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A review of electricity product differentiation

C.K. Woo [a], P. Sreedharan [b], J. Hargreaves [b], F. Kahrl [b], J. Wang [c,e,*], I. Horowitz [d]

[a] Department of Economics, Hong Kong Baptist University, Hong Kong
[b] Energy and Environmental Economics, Inc., 101 Montgomery Street, Suite 1600, San Francisco, CA 94104, USA
[c] Decision and Information Sciences Division, Argonne National Laboratory, Argonne, IL 60439, USA
[d] Warrington College of Business, University of Florida, Gainesville, FL 32611, USA
[e] School of Economics and Management, Shanghai University of Electric Power, Ping Yang Road No. 2103, Yangpu District, Shanghai, China

HIGHLIGHTS

- Electricity has distinct attributes for forming differentiated products.
- This paper is a literature review of electricity product differentiation.
- It describes real-world examples of product differentiation.
- It finds product differentiation improves grid operations and planning.

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ABSTRACT

This review is motivated by our recognition that an adequate and reliable electricity supply is a critical element in economic growth. From a customer's perspective, electricity has several distinct attributes: quality, reliability, time of use, consumption (kW h) volume, maximum demand (kW), and environmental impact. A differentiated product can be formed by packaging its non-price attributes at a commensurate price. The review weaves the academic literature with examples from the real world to address two substantive questions. First, is product differentiation a meaningful concept for electricity? Second, can product differentiation improve grid operations and planning, thereby lowering the cost of delivering electricity services? Based on our analysis and comprehensive review of the extant literature, our answer is "yes" to both questions. We conclude that applying product differentiation to electricity can greatly induce end-users to more effectively and efficiently satisfy their demands upon the system, and to do so in an environmentally friendly way.

Contents

* Corresponding author. Tel.: +1 630 252 1474.
E-mail address: jianhui.wang@anl.gov (J. Wang).

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1. Introduction

Product differentiation recognizes that customers have heterogeneous preferences, with varying willingness-to-pay (WTP) for differentiated products [1,2]. From a customer's perspective, electricity has several distinct attributes: power quality, level of reliability, time of use (TOU), volume of usage (kW h), maximum demand (kW), and level of environmental impact. A differentiated product can be formed by packaging its non-price attributes at a commensurate price. But because of the unique characteristics of electricity, customers have historically had only limited options for purchasing differentiated electricity products.

By canvassing a large body of literature and real-world examples, this review seeks to answer the following questions:

- Is product differentiation a meaningful concept for electricity? Based on our analysis in Sections 3–6, our answer is "yes".
- Can product differentiation improve grid operations and planning, thus lowering the cost of delivering electricity services? Based on the examples described below, our answer is "yes".

This review is motivated by our recognition that an adequate and reliable electricity supply is critical for an economy's growth [3–5], and that electricity outages can be both inconvenient and cause large financial losses [6–11]. The problem of least-cost grid operations and planning is difficult, chiefly because of several unique features of electricity. First, unlike other forms of primary energy (e.g., coal, natural gas) or energy carriers (e.g., gasoline, methanol, hydrogen), electricity cannot be economically stored and must be supplied in real time to meet randomly fluctuating demand [12]. Second, except for a few end-uses, such as cooking and heating with natural gas, electricity does not have close substitutes in real time. As a result, reliably meeting real-time demands requires capacity reserves that can be flexibly dispatched to maintain an electrical system's load-resource balance [13–18]. Third, a major facility (e.g., a high-voltage transmission line) can fail unexpectedly, with cascading effects that propagate throughout an interconnected network, as dramatically illustrated by the 14 August 2003 outage in the eastern portion of North America [19]. Finally, capacity additions are lumpy and require long lead times, implying that construction of new facilities may need to begin even when an electricity system has a capacity surplus, and well before the realization of an anticipated growth in demand [20,21].

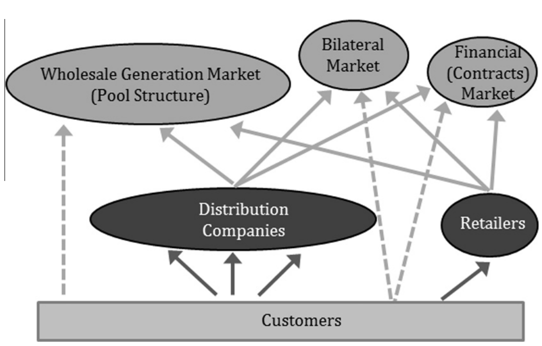

Fig. 1. A stylized model of electricity market restructuring.

The electricity industry has traditionally been dominated by vertically-integrated utilities. In making least-cost operations and planning decisions, each utility has full control of its locational resources and their additions, and a wealth of information as to its loads by individual location, as well as projections for future locational demands on the system [13–18,22,23]. In the last two decades, however, the industry has witnessed three transformative events.

The first event is market restructuring to introduce wholesale-market competition in Australia, New Zealand, parts of North and South America, and Europe [24–33]. The second event is government-supported large-scale development of renewable energy (e.g., hydro, wind, solar, geothermal, biomass, and landfill gas) in North America, Europe, and Asia in response to concerns over environmental pollution, climate change, and energy security [34–47]. The third event is the technological advances in advanced metering infrastructures (AMI) and smart grids [48–56].

With regard to the first event, market restructuring has substantially complicated the least-cost operations-and-planning problem because it transforms an industry once dominated by integrated utilities into one that relies on competition to deliver generation and retail services. Fig. 1 portrays a stylized model of market restructuring wherein customers can buy electricity directly from wholesale generation markets (i.e., the power pool and the bilateral market), or through load-serving entities (LSEs), such as local distribution companies (LDCs) and retailers that procure power from wholesale generation markets [24–33]. The LSEs may be obligated to procure renewable energy to comply with mandatory targets under a renewable portfolio standard (RPS) set by the government [35,37–39,42–47]. Since spot electricity prices are highly volatile with occasional spikes [57–68], LSEs and customers may seek to manage electricity spot-price risk using such hedge instruments as, tolling agreements, forward contracts, and capacity options that are traded in financial markets [69–74].

Though not shown in Fig. 1, an independent system operator (ISO) leases transmission facilities, performs generator dispatch, manages congestion, sets the pool's market-clearing prices, and administers an open-access transmission tariff that offers fair and comparable access to all market participants. The ISO does not own any generation or transmission resources, but it nonetheless has responsibility for real-time operations and long-term transmission planning. As wholesale energy market prices are likely to be insufficient to induce investment in conventional generation [75,76], the ISO may operate a capacity market, in addition to the power pool, to procure the capacity that will ensure resource adequacy [77–79]. When compared to an integrated utility, the ISO has very little control over non-transmission resource output and investment, and hence faces greater uncertainty regarding generator behavior and the timing and location of new resource additions [80–87].

With regard to the second event, large-scale development of renewable generation introduces a substantial risk previously unseen by an ISO. Consider wind generation, which has large and random output fluctuations, highly unpredictable availability, and limited dispatchability in reducing (but not increasing) output. Since wind generation has zero fuel cost, the ISO economically dispatches wind generation to displace marginal generation with high fuel cost, unless curtailed to resolve grid congestion and instability [88–89]. Hence, wind-generation expansion reduces wholesale spot electricity prices and diminishes the incentive for natural-gas-fired generation investments [90–95], even when such investments are urgently needed to integrate new wind-generation capacity into the grid [96–98].

With regard to the third event, AMI and smart grid technologies enable electricity product differentiation that was infeasible 20 years ago [5,48–53]. As will be shown below, such technologies help implement locational real-time pricing with frequently updated hourly prices, reliability differentiation with two-way communications, and competitive bidding that determines market-clearing prices and allocation of electricity resources.

In light of these three events, this review contributes to the electricity economics literature by using real-world examples to demonstrate that product differentiation can improve electricity grid operations and planning. Aimed to enrich the dialogue on demand response [99–105], it considers traditional products under simple metering [106,107], recent enhancements enabled by AMI [108–113], and future products that take advantage of two-way communications and competitive bidding in a smart grid with AMI. Hence, the paper's information will be of interest to policymakers and analysts in many nations, including China whose electricity industry is now undergoing regulatory and market reforms, seeing large-scale renewable development, and the implementation of AMI and smart-grid technologies [114–132].[1]

2. Criteria for a useful differentiated product

We propose a set of criteria to determine if a differentiated product is useful for grid operations and planning. For expositional ease and concreteness, we assume that the product is provided by a regulated LDC, subject to cost-of-service regulation [107]. This assumption reflects the current market environment in most parts of North America, even though active retail competition exists in some states (e.g., New York and Texas).

Our proposed criteria are as follows:

- Financial viability. The differentiated product should be financially viable and yield revenue that is sufficient to cover the LDC's cost of provision. This ensures that the product's purchase by some customers does not lead to losses to the LDC, which in turn causes bill increases to other customers [110].
- Customer acceptance. The differentiated product should be acceptable to customers, because a product that few customers want cannot play a meaningful role in the grid operations-and-planning decision process. A case in point is real-time pricing (RTP) [22,133], which bills electricity consumption at time-varying prices and is unattractive to small customers because of the product's complexity and price volatility; this is notwithstanding that industrial RTP has been implemented in such states as North Carolina, New York and Texas [134–136].
- Customer engagement. The product should exploit the operational flexibility offered by two-way communications and smart devices. Notable examples are remotely- activated programmable thermostats for space cooling, and instantaneous fuel switching between natural gas and electricity for space and water heating [51,110].
- Reliability management. The product should help balance locational demands and supplies, because imbalances jeopardize reliability, potentially triggering voltage collapse and cascading outages, with ensuing significant economic losses [6–12,19]. It should also help a system to meet the reliability standards of a governing body, such as the North American Electricity Reliability Corporation (NERC), which sets the one-day-in-10-years loss-of-load-expectation (LOLE) standard for planning reserves and the seven-percent-of-peak-demand standard for operating reserves [137].
- Asset utilization. The product should improve utilization of existing assets and reduce demand spikes, thus diminishing the need for new investments. A good example is reliability differentiation that enables the efficient allocation of limited capacity during severe power shortages [109–113,138–139].
- Renewable-energy development. The product should help develop and integrate the intermittent renewable resources, such as solar and wind, that are critical for achieving a clean and sustainable electricity supply [5,42,51–53,112,113,140]. A case in point is a low super-off-peak charging rate for electrical vehicles (EV) to avoid curtailment of excessive wind energy during early morning hours (e.g., 02:00–05:00) when system loads are low [111,141–143].
- Greenhouse gas (GHG) emissions reductions. The differentiated product should help reduce GHG emissions by (a) vehicles that use gasoline and diesel, and (b) generation plants that burn fossil fuels, especially coal [144]. While super-off-peak EV charging with wind energy can help reduce vehicle emissions, reducing output from coal-fired plants requires conservation actions and energy efficiency investment by customers, which can be encouraged by a product that discourages consumption [145,146].

3. Product differentiation under simple metering

Product differentiation is limited by the metering technology in place. A simple meter that records a customer's monthly kW h consumption can only support products whose prices vary by kW h volume. A more sophisticated meter that records a customer's monthly kW h and maximum kW can support products with kW h and kW differentiation. This section first discusses these products based on nonlinear pricing [106,109]. It then describes a recent product that aims to strengthen the price signal for conservation in an environment of rising cost for new supplies.

3.1. Inclining block rates

Used by an LDC for its default service for residential customers that have not made an explicit selection for an optional service (e.g., TOU pricing), inclining block rates have been a part of U.S. energy policy since the 1970s. Summer inclining block rates are well established on the West Coast and in Southwestern states and winter inclining block rates are widely used in the West, Southeast, and Great Lakes regions [146].

The popularity of inclining block rates in the U.S. is due in large part to Section 111 of the 1978 Public Utility Regulatory Policy Act

[1] As pointed out by an insightful referee, a comprehensive discussion of the applicability and usefulness of electricity differentiation in China is well beyond the scope of this paper. That said, this is an important topic that should be explored in a separate paper.

(PURPA), which discourages electric utilities from using declining block rates with volumetric discounts, because such rates likely encourage residential electricity consumption. Section 114 of the same act permits lower lifeline rates for "essential needs (as defined by the State regulatory authority…)." The implication of these two sections is that LDCs should employ an inclining block tariff that has a relatively low "lifeline" rate for residential customers when meeting their "essential needs," and a higher rate for usage in excess of those needs.

To see the conservation incentive of inclining block rates, consider a two-tier tariff with per kW h rate P_1 that applies to a customer's monthly consumption up to the K-kW h threshold and P_2 that applies to consumption above K. The customer's monthly bill for Q kW h of consumption is:

$$B = P_1 \min(Q, K) + P_2 max(Q - K, 0).$$

For a customer with a rate of consumption Q that is above the tier-1 threshold K, the average rate is $P = [P_1K + P_2\ (Q - K)]/Q$, which is increasing at a decreasing rate with Q. As Q increases, P converges to P_2. Hence, the tariff discourages consumption by large users, by charging a higher price P_2 for a higher rate of usage Q.

Residential conservation can be seen as the outcome of a customer's two-stage decision process [147–149]:

- *Stage 1:* Given its income, preferences, and demographics, the customer selects a portfolio of energy-using durables based on the trade-offs between the portfolio's capital cost and the expected operating cost, so as to achieve its preferred levels of end-uses (e.g., space conditioning, water heating, lighting, cooking, clothes washing and drying, and dishwashing).
- *Stage 2:* The customer determines utilization of its chosen portfolio, based on the electricity rates and its income, preferences, and demographics.

When compared to a flat rate, inclining block rates have two conservation effects. In Stage 1, the rates magnify the operating cost of an energy-inefficient portfolio for usage extending beyond the lower-priced first tier. *Ceteris paribus*, the operating-cost increase induces customers to select a more energy-efficient portfolio. In Stage 2, the inclining block rates discourage utilization of the chosen portfolio, because they result in a per kW h payment that rises with consumption. Taken together, these two effects reinforce residential conservation, as confirmed by the conservative range of negative price elasticity estimates of −0.1 to −0.3 for residential electricity consumption [147–154].

3.2. Hopkinson tariff

A simple Hopkinson tariff, which is typically applied to an LDC's default service for large non-residential customers such as industrial plants and commercial buildings, has a linear per kW h rate that applies to a customer's monthly kW h consumption in a billing month, and a linear per kW charge that applies to that customer's monthly maximum kW [155,156]. While the tariff discourages the customer from spiking its kW demand, it tends to encourage the customer to increase its kW h consumption, so as to spread the kW charge over more kW h [157]. Thus, the tariff helps improve a system's load factor and hence capacity utilization.

3.3. Conservation tariff

Replacing an existing flat rate for kW h consumption with inclining block rates does not necessarily lead to overall conservation at the system level. This is because cost-of-service regulation requires that the revenue collected under the inclining block rates be the same as the revenue under the flat rate. As a result, small (large) users with consumption below (above) the first-tier threshold will see a rate decrease (increase), thus increasing (decreasing) their consumption. Overall conservation occurs only when the small users' consumption increase is more than offset by the large users' consumption decrease.

To ensure that every customer sees a conservation price signal, consider the two-part conservation tariff adopted in 2011 by BC Hydro for general service customers with monthly demands in excess of 150 kW [145,158]. Under this tariff, a customer's bill has two parts. The first part is the customer's historical kW h consumption and kW demand billed at the old rate design.[2] The second part is the customer's consumption change (relative to the customer's historical levels) priced at BC Hydro's relatively high long-run marginal cost (LRMC), as measured by the incremental cost paid by BC Hydro for new resources.

The two-part billing implies that a customer's incremental (decremental) consumption is always charged (credited) at the LRMC, which tends to be high for an LDC that is required to meet a high RPS target (e.g., 33% of retail sales by 2020 in California) [159]. Hence, all customers will see an LRMC-based price signal for conservation, which is an important attribute of an energy-efficient society.

3.4. Evaluation

Inclining block rates and a conservation tariff are effective in reducing an LDC's energy requirements and helping achieve a GHG reduction, when the requirement is largely met by conventional generation that burns fossil fuels. They are ineffective in customer engagement, however, because a customer may be unaware of the rates that it is paying on a daily basis [150].

Consider a residential customer with a meter installed outside the home. At the start of a billing period, the customer faces the tier-1 rate. The customer then pays the tier-2 rate after its cumulative consumption within the billing period exceeds the threshold. Unless the customer knows its daily consumption and what the LDC charges for that consumption, it does not have the clear daily price signals that would impel its conservation decisions. Thus, an immediate improvement is information feedback through an in-home display, which has been found to induce reductions in consumption of as much as 14% [160].

Inclining block rates and a conservation tariff are also ineffective for reliability management, asset utilization, and the development of renewable energy. This is because they do not provide incentives for customers to reduce their kW demands during capacity shortages, or to increase their demands when there is abundant wind energy. Hence, in the next section we consider enhancements made possible by AMI.

4. Enhancements enabled by AMI

Marginal-cost pricing of electricity is economically efficient [23,106,108]. Since an electrical system's marginal costs vary by time and location [22,161–164], RTP by location has been implemented as locational marginal-cost pricing (LMP) [133,165] in New York, New England, PJM, Texas, and California. But LMP is seldom used by LDCs, chiefly due to concerns of customer acceptance and understanding, bill impacts, and tariff complexities.

4.1. Time-varying pricing

Real-time pricing for an LDC's large customers can occur via a mandatory tariff or as a rate option [134–136]. Replacing an

[2] Designed to limit a kW demand spike and encourage kW h consumption, the old design is a Hopkinson tariff with inclining block rates for kW demand and declining block rates for kW h consumption.

existing tariff (which can be TOU for large users or non-TOU for small users) with mandatory RTP, is often unacceptable to customers, however, because of the potentially large and adverse bill impacts. One possibility is to modify the existing tariff so that high prices are transmitted to a customer only on system peak days, resulting in critical-peak pricing (CPP) [166]. There are, however, other alternatives that customers may find more acceptable, as described in the remainder of this section.

4.1.1. Two-part RTP rate option

A rate option allows a customer to choose between the default service tariff and an alternative tariff, which is similar to a prospective home owner being able to choose between a fixed-rate and a variable-rate loan. Since the customer can make the choice that best suits its needs, from the customer's perspective an optional RTP is generally preferable to mandatory RTP.

Designing an RTP rate option can be challenging because of adverse self-selection by customers [110]. A case in point is a customer served under a simple Hopkinson tariff. If the customer has relatively low usage during the daytime hours, it may achieve bill savings by taking the RTP option, without providing any benefit to the electricity system. As the LDC sees large losses from offering the option, it may raise the rates for the other customers, who may in turn oppose the option.

A two-part RTP option such as was adopted by B.C. Hydro in 1996, circumvents the adverse self-selection problem [167]. The first part is the customer's historical consumption profile billed at the otherwise applicable Hopkinson tariff. The second part is the customer's hourly consumption deviation (which can be positive or negative) billed at the RTP hourly rates. The option is expected to break even if each hourly rate is set at the wholesale market price for that hour, and to be profitable if each hourly rate is set at the equally-weighted average of the Hopkinson tariff's energy charge and the wholesale market price for that hour.[3] Though remarkably simple, this design ensures that no customer can have bill savings without reducing (increasing) consumption during the high-price (low-price) hours.

A variant of two-part RTP is the two-part TOU rate option [145,168]. Instead of hourly pricing at the wholesale market price, the TOU option's on-peak and off-peak rates can be set at the wholesale market's on-peak and off-peak forward prices, which are 6–10% higher than the expected spot prices [169].

4.1.2. Customer load response

Time-varying pricing aids grid operations and planning by reducing system peak consumption and promoting off-peak consumption [99–104]. The size of this benefit depends on customer load response to time-varying pricing. Empirical evidence suggests that customer load response *sans* enabling technologies such as programmable thermostats, is moderate, with low own-price elasticity estimates of between 0.0 and −0.1 [100,134–136,170–182]. With enabling technologies in place, a customer can cut its kW demand by as much as 50% [183–187]. This underscores the importance of smart devices in a customer's ability to respond to time-varying pricing.

4.2. Reliability differentiation

Reliability differentiation can be implemented as a demand subscription service (DSS), a curtailable service, or an interruptible service [113,138,156]. A useful representation of reliability differentiation is DSS, which stipulates that before receiving service, a customer must subscribe to a firm service level (FSL). The customer pays a firm demand charge posted by the LDC for each kW in the FSL and per kW h usage rates by TOU for the kW h consumed.[4] The usage rates may be nonlinear, as in an inclining block tariff. To be sure, not all customers would make an explicit FSL selection. The default FSL for these customers may be based on their historical peak kW.

The DSS encompasses the commonly used non-firm rate options used in North America:

- Interruptible service. The customer set its FSL = 0 so that the LDC can interrupt its entire load during a system emergency.
- End-use-specific interruptible service (e.g., air conditioning (AC) load shedding). The customer's FSL includes the non-AC loads but not the AC loads. Thus, the LDC can only interrupt the customer's AC load during a system emergency.
- Curtailable service. The customer sets its FSL below its peak kW demand so that the difference between the peak kW demand and the FSL is its curtailable load. Upon the LDC's request, the customer reduces its total load below the self-chosen FSL during a system emergency.
- End-use-specific curtailable service (e.g., a remotely-activated smart thermostat for air conditioning). A customer's FSL includes the non-AC loads and a portion of the AC loads.

With regard to grid operations, DSS efficiently allocates the limited capacity during a shortage, because customers with relatively high outage costs tend to subscribe higher FSLs than do those with relatively low outage costs [138,188–190]. As the capacity allocation is based on each customer's FSL selection, more capacity will go to customers that place a greater value on reliable electricity service.

With regard to grid planning, the DSS induces customers to reveal their demands for firm capacity, greatly reducing the system's reserve requirements. Consider, for example, California's planning reserve requirement of 15–17% of the system-peak forecast under extreme summer weather [192]. This requirement can be reduced by a system-wide implementation of DSS, because the system's firm-load obligation is readily computed as the sum of all customer-specific FSL subscriptions and these are known with certainty, prior to each customer's actual usage.

4.3. Evaluation

Products based on time-varying pricing and reliability differentiation exploit the billing flexibility offered by AMI and make limited use of two-way communications and smart devices. They help balance locational demands and supplies and reduce the system's reserve requirements. Since they reduce demand spikes, they improve utilization of existing assets and diminish the need for new investments. They help integrate intermittent renewable resources because (1) they convey low price signals when renewable energy is abundant, and (2) they resolve shortages when renewable energy output suddenly drops [113]. Finally, they can help reduce GHG emissions when implemented as rate options that complement tariffs with strong conservation signals [111].

5. Future products enabled by two-way communications and competitive bidding

This section considers products beyond the enhancements discussed in Section 4. All these products entail two-way

[3] This is because the hourly rate during a high-market-price hour leads to reduced consumption and cost savings that can more than offset the revenue loss. Similarly, the hourly rate during a low-market-price hour leads to increased consumption and revenue gains that can more than offset the cost increase.

[4] Alternatively, the customer may receive a bill credit for the curtailable loads and usage associated with those loads [191].

communications and competitive bidding, foretelling what customers may see in the future. While they can further improve grid operations and planning, they have additional implementation costs. Thus, their net benefits should be considered prior to their adoption.

5.1. Competitive bidding for curtailable load

An LDC may use competitive demand bidding to engage customers on a daily basis to provide a grid's operating reserve. A competitive Vickrey auction entails a customer's submitting a multi-dimensional bid in response to an LDC's daily request for a curtailable-load target (e.g., 50 MW). Each bid is required to specify the amount of load that can be curtailed, along with the per kW upfront payment and the per kW h usage price for each of the curtailable kW [193].[5] The LDC selects the submitted bids with the lowest per kW payments to meet the curtailable-load target. All winning bidders are paid the lowest upfront payment of the last rejected bid. When needed, the LDC dispatches the selected bids, starting with the one with the lowest per kW h usage rate. All dispatched bids receive the market-clearing price. The resulting bid selection and dispatch are the least-cost solutions for achieving the curtailable-load target in a competitive auction setting.

5.2. Generalized demand subscription service

Generalized demand subscription service (GDSS) [111] is a variant of the simple DSS of Section 4. GDSS requires that each customer make an FSL subscription (e.g., 100 kW) before receiving electricity service. The customer may then alter its position (e.g., from the first to the last one to be curtailed) in the curtailment queue, if the LDC can accommodate the request and the customer is willing to pay a charge for the cost of queue adjustment. Moreover, the customer can segment its FSL subscription such that each has a self-stated curtailment price trigger (e.g., the first 10 kW at $2/kW h, the next 50 kW at $5/kW h, and so forth). In effect, the customer informs the LDC of its willingness-to-accept (WTA) additional curtailment, beyond the non-firm load declared under its FSL selection. The customer can update the FSL delineation on a daily basis, so as to meet its changing preferences (e.g., raising the self-stated price triggers by an industrial user to meet a production deadline).

With regard to grid operations, the LDC uses the GDSS to efficiently allocate limited capacity during shortages, based on each customer's curtailable load and FSL delineation. With regard to grid planning, the GDSS induces customers to reveal their preferences for firm capacity. In particular, if customers indicate low WTAs for reliability deterioration, even infrequent system expansions should not occur. When the LDC frequently makes high WTA-based payments for load curtailments, system expansion should occur to resolve any shortage.

5.3. Competitive bidding for curtailable supply

5.3.1. Customer-side distributed generation

New products that leverage smart-grid infrastructures could facilitate the integration of distributed generation (DG). Customer-side DG is currently treated as must-take by LDCs. High penetration of DG can create issues on the distribution network such as voltage regulation. Smart- grid technologies, however, could allow owners of these systems to curtail their supplies or cede control of curtailment to their LDC, subject to the terms of a contractual agreement, as is common with large-scale renewable generation. Since customer-side DG is profit motivated, any curtailment product that makes both the LDC and DG owners economically better off has the potential for significant uptake. Benefits to the LDC could include reduced investment in transmission infrastructure, and lower flexibility reserve requirements. Just as smart-grid technologies allow differentiation of load-based products, competitive bidding and real-time pricing frameworks can be made available to suppliers.

Competitive bidding, as described in Section 5.1, could be used to establish an efficient ordering of DG owners willing to be curtailed, producing the least-cost solution to curtailment of supply, and creating a new market in curtailable energy. Efficient supply curtailment can also be achieved through RTP: when the price is lower than marginal cost less production incentive payments, a profit-maximizing generator will shut off. RTP, however, may dampen investment in DG technologies. The losses from curtailment under RTP incurred by the DG owners expose them to open-ended risk on their investment.

5.3.2. Large-scale renewable energy

Large-scale renewable generators already tailor their power-purchase agreements (PPAs) to the levels of curtailment risk they are willing to accept. Greater risk commands higher power prices. A more efficient solution to curtailment of these units could be achieved, however, through the competitive bidding market for curtailable supply, as outlined above. There would be no need to separate the markets for renewable generators.

5.4. Renewables firming rate

A renewables firming rate strives to maintain reliability with increasing renewable generation. It encourages customers to exercise their controllable resources to neutralize the impacts from distributed renewable generation.

The rate operates as follows. The LDC offers a bill discount to a customer, in exchange for its commitment to stay within a bandwidth (e.g., ±5%) of its prescheduled net load. When the customer's load deviations exceed the bandwidth, the LDC imposes a per kW h penalty on the deviations.

After joining this rate, the customer would submit a schedule based on its anticipated net electrical needs, taking into account onsite generation from renewables. In real time, the customer would seek to maximize the returns of this rate, using its monitoring systems and controllable loads to manage its net load requirements, based on actual electrical needs and renewable generation.

5.5. Wholesale-market participation for flexible and responsive loads

Thus far, we have assumed product differentiation primarily implemented by an LDC. This assumption should be relaxed to reflect the continuous evolution of the electricity industry. Here we describe a case in point: flexible load response as a resource bidding into current and future ancillary services markets for enabling the integration of renewable energy. Using demand-side resources to support renewables integration has been discussed in the literature along with the advantages of using load-based resources for meeting this need, over traditional capacity resources [194–196].

Grid operators currently manage variability in the system at the sub-hourly level [197,198] through short-term energy-imbalance markets and ancillary services markets (spinning, non-spinning, frequency regulation services). With a few exceptions, these services are provided by generators. Loads, however, are increasingly being considered for renewables integration services, because they may be able to do so more cost-effectively and with faster response times. Utilizing load-based resources in a significant way will,

[5] The amount of curtailed energy should reflect the customer's curtailable kW's load factor. For example, if the load factor is 0.5, the curtailed energy per kW per hour is only 0.5 kW h, not 1 kW h.

however, require a change from the event-based demand-response paradigm that currently exists, to one that emphasizes the quality of the resource. Products will need to be structured and priced to value quantity and flexibility [194].

A multitude of load types could provide grid-integration services through wholesale markets, such as university campus microgrids, motor loads of manufacturing plants and wastewater treatment facilities, electric vehicle fleets and large thermal storage facilities. Electric vehicles, aluminum smelting, and oil extraction from tar sands and shale deposits are described as especially flexible loads [195]. AMI and the IT infrastructure that is part and parcel of a smart grid could motivate direct load-control strategies in which either a utility or third-party aggregator could control smaller commercial and residential loads [196].

6. Technologies that support and spawn new electricity products

New products and tariffs can drive technological innovation, and technology innovation can spawn new products. Fig. 2 shows that technology impacts load, which in turn determines the value of a differentiated product (e.g., RTP). Load impacts may provide a regulation service on a second-by-second basis or yield permanent load shifting sustained over hours. The product induces a load impact via a price signal (e.g., dynamic pricing) or direct load control (e.g., an externally controllable thermostat).

The load impact can come from an individual device or systems of devices, which may be energy consuming or generating. The scale of the system may range from a university microgrid controller—which controls multiple buildings, onsite generation, thermal storage, and other central mechanical systems—to individual residential appliances remotely controlled by two-way communications.

To connect the economics and engineering aspects of new products, the remainder of this section discusses three examples of technology: smart products, thermal energy storage and electric vehicles, and microgrids and DG.

6.1. Smart devices and appliances

Smart devices, along with AMI and two-way communications, allow residential customers to take advantage of the products described in Section 5. While commercial and industrial customers have had interval meters and digital energy management systems for decades, residential customers have historically not had the metering, controllability, or communications systems. Going forward, however, residential customers can utilize the communications and networking technologies for energy management and home automation described in [199,200]. A case in point is smart appliances already available from some manufacturers, which can be programmed to respond to price signals and can also be used in direct load-control products.

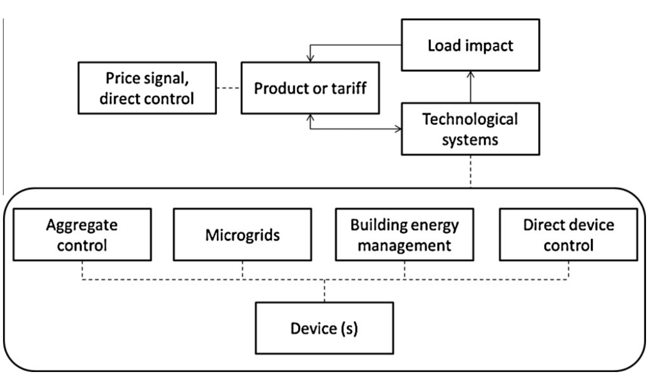

Fig. 2. Relationship between technological systems and electricity products.

Accompanying smart appliances are home energy management (HEM) systems. Since most price-signal products apply to total load, it is necessary to optimize the load for an entire home, taking into account the diversity, interruptibility and controllability of individual household loads [201,202]. Advanced algorithms may improve the performance of an HEM [203,204]. Coordinated control extends beyond the household to the utility level, thus preventing new peak-load problems that may occur when multiple homes autonomously respond to a single price signal [205].

There are tradeoffs between the implementation cost of these control strategies and their benefits. For instance, power monitoring of individual appliances may be prohibitively expensive, and estimation methods may be used for implementing low-cost load-management strategies [206,207].

6.2. Customer-side storage and electric vehicles

Storage systems bring flexibility to consumer loads and facilitate the use of the products described in Section 5, including demand subscription and renewables integration services. Customer-side storage is available in batteries (stationary and electric vehicles), thermal systems (chilled-water tanks, water heaters, refrigerated warehouses), and in industrial process control (altering industrial motor loads).

Thermal energy storage systems are particularly well suited for products that encourage load shifting [208,209]. For example, TOU and RTP pricing encourage consumers to store energy during low-price hours for later use during high-price hours. Similarly, reliability differentiation via GDSS may target vehicle charging, which can be curtailed with little impact to the customer.

Coordinated charging of multiple devices through an aggregator or supervisory control system can create scaled effects and ancillary services for integrating renewables. Since wind generation is often night peaking, these devices in large numbers can reduce a grid's fast-ramping reserve requirements [210]. For example, electric vehicles can be used to smooth wind generation and to supply flexible loads [211–213].

6.3. Microgrids and virtual power plants

Microgrids allow customers to manage their net loads by controlling a mix of generation, storage, and energy-consuming devices, thereby operating as virtual power plants. A case in point is the microgrid of the University of California, San Diego (UCSD), which has combined heat and power systems, thermal energy storage, electric and steam chillers, and visibility and controllability of multiple buildings. UCSD has around 2 MW of solar PV, advanced solar forecasting, a fuel cell, and electric vehicle charging stations to contribute towards flexible operations.

UCSD currently manages its electrical loads during system peak hours by discharging thermal storage tanks during the day, limiting electric chiller operations and operating CHP systems. With improved predictive and operational tools, these systems can be further optimized to minimize costs under RTP and GDSS.

7. Conclusion

One can, and many have, debated the chicken-and-egg relationship between economic growth and electricity consumption [3,4]. What is indisputable, however, is that the two are inextricably intertwined. It is therefore equally incumbent upon policy makers in the public sector and senior management in the electricity industry to embrace rapidly changing technologies, particularly smart-grid technologies and advanced metering infrastructures, in a world that is increasingly concerned with environmental issues and hence the development of non-polluting renewable-energy resources. One such direction, the one that has been the focus of this survey, is the provision of differentiated products to electricity customers – which means virtually every person and business in all but the most primitive societies.

Suppliers have a plethora of options by which they can differentiate their products, and those options are expanding as technological advancements occur unabated. With reliability of supply a prime consideration, the options run a gamut from allowing customers to choose between various rate structures and offering a demand subscription service that allows customers to pay for their places on the cut-off ladder in the event that a supplier is overwhelmed by demands on the system, to smart grids armed with remotely-activated demand-response control devices, through which electricity usage becomes instantaneously sensitive to price changes. Energy conservation and encouraging the development and use of renewables are also accorded pride of place in the policy-making hierarchy of objectives. There is, in effect, an emerging partnership between energy consumers and energy providers wherein the industry is developing products designed to induce end-users to more effectively and efficiently satisfy their demands upon the system, and to do so in an environmentally friendly way. With great appreciation, we applaud these efforts.

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