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IAEE ENERGY FORUM

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PRESIDENT'S MESSAGE

Six months already!

Six months under my one-year term as a president of IAEE has already passed; what have I achieved? It has been six months since the unsolicited arrival of Covid-19; what have we learned from it? Despite the enormity, gravity and the unprecedented long-term losses associated with the virus, there has been a few (some small, some significant) benefits or eye-opening virtues that emerged from the lockdowns.

Who would have thought that we could be without the stress of the daily two-hour commute? Who would have thought that we could be looking for more quality family time? Who would have thought that husbands could find new hobbies or contribute more for household? We have more time to read, relax and think, while simply baking, cooking, cleaning, walking, gardening... In Japan, we are surprised but butter and flour disappeared from shelves of stores because school kids joined the force and started to bake cakes at home.

These are challenging times for humanity, no doubt, but for many of earth's "other" inhabitants, it is like a blessing with clearer skies, quiet streets and tranquil shores inviting nature and wildlife back such as bluer and cleaner water in Venice canals or cleaner sky in China. Who would have thought that nature needed a break?

But what are we learning from all this? Will we take this opportunity to change just a few of the things we know we have been doing wrong for a long time? Will we reassess our needs and adjust accordingly? What about you dear members? Have you made a few resolutions to change the future?

IAEE is also adjusting to the new reality and we are preparing platforms to virtually contact each other. I hope that many of you are enjoying IAEE's continuous roll-out of webinars and podcasts. For those of you who have not done so, please check out our webinar listing at https://www.iaee.org/en/Webinars/ and join us.

We have been punctually conducting these webinar series hoping to unite our members and invite new faces from all over the world. We have covered a variety of topics so far. And yet, we still have lots to cover. If you are interested in leading one of our webinars, please reach out to our Executive Director, David Williams at iaee@iaee.org. Your contribution will make a difference.

Please do not forget to check out the new dates for 2021 conferences as well.

See https://www.iaee.org/documents/2010/IAEE-Affiliate_Master_Calendar.pdf

We look forward to seeing all members in Paris and in other places in 2021 to exchange news and discuss energy matters, face to face. Please stay safe, until then.

Yukari Niwa Yamashita

Careers, Energy Education and Scholarships Online Databases

IAEE is pleased to highlight our online careers database, with special focus on graduate positions. Please visit http://www.iaee.org/en/students/student_careers.asp for a listing of employment opportunities.

Employers are invited to use this database, at no cost, to advertise their graduate, senior graduate or seasoned professional positions to the IAEE membership and visitors to the IAEE website seeking employment assistance.

The IAEE is also pleased to highlight the Energy Economics Education database available at http://www.iaee.org/en/students/eee.aspx Members from academia are kindly invited to list, at no cost, graduate, postgraduate and research programs as well as their university and research centers in this online database. For students and interested individuals looking to enhance their knowledge within the field of energy and economics, this is a valuable database to reference.

Further, IAEE has also launched a Scholarship Database, open at no cost to different grants and scholarship providers in Energy Economics and related fields. This is available at http://www.iaee.org/en/students/ListScholarships.aspx

We look forward to your participation in these new initiatives.

IAEE MISSION STATEMENT

The International Association for Energy Economics is an independent, non-profit, global membership organisation for business, government, academic and other professionals concerned with energy and related issues in the international community. We advance the knowledge, understanding and application of economics across all aspects of energy and foster communication amongst energy concerned professionals.

WE FACILITATE:

- Worldwide information flow and exchange of ideas on energy issues
- High quality research
- Development and education of students and energy professionals

WE ACCOMPLISH THIS THROUGH:

- Providing leading edge publications and electronic media
- Organizing international and regional conferences
- Building networks of energy concerned professionals

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Editor's Notes

We conclude our coverage of the theme, *Electricity Distribution,* in the issue. As noted in the last issue, we are most grateful for our reader response. I believe this theme brought forth a record response in artiicle numbers.

Brock Mosovsky and **Steven Dahlke** note that electricity supply and distribution is becoming increasingly decentralized and intermittent. They demonstrate how optimized and automated battery dispatch relative to dynamic retail rate structures can shape electricity demand profiles in a way that is economically beneficial to both utilities and their customers.

Marina Bertolini notes that Institutional willingness to move towards a new market paradigm for electricity is clear; technological tools are ready to be applied; economic research is endowed with robust theoretical models on market functioning. Why are we still waiting for energy markets' revolution? The answer could be the high uncertainty that blocks regulation.

Alan Rai posits that despite a significant increase in VRE penetration and digital technologies, most electricity customers in Australia remain on network tariffs designed for a more traditional electricity system.He discusses the emergence of more dynamic network tariffs, and argues tariffs need to continue to become more dynamic and cost-reflective given expected increases in digital load controlling technologies, DER and VRE penetration, in order to achieve efficient and equitable outcomes.

Robert Kleinberg and **Marie Fagan** note that Econometric analysis shows that U.S. upstream research and development efforts track oil price movements with a delay, while case studies show that the results of technology development requiring substantial R&D resources are often driven by innovations that arise independently of the business cycle.

Andrés Alonso comments on the application of a public policy coming from the Chilean mining industry that will allow the regulated electricty consumers in Chile to save more than 20,000 million dollars compared to the level of prices paid in 2013.

Daiman Shaw-Williams notes that in the distribution network sector, much has been made of the cost of adaptation and yet it also stands to gain significantly by moving to new business models. Through digitalisation and the incentivisation of localised network supporting behaviour, new models of aggregation can lead the way in investment in optimisation.

Bruce Mountain, Steven Percy and **Kelly Burns** report on an analysis of 48,677 residential electricity bills that reveal rooftop photovoltaics (PV) reduces prices for all customers. Even high penetration of residential rooftop PV does not have a big impact on network usage.

Mohammad Ansarin notes that there is some controversy about pricing electricity, especially where there's small-scale solar generation. Persistent misunderstandings exist about tariff fairness in debates between utilities, regulators, consumers, and solar energy advocates. What is needed most are objective evaluations of a tariff's pros and cons and viewing electricity more as a private good.

Doug Reynolds investigates in "Competitive Electric Utility Analysis" how electric utility markets can or cannot be compared to a road network in a city and if power generators on a grid resemble perfect competition, monopolistically competitive markets, or oligopolistic competition. The efficiency is assessed compared to a regulated monopoly

Yoshihiro Yamamoto posits that customers could mitigate the imbalance between supply and demand with devices such as photovoltaic systems and energy storage systems. Although aggregation of those operations is effective, it may be difficult for some small-scale owners to be aggregated. He presents a rewarding system to encourage them to operate those devices appropriately.

John Morris examines the history and potential future of retail rates in the electric power industry. Changes in information and technology have impacted retail energy rates in the past and will likely continue to do so in the future. As long as our wealth stays the same or increases, changes in technology and the availability of information will increase at an increasing rate. Hence, utility rate structures in the future will need to be more flexible and dynamic to accommodate the increasing rate of change.

Burcin Unel, Sylwia Bialek, Jip Kim and **Yury Dvorkin** note that proliferation of distributed energy resources spurred discussions about how reform today's utility regulation. However, these discussions overlook the role information plays in optimal regulation. They discuss how information, or lack thereof, can affect the cost-effectiveness of the transition to a clean and distributed energy future.

Jackie Ashley reports on British Columbia's approach to demystifying the various energy cost-effectiveness tests by looking at the question from the perspective of 'effectiveness (how effective is the energy efficiency program in 'nudging' a customer to change their behaviour or investment decision?) and balance' (do all customers have a reasonable opportunity to benefit from energy efficiency programs? She discusses in detail the 'effectiveness and balance' approach to reviewing energy efficiency programs.

IAEE/Affiliate Master Calendar of Events

(Note: All conferences are presented in English unless otherwise noted)

Date	Event, Event Title	Location	Supporting Organization(s)	Contact
2020				
May 13-15	5th Annual HAEE Symposium: *Energy Transition V: Global & Local Perspective*	Athens, Greece	HAEE	Spiros Papaefthimiou http://haee.gr/
June 21-24	43rd IAEE International Conference *Energy Challenges at a Turning Point*	Paris/France	FAEE/IAEE	Christophe Bonnery https://www.faee.fr/
Sept 18-19	5th IAEE Eurasian Conference *Energy Supply, Sustainability and Electric Mobility: Regional Challenges and Opportunities*	Baku, Azerbaijian	IAEE	Vilayat Valiyev https://www.eurasianconference.com/
Sept 22-23	BIEE Oxford 2020 Research Conference *Energy for a Net Zero Society: Achieving a Just Transition*	Oxford, U.K.	BIEE	Debbie Heywod http://www.biee.org/
November 1-4	38th USAEE/IAEE North American Conference *Energy Economics: Bringing Markets, Policy and Technology Together*	Austin, TX, USA	USAEE/IAEE	David Williams http://www.usaee.org/usaee2020/
2021				
March 21-23	8th Latin American Energy Economics Conference	Bogota, Colombia.	ALADEE	Gerardo Rabinovich
July 25-28	44th IAEE International Conference *Mapping the Global Energy Future: Voyage in Unchartered Territory*	Tokyo, Japan	IEEJ/IAEE	Yukari Yamashita https://iaee2021.org/
August 29 – September 1	17th IAEE European Conference *The Future of Global Energy Systems*	Athens, Greece	HAEE/IAEE	Spiros Papaefthimiou http://haee.gr/
2022				
February 6-10	45th IAEE International Conference *Energy Market Transformation in a: Globalized World*	Saudi Arabia	SAEE/IAEE	Yaser Faquih
September 4-7	18th IAEE European Conference *The Global Energy Transition: Toward Decarbonization*	Milan, Italy	AIEE/IAEE	Carlo Di Primio https://www.aiee.it/
2023				
June 25-27	46th IAEE International Conference *Overcoming the Energy Challenge*	Izmir, Turkey	TRAEE/IAEE	Gurkan Kumbaroglu http://www.traee.org/
2024				
May-June	47th IAEE International Conference *Forces of Change in Energy: Evolution, Disruption or Stability*	New Orleans	USAEE	David Williams www.usaee.org

Retail Rate Structures for Electric Distribution Networks in Transition: A Case for Automation

BY BROCK MOSOVSKY AND STEVEN DAHLKE

Introduction

Clean energy technologies are increasingly being deployed on electric distribution systems and retail electricity pricing is evolving to support the transition. This evolution involves moving from rates characterized by flat energy charges and net metering policies for distributed energy resources (DERs) towards modern structures that more accurately reflect a utility's costs to supply and deliver electricity. These include time-of-use schedules, demand charges, feed-in tariffs (FITs) for over-generation by DERs, and other dynamic pricing signals. These modern rate structures provide economic signals that encourage energy consumption during periods when supply is abundant and discourage consumption during periods when demand is higher and grid resources are more constrained.

Historically, net energy metering (NEM) policies have been the dominant compensation mechanism driving renewable DER growth in the United States, the large majority of which has been small-scale solar photovoltaics.(1) NEM requires utilities to compensate excess production from customer-owned generation at the relatively static retail electricity price. Under this paradigm, small-scale (<1MW) solar generation has grown an average of 27% per year from 2014-2018, and currently provides 33% of all solar energy in the United States.(2) Clearly, NEM policies have been an effective tool to stimulate early investment in distributed clean energy; however, policymakers have begun to shift away from this model for future distribution systems.(3)

NEM becomes less efficient as DER penetrations increase to substantial levels. As this occurs, the grid can become oversupplied with a particular form of generation (e.g., solar). This decreases the marginal value of each kilowatt-hour generated and increases grid management costs to accommodate the excess energy. Such a scenario is now common in California where mid-day solar penetrations can be so great that more traditional generation resources are forced to ramp down their operation in response.(4) As distributed generation levels rise, compensating DERs at static retail energy rates is an increasingly inaccurate reflection of their marginal value. Moreover, the intermittency of these DERs requires the utility to provide backup capacity to satisfy customer demand when the sun is not shining or the wind is not blowing. In both cases, DER growth with static net metering compensation leaves utilities to make up the balance in a skewed equation of value.

The decentralized and intermittent grid of today is different from the centralized and dispatchable grid of previous decades. As a result, static electricity rates that once provided a simple and effective mechanism for suppliers to recuperate costs are becoming increasingly inefficient and detached from the evolving price dynamics in organized wholesale markets with increasing renewable penetrations.(5,6) For this reason, utilities are now tackling the problem of designing retail rates that incentivize and shape their customers' energy consumption to better align with periods when energy is more abundant. For customers, this could mean enacting behavioral changes that adjust their traditional patterns of electricity usage to take advantage of reduced costs during certain times of day. It could also mean employing "load shifting" technologies such as home batteries, electric vehicles, or smart thermostats to automate the shifting of electricity usage behind the meter and capitalize on periods of low retail prices. In either case, both the utility and the customer benefit economically: the utility by receiving demand profiles that are less costly to serve and the customer by reducing their monthly electricity bill.

Brock Mosovsky is Co-Founder & Director of Analytics, cQuant.io **Steven Dahlke** is a Solar Research Fellow with the U.S. Department of Energy. Mosovsky can be reached at brock@cquant.io

In the past, regulators typically pushed back on dynamic retail electricity pricing because of concerns with exposing customers to increased uncertainty in their energy bills.(7) Additionally, behavioral and psychological changes are notoriously difficult to effect. Today, however, the emergence of cost-effective battery storage is providing new impetus and feasibility to retail rate reforms. Distributed storage can overcome traditional psychological and regulatory barriers by automating changes in consumption patterns in response to new price signals. This includes arbitraging energy rates between periods with differing time-of-use prices, shaving peaks to reduce demand charges on monthly bills, and reducing exports in jurisdictions where compensation for excess renewable energy is only a fraction of the rate for electricity purchased from the grid. In this way, storage coupled with dynamic retail rates provide a promising path forward for electricity distribution networks in transition.

Insights

We propose two prerequisites for DER-focused retail rate design to be successful in uncovering the true economic value of these resources:

- Shifting of customer electricity demand from one period of the day to another must be auto-

matable. Relying on behavioral changes alone will not result in sufficient adoption to effect systemic change.
- Utilities must understand how various rate structures will modify customer demand profiles, both at the individual customer level and in aggregate for a given penetration level of distributed storage. This requires advanced analytical modeling and optimization.

If the above prerequisites are met, retail rates themselves have the ability to "shape" or "mold" customer demand profiles to better align with periods when supply is abundant and associated costs to serve demand are low. The overall effect should be one of net economic benefit to both the utility and its customers: a rare win-win outcome.

To inform an example of how retail rates can be used to shape customer demand, consider first several relatively standard retail rate structures: time-of-use (TOU) rates, demand charges, and feed-in tariffs (FITs). TOU rates charge customers different amounts based on when electricity is consumed. They generally encourage customers to shift some of their energy consumption from periods of high prices to periods of low prices. A battery can derive value from TOU rates by arbitraging the rate schedule; that is, it can charge when prices are low and discharge when prices are high, saving the customer the difference between the two rates. Such rates may vary seasonally, by day of week, and/or by hour of day. Whereas TOU rates focus on energy volumes (kWh), demand charges bill a customer based on their maximum power consumption (kW). These too provide value to a battery insofar as it can discharge when the customer's native demand (demand in absence of any on-site generation or storage) is highest, reducing the maximum amount of power the customer must draw from the grid. This mode of operation is often referred to as "peak shaving". Finally FITs offer a third revenue stream for a battery in jurisdictions without NEM where compensation for energy exported to the grid is less than the retail rate the customer would pay to buy that energy back. Such a structure discourages export of electricity during periods when rooftop solar generates more electricity than the customer's demand, and batteries can "soak up" this excess energy, storing it for discharge later when needed. This avoids the loss in value that would result from sending the over-generation back to the grid, resulting in a net financial gain for the customer. For a more detailed discussion of modern retail rate structures and their use in conjunction with DERs and battery storage, see Faruqui 2018.(8)

Retail Case Study – Rooftop Solar, No Battery

With the above rate structures in mind, we examine the retail bill dynamics of a hypothetical commercial customer in California with a large rooftop solar installation and a demand profile that peaks sharply in the evening hours. Figure 1 illustrates hourly energy profiles for such a customer on a representative day in July. We analyze the case where the customer's retail rate schedule includes a two-period TOU-based energy rate (on-peak hours are shaded red in the figure), a demand charge calculated from the maximum demand in any hour, and a FIT that compensates electricity sent back to the grid at a rate significantly below the customer's retail energy rate. Additional details of the retail rate schedule analyzed are provided in Table 1.

RATE COMPONENT	SCHEDULE	RATE
ON-PEAK ENERGY	M-F, hour-ending 1200-2200	\$0.23/kWh
OFF-PEAK ENERGY	M-F, hour-ending 0100-1100, 2300-2400 Sa-Su & holidays, all hours	\$0.15/kWh
DEMAND	Maximum across all hours of billing cycle	\$12/kW-month
SOLAR FIT	All hours, all kWh sent to grid	\$0.10/kWh

Table 1. Example July rate schedule for a commercial customer in California.

As seen in the figure, the customer generates more solar energy than their native electricity demand in hours-ending 10 AM through 4 PM. In this example, the misalignment between the customer's native demand profile and that of the solar generation results in significant and frequent over-generation for photovoltaic systems of any appreciable size. Since there is no battery to consume the surplus energy, it must be sent back to the grid and the customer is compensated through the FIT at less than half the rate they would pay for energy during the on-peak period. This represents a significant loss of value compared to if they were able to consume that energy behind the meter to directly offset their demand.

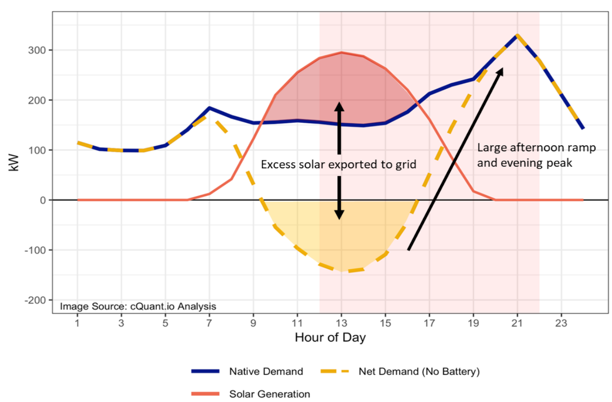

Figure 1. Hourly native demand, on-site solar generation, and net demand for a commercial customer in California with a late-evening peaking load on a representative day in July. Red shading denotes hours that correspond to the customer's on-peak TOU rate period. Surplus mid-day solar and a sharp peak in evening demand present economic opportunities for a battery relative to TOU rates, demand charges, and FITs.

The sharp evening demand peak seen in Figure 1 also represents a financial hurdle for the customer. It contributes an out-sized cost to the customer's energy bill for high levels of demand that persist for only a few hours of the day. In particular, the single highest hourly demand, occurring in hour-ending 9 PM, is more than 40 kW greater than the second-highest hourly demand. With a demand rate of $12/kW-month, the customer could save more than $500 on their monthly bill if they were able to reduce their usage in just this single peak hour of the day. Because of the potential for large bill savings by modifying demand in just a small number of hours, such "peaky" load profiles can provide a compelling value proposition for batteries when the appropriate retail rate structures are in place, as we will see in section on *Retail Case Study – Rooftop Solar With On-Site Battery* below.

Despite the misalignment of shaping relative to the customer's native demand profile, rooftop solar does provide significant value in this example by directly offsetting a good deal of mid-day energy consumption. Here, solar contributes more than a 35% reduction in the customer's July electricity bill (see Figure 3 below). However, the consistent mid-day overgeneration leaves value on the table because FIT compensation is so much less than the customer's retail energy rate.

Retail Case Study – Rooftop Solar With On-Site Battery

To understand how adding a battery could improve overall bill economics for the example customer introduced above we used an optimization model to compute optimal dispatch of an 800 kWh/200 kW battery system relative to the customer's native hourly load profile, their hourly solar generation, and all the retail rate components described in Table 1. Sized this way, the battery could store just under 20% of the customer's daily July energy usage and could discharge at roughly 2/3 of their peak demand. Figure 2 shows the resulting optimal charge and discharge pattern of the battery (solid light blue line) that minimized the customer's total retail bill and the corresponding net demand purchased from the grid (solid yellow line). As seen in the figure, the battery's operation virtually eliminated the export of energy back to the grid and significantly reduced the peak net demand. The result was a 25% reduction in the total July electricity bill compared to the case of rooftop solar alone (see Figure 3).

In the example, the battery is able to derive value in three ways: by peak shaving to reduce demand charges, by reducing grid export to avoid economic losses from the low FIT, and by arbitraging the TOU schedule to capture the differential between on-peak and off-peak energy rates. This value is possible only because the retail rates compensate the battery for charging and discharging at very specific times. Combined with automation and optimization of the battery's operation, the two prerequisites of successful DER rate design we proposed above, the retail rates actually shape the customer's net demand. As a result, we see how application of a few simple and well-understood rate components can transform a customer's grid-based energy usage (net demand) in a way that benefits both the customer and the utility (see Table 2).

It is important to note that the battery's operation in our analysis is completely and automatically determined by the optimization model in response to the economic signals at play. Interactions between rate components can be highly complex, but an optimization model is designed to efficiently account for all these complexities when identifying the best outcome. Furthermore, the model guarantees that the outcome respects important constraints on battery operation, e.g., maximum charge/discharge rates, maximum energy storage capacity, etc. Such models will be key components of future utility rate design, as noted in prerequisite two above.

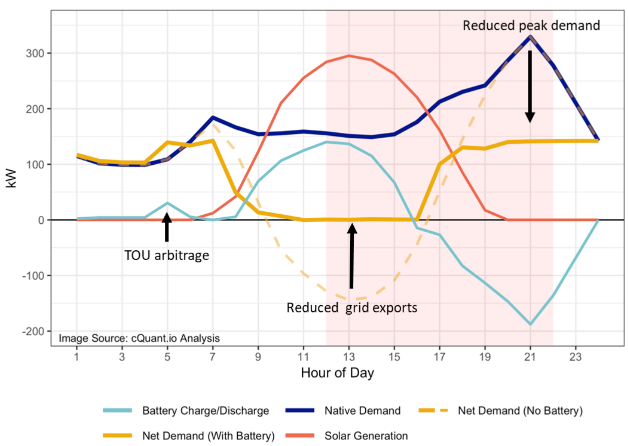

Figure 2. Optimal hourly battery operation relative to customer demand, solar generation, and retail rates including TOU, demand, and FIT components. The battery operates to avoid export of excess solar energy to the grid, reduce peak net demand, and arbitrage TOU schedules to the economic benefit of the customer, as seen by the solid yellow curve.

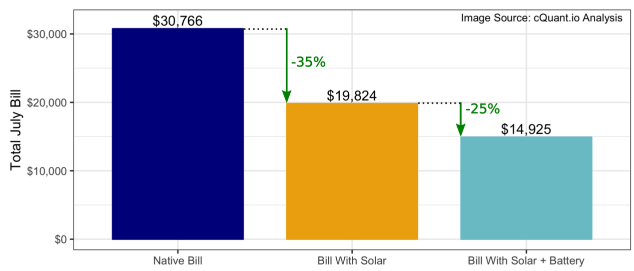

Figure 3. July electricity bill for a large commercial customer in California with only grid purchases (native bill), with rooftop solar, and with solar-plus-storage.

While the bill reductions shown in Figure 3 are striking, we do acknowledge several challenges with achieving such results in real-world applications. Technologies to automate battery operation in real-time are still in development; these are needed to satisfy the first prerequisite for DER-centric rate design noted above. Additionally, uncertainty in customer demand and solar production make perfect real-time optimization difficult to achieve, meaning actual battery operation may be suboptimal, providing less value to both the customer and the utility in practice than in theory. Finally, different customer load profiles will respond to the same rate structures in different ways, meaning there is no "one-size-fits-all" approach to rate specification. Further research and modeling is needed to better understand how retail rates can be designed to shape electricity consumption for individual customer sub-classes that share similar demand profile attributes. The above considerations notwithstanding, we believe there is great benefit to broadening current understanding of how batteries can respond to utility rate signals in an era of ever-increasing artificial intelligence and automation

EFFECT OF BATTERY	CUSTOMER BENEFIT	UTILITY BENEFIT
REDUCED PEAK NET DEMAND	Reduced demand charges	Reduced system peak, reduced system ramp
REDUCED EXPORT TO GRID	Increased value of rooftop solar generation	Mitigation of "Duck Curve" effects, reduced two-way power flow on grid, reduced system ramp
INCREASED OFF-PEAK CONSUMPTION	Bill reduction due to TOU rate arbitrage	Reduction in on-peak consumption, flatter system demand profile

Table 2. The mutual benefits of batteries to both utilities and their customers.

Conclusions

This analysis has shown how pairing a battery with rooftop solar can simultaneously accomplish several goals for both retail customers and utilities when battery operation is optimized to a relatively simple rate structure. Our case study analyzed the monthly electricity bill for a customer with on-site solar paying a basic two-level TOU energy rate plus demand charge in a jurisdiction without NEM. The cost-minimizing optimization eliminated two-way power flows, mitigated solar "Duck Curve" effects, reduced evening ramp, and lowered peak demand. In this way, combination of a battery with dynamic retail rate structures aligned the customer's economic incentives with the utility's operational goals.

We stress the importance of automating a battery's response to dynamic rate structures. This enables a customer to realize battery value without significant behavioral change. Furthermore, automation implies that the customer need not understand or even consider the complex analytics associated with optimizing battery operation. On the other hand, optimization modeling is important for utilities to understand before implementing next-generation rate design in a decentralized grid. Once a utility understands optimal battery operation relative to various rate structures, it can develop programs that fully abstract the analytical details away from the customer, simplifying the path toward adoption. Such programs could include providing incentives for or the direct provision of customer-sited batteries with solar installations, while the utility retains operational control of the battery. In exchange, the utility and customer would share battery value through avoided supply costs and retail bill savings, respectively.

The illustrative case presented in this article is just one example of the value from solar-plus-storage along with new rate structures. In general, analytics should be customized to customers' native demand profiles and a region's renewable energy production characteristics, along with a variety of dynamic rate structures. Further research should focus on how batteries respond to other rate structures, how responses interact with different load profiles to incent a desired load pattern, and how program design could be accomplished.

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Energy Transition: Interdisciplinary Approaches Against Uncertainty

BY MARINA BERTOLINI

Marina Bertolini is with the University of Padova, Department Of Economics and Management and CRIEP – Interuniversity Research Center on Public Economics (Italy). She may be reached at marina.bertolini@unipd.it

Introduction

Radical innovations in the way in which energy is produced, distributed, and traded are expected all over the world (EU, 2017; IEA, 2019). In the eye of legislators, these innovations are both technological and organizational: technology, however, seems to be quite ready – at least at the theoretical level - but what really is lacking is the environment, where to apply it.

One of the main targets of the expected energy revolution is the inclusion in the markets all existing players (end-users, producers, distribution system operators, transmission system operators, etc.) with old and new tasks, and "new" players – with *prosumers* and *aggregators* on the front line.

Since political announcements are frequent, and a willingness to open the markets can be now taken as given, the fact that so far only a mild attempt to move in this direction has been made, implies that the realization of the strategy is not that easy.

Reasons for this could be many, but one of the big issues of this revolution is surely the uncertainty we meet at different levels and in all fields. Technically, because we care about system stability, letting more agents in the market or even moving system control from central to a peripheral level, sounds like a menace. Economically, playing on natural monopolies is always tricky, and uncertainty and risk deriving from the opening of the markets impact every decision of rational agents.

Literature so far: some examples

In recent years, the participation of renewable energy sources in specific markets, e.g., ancillary markets have been studied, but despite the accurate design for both energy and ancillary service markets, there are still difficulties in supporting high renewable penetration (Banshwara A. et al., 2017).

With the so called *Smart Grid*, local agents can effectively contribute to real-time balancing of the electric system and, in this way, be paid for reducing network imbalance costs (Belli et al., 2017; Burgio et al., 2017; Puglisi et al., 2017; McPherson M., Tahseen S., 2018). Given this, it is necessary to study the reactions of market agents to the new scenarios. The presence of a *smart* electricity grid empowers small producers to enter the market, having an impact on decisions in investment time and size (Bertolini M., D'Alpaos C., Moretto M., 2018).

Integrating distributed renewable energy sources (RES) into the system means that distributed energy power plants will be allowed to participate to energy markets, at least at the local level: renewable energy sources (RES), for instance, could be involved in zonal energy markets, or in the balancing market or in the ancillary service market (Ruester et al., 2014). At the same time, grid operators, i.e , Distribution System Operators (DSOs) and Transmission System Operators (TSOs) need to adapt their grid management in order to take into consideration these new agents in the market.

Literature moving on and further research

Despite all the valuable contributions to worldwide debate, there is always something missing for the concrete application of new local market models. This might derive from a lack of understanding on the part of the various disciplines on how physical markets really function. In a highly innovative and uncertain world, binding disciplines could be a valuable way to overcome critical points. Market equilibria, indeed, derive from economic theories and agents' behaviour: working for systems stability. Avoiding the correct economic approach leads to unexpected results. Similarly, part of the variance in economic parameters (i.e., costs and prices) could be explained by means of technical functioning. Uncertainty rate can be reduced with a common approach; Interdisciplinary can be seen as a risk mitigation strategy in designing new markets. Dealing with the topic with an interdisciplinary approach, however, is still quite complicated.

In a recent working paper, we tried to provide a definition of *smart* investment that disregards the usual understanding of investment and considers the impact that the investment has on the local (and total) grid. After a wide overview of definitions provided by both grey and scientific literature, we concluded that *smart* investments are those impacting on "the reduction of market risks faced by market players, such as production firms, consumers, and distribution system operators (DSOs) who manage local grids" (Bertolini et al., 2018). *Smartness*, then, is connected to volatility of prices and flows, which are the direct expression of uncertainty.

Moving from this definition, we provide a simple industrial organization model that "confirmed the intuition that investments in SGs have a pro-competitive, risk-reduction effect" attributable to the reduction of market risk. This effect seems to prevail on the competition effect when the demand uncertainty and firms heterogeneity is high, allowing small and risk-averse firms to enter the market

Even though the intuition on the link between smartness and volatility was corroborated by long discussion in an interdisciplinary research group, the next step is to include in market models and simulations features, tools and effects actually present in the network. There is a lack of a consideration of this in current literature. From the economic theory perspective, the market functioning seems equivalent to the actual in absence of grid boundaries, and technical optimization models usually lack a definition of price equilibria.

The absence of a coordinated research approach prevents the creation of a reliable environment for market agents: only "enriched" models (technical and economic) could lead to an effective regulatory framework.

Regulation is truly relevant in this sector, where natural monopolies make incumbents particularly strong. Market power in natural monopolies has always been an issue, but it will become even more relevant if we consider the introduction of new market forms, especially at the local level. An explicative example can be found in the SmartNet project (http://smartnetproject. eu/), where the role of the DSOs emerges to be fundamental. If DSOs are in charge of investing on the grid, they could keep structures and potential congestions that may prevent market access. Aggregators, on the other side, are encouraged to enter the market to manage small resources and reduce volatility of flows (Burger et al., 2017; Iria and Soares, 2019). They are endowed with the power to set market prices at the balancing level, but without proper regulation they could play strategically both in the day ahead and balancing market. Economically, there is a lot of risk connected to price level; technically, this is the result of strong players with targets that are not necessarily consistent with system stability.

Conclusion

To really foster the Energy Transition in electricity markets and reach all the results we expect from it (opening the market, greening the production, reducing wastes), we must deal with the uncertainty generated by the process. To translate a new solution in a proper environment to a successful regulatory framework, an interdisciplinary approach is needed. To do this, we all must relax our boundaries. Economists must abandon the "purity" and universal applicability that they usually want to obtain by models, and apply them to real networks; engineers have to deal with the idea that, in opening markets, the system must be re-adapted, considering the dynamic interaction with market operators, and this means to consider agent's economic choices. Both the disciplines must interact with other research fields that, in one way or another, are touched by the energy market revolution (Information Technologies, of course, but also social and environmental sciences). Strengthening the collaboration between disciplines is costly, especially in terms of time, and asks for an increase in *perceived* uncertainty, since assumptions must rely on reciprocal trust. Keeping the current approaches, again, gives only the impression of providing solutions for the effective realization of energy markets – otherwise they will already have been put in place.

A key aspect for the design of local markets, their functioning and investments is to deal with *uncertainty* on both prices and flows: from the economic perspective, this could limit competition and reduce overall welfare; from the technical perspective, systems stability is in danger. Separate solutions to the problems are not sufficient: The next – urgent – step in research regards the joint modelling of local markets.

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Network Tariffs in an Increasingly Distributed, Decentralised, and Decarbonised Power System

BY ALAN RAI

Alan Rai is a Director at Baringa Partners LLP, and a Senior Fellow at the University of Technology, Sydney (UTS). His email is alan.rai@uts.edu.au. Thanks to Garth Crawford, Tim Nelson and Greg Williams for their comments. The views expressed in this article are those of the author and not necessarily those of Baringa Partners or UTS.

See footnotes at end of text.

Australia has seen significant increases in the penetration of variable renewable energy (VRE) driven by the Renewable Energy Target (RET)[1]: Wind (at the utility scale) and rooftop PV (at the small scale). As at end-November 2019, more than 1 in 5 Australian households, around 2.3 million, had rooftop PV, a 27-fold increase over the past decade, or a compound average growth of 40 per cent p.a.[2] Across Australia's National Electricity Market (NEM)[3] combined small-scale (i.e., system sizes of 100kW or less) rooftop PV capacity is around 8½ GW, equivalent to almost 20 per cent of utility-scale generation capacity in the NEM. Uptake has been especially prevalent in Queensland (QLD) and South Australia (S.A.), where over 1-in-3 households have installed rooftop PV.

There has been a significant, albeit less stellar, increase in utility-scale (i.e., system sizes 5MW or more) VRE penetration across the NEM. NEM-wide, VRE penetration was around 15 per cent over calendar year 2019, compared to 1.4 per cent a decade ago. Most of this increase has occurred in S.A., where utility-scale VRE penetration is close to 50 per cent, followed by Victoria (16 per cent penetration rate).

This increase in utility- and small-scale VRE penetration has fundamentally changed the nature of intra- and inter-day electricity demand, with lower demand troughs, faster ramps, yet largely unchanged demand peaks. Intra-day demand increasingly resembles a 'duck' curve (or for Australia, an 'emu' curve), with PV export congestion and export-induced system security concerns increasingly an issue in the middle of the day (Rai et al., 2019).

Efficiency considerations

The Australian Energy Market Commission (AEMC), the rule maker for the NEM and energy policy advisor to governments, made a series of rule changes from late 2014 onward to facilitate the move to more efficient network price signals (AEMC, 2014). In the pre-DER world, efficient network price signals focused on managing peak demand (e.g., 'peak shaving') as a means of maintaining power system reliability and security whilst maintaining affordability. In the same way, efficient network price signals remain important in today's age of decarbonisation and the 'prosumer'.

The difference today is efficient signals are needed for both withdrawals (i.e., consumption and demand) and injections (i.e., supply and production), to manage import and export congestion. The importance of such price signals is growing: rooftop PV capacity is projected to double by 2030, and uptake of other distributed energy resources (DERs), chiefly electric vehicles (EVs) and home batteries, are likely to also accelerate (Rai et al., 2019). In addition, the increasing prevalence of new digital load-control technologies, such as Google Home and Nest, may result in demand that was once thought to be price-inelastic in the short-term becoming price-elastic.

Network congestion – on imports or exports – is often highly localised (i.e., within distribution networks). Hence, efficient price signals must include a spatial and time dimension. However, most time-of-use (ToU) and demand tariffs apply over an entire network, penalising customers in network locations where there is no congestion challenge and providing these customers with no commensurate network benefits (Markham, 2019).

Further, most electricity customers remain on time-invariant, volumetric, network tariffs for both imports and exports: a flat 'average-cost' tariff. While some dynamic (i.e., time-varying) network tariffs exist, chiefly time-of-Use (ToU) tariffs, these relate solely to imports. Moreover, their uptake remains very low due to:

- a low penetration of enabling technologies, chiefly 'smart' meters to enable demand and ToU tariffs, respectively. Outside Victoria, smart meter penetration is around 20 per cent. While penetration rates have risen over time, the growth rate is modest as smart meters are mandatory only for new meter installations or replacing existing accumulation (type-6) meters, and
- the opt-in nature of dynamic tariffs for small electricity consumers, even in Victoria, where residential smart meter penetration rates are close to 100 per cent.

In terms of exports, network tariffs indirectly incentivise self-consumption via-a-vis exports through varying import (i.e., ToU) prices; direct incentives, via feed-in tariffs (FiTs), are provided by retailers, not networks. FiTs are also predominantly time-invariant. And there are no demand charges applied for exports; instead, installed PV capacity is rationed by imposing limits on inverters, a blunt way of dealing with export constraints.[4]

In this article, we use "retail tariff" and "network tariff" somewhat interchangeably, though the two terms are distinct (i.e., the former is offered by the retailer; the latter by the network provider). We do this because, in the NEM's experience, most retail tariffs closely resemble the structure of the corresponding network tariff. This is because retailers are unable or unwilling to hedge any basis (i.e., volume) risk arising from differences between retail and network tariff structures.[5] In contrast, there is a multitude of hedging options in relation to wholesale spot prices (such as vertical integration and financial derivatives), despite spot prices being even more dynamic than network prices.[6] Therefore, if network tariffs were to become more dynamic and cost-reflective, it is possible retailer tariffs could become similarly so at the margin.

A corollary of this is that, were network tariffs to become more dynamic and cost-reflective, it is likely retailer tariffs would become similarly so.

Finally, the focus below is on retail customers, which include residential customers and other 'small' customers (such as small businesses), as larger customers already face dynamic network prices.

Equity considerations

Equity is also an important consideration in network tariff design. An equitable tariff could mean one or both of the following:

- Customers pay a "fair share" of the sunk network costs (i.e., costs unrelated to network utilisation). It is not always clear how these costs should be recovered equitably. For example, these costs could be recovered by charging all customers a uniform fixed charge, consistent with the 'sunk' nature of the costs. However, this can be regressive (i.e., low-income, low-consumption customers are disadvantaged). To offset this, the size of fixed charges can be based on customer demand or socioeconomic status (Burger et al., 2020).
- A tariff that accounts for the extent of financial vulnerability (or ability to pay) of customers; for example, a tariff that is consistent with first-, second- or third-degree price discrimination. Inclining-block tariffs were often considered an example of this (Borenstein, 2012). However, these types of tariffs can be regressive when income/wealth and consumption become negatively correlated due to the increased uptake of rooftop PV predominantly by high-income/high-wealth households (Rai and Nelson, 2019).

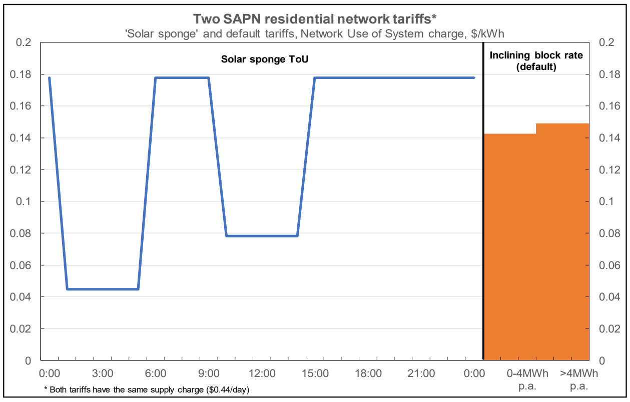
The conventional economist's view is that equity considerations should be best addressed by governments via tax-and-transfer (aka 'redistribution') schemes, rather than by electricity tariff design. However, failures in redistribution schemes, both within the electricity sector (e.g., energy concession schemes) and outside, have undermined this conventional view (Rai and Nelson, 2019).

Furthermore, efficiency and equity can both be enhanced, at least for some tariff designs. Amongst others, Schittekatte et al. (2018), Simshauser (2016), and Simshauser & Downer (2016) find flat-rate volumetric tariffs to be inefficient and inequitable vis-à-vis both ToU tariffs, and ToU tariffs coupled with capacity charges. Schittekatte et al. (2018) argues ToU tariffs on withdrawals and injections are more efficient and equitable than withdrawal-only ToU (even when coupled with demand charges) tariffs under increasing DER uptake. The ability of certain tariff structures to remain efficient and equitable under rising DER penetration (in particular, PV-cum-battery storage systems) is an active area of research, illustrated by the findings of Schittekatte et al. (2018) vis-à-vis Simshauser (2016).

With this in mind, we now discuss the emergence of more dynamic network tariffs in two of the distribution network areas with the highest VRE penetration rates: S.A., and South East Queensland. Our key finding is that network tariffs need to continually evolve towards a more dynamic state – while proposed tariffs are innovative in nature vis-à-vis past tariffs, they are inherently backward-looking and so likely to result in growing inefficiencies and inequities.

South Australia

Electricity distributor SA Power Networks (SAPN) is currently trialling a "solar sponge" residential tariff



Source: SA Power Networks (2019)

directly with customers (i.e., not via retailers), to inform its 2020-2025 tariff structure statement. This ToU tariff differs from the default tariff (an inclining-block) as shown in the figure.[7]

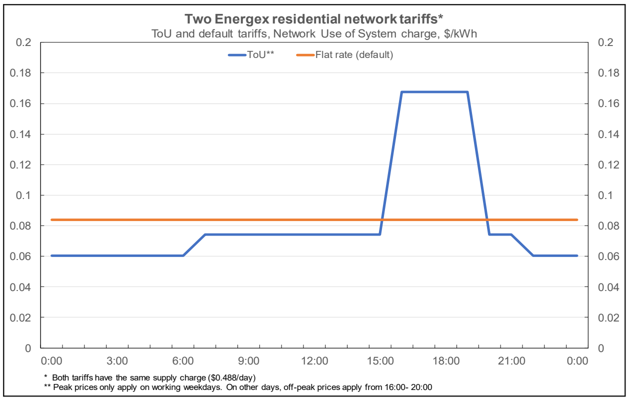
The "solar sponge" component of the ToU tariff is designed to incentivise households to consume electricity at times of high PV generation. Participation in the trial is limited by SAPN to 7,000 customers (SA Power Networks, 2019). This type of ToU tariff is similar to the 'Sunshine tariff' offered by Western Power Distribution to residential customers in the South West of England during 2016, and similar residential tariffs in parts of North America (Faruqui, 2018).

South-east Queensland

Energex, the distribution network provider for South East Queensland, has a two-part tariff as the default, and two optional residential tariffs: (i) a ToU, and (ii) a demand charge coupled with a (two-period) ToU tariff. The ToU and default tariffs are shown in the below figure.[8]

Rooftop PV penetration in some parts of South East Queensland is around 50 per cent, well above the 40 per cent threshold where reverse power flows occur with associated power quality issues (Johnston, 2019). Despite this, Energex does not yet offer a 'solar sponge'-type tariff. Given issues associated with managing the distribution sub-network with such high PV penetration rates, it is likely that some form of control on PV will be needed, via price signals (an incentives-based 'carrot-and-stick' approach) and/or direct network operator control of the devices.

Concluding remarks



Source: Energex (2019)

While it can be beneficial to wait for DER uptake to reach levels that necessitate new tariffs or changes to existing tariffs – as is the case with the "solar sponge" tariff – the danger is that uptake occurs faster and earlier than expected, resulting in significant cross-subsidies from ex-DER to cum-DER customers, and in higher network augmentation costs while the wrong price signals remain in place. This reactive approach to tariff design allowed the air-conditioner-induced acceleration in peak demand during the 2000s, and the more recent rooftop PV-induced voltage issues. Unless tariffs are designed somewhat pro-actively, inefficiencies and inequities are likely to also occur in relation to the operation and response of EVs and batteries to the wrong price signals.

Constantly revising or redesigning tariff structures to reflect the impact of greater penetration or utilisation of specific DERs is time- and labour-intensive, and also creates other issues such as:

- claims that networks are trying to "tax the sun" (in the case of solar sponge-type tariffs) or obstructing the movement towards greater decentralisation and democratisation of energy supply, whenever new technology-specific tariffs are proposed. However, the alternative to price signals, such as direct control of devices by networks or specifying PV inverter limits, directly disempower consumers in comparison to providing efficient price signals
- increased complexity under a technology-specific approach to tariff design. Even before finalising the design of its 'solar sponge', there were questions about SAPN expanding its controlled load tariffs to include EVs and batteries. Is this technology-specific approach to tariff design likely to be an efficient response to the emergence and proliferation of new technologies (noting the set of DERs is limited only by our imagination)?, and
- a reactive and technology-specific approach to tariff design is easier said than done: customers, having tuned their usage patterns and investment and operational decisions (the latter especially relevant for batteries) to a particular set of prices and time periods, may be highly averse to changes that undermine these decisions.

So, what is the best way forward? In short, a move to network tariffs that are technology-agnostic and based on dynamic charges for withdrawals and injections that are sufficiently future-proofed. This tariff should be the default (i.e., an opt-out) and have the following form:

- a hosting capacity charge (i.e., $/kVa), based on the nominal limit of net export/import ideally at the connection point, perhaps differentiated by peak and off-peak time periods
- locational ToU charges for withdrawals and injections, to incentivise PV exports at times of high peak demand (and PV self-consumption at other times), which would be especially useful in those sub-network areas where PV hosting capacity is nearing its limits, and
- fixed charges to recover residual sunk costs, taking account of equity considerations (e.g., fixed charges that vary by postcode) as suggested by Burger et al. (2020).

Some degree of network control is likely to be needed even if efficient price signals were in place, reflecting the potential for co-ordination failures and other possible market failures. Such a blend of centralised and decentralised operational decision making is standard practice at the transmission (i.e. wholesale) level, and reflects the inadequacies of relying solely on price signals as a mechanism to co-ordinate and control decision making.

And what about retail tariffs? Retailers can structure their tariffs in line with dynamic network tariffs, as they have predominantly done to date, or provide other structures more suited to customers' preferences. Declining costs of smart meters and other digitally enabled demand response-enabling devices make the latter more viable today, and increasingly going forward, than historically.

While a dynamic, technology-agnostic, tariff would be time-consuming to design and would create winners and losers, the same applies for the existing approach. As tariff (re)design is an intensive process in any event, it seems better to invest the time designing future-proof tariffs. It is also more empowering to let consumers make their own decisions, guided by efficient price signals, combined with an ability for networks to control DER if and when price signals are, on their own, insufficient.

Footnotes

[1] The RET consists of the Large-scale RET (LRET) and the Small-scale Renewable Energy Scheme (SRES). The LRET obligates retailers to buy certificates equal to the annual targets for electricity generated from renewables. It has annual TWh targets, with a target of 33 TWh in 2020, which remains the same through to 2030 when the scheme ends. Like the LRET, the SRES provides a subsidy through to 2030. Unlike the LRET, there is no annual target under the SRES (i.e., it is an uncapped scheme). For more, see http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target

[2] http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations

[3] The NEM is an interconnected electricity market which operates in the five eastern and southern states of Australia, as well as the Australian Capital Territory.

[4] Inverter limits vary by distribution network area and by whether the connection is single- or three-phase. Typically, 5kW is imposed for single-phase connections. . For more details, see https://www.energymatters.com.au/residential-solar/rooftop-solar-power-panels-install-state/

[5] For example, a retailer could offer a volumetric-only tariff as a simpler alternative to a two-part tariff which the retailer faces from the network provider.

[6] This seems to be one of the side-effects of retailer-distributor structural separation. However, technological change – in particular, the declining costs of smart meters and other types of demand response-enabling devices – might improve the ability to hedge basis risk and in turn lead to differing retail and network tariff structures.

[76] SAPN also offers an opt-in demand tariff, with an optional hot water controlled-load component, which can turn on between 10am and 3pm CST when high solar PV output typically occurs.

[8] Energex also offer 'secondary', controlled-load, tariffs with each of these three 'primary' tariffs (Energex, 2019).

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Business Cycles and Innovation Cycles in the U.S. Upstream Oil & Gas Industry

BY ROBERT L. KLEINBERG AND MARIE N. FAGAN

Introduction

When oil and gas prices are declining and low, "innovation" is frequently invoked as the key to continued petroleum industry viability and profitability. But what kind of innovation can be expected on the short time scales – on the order of a year – invoked by industry executives, analysts, and the press?

Efficiency, process, and technical improvements, which do not require significant research and development investments, continue independent of business cycles. These classes of improvements can indeed increase production and reduce costs over relatively short time scales. On the other hand, major technological innovations that require sustained investments of human and financial resources can take a decade or more to mature. In this research, we develop insights that can help the upstream oil and gas industry—exploration and production (E&P) companies as well as service companies—better understand oil price and innovation cycles. Our approach combines a top-down econometric analysis of innovation efforts, and bottom-up case studies of innovation results. An extended treatment of this work is published elsewhere [Kleinberg & Fagan, 2019].

Econometric Analysis

How does innovation effort respond to changes in the business cycle? Do service companies and exploration and production companies behave in the same way? In this section, we use company-level data and an econometric model to shed light on these questions. R&D spending is an input into the innovation process, not an output, so it serves as an appropriate metric for innovation effort, though it is not a measure of innovation itself. Details and quantitative results of our econometric analysis are presented elsewhere [Kleinberg & Fagan, 2019]. We summarize our methods and findings here.

We examined R&D spending across two long oil price cycles. Exploration and production (E&P) companies are represented by the set of companies which have reported to the Energy Information Administration's Financial Reporting System (FRS). This data set encompasses U.S.-based energy companies and the U.S.-based subsidiaries of public foreign oil and gas companies that had at least 1% of U.S. oil or gas production or reserves in a given year. For this reason, the data set is focused on R&D spending in the United States. The companies which comprise the FRS data set have changed over time as energy companies have been involved in mergers, acquisitions, and spinoffs. The oilfield service companies are represented by Schlumberger, which is a very large presence in the service industry, with R&D spending (on a global basis) often equal to or greater than the combined R&D expenditures of its major competitors, far larger than all but the largest global oil companies, and at a level which has sometimes even exceeded R&D spending of the FRS companies as a group.

Robert Kleinberg is with the Center on Global Energy Policy, Columbia University and the Institute for Sustainable Energy, Boston University. He may be reached at robert@robertkleinberg.com **Marie Fagan** is with London Economics International LLC.

A shown in Figure 1, the surge in oil prices in the late 1970s seems to have supported interest in innovation by both U.S.-based E&P companies and oilfield service companies (represented by Schlumberger). For the E&P companies, R&D spending on oil and gas recovery surged immediately with rising oil prices in the late 1970s; then declined along with weakening oil prices. The same pattern emerged in a second upswing, during the oil price surge of 2000-2007. And, as in the 1980s, when oil prices later collapsed, the E&P companies cut back R&D precipitously.

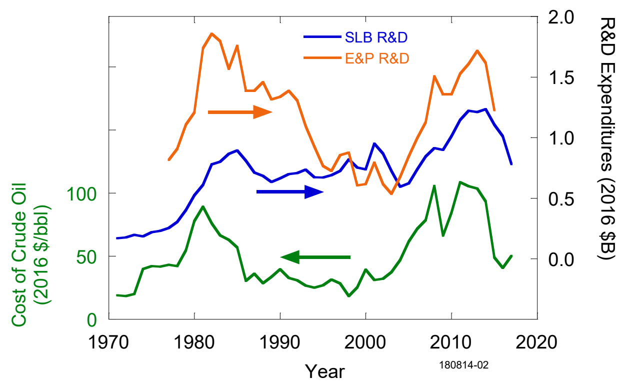

Figure 1. R&D expenditures and oil prices. Green line: Refiner acquisition cost of crude oil [EIA, 2018]; Blue line: Schlumberger R&D spending, [Schlumberger, 2018]; Orange line: E&P R&D spending [IHS Markit, 2017]. All data are in real (2016) dollars [Census Bureau, 2017]. The complete list of FRS companies is available at [EIA, 2010].

Schlumberger's R&D spending showed a different pattern. It increased much more gradually, and with a lag during the first oil price boom. Compared to the E&P companies, its subsequent decline was much smaller. It sustained its R&D spending during the low-price years of the 1990s. When prices boomed in 2000-2007, it raised spending, but again, much less dramatically, and again with a lag compared to oil prices and to E&P companies' R&D spending. However, since 2014, Schlumberger R&D spending has followed falling oil prices more closely.

Because it is clear from Figure 1, above, that the E&P companies' R&D spending has a different relationship to oil prices than Schlumberger's, we estimate separate models for Schlumberger and for the E&P companies. Quantitative results show that Schlumberger was less sensitive than the E&P companies to both ups and downs of the oil price cycle, and its response was symmetrical, i.e., about the same for an upturn or a downturn in prices. In contrast, the E&P companies' R&D spending was more cyclical. R&D spending responded more strongly to both increases in oil prices and oil price declines. This response was somewhat asymmetrical, as there was a larger impact on R&D spending from a decline in oil prices. Long-term elasticity estimates were larger than short-term estimates, as expected. For Schlumberger, these were about 3-4 times larger than the short-term estimates and were nearly symmetrical. For the E&P companies, the long-term elasticities were also substantially larger than the short-term elasticities, and they were asymmetrical with a larger response to an oil price downturn.

Case Studies

The econometric analysis helped to quantify the impact of the oil price cycle on innovation effort. What about innovation results? We turn now to case studies of specific technologies to illustrate the relationship of each stage of innovation to the oil price cycle, to help discover whether high and rising oil prices give birth to major innovations, or whether low or falling oil prices speed up innovations.

We partition innovation into four classes.

- Process and efficiency improvements. These are routine and continue through the life of an oil or gas field independently of business cycles.
- Technical improvements. These are innovative but do not require significant R&D investment. These too typically continue irrespective of business cycles.
- Major technological inventions. These require substantial R&D resources in order to be brought to market.
- Industry-changing innovations that profoundly affect oil or gas supply. An example from the twentieth century is secondary oil recovery by water flood or reservoir pressure maintenance. A more recent example is the combination of horizontal well construction and staged, massive hydraulic fracturing.

Process and efficiency improvements. The business cycle is not the only driver of oil and gas industry development. Each newly discovered resource poses challenges that must be overcome in the course of its development. Early in the development cycle of these emergent resources, costs increase rapidly. Later, costs decline due to process and efficiency improvements. In some circles this has been called innovative, and there is no doubt a great deal of practical ingenuity involved, but such developments are widespread, generally predictable, and do not rely on research and development investments.

Technical improvements. We define technical innovation as activities that require new, adopted, or adapted engineering solutions, but not necessarily requiring substantial research and development efforts. Pad drilling and super fracks are examples of technical innovations that reflect good engineering practice and optimization. They do not require substantial R&D expenditures and, like process and efficiency improvements, they are unaffected by business cycles.

Major technological inventions. Elsewhere [Kleinberg & Fagan, 2019] we present five case studies illustrating the course of technology development in the oil and gas industry. All required significant research and development investments. The case studies reveal a general pattern of development, superimposed upon which are variations specific to individual technologies. We observe that in many cases technologists lay the scientific ground work and perform proof-of-principle demonstrations independently of the business cycle. When energy prices are rising and high, R&D is accelerated by financial and human resources that pour into oilfield research and development. Nonetheless, major technological developments in the petroleum industry tend to mature slowly. The development of sophisticated geophysical technology is difficult; many problems of measurement physics, electrical engineering, and mechanical engineering must be overcome. Another barrier is inherent in the structure of the industry. Rig time is a major expense of drillers and the risk of losing a well to borehole collapse is an ever-present danger. Thus, there is significant resistance to innovators who wish to test prototype equipment in wells. These factors combine to lengthen the upstream oil and gas technology development cycle; ten years or more from concept to commercialization is the norm. It is frequently the case that by the time innovations are widely deployed, resource prices and business activity have declined, and return on investment is delayed.

The role of government and academic institutions

Research in government laboratories, government support for external research, and academic research have played important roles in oil and gas industry technology development. The public is sensitive to changes in energy prices, and officials respond by creating programs that address societal concerns. Similarly, university programs react to faculty and student interest in the problems of the day.

The closer a product or technique is to commercialization the more its success depends on closely following the evolving demands of the market. The research and development divisions of industry participants maintain a level of contact with their operating groups and clients that cannot be replicated in an academic environment. Thus, outside of narrowly targeted investigations with near-term deliverables, academic and government programs are best directed to long-range objectives beyond the scope of in-house industrial R&D [National Research Council, 2014].

Discussion

We have shown that upstream oil and gas innovation efforts grow during periods of rising and high product prices, and shrink during periods of falling and low prices. We have also shown that product development cycles that depend on significant research and development investments are typically a decade or more in length. Economic cycles can have similar lengths, but because human and financial investments in R&D inevitably lag price signals, substantial support for a project may not commence until the midpoint or even the end of a economic upturn. Bringing a project to a successful conclusion often requires continuation of support during industry downturns.

By the time a product has been tested and enters the market, commodity prices may have collapsed, client interest in the innovation may have waned, and the rate of market growth is stunted. As a result, net present value forecasts based on market conditions at the commencement of a project may considerably overestimate the actual value of the innovation to the investor. In rare instances, as in the example of horizontal drilling combined with staged hydraulic fracturing ("fracking"), the widespread adoption of the technology itself is responsible for falling commodity prices [Braziel, 2016]. Exploration and production companies at large benefit from better upstream technology, but the innovators themselves can fail to capture the full value of the innovation.

The response of the U.S. petroleum industry to the mismatch between price cycles and technology cycles has been to de-risk technology development by outsourcing it. In the 1980s and 1990s the major oil companies, which had historically been drivers of oilfield innovation, downsized or closed their research and development operations. They looked to the oilfield service sector to take up the slack. In a second wave of outsourcing, service companies purchased technology by consolidation and by devouring start-ups, rather than developing it by organic growth [Schlumberger, 2014].

Ironically, the strategy of de-risking R&D risks undermining future technological prowess. Oilfield technology is not like information technology, where expertise can be developed quickly by youthful entrepreneurs. It is more akin to defense contracting or heavy machinery design, which benefit from innovators with long experience in their fields, who have access to a deep infrastructure of skilled technicians and specialized prototyping and test equipment.

While not unique to the upstream oil and gas sector, the mismatch between business cycles and development cycles is unusually severe there. Petroleum markets are unusually volatile; this is the reason gasoline prices are excluded from the U.S. core consumer price index. Moreover, the combination of front-loaded capital expenditure and substantial geological risk discourages the use of untried innovations. By contrast, in the consumer electronics and software industries, development cycles are shorter and the customer population is biased toward novelty, which speeds testing and acceptance. In the pharmaceutical industry, development cycles are even longer than in the upstream oil and gas sector, but market conditions are fundamentally more predictable.

Conclusions

Our results show that research and development efforts often follow the boom-bust pattern of oil price cycles while research and development results have often reflected sustained technical effort through market cycles. We conclude that industrial organizations willing to continue support for research and development through market declines – even if at reduced levels – are best prepared to benefit from ensuing market upturns. They are also best able to benefit from technological innovations coming from competitors or from outside the industry. A competitor's first-mover advantage can be minimized or quickly overcome by a technically adept fast follower.

Government, government-sponsored, and academic research has an important but limited role in technology development. Government and academic programs work best when they are dealing with long-range problems industry is not yet tackling, and may seemingly be of little interest to it. Even more importantly, because we are unable to accurately forecast future commercial and technology needs, the training of the next generation of scientists and engineers should be a national priority.

The future of upstream oil and gas innovation is unclear. On one hand, the attention of governments, the public, and the capital markets, is on renewable energy sources and technologies that reduce the demand for fossil fuels, such as more efficient and battery powered vehicles. On the other hand, reference case [EIA 2018d] or stated policies [IEA, 2019] forecasts predict that oil consumption is likely to remain steady through 2040. The natural decline of hydrocarbon reservoirs averages 6% per year for conventional oil fields [IEA, 2013], and fields producing tight oil, which now accounts for about 5% of the global crude oil market, decline even faster [Kleinberg et al., 2018a]. With world oil production at 100 million barrels per day, this implies that at least 6 million barrels per day of new production will need to be developed every year. It remains to be seen whether major innovations in the upstream oil and gas industry will be required to meet this demand.

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Electricity Bidding Processes: a Contribution of Mining to Public Policies in Chile

BY ANDRÉS ALONSO

Andrés Alonso is a member of the Board of the Coordinador Eléctrico Nacional de Chile and Associated Researcher at the Advanced Center of Electrical and Electronic Engineering, AC3E, of the Universidad Técnica Federico Santa María. This work has been supported by the Project CONICYT-Basal FB0008.The opinions of this article are those of its author and do not necessarily represent the opinions of the Coordinador, Eléctrico Nacional de Chile, its President or individual Members of the Board and are not binding on the Coordinador.

See footnote at end of text

In Chile in November of 2017, the bidding process for electricity supply of distribution companies was awarded in accordance with a framework established by Law No. 20,805 and approved by the National Congress in 2015. The result of this bidding process was once again very successful, as was the first bidding process held with this framework in August 2016, providing lower energy prices than the previous year and historically low.

Undoubtedly, the main reason for the achievements in the aforementioned bidding processes was the increase in competition that occurred in the electricity generation sector as a result of a series of factors. The greatest contribution to the observed competition was the market design developed for the bidding processes and its reduction of the entry barriers for potential bidders. This design was strongly influenced by the process the Chilean mining industry had used for its electricity supply bidding processes

Indeed, in 2005, Minera Escondida, which develops the largest copper mine in the world and whose electricity consumption represents 8% of the total consumption of Chile, confronted a severe risk to its electricity supply, both from the point of view of security of supply, as well as the cost thereof. In the 2000s, the company had contracted for electricity supply at very low prices with the power generation company Gas Atacama, which was used Argentine natural gas to produce its electricity. However, in 2004, the supply of Argentinian gas to Chile gradually began to decline because Argentina favored its domestic gas users, which experienced an exponential growth as a result of its policy of freezing prices to local consumers. This caused Gas Atacama to operate with gas oil when there were interruptions, fuel with a much higher operating cost and higher probability of failure for the power plants.

Given this situation, the management of Minera Escondida decided to carry out a strategy that consisted mainly on calling an international bidding process for electricity supply with a market design that included a tender process of at least one year, with a start of supply in a term of 5 years, through a long-term contract greater than 15 years and bankable characteristics. These characteristics allowed the process to be financed as a “Project Finance”, which means that the economic flows of the project could guarantee the payment of the debt. In addition, during the bidding process, Minera Escondida would manage the sectoral and environmental permits of a power plant, the Central Kelar, which was made available to potential bidders in the bidding process as an alternative to competitive backing and, in the last case, to build it directly if they did not find adequate price and security conditions for their electricity supply.

All of the above was designed with the aim of increasing competition by reducing the entry barriers in the bidding process, in order to obtain the best technical and economic conditions for electricity supply of the company.

The result of this process was announced in 2007 and the supply of Minera Escondida was awarded under very convenient conditions to the Angamos Plant, a project of the generation company AES Gener, which was already operating in the Chilean electricity sector. The Angamos Power Plant started its operation in 2011.

This strategy based on the principles of: international bidding through a process of at least one year, a start of supply in the fifth year, a bankable long-term contract and an alternative supply of competitive backing was also followed by the mining company Codelco for the supply of its operations in the center-north area of Chile in 2007, which represented 50% of its consumption. Codelco is the largest copper producer in the world and its electricity consumption represents 12% of the total consumption of Chile. In that instance, the competitive backup alternative was the Energía Minera power plant. This process concluded with the awarding of the supply to the Santa María Power Plant in 2010, a project of the electric generation company Colbún, which was already operating in the Chilean electricity sector. The Santa María Power Plant started its operation in 2012.

It is necessary to emphasize that due to the awards to companies that were already operating in the electricity sector, there were voices that criticized taking so much effort in the competitiveness of the process to finally end up signing a supply contract with existing companies. Over time, and in the face of the results achieved, it was evident that the criticisms reflected a lack of vision regarding the objectives of a supply bidding process, because they did not consider the conditions that these large mining companies would have had to accept if they had not had real alternatives of supply creating the necessary competition.

At the beginning of 2014, mining companies brought these experiences to the attention of the incoming government, given that in the supply bids for the distribution companies of 2013, the values obtained were much higher than the results previously obtained by the mining companies.

The government predicted how powerful a public electricity supply policy based on the aforementioned principles could be for electricity distribution companies. To implement such principles, it was required to make a legal modification and also to find which would be the alternative competitive backing.

The decision was to proceed with the legal modification and led to the enactment of Law No. 20,805, which was treated in the National Congress in the record time of 8 months, with majority support from all political sectors. The backup alternative was raised by the state-owned Empresa Nacional del Petróleo, ENAP, through its own project, the Nueva Era plant, and another alternative that was negotiated with Codelco, the Luz Minera power plant. Given the lack of experience of ENAP in the generation of electricity a strategic partner was sought in a tender process, and ultimately the Japanese company, Mitsui was chosen

To carry out the strategy of a legal modification and to make in parallel an international call, with road shows included, and a design of competitive bidding rules in a limited period of time was a titanic task, carried out with great success by its executors.

The results obtained were impressive. The average price reached in the 2017 tender was 32.5 dollars per MWh, 32% lower than the 47.5 dollars per MWh in 2016 and 75% lower than the value obtained in the 2013 tender, which was awarded at 128.9 dollars per MWh.

More than 100 bidders participated in the processes described. The entire supply was awarded, the bids received were seven times the energy tendered, over 50% of the energy came from new entrants to the electricity generation market, and about 40% was awarded to –wind and solar– renewable energy plants. This has led to multiple recognitions of the Chilean model, and to the publication of the experience as an example of a good public policy[1].

It is not possible to believe that the success of the 2016 and 2017 bidding processes is only the result of the application of the electricity supply strategy of the large Chilean mining industry. Undoubtedly, there are many other factors. Especially, it is important to consider the significant cost reductions of wind and solar renewable energy as a result of technological development, as well as other factors, such as greater risk accepted by the owners of wind and solar technologies, reduction of costs and transmission risks for electric generators, support for investors to obtain sectoral and environmental permits, etc. In addition to the above, the establishment of participatory processes between the sectoral authorities and the different stakeholders of the national energy market, was undoubtedly another key factor.

The achievements are remarkable. In these last two supply bidding processes for electricity distribution companies, regulated consumers in Chile will save more than 20,000 million dollars compared to the level of prices in 2013 and, as a result of such processes, this country will have in the future one of the lowest energy prices in the world. This is fundamentally the product of an effective execution of a well-designed market strategy, which was largely proposed by the Chilean mining sector, as a result of its experience in its own electric supply processes.

Footnote

[1]Nueva ley chilena de licitaciones de suministro eléctrico para clientes regulados: un caso de éxito?. Comisión Nacional de Energía y Banco Interamericano de Desarrollo. June 2017. La Revolución Energética en Chile?. Máximo Pacheco (Editor). Universidad Diego portales. 2018.

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Rooftop PV and Electricity Distributors: Who Wins and Who Loses?

BY BRUCE MOUNTAIN, STEVEN PERCY AND KELLY BURNS,

Bruce Mountain, Steven Percy and **Kelly Burns** are all with Victoria University. Bruce Mountain can be reached at, bruce.mountain@vu.edu.au

Introduction and background

The electricity system in Australia is decentralising as consumers increasingly partially self-supply through the installation of rooftop photovoltaics (PV). In Victoria, Australia's second most populous state, a PV system can be found on the roof of every sixth home. Policy promoting rooftop PV has been politically popular and the Victorian Government seeks to more than double the uptake of residential rooftop PV over the coming decade. Rooftop PV is also rapidly expanding amongst larger commercial and industrial customers. Facilitating the connection of distributed generation and providing for two-way power flows have become core activities for Victoria's distributors.

In tandem with the rise of rooftop PV, the extent of cross-subsidies from consumers without rooftop PV to those with rooftop PV has attracted attention. Australian studies (Wood and Blowers, 2015; Simshauser, 2016) suggest consumers with rooftop PV are being subsidised by other customers. These studies reflect their authors' views of what consumers with rooftop PV should be paying for the use of distribution networks compared to what they estimate they are actually paying.

However studies that measure, empirically, the impact of rooftop PV on distributors' charges based on actual bill data, have not yet been published. In addition, while studies and reports (Byrne et al., 2018; Ausnet Services, 2019) recognise that rooftop PV impacts wholesale market prices, this effect also remains hitherto unquantified. The incremental expenditure by consumers and/or distributors needed to resolve localised voltage issues possibly attributed to rooftop PV has become the focus of attention in regulatory applications. But here too, the issues are not yet well understood. It is unsurprising, therefore, that the price impacts of rooftop PV for consumers, producers and distributors remain contested.

In this article we report on econometric studies that seek to fill some of these knowledge gaps, through analysis of the electricity bills of 48 677 households in Victoria, of which 7,212 have installed rooftop PV. Our rich dataset allows us to account for heterogeneity amongst consumers with and without rooftop PV (for example in respect of their actual retail electricity rates, their tariff structures, the size of their PV system and in relation to the volume of their grid purchases, their distributors and their specific network tariffs). We derive statistically robust estimates of the effect of rooftop PV on distributors' revenues and prices, and also on the impact of rooftop PV on wholesale market prices. These findings have important implications for policy affecting distributed generation and the economic regulation of distributors.

Data and Analysis

Our data is obtained from 48 677 residential electricity bills (in their original PDF format) that were provided to us. These bills were originally voluntarily uploaded to the Victorian government's electricity price comparison website over the period from July 2018 to December 2018. Relevant data (such as usage, tariff type and rate, rooftop PV export, feed-in prices, discounts, government concessions, distributor and retailer) are extracted from the PDF files using commercially available software specifically designed to automatically extract information from pdf files (described further in Mountain and Rizio (2019)).

Our research method to estimate the network impacts of rooftop PV is as follows:

- First we estimate the rooftop PV capacity and hence the gross annual PV generation for each of the 7,212 households in our dataset with rooftop PV, using the model in Mountain and Gassem (2020).
- Second, since the annual rooftop PV production exported to the grid is estimated for each customer based on the data in their bills, it is possible to derive the rooftop PV production that is consumed on the premises of those dwellings with rooftop PV.
- Third, we estimate the impact of rooftop solar on the revenues recovered by network service providers through an ordinary least squares regression with annual distributor revenue as the dependent variable and the volume of grid purchases (plus rooftop PV-sourced electricity used on the premises for households with rooftop PV), dummy variables for whether the household had a concession, controlled load or rooftop solar, their distributor and tariff type as independent variables. Model diagnostic tests validate the robustness of the findings

To determine the impact of residential rooftop PV on wholesale electricity markets, in the tradition of "merit order effect" studies (e.g., Würzburg, Labandeira and Linares, 2013; Cludius et al., 2014; Bushnell and Novan, 2018) and specifically following Mountain et al. (2018) we regress the half hourly Settlement Price in the Victorian region of the National Electricity Market against wind generation, solar (large scale and rooftop PV) generation, demand plus inter-regional exports, gas prices, coal generation capacity, and a dummy to account for monthly fixed effects. The wholesale price data used in the model covered half-hourly intervals from 1st April 2016 to 30th October 2018. The coefficient on solar generation establishes the impact of rooftop PV generation on wholesale prices. Model diagnostic tests validate the robustness of the findings.

Results

In our sample, households with rooftop PV on average each export 2.2 MWh per year and our models estimate self-consumption of 1.6 MWh per year per household. In total, for the one in six households that have rooftop PV, this means 0.7 TWh per year of production from large-scale generation that has been substituted by rooftop PV generation and used on-site. The exported rooftop PV generation (worth 0.9 TWh per year) is sold to other customers on the distribution network.

Substituting large scale production for distributed production reduces demand as measured on the transmission system by the distributed production. But the demand reduction from distributed supply measured on the distribution network is only the amount of distributed production used on-site. This is because distributed production that is exported to the grid is sold to other uses on the distribution grid. The decline in annual electrical demand in Victoria, as measured on the transmission system over the decade to 2020, was 7.9 TWh or 29.5% per capita after accounting for population growth. However, when measured on the distribution network, annual demand declined by only 6.3 TWh (25% per capita). When measured at the level of the distribution network, large scale electricity production displaced by residential rooftop PV accounted for 10% of the annual demand reduction between 2010 and 2019. Non-residential rooftop solar accounted for 5% of the annual demand reduction over this period.

Our models estimate that on average households with PV paid $590 less per year for electricity (about 30% of what their bills would be if they did not have rooftop PV). This is likely to explain in part the finding in Best and Burke (2019) that access to rooftop PV is associated with much lower household electricity bill payment stress. However, estimating private benefits from rooftop PV is complicated by the large reductions in PV capital costs, the large increase in electricity prices and big changes in the levels of policy support. Over the decade, policy makers responded to decreasing PV capital costs and increasing grid-supplied electricity prices by sharply reducing subsidies (Mountain & Szuster, 2015) although means-tested capital subsidies have increased again pursuant to the Victorian government's "Solar Homes" policy.

The small impact of residential rooftop PV on the volume of grid-supplied electricity is reflected also in the small impact of foregone network-delivered electricity on network usage prices (network providers in Victoria are subjected to revenue cap regulation and so are not exposed to lower sales volumes within a regulatory control period). Specifically, our model estimates that residential rooftop PV resulted in network access charges $1.3/MWh (about 1 %) higher than they otherwise would be. Households with PV are typically on two-rate time of use tariffs and households without PV are typically on single rate non-time variant tariffs. This effect would be even smaller if households with or without PV had the same tariff structures.

With respect to wholesale market impacts, our model estimates that residential rooftop PV reduced wholesale market prices by $6.4/MWh (about 8%) in 2019.

The net effect of wholesale price reductions and network price increases associated with residential rooftop PV was $217m in 2019. The extent to which this benefit is captured by suppliers (in higher profits) or passed on to consumers (in lower prices) is not knowable with certainty. Assuming it was all passed on to consumers and calculated per MWh supplied, it is worth $5/MWh. If calculated per connection to the grid, it is worth $84 per year. Since the majority of electricity consumed is charged per MWh, we expect that recovery per MWh is likely to provide a more reasonable way to state the shared price benefits of rooftop PV.

Conclusions

Our analysis provides insight into the implications for consumers, distributors and electricity producers of the decentralisation of electricity supply. The main conclusion is that rooftop PV pushes down prices in wholesale markets far more than it raises prices for the provision of network services. This was somewhat unexpected and might be explained by Victoria's extraordinarily high wholesale market prices and also by the fact that despite the high penetration of rooftop solar, the amount of grid-supplied electricity that is displaced by rooftop supply is not large. As we noted earlier, the substitution of grid supply in favour of partial self-supply for the one in six households that have installed rooftop PV accounts for 20% of the decline in grid-supplied electricity (measured at the level of the transmission system). But only 9% of this is displaced grid supply. The remaining 11% is surplus rooftop PV production that is routed through the distribution system and distributors charge for the sale of this electricity just as they would if the electricity had entered distribution networks from the high voltage transmission system.

An additional factor explaining the small impact of distributed supply on distributors' revenues is that distributors have adjusted their pricing structures to increase the fixed proportion of their charges. Over the 8 years to 2019, the distributors' fixed charges increased by 490% while consumption charges only increased by 61% on average. By 2019, on average one third of the revenue that distributors recovered from residential customers was fixed. Such a high proportion of revenue recovery from fixed charges explains in part why rooftop PV production only gives rise to a $1.3/

MWh (about 1%) increase in network prices relative to what they otherwise would have been.

Doubling the uptake of residential rooftop PV (the current government's policy) is likely to lead to less than a 2% increase in network prices (since household consumption is declining and the proportion of distributors' revenues that are recovered through fixed charges is likely to increase.

On the question of the incremental expenditure (by consumers and/or distributors) that is needed to ensure that distributors are able to resolve localised voltage issues possibly associated with greater amounts of rooftop PV, our survey of the Australian evidence suggests much remains to be done to understand the nature of this issue. However in a recent regulatory filing, Victoria's largest distributor, Ausnet Services, is seeking approval for around $12m per year for the next five years to expand distributed supply capacity. It is claimed this will increase charges to residential consumers by AUD0.72 per residential customer per year. Other distributors in Victoria are proposing proportionally similar amounts. Rising distributed generation may present some technical challenges, but distributors' expenditure proposals suggest that meeting these challengers will not be expensive.

Policy implications

Rooftop PV is likely to provide private benefits that exceed private costs since consumers can choose not to install it. However the amount of this benefit is likely to range widely. Households with rooftop PV obtain benefits that households without PV do not obtain. Private benefits of rooftop PV in aggregate may exceed shared benefits in aggregate. However private benefits do not come at the expense of shared costs. The shared benefits for consumers (in the form of lower wholesale prices) far exceed shared costs (higher network prices) although large customers are likely to gain disproportionately more of the shared benefit through their relatively higher exposure to energy rather than distribution charges. Policy makers responding to the politically popular desire for rooftop PV might take comfort from the evidence that rooftop PV also reduces prices for all electricity consumers.

Finally, the results of our study draw attention to the question of the appropriate allocation of the costs and benefits of technology change. Even after one in six homes connected to rooftop PV over the last decade, only 10% of the reduction in demand on distribution networks is attributed to residential rooftop PV, and 5% to non-residential rooftop PV. The remaining 85% of the demand reduction is explained by some combination of lower consumption in response to higher electricity prices, and more efficient appliances. While these outcomes are likely to be somewhat context specific, it is clear in Australia at least that concerns about a "death spiral" in distribution networks associated with ever greater distributed supply are misplaced. If there is a case to reconsider whether distributors should continue to be protected from technology change, this rests not in the expansion of distributed supply but rather in the reduction in consumer demand for grid-supplied electricity.

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Shaw-Williams (continued from page YY)

spending if this was addressed by onsite generation and storage then it is a radically different model of network that will be required.

Distribution networks account for the greatest proportion of losses on the network. The opportunity to avoid them through the co-location of generation and demand is the low-hanging fruit of the transition and the benefits arising from households adopting PV already has resulted in tangible economic benefits for all consumers through reduced loss factors (Shaw-Williams et al., 2019b).

It is to be noted that these are all additional benefits that would justify the rapid evolution of existing business models let alone the threat of catastrophic climate change. These are tangible benefits that can be achieved with forward looking policy settings that will force the reduction of barriers to the network and incentivise innovation on it.

Conclusion

The role of DNSPs as gatekeepers to the network is the crucial fulcrum point of the transition. Households equipped with solar arrays and combined with battery units provide the means by which the network can be managed effectively, and midday surplus be shifted to meet residential evening peak. With the challenge of residential peak adequately addressed the issue of what to do with surplus capacity in the network becomes the crucial challenge. The sunk costs of the large-scale overinvestment in the network is a millstone around the neck of a rapid transition in Queensland. Without the write down of a significant portion of the network value on one hand, and a relaxation of restrictions of access to the network on the other, the transition will lag.

With residential generation and storage to address the evening peaks, stand alone systems enabling the removal of thousands of kilometres of poorly utilised lines and large scale solar meeting the business hour needs of industry, and with automated and localised optimisation of the network a path to a decarbonised energy sector becomes clearer.

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On the Fairness Debate Surrounding Electricity Tariff Design in the Renewable Energy Era

BY MOHAMMAD ANSARIN

Mohammad Ansarin is with the Rotterdam School of Management at Erasmus University. He can be reached at ansarin@rsm.nl

See footnotes at end of text.

Households have begun to seize the means of (energy) production. Germany (Karl Marx's birthplace) was the first region to widely adopt small-scale electricity generation from renewable sources (Wirth 2020). Other regions, such as the U.S. state of California, are quickly catching up. As these residential generation units grow in number, the electricity tariffs used for households no longer seem suitable for an entity that both consumes and produces: a prosumer.

Energy is generally considered to be a public good; historically, pricing it has been a matter of not just economics, but also politics (Yakubovich, Granovetter, and Mcguire 2005). The debate surrounding electricity tariff design hosts the usual suspects. These are utilities, generation companies, grid operators, public regulators, politicians, and some relevant consultants. Recently, these stakeholders have been joined by the manufacturers, financiers, and installers of small-scale renewable energy systems. The arguments and concerns in the tariff debates have also changed.

One particular concern for all sides is fairness. Let's be clear about what "fairness" is in this context, or better to phrase what it is not: the undue transfer of costs from one consumer to another (Bonbright 1961). All stakeholders tend to agree that this is bad, but disagreement remains on the word "undue" (Heald 1997). Utilities find it "undue" to charge some tariff subscribers more and others less for the same product. Regulators find it "undue" to transfer a cost burden from the privileged to the disadvantaged. Households and generation companies, however, may have made large investments based on returns from a specific tariff. They would find it "undue" to have the tariff changed before their financial returns are realized.[1] For now, let's focus on the first definition, i.e. when customers pay more or less than they should for electricity.

With this definition, unfairness can appear in different ways. One of these is from a utility's fixed and/or sunk costs, which mostly reflect grid capacity investments and operations/maintenance (Simshauser 2016). Utilities often recover some or all of these costs from a per-kWh fee. If a household owns solar panels, they take fewer kWhs from the utility, and thus pay less of the fixed and sunk costs. But the utility must recover these costs regardless of how much energy it sells. When it inevitably increases prices to cover the revenue shortfall, solar non-owners are the disadvantaged ones who pay more than they would have otherwise. Hence, non-owners end up covering the fixed and sunk costs for solar owners.

The revenue shortfall complaint surfaces often, especially from utilities based where solar energy is growing. The U.S. states of California, Nevada, and Arizona have witnessed many such complaints towards public utility commissions (Klass 2019). For these commissions, and regulators in general, there are more concerning implications too. Solar panel owners tend to be well-off (Borenstein 2017), so there's an implication of cost transfers from the wealthy (owners) to the median (solar non-owners) energy user. In other words, there are wealth transfers from the median to the wealthy. Thus, regulators become particularly concerned, as this constitutes their form of "undue". Solar energy interest groups have a common retort to this: solar generation creates benefits for multiple stakeholders, both within and without the immediate tariff debate. These benefits can offset the wealth transfers, perhaps even negate them. However, there is widespread disagreement about these benefits and their extent (Klass 2019). Moreover, costs are incurred for the utilities, while benefits are for households and businesses (and the environment, of course). Principle agent problems are not lost on the public regulators, who are then faced with the need to internalize these benefits for utilities.

One common solution is to price a household's electricity generation separately, based on a Feed-in tariff. Pricing consumption and generation together, the reasoning goes, masks the differing burden and benefit of a household's generation versus its consumption. For example, consumption pricing would include fixed costs, generation benefits shouldn't. Likewise, generation benefits would include clean energy incentives, but consumption shouldn't. If both are priced separately, one can price benefits and costs as one sees fit.

But does this reasoning hold in the real world? We used some household consumption and generation and pricing data from Austin, Texas, to look into this.[2] For a set of households owning solar photo-voltaic panels, we compared the real costs of electricity trade with their tariff bills. The difference measures how equal are subscribers' costs and benefits, assuming that the utility generates revenue equal to costs. For a set of representative tariffs, from flat rates to real-time dynamic pricing, the conclusion is the same: fairness does not depend so much on whether or not we separate generation.

This result is driven by two important factors. First, Texas has a well-functioning Renewable Portfolio Standards market for solar generation, whose compensations trickle down to households in a way that offsets some of the utility's sunk and fixed costs.

Second, solar generation in Austin, TX, often offsets some of the customer base's peak energy demand, lessening the capacity burden on utilities by about 10%. The former is rare (for now), but the latter is common in many regions, especially those with high demand from air conditioning devices. The end-result is that solar owners indeed pay less than non-owners, but their benefits to the utility compensate for much of this loss.

Regulators also have other tools to internalize solar costs and benefits. One could separate fixed costs as a bill item, as Arizona and Nevada utilities have done with mixed results (Klass 2019; Singh and Scheller-Wolf 2017). However, such fixed costs would be a disproportionately larger burden on low-income households than high-income households.[3] This concern of regulators leads them to disfavor fixed costs as a means to solve the revenue shortfall issue. In other words, regulators appreciate the previous cross-subsidy that existed when all costs were contained in a per-kWh charge. Yet some research, e.g., (Borenstein 2012), has shown that simpler means-tested programs can perform equally well, with fewer side effects. Separating these implicit cross-subsidies into a means-tested program seems like an easy but important step in the solution.

Another promising development, smart meters, can also simplify solutions. Smart meters (more precisely, advanced metering infrastructure) measures a user's electricity consumption (or generation) on a far more granular basis than legacy meters, with automated communications (and in some instances, control) infrastructure. In many regions, smart metering programs have shown significant cost savings for operations and maintenance activities. Smart meters can also provide price signals to households, increasing their responsiveness to electricity prices (Office of Electricity Delivery and Energy Reliability 2016). A consequence of this frequent measurement of electricity is the ability to price electricity with more granularity, leading to fewer unfairness concerns. Indeed, our research found that using smart meters, combined with suitable tariffs, could greatly reduce pricing unfairness. Compared to flat-rate tariff with legacy meters, even a simple time-of-use tariff with high daytime and low nighttime prices reduced the median cost transfer by an order of magnitude. Instead of debating whether or not generation units should be separately measured (and accounted), we should debate whether or not smart meters and smart tariffs should be used.

In the renewable energy era, many regulators still encourage households to install solar panels. Yet in so doing, these passive consumers transform into active and calculating prosumers. They may no longer view their electricity trade passively as an added household bill; rather, it becomes an investment with implicit positive social-environmental outcomes. For our dataset, the median household subscribed to a flat-rate per-kWh tariff unfairly paid (or gained) about 0.4% of median annual household income, or about $220: small on the median (albeit important for the poor). However, $220 is also equal to about 27% of the annual return on investment of an average solar PV installation in our dataset. The losers of this unfairness would complain about their lost returns on investment. The winners would complain about any change that would threaten their returns on investment. Hence, these prosumers would no longer view energy as a public good, but as something they can and should privately control. One could reason similarly with regards to electric vehicles, which make it possible to privately acquire the energy used for transportation, and smart meters, which give consumers the necessary information for optimizing their consumption. Energy is a public good; that is, it used to be.

Given these observations, two changes in the solar energy debate seem warranted. First, and foremost, there is a need for accurate and objective (and publicly disseminated) information about the costs and benefits of small-scale renewable energy installations. Some good examples are Value of Solar studies from the US states of Texas (Rábago et al. 2012) and Minnesota (Division of Energy Resources 2014). Second, electricity has become less of a public good and more of a marketable product. Much of the fairness consequences of traditional tariff designs reflect the designers' public goods approach. Electricity is in transition, however, to a private good and demands pricing that matches its nature. These two changes would ensure that all participants in the tariff debate can reach a shared understanding of what is and is not fair. It then becomes rather straightforward to turn the tariff debate into a tariff agreement.

Footnotes

[1] These mirror the terms used by (Burger et al. 2019). A survey among Dutch households of the meaning of "fairness" can be found in (Neuteleers, Mulder, and Hindriks 2017).

[2] We are grateful to the Pecan Street Dataport and the Electricity Reliability Council of Texas for granting us access to datasets, and to Austin Energy for their continued provision of public data.

[3] (Borenstein 2016) describes fixed costs recovery from various tariffs.

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Competitive Electric Utility Analysis

BY DOUGLAS B. REYNOLDS

Douglas B. Reynolds is a professor of petroleum and energy economics at the University of Alaska Fairbanks. He can be contacted at DBReynolds@Alaska.edu

In the 1990s much discussion occurred over how electric utility monopolies had overbuilt their supply of power generation capacity and did other inefficient actions that were "wasting money." The thinking was, along Chicago School lines, that utilities would be more efficient if there were competition. That way uneconomic generation would go out of business even while new, low-cost generation would come into the mix. Theoretically, new, small and low-capital cost natural gas generation would lose less money than large, high-capital cost coal generators in a competitive game theoretic interaction, which would result in the cheapest generators staying in business. Nevertheless, understanding how exactly such a competitive grid works is a challenge.

One way to analyze it is to compare competitive electric generators on a grid as analogous to a city's road system. Both the grid and the roads are transportation networks: the roads for people and the grids for electricity. With city roads you are connecting people to homes and businesses, and where those businesses can compete with each other and be located at optimal locations and with optimal sizes all over the city. Generators on a grid can also be located anywhere. The people on roads drive to and from their residential housing, which are akin to electric power consumers on a grid, again located in many locations and where the people can then drive, or ride, from their residences to businesses in order to work or shop.

Within this discussion is a debate similar to what transpired in the 1930s between the ideal of free markets creating an economy, and the ideal of a planned engineered economy, sometimes called technocracy but loosely based on Communism. After all, considering how the Great Depression showed intractable problems with market mechanisms, technocracy (or communism) looked appealing at the time. Similarly, it would be good to compare the ideal of an electric power market to other types of competitive markets to judge its effectiveness. Issues such as congestion, qualitative competition and technological advancement can be taken up.

Competitive Types

According to the principles of Economics there are four economic structures with varying degrees of competition: Perfect Competition, Monopolistically Competitive, Oligopoly and Monopoly.

Recall the conditions for Perfect Competition include, perfect information, easy entry and easy exit, many small firms, such that no one firm has any kind of market power, and a single well known market price. None of that exists for the electric power market. First, there is no easy entry and easy exit for electric power generators, which are often some of the most environmentally controversial facilities there are, requiring permits, long lead times and more often than not court actions just to get set up. Then there are usually economies of scale that determine the cheapest generator, not just for base power, but for peak power as well. Also most generators, (if not compelled to do so by regulation), keep their costs and strategies hidden so that they can make more money. So there is no naturally occurring perfect information.

Price often varies due to daily market changes. Theoretically, the supply and demand transactions happen when the operator dispatches the lowest cost provider to the grid at an instant of time, although not necessarily charging a price equal to the average cost at that instant. Plus, when there is a price change, many purchasing customers do not even bother to react to it. And even if a customer sets up smart grid techniques to turn on a water heater say at a low price interval, cannot such techniques be used equally as easily by a utility monopoly as well?

One ideal in competition is to allow generators to sell directly to load paying customers based on offering a low price, long run contract to various customers. So, again that is not by definition close to a perfect competition ideal where everyone can buy at the lowest price, not just a few strategic partners. That all suggests that power markets are not perfectly competitive. But maybe, power markets are monopolistically competitive.

For a monopolistically competitive market to exist, it still has to be the case that each generator has easy entry into and easy exit from the market, which again does not exist. You also have to have many small generators, anyone of which cannot have any kind of market power, which also normally does not exist. Most strikingly, monopolistic competition implies differentiation of the product by quality, but since it is all only electricity you are selling, there is no differentiation of the product, only differentiation of quantities and possibly prices if you are allowed direct long term contracts, but then that would not be exactly monopolistic competition.

So the power market is not perfect competition, it's not monopolistically competitive, and since we are creating the market out of thin air, it cannot be a monopoly. Therefore, by definition, it has to be oligopolistic competition. So, what does the ideal of oligopolistic competition look like?

Basically, oligopolistic competition is a game between relatively large players in comparison to the individual market. The players normally have the economies of scale not only to create the cheapest average cost generators, but the economies of scale to actually go through the environmental and regulatory gauntlet to even build a generator in the first place. Small solar generators are often allowed in the market by regulatory fiat, which therefore suggests a lack of easy entry and easy exit. Thus, it usually takes deep pockets to get into the market and deep pockets to win, i.e., make a profit, by undercutting competition. The oligopolist cuts prices in order to put its competitors out of business, or it buys out the competition, and then raises prices. The only alleviation of that type of cut throat competition to swallow up competitors is: (get this) regulation!

Wait, the whole point of the exercise was that regulation was not working and that's why we needed competition in the first place. If unfettered oligopolistic competition would end up in a Rockefelleresque monopoly, then it can't provide cheap electric power, (by definition of game theoretic oligopoly power) and not work either, then we are back to regulation. It is like saying regulation works better than regulation.

Congestion

Keep in mind the physical differences between a power grid and a road system. Can they be compared or are they different? Consider Congestion.

A road system and a power grid both have congestion. The road system's commuters for example get into traffic jams at rush hour and it can take an extra hour maybe to get home, although if you do that enough, you might vary your commuter timing or vary where you live or even vary where you work or shop. With a power grid, since power production and consumption are instantaneous, then if there is congestion, the electric power is not storable on its journey; and so if the power cannot get through at all it will be lost. That is, a road transportation system is for storable items, the commuter or the cargo items in a truck, which all will eventually get through. The power grid, if it is congested, cannot store the power and the electric power can generate heat losses on the line or may not get through at all.

While this may sound like a small loss for the power system, it actually means that when a road system engineering planning mistake is made, it will only add a waiting time to the delivery moment of a storable transportable item. For the grid system, an engineering planning mistake will create loses to the system that could continue until the congested node is built out or built around. So, how do you plan? For both systems, the engineer looks at congested nodes and starts to plan expansions around them. However, since the grid system is supposed to be designed to add and subtract power in many locations, and instantaneously, the solution is often to simply over-build the entire system to be able to take extra power from anywhere at any time.

Whereas the road engineer will have a two lane road in rural areas, the electric power generator may need a four lane highway equivalent (not including high voltage transmission), just in case someone big moves in. And where as the road engineer will have a four lane highway in the suburbs, the electric power generator needs to have the equivalent of eight lanes to make sure the instantaneous power gets through. Then in down town areas where ten lanes will do, the power engineer builds twenty or thirty lanes equivalent to keep competition open.

That is an interesting concept: over-building a system. No one ever talks about how over-building a grid is by definition "inefficient" in the so called "efficient" market grid system. On the other hand, a planned monopoly system would place generators strategically so as not to have to over-build power lines. Therefore, not only is the number of power generators going to end up being more than necessary in an oligopolistic competitive market in order to insure competition (creating a game theoretic interaction), but the grid itself will have to be over-built to allow the implementation of this relatively inefficient oligopoly game to play out.

Then on top of that you are going to allow prosumers (customers that both use and produce electric power) to produce their own small electric power output and sell it to the grid which can add to synchronous zone problems and other engineering problems for the grid's stability. It is hard to imagine how the oligopolistic, prosumer, over built grid is making competitive cost reductions to the average consumer. But wait, according to EIA (2019) statistics, it isn't. Inflation adjusted average costs of power are down a bit over ten years, but much of the reductions happened early on when natural gas prices were in decline.

Nothing Qualitative to Compete Over

In a city with businesses situated along a road system, the usual way to compete is not so much with lower prices, but with better service, higher quality items and maybe convenience. That is you compete qualitatively not with price. Even the discount stores add a qualitative edge to their discounts to compete. But all that doesn't work in a competitive electricity generator market where it is exactly the same product, electricity with a standard voltage, phase and frequency, that is being sold and indeed the electricity is wanted instantly when it is needed and at the lowest possible price. That leaves no room for firms to make a profit by marketing their quality. So electric utilities are not like restaurants or automobile producers with varying degrees of quality, styling and performance, they are just providing one simple commodity: electricity. The only way to make money in such a framework is to undercut competition and buy it out, or make agreements with each other (tacit or formal) to not undercut each other and keep prices high.

Moreover, generators have economies of scale.

So, bigger generators are, over the long run, cheaper than smaller generators. That means even if a small intermittent generator, like a solar panel, takes away market share from a large generator, then that large generator becomes more cost inefficient, especially if it is required to turn on and off causing its turbines to degrade. But also generators can be set up to specialize in peaking needs, i.e., close to central peaking power demand locations to reduce line losses, or set up for base power needs, i.e., for efficient 24 hour generation, all of which can get destroyed with oligopolistic competition. Basically, power utility competition is like trying to fit every square, base-power, peg into a round peaking-power hole and that reduces cost cutting specialization abilities.

Then on top of all that you allow small time residential solar and wind generators to surge in and out of the mix so that the changing supply reduces effective planning over when to turn on and off generation at specific times during the day. It reminds one more of having too many cooks in the kitchen, than of an efficient market. Therefore, it is hard to make a profit. And if it is hard to make a profit, there is not going to be a lot of competition.

Technology

The real issue here is technology. The thinking is that this inefficient oligopoly set up, no matter how convoluted it is, at least causes leaps and bounds in technological changes. But really it hasn't been normal competition that has created the bulk of better wind and solar technology, but simply government subsides. Government R and D is certainly to be applauded but let's keep the record straight and acknowledge that it isn't exactly the competition that has created all the renewable technological changes at all, but government outlays. Carbon taxes could also be a factor but again that will be a factor no matter the utility configuration.

So, then you say that with AI (artificial intelligence) it should be possible, like the cell phone networks, to create an all-powerful planning mechanism. But cell phone users have the lea way to locate anywhere within a few miles of a cell tower and the tower can fairly cheaply be over-built for excess capacity at a small cost. Plus the planning of each cell system is done by the head of the company, not by competition. There are cell competitors, but that would be like having power grid competitors, not competitive generators. By contrast a power grid needs a physical connection and built to specifications to each generator, high-voltage transformer, low voltage substation or paying customer and where they cannot move or place too large of a load or supply capacity into that grid connection. This suggests that a planned monopoly would be more conducive to implementing AI and technological innovations than oligopolistic competition.

Basically a power grid cannot create nearly the flexible changes to traffic that a cell phone grid can or a road system can which means you need central planning to make a truly efficient power utility using economies of scale for generation capacity, economies of scale and planning for gird connections, and if need be economies of scale for carbon emission reduction strategies, i.e., you want to have a natural monopoly.

Conclusion

So then the question is, if prosumers, emission mandates and oligopolistic competition in power does not really create competitive efficiency, then what would? Probably it would have to be a planned system. It would not necessarily be a government monopoly, where there is a tendency to under-invest or over-invest due to a lack of appropriate incentives; or it would not necessarily be a regulated private monopoly, which tends to use gold platting (using high cost options instead of low cost options) to gain a return; but maybe it could be an incentivized management system. An incentivized management system would be kind of like how a private company is run by a CEO with stock options. But instead of stock options, as Reynolds and Zhou (2019) show, a socially optimal bonus mechanism, not based on the utilities value but based on price and cost reductions for customers and other social benefits, might work. At least a bonus mechanism might add better planning and least cost options into the mix but it would also create true transparency.

Interestingly, the real point of the competitive market is probably not to reduce prices, but to reduce transparency. For example, high cost carbon reduction policies can more easily be hidden using a complex market mechanism rather than a simple monopoly. If there were true transparency, though, then that would cause political resistance to the high costs of actually trying new renewable technologies. Indeed, it may be the lack of transparency of the so called competitive power grid system that everyone likes so much, not the cost reductions. In that way everyone can claim the power grid is doing all things for all people: empowering consumers, reducing carbon emission and creating new technology, when in fact it is just a boring old electric utility that simply produces electric power, distributes it where needed and covers its costs. You would like an electric power utility to be as exciting as rockets to Mars, but it just isn't that exciting.

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fILLER 2

Rewarding a Group of Customers for Mitigating the Imbalance of Electricity

BY YOSHIHIRO YAMAMOTO

Yoshihiro Yamamoto is with Takasaki City University of Economics, Japan. He may be reached at ysyama@tcue.ac.jp

Customers playing active roles

Customers have traditionally purchased electricity to use appliances, and paid for their consumption. They are considered passive because a public utility is under an obligation to meet their demands.

Recently, some customers have come to play an active role, beyond just consuming electricity for appliances, with devices such as photovoltaic systems, electric vehicles, rechargeable battery systems, and heat pump water heaters. Photovoltaic systems enable them to produce electricity; however, the amount of electricity produced depends on natural conditions. Alternatively, the amount of electricity produced or consumed may be controlled for some devices: not only are electric vehicles and rechargeable battery systems charged but they also discharge electricity and heat pump water heaters transform electricity into hot water to be used later.

Those operations will make the management of the power system more complicated, possibly causing phenomena such as excess supply and reverse power flow, and resulting in frequency or voltage instability, or transmission security degradation (Stoft, 2002). However, if operated to mitigate the imbalance between supply and demand, those devices may contribute to load leveling, decarbonization, affordable energy provision, frequency stability, and so on. For example, an aggregator is performing such a task for a set of commercial, business, or residential buildings equipped to facilitate the aggregation of operations (Zurborg, 2010; DOE, 2015). In contrast, there seem to be still difficulties with some individual homes and small-scale facilities in being aggregated. Thus, it is essential to consider how to deal with such small-scale owners of those devices in an attempt to mitigate the imbalance. This article presents one of such methods, which incentivizes them by a reward for acting appropriately.

Rewarding small-scale owners

The reward should be additional to or compatible with the ongoing billing system since the fact that electricity is sold and purchased does not change. What should be rewarded is a contribution toward mitigating the imbalance between supply and demand. For example, suppose that the imbalance was mitigated as a household consumed electricity, then, the household should be remunerated for its contribution toward the mitigation, while paying for that consumption.

The rewarding system should be designed on a local basis since supply and demand situations vary from area to area. In particular, the photovoltaic electricity supply differs according to the location. Accordingly, we consider is a certain group of customers in the vicinity on the electricity network, which will be determined from an engineering point of view.

The idea of being designed on a local basis is also supported in terms of remunerating customers appropriately. The influence of every individual customer on the outcome of a whole market is too tiny to assess. However, if a group of customers are considered, the actions of each member can influence the outcome by the group. Hence, to assess each contribution, the rewarding system should be targeted at a group of customers, not at a market as a whole.

Thus, the problem is how should we assess the value a group of generation customers and then divide it among the members. In addressing this problem, it might be helpful to separate technological and economic aspects.

The technological aspect concerns how to achieve or maintain the balance between supply and demand within the group. However, the economic aspect is concerned with how to assess the outcome by the group and reward its members accordingly. As this perspective suggests, the economic consideration comes after the technological arrangements. In other words, one possible approach to the problem is to work with the outcome of trade, ignoring the technological arrangements. Note that the reward calculated after trade will work as an incentive since trade is made period after period so that customers would be trying to be better off next time.

How to assess the value generated

Let us address the problem of assessing the value generated, based on the outcome of trade. We present one of potential methods. It considers the discrepancies between production and consumption of electricity within the group for a period in question. The reason is that, regarding mitigating the imbalance, supply is timely if there is more demand and conversely, demand is timely if there is more supply; the discrepancies are finally to be cleared by a system operator using resources outside of the group. In other words, the production should be positively valued if all of it was seemingly consumed within the group or the consumption should be positively valued if all of it was seemingly met within the group, during that period. Note that when the production is positively valued, the consumption is negatively valued or vice versa.

Three points are made. First, the amount of the positive value must be equal to that of the negative value to make the rewarding system a zero-sum game. Second, the positive or negative value should be set at such a level that it would encourage those to whom it is allocated to operate their devices appropriately. Lastly, usual consumption of electricity is negatively valued if the production was smaller than the consumption within the group or vice versa.

How to divide the value among the members

Finally, let us address the problem of dividing the value among every member of the group as a payoff. We present two possible methods, which are based on coalitional game theory (Osborne and Rubinstein, 1994). The first method is to divide the value depending on the contribution of each member. This applies the concept of the Shapley value of a coalitional game. It is considered that the group has been formed by a customer entering an existing group one after another. In this process, every customer makes a positive or negative contribution to the existing group, the amount of which may be calculated in the same way as assessing the value above described. Considering all the possible orderings of a customer entering to form the final group, we can specify the contribution of every member of the group.

The second method is to divide the value to sustain the group. This applies the concept of the core of a coalitional game. Were it to be more profitable for some customers to form a new group than it were to stay in the current group, the rewarding system based on a group of customers would no longer be sustainable. Thus, it is required that any subset of customers not be able to be better off by this kind of deviation.

Concluding remarks

We discussed the rewarding system for mitigating the imbalance between supply and demand of electricity within a group of customers, especially connected with individual homes and small-scale facilities, which are less likely to be included in the aggregation that has been intensively discussed for energy transitions. Thus, our system may serve as a complementary mechanism to it.

The rewarding system may work well by providing relevant information, supporting decision-making of customers. For example, if the information on the current supply and demand situation is provided, they might accordingly increase or decrease either production or consumption under the rewarding system.

Since the rewarding system targets a group of customers, there will be some concern about free riding. A field experiment will be helpful to evaluate the effectiveness of our system as an incentive.

The rewarding system presented here is one of the possibilities aimed at supporting energy transitions. It considers mitigating the imbalance between supply and demand within a group of customers only. Different suggestions may be made if other aspects are considered.

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Electric Utilities and their Rates: Evolution and Economic Efficiency

BY JOHN R. MORRIS

John R. Morris is a Principal at Economists Incorporated in Washington, DC. He studies competition in energy industries and submits expert reports before the U.S. Department of Justice, the Federal Energy Regulatory Commission, and other regulatory agencies. He may be contacted at morris.j@ei.com.

See footnotes at end of text.

. Introduction

Changes in technology and the availability of information have impacted retail energy rates in the past and will do so at an increasing rate in the future. Although we do not know with perfect precision the exact change in information or technology that resulted in a particular rate paradigm during any epoch, we can observe the changes in information and technology and the changes in rates and rate structures. We can then correlate the two sets of changes and theorize about the relationship between the two. For example, real-time pricing was not an option until technology was sufficiently low cost to track usage by hour and efficiently communicate costs from the end-user. Adoption of such technologies takes time and is related to the both the accepted pricing structure and the inherent cost structure of that era.

We know the current situation and the future with even less precision. We observe facts and behavior today, but we typically have only hypotheses—often based on past experience—about how the facts and behavior are related. For the future, we have only hopes and theories about facts and behavior and how they will interact. But like Dicken's Scrooge, we might clearly see disastrous outcomes if we do not change, and hope for better outcomes if we do change. Hence, this article examines the ghosts of the past, present, and future to see if we can identify changes that lead us from the course of current practices to more hopeful outcomes in the future.

Before exploring the past, present, and future, it is desirable to grapple with the concepts of technology and information. Information refers to data and facts, which are typically considered objective, and knowledge, which can be subjective and open to personal interpretation. Knowledge generally refers to an accumulation of data and facts, and some understanding, organization, or relationship between those facts. For example, the utility rates, measured costs, and calculated rates of return by a specific formula are facts. The accumulation of those facts along with a rate paradigm, such as the allowed rate or return should be comparable to firms with comparable risk, is a set of knowledge. Technology is the application of knowledge to specific tasks, such as reading and recording electric meters and calculating the rate of return.

Information and technology are intertwined like space and time. Information on the operation of electronic and digital processes allow for the real-time reading of meters and the communication of prices through technology. The real-time reading of meters allow for more information. Technology that relays the real-time meter information to end-uses in turn provides more information on the relationship between usage and prices. This, in turn, can affect forecasts of necessary generation capacity and future costs.

Information and technology are not limited to the hardware and processes of operating a regulated utility. Information and technology also can refer to the regulatory paradigms used to set rates and allowed activities for regulated utilities. These paradigms are based upon a set of knowledge and beliefs that people have at any given time. As available facts and knowledge change, the desire for a particular paradigm change as well.

We now turn to the past, present and future.

The Ghost of the Past

The benefits of rate regulation to the owners of electricity electric utilities have varied over time. As is typical for new and innovative products, initially there was little or no regulation of electric utility rates. Electric energy was initially a product of the rich, with prices around $3/kWh in real terms today.[1] This is about 25 times current average prices for residential customers. The main form of regulation was municipal franchise authority, which restricted the number of competitors. Municipalities often authorized multiple systems, and the resulting competition and advances in technology dropped prices down to about $0.38/kWh in real terms by 1909.[1]

In 1898 Samuel Insull, the founder of Chicago Edison, proposed a different business model for electric utilities.[2] He proposed a regulatory compact in which exclusive franchise territories would be granted by the states in exchange for cost-of-service regulation of pricing. This new form of regulation began in Wisconsin and New York in 1908 and by 1917 45 states had adopted state-wide regulation of electric utilities.[3] The regulation was very successful at achieving Insull's goals. Jarrell (1978) reports that the state regulation was associated with a 25 percent increase in average prices and 40 percent increase in average profits.

This change to state-wide regulation of entry and rates was based on a theory that had been growing for at least 60 years by that time, the theory of natural monopoly. Classical economists had used the term natural monopoly to distinguish a sole seller of a product that was due to circumstances rather than a grant by the government. For example, a vineyard with a certain type of soil may produce wine with a particular flavor that is distinguishable from other types of wine. The term was first applied to businesses that we today consider natural monopolies by John Stuart Mill in 1848 when he applied it to the production of gas and water. Walrus in 1875 applied the term to transportation industries such as railways, roads, and canals. The theory of natural monopoly as we know it today was first put forth by Alfred Marshal in 1890 when he proposed a different definition, that of "indivisible industries." To state the concept of the time in today's language, natural monopolies were industries where the least-cost provision of the good would be provided by a single company. Hence, in theory, the least-cost provision of electric energy could be accomplished by a single company, which justified the restrictions on competing companies. And because the market was left with one, or a very small number of sellers, rate regulation was necessary to constrain the pricing of the monopoly seller.

It should be noted that price regulation dealt with the provision of a commodity—electric energy. The business model was to produce electric energy and then deliver that energy to end users. Just like natural gas and water, electric energy was largely a homogeneous commodity service and one did not worry much about quality or differentiation of multiple products. This provided for a relatively simple regulatory paradigm that worked with relatively few hiccups until the 1970s.

The 1970s brought many challenges to investor-owned electric utilities in the United States, of which I will name only a few. A command and control mindset left over from the 1930s and 1940s pervaded the government in the early 1970s. One facet of this mindset was price controls for natural gas and oil, which created substantial shortages as a result of inflation and oil embargos by OPEC. Utilities turned to coal and nuclear energy to power new power plants, but these also ran into substantial issues. The environmental movement was growing in the U.S., resulting in Congress and the EPA putting new restrictions on coal-fired power plants. Some of these restrictions could be met by the low-sulfur coals of the Powder River Basin, but others required costly equipment upgrades at the plants. Fears surrounding the safety of nuclear energy resulted in modifications of plants under construction, which greatly increased the cost of nuclear power. When the costs of higher fuel prices and higher capital costs were passed along to consumers, the growth rate of electric consumption declined substantially. Growth rates averaged about 10 percent in the 1950s, 7.5 percent in the 1960s, and less than 5 percent in the 1970s.[4] The growth rate from 1973 to 1985 was only 2.5 percent.[5] Some utilities found that substantial rate increases could even lead to absolute declines in consumption.

The 1970s produced three lasting legacies. The first is the implementation of automatic rate adjustments for changes in fuel and purchased power costs. The rapid rise in fuel costs during the 1970s presented the biggest risk for utilities. Traditionally, a regulated utility facing increased purchased power or fuel costs would have needed to file a new rate case, which was both costly and time consuming for the utility. Automatic rate adjustment mechanisms eliminated the need for utilities to submit new rate case filings. By the end of the 1970s, the vast majority of states had adopted procedures to allow utilities to adjust rates for changes in fuel costs without the need to submit a full rate case filing.

Secondly, the 1970s brought increasing skepticism of the efficacy of regulation and the natural monopoly theory of the provision of electric energy. The attack of the regulatory framework came from two directions. First, the spread of electric and then electronic computing power reduced the costs of statistical studies of prices and costs in the industry. In a seminal article in 1962, George Stigler and Claire Friedland questioned whether rate regulation actually lowered rates to consumers. This work was followed by many similar works in the 1970s, such as Jarrell (1978), who suggested that regulation actually raised rates. Others, such as Alfred Kahn, questioned not only the rates of regulated companies, but also the quality of the service offerings. Kahn argued that it was much easier to regulate the rates for existing products and service offerings than to regulate whether the current offerings were really the correct offerings or whether a utility should offer more variety in terms of products, services, and rate structure.[6] Moreover, both lines of analysis found that competition, even highly imperfect and flawed competition, was often much better at providing the value that consumers ultimately desire.

The third legacy is a crack in the paradigm that electric utilities simply supply a commodity that is easy to determine costs and regulate. The Public Utility Regulatory Policy Act of 1978 ("PURPA") and the Natural Gas Policy Act of 1978 ("NGPA"), depending on perspective, are either the most flawed pieces of legislation ever or the most ingenious. As written, both acts have severe flaws and substantial economic inefficiencies. But both provided information of inestimable value. The NGPA very quickly showed that the "shortage" of natural gas is nothing more than the traditional shortage that develops when regulators attempt to keep a price below a competitive level for a substantial period.

Within 11 years of its implementation, natural gas prices were completely deregulated at the wellhead level and much of the NGPA repealed, due in large part to the plentiful gas supplies brought forth with higher price ceilings. PURPA forced electric utilities to connect and purchase from certain classes of generators called qualifying facilities (QFs). The interconnection requirements and the new supplies of natural gas by the mid-1980s revealed that gas-fired generation could be provided at much lower-cost than newly proposed coal-fired and nuclear generation. Although this had substantial impacts on utility regulation, it was the interconnection and purchase requirements that changed the fundamental characteristics of electric utilities from simply providers of electric energy to network operators.

The concept of utilities as network operators at the wholesale level was codified in the National Energy Policy Act of 1992, which required transmission-owning utilities to open their transmission systems to all who were willing to pay for transmission service. FERC formalized this requirement four years later in Order No. 888. Since then FERC has issued over 250 "landmark" orders in the industry.[7] The range of these landmark orders goes from transmission reliability standards to market-rate authority for generation owners, but the majority deal with transmission access issues such generation interconnection and refining the definition of nondiscriminatory transmission access.

Upheavals in the cost of generation and the advent of transmission access led to major restructuring in many states in the 1990s. Many of the eastern states adopted competitive retail access and back-up, provider of last resort, or standard offer service for the utilities. Instead of being vertically integrated from generation, through transmission, to distribution, and retail sales, many utilities became "wires-only" companies. Rather than primarily being in the business of selling a commodity, they became primarily in the business of delivering a commodity. In this respect, they became more like common carriers and less like merchant operators. The crack created by PURPA suddenly was a large hole in the dike with competition rushing in.

Technology has advanced tremendously since PURPA was passed in 1978. On August 12, 1981, IBM introduced the IBM 5150, its first personal computer. Although personal computers were available before then, the IBM 5150 legitimized PCs and began the mass marketing of personal computers. The accompanying explosion of computing and communications technology has radically changed our lives, and also changed opportunities in the electric utility industry. The advent of real-time metering and communications allows many new opportunities to manage energy infrastructure and usage. These technologies now present opportunities for electric utilities.

The Ghost of the Present

Today electric utilities are in a transition period. Most electric utilities fall into two categories: traditional vertically integrated utilities and those that have unbundled generation services from the business of transmission and distribution wires.[8] But regardless of structure, the old paradigm treated an electricity utility as one that either sells or delivers the commodity of electricity. This paradigm, along with common rate structures, has created rate issues for many utilities.

The technologies of electric generation, transmission, and distribution each currently feature two attributes that create pricing issues. First, investments create substantial site-specific, sunk costs. The economic problem created by such investments is that without some long-term contracting mechanism, the buyers of these goods are often in a position to expropriate the value of the site-specific sunk investments. Exclusive franchise territories can solve this issue, but that creates another risk: regulators can set rates so as to transfer the value of the sunk costs to the customers. Fortunately, the Supreme Court decisions in Smith v. Ames, 169 U.S. 467 (1898) and Bluefield Water Works v. Public Service Comm'n, 262 U.S. 679 (1923) have limited the ability of regulators to take such actions. But there is still a risk that regulators will set rates in a manner that does not allow for full recoupment of costs. Second, investments represent a substantial amount of joint costs. A 13kV transmission line running down a street often costs the same whether there are 12 or 15 houses connected to the line. So, if 12 houses are being served and a 13th house desires service, is the economically efficient rate one in which the 13th house pays the low incremental costs or a rate in which it pays the average cost of serving all the houses? Either choice creates incentives that can either increase of decrease social welfare depending upon the specific circumstances.

Attempting to reconcile these issues, and likely other issues, electric utility rates evolved so that non-trivial portions of what economists call "fixed" costs have been recovered in the variable portion of electric rates. In essence, the usage of electric energy subsidizes the cost of providing access to electric energy through a wired network. Such a rate structure can give incentives for end-users to install generation that is higher-cost than the centralized generation services provided by utilities or large merchant generators. Knowing the PURPA mandates, some utilities foresaw these incentives and revised tariffs to eliminate or reduce such incentives. Other utilities attempted to revise tariffs to reduce the inefficient incentives, but were thwarted by state regulatory commissions. Other utilities did not take action until the entry of small-scale distributed generation began to have significant financial impact. So today, we have utilities in each of these categories.

The debates about utility rates and what is an efficient rate structure today are largely discussed from the point of view of the old paradigm that electric utilities are primarily in the business of selling or delivering electric energy. End-use installation of generation resources are viewed mainly as substitute sources of energy that do not obviate the need for distribution (or transmission) systems, nor affect total system demand for services. The purpose of electric distribution utilities is not questioned.

Programs instituting performance-based ratemaking ("PBR") typically do not change this paradigm. Traditionally PBR sets price-caps that allow the utility to earn higher profits if costs are below the level used to set the cap, and incur losses if costs were above the benchmark. Share the savings programs with fuel costs is one type of PBR in the electric utility industry.

Unfortunately, these programs are often set so that the utility has little ability to profit. Price-cap PBR can lead to adverse incentives for utility performance, including the incentive for poor quality service.

Performance incentive mechanisms (PIMs) are another form of PBR. For example, some gain or profit to the utility is allowed or a penalty incurred if it meets a performance goal such as restoring service within some period of time after an outage. PIMs are often ad hoc based on the preferences or desires of regulatory commissions as opposed to true incentive mechanisms that match consumer demands to utility service. Yet, PIMs do provide the potential for reliably serving consumer demand. For example, estimates could be made of the benefits of greater reliability and the reliability increases from installing underground wiring. These two estimates would establish the consumer value associated with underground wiring.[9] A regulatory agency could then allow the utility to install underground wiring in all areas where the collective consumer value is greater than the costs, and then place the added capital into the rate base. Because competitive firms would collect more than cost for some period before entry eroded the profitability of the innovation, same added benefit could be added for regulated utilities such that consumers receive greater net value and the utility receives higher profits than they would by simply maintaining overhead distribution lines.

Finally, the substantial incentives to install distributed generation have created significant amounts of distributed generation in some locations. End-users do not intrinsically desire solar panels and wind turbines to be installed at their homes. Solar panels and wind turbines are installed mainly because economic incentives have been created for their installation. The cost of utility scale photovoltaic ("PV") solar is less than one-half of residential scale cost.[10] The main driver of the cost difference is the marketing costs involved with residential scale installations. It is more efficient to install utility scale solar and deliver the energy over distribution wires rather than have distributed installations.

Distributed generation installations are supported by utility rates with energy charges that contribute to fixed-cost recovery. Federal tax credits reduce the cost of installation by 30 percent. States can also provide subsidies, such as California providing over $2 billion in rebates for distributed solar installations. Renewable portfolio standards (RPS) also provide incentives. RPS often provide for within-jurisdiction requirements for wind and solar energy and penalties for not meeting these standards. In the District of Columbia, the penalty for solar shortfalls is $500/MWh, or $0.50/kWh. As a result, the value of a solar renewable energy credit (SREC) in 2017 was around $400/MWh. Given these incentives and the desire for lower net costs of energy, it is not surprising that distributed technologies have been adopted.

The Ghost of the Future

The adoption of distributed energy resources (DERs) will increase. The future is driven by consumer demand, technology, and the incentives created by government. Consumer demand, in some respects, is quite simple. All consumers desire free, limitless, usable energy. Technology, however, does not allow this. Available energy is finite and costly. Changes in the deployment of technology that increase availability and reduce net costs are valued by consumers. Given current low interest rates, the federal government's proclivity to borrow money, and desire of Congress to give benefits to homeowners, DERs are likely here to stay. Moreover, technology increases at an increasing rate. New technology allows more production with fewer human resources, which frees additional human resources to pursue new and better technologies. Given the trends using fewer resources for a given amount of work, the cost of DERs are likely to fall relative to utility-scale energy resources. For PV technologies today, other than marketing costs the cost of home installations are not substantially higher than utility scale. So fundamental economic changes will drive DERs as well government policies.

DERs substantially change the nature of electricity distribution. Rather than being used as a system to deliver energy to end-users, electricity distribution systems become networks more like the internet that transmit messages along an ever changing array of paths. Real-time communication between end users and the utility, which is clearly feasible with wireless communication and standardized TCP/IP, will unleash the potential for the electric grid. Two potential paradigms come to mind.

In one paradigm, the utility would serve as a central dispatcher, much like RTO operators operate the bulk transmission system. There are some precedents for this at the retail level. Cable operators, for example, gained control of their networks by requiring set-top boxes as an interface between the cable system and viewing screens. Another example is "energy savings" solutions today where utilities have control over high-demand equipment such as air conditioners in order to reduce peak demand. In such a system, an end-user could place clothes in a dryer before going to work and the utility would decide the optimal time for the drying to occur. Given control over the system, including end-use generation, storage, and large demands, the utility would then operate the system to achieve some objective. For example, the object could be to minimize total energy costs for the end user. But many other objectives come to mind, such as minimizing total energy costs for a group of users, minimizing carbon emissions for individual users, or minimizing carbon emissions for a group of users. Utilities would offer an array of choices, and let end-users decide which preferences should be pursued by the utility. Utility compensation would be based, at least in part, on how well it achieves its goals.

The other paradigm is that the utility would send price signals to each end-user, and the end-user would be free to make all its choices based upon the price signals sent by the utility. For example, the end-user might program its battery to store energy when real-time energy prices are less than 20 cents per kWh and to release energy when real-time prices are above 80 cents per kWh. This paradigm would not achieve the full benefits from central coordination, but it may be more palatable to end-users.

Standards and requirements for appliances are necessary to facilitate the transition to the modern utility. The federal government has established minimum energy standards for appliances, and the Energy Star program has encouraged companies to go beyond these standards. The next step is to create a standard communication protocol and options built into the appliances to allow for remote operation. The protocols will allow for end-user control or for control by another with the end-user's permission. Given the ubiquitous use of electronic control and communication today such a standard will not substantially increase the cost of most large appliances.

The difficult part of any change is to know which changes are economically efficient and which are not. In competitive markets, companies compete with different service offerings, whether the difference is in terms of features, options, or prices. Those with superior offerings drive out those with inferior offerings. Through the market test, the more efficient providers prevail over the less efficient. Although there are over 40 utility holding companies and at least fifty-one jurisdictions, differences across utilities will not provide enough variety to determine the most desirable choices for end-users. A program that is successful in California may have little applicability in North Dakota. Instead, utilities will offer pilot programs in select areas to see the share of end-users that prefer the new option. If sufficient demand exists to support the option, then it would be economically efficient to give that choice to consumers.

Before these changes occur, state regulatory agencies will need to shift their regulatory paradigm. Rather than focusing on a specific set of prices, regulatory agencies will need to shift to focusing on consumer value. A utility that delivers 60 percent of end-use consumption may have 10 percent higher distribution rates than a utility that deliveries 80 percent of consumption, but may be delivering greater value to its end-users because of the savings the end-users receive on the additional 20 percent of self-generation. Similarly, a utility offering centralized communications and dispatch functions would have higher costs than a utility that does not, but may provide greater value to consumers because of the energy cost savings from the centralized dispatch services.

Conclusion

The conclusion is simple: the past is prologue. The changes in technology and fundamental economics in the past have driven changes in regulation and rate structures, and they will drive changes in the future. Moreover, the rate of change will be increasing, which means that more flexible rate structures will be necessary. The fuel cost adjustment clauses and formula rates electric transmission service are two examples of rate structures that automatically adjust for changes in cost and demand. Rate structures will also change to accommodate DERs and the challenges that they present. Innovative utilities will develop new services that that will take advantage of new technologies and provide greater net benefits to end-users—and keep some of the benefits for themselves. In other words, perhaps Scrooge was able to save Tiny Tim and still salt away enough money for a comfortable retirement.

Footnotes

[1] See Wren, Strain & Britt (2018), at 3, reporting that prices were $0.20/kWh in 1892.

[2] Id.

[3] Id.

[4] Id.

[5] EIA.

[6] Geddes (1992).

[7] Kahn (1970), Volume 2, at 325-6.

[8] See https://www.ferc.gov/legal/maj-ord-reg.asp?new=sc3.

[9] A few utilities fall into other categories such as owning generation and distribution wires but not transmission, or unbundled from both generation and transmission.

[10] Another methodology would be to observe what end-users are willing to pay for underground wiring in new developments.

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Effectiveness and Balance: a Canadian Regulator's Approach to Review of Energy Efficiency Funding Proposals

BY JACKIE ASHLEY

INTRODUCTION

Energy efficiency programs encourage customers to be more efficient in their use of energy. However, they also require a source of funding, and it can be difficult to explain why utilities should fund programs that encourage customers to use less (rather than more) of their product. In addition, customers may complain that these programs are unfair as they typically increase rates and not all customers (in particular low-income customers) benefit from them.

To obtain funding for energy efficiency programs it is therefore critical to be able to explain in 'plain English' why it is in the public interest for these programs to be funded, and to address equity concerns around who pays and who benefits.

This article puts forward an 'Effectiveness and Balance' response to this issue based on the approach used in British Columbia (BC), Canada which may assist organizations secure funding for their own cost-effective and balanced energy efficiency programs.

The model described here has its origins in the cost-effectiveness tests described in the 2001 California Public Utilities Commission Standard Practice Manual. In 2008, the BC government enacted the Demand-Side Measures Regulation (Regulation) which outlined the cost-effectiveness tests to use in British Columbia and programs that must be included to ensure a balanced portfolio (such as low-income and educational programs).

In 2014, the British Columbia government updated the Regulation to recognize emissions reduction and non-energy benefits and allow utilities to claim a portion of savings from any code or standard towards which market transformation activities were targeted. In the same year, the British Columbia Utilities Commission published a decision which applied the Regulation to a utility's funding request, and it is this decision which forms the foundation for the model described in this paper. Additional refinements have been made since that date, including minimum levels of funding required for programs that provide direct support to governments crafting new codes and standards promoting efficiency, and the appropriate test to use for utility electrification programs that increase load. Undoubtably this model will continue to be refined in the future.

CORE ASSUMPTIONS

Before getting into the details of developing and evaluating energy efficiency programs, it is important to start with a definition of 'success' that is shared by all parties involved.

Defining 'Success'

Should 'success' be defined as only focusing on efficient supply of electricity, or do we also care about whether the customer is efficient in their use of electricity once it is delivered?

In British Columbia, 'success' is when customers receive their heat, light, power (and now with the advent of electric cars, even transportation) at the lowest total cost. This means that we focus on the whole market - promoting both the efficient supply and efficient use of electricity.

Customers in jurisdictions with this 'whole market' definition of success will therefore receive the services they need (heat, light etc.) at a lower overall cost than jurisdictions who only focus on the supply side of the market.

This broader definition of 'success' (promoting both the efficient supply and efficient use of electricity) is the one adopted in this article.

Jackie Ashley is with the British Columbia Utilities Commission where she focuses on improving the efficiency of both the supply and the demand side of the electricity and gas markets, Prior to joining BCUC she was with BC Hydro and the New Zealand Electricity Authority. She may be reached at jackie.ashley@bcuc.com

Aligning Incentives

Steps to improve the efficiency of the demand side of the market require a source of funding and an entity to deliver the programs. It is important that all parties involved share the same definition of success.

As mentioned previously, companies operating in a competitive environment are generally not in the business of helping their customers use less of their product. This is because the lower sales would typically result in lower profits.

However, regulated companies are different. In their case the regulator determines how much profit the utility is allowed to earn, adds on allowed costs, and then uses an estimate of future sales volumes to set the rates to be charged. The regulator can therefore assure the utility that it will be able to recover the cost of energy efficiency programs in its rates, and can even provide the utility with a financial incentive to run these programs effectively.

For example, where it is cheaper for the utility to meet customers need for energy through energy efficiency programs rather than new supply options, the regulator can require and incent a regulated utility to take on this additional role.

Where it is not possible to fully mitigate a utility's incentive to sell more (rather than less) of its product, or where there is a desire to offer programs that targets more than one fuel source (such as electricity and heating oil) an alternative option is for the utility to provide the funding for energy efficiency programs (and recover those costs in its rates), but for an independent third party to design and deliver the energy efficiency programs. This approach is used in Nova Scotia.

EFFECTIVENESS

Once we have established a definition of 'success' as promoting both the efficient supply and use of electricity, we need to identify where customers are wasting electricity and design cost-effective programs to reduce waste. The following two step approach can be used:

Step One: Is There a Problem?

How do we know when a customer is wasting electricity, for example by continuing to use inefficient equipment or by not using the equipment that they have in an efficient way?

The analysis that identifies where waste is occurring is referred to in British Columbia as a 'Conservation Potential Review'. This starts with a list of alternative investment decisions available to the customer that could improve efficiency (such as investing in efficient motors, lightbulbs, insulation etc.) or customer behaviours (such as turning off lights when not in use).

The Conservation Potential Review then estimates if the cost to the customer of becoming more energy efficient is lower than the cost to the utility of the energy that is being wasted. If the answer is yes, it is then in the public interest to 'nudge' the customer into making that investment decision/behaviour change.

For example, let's say we wanted to find out whether it is in the public interest to 'nudge' a customer into replacing their incandescent lightbulbs with LED bulbs. To do this, we would compare the cost of the LED lightbulb with the value of electricity saved over the expected life of the LED lightbulb. If the value of electricity saved exceeds the cost of the LED lightbulb, it would pass this test.

There are some nuances in this calculation:

- Cost of the investment: this represents the incremental cost to the customer of making the energy efficiency investment (including the cost of their own time) before any incentives are received from energy efficiency programs. If this test is done on the proposed energy efficiency program, it will also include the costs of administering the program.
- Value of energy saved: the value of energy saved is not the reduction in the customer's bill, but the utility's avoided costs. If the energy saved is over the long term, a long-run avoided cost should be used. As the energy saved is at the customer's meter, the value should also include avoided: incremental network losses; network upgrade costs; and generation reserves. Adjustments may also be appropriate to reflect the beneficial seasonal and within-day shape of energy saved.
- Emission reduction: The energy saved is equivalent to 'clean' electricity, and so the value of emission reductions should also be included as a benefit in the calculation. This could be undertaken by pricing the CO_2 saved at an appropriate value, or (as used in British Columbia) valuing the energy saved at the avoided cost of clean electricity.
- Non-energy benefits/drawbacks: Some energy efficiency investments have other non-energy benefits (for example, double glazed windows can offer noise reduction, an insulated house can offer health and comfort benefits). As a result, 'nudging' the customer to make these types of investments can still be in the public interest even if not all the costs are recovered through energy savings. In British Columbia, these non-energy benefits may be estimated and included in the calculation.

  To the extent that there are non-energy drawbacks (for example, where the more efficient product is less aesthetically pleasing to the customer), this can also be considered.

This first test (which can be referred to as a total resource cost test or societal test depending on the inputs used) can be considered an initial screening test. It ensures that the energy efficiency program is 'nudging' the customer into making a decision that makes sense from a societal perspective. There may be some investments that do not pass this initial screening test but which may be still in the public interest – for example, a new technology where costs are expected to decrease in the future. Some level of judgment in interpreting the test result is therefore required.

In undertaking this analysis, it is important that the list of potential new investment opportunities reviewed is kept current. Otherwise there is a 'picking winners' risk where the energy efficiency programs 'nudge' customers to invest in a particular product when there is a better product available on the market.

This test can also be used to determine if it is in the public interest to 'nudge' a customer to switch from a fossil fuel for their energy needs (cooking, heating, power, transportation, etc.) to cleaner electricity. In this case, the test would be to see if the total cost of electricity as defined above (energy, emissions, non-energy benefits/drawbacks) is lower than the total cost of the fossil fuel currently being used.

It is important to note that this screening test does not include the size of any incentive provided to the customer to 'nudge' them into making an energy efficient investment – it therefore only identifies if there is a problem and not whether the energy efficiency program is effective in addressing the problem.

For example, an energy efficiency program to encourage customers to invest in LED lights could include proposals to give away $1, $10 or even $100 with every $5 lightbulb purchased, and these different incentive levels would not affect the results of this first screening test. As a result, even if a program passes this step, it is important to continue to step two below.

Step Two – Can the Utility Fix the Problem?

Once you have identified the investments or behaviours customers should be making to reduce waste (Step One), the next step is to determine if it is cheaper for the utility to 'nudge' the customer to be more efficient in their use of electricity, or to continue to supply the electricity that is being wasted.

This step is typically undertaken in a utility's Integrated Resource Plan (a longer-term outlook of how the utility intends to meet forecast demand), where several energy efficiency portfolio options can be evaluated against supply side options. However, this test can also be performed on an individual energy efficiency program by program basis.

Developing and evaluating energy efficiency programs involves (i) identifying the market barriers preventing a customer from making efficient decisions regarding their energy use and designing programs to mitigate those market barriers (and so 'nudge' the customer into making efficient decisions), and (ii) estimating whether the cost of these energy efficiency programs is lower than the utility's cost of supplying the electricity that is being wasted.

Design programs to mitigate market barriers.

This step requires a very good understanding of the customer in order to identify why they are being inefficient in their use of electricity, together with marketing expertise to determine how best to 'nudge' the customer into changing their behaviour. If the utility does not already have this expertise they will need to acquire it.

Market barriers preventing customers from being efficient in their energy use could include a requirement for a short payback period (for example, a customer desire for a 2-year payback period when the investment's payback period is 4 years). In this case, a program to 'nudge' a customer to make the energy efficient investment might include a utility incentive to shorten the payback period.

Market barriers could also include a lack of information or time, for example where energy efficiency is not a key priority for the customer. In this case, a program to reduce the 'hassle factor' for the customer (such as providing subsidised energy audits and/or energy efficiency managers to commercial and industrial customers) may be appropriate. Other market barriers could include a lack of available product and/or product awareness, in which case working with suppliers and trade organizations can be an effective option. For example, in BC one utility runs a Trade Ally Network program that develops and maintains a contractor network to promote energy efficiency programs and customer messaging.

Low cost ways to encourage increased energy efficiency can also include the utility providing resources to various levels of governments to assist in the development of new codes and standards (such as improved building codes), or the development of rate designs (such as inclining block rates) which can reduce payback periods for customers. In British Columbia, utilities are required to devote a minimum level of their energy efficiency portfolio spending to support the development and enforcement of energy efficiency related codes and standards.

Partnerships with other trusted service providers (such as low-income and affordable housing associations, community groups) can also be an effective way of delivering energy efficiency programs to target market segments.

In addition, while it can be useful to review energy efficiency program offerings of other jurisdictions, programs that work well in one jurisdiction may not always work well in others. There may also be a benefit from developing targeted programs for different customer sub-groups, for example programs offered in rural areas may be more effective if designed differently from those offered in cities.

Customer end-use surveys can also be a useful tool in developing energy efficiency programs for segmented markets. In BC, residential and commercial end-use surveys capture a range of building characteristics, fuel choices and installed appliances, energy-use behaviours, customer economic background and attitudes towards energy issues. This dataset can then be 'sliced and diced' to help design programs targeted at different customer segments.

Evaluate cost-effectiveness of programs.

Once energy efficiency programs are designed, the last part of the effectiveness step is to estimate whether it is cheaper for the utility to 'nudge' the customer into making these energy efficiency investments (or behavioural changes) or supply the energy that would otherwise be wasted. It can be useful to show this test result as a $/MWh or ¢/kWh of energy saved from the energy efficiency program.

Unlike Step One, where we determine if there is a 'problem', the test in Step Two (also called the utility cost test) includes the cost of any incentive provided by the utility. If an energy efficiency program does not pass this test, it could be an indicator that the program is not effective in targeting the market barrier (for example, the market barrier could be around lack of time/information while the program is focused on offering incentives). It could also be that a significant level of the benefits to the customer relate to non-energy benefits (such as improved health or comfort), and so it might be more appropriate for another funding agency (such as the government) to fund this program rather than utility ratepayers.

There are some nuances with this test:

- **Value of energy saved**: the $/MWh value should be the same as that used in Step One.
- **Free-rider adjustment:** There may be some customers who participate in the energy ef-

ficiency program (for example, by receiving a rebate for installing an efficient motor or receiving a subsidized energy efficiency audit), when they would have done this anyway without an incentive. These customers are referred to as 'free-riders', and the energy associated with estimated free-riders should be deducted from the total energy savings estimated to result from the program.

- **Spillover adjustment:** In this case, a customer undertakes an energy efficiency investment or behaviour change because of an energy efficiency program but does not directly participate in that program. An example could be where an energy efficiency program encourages market transformation such that the more efficient product becomes 'business as usual'. The estimated savings from the energy efficiency program can therefore be grossed up for any spillover effect. For example, in British Columbia utilities are allowed to claim a portion of savings from any code or standards towards which market transformation programs were targeted.

If a program passes the utility cost test it demonstrates that it is lower cost for a utility to 'nudge' a customer into changing their behaviour instead of supplying the energy that would otherwise be wasted.

It is important to not discount energy efficiency programs that can have significant benefits (such as advertising or educational programs) just because their energy savings can be hard to measure. Some level of judgment is therefore required. In British Columbia, utilities are required to offer education programs as part of their portfolio of energy efficiency offerings. Other effectiveness considerations in putting together a portfolio include minimizing 'missed opportunities' and maintaining customer and trade relationships.

Lost opportunities occur where there is a limited time window to encourage improved customer efficiency (for example, new building construction or factory retrofit), such that if the energy efficiency investment is not made at that time it can be significantly more expensive to undertake later on. It therefore might be appropriate to include higher cost programs in the portfolio targeted at minimizing lost opportunities. Energy efficiency programs can also benefit from building relationships with partners, such as customers, retailers and trade organizations. It can be useful to ensure that the portfolio includes programs that maintain these relationships.

Another consideration in designing energy efficiency programs is to look at the whole system (such as the whole house or factory) rather than individual measures. An example of this is a British Columbia utility's commercial performance program for existing buildings. This includes funding for energy efficiency audits, funding towards the cost of cost-effective capital investments, and additional bonus funding if the customer successfully implements one or more approved conservation measure In British Columbia, the cost-effectiveness tests can also be applied at the portfolio level (instead of at the program level). This gives the utility increased flexibility to include 'hard to measure' or higher cost programs in its portfolio.

Other Tests

Other energy efficiency program tests include the participant cost test and the rate impact test. While they are not included in the effectiveness considerations above, they can provide useful information:

- **Participant cost test**: this test measures the payback period to a customer of participating in the energy efficiency program – for example, a lighting program could have a payback period of a couple of years. The participant cost test result can be useful in setting the incentive level (for example, if a customer requires a payback period of 2 years before making an energy efficiency investment, the incentive level could be set to provide this). However, the need for a low payback period to 'nudge' a customer into changing their behaviour could also indicate that other market barriers (such as a lack of time or information) might be a more appropriate target of energy efficiency programs.
- **Ratepayer impact test**: this test identifies whether customers who do not participate in an energy efficiency program will still benefit from other utility customers becoming more efficient. Generally, all customers benefit from energy efficiency programs offered to an unprofitable customer (i.e. where incremental revenues do not cover incremental costs). While a utility can use energy efficiency programs to reduce sales to unprofitable customers, a more appropriate action could be to change the rate design such that incremental sales to the customer at least recover incremental costs.
  The ratepayer impact test is, however, used in British Columbia to evaluate fuel switching programs to 'nudge' customers to switch from fossil fuels (for their cooking, heat, power, etc. needs) to cleaner electricity. Utility funded fuel switching programs pass this test when the net income from additional utility sales (revenues less marginal costs) exceeds the utility cost required to obtain them.

BALANCE

The effectiveness considerations above should result in identification of cost-effective energy efficiency programs that 'nudge' customers into reducing their waste of energy.

Assuming the cost of these programs are recovered from all customers through the utility rates, the next step is to ensure that all customers have a reasonable opportunity to participate in them.

This 'Balance' step requires a review of the utility programs by customer group (e.g., residential, commercial, industrial) and/or by region (e.g., rural vs. urban) to ensure that a reasonable level of funding is allocated to each group. Useful metrics to perform this analysis can include energy efficiency spend by customer group as a percentage of group revenue, and energy efficiency MWh savings by customer group as a percentage of group MWh sales. There is no requirement that percentage funding levels are similar for each customer group, however this step will ensure that energy efficiency funding is not just targeted towards the lowest cost customer group.

Balance considerations also require a review of energy efficiency programs to ensure that they include programs specifically designed to target 'hard to reach' customers such as low-income customers and renters. Low-income customers and landlords with tenants who pay the electricity bill are less likely to participate in traditional energy efficiency programs. In British Columbia, there is a requirement that utility energy efficiency programs include programs that specifically target these 'hard to reach' customer segments.

DEALING WITH UNCERTAINTY

It is fairly straight forward to install a meter on a generator to measure the amount of energy generated, but the amount of energy delivered from energy efficiency programs can be harder to measure. This measurement uncertainty can make it harder to obtain funding for cost-effective energy efficiency programs.

The level of measurement uncertainty inherent in energy efficiency programs can, however, be reduced significantly by following established protocols for evaluation, measurement and verification (such as International Performance Measurement and Verification Protocols). If a region does not have expertise in this area, training programs may need to be established.

Lack of adequate metering can also result in measurement uncertainty. One way of addressing this is to develop a 'Deemed Savings Manual' which estimates energy savings for installed energy efficiency measures per unit (e.g., efficient light or pump installed). While this takes some coordination and effort up-front, the results can provide relative accuracy on average. An example is California's Database for Energy Efficiency Resources (DEER).

Some level of uncertainty may also be acceptable where the estimated cost of energy efficiency programs is significantly lower than supply side costs.

Another concern that is sometimes levied on energy efficiency programs is that the customer may change their behaviour after making an energy efficiency investment. For example, an industrial customer may increase their production after they improve the efficiency of their equipment, or a residential customer may set their thermostat to a more comfortable level after improving the efficiency of their home.

In addressing this concern, it is important to look at what is driving the increase in consumption and cycle back to the definition of success outlined above. 'Success' is a reduction in waste of electricity, not just less use of electricity. Provided the customer is not wasting this additional electricity consumed, any increase in consumption can be ignored when it comes to evaluating the cost-effectiveness of the program.

However, if the increase in consumption is due to a waste of electricity (for example, the customer installs LED lights but then leaves them on when not needed), then this waste should be deducted from the estimated electricity savings.

CONCLUSION

Energy efficiency programs that encourage customers to be more efficient in their use of energy can be a low-cost way of meeting a jurisdiction's energy needs.

It is hoped that this article will assist organizations secure funding for energy efficiency programs by providing a 'plain English' overview of how we can ensure these programs are cost-effective and address equity concerns around who pays and who benefits

Utilities can also be a valuable vehicle to fund and deliver cost-effective and balanced energy efficiency programs. As noted by a utility energy efficiency expert in Britsh Columbia, "If we can give utilities the mandate to support energy efficiency and the economic driver, they will pursue it."

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DISCLAIMER

This article does not represent the views or opinions of the BCUC, nor does it express, or intend to express, any opinion on pending or future matters before the BCUC. The analysis and information contained within this paper were compiled personally by the author, and not in a professional capacity as an employee of the BCUC.

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