existing computer technology, and storage capabilities precluded using this method for the introductory program.

Table 1. Alternative Methods to Allocate Monthly-Read Consumption Data

Method	Strengths	Weaknesses
System Load Proxy - subtract known interval loads from total utility system load. Use this difference to allocate monthly-read data.	Simple & inexpensive solution. Representative of the overall system load.	Not fair representation of customer segment load shapes.
Deemed Load - use simple variables like sunrise or sunset to estimate patterned load shapes.	Simple & inexpensive method. Accurate approach for estimating flat or patterned loads.	Only appropriate for loads like streetlights, traffic signals and telephone booths.
Static Estimation - utilize prior year same day historical load shape data by market segment to allocate monthly-read meter data.	Data availability from internal load research studies. Representative of current tariff pricing.	Does not accurately represent daily variability caused by weather. Not applicable for highly variable commercial and industrial loads.
Historical Proxy Day - select the load shape from days with similar weather conditions or other conditions as the best proxy for allocating daily loads.	Accurate representation of customer segment and total system loads.	Difficult method to use for load forecasting. Generally not applicable for highly variable industrial loads.
Modeled Approach - create models based on weather, day-type, holiday, and other variables to estimate energy consumption. Combine with static load profile data to allocate monthly-read meter data.	Uses both static load profile data and dynamic weather variables to allocate monthly-read meter loads. Provides capability for load forecasting.	No agreement on which modeling methods are best.
Dynamic Profiling - utilize actual load data collected for each day as the bases for allocating monthly-read consumption data for that day.	Most accurate method available to allocate monthly meter loads. Only accurate method for large variable commercial and industrial loads.	Expensive. Data intensive.

The approach adopted by PGE was a combination of dynamic profiling, deemed, and modeled methods. PGE decided to use dynamic profiling for large commercial and industrial meters. Our existing coverage of the larger meters using telemetry-based hourly metering was fairly complete. Additional interval metering & telemetry was added as ESPs signed up large customers. Next, the deemed approach was recommended for constant and daylight-hour dependent loads. Finally, a modeling approach was devised for the remaining residential and commercial customer segments to model the variable effects of weather, day of week and other factors. During our analysis, we determined that our metering and sampling was sufficient in the residential market and moderate-size commercial market, but not adequate for the small commercial market. Additional load research metering was needed to supplement the sample for the less than 100 kW groups. This required about 150 additional meters to meet Customer Choice and additional rate making requirements. The details of the complete methodology adopted by PGE are described further in the next sections.

Load Forecasting and Post-DOF Estimation Methodology Adopted by Utility

PGE designed the methodology and supporting software to forecast the hourly load requirements for each ESP operating in the service territory based on the portfolio of customers these ESP's maintain. ESP's are contractually required to deliver power to meet the forecast. Further, after the day of flow (DOF), PGE estimates the quantity of power consumed by each ESP's customers on an hourly basis. The estimates of actual use coupled with the amount of power delivered are billing determinants in the financial settlement that occurs between an ESP and PGE for balancing services.

PGE's load forecasting and post-DOF load estimation methodology has 3 major phases: 1) a DOF-1 forecast; 2) a DOF+1 preliminary estimate of load; and 3) a DOF+35 final estimate of load. It is not the purpose of this paper to go into detail of how the forecasting and load estimation process works. However, it is important to note that load models play a direct and identical role in the first two phases and an equally important but indirect role in the third phase. As the role of load models is identical in phases 1) and 2) it will suffice to describe how load research based load models are developed and used in the forecasting process.

Forecasting ESP daily load profiles

With the advent of competition in the electricity marketplace multiple ESPs need to schedule power into a utility's service territory, again on an hourly basis. There are two approaches to accomplishing this. The first allows the various ESP's to forecast their individual loads, set their schedules, and communicate them to PGE by 6 am on DOF-1 so that PGE can schedule the purchase or sale of power to balance total scheduled power with total system forecast demand. The second requires PGE to partition the forecasted hourly system load among ESP's and prescribe each ESP's schedule by 6 am of DOF-1 so that they can purchase power to meet to the schedule. PGE has chosen to provide forecasted hourly loads to ESP's during the introductory program.

To accomplish this, the total system load forecast needs to be partitioned into the load forecasts for the various ESP's. With this approach, PGE is considered just another one of these ESP's. As each ESP's load requirements depend on its particular portfolio of customers it is necessary to build the individual ESP's forecasts based of the anticipated load of its individual customers. However, because the ESP's portfolios of meters are ever changing they do not form a stable partition of the population of meters upon which to build a forecasting scheme. To circumvent this problem, a more permanent meter segmentation structure is used to build a bottom-up or meter-by-meter forecast of total system First, a bottom-up forecast, balanced to the top-down forecast for the day is calculated. This bottom-up forecast is then partitioned out, segment-by-segment, to the various ESP's based on their current share of the market in each segment. Summing an ESP's forecasted load across segments then gives their total forecast for that day. Figure 1 is a high level schematic of this process.

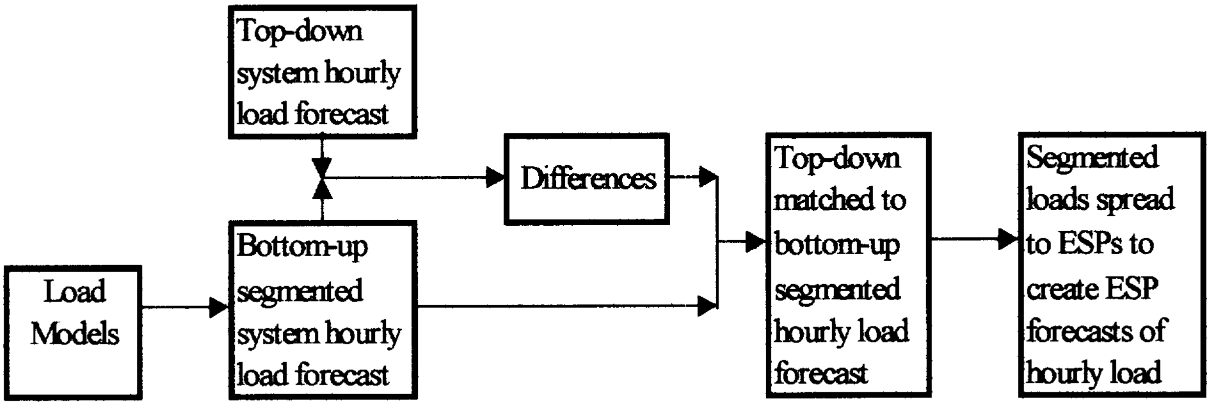

Figure 1. Forecasting ESP Hourly Load Profiles load.

The Structure for PGE's Bottom-up Forecast of System Load

The entire population of meters in the service territory fall into one of two classes: MRMR (Monthly Recorded/Monthly Read) meters, and HRDR (Hourly Recorded/Daily Read) meters. The MRMR meters are further divided into eight segments based on the general characteristics of the load. These eight meter segments include:

Residential electric space heat
Residential non-electric space heat
Night lighting (photocell activated)
Flat (traffic control)
Commercial/Industrial > 1000 kW
Commercial/Industrial 200 to 1000 kW
Commercial/Industrial 30 to 200 kW
Commercial/Industrial <30 kW

For each of the segments in Table 2, the hourly load profile for the collection of meters in the segment must be forecasted. This requires a load model for the typical meter in each segment and a count of the number of meters currently in that segment. The segment specific load models needs to be responsive to the fluctuations in both hourly load shape and daily load magnitude as weather and other causal factors for electricity consumption vary over the year. For forecasting purposes, load models also need to be developed for each individual HRDR meter responsive to the hourly load patterns and magnitudes of their historic loads.

Developing Segment Load Models for MRMR Meters

Each segment's load model consists of 3 components:

1) catalog of characteristic hourly load shapes,
2) catalog of daily load magnitude generators relating the segment's typical meter daily load to temperature, day of the week, month of year, holidays, school schedules, and daylight saving times conversion days, and
3) a calendar relating the day of the year to the appropriate hourly load shape and daily load magnitude generators from the two catalogs above.

Now that we know what we need, it is fairly straightforward to go to the load research data to estimate the required quantities, provided we have load research data and that it is amenable to the above meter segmentation scheme. Admittedly, there is nothing unusual about PGE's segmentation scheme. It is a compromise between the availability of load research data, the ability to map each meter positively into a segment, and a political need to create segments that make sense to ESPs and regulatory agencies. In PGE's case the sample of load research meters was fielded with a different segmentation in mind - with a SIC construct for commercial/industrial meters and with a more detailed end use construct in the residential market. As a result the weights for the individual load research meters within the segments were developed based on a SIC or end use based stratification within segment. There were no load research meters for the night lighting and flat segments but load shapes for these two segments were constructed based on the changing times of sunrise and sunset and the number of hours in the day respectively. Further, load magnitude models were developed based on monthly load values for these two segments.

The steps to generate the load model for each segment are as follows:

1) Using an appropriate weighting of the load research data within a segment, develop the annual hourly load profile for the typical meter in each segment.
2) Identify a family of daily load shapes that characterize the different patterns of load experienced during the year.
3) Calculate the daily kWh load and model that load as a function of mid-range temperature and other driver variables.
4) Build a calendar relating each day of the forecast year to a load shape and a load magnitude model.

To actually make the forecast, two additional ingredients are needed: the forecasted mid-range temperature and the count of the number of meters currently in each segment. For the forecast day, select from the calendar that day's assigned load shape and load magnitude generator model. Calculate the forecasted load for the typical meter in the segment using the load magnitude generator and the forecasted mid-range temperature and spread the forecasted load over the load shape for the day. To forecast the load for the total segment, multiply the typical meters load profile by the number of meters in the segment.

Accomplishing this for all segments and adding forecasted load loss results in a bottom-up forecast for all the MRMR meters in the system. Before proceeding to balancing the forecast to the top-down forecast, we must also forecast the load for the HRDR meters.

Developing Individual Load Models For HRDR Meters

Meters which record hourly load and are read daily give us more timely information for the forecasting process. PGE currently maintains over 150 such meters, all on large loads. They are generally in place for billing purposes though some have been installed for load research purposes. In any case these meters give timely and accurate data on a set of large consumption meters. As all of these meters are on commercial or industrial load they generally have two characteristics. The business process of the company controls the load shapes and the magnitude of the load generally is independent of temperature over short periods of time and typically does not change from week to week. Thus in most cases a forecast for the load tomorrow is the load on the meter in question on the same day of the prior week. When forecasting a weekend holiday, a recent Sunday load is generally a good model. When forecasting a weekday holiday, the same day prior week forecast is probably best.

This approach does not always work well. In some cases the load is sensitive to temperature and the forecast for such a meter can be improved by developing a temperature adjustment component to the same day last week method. In other cases the load is so variable day to day that there is little chance of making a good forecast. In these cases, the most that can be done is to avoid making a bad forecast. This can be accomplished by averaging the loads from the last seven days or the load from the same day over the past 4 weeks. Once the forecasts for the HRDR meters are calculated forecasted load loss is added.

Balancing The Bottom-Up Forecast To The Top-Down Forecast

The bottom-up forecast is now complete as the sum of the MRMR and the HRDR forecasted load plus estimated line and other losses. Prior to partitioning the total system forecasted load among the various ESP's it is necessary that the bottom-up forecast, which is to be partitioned, equal the top-down system forecast. This is accomplished by calculating the hour by hour difference between the two forecasts and proportionally spreading the difference over the MRMR segment forecasts. This forces a balance between the bottom-up and the top-down forecasts. There are two aspects of this process which deserve attention. First some of the imbalance called unaccounted for energy (UFE) should be assigned to HRDR meters also. Also a proportional allocation of UFE across the MRMR meters is in response to the fact that currently we do not have better models of how to spread it. Both of these issues will lead to challenging work in the future.

ESP Forecasts on DOF-1

Now that the bottom-up forecasts based on meter segments and individual HRDR meters is created and balanced to the total system forecast we can apportion each segment's load profile out to the appropriate ESPs based on the relative proportion of the daily load in that segment which has been historically used by the ESP's customers. Such proportions are calculated from the most recent monthly load readings for the individual meters. The individual HRDR meter's forecasts are also assigned to the serving ESP. Each ESP forecast is created by summing their eight segment forecasted loads and their HRDR forecasted loads.

DOF+1 Preliminary Estimation by ESP

The day after power is delivered and consumed PGE calculates an estimate of the actual load consumed (plus losses) by the collective customers of each ESP. The process for calculating these ESP load profiles is identical in form to the forecasting of ESP load profiles described above. The difference is that 3 inputs have changed. The actual system load is now known and used as the top-down control total to which the bottom-up estimate must match. The HRDR meters have been read so the actual load on the DOF for these meters is known. Finally, the day's actual mid-range temperature is known and can be used in the load magnitude generator to estimate the daily load for the typical meter in each segment.

Besides yielding a preliminary estimate of each ESP's actual load profile, this step produces total system load matched segment profiles. In some sense, these profiles are pseudo-dynamic in that they are informed by the actual total system load profile for the day. Thus changes in system load due to abnormal weather patterns, varying cloud cover, outages, and other factors which are generally noise in modeling of load are reflected in the segment profiles 'tuned' to the system load. These 'tuned' segment profiles are retained to be used as load spreading models in the final estimation of ESP load profiles.

DOF+35 Final Estimate of Actual Load by ESP

MRMR meters are read on their normal monthly cycle schedule. As a final step it is necessary to spread this monthly read load which has been accumulated over the meter read period to each of those hours. The model by which this is accomplished is to use the 'tuned' segment load profiles calculated in the previous step. While this model is not necessarily appropriate for any individual meter it is appropriate for the collection of meters within the segment served by an ESP provided that ESP has a fairly representative sample of the meters from the segment. Once actual MRMR recorded loads are spread to their meter recording periods they are summed by ESP along with the ESP's HRDR recorded loads. Losses are added to achieve estimates of total ESP load. At this point UFE is again calculated and spread back over the ESP's in proportion of their MRMR loads to determine the final estimates of ESP load for a given day.

Preliminary Findings

At this time there is insufficient data from the direct access pilot to provide meaningful statistical results on the accuracy of PGE's methodology for both forecasting ESP load requirements and to reconcile their customers' actual electricity consumption to the power scheduled and shipped to the utility. However, preliminary observations are reported.

Based on very early program experience, PGE is quite satisfied that accurate pre-DOF forecasts and post-DOF estimates of ESP load are being developed using profiling methods for all but the largest metered loads. PGE has identified that the quality of the forecasts depends more on the quality of the total system forecast (i.e., which is used as the control total for the bottom-up forecast) then on the quality of the segment profiles. However, in the post-DOF estimation process, when the actual total system load is known, the quality of load partitioning among ESP's becomes highly dependent on the quality of the segment profiles.

To attain quality forecasts and estimates of ESP loads, it is necessary to have good estimates of the total market segment loads, which in turn requires good load research data from each segment. The market segmentation structure needs to be complex enough to capture major differences in load patterns, but simple enough to allow for an adequate sample size per segment to accurately estimate the annual load profile for the typical meter within the segment. Further, the families of load shapes and load magnitude models must be diverse enough to reflect basic differences in daily load profiles while not being over-parameterized to the extent that they are not estimable.

Finally, the forecasting and estimation algorithm which uses the load research generated load profiles in its processes must recognize the limitations of load profiling and make statistical improvements to compensate for those limitations. For example the most obvious limitation is that in an evolving energy market the load research data from one time period can give biased estimates of load magnitude for a later time period. Thus the forecasting and estimation algorithm should estimate such bias and correct for it in future computations. Likewise, the process of apportioning out a segment's load to the ESP based on an estimate of ESP share of segment may also be biased and statistical correction can be made.

Conclusions

This paper identified that utility load profile based models show promise in accurately allocating monthly-read meter data to identify ESP's hourly load forecasts and scheduling requirements. However, there are some early lessons learned of how to improve the accuracy of forecasts of ESP's load requirements and to reconcile their customers' actual electricity consumption to the power scheduled and shipped to the utility.

First, more accurate methods are needed to allocate line losses across all hours of the monthly billing cycle. Line losses are influenced by the magnitude of the system load and temperature. Current utility practices for estimating line losses are very simplistic. Line losses are underestimated during peak load time periods and overestimated during off-peak load time periods. Better algorithms are needed to allocate line losses by hour. PGE plans to study the correlation of hourly total system loads with the residual difference between the forecast and actual system loads to develop improved line loss estimation algorithms.

Second, PGE adopted a simple method for spreading unexplained forecasting error (UFE) proportional to the magnitude of each ESP's hourly loads. Factors such as weather obviously influence UFE, suggesting more sophisticated models are needed in the future to more fairly allocate UFE to weather sensitive customer loads and to the respective ESP's who serve that load. Again, better algorithms are needed to allocate UFE to customer segments and their respective ESP's.

Finally, the use of load research to support direct access forecasting and reconciliation is still in its infancy. More research is needed to learn what models and methods work best. This should keep many consultants, load researchers, and programmers fully employed for the foreseeable future.

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