Cost-Benefit Analysis of Demand Response Programs Incorporated in Open Modeling Framework

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***Abstract*—Rural electric cooperatives (consumer-owned, not-for-profit utilities) develop Demand Response (DR) programs to shift and reduce peak demand, delay capital investment in the distribution grid and reduce wholesale energy demand. Cooperatives have developed a planning tool to project the expected cost and benefit of DR programs; this paper aims to explain this model. The model is a part of the Open Modeling Framework (OMF), developed by the National Rural Electric Cooperative Association (NRECA). The OMF allows cooperative engineers to run various distribution models, import data from commercial tools, visualize the results, and collaborate through a web interface. The DR model can simulate Time of Use (TOU), Critical Peak Pricing (CPP), Peak Time Rebate (PTR), and Direct Load Control (DLC) programs for the purpose of cost-benefit analysis (CBA). It uses the Price Impact Simulation Model (PRISM) to estimate changes to system load profiles based on changes in incentives. The model calculates net present value (NPV), payback period and benefit-to-cost ratio across a program lifetime.**

***Index Terms*—Critical Peak Pricing, Demand Response, Demand Side Management, Direct Load Control, Dynamic Pricing Programs, Open Modeling Framework, Peak Time Rebate, Real Time Pricing, Time of Use.**

I. Introduction

The Electric Power Research Institute introduced the term demand side management (DSM) in the 1980s [1]. DSM programs are designed to manage load, conserve energy or use energy more efficiently. Utilities develop these programs to decrease and shift energy consumption for the benefit of utilities and consumers [2], [3]. In deregulated power system markets, DSM activities are classified in the literature as either demand response (DR) or energy efficiency [4]. DR is an prominent application of smart grid technology [5], [6]. According to the US Department of Energy, DR is defined as consumer change in energy use as a result of changes in the electricity price or rebates during particular times of day. An additional benefit of these techniques is improvement in power system reliability without the cost of bringing additional generation assets online [7]. Distribution cooperatives have been deploying DR since the 1970s and have the most loads capable of DR (per consumer) of any utility class [8].

DR provides multiple benefits to transmission grids and distribution systems. DR programs are able to mitigate transmission congestion, delay transmission expansion projects, and improve the reliability of the transmission grid. At the distribution level, DR can relieve voltage problems and reduce congestion at distribution substations. Based on the typical cost structure of their power supply, cooperatives that reduce peak demand and hence reduce the operating costs of generation and transmission assets. DR programs provide other benefits such as lower line losses, reductions in thermal damage to system components (e.g. distribution transformers), and easier integration of renewable energy resources [2], [5], [9], [10]. Overall, successful DR programs can reduce the cost of electricity for all consumers on a system.

Estimating the baseline load profile (BLP) is important to estimate the benefits of DR programs. There are several statistical models used to estimate BLPs. Reference [11] evaluates seven different models and classifies the models into two main types: those that use an averaging method, and those that use explicit weather models. The main goal of that study was to evaluate the performance of the models and relate the performance to the building types present on the system. The study found that applying morning adjustments (using data from the day of a DR event to adjust the estimated BLP up or down) and incorporating temperature corrections improves the accuracy of BLP estimation.

Several papers in the literature have studied models of different DR program types. Reference [1] models an emergency demand response program (EDRP) and a time-of-use (TOU) program using spot prices. The authors formulate how these DR programs can affect electricity demand and price, and they calculate the maximum benefit consumers can obtain. The same authors in [12] develop an economic model for Interruptible or Curtailed Load programs. They conducted a simulation study to evaluate the performance of the model using a one-year hourly load curve. The results demonstrate how consumer demand depends on the price elasticity of demand and electricity price. The model attempts to calculate how the DR program can improve both load profile characteristics and consumer satisfaction.

The National Rural Electric Cooperative Association (NRECA) has reviewed previous DR study objectives, results from cooperatives who participated in previous DR studies, and various implementation approaches for DR programs. The reports [9] and [10] provide information and data about DR programs piloted by NRECA members. The reports conclude that using enabling technologies, such as advanced metering infrastructure (AMI), lead to more peak reduction.

In this paper, we describe a cost-benefit analysis (CBA) model for DR programs that we built with the support of NRECA. The model relies on the OMF for data import, visualization and computational resources. The model described is available to the distribution cooperatives via the website https://www.omf.coop as a user-friendly DR planning tool. The model can calculate the costs and benefits of TOU, CPP, PTR, and direct load control (DLC) programs. The rest of the paper is organized as follows: Section II describes the different types of DR programs. Section III explains the developed model, including the inputs and the outputs of the model, an overview of PRISM and the OMF, and details about the calculations we use. Section IV presents the simulation results using an example data set. Section V concludes the paper and provides ideas for future work.

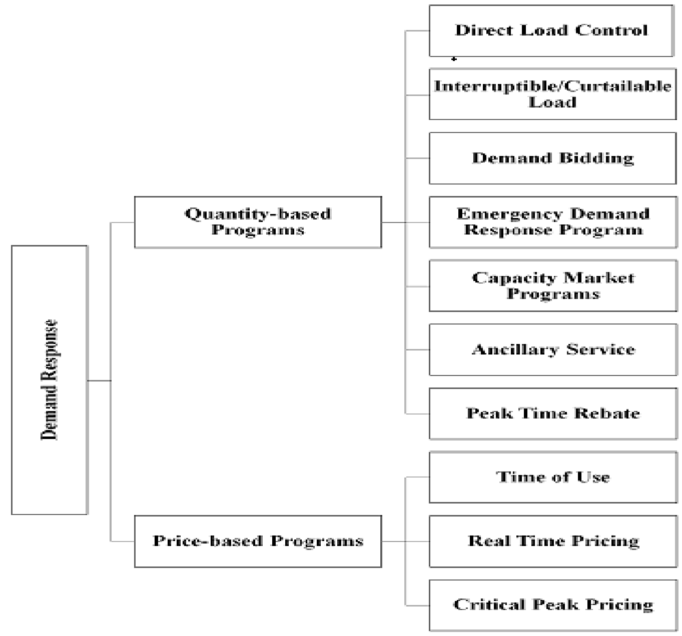

Fig. 1. The classifications of DR programs

II. DEMAND RESPONSE CLASSIFICATION

A. Demand Response Classifications

DR programs can be classified as either price-based or quantity-based programs. Price-based programs attempt to reduce consumer energy demand through price signals. Quantity-based programs, on the other hand, attempt to lower homeowner demand through direct utility control of certain loads in the home such as air conditioners, electric water heaters, and/or pool pumps [11].

The different quantity-based and price-based programs can be further categorized as follows. TOU programs offer consumers multiple electricity rates depending on the hour of the day in which the energy is consumed, typically in two to three rate tiers. RTP programs are similar to TOU programs except the rate changes in real time (e.g. hourly) rather than at pre-defined times and rates [13]. CPP programs use time-based pricing on a limited number of days each year when the total system load is expected to be highest. In quantity-based programs the utility pays consumers to interrupt part of the load (Interruptible/Curtailable Load), or directly controls some loads through switches (i.e., DLC). There are other programs such as Demand Bidding, capacity market programs, ancillary service, and EDRP. The following subsection (II-B) explains in more detail the programs implemented in this study.

B. Overview of the implemented programs

Cooperatives are interested in DR programs that are able to shift and reduce the peak demand, delay capital investment in the distribution grid or reduce wholesale energy demand. To decide which programs to implement, cooperatives consider multiple factors such as the types of loads in the service territory, end-user demographics and behavior, the current rate structure, generation capacity and what enabling technologies are available. This section describes the programs for which the CBA model was developed.

TOU programs divide the day into two or more price tiers. In the season that DR is applied, the programs divide each day in to tiers and charge different rates for each tier. In simple TOU, the rate is divided into peak and off-peak. TOU rate structures may have an additional tier defining a shoulder period between on-peak and off-peak. Due to its fixed rate pattern, TOU can result in persistent load shifting to off-peak times. However, TOU programs may be unable to reduce total energy consumption [8]. TOU programs incentive the use of modern loads such as plug-in electric vehicles and smart appliances during off-peak times. RTP produces an even more dynamic pricing environment where consumers are more directly exposed to wholesale market prices with the goal of producing an incentive to reduce load when energy is more expensive to procure [13].

CPP is similar to TOU; however, it is only applied on a few utility-specified days of the year. CPP rates are applied during particular peak times determined ahead of time. CPP programs typically feature lower rates during the year in order to impose much higher rates during the critical peaks which occur on a limited days of the year. When developing a CPP program, the peak days are determined based on the system-wide peak loads or peak demand from the cooperative's energy supplier(s). When the forecasted load reaches a critical limit, the cooperatives call for a critical peak day [9].

PTR also seeks to reduce load by providing a rebate incentive to customers during the peak periods. To determine the amount of load reduction, the cooperatives must determine the baseline for consumption; this is achieved using multiple statistical techniques as discussed in [11]. PTR programs keep a flat rate and call for events on forecasted peaks (e.g. hot and humid summer days or very cold days in the winter). As the program's goal is to produce consumption changes, utilities call for events a day ahead of time. Consumers decide if they want to participate in the program and are thus not penalized if are unable to reduce their demand. In general, the time-based programs require AMI data to evaluate the effectiveness of the programs.

DLC is a quantity-based DR program where the utility remotely controls particular loads at consumer sites. The utility installs switching devices on particular loads to disconnect them when needed. An incentive payment is provided and is set based on lower off-peak rates or credits. DLC can achieve demand reduction, and the program has more potential to be dispatchable compared to price-based programs because it is entirely under the control of the utility. These programs usually control air conditioners and water heaters.

III. COST BENEFIT MODEL OF DEMAND RESPONSE

A. Open Modeling Framework (OMF)

NRECA has created the OMF to allow its members to conduct economic analyses of power system investments with an emphasis on emerging and smart grid technologies. This open source platform, as a planning tool, aims to help co-operatives to examine the cost-effectiveness of the programs that they plan to deploy. For evaluating technologies such as DR, OMF integrates mathematical modeling techniques with a large database of input data such as regional weather data, load data, smart grid components as well as typical financial parameters. The outputs of the models include charts and monetized values [14].

B. Price Impact Simulation Model (PRISM)

As the vision of the smart grid starts to become a reality, it introduces changes in grid components and market structures. One change is new mechanisms for electricity pricing (dynamic pricing). Flat rates for consumers ignore the variation in the wholesale electricity price, leading to competition for system resources during periods of high demand. Dynamic pricing rate design can avoid this problem.

The Brattle group has developed a load response model that calculates the impact of the electricity price on demand. PRISM was developed during the California statewide pricing pilot, which was conducted by investor-owned utilities and the regulatory commission to assess the response of consumers to dynamic rates. The purpose of the pilot was to examine the change in the pattern of consumption when the pricing rate designs change [15].

Price elasticity is a key determinant of the effectiveness of DR. Our model uses two elasticity inputs: the elasticity of substitution and the daily price elasticity. The elasticity of substitution measures the change in load produced by the price differential in two adjacent periods. Thus, this elasticity represents the absolute change in the load shape (shifting in the load) as a response to the new dynamic rates. In other words, it is the willingness of the consumers to shift their loads from one time of day to another. Daily elasticity relates the difference in the average price without a DR program to the price while the program is active. PRISM inputs also include the characteristics of the utility such as weather conditions, load profiles, dynamic rates, and penetration of air conditioning. There is a correlation between temperature and peak reduction from time-based pricing. In general, regions with hotter weather tend to experience more peak reduction. The load profile and the dynamic rate are important inputs to evaluate the load change resulting from the dynamic rate and to compare the price difference between the existing rate and the dynamic rates [16].

C. Inputs and Outputs of DR Cost Benefits Analysis Model

When considering making a business case for a DR program, distribution cooperatives need to estimate the financial impact of the applied DR programs. For a given DR deployment, having detailed costs of all the components is important to define the CBA as a whole, and the business case should quantify the costs and benefits over the lifetime of the applied programs (e.g., 25 years) [9], [17].

The CBA model differs based on the kind of DR program. Multiple programs require the purchase and installation of enabling technologies, and this additional cost must be considered. Furthermore, some programs do not reduce consumption but instead flatten the load curve. The general inputs of the CBA model of the DR programs are as follows:

- DR program: This includes the total cost of deploying the program (purchase cost of the needed technology, and the annual operation cost).
- The baseline energy consumption: This includes historical hourly load data (8760 hours).
- The cost of power, which includes the demand charge cost, the wholesale energy cost, and the retail price.
- The participation rate: (the percentage of managed load by the program).
- The dynamic rates (e.g., off-peak and peak rates, or RTP rate), and the price elasticities (i.e., the substitution elasticity and the daily elasticity).
- The length of the analysis (e.g. 25 years).
- The months and the hours when the DR program is applied.

The outputs of the cost benefit model are as follows:

- The estimated load curve after applying the program.
- The first year financial impact. This includes annual demand, energy sales, energy cost and peak demand cost for the base case, and the DR case.
- Total cost, total benefit and the benefit-to-cost ratio for the whole investment period.
- NPV, lifetime cash flow, and simple payback period.

D. Cost-Benefit Analysis Calculations

This subsection explains the calculations of CBA components. Model users are able to input the values that represent the characteristics of their systems' demand and electricity prices and obtain a CBA report of the deployed program for the lifetime of the program [18]. The calculations are as follows: 1. Base case profit calculation:

$$\begin{aligned} ES &= Q\pi_r && (1) \\ EC &= Q\pi_w && (2) \\ PDC &= \sum_{m=1}^{12} \pi_D P_m && (3) \\ P &= ES - EC - PDC && (4) \end{aligned}$$

Where Q is the energy consumption. π_w, π_r, and π_D are the wholesale, retail, and peak demand prices respectively. P_m are the monthly peak demand levels. ES, EC, and PDC are the energy sales, energy cost, and peak demand charges respectively. In (4), P is the base case profit.
2. DR program profit calculation:

$$\begin{aligned} ES' &= \sum_{h=1}^{8760} D'_h \pi_{DR} && (5) \\ EC' &= Q'\pi_w && (6) \\ PDC' &= \sum_{m=1}^{12} \pi_D P'_m && (7) \\ P' &= ES' - EC' - PDC' && (8) \end{aligned}$$

Where D' is the hourly modified demand curve and π_{DR} is the applied DR dynamic pricing rate. The superscript ' $\prime$ ' indicates the modification done by applying DR between (e.g. P' is the profit of applying the DR program).
3. Total cost calculation:

$$TC = DR_{inv} + C_{OM} \quad (9)$$

Where TC, DR_{inv}, and C_{OM} are the total cost, the purchased and installation cost (i.e., the investment cost) of the DR equipment, and the lifetime operation and maintenance cost respectively. 4. Benefits calculation:

$$ESB = \sum_{Y=1}^{Lifetime} (ES' - ES)^{AS} \quad (10)$$

Where ESB is the benefit of the change in energy sales and AS is the annual scaling of the load growth.

$$\begin{aligned} PCB &= \sum_{Y=1}^{Lifetime} (PDC' - PDC)^{AS} && (11) \\ TB &= PCB + ESB && (12) \end{aligned}$$

Where PCB is the peak change benefit and TB is the total benefit.
5. Calculation of net present value, cash flow, payback period and benefit-to-cost ratio:

$$NPV = \sum_{Y=1}^{Lifetime} NB/(1+r)^Y \quad (13)$$

Where NPV is the net present value, NB is the net benefit, and r is the discount rate.

$$n_p = \frac{DR_{inv}}{\left(\frac{TB}{Lifetime}\right)} \quad (14)$$

Where n_p is the payback period.

$$BCR = \frac{TB}{TC} \quad (15)$$

Where BCR is the benefit-to-cost ratio.

IV. SIMULATION RESULTS

In this section, we present the simulation results based on an example data set. Fig. 2 depicts the model inputs as they appear in the user interface. It shows that the inputs include the base case and the DR program case variables. The base case inputs include the general utility operating parameters such as the cost of power (e.g. demand charge, wholesale costs, and retail energy costs), annual load growth, discount rate, and the historical demand curve. The DR program variables include the applied program options with their respective rates, hours of the day and the months where the program is applied, and elasticities of demand. The results of

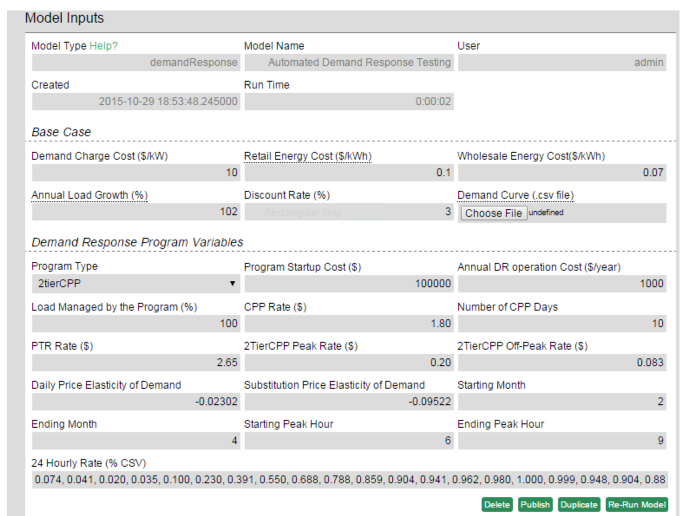

Fig. 2. Demand Response inputs of the model as it is visualized in the web interface

the CBA are also presented in this section. These include the following outputs: (i) Demand curve in the base case as well as the simulated demand curve after applying particular DR program as shown in Fig. 3. (ii) First year financial impact which includes the annual demand, energy sale, energy cost, and peak demand cost for both the base case and DR case as shown in Fig.4. (iii) The program lifetime cash flow chart includes all the associated costs and benefits, net present value, payback period and benefit-to-cost ratio. Figures 5-8 show the program lifetime cash flow chart.

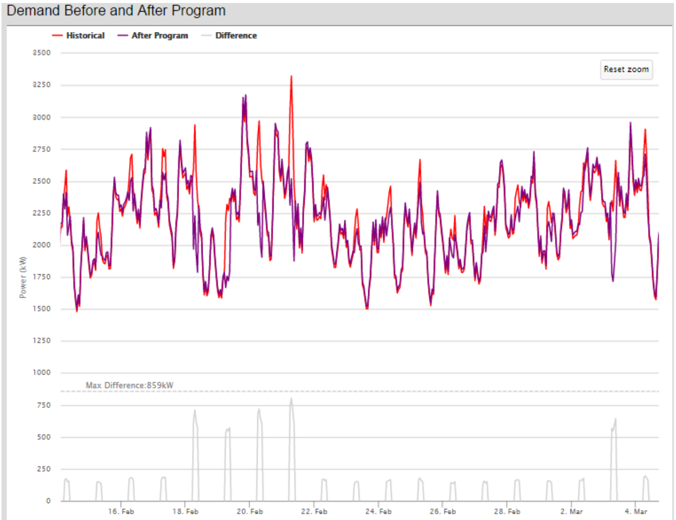

Fig. 3. Demand curve before and after applying the demand response program (Historical demand in red, the modified demand in purple, and the reduction in gray)

First Year Financial Impact

	Annual Demand (kWh)	Energy Sales ($)	Energy Cost ($)	Peak Demand Cost ($)	DR Program Cost ($)
Base Case	14,222,776	1,422,278	995,594	325,690	0
Demand Response Case	14,201,354	1,448,621	994,095	323,906	100,000

Fig. 4. The first year financial impact

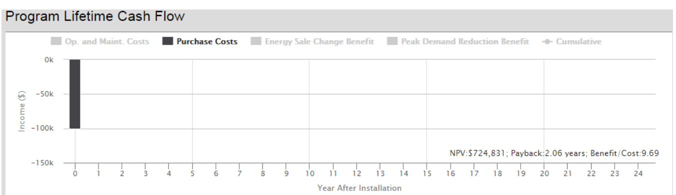

Fig. 5. Purchase cost is shown in the program lifetime cash flow chart

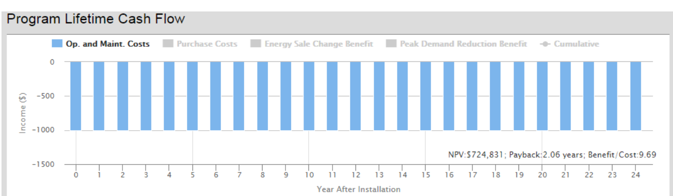

Fig. 6. Operation and maintenance cost is shown in the program lifetime cash flow chart

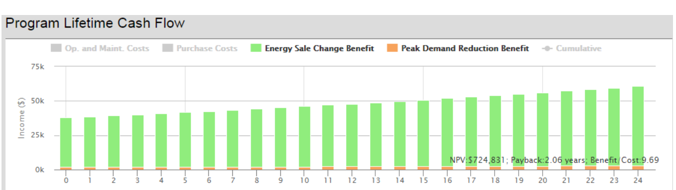

Fig. 7. Energy sale change benefit and peak demand reduction benefit

V. Conclusion

The OMF gives cooperatives access to the latest research on power system analysis and operation while providing an easily accessible user interface. As part of that suite of tools, the DR model implemented here can provide cooperatives insight into the technical and financial feasibility of various DR programs. With a very limited set of system-specific inputs, cooperatives can see the impact on their system load due to DR programs and what the financial impact of a given program could be.

To further expand the functionality of this model, adding energy efficiency programs would allow utilities to analyze the full set of demand side management resources.

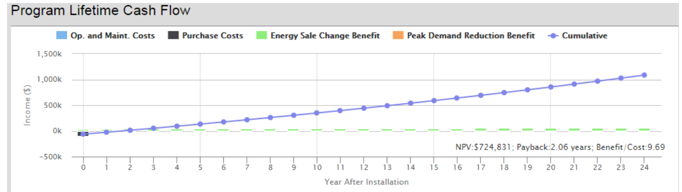

Fig. 8. DR program lifetime cash flow

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