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

Elta Koliou [a, *], Cajsa Bartusch [b], Angela Picciariello [a], Tobias Eklund [a], Lennart Söder [a], Rudi A. Hakvoort [c]

[a] *School of Electrical Engineering, KTH Royal Institute of Technology, Teknikringen 33 KTH, 10044 Stockholm, Sweden*
[b] *Uppsala University, Department of Engineering Sciences, Division of Industrial Engineering & Management, P.O. Box 534, SE-751 21 Uppsala, Sweden*
[c] *Delft University of Technology, Faculty of Technology Policy and Management, Jaffalaan 5, 2628BX Delft, The Netherlands*

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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-

* Corresponding author. Present address: Delft University of Technology, Faculty of Technology Policy and Management, Jaffalaan 5, 2628BX Delft, The Netherlands.
E-mail addresses: elta@kth.se, e.koliou@tudelft.nl (E. Koliou), Cajsa.Bartusch@Angstrom.uu.se (C. Bartusch), angelp@kth.se (A. Picciariello), toek@kth.se (T. Eklund), lennart.soder@ee.kth.se (L. Söder), r.a.hakvoort@tudelft.nl (R.A. Hakvoort).

[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