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Quantifying distribution-system operators' economic incentives to promote residential demand response

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A B S T R A C T

Demand response (DR) from end-users is widely investigated as a power-system flexibility resource in a European smart-grid environment. Limited knowledge exists on the added value such flexibility can bring to actors in the electricity value chain. This work investigates the economic effect of consumption flexibility under current regulatory remuneration on distribution-system operators with a Swedish case study. Results indicate DR leads to savings for the distribution-system operator, which might be used towards smart-grid investments. Peak demand is and will continue to be a main driver for grid costs and therefore should be a focal point in tariff design.

1. Introduction

Electricity networks are in the midst of a radical smart-grid transformation. The aim is to shift the current market structure from a top-down model where 'generation follows demand' to one where demand and supply mutually optimize the system and adapt to grid capacity limitations. Such a shift must accommodate the local integration of a variety of distributed energy resources (DER): distributed generation (DG), local storage, electric vehicles (EVs) and overall active demand (Ackermann et al., 2001; Pérez-Arriaga et al., 2013). Along these lines, local distribution networks will compel greater flexibility. One flexibility resource that remains largely untapped is residential demand response (DR), which constitutes "*changes in electric usage by end-use consumers from their normal load patterns in response to changes in electricity prices and/or incentive payments designed to adjust electricity usage, or in response to the acceptance of the consumer's bid, including through aggregation*" (ACER, 2012). Demand-response programs have become a widely investigated solution for warranting grid reliability and market efficiency (Strbac, 2008). The value of this opportunity will vary according to the type of service, location in the system, agent accessing the flexibility and the time at which the flexibility becomes available (Pérez-Arriaga et al., 2013).

Flexibility is signaled via incentive-based and price-based mechanisms, which are not mutually exclusive. Incentive-based programs compensate end-users for participation in accordance with an ex-ante contract for flexibility provision (e.g. direct load control, emergency DR, curtailable services and demand bidding/buyback). Price-based demand-response programs consist of variable prices reflective of active hourly market and/or grid conditions inclusive of real-time pricing (RTP)[1]; time-of-use (ToU),[2] and critical-peak pricing (CPP)[3] (FERC, 2006). When subject to demand-

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[1] Reflective of day of system operation or signals from day-ahead planning.
[2] Depending on pre-specified time blocks and can vary by day, week, month and season.
[3] Consisting of signaling pre-defined simulated system contingencies reflective of critical peak periods (40–150 hours per year) with abnormally high prices during event days, and a discount for noncritical periods of that specified day.

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response programs, general actions that a customer can take include decreasing consumption during peak periods where prices are high and shifting consumption during peak periods to off-peak (Albadi and El-Saadany, 2008).

The proliferation of DR in an electricity system will have multiple effects in terms of inducing cost management and mitigating environmental impact (Strbac, 2008). Physically, DR will improve security of supply and added flexibility in electricity markets will prompt efficiency and liquidity (Albadi and El-Saadany, 2008; Torriti et al., 2010). The potential for DR in Europe is expected to be high due to the plethora of economic opportunities it opens to small end-users (Torriti et al., 2010). Demand-response programs enable consumers to actively participate in energy markets and in the optimal operation of the grid, which in turn gives them the chance to benefit from optimizing usage based on communicated price conditions (EC, 2014). DR is of great interest as a flexibility resource, but nonetheless has not been thoroughly investigated in order to assess the rage of potential savings that can be achieved in the electricity value chain; electricity distribution is one of these lacking domains.

For the distribution-system operator, both peak shaving and peak-load shifting will have the same effect on the grid in terms of reduced power flow through the network at a given time (Pérez-Arriaga et al., 2013). Hence, DR has a twofold application for the grid: to add a flexibility resource for system balancing, and to mitigate both transmission and distribution overload (Strbac, 2008). This work will focus on exploring the latter influence for distribution-system operators to reduce the level of load variations in the system.

Fundamentally, "*bringing demand response to fruition*" (Bartusch and Alvehag, 2014) via implementation programs is a matter of technical system operation; that is, a real-time strategy requiring transparency of grid activity. At present, DR (from small end-users) as a competitive activity is difficult to achieve due to escalating complexities in both the production and consumption of electricity. Distribution-system operators provide the closest physical connection to customers. With full access to information about the status of the local network, including consumption and production profiles of so-called "prosumers," distribution-system operators are the most pragmatic entity to signal and access end-user flexibility under present system design (Koliou et al., 2014).

By 2020, it is estimated that European electricity networks will require investments in the range of 600 billion Euro, of which over half will be in distribution grids. It is estimated that by 2035, investments in distribution will grow 75 percent compared to current levels (Eurelectric, 2014). It is thus important to focus on mitigating distribution system costs and optimizing smart-grid investments.

This study provides insight into the impact of DR on the minimization of costs for the distribution-system operator. Specifically, Section 2 investigates distribution cost remuneration and Section 3 considers the implications for cost drivers from signaling a demand–response program. A quantifiable and generally applicable approach to assessing the economic benefit of DR is presented in Section 4, followed by a discussion of the results in Section 5. Section 6 assesses smart-grid related costs for distribution. Finally, Section 7 provides some concluding remarks and recommendations.

2. Distribution in the European smart grid: role, responsibilities and tariffs

2.1. Role and responsibilities

2.1.1. Traditional

As regulated natural monopolies, distribution-system operators exhibit high fixed (sunk) costs, economies of scale, loss of efficiency with competition, and the provision of a public good to which citizens cannot be denied access. Traditional electricity networks are designed to handle extreme cases of maximum power flow that seldom occur due to the hourly, daily, weekly, monthly and seasonal variance in grid load. Tailoring the grid to fit such dimensions is costly (Forsberg and Fritz, 2001), but nonetheless consistent with current tariffs set by European regulators.

2.1.2. Smart grid

In a smart-grid environment, the roles and responsibilities of actors in the value chain of electricity evolve in order to accommodate the integration of distributed generation, energy-efficiency services, electric vehicles and their charging points, local balancing, flexibility procurement, smart-energy systems, and large volumes of data (FSR and BNetz A, 2014). Distribution-system operators are at the heart of successfully implementing changes at the consumer level all while warranting to end-users a high level of reliability and quality of service via optimal system planning, development, connection, operation and facilitation of the retail market (Eurelectric, 2013). Escalating intricacies in system architecture are increasing the complexity and dynamics of service provision, in turn bringing to light the paucity of accurate economic signals to grid users under the regulated tariff (Pérez-Arriaga et al., 2013).

2.2. Distribution remuneration

Economic incentives for distribution-system operators (and therefore customers) are pre-defined in the tariffs set by the regulator. Strictly speaking, "power regulation" is an umbrella concept referring to both the remuneration of total (or allowed) network costs and the allocation of these costs to network users. It is important to make the distinction between network regulation (in a strict sense limited to the remuneration of total allowed network costs and the incentives this offers to network operators) and network tariffication (which is then dedicated to the allocation of these costs to the users, yielding full-cost recovery). Such costs consist of operational expenditure (OPEX) and capital expenditure (CAPEX). The former pertain to daily operational expenses of power-flow management while the latter consist of long-term investments made in physical assets (Hakvoort et al., 2013).

2.2.1. Underlying theory of network pricing

Fundamentally, when looking at network pricing, there is a conflict between short-term and long-term objectives. Active distribution management is concerned with short-term grid operation, which signals long-term network expansion depending on how the network is being used. Electricity distribution exhibits a high degree of asset-specificity, with capital expenditures that are exponentially larger when compared to operational expenditures (de Joode et al., 2009). In theory, optimal tariffs (with respect to allocative efficiency) are reached on economic principles of marginal cost, with a change in the total cost arising when the quantity produced increases by one unit. In Europe, wholesale electricity markets have evolved towards sending optimal economic signals via marginal-cost pricing for energy trading on at least an hour-by-hour basis to incorporate the short-term costs of electricity production. If such an approach is taken in pricing distribution it would entail the use of energy sale or purchase prices as pertaining to each node in the grid (Reneses and Rodríguez, 2014). Along these lines, marginal-cost application would be inclusive of power losses and congestion constraints, taking the network capacity as a given. The setting of tariffs based on short-run marginal costs has several shortcomings. At the distribution level it requires locational marginal pricing, that is, nodal pricing,[4] which is theoretically optimal for communicating losses and congestion in real time. However, at the distribution level, the network is rarely used to its full capacity. As a result, congestion is virtually nonexistent (except when manifested into relatively rare outages). In turn, little to no recovery of the total cost of service provision is signaled at present, which in turn provides very little incentive for future demand-side developments (Reneses and Rodríguez, 2014). Reneses and Rodríguez (2014) point to an application in Pérez-Arriaga et al. (1995) and Ponce de Leão and Saraiva (2003) where cost recovery is below 25 percent for transmission and estimated to be even lower at the distribution level. Full cost recovery requires the addition of extra costs, which in turn distorts the message that short-run marginal pricing is meant to send. The short-run marginal-cost method is optimal for pricing operational expenditures in distribution (Hakvoort et al., 2013; Pérez-Arriaga, 2013; Frontier Economics, 2013; Similä et al., 2011), at least for Europe if not elsewhere.

Furthermore, investments in networks are considered discrete and therefore take the existing grid as a baseline and optimize expansion for a given trend in demand (Reneses and Rodríguez, 2014). When considering investments, marginal pricing then considers long-run costs, which are exponentially larger. In this sense, long-run marginal pricing can be calculated via demand and technology forecasts in two forms. First, the marginally incremental approach takes into consideration permanent demand increments over the relevant years and looks at the present value of future costs. Second, through an average incremental-cost approach, demand and technology developments are also forecasted but project costs are averaged yearly by dividing by the present value of the change in demand (Hakvoort et al., 2013; Pérez-Arriaga, 2013; Frontier Economics, 2013; Similä et al., 2011).

The marginal incremental approach is the theoretical 'pure' estimate of long-run costs, but is more difficult to calculate. Specifically, in a smart-grid investment environment that fosters the energy-efficient appliances and demand-response programs, technology risk is high and demand forecasts difficult to appraise. An average-cost approach allows the incorporation of investment lumps to be smoothed. Simultaneously, future levels and trends in costs of rising demand are reflected over time (Similä et al., 2011). In the long-term, the calculated network remuneration must promote efficient development of the grid for the benefit of network users. In the tariff it may be important to provide customers incentives to use the network efficiently, which may include location-specific and time-specific rates (Hakvoort et al., 2013; Similä et al., 2011). Tariff regulation at a minimum has to meet three objectives (Hakvoort et al., 2013):

1. *The total tariff revenue must cover the incurred costs*, i.e. the capital and operating cost of the infrastructure should be fully covered by the grid tariffs.
2. *Tariffs must be non-discriminatory*. Similar network use (by the same or other market party) should result in the same conditions for the same rate in order to not disturb the electricity market.
3. *Tariffs must be transparent*. The methodology for determining the rates should be clear to all network users.

Below follows a discussion of the specific tariff design elements.

2.2.2. Tariff design

For the distribution-system operator, network use refers to consumption (electricity withdrawal), production (electricity injection), and prosumption (combined withdrawal and injection). Distribution network fees have three critical facets: (i) the initial network connection charge (a one-time flat payment in Euro); (ii) network tariff level (use-of-system charge) for allowed revenue during the regulatory period and; (iii) the network tariff structure,[5] i.e. network charges according to consumer categories, periods of grid use, and the mobility of loads when considering DER (Eurelectric, 2013). The initial connection charge becomes critical when connecting own distributed generation (e.g. solar photovoltaics) since it pertains to who bears the cost responsibility for externalities imposed to the system.[6] The tariff level pertains to the amount of remunerated recovery for the distribution system operator during the regulatory period, an aspect that becomes critical under the consideration of new investments in the (smarter) grid. Finally, the network tariff structure is relevant with regard to stimulating end-user flexibility (Pérez-Arriaga et al., 2013). All three aspects are important with respect to distribution-system operator remuneration, but we focus the remainder of our discussion on the smart-grid tariff structure.

A widely cited publication on network tariff design (Pérez-Arriaga and Smeers, 2003) finds that in a perfect system: (i) network charges are computed ex-ante (i.e. prior to delivery of electricity to customers): (ii) network charges do not depend on commercial transactions (i.e. electricity market trading); and (iii) network costs are allocated to those who cause them or who benefit from the deployment of the assets (on the basis of the beneficiary-pays principle). The problem with the current method is that although the rates cover costs, limited economic incentives are given to network users (Eurelectric, 2013; Similä et al., 2011).

2.2.2.1. Tariff structure. The network tariff is commonly referred to as the use-of-system charge paid periodically by consumers (either monthly or bi-monthly), incorporating volumetric and/or capacity components (Pérez-Arriaga, 2013). Design of the use-of-system charge requires the identification of cost drivers followed by the determination of appropriate rate schemes. As briefly mentioned above, general cost drivers consist of CAPEX and OPEX in addition to other miscellaneous expenditures deemed either variable or fixed costs (Eurelectric, 2013; de Joode et al., 2009). Volumetric charges are proportional to the energy demand charged in Euros per kilowatt-hour (€/kWh). Capacity charges are a reflection of the load contribution to peak demand in the network charged in Euros per kilowatt (€/kW) or Euros per kilowatt per month, depending on the structure of the tariff. Other fees include customer charges for management and support that (more often than not) are a part of the use-of-system charge (Pérez-Arriaga, 2013).

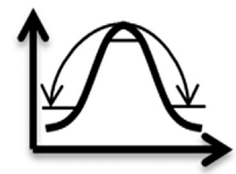
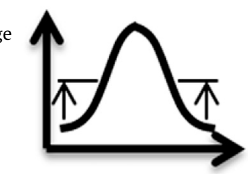
Table 1 summarizes the distribution-tariff design options with their direct impact on load: strategic conservation (overall energy efficiency resulting in reduced consumption); peak shaving (only a

[4] Nodal pricing is applied in the United States, but there are some fundamental differences in system operation and market. Basically, in the United States there is a pool where market and physical system are optimized simultaneously while in Europe the market and physical gird clear separately on a day-ahead basis and optimize coordination until the moment of delivery at the day.

[5] The customer charge is at times incorporated in the use-of-system charge.

[6] This charge can be shallow, shallowish, or deep. A shallow charge means the developer of the DG bears the grid connection cost; a shallowish charge indicates that the DG owner (household) bears the connection and a share of the grid reinforcement cost; a deep charge puts the full responsibility of the grid connection and grid reinforcement cost on the DG owner. In most European countries DG owners are subject to a shallow charge.

Table 1
Impact of major tariff options on load and network costs (adapted from Eurelectric (2013)).

Type of network tariff	Design	Direct load impact
Volumetric charge	• Energy (€/kWh)	 Strategic conservation
Two-part tariff (capacity & volumetric energy charge)	• Power (€/kW) • Energy component (€/kWh) with a flat rate or time-of-use energy charge	 Peak shaving
Time-of-use volumetric	• High €/kWh (peak) • Low €/kWh (off-peak)	 Load shifting
Capacity-based	• Power (€/kW) • Can also have a 'dynamic' component with high prices at peak hours and low or no charge at off-peak hours	 Valley filling

reduction at peak hours); load shifting (displacing load from peak hours to off-peak); and valley filling (increasing load consumption at off-peak hours). Recent studies (Pérez-Arriaga et al., 2013; Reneses and Rodríguez, 2014; Ramos et al., 2014) on the future of distribution recommend that at the most basic level tariffs should veer away from exclusive volumetric charges (€/kWh) and move towards incorporating a capacity charge (€/kW) (otherwise referred to as a demand-based tariff) to properly reflect the impact of agents' consumption and/or production on network costs. TemaNord (2014) point out that the introduction of capacity-based distribution pricing has the potential to reduce costs in the grid and increase end-user flexibility. Overall, capacity-based tariffs can reduce the grid utilization, even when capacity is not deemed scarce.

Peak demand is a main driver for grid cost, yielding a tendency to over-size the grid due to reliability constraints. Tariffs should therefore encourage peak-load mitigation via capacity-based tariffs as the optimal approach (Eurelectric, 2013). To illustrate, starting in 2006, a Swedish distribution-system operator, Sala Heby Energi Elnät AB, ran a pilot project with 500 residential customers involving a demand-based, time-of-use distribution tariff to incentivize DR. The results of the study suggest that customers had a positive attitude to the program in question, adapting their electricity consumption pattern to price signals by decreasing peak load in peak hours and shifting consumption from peak to off-peak hours. During the study's six years, for the summer and winter periods respectively, there was an average reduction in households' individual peak demand of 9.3 and 7.5 percent, and in the peak distributed demand of 15.6 and 8.4 percent; this in turn led to a shift in electricity consumption from peak to off-peak hours by 2.4 and 0.2 percent (Bartusch and Alvehag, 2014). Costs to households decreased in the range of 14–41 percent during the pilot, but the analysis also revealed that these savings were affected by low tariff rates (Bartusch et al., 2011).

2.3. Distribution in Europe

In European distribution systems, differences start with the physical grid in terms of voltage levels. In Italy, for instance, distribution begins at 200 kV, Sweden at 130 kV, and France at 20 kV (Pérez-Arriaga et al., 2013). In addition, the current tariff structure in member states is inherited from earlier regulatory regimes, where the end-user tariff consolidated generation and distribution and revenue requirements. Moreover, within Europe, the use-of-system charges incorporate one or all three tariff-design elements: a fixed charge, a capacity charge, and an energy charge (see Table 2). When considering distribution as part of the total end-user electricity bill among the member states, costs range between 10 and 30 percent (GEODE, 2014).

3. Assessment of distribution cost drivers and signaling of demand response

In a survey conducted by Eurelectric (2014), distribution-system operators across Europe consider smart metering, network automation, and investments in DR and integration of distributed and renewable generation to be the most important investments for smart-grids. For distribution-system operators, the signaling of a

Table 2
Residential use-of-system charges for select European countries, ref. data Eurelectric (2013).

Country	Fixed charge (Euro)	Capacity charge (Euro/kW)	Energy charge (Euro/kWh)
Belgium	Yes	No	Yes
Czech Republic	Yes	No	Yes
Germany	Possible	No	Yes
Denmark	Yes	No	Yes
Estonia	Yes	No	Yes
Spain	No	Yes	Yes
Finland	Yes	No	Yes
France	Yes	Yes	Yes
Greece	No	Yes	Yes
Italy	No	Yes	Yes
Lithuania	Possible	No	Yes
Netherlands	Yes	Yes	No
Norway	Yes	Seldom	Yes
Poland	Yes	No	Yes
Portugal	No	Yes	Yes
Sweden	Yes	Seldom	Yes

demand—response program can have an economic influence on the minimization of costs with respect to power losses in the grid and peak load, both factors consequently affecting ongoing grid investments (Bartusch and Alvehag, 2014; Eurelectric, 2013).

3.1. Cost structure of distribution-system operator

The structure of full costs differs from one distribution-system operator to another in Europe, but the basic cost factors remain the same. In Capgemini (2008a), a comparison of gross distribution costs per MWh delivered reveals a variation from 9 Euro per MWh to more than 50 Euro per MWh. As Fig. 1 reveals, for the average European distribution-system operator, 25 percent of costs are related to asset financing and depreciation, 34 percent to network operation, 20 percent to transmission access and 5 percent to losses. The remaining costs pertain to taxes and customer service. More than 40 percent of annual costs are directly linked to the volume of net delivered energy; such costs pertain to transmission access, power losses, and customer service. More than half of the total costs are deemed either fully or party controllable. The consensus among European policymaker and lobbyists is that improved consumption efficiency can improve distribution-system operators' long-term economic performance (EC, 2014; Eurelectric, 2013; Capgemini, 2008a). This is in line with the theory of tariff pricing that takes the long-term performance of distribution into consideration.

3.2. Optimizing costs of short-term distribution operation

A widely held view is that distribution network tariffs should be implemented to the extent that they reflect underlying grid costs (Eurelectric, 2013; Hakvoort et al., 2013; TemaNord, 2014). Tariffs are the signal to consumers to optimize (i.e. minimize) costs. As mentioned above, the level of allowed revenue for distribution-system operators is set by the regulator. This level affects the overall investment behavior of operators, and is thus a critical

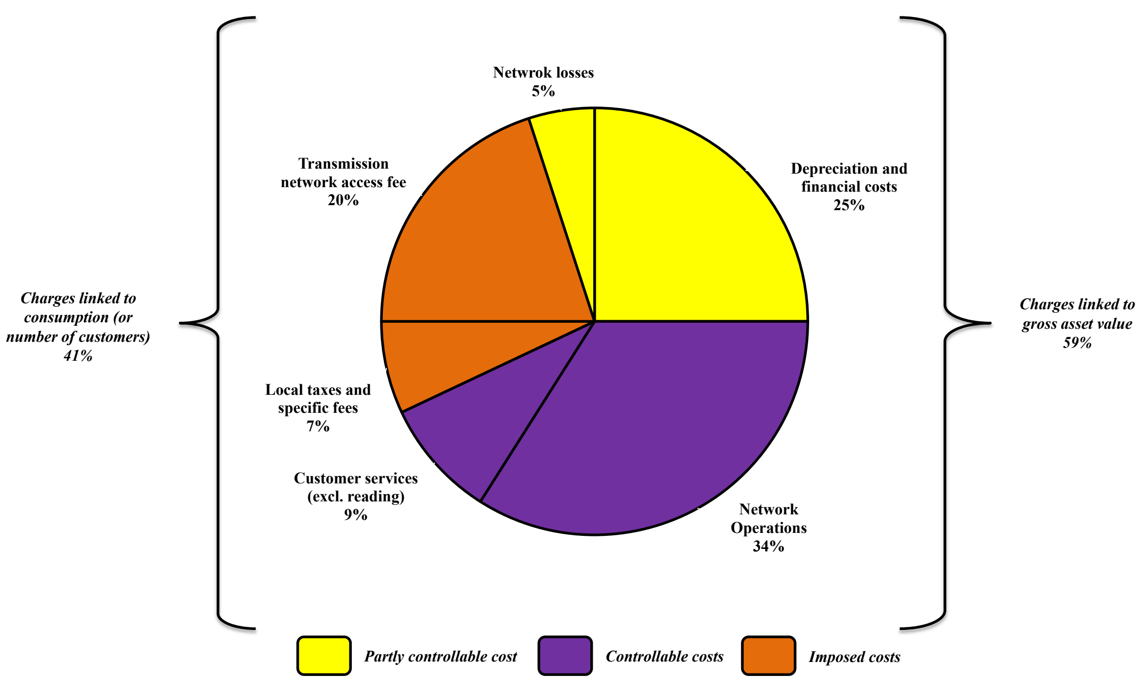


Fig. 1. Average cost structure for a distribution-system operator in Europe, ref. Capgemini (2008a).

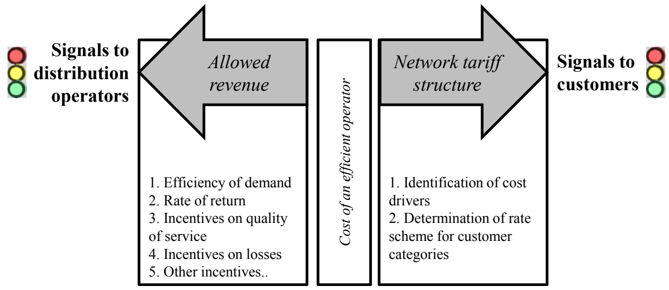


Fig. 2. Signals provided by network tariffs, adapted from Eurelectric (2013).

factor for the development of smart grids. The tariff level has an impact on investment recovery; hence the emphasis placed on the identification of cost drivers for pricing. Moreover, network tariffs are paid by customers and therefore the price structure should affect customer behavior (Eurelectric, 2013). See Fig. 2 for a summary of the signals provided by grid network tariffs to both distribution-system operators and consumers.

TemaNord (2014) highlight that when it comes to grid operation, the only thing that varies with the amount of load is the losses incurred in the energy delivery. Such losses increase when the grid is operated closer to its maximum capacity limit, at which time distribution assets are used sub-optimally (decreasing their overall service life).

A series of interviews conducted with the CEO of Sala-Heby Energi Elnät AB, a distribution-system operator experienced in successfully implementing demand-response programs (Mårtensson, 2013a; Mårtensson, 2013b), emphasizes the importance of mitigating costs by optimizing for losses, peak loads, and grid investment through DR. Optimization will have at least some impact on about 75 percent of the distribution system cost drivers in Europe (see Fig. 1).

In the following section we describe our generally applicable simulation approach towards assessing these cost factors for distribution, using Sweden as a case study. The proposed model can be adapted to all distribution-system operations within similar market structures and to inform regulators of the magnitude of benefits that can be obtained from implementing a demand-response program.

4. Quantifying demand response

Assessing the economic effect of DR in distribution requires the consideration of factors related to power losses, peak loads, and grid investments. Using distribution data from a Swedish operator, an analysis was conducted to quantify the impact of DR. We begin with an introduction to the Swedish regulatory model in order to understand how tariffs are set, followed by an assessment of the costs subject to potential optimization.

4.1. Swedish regulatory model

Regulatory oversight from the Energy Markets Inspectorate (the Swedish regulator) runs for a four-year period. The current regulatory period is from 2012 to 2015, with distribution tariff remuneration determined via an ex-ante revenue cap. As illustrated in Fig. 3, distribution costs are split into capital and operating expenditures. CAPEX are the costs associated with the 'asset base'[7] for distribution (equipment and depreciation during the supervision period). OPEX are split into controllable costs (e.g. staff and services) and non-controllable costs (including network power losses, taxes, authority fees, and charges for connecting to the sub-transmission level, known as the feeding-grid charge). Under the current framework, costs regarded as controllable are subject to an efficiency target, while costs regarded as non-controllable are not (EI, 2009; NordREG, 2011). Note, with the right framework of incentives some losses may be controllable as discussed below.

Distribution is comprised of complex processes of physical system operation that are governed by regulatory arrangements (ERGEG, 2008). The added flexibility of DR is aimed at improving system efficiency, but it also intensifies the already intricate processes of the distribution-system operator (Shaw et al., 2007; Capgemini, 2008b; Balijepalli et al., 2011). At present, the traditional system comprising of downstream power flows is challenged by the integration of distributed energy resources. Distribution-system operators along with regulators are reacting to developments in upstream generation patterns and prices while simultaneously managing local developments in both production and consumption (Pérez-Arriaga et al., 2013).

4.2. Quantifying the impact of demand response

Determining the tariff scheme for recovering allowed revenue in accordance with costs requires the consideration of several aspects (Eurelectric, 2013; Similä et al., 2011):

- Load (consumption) versus generation (local production) within the grid;
- Load profiles and size of consumption (energy transferred);
- Network structure (urban versus rural and voltage size);
- Temporal variations (seasonal, monthly, weekly, daily, peak and off-peak etc.)

In order to determine the total grid demand, average initial load is aggregated[8] in kilowatt-hours as follows:

$$\overline{E}_{IL} = (x_1 + y_1, \ldots, x_n + y_n) \quad (1)$$

where $\overline{E}_{IL}$ is the total 'Initial Load' prior to DR, x is the hourly electricity imported through the upper grid level and y the electricity production within the distribution system (see Fig. 4).

As stated earlier, peak load is a main cost driver for distribution, making it important to isolate the peak-load periods for the design of appropriate demand-response programs. In the subject system, peak grid use is observed to occur between the hours of 09:00 and 20:00, while off-peak use falls between 21:00 and 08:00. Peak hours of consumption vary per distribution system and over time and should be defined accordingly. For instance, in Bartusch and Alvehag (2014) the peak hours are from 07:00 to 19:00 in the respective distribution area, while in SWECO (2012) peak hours for distribution fall between 06:00 to 22:00.

The authors consider peak and off-peak hours in the distributing area to simulate a two-band time–of-use demand-response program under two scenarios. Scenario 1 explores an arbitrary but reasonable 10 percent load shift from peak consumption and evenly distributes the load to off-peak hours, such that overall consumption remains the same but the load is more evenly

[7] The asset base includes power lines, cables, substations, transformers, systems for operating assets, and meters.

[8] This includes both the energy fed into the distribution grid through the sub-transmission level and the electricity that is locally produced within the distribution area from 2007 to 2012. The DSO providing the data is considered to be one of the smallest in Sweden with 13,211 customers in the distribution area and a total yearly demand of 199,690 MW h.

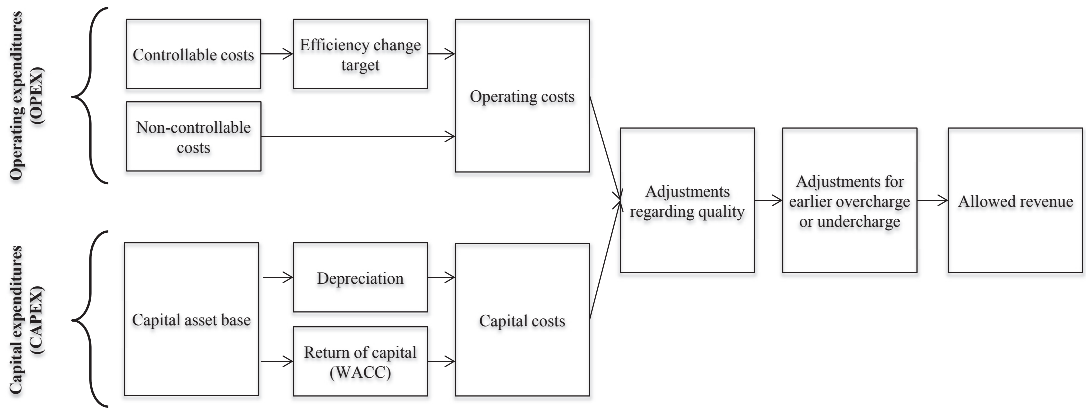


Fig. 3. Structure of regulatory model for Sweden (NordREG, 2011). WACC – weighted average cost of capital calculation.

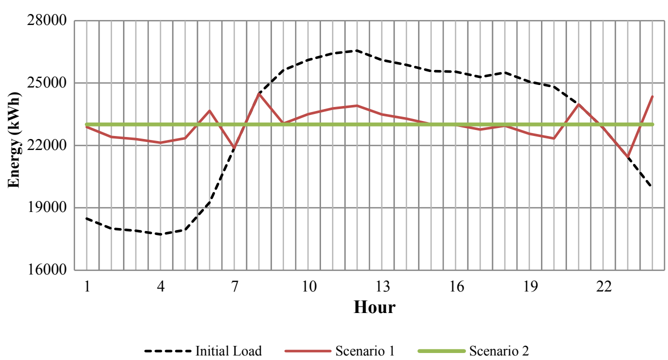


Fig. 4. Average daily load in the distribution system.

distributed (represented by the red (in the web version) line in Fig. 4).[9] Scenario 2 looks at the optimal case of DR, where the load from peak-hours is evenly distributed throughout the off-peak hours in order to yield a flat distribution load curve (the green (in the web version) line in Fig. 3). A flat load simulation is aimed at representing the ideal power–demand curve that a smart grid seeks in order to improve system efficiency, cost effectiveness, and overall reliability and power quality. One of the means used to achieve these smart grid goals is via flattening of the power–demand curve. Along these lines, recommendations for the utilization of DR point to a more evenly distributed load without changing the total amount of electricity consumed i.e. minimizing discomfort for the consumer. Simulating a flat load is a means of capturing the optimization of all distributed energy resources in a distribution area (Carillo Aparicio et al., 2014).

Both scenarios illustrate the impact of a time-of-use distribution tariff specifically targeted at incentivizing the use of the grid below a certain capacity threshold. As mentioned above, capacity based tariffs aid in promoting optimal utilization of the distribution system (see 2.2.2.1 and Table 1).

On the basis of the above analysis, load shift ($\overline{E}_{LS}$) from DR is constructed as follows:

$$\overline{E}_{LS} = f\left(\overline{E}_{IL}\right) = \left(z_{1,LS}, z_{2,LS}, \ldots, z_{n,LS}\right) \tag{2}$$

$\overline{E}_{LS}$ is comprised of hourly load data from $\overline{E}_{IL}$ and is then adjusted by the demand-response load shifting estimation(s) (for both scenario 1 and 2), $f(x)$, where z corresponds to each hour with DR which is calculated as the respective modification per peak hour to an off-peak hour per scenario. For scenario 1, at each of the peak hours per day for the year there is a 10 percent load reduction that is then shifted and evenly distributed to the off-peak hours. For scenario 2, the load is optimized to yield a flat load curve over one year such that the overall consumption for a specific year does not change. See Fig. 4 for average values of one day over the year.

Considering a feasible 10 percent load shift and an optimal flattened load, we continue with an analysis of the cost factors that can be optimized by engaging DR: power losses, peak loads, and grid investments (via postponement or avoidance).

4.2.1. *Demand response for the reducing power losses*

Since we are concerned with the aggregate impact of power losses, the simulation assumes that load is equal in all parts of the distribution grid (which is not the case in reality). Total distribution network power losses are the aggregated differences between the measured power entering the grid and that which is consumed (measured at the customer meter) (ERGEG, 2008). Swedish distribution-system operators are required to purchase electricity from the spot market (Nord Pool[10]) to cover power losses occurring within their grid (as is the case in other European countries, including the Netherlands); this is regarded as the cost of covering losses (EI, 2009; NordREG, 2011).

Power losses in a distribution system can be both non-technical and technical and both fixed and variable. The implementation of a demand–response program can only impact the minimization of variable technical losses in the distribution system. Non-technical losses consist of delivered electricity that is not compensated, such as theft, errors in metering, non-metered delivery,[11] and own consumption by the operator (ERGEG, 2008). Such losses can be costly but cannot be affected by DR. Fixed technical losses are independent of power flow, such as those resulting from iron loss in transformers (ERGEG, 2008), and are therefore not affected by load management. Comparatively, variable technical losses (occurring in transformers as well as power lines) can be mitigated by DR since

[9] Evidence from Bartusch and Alvehag (2014) indicates that such a load shift is feasible from consumers. Ibrahim and Skillbäck (2012) corroborate that a 5 to 15 percent load shift is feasible with the implementation of a two-band time-of-use tariff for distribution.

[10] More more information, see http://www.nordpoolspot.com.

[11] For example, public lighting.

they are the direct cause of natural resistance in power lines (Shaw et al., 2007). In Sweden, electric power transmission and distribution losses equal approximately 7 percent of total yearly electricity production (World bank, 2010-2014). For the distribution-system operator analyzed in this simulation,[12] average losses for the year are 4.3 percent, below the European average (see Fig. 1).

Variable power losses are proportional to the squared power flow within the grid (that is, precisely yielding a quadratic value relative to load). As a result, the simulation considers this proportionality to create a loss vector (Δ_L) varying with the load output when the load goes from P_a to P_b:

$$\Delta_L = \frac{P_a^2 - P_b^2}{P_a^2} \tag{3}$$

For both the initial load curve $\overline{E}_{IL}$ and shifted $\overline{E}_{LS}$ curves (feasible and optimal) average variable losses (L_v) are calculated as follows:

$$L_v = 0.043\left(1 - L_{fv}\right) \tag{4}$$

L_{fv} corresponds to the proportion of fixed to variable ones (Shaw et al., 2007), set at 1 to 5 for this system (Mårtensson, 2013a). Total (variable) losses can then be compared using $\overline{E}_{LS}$ and $\overline{E}_{IL}$ (before and after DR for both scenarios), in this way determining the impact of DR in kilowatt-hours, which can then be multiplied by the spot market price for economic evaluation purposes.

4.2.2. Demand response for alleviating peak loads

Distribution-system operators incur costs at the connection point to the high-voltage transmission grid (Pérez-Arriaga, 2013; Rodríguez-Ortega et al., 2008). In order to pass electricity from the transmission to the distribution grid, Swedish distribution-system operators pay a 'feeding-grid' charge for the withdrawal from or injection to the grid. The fee is divided into three parts that are updated on a yearly basis and paid for monthly by customers (Vattenfall Distribution, 2013; Fortum Distribution, 2013; E.ON, 2013). The first part is a fixed capacity fee that is paid in Euros regardless of the amount of power or energy transferred. Since the remuneration is fixed ex-ante, load shifting has no impact on this charge. The second component is a variable charge for the actual energy transferred during the year, calculated on the basis of a pre-specified fixed price per kWh; only overall load reduction will have an effect so this charge will not be affected by load shifting (since the total energy consumed remains the same). Finally, a variable capacity component (€/kW) is charged to the distribution-system operator for staying within a subscribed level of maximum power on the grid. Once this pre-specified level is surpassed, the operator is charged a higher fee per kW. In the past year, the distribution-system operator paid 20 Euro per kW for the agreed level and 30 Euro per kW for deviations.[13]

When signaling DR, load shifting from peak to off-peak hours decreases the peak capacity level (Mårtensson, 2013b). The maximum level of power is a complicated component to calculate due to the stochastic nature of end-user consumption patterns. To illustrate, Sweden has a capricious climate and homes are heated with electricity, with potentially devastating consequences for distribution-system operators. From one year to the next, electricity consumption from residential customers may vary ±10 percent as a result of home heating (ERGEG, 2008). In this context, minimizing the pre-defined peak capacity leads to overall lower costs for the distribution-system operator (Mårtensson, 2013b).

At each distribution connection point this power level is optimized differently, depending on the connection to the high-voltage operator.[14] For this simulation we take the Vattenfall approach (Vattenfall Distribution, 2013) to optimize the subscribed power level by averaging the 2 maximum load values per month over the year, as indicated in equation (5).

$$E_{Lm,max} = \frac{x_1 + x_2}{2} \tag{5}$$

$E_{Lm,\ max}$ is the maximum subscribed power defined by the regional grid operator for a given load curve of year m where x_1 and x_2 are the two highest capacity values in the grid for the year m. Any penalty for deviating from the set subscribed level is settled for a given year by comparing the actual maximum capacity (E_d) with the subscribed maximum power ($E_{Lm,\ max}$) in the contract. Total costs for the feeding grid for any given year are calculated as follows:

$$C_{Lm} = E_d{*}C_d + E_{Lm,max}{*}C_p \tag{6}$$

where C_{Lm} is the total cost for year m, C_d the deviation cost per kW and C_p the cost for the contracted capacity level. Yearly variations allow the simulation to capture demand fluctuations between years. The model therefore optimizes the maximum level with the accessible load data over the 5-year period as a result of the lowest possible sum of costs for the difference between the initial and shifted loads for both scenarios:

$$\Delta_{fee} = C_{ILc,opt} - C_{LSc,opt} \tag{7}$$

where Δ_{fee} represents the change in costs for the specific regional capacity level contract, $C_{ILc,opt}$ is the change in cost for the optimal capacity value of the initial load without DR and $C_{LSc,\ opt}$ is the optimized cost for the shifted load capacity with DR calculated for both scenario 1 and 2.

4.2.3. Demand response for postponing network investments

Distribution investment costs come in two forms that cannot be considered as mutually exclusive since equipment has long lifecycles: investing in new equipment at the end of their lifecycle, and upgrading existing assets to cope with higher demand (Mårtensson, 2013a). The standard lifetime for distribution assets is estimated at 40 years; in order to mitigate short-run marginal costs, increasing the depreciation rate by 5–10 years has been recommended (Sweco, 2010). It can be argued that if demand variations are minimized, grid assets could be better utilized over their lifetime and their service lives extended. Specifically, peak-load shifting decreases load fluctuations as long as extreme demand variations remain low (Eurelectric, 2013). With cautious use of distribution assets, equipment upgrades and replacements can be postponed by several years or even avoided altogether (which might further extend lifetimes). Subsequently, our simulation mainly considers investments that are mostly geared towards grid upgrades to existing equipment to cope with rising demand rather than the full replacement of equipment.

We use the net present value (*NPV*) methodology, commonly

[12] Sala-Heby Energi Elnät AB.

[13] 182 SEK for the agreed level and 273 SEK for deviating (December 8th, 2014 exchange rate).

[14] Fortum changes the level on a weekly basis using the mean of the two highest hourly values during each calendar week (Fortum Distribution, 2013). For comparison, E.ON takes seasonal variations into consideration and separates winter weekdays from the rest of the year. The maximum power is than calculated by using the mean of the two highest monthly load values for the year for winter and non-winter days (E.ON, 2013).

used to sum up the current value of cash flows over the time that investments are active:

$$NPV = \sum_{i=0}^{n} \frac{C_i}{(1-r)^i} - K \tag{8}$$

where n is the number of years of active investment, C_i the cash flow for year i, r the rate of discount pre-set at 0.052.[15] K is the initial investment in year zero and it is disregarded in this part of the simulation since incorporating it in the calculation for postponing future investments presents a negative cash flow; we present the values as positive in the economic outcome below. The net worth of this distribution-system operator is approximately 15 million Euro,[16] with increasing assets at an approximate average rate of 1.6 percent yearly (PROFF, 2013).

For the simulation, we consider the optimal case, where the grid is utilized to its full capacity. We therefore model the actual maximum capacity instead of the subscribed (agreed upon) level discussed in Section 4.2.2. Savings are reflected in the decrease in asset investment until the point in time (the year) when the grid load is expected to surpass the available physical network capacity.

The impact of DR is represented as the maximum peak ratio (E_{max}) between the initial peak load ($E_{IL,\ max}$) and shifted peak load ($E_{LS,\ max}$).

$$E_{max} = \frac{E_{IL,max}}{E_{LS,max}} \tag{9}$$

The inverse of this ratio yields the number of years that demand-response implementation can postpone future investments in the grid per our simulation:

$$E_{max} = (1+I)^n \tag{10}$$

where I is the estimated increase in grid assets[17], (in this case $I = 0.016$, representing the yearly average 1.6% increase in grid assets of the distribution-system operator in question) and n the years of investment load shifting saves. To solve for n, the equation can be written as follows:

$$n = \frac{\ln E_{\max}}{\ln\ (I+1)} \tag{11}$$

Postponed investments are then valued and discounted over years n to obtain the NPV. However, a value for the postponed investments for each year must be established first. The investment at year zero (C_0) is calculated as the multiplication of the maximum peak ratio (E_{max}) with the current distribution asset-base A:

$$C_0 = I{*}A \tag{12}$$

In order to properly reflect the rising cost of investments, the total cost (C_i) must be increased each consecutive year by I:

$$C_i = C_{i-1}(I+1) \tag{13}$$

[15] Prescribed value by the Swedish Energy Markets Inspectorate for the regulatory period 2012–2015 (EI, 2011).

[16] Specifically, 144,100,854 Euro with the exchange rate of December 8th, 2014 (133,989,000 SEK).

[17] Average yearly increase in distribution assets is derived from historical values of capital assets for the distribution-system operator from 2009 to 2012 (PROFF, 2013).

5. Economic outcome

Our results are biased since the simulation was designed to illustrate the positive economic impact of load shifting in terms of optimizing costs for the distribution-system operator. Lower overall consumption in the distribution system will yield additional savings as well as decreased revenues (Eurelectric, 2013). Although we do not consider these effects, it is important to keep in mind when analyzing the results reported in the following sections.

Table 3 summarizes the simulation results from implementing a demand-response program in the distribution system: scenario 1 represents a 10 percent (feasible) load shift from peak to off-peak hours and scenario 2 illustrates the optimal case of load management by flattering the consumption curve in the distribution service area. Overall, we see that under scenario 1, DR brings about the highest annual savings per customer from investment savings, followed by peak capacity optimization and losses. For scenario 2, maximum savings are achieved from optimizing the peak capacity level followed by losses and postponing investments. In the following section, we discuss in detail the results related to each cost factor.

5.1. Discussion of simulation results

5.1.1. Power losses

The simulation indicates that the theoretically available maximum DR would help the distribution-system operator reduce up to 19% of annual losses, in turn yielding savings of more than 36%, which in this case corresponds to 121,000 Euro[18] (approximately 2% of yearly turnover[19]). Per customer[20] savings from the annual minimization of losses amount to about 9 Euro per year. Interestingly, the authors observe that when shifting losses from peak day-time hours to off-peak night-time hours, the use of day-ahead spot market prices results in lower overall purchasing costs related to power losses for the distribution-system operator.

In this distribution system, with a yearly demand of 199,690 MW-hours (MWhs), losses are approximately equal to 8587 MWhs (considering average losses of 4.3% mentioned above 4.2.1). When considering losses, savings can be achieved in different orders of magnitude depending on the procurement pricing method: fixed ex-ante contracting (no real time dynamics), day-ahead pricing, intraday pricing, and imbalance pricing. Although real-time market transparency for procurement is optimal, current regulation regards losses as non-controllable and these costs are passed to consumers, which gives distribution-system operators have little incentive to seek the engagement of consumers in demand-response programs.

In most European countries, the distribution-system operators are responsible for the procurement of electricity for losses (e.g. Austria, Belgium, Switzerland, Germany, Denmark, Estonia, Finland, France, Lithuania, Netherlands, Poland and Sweden); otherwise, this responsibility falls to the electricity suppliers although this does not necessarily mean that the distributors do not receive incentives with regard to losses reductions (Eurelectric, 2013).

5.1.2. Peak loads

An optimal flattened load curve suggests that the subscribed level of power could theoretically be decreased by a maximum of 51%, resulting in 46% cost savings and corresponding to more than

[18] Euro value of December 8th 2014.

[19] Yearly turnover is approximately 6 Euro million from 2008 to 2012 (PROFF, 2013).

[20] Customer refers to residential customers.

Table 3
Savings from demand response.

		Scenario 1: 10% load shift	Scenario 2: uniform load
Power losses	Reduction in losses during one year (kWh)	346,756	1,635,036
	Decrease in mean arithmetic loss over the year (%)	4%	19%
	Reduction in cost per year (Euro)	27,058 €	121,064 €
	Annual difference in cost per customer (Euro)	2.1 €	9.2 €
	Total reduction in cost per year (percent)	8%	36%
Peak demand	Optimized value for subscribed maximum power (kW)	38,499	19,770
	Reduction in the level of maximum power (%)	2%	51%
	Annual reduction in cost per year (Euro)	43,578 €	471,071 €
	Annual reduction in cost per customer (Euro)	3.3 €	35.6 €
	Reduction in cost per year for the operator (%)	5%	46%
Grid investments	Difference in annual cost (Euro)	109,571 €	114,420 €
	Years of delayed investments	2	43
	Annual cost decrease per customer (Euro)	8.3 €	8.6 €

Initial calculations in Swedish Krona (SEK), using exchange rate December 8th 2014 (1SEK equal to 0.11Euro).

471,000 Euro[21] for the distribution-system operator. With a 10-percent load shift, the subscribed level of peak load can decrease by 2% and reduce annual costs for the distribution-system operator by 5%. Since there is no guarantee of end-user DR, capitalizing on this potential is still a high-risk endeavor. Even if DR is able to reduce part of the load fluctuations, some peaks will still persist and those will ultimately determine the costs related to the peak-capacity charge.

Peak demand has been and continues to be the main driver for network costs (Rodríguez-Ortega et al., 2008). In this way, distribution-system operators can 'buy' lower risk by increasing their maximum level of subscribed power or promoting consumption flexibility through demand-response programs. Hedging for risk of maximum subscribed power implies the existence of an optimal level that will be different for each distribution-system operator (considering regional, seasonal, monthly, weekly, and hourly variations).

The current design of capacity tariffs places the brunt of the burden with the distribution-system operator. DR may result in a smoother load curve, from which higher grid levels will reap all the benefits without having any of the responsibilities involved in program implementation. Under Swedish law, this capacity fee is considered yet another non-controllable cost that is passed directly to the consumer. Consequently, both costs and benefits accumulate to the customer and not the distribution-system operator.

5.1.2.1. Individual contribution to peak. The data for our case study consist of almost 90-percent energy transferred to residential customers; we therefore see fit to have a simple assessment of what load shifting collectively means for the distribution area and possibly other customer groups. For instance, reducing the level of maximum subscribed power means a collective set level at 39, 269 kW; individual households in the distribution contribute only about 3 kW to this maximum. When looking at DR it is important to keep in mind these individual contributions to the total energy use. In accordance with the initial consumption curve derived above in Fig. 4, we can construct an average load for each household as shown in Fig. 5.

Individual consumers have an average maximum hourly consumption of 2 kWhs at peak hour and a minimum of 1.3 kWhs at an off-peak hour. The difference between the maximum and minimum consumption is roughly equal to the displacement of a load of laundry.[22] With a 10 percent load shift, maximum average consumption is 1.8 kWhs with a minimum of 1.6 kWhs, a difference roughly equal to heating 2 L of water in a kettle.[23] These figures illustrate that on an individual basis, households have to do very little to shift load from peak to off-peak hours. Key questions, though, are how important is it for consumers to do things at a specific time and what appliances are they willing and able to have controlled in order to comply with demand-response programs? With visual aid from smart meters, in-home displays, and smartphone applications, the set level of power for the distribution system and individual contributions to the peak can be communicated to end-users. Consumers can consciously decide to stay below the threshold by manually choosing not to use certain appliances at communicated hours. In order to not disturb comfort, household appliances can also be programed to automatically respond to the distribution system needs at times of distress either signaled by peaking conditions or congestion.

5.1.3. Grid investments

The relevance of the simulation for grid infrastructure investments is surrounded by the most uncertainty, and yet is of most interest when considering optimal grid utilization over the long term. Distribution-system operators face specific and changing needs that are hard to plan for in advance (for example, which distributed generation technologies will be favored by consumers or the penetration level of electric vehicles). Moreover, distribution equipment has long lifecycles; as a result upgrades and reinvestment needs are difficult to forecast. On this basis, it is difficult to estimate with accuracy the expected new investments and upgrades over the coming years. Delaying investments for 2 years is a way of optimizing for short-term operational objectives (2.2.1). An investment delay of 43 years allows the simulation to capture the cumulative long-term effects of optimal operations. It was indicated that the average lifetime of distribution assets is at least 40 years (Sweco, 2010), with maintenance and upgrades needed over the lifetime but not necessarily replacement. A 43 year outlook with DR is an indication that equipment can be used to its full lifetime without needing replacement.

Overall, the simulation shows that in the optimal case of DR, the grid could be designed to cope with only half of the current demand, yielding nearly a one-third reduction in the net present value of the current asset base. The simulations suggest that postponing future investments over a period of 43 years can accumulate savings of greater than 117,000 Euro[24] and 8.6 Euro[25]

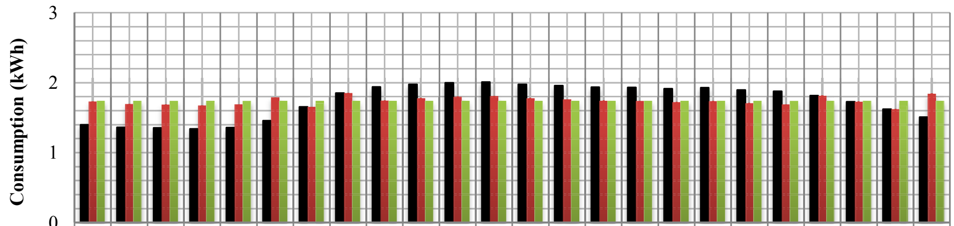
[21] Euro value of December 8th 2014.

[22] EU energy label A-rated gives an average consumption at 40 °C using a 2 kg load to be 0.63 kWh (Carbon footprint, 2014).

[23] A measure from ref. Carbon Footprint (2014).

[24] Euro value of December 8th 2014.

[25] Euro value of December 8th 2014.



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Initial load	1.4	1.36	1.35	1.34	1.36	1.46	1.66	1.85	1.94	1.98	2	2.01	1.98	1.96	1.94	1.93	1.91	1.93	1.9	1.88	1.81	1.73	1.62	1.51
10% Load shift	1.73	1.7	1.69	1.68	1.69	1.79	1.66	1.85	1.74	1.78	1.8	1.81	1.78	1.76	1.74	1.74	1.72	1.74	1.71	1.69	1.81	1.73	1.62	1.84
Flat load	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74

Fig. 5. Average individual contribution to total energy use in the system for every hour of the day (1–24).

per customer (with maximum shifting capability), whereas a modest 10 percent DR over a period of 2 years still saves more than 109,000 Euro per year for the distribution-system operator and 8.3 Euro per customer. Both scenarios involving postponed investments display similar yearly savings potential for both the distribution-system operator and customers. Such results further support a shift in focus towards signals that impact peak load and losses, especially since grid investments are directly affected by power losses and the maximum load levels reached. As pointed out by Rodríguez-Ortega et al. (2008), operators' incurred costs for covering power losses are in the same order of magnitude as costs of grid investments. This means that if one or both of these factors are targeted via demand-response programs, grid infrastructure investments will be directly affected.

These quantified benefits can be captured by end-users upon implementation of a demand-response mechanism. Currently in Sweden and most European countries, regulatory periods span an average of 4 years for distribution-system operators, a short time frame that may not allow consumers to realize financial savings during the same period. One recommendation from a European perspective is to increase the regulatory period to greater than 4 years (as is the case in the RIIO model of the UK, which allows for an 8-year period) such that resulting benefits produced from smart-grid investments and services are more associated to the regulatory period during which they are implemented (Pérez-Arriaga et al., 2013).

6. Distribution smart-grid costs and demand response

As mentioned above, when it comes to quantifying the benefits of DR, the impact on investments is uncertain. This uncertainty escalates when taking into consideration the capital expenditure for investments in smart-grid equipment needed for the full exploitation of demand-side flexibility. Using the Swedish case, we quantify some of these costs for the distribution-system operator.

6.1. The smart-grid environment

Tariff design is concerned with the allocation of network costs and the stimulus of appropriate incentives by establishing a process for determining who pays for what services and how much (Rodríguez-Ortega et al., 2008). Significant changes are expected in the current Swedish regulatory model for the coming 2016 to 2019 period based on the impact of distributed energy resources (Eurelectric, 2014). Capital expenditures will see an initial temporary spike when accounting for future costs that incorporate vast enabling technology. Returns on these investments will likely not be realized during a short regulatory period, hence the consideration of long-term average costs as discussed in Section 2.2.1. Operational expenditures will also see an increase as a result of the new roles and responsibilities of the distribution-system operator as a market facilitator in smart-grid implementation (Pérez-Arriaga et al., 2013).

6.2. Costs for incorporating smart-grid upgrades

In order to stimulate DR in households it is important to install the necessary equipment for such capability. For the distribution-system operator, this entails upgrades to the current physical system, which is difficult to estimate due to the limited availability of cost figures for intelligent infrastructure and the information and communication technologies needed for DR (Prüggler, 2013). Considering calculations from Meisl et al. (2012), costs for demand-response enabling infrastructure amount to about one thousand Euro for a single household (which is about 5 times the calculated cost of the smart meter rollout[26] per household in Sweden). This five-fold difference in cost is a result of integrating information and communication technology, specifically a micro-grid controller and sensors and actuators (Prüggler, 2013; Meisl et al., 2012). This estimate is evenly divided in terms of smart-grid investments in the distribution-control aggregation system and the installation of sensors and other software (both in the grid and households). Meisl et al. (2012) also expect equipment maintenance costs at an average 50 Euro per household per year. In our simulation, the cost of an upgrade to a 'smart-grid' system would be upwards of 13.2 million Euro, compared to a smart-meter rollout cost of approximately 2.7 million Euro. To put these values in perspective, the smart-grid investment is comparable to the current net worth of the distribution-system valued at 14.5 million Euro. Essentially, the upgrade to a smart grid entails doubling of the current asset base. Given this investment scale and associated technological risk, it is understandable why Eurelectric (2014), emphasizes the role of predictable and stable regulation in attracting the necessary financial capital.

The truth of the matter is that upgrading a system smart-grid status increases overall investments and therefore costs; this is a fact that regulation needs to embrace. Pursuing the implementation of a time-of-use demand-response program at this stage allows for savings to accrue in the coming years. Specifically, in Sweden where customers already receive a separate bill for network charges (Eurelectric, 2013), this type of program may prevail to incentivize customer load modification. It can be argued that separate billing causes more confusion for end-users. In the

[26] The cost of smart-meter implementation in Sweden was approximately 200 Euro per household, resulting in a total implementation cost of approximately 1–1.5 billion Euro for the country. See http://www.wec-policies.enerdata.eu/Documents/cases-studies/Smart_Billing.pdf.

case of countries like Sweden where such billing practices are the norm, the existing system design can be used for the proliferation of demand-response programs at the distribution level. Our case study indicates that a modest DR of 10 percent at peak hours can be incentivized under present conditions with little to no additional costs through a change in the tariff that provides a time varying capacity charge to consumers. The accrued savings of almost 200 thousand Euro[27] yearly (see Table 3) can either go towards smart-grid investments or reduce customer bills. Once the cloud of uncertainty over which type of smart-grid investments should prevail in a specific system settles and costs are made more clear, appropriate regulation will catch up, conventional investments will be displaced, thus reducing long run capacity costs and enable the effective integration of distributed energy resources without compromising the quality of supply. Our proposed approach simply allows for an incremental action to be taken in the short term until smart-grid practices become further entrenched.

7. Conclusions and recommendations

Distribution-system operators will bear the brunt of investments needed as passive end-users become active agents in both consumption and production. The stimulus of DR is one way of curbing rising electricity costs. This study developed a way of analyzing and quantifying the effects of a tariff-based demand-response program in this context. The above taken approach can be adopted by other distribution-system operators and regulators seeking insight into the economic benefits they can amass from the implementation of a time-of-use capacity tariff.

Based on our analysis, it is evident that moving load from peak to off-peak hours has several direct effects on distribution costs with different ranges of magnitude. In our simulated case study, we assess power losses, peak loads, and grid investments under a feasible 10 percent load shift scenario and an optimal scenario of a flattened distribution load. The overall assessment indicates that decreasing peak consumption will reduce overall costs both for the distribution-system operator and consumers since it directly impacts about 75 percent of the cost drivers for an average European operator (see Fig. 1).

As mentioned earlier, due to their resistive nature, power losses increase proportionately to power flow (load squared) and therefore both losses in the system and costs for covering them will decline significantly when load is shifted from peak to off-peak hours. Although losses in an average European distribution system account for approximately 5 percent of total distribution costs, optimizing can have other direct impacts. Losses increase when the grid is operated closer to its maximum capacity when assets are not used optimally. Specifically, operating the grid near its maximum capability on a long-term basis will decrease the average lifetime of assets and equipment, in turn raising investment costs which might otherwise be postponed or avoided. More certainty about the utilization of grid allows for better forecasts in grid planning and therefore more robust tariff design. A time-varying capacity-based tariff that promotes efficient use of the grid is recommended. Moreover, pricing can also decrease the maximum subscribed level of power to upper levels of the system while additionally minimizing the likelihood of surpassing the set threshold.

The above simulation indicates that 10 percent DR at peak hours reduces the overall level of maximum subscribed capacity by 2 percent and reduces the yearly costs of the distribution-system operator by 5 percent. If all customers within the distribution area were incentivized to collectively remain below a certain threshold, then further savings can accrue. We recommend a simple way of approaching consumers collectively for initial engagement and incremental smart-grid changes thereafter.

Incentivizing a flatter load via load shifting in the distribution level throughout the day will affect the system overall (as residential demand is a quarter of the total demand in most European countries). An initiative to smooth load via energy efficiency and load shifting methods will lead to cost savings at the wholesale electricity level, which implies lower procurement costs for suppliers, and savings in grid investment for the network operator in terms of supply and network investments. At peak-demand times, potentially more expensive generation is dispatched at higher wholesale generation prices. A more uniform load throughout the day should yield lower costs and prices overall. Moreover, as illustrated in the simulation, peak demand determines the amount of network capacity that is required for both transmission and distribution.

Regulators have a daunting task in designing innovative remuneration schemes that ensure the alignment of short-run operational and long-run investment and recovery objectives. Our analysis on distribution costs recommends that variable capacity-based tariffs are the proper approach to signaling the short-term status of the grid to end users which in turn instigates load responsiveness that will yield long-term benefits in the form of optimal use of grid assets.

Our study offers insight into quantifying the magnitude of economic benefits that can be achieved with demand-response flexibility in the distribution system. The simulation approach provides the first step in quantifying the considerable benefits that can be gained from implementing a time-of-use demand-response program tailored to an electricity distribution area.

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