THE ICER CHRONICLE

A FOCUS ON INTERNATIONAL ENERGY REGULATION

EDITION 8, MARCH 2018

The ICER Chronicle Edition 8 (March 2018)

A FOCUS ON INTERNATIONAL ENERGY REGULATION

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Foreword

In today's world, as in the millennia before, this axiom has lived: Change is the only constant. Those who ignore change around them do so at their own peril, but those who embrace it — who study it, evaluate it and prepare for it — set themselves apart.

We see change all around us in the energy sector. Customers want to play new and more hands-on roles in how they consume and pay for utility service. In the face of changing economic and environmental conditions, governments, utilities, and other stakeholders are evaluating how generation portfolios and market structures must be changed.

As an international community of energy regulators, we must determine the prudency and affordability of all the steps and strategies to respond to change, knowing that our duty is to ensure safe, reliable, and affordable service. This edition of *The Chronicle* highlights how the best and the brightest in our field are navigating the changing energy sector, with an eye toward improved service and a better quality of life for millions of people.

From Mexico, we learn how regulators — in their own words — embraced change as they drafted a comprehensive rule for distributed generation. From West Africa, we explore the progress in implementing a regional market, which offers the promise of increased access and economic development. We also have the pleasure to learn from our ICER 2018 Distinguished Scholar Award recipients about the potential for change in Haiti's power sector and the challenges facing regulators in working with both traditional customers and those who desire more modern conveniences.

I am once again grateful and privileged for the opportunity to highlight respected leaders in our field through our Women in Energy section. In these stories, we hear about the lessons learned from industry leaders who have encountered new opportunities and unfamiliar waters on their career path.

Within ICER, this is also a time of change. I would like to announce that this will be my last edition of *The Chronicle* as ICER Chairman. I want to express my sincerest gratitude for all who have contributed their time and expertise to our efforts these past two years, both within *The Chronicle* and across ICER's work.

As always, we welcome your feedback. Should you have an original article that you think would be of interest for a future edition of *The Chronicle*, please submit it to chronicle@icerregulators.net.

Thank you for your leadership in this time of change and your commitment to sharing best practices internationally.

John W. Betkoski III
ICER Chairman

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Background

In 2013, ICER Virtual Working Group (VWG) 4: Regulatory Best Practices launched the Chronicle as a means to further promote its goals of enhanced exchange of regulatory research and expertise. Under the 2016 restructuring of ICER into three new virtual working groups, the ICER Chronicle continues as a foundational project under ICER leadership.

The ICER Chronicle is published twice a year and selected articles enhance regulatory knowledge around the world. The articles provide a variety of perspectives on different technical topics. It is important to include articles from and of relevance to developing and transitioning economies.

The ICER Chronicle is open to submissions from regulators, academia, industry, consultants and others (such as consumer groups). This ensures a variety of perspectives and increases the exchange of information and messages among the various groups. Submissions will be collected on a rolling basis, in addition to formal Calls for Articles. You are invited to send your article to chronicle@icer-regulators.net.

For past editions of the ICER Chronicle or to start a subscription, please email chronicle@icerregulators.net.

Women in Energy Stories

Share your story in *The ICER Chronicle*

Share your professional expertise by submitting an article on regulatory issues or tell your story for the Women in Energy Story section. Stories can be about anything relevant to Women in Energy (WIE), such as challenges women faced in their careers; pioneering work they have undertaken; obstacles they have overcome, and the lessons that can be shared.

Interested in submitting a story to *The ICER Chronicle*?

Submit your paper (as a Word document) to chronicle@icer-regulators.net.

Watch Women in Energy Interviews

Maia Melikidze:

Part 1: https://www.youtube.com/watch?v=CNgvozCGsNU

Part 2: https://www.youtube.com/watch?v=GkYKU8v11Cc

Gulefsan Demirbas:

https://www.youtube.com/watch?v=mr0rppWBQBE

Women in Energy
The ICER International Network

The Story of the Newcomer

Silviya Deyanova, E-Control

I am currently employed as audit expert in the Tariffs Department of the Austrian energy regulator. Describing what I do and where I work to those unfamiliar with the energy business has always been a challenge. I usually say, in my department we calculate the tariffs, even though the work hidden behind this statement is a complex process that attempts to balance the interests of consumers and the interests of network distribution companies. Since I only started working at the Austrian energy regulator less than a year ago, my story will be that of a newcomer.

October 2013: I remember it was my first accounting lecture at Vienna University of Economics and Business Administration. I entered a classroom, looked around and one thing caught my attention, there were almost only women present in the classroom. Being curious about the matter, I started counting and found that out of 30 people attending the class, 23 were women. This astonishing figure made me reanalyze some of my earlier experiences, such as my first energy management lecture at the University of Vienna, which I attended just about a year before. Back then I did not count the people, but now I am quite certain that of about 50 students in the classroom—more than 70 percent— were men.

October 2015: After I obtained my master's in finance and accounting, I started working at a huge auditing company where I was in charge of auditing energy and utility companies in particular. During this time I had the opportunity to learn a lot and, most importantly, to find out what I really enjoy doing. The actual moment of realization happened when I was auditing one of the biggest DSOs in Vienna. I got so involved with the work that I realized I should focus on the energy sector as much as possible. However, at the time it was very tough to leave financial auditing and completely change career goals.

January 2017: My first audit in the role of the energy regulator was very exciting. I was visiting a small DSO south of Vienna. I entered the conference room where the meeting took place and, somewhat surprisingly, I was the only woman there. All the executives of the DSO were staring at me when I started introducing myself. Maybe they did not take me very seriously at that moment, but by the end of the meeting they were more than surprised and I was able to get all the answers I needed for my audit. My first audit as part of the Austrian energy regulator made me realize how important communication skills are. As a regulator, one should be able to negotiate, to demand information, and at the same time to get the best out of each situation. Since I am a foreigner working for the Austrian energy regulator this has not always been easy for me, but I am constantly working on improving my cultural and communication skills.

Today: I still count myself as a newcomer at the Austrian energy regulator. I have a long and exciting path in front of me, but I will commit my efforts and I will work with the goal of enriching my knowledge.

Work-life balance: In this early stage of my career in energy regulation I have to devote a lot of my time to working, reading, and improving my knowledge of the market and the technical aspects of the business. Time management is extremely important in this case. Until now I have been able to organize my time so that I work hard but still have time for my friends and family. Living abroad does not make this easier, as in order to see my family I need to fly 1,000 kilometers, hence planning is essential, but I know that all my loved ones support me and understand that what I do is very important for my future and for my happiness.

My success: I have always had my 5-year plans. The first one started when I was in high school. My goal was that five years later, I would speak German well and would live in a German-speaking country. I achieved both.

The second five-year plan started when I had already moved to Austria. The plan was to be done with my studies and to have stable job in five years' time. I achieved this as well.

My new five-year plan is to become an expert in the energy field and build my future family. Well, I have five years to achieve this and I will do my best, so that in five years I can look back and I can say: ACHIEVED.

My mentors and inspiration:

During the last years I have met many inspiring people and I have learned a lot. At the beginning of my career, as a part of the world of accounting and auditing, I developed precision and attention to detail and gained a lot of professional knowledge. However, I must say I am very grateful I was able to enter the world of energy, as the people I met on the way not only taught me about technical and energy-specific matters, but also gave me very valuable insights for my personal growth and development.

A couple of months ago, I attended a regulation seminar where I met a girl from Madagascar doing her PhD in electrical engineering in France. When she introduced herself in the auditorium she said that she felt insecure about her future career opportunities in energy, even though in my opinion she was one of the most prominent attendees in the whole seminar. My advice to her and to all young women who pursue a career in energy is not to be afraid. Energy regulation is changing very quickly and there are many strong women who are leaders in the market. They prove that energy is no longer exclusively a man's world, as we all work for a common goal contributing the best of each of us, regardless of gender. Therefore, to succeed, make achievable short-term plans, commit yourself, and achieve them.

Silviya Deyanova

Silviya Deyanova started her career as financial accountant and auditor. Only a year ago she joined the Austrian regulator and currently works in the Tariffs Department as audit expert for gas and electricity distribution system operators. Originally from Bulgaria, she has lived in Austria for six years. Silviya holds two master's degrees: one in finance and accounting from Vienna University of Economics and Business Administration and one in energy management from the University of Vienna.

Women in Energy
The ICER International Network

Growing through Change

Anne Hoskins, Chief Policy Officer at Sunrun and former Commissioner, Maryland Public Service Commission

In 2013 I was appointed to fill an unexpired term on the Maryland Public Service Commission. As that term ended in mid-2016, I wrote an article for ICER, as I looked forward to exploring my next challenge. Now two years later, ICER has asked me for an updated version.

The year 2016 was a time to reflect on the varied positions I had held over my career: energy regulator, energy utility executive, telecommunications lawyer, and governor's policy advisor. I was facing my sixth career transition since I graduated from Harvard Law School, consistent with the experience of an increasing number of professionals in today's economy. In the world of state regulators, the average term for a Commissioner is 3 years—so while regulators often strive to provide consistency and rationality in utility regulation, they must be comfortable with change and uncertainty in their personal lives.

I find career changes both exciting and daunting, but always fulfilling. With each move, I have made new relationships, grown an ever-expanding network of diverse friends and colleagues, and had the opportunity to live in new places. As a mother and wife, I have also always considered the impact of my new opportunities (and related moves) on my husband and our four kids. But in 2016, my move was even more monumental because it coincided with my youngest child's graduation from high school. For the first time, I did not need to worry about finding a good school or about how my children would manage in a new environment. It was strangely liberating. I have gained so much from parenting and would not trade it for anything, but there is no denying that balancing work and family requires tremendous energy. I saw the beginning of a new chapter, one in which I could concentrate even more energy and attention on my professional career.

It's an exciting time to work in the energy field. Perhaps presciently I attended a "women in solar energy" workshop in the spring of 2016 and was amazed to find a room filled predominantly with women younger than 35. They spoke about the tremendous growth underway in their companies, but also about the "ceilings" some of them were seeing. I thought about the importance of ensuring that the new energy economy, spurred by technology and creativity, would embrace the value of diversity and fully engage the large pool of talented young women graduating from business, law, and engineering schools. One of the challenges mentioned by some of the young women was a lack of mentorship and sponsorship. This is where I believe women of my generation need to step up and provide support to younger women who are striving to build careers in the energy industry. Young women need to be encouraged to take chances and to make time to network and build relationships, both within their organizations and beyond. Most of the opportunities I have had in my career came to fruition not just because I was qualified and worked hard, but because I used my networks from previous jobs, college, graduate school, law school, and politics. In fact, women of all ages need to embrace networking as an essential element of career development and not view it as something unseemly or extraneous.

The ICER Women in Energy network provides a valuable mechanism for mentorship for women regulators. During my first year as a commissioner, I signed up for the WIE mentorship program. To my great benefit, I was assigned to work with another new commissioner and we decided to mentor each other. She became a trusted adviser and friend, and someone I could call at any time to work through a challenge.

It was due to networking with another long-time woman colleague that I learned of the opportunity to serve as Chief Policy Officer at Sunrun after my term expired. Sunrun is the leading residential solar and storage provider in the U.S., and is led by a dynamic woman CEO, Lynn Jurich. The timing and opportunity was perfect for me: I negotiated my new position as I dropped my son off at Syracuse University and headed to the West Coast the following month to join Sunrun. I am now leading a dynamic, committed policy team—that includes many young women who remind me of the young women I met in 2016—and helping to pave the way for a cleaner, more diversified energy sector across the country.

As I look back now at my time as a commissioner and NARUC member, one of my most meaningful initiatives involved my role as Chair of NARUC's International Relations Committee. I focused on supporting the work of NARUC's excellent professional international relations staff and sought ways to engage a broader range of commissioners in NARUC's international activities. I encouraged fellow commissioners to pursue exciting opportunities to make contributions beyond their own states by participating in NARUC's international activities. I also shared my experiences of providing regulatory training in Tanzania and Macedonia, and in cooperating with international regulators at the World Forum on Energy Regulation and the ERRA Energy Investment and Regulation conference. In just one year as a NARUC committee chair, I grew into a much more informed international citizen and, in the process, became a stronger leader.

I was thrilled last month to join the NARUC International Relations Committee again, this time as a guest presenter. I spoke about the lessons the U.S. can learn from Australia and Germany in making rooftop solar less costly and more accessible: reducing permitting and interconnection barriers, and ensuring fair compensation for the electricity provided by solar customers to their neighbors. True to my experience as a commissioner, I value in my current role understanding energy policy and regulation from around the world, particularly as we work to overcome global challenges, such as climate change and energy security.

At Sunrun, one of our values is to "be the change you wish to see in the world." Back in March 2016, I had no idea what would come next in my career – or that I would be living and working in California today. But change was inevitable, as my term of service came to a close. I'm happy to report that I have embraced another transition and am working every day to change our world for the better, too.

Initially written 3/2016 and updated 2/2018.

Anne Hoskins

Anne Hoskins serves as Chief Policy Officer of Sunrun, the largest dedicated residential solar and storage company in the United States. She leads Sunrun's policy efforts to expand consumer access to solar energy and deploy local solar energy that modernizes the grid and benefits all grid users. Anne previously served on the Maryland Public Service Commission where she was a member of the National Association of Regulatory Utility Commissioners (NARUC) Board of Directors, Chair of the NARUC International Relations Committee and a board member of the Organization of PJM States (OPSI). Anne also led federal and state advocacy for an electric and gas utility, and served as a Visiting Research Scholar and Instructor at Princeton University, a telecommunications attorney and as a Governor's policy advisor. She is a graduate of Harvard Law School, the Woodrow Wilson School of Public and International Affairs at Princeton, and Cornell University.

Embracing Change While Creating a New Market: A View on Distributed Generation

Montserrat Ramiro Ximénez and Mariana C. Jiménez

When power markets first opened to competition in the nineties, no regulator could have imagined the challenges these markets face today. Distributed generation (DG) and storage were seen as promising technologies, but few believed in their commercial potential, so there was no reason to worry about their impact on generation, transmission, distribution, and supply. However, falling prices of solar photovoltaic modules and batteries have changed the picture completely. Practically all regulators in the world now face the need to reshape their regulatory framework to accommodate these new technologies without jeopardizing the revenue flows of transmission, distribution, or base load technologies, still needed to maintain the system's balance.

Although penetration of distributed energy systems is not as widespread as in other countries, Mexico is not an exception to this global trend. What's more, the opening of electricity markets to competition following the 2013 energy reform is fueling the interest of private companies to invest in these technologies. In fact, the recent experience of Mexico's Energy Regulatory Commission (CRE) shows that distributed energy systems are one of the top interests of private companies and investors' agendas.

The possibility to reduce energy costs, their relatively speedy construction, and the flexibility offered by DG are some of the reasons why companies are interested in these technologies. Moreover, in countries like Mexico, where there is an obligation on clean energy consumption,[1] DG is an attractive alternative to comply with the requirement while becoming a 'prosumer.' At the system level, DG is also considered to provide valuable ancillary services and defers the need for investments in new assets.

At the network level, DG may have opposing effects: on the one hand, DG may reduce distribution and transmission needs during peak hours; hence, decreases the costs of maintaining, upgrading, or replacing these networks in the long run. On the flip side, DG projects located on sites with no system limitation, such as network congestion, might actually lead to additional spending on network assets or procurement of ancillary services to manage frequency variations in the case of intermittent sources [1]. It is crucial that regulation considers factors that lead to one outcome or the other and creates market signals for participants and investors to ensure DG deployment is beneficial for the system.

With this in mind, CRE has worked recently to define *'Abasto Aislado'* (translated as 'Isolated Supply'), a legal figure for energy generated or imported to meet onsite needs, or for exporting, without using the National Transmission Network or the General Distribution Network. In other words, the instrument to regulate distributed generators including embedded, behind the meter and even off-grid systems.

In this article, we discuss the main concerns and outcomes faced by the Mexican regulator in the process of drafting a comprehensive DG regulation, with the purpose of contributing to the global debate on how to integrate and cope with distributed energy in the electricity markets of the future.

What is Distributed Generation?

The definition of DG varies across jurisdictions (Table 1). Hence, throughout the article we will abide

1. Mexico has the following legally binding goals in terms of clean energy generation: 35 percent by 2024, 37.7 percent by 2030, and 50 percent by 2050.

by the definition presented by Ackerman et al. in 2001, that is, "Distributed generation is an electric power source connected directly to the distribution network or on the customer side of the meter." [2]

Table 1—Examples of Definitions Given to DG or Distributed Energy Resource across Different Markets

Institution or regulator	Definition
North American Electric Reliability Corporation (NERC, United States of America)	"A Distributed Energy Resource is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric Systems [3]."
Office of Gas and Electricity Markets (OFGEM, Great Britain)	"DG is also known as embedded or dispersed generation. It is electricity generating plant that is connected to a distribution network rather than the transmission network [4]."
California Energy Commission (CEC, United States of America)	"Electricity production that is on-site or close to a load center and is interconnected to the utility distribution system [5]."
Energy Networks Association (ENA, Australia)	"Distributed or embedded generation is any form of generation which is connected to (or embedded in) an electrical distribution networks [6]."
Joint Research Center of the European Commission (JRC, EU)	"DG is an electric power source, connected to the grid at distribution level voltages, serving a customer on-site or providing support to a distribution network [7]."

Mexican law uses a specific figure called '*Generación Distribuida*,' which literally translates into *Distributed Generation*, but it only encompasses generation systems up to 500kW of capacity, leaving out medium and large-scale systems that could fit perfectly in the DG definition we adopted. CRE published the regulation for this particular figure in February 2016, including three compensation schemes[2] that were positively received by users. Although we believe '*Generación Distribuida*' is a much needed and popular figure in the Mexican regulation that promotes small-scale distributed technologies such as residential solar panels, the definition proved too restrictive for the broader discussion about the risks, challenges, and benefits of moving toward a more decentralized energy system.

As mentioned before, *Abasto Aislado* is the other figure where the particularities of distributed generation are recognized in Mexican post-reform regulation and will be the focus of the present article. Mexican legislation previous to the reform allowed for other legal schemes that could fit DG projects ('*Cogeneración*' and '*Autoabastecimiento*'), but as permits of this kind are no longer granted, we will not discuss them any further in the present article.

Net versus Gross Charging

One of the most polemic issues in the discussion on how to recognize Abasto Aislado's particularities was whether to charge for network usage and other related services, on a net or gross basis. This issue only concerns systems interconnected to the national electric system for the purpose of buying or selling energy or using the grid as a backup. Off-grid systems, of course, are exempted from these charges.

Supporters of net charging, that is charging of transmission and distribution services only for the energy that was injected or extracted from the grid, argue that this type of charge recognizes the positive impact that reducing demand at the point of consumption has on overall system performance. In this sense, energy under *Abasto Aislado* is perceived as 'negative demand' instead of generation.

According to this vision, the Commission agreed that the following services will be charged on a net basis for systems in *Abasto Aislado:* transmission and distribution services, market operation and system control services, surveillance costs, ancillary services outside the wholesale electricity market such as reactive reserves, reactive capacity, emergency starting services, island operation, and dead bus connection.

We are convinced that net charging is the right approach, as the impact on the network is defined for

2. The three allowed compensation schemes are net metering, net billing, and total energy sales.

what is going in and out at the point of connection, not behind. This approach is used in other markets and supported by specialized studies such as the 'Utility of the Future' 2016 report from the Massachusetts Institute of Technology Energy Initiative: *"Cost-reflective electricity prices and regulated charges should be based only on what is metered at the point of connection to the power system-that is, the injections and withdrawals of electric power at a given time and place, rather than the specific devices behind the meter."* [8]

Nevertheless, there is still concern that other issues, such as locational signals or a potential capacity cap for accessing net treatment, were overlooked. The worst-case scenario may lead to inefficient investments and increased system costs. Furthermore, as it is currently defined, *Abasto Aislado* does not provide additional payments—as other markets do—to recognize distributed generators that help defer transmission investment.

International Experience

The international experience reviewed for this article shows that in advanced markets DG systems are subject to net treatment on charges, such as transmission network use or ancillary services. A summary of the benefits given to embedded generators in other jurisdictions is presented in Table 2 based on the findings of Frontier Economics' 2006 report [9].

Table 2—Treatment of Charges for Embedded Generation Systems in Different Markets (2006).

Countries	Net/Gross for Reserve, Ancillary & Market Admin Charges	Cap on Net Treat-ment	Date commenced
Australia	Net	None	NEM start (1998)
Great Britain	Net	100 MW	Pool start (1990)
PJM (US)	Net	1,500 MW	May 6 Order (2004)
New Zealand	Gross	-	NZEM start (1996)

In the case of network charges, according to the same report, Australia and Great Britain used to charge on a peak demand (MW) and net consumption basis (MWh). This arrangement was supposed to ensure that peak demand-based charges recovered network long-run costs, whereas net consumption-based charges reflected potential savings on upstream costs, such as avoided network expansion [9].

DG Payments in the UK: Continued but Reduced

Great Britain's energy regulator, OFGEM, has recently reviewed its mechanism and changed its transmission charging arrangement for embedded generators below 100MW capacity. Under the former mechanism, eligible generators were paid by suppliers—Transmission Network Use of System (TNUoS) Demand Residual Payments—for generating energy during triad periods, that is the three half-hour periods of highest transmission demand between November and February, separated by at least 10 days. Moreover, embedded generators in this range were also not charged for TNUoS generation residual or Balancing Services Use of system (BSUoS) generation charges, being only charged for BSUoS demand charge payments on a net consumption basis [10].

An assessment performed by OFGEM showed that TNUoS Demand Residual Payments (TDR) were costing regular customers 370 million GB pounds per year (around 490 million US dollars), a quantity that could nearly double by 2021 if no actions were taken [10]. After a consultation and review process, OFGEM finally decided to reduce the level of TDR payments for embedded generators under 100MW capacity. The rest of the benefits provided to these generators remained unaffected by OFGEM's recent decision. The regulator has already announced its intentions to review them to fairly reflect the fact that, even if it is only a few times, DG uses and benefits from the network and should contribute to recover its sunk costs through fair residual charges [11].

Takeaways from Australia

Australia has undergone a series of changes to its National Electricity Rules (NER) to incentivize efficient investment in, and use of, DG. These adjustments aim at recognizing that value of investments in non-network solutions, such as DG, depends on different aspects. Hence, Australia's NER now allow for cost-reflective distribution and consumption network tariffs, network support payments for embedded generators up to 5MW, avoided TNUoS charges, regulatory investment test for distribution and transmission, capital expenditure sharing scheme, the efficiency benefit sharing scheme, and the small generation aggregator framework [1].

Regarding avoided TNUoS charges, the Australian Energy Market Commission recognizes that if a customer reduces its consumption from the network at peak hours by installing DG, he should pay lower network charges as this entails a benefit to the system. However, the Australian Commission acknowledges that these benefits are highly dependent on the generator's ability to meet any on-site demand, or to export electricity, when the network is constrained. In contrast, if DG is located on areas with plenty of network capacity and no system limitations, it might actually increase network costs, representing a risk instead of a benefit to the grid [1].

Back to the Mexican Case: Is Asset's Ownership Relevant?

According to the Mexican law, the power generated or imported through the Abasto Aislado scheme is exclusively to meet a load's 'needs.' Hence, to narrow the concept of someone's 'needs,' CRE determined that to be considered *Abasto Aislado*, the load and the generation asset must be owned by the same person or by different members of one corporate group.

Feedback from the industry pointed out that this definition could curb access to financing for some projects, and leave out successful business models, such as leasing and service-based schemes promoted by Energy Services Companies (ESCOs). In fact, the 2014 report of the Energy Center of Wisconsin, 'Third-Party Distributed Generation: Issues and Challenges for Policymakers," states, "In physical sense customer-owned and third party distributed generation systems are often indistinguishable. Yet, the third party ownership option is a critical factor in that it provides financing flexibility to customers interested in on-site generation." [12]

Moreover, CRE realized that this interpretation of *Abasto Aislado* did not acknowledge that most distributed energy users are not involved—and have no interest—in entering the business of electricity generation and retailing, therefore, being more willing to enter in third-party ownership business models with companies such as ESCOs.

To overcome this issue, CRE defined an additional scheme under the Generation figure, named *'Generación Local'* or 'Local Generation.' *Generación Local* acknowledges the benefits that generating electricity near the consumption point might add to the system, without regard to the ownership of the generation asset. Under this definition, it is also possible to share the electricity produced with other companies (not necessarily members of the same corporate group) near the production site through a private network. Generation systems under Generación Local are subject to the same net treatment as that of Abasto Aislado, which has been already explained in this article.

Nevertheless, *Generación Local* is also subject to additional requirements. For instance, the transactions between the distributed generator and the consumers must occur through a qualified supplier,[3] current market rules require all users (with the exception of market participant qualified users) to be represented in the wholesale electricity market. Even considering the case when the electricity produced and consumed never leaves the private network, its 'sale' would still need to be done through a qualified supplier as the law does not explicitly exclude this type of deal from being a wholesale market transaction, contrary to the case of *Abasto Aislado*.

However, is it necessary to have a qualified supplier in this transaction? What are the actual benefits to consumers and to the system as a whole? Are these benefits worth the extra costs set on consumers from *Generación Local*?

We believe the asset ownership requirement to qualify as *Abasto Aislado* is not as efficient as using other requirements to set aside large scale DG from traditional generators. Frontier Economic's report said *"In our view, the merits and demerits of the various options discussed above for recovering costs do not depend on whether the embedded generator and load are located on the same premises or are owned by the same person. Ownership and proximity of the embedded generator are only relevant to the policy issue of 'what is transmission'."* [9]

3. Under Mexican law, a qualified supplier is the electricity supplier that serves end users with a load or an aggregation of loads with over 1MW capacity.

Embracing Change to Move into the Future

The 2013 energy reform introduced two new figures where DG projects could fit in Mexican regulation: *Abasto Aislado* and *Generación Distribuida*. Both of these figures were defined in the law with certain specifications: a 500kW capacity limit for *Generación Distribuida* and the condition to meet individual needs in the case of *Abasto Aislado*, which led to the creation of a new figure within the existing Generator figure called *Generación Local*. The latter is an effort to recognize business models common in DG projects, but unable to enter in the definitions established by law.

Considering all these findings, we would like to put forward the following recommendations aimed at rethinking the way DG is currently defined and regulated in Mexico. The objective is to be more effective and cope with the potential disruption from higher penetration of distributed technologies:

1. Unless we have more evidence that asset ownership requirements have a positive impact on the market and on network's performance, we should stay open to propose redefining *Abasto Aislado*—as the legal figure that comprises distributed systems over 500kw—so that it does not preclude alternative property arrangements and business models.

2. Consider recovering the name *Generación Distribuida*, leaving systems under 500kW capacity with its associated benefits under a special category within this scheme, for instance, *'Micro y Pequeña Generación Distribuida'* ('Micro and Small Energy Generation' in English).

3. Distinguish between systems connected to the distribution network and those located behind the meter as both have different implications on the system's performance and on associated network costs and potential savings. Probably through a capacity cap (e.g., 100MW in the UK or 20MW in California) defined by a thorough evaluation of the national network's characteristics and performance.

4. Acknowledge net treatment to be a reasonable approach for charging ancillary or network services only in conjunction with locational signals. Currently, we do not think that *Abasto Aislado*, *Generación Local*, or even *Generación Distribuida* effectively take into account this aspect. Location is a relevant factor to recognize DG benefits but also its costs.

5. Evaluate the implementation of a capacity-based fixed charge to ensure Transmission and Distribution Network Operator recover sunk costs, even if distributed generation increases considerably.

6. Assess the possibility of implementing a financial scheme to pay distributed generators that are in fact contributing to long-term reductions in network construction, maintenance or substitution costs. An evaluation mechanism to identify these generators and estimate the long-run cost reductions associated with them needs to be done simultaneously.

We are fully aware of the regulator's responsibility to send stability signals to the market. We also believe regulation is a living entity that needs to evolve so it can better accommodate new technologies and business models that promote higher market efficiencies, and thus better prices for end users. We believe regulators should not be afraid of making changes, as long as these are thoughtful and aimed at improving efficiency and benefits to consumers.

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Perspectives in Regulating a Regional Electricity Market: The ECOWAS Experience

Ifey Ikeonu, Energy Policy & Regulation Consultant

Introduction

The Economic Community of West African States (ECOWAS) is made up of 15 countries of West Africa, including Benin, Burkina Faso, Cabo Verde, Cote D'Ivoire, Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, and Togo.

West Africa as a region is blessed with enormous natural energy resources for electricity generation including vast oil and gas reserves to be found primarily in Nigeria, Cote D'Ivoire, and Ghana; huge hydro resources in countries like Ghana, Nigeria, Mali, Niger, and Guinea; coal reserves in Nigeria and uranium in Niger. In addition, other renewable energy sources like solar and wind abound in the region. Generally, Africa as a continent has the cumulative highest sunshine hours annually with more than 85 percent of the continent's landscape receiving a global solar horizontal irradiation at or over 2,000 kWh/(m2 year).

In spite of these resources, ECOWAS has continued to suffer huge deficit in electricity supply and has not being able to convert these huge potentials into actual electricity for the teeming populace as average electricity consumption per capita is about 118kWh.[1] ECOWAS has an average access to electricity rate of about 38 percent,[2] one of the lowest in the world.

It was therefore in a bid to harness the huge energy resources within the region and translate the potential into actual energy to fast track the socioeconomic development of the region that the ECOWAS Authority of Heads and State and Government, in 2003, approved the ECOWAS Energy Protocol.

WAPP at a Glance

Total Population of West Africa	348,631,936	million
Average Urban Electricity Access Rate	51.39%	
Average Rural Electricity Access Rate	13.48%	
Average Regional Electrification Rate	29.16%	
Average Cost of Electricity in WAPP ($)		
Electricity Generation		
Total Installed Capacity Hydro/Thermal (GW)	5	16
Ratio of Hydro/Thermal Asset	22%	78%
Total Available Capacity Hydro/Thermal (GW)	3	9
Total Hydro Energy Generation (TWh)	17	
Total Thermal Energy Generation (TWh)	43	
Ration of Hydro/Thermal Energy Generation	27%	72%
Total Renewable Energy Available (GWh)	6	
Transmission Infrastructure		
HV Transmission System 330 kV - 60 kV of 800 Transmission Lines	15,000 km	
Number of Substations	600	
Number of Power Plants (Hydro & Thermal)	200	

Source: B. Adeyomo WAPP Presentation 2017

The ECOWAS Energy Protocol

The ECOWAS Energy Protocol of 31 January 2003 articulated a vision of establishing a framework for investment in energy and long-term energy trade within the region to support the following regional goals:

- Increased access to energy
- Stable, affordable, reliable & sustainable electricity supply
- Achieving the Millennium Development Goals
- Peace and security

The achievement of these goals is to be driven by balanced development of the diverse primary energy resources of the ECOWAS member states for the mutual benefit of the region leveraging on economy of scales.

Member states were also mandated to ensure long-term cooperation in the energy sector and unfettered access to energy transmission networks to facilitate and sustain increased cross-border electricity trading among member states. The Protocol also provided for the creation of regional institutions and agencies required to achieve the set objectives, including the creation of a regional electricity regulatory body.

Establishment of Regional Bodies for the Impementation of the Energy Protocol

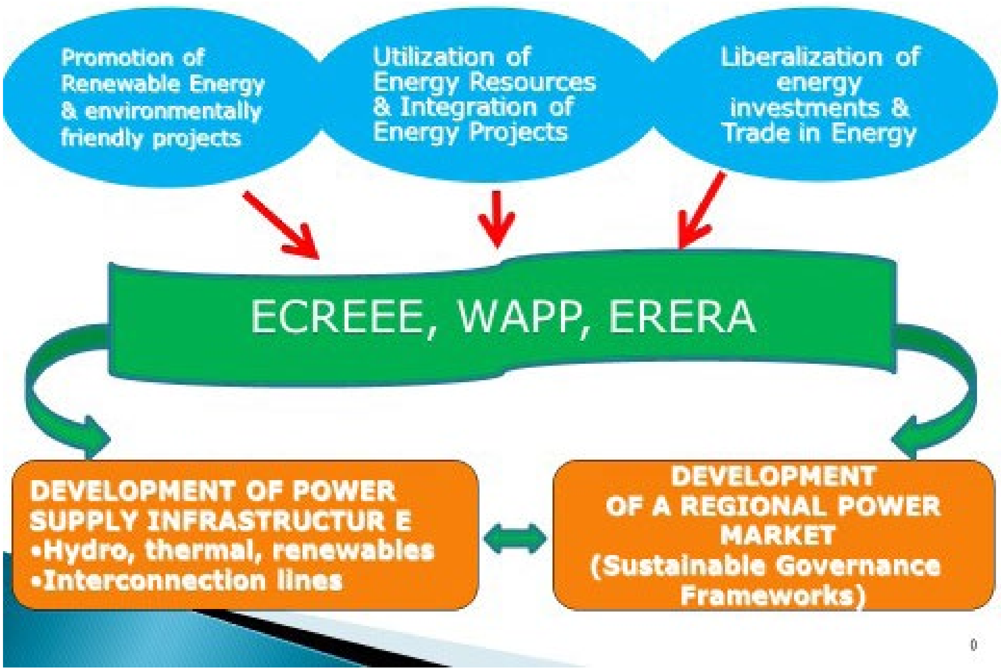
In furtherance of the implementation of the Energy Protocol, four regional bodies were established to drive the regional integrated energy programme. These are the West African Gas Pipeline Authority (WAGPA), the West African Power Pool (WAPP), the ECOWAS Regional Electricity Regulatory Authority (ERERA), and the ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE). The roles of WAPP and ERERA are discussed below.

3.1 The West African Power Pool (WAPP)

The West African Power Pool is a specialized institution of ECOWAS established in 2006. WAPP's primary mandate is to facilitate the integration of regional power systems towards the realization of a regional electricity market. It is therefore responsible for developing the regional electricity master plan and implementing the regional electricity interconnection projects. WAPP is made up of public and private generation, transmission and distribution companies involved in the operation of electricity in West Africa.

WAPP plays a very active part in promoting new investment in transmission and generation in the

ECOWAS Vision: Energy Protocol

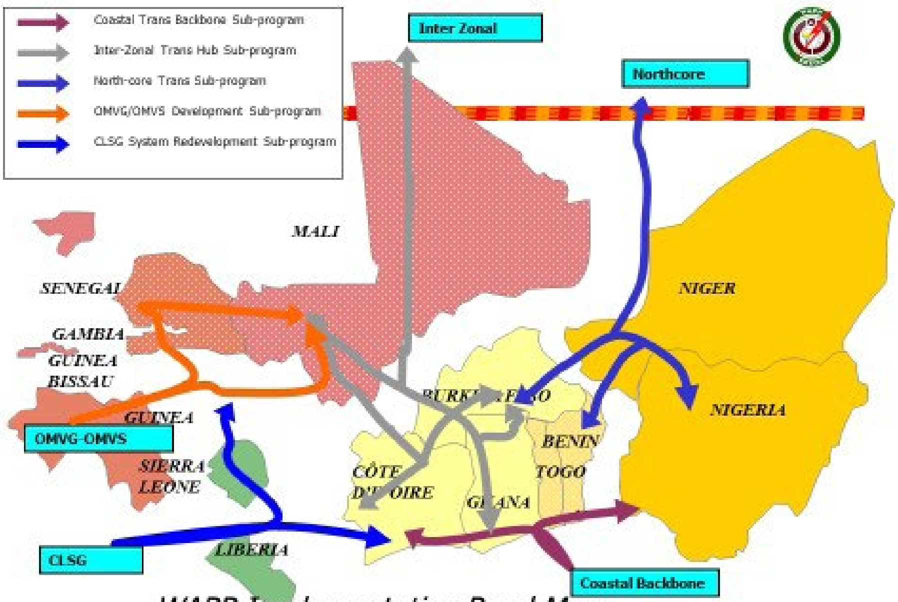


regional market and has been instrumental to the development of a number of regional transmission projects to improve interconnectivity among member states. A number of interconnection projects are already in existence, while there are plans in place to construct new interconnections to ensure that the entire sub-region is completely looped.

The existing and proposed interconnections are shown below.

3.2 The ECOWAS Regional Electricity Regulatory Authority (ERERA)

ERERA was established in 2008 as a specialized Institution of ECOWAS with the mandate of regulating cross-border electricity trading among member States and creating a conducive and enabling environment to attract private sector investment into the regional electricity market.

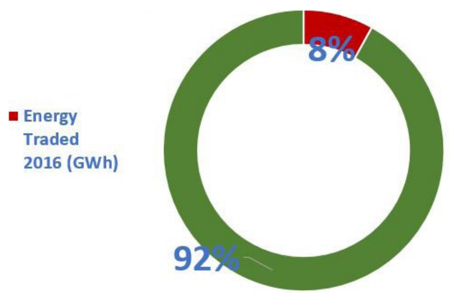


WAPP Implementation Road Map

WAPP is currently working on a number of regional transmission network projects, including the Ghana–Burkina Faso interconnection, the Cote d'Ivoire-Sierra Leone-Liberia-Guinea (CSLG) Interconnection project, as well as the OMVG (Gambia-Guinea-Guinea Bissau-Senegal) project.

Currently, electricity trading among member states is quite low accounting for less than 10 percent of total energy generated.

Percentage Trade of Total Energy Generated



Source: B. Adeyomo WAPP presentation 2017

ERERA's Role as Regional Regulator

ERERA has the novelty of being one a couple of regional electricity regulators in the world. Indeed, the only other regional regulator similar to ERERA is Comisión Regional de Interconexión Eléctrica (CRIE), the Regional Electric Interconnection Commission of Central America, which was created under the Framework Treaty of the Central America Electricity Market. The treaty was entered into by the governments of Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, and Panama for an electrical interconnection system for Central American Countries (the SIEPAC Project).

Similar to the vision behind the creation of the West African Power Pool, SIEPAC was conceived to stimulate the creation and consolidation of a regional electricity market through the promotion and establishment of legal, regulatory, and technical mechanisms to facilitate the participation of the private sector in the build-up of generation and transmission infrastructure for improved cross-border electricity trading between the various countries.

CRIE, like ERERA, is guided by the principles of gradualism, competitiveness, and reciprocity in the development of the regional electricity market.

However, whereas the mandate of CRIE as regional regulator appears to be limited to providing the regulatory framework required for the implementation of the SIPEC project, the mandate of ERERA as regional regulator is wider as it is has powers to intervene in every aspect of the regional electricity market to ensure conformity with the regional rules and upon invitation, to also offer national regulators assistance on technical issues. The overall mission of ERERA as provided by the Regulation on its operations[3] includes:

- The regulation of cross border power trading among ECOWAS member states
- Overseeing the implementation of the necessary conditions to ensure availability and reliability of electricity
- Ensuring a conducive regulatory and economic environment suitable for the development of the regional market

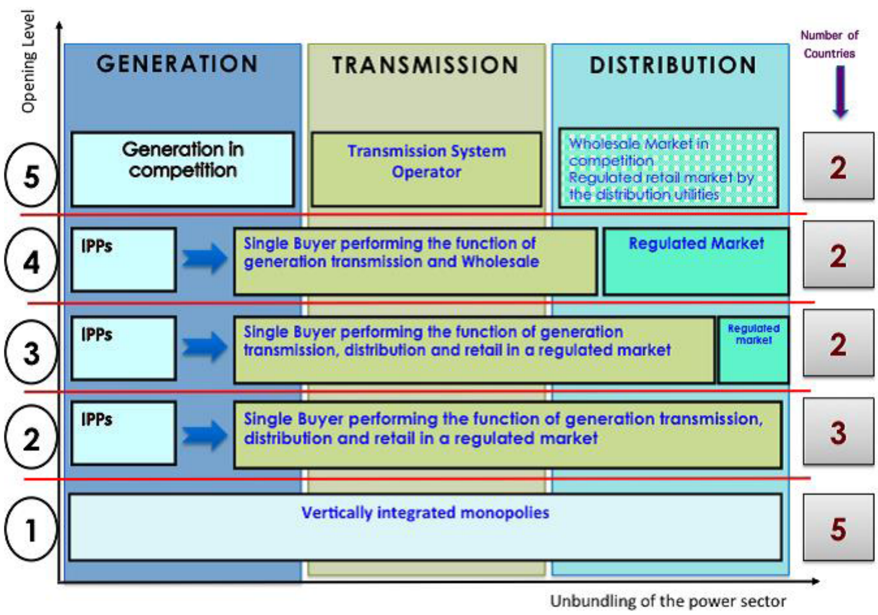
Accordingly, ERERA's mandate allows it to set rules for both the technical and economic regulation of all cross-border electricity trading within the ECOWAS region. In addition, it is also responsible for ensuring the development and monitoring of the regional electricity market and is equally vested with quasi-judicial powers to resolve disputes among market participants. In addition to its role on the regional market, ERERA also has powers to, upon request, assist member states as well as national regulators on technical issues with respect to domestic regulation. All of these attributes contribute to the uniqueness of ERERA as a regional regulator and it is doubtful if there is currently any other regional regulator vested with as much powers with regards to a regional electricity market.

Status of the Domestic Electricity Sectors Within ECOWAS

The creation of a regional market consisting of countries with varying and wide differences in the status of their national markets has been a major challenge in the setting up of the ECOWAS regional electricity market. The 14 countries involved in the West African Power Pool (Cabo Verde, an Island, is not part of the interconnected system) range from very small countries with vertically integrated state owned utilities to partially unbundled systems and on to countries such as Nigeria that have fully unbundled and privatised the erstwhile state-owned power companies.

ERERA, in 2012, had to perform initial studies to assess the status of the power sector in all member states to establish a strategy for a way forward. The result of the study showed that the member states could be categorized into four different groups in terms of the level of reform and private sector participation in the electricity sector. The categories are summarized graphically in Table 2.

Table 2: Status of ECOWAS Domestic Power Sectors in 2012



This disparity in the levels of development of the various national markets on the face of it constituted a major impediment to the development of the regional electricity market as it was obvious that without a basic degree of harmonization by all member states, an integrated electricity market will be difficult to establish and operationalize. Consequently following a number of stakeholder consultation, a number of minimum criteria were identified that would form the initial basic framework for harmonization of policies and legal framework by the 14 member states to allow for the effective takeoff of the regional electricity market. These minimum criteria were captured in the legal document known as the Directive on the Organisation of the Regional Electricity Market enacted by the ECOWAS Council of Ministers on 21st June 2013.[4]

Directive on the Organisation of the Regional Electricity Market

Article 19 of the ERERA Regulations stipulates clearly the Principles that will govern the regional electricity market and further empowers the ECOWAS Council of Ministers to enact the necessary Directive that will inculcate these Principles and make them binding on all member states. The objective of the Directive is to define the general principles that will govern the Regional Electricity Market within the framework of the ECOWAS Energy Protocol.

Accordingly, the Directive addressed the following issues:

a) Market design:

In line with the principles of the ECOWAS Energy Protocol, the Directive provided that the development and establishment of the regional electricity market shall evolve in three (3) phases according to the Regional Market Rules[5] approved by ERERA. The Market Design, which has since been approved by ERERA, provides for three distinctive phases. The first phase consists of trading by way of bilateral contracts (using approved model contracts), which can be short, medium, or long term.

The second phase of the market will consist of a mixture of bilateral contracts and short-term, day-ahead market. Eligible customers will be able to enter into cross border power purchase contracts with generators and transmission tariffs will be guided by the approved methodology.

The third and final stage envisages that the market will be fully liquid with sufficient regional transmission capability and excess generation capacity in some countries. This will ensure a completely deregulated wholesale electricity market.

Each of these stages will be preceded by the completion of agreed conditions precedent to signal the preparedness of the member states and market participants to fulfill the requirements for the effectiveness of each stage.

With the completion of most of the conditions precedents for the commencement of Phase 1 of the regional market, it is anticipated that the official commencement of the market will be declared early 2018.

b) Structure of National Electricity Markets:

A previous study performed by ERERA revealed that not only were the electricity utilities in most of the member states vertically integrated, it was also clear that in the short term, theses utilities will not be vertically unbundled due primarily to their very small sizes and need for economies of scales. It was also apparent from the studies that there was no separation of costs in accounting for the various segments of the business (generation, transmission, and distribution). It was, therefore necessary to ensure that at the very least, all member states will ensure clear cost unbundling along functional lines to allow for transparency and effective allocation of costs, needed for tariff determination in the electricity market. To this end, therefore, the Directive provided that all member states shall ensure that their existing Electricity Acts and relevant regulations be amended to provide for functional separation of accounts in terms of generation, transmission, and distribution segments.

Some of the countries have commenced action in this area but it does appear that there are real challenges with the required technical capacity coupled with the fact that there is a reluctance to change from the historical accounting model that these utilities have been used to over the years.

c) Regional Transmission Network Open Access:

An obvious prerequisite to the off-take of a regional electricity market is open access to the regional grid. Again, a result of the study by ERERA prior to the enactment of the Directive revealed that of the 14 WAPP member states, only Nigeria and Ghana had laws that allowed for open third-party access to the transmission network. The market principles have also envisaged the participation of major eligible customers in the regional market during Phase 2 and thus the need to provide for third-party unfettered access for this class of customers. Again, most of the existing national legislation in the member states had no provision for determination of eligible customers and consequently, no provision for open access to such customers.

The Directive, therefore, provided for member states to amend their laws to allow for open access to the transmission network on the one hand, while also providing for third-party access to eligible customers on the other hand.

Although a number of member states have amended their laws to allow for third-party access especially with regards to the participation of IPPS, the issue of eligible customers still remain a challenge, as only Nigeria and Ghana have rules allowing for the participation of eligible or bulk customers in the national electricity markets. ERERA also is working on a guideline to assist member states in this area.

d) Harmonization of Contracts:

The market design for the Phase 1 of the Regional Electricity Market provides for trading amongst market participants to be basically by way of bilateral contracts. Currently, the level of cross-border electricity trading among member states is quite low (8 percent) of total power generated in the region.

Whereas West Africa as a region has a long history of cross border electricity trading, the contractual frameworks for most of these transactions were borne more out of political expediency than the need to have in place a commercially viable contract. With the ongoing reform in most of the counties, it has become imperative to review these contacts to make them more sustainable and to also ensure that all new contract are legally structured in line with the emerging regional electricity market.

A number of member states have previously approached ERERA as regional regulator to provide assistance to them in the negotiation of Power Purchase Agreements. This dearth in capacity, therefore, made it necessary to entrust ERERA with the mandate of developing model bilateral contracts for power sales/purchase, as well as developing standard connection and use of network agreements. After consultations with stakeholders, ERERA, working with WAPP, developed the model bilateral contracts. A standard Connection and Use of Network Agreement for access to the Regional Grid and WAPP Operational Manual[6] have also been developed by WAPP for approval by ERERA.

e) Strengthening of National Regulatory Authorities:

ERERA's role as regional regulator is complemented by the role of the national regulators as the regional market itself can only be sustainably established based on the viability of the domestic markets. In 2012 when ERERA carried out its regulatory studies on the current state of the power sector in the ECOWAS region, 11 of the 15 member states had in place regulators for the electricity sector, whereas four of the countries had no regulators.

For the 11 countries that had regulators in place, most of the regulators did not have the requisite powers to perform core regulatory activities such as tariff setting and market monitoring. Furthermore, most of the regulatory bodies were under-funded and lacked the requisite human and technical capacity to function effectively.

In view of the key role regulation and governance has to play in the successful development and functioning of the regional electricity market, the Directive provided that not only are all member states required to establish independent electricity regulatory agencies, all such bodies (including the existing ones) are to be given the required financial support and powers to undertake key regulatory activities including tariff setting and market monitoring.

Currently, all but one of the 15 ECOWAS Member States have now established regulatory authorities for the electricity sector (a number of them are multisectorial regulators). There have also been steps by some of the countries such as Senegal, Cote d'Ivoire, and Burkina Faso to amend their existing laws to strengthen the capacity of the regulators.

f) Tariff Methodology:

In line with the regulation on the organization and operation of ERERA, the Directive empowers ERERA (following consultations with stakeholders) to approve the cross border transmission electricity tariff methodology.

It also stated that cross-border transmission tariff for new contracts will be determined by the approved regional transmission pricing methodology. ERERA has approved the transmission methodology[7] based on the Mw-KM load flow.

g) Support for Implementation of Directives

The successful development of a regional market requires the collaboration of all key stakeholders, especially the state actors. To this end, therefore, the Directives enjoin all national regulators to support ERERA in the implementation of the Directives at the various national levels.

Member states were also given a time frame of 24 months within which to comply with the provisions of the Directives. States that are unable to comply within the stated timeframe or face peculiar challenges in the implementation of the Directives were also required to inform ERERA of any challenges being faced in implementing the Directives.

ERERA has enjoyed a lot of support on the implementation of the Directives from the various State Actors as can be seen in the collaboration process that saw ERERA working with the Governments of Guinea, Sierra–Leone, Benin, and Liberia to assist in establishing their regulatory commissions. The ERERA Consultative Committees of Regulators and Operators, respectively, consisting of representatives from all member states, have also been instrumental in assisting ERERA to develop all the rules, regulations, and orders necessary for the commencement of the regional market.

Challenges

The development of the ECOWAS Regional Electricity Market has not been without its peculiar challenges. One of the major challenges is the wide disparity in the status of the various national markets with regards to the reform and operations of the domestic markets. Whereas some of the sectors are fully unbundled and privatized in some cases, there are other countries that do not have even any form of private sector participation.

The issue of adequate generation, transmission and distribution infrastructure still remains a major handicap as no single country in the ECOWAS inter-connected system is energy sufficient and neither is the current transmission grid sufficient and robust enough to support the market.

While there has been significant reform in the electricity sector in a number of member states, there still remains the need to quicken the pace of reforms to at least support a minimum level of harmonization that will support the development of the regional electricity market.

Conclusion

The ECOWAS regional electricity market, which was conceived to facilitate the harnessing of the huge energy resources in the region to improve access to electricity and act as a catalyst for the economic and social development of the region, has so far recorded a number of successes even though it will take a long time to achieve all the key objectives.

One of the key factors that have facilitated this regional integration initiative is a shared regional vision that has manifested in the political will among all member states to take the necessary actions.

The need for a clear and transparent institutional and legal framework for the implementation of the regional market has been critical in driving this initiative. ERERA as regional regulator was given full legal capacity to establish and promote the regional market. This has made it possible to put in place a clear and definitive roadmap for the realization of this regional vision.

Collaboration with national stakeholders in the electricity market is a key factor for the efficient operation of the regional market. In the case of ECOWAS, ERERA has through the establishment of the Consultative Committee of Regulators and Operators, created an effective dialogue platform to discuss pertinent issues relating to the regional electricity market.

Although some successes have been accomplished, it is still important that pressure is brought to bear on national governments that have been slow in carrying out the reform programme in some of the countries to fast track these initiatives. Without the acceptable level of harmonization envisaged by the Directive on the Organization of the Regional Electricity Market, it will be difficult to move to other stages of the regional market development. If the reforms triggered by the establishment of the market are pursued assiduously, then the ECOWAS region may well be on the right path to increasing access to electricity, which will in turn jump-start the much-needed economic and infrastructural development within the region.

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Cost Benefit Analysis of Power Sector Reform in Haiti

Juan A. B. Belt (Lead Author), Nicolas Allien, Jay Mackinnon, and Bahman Kashi

June 27, 2017

This study was performed by a team from Limestone Analytics (www.limestone-analytics.com) with financial support from Copenhagen Consensus Center under Haiti Priorise Project.

The intervention proposed in this study was selected as the best project for Haiti among 85 submissions by an eminent panel of economists at Haiti Priorise (http://www.copenhagenconsensus.com/Haiti-Priorise).

The International Confederation of Energy Regulators (ICER) voted to award the authors the 2018 ICER Distinguished Scholar Award in the category of Impact on Developing Countries.

Acknowledgments

We would like to thank Dr. Allen Eisendrath (USAID) for providing data on the reform program of the Kabul Distribution Company (DABS) and for the Haiti power sector, and for many useful discussions over the years on management contracts and their potential for turning around utilities. We would also like to thank Jeremy Foster and Jeffrey Haeni for providing us with additional information on Haiti. We are grateful to the Copenhagen Consensus Center for financial support for the development of this paper. All errors remain with the authors.

Academic Abstract

This paper argues that to improve the power sector in Haiti, which now constitutes a critical constraint to economic growth, it would be necessary to carry out a significant regulatory and utility governance reform; without these reforms, any physical investment program would be ineffective and unsustainable. Haiti has the most underdeveloped and inefficient power sector in the Americas. Numerous past attempts to reform it have failed due to lack of political will. In this paper, we consider a multi-phase program of reform and assess its feasibility. In the first phase, the Government of Haiti (GOH) carries the corporatization of units of Electricité d'Haïti (EDH); introduces management contracts, leases, and concessions; and privatizes EDH units as appropriate. If the first phase succeeds we propose proceeding to later phases that would support EDH. Costs have been estimated based on a similar program implemented in Afghanistan by the United States Agency for International Development (USAID). Our estimation of economic benefits is based on a projected reduction in technical losses, valued at the retail price of electricity for average consumers; net gains in consumer surplus resulting from servicing high value customers are excluded from the model due to lack of reliable data to support a quantitative estimate. Furthermore, the analysis is conducted based on a 50 percent chance of success for the reform. At these conservative measures of costs and benefits, the project is found to be economically and financially viable (Economic IRR: 15 percent, Economic NPV: 11 Million 2017 USD, Financial IRR: 28 percent, Financial NPV: 78 Million 2017 USD).

Acronyms

ATC&C	Average Technical, Commercial and Collection Losses
CBA	Cost Benefit Analysis
DABS	Da Afghanistan Breshna Sherkat
DISCOS	Distribution Companies
EDH	Electricité d'Haïti
EIRR	Economic Internal Rate of Return
ENPV	Economic Net Present Value
GOH	Government of Haiti
IDB	Inter-American Development Bank
IRR	Internal Rate of Return
IPP	Independent Power Producer
KESIP	Kabul Electricity Service Improvement Program
MDB	Multilateral Development Bank
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
PPA	Power Purchase Agreement
USAID	United States Agency for International Development

Summary and Conclusions

Introduction

This paper argues that to improve the power sector in Haiti, which now constitutes a critical constraint to economic growth, it would be necessary to carry out a significant regulatory and utility governance reform; without these reforms, any physical investment program would be ineffective and unsustainable. All bilateral donors and multilateral development banks should coordinate closely to ensure that all assistance to the power sector is conditioned on tangible and verifiable steps to reform the sector.

An eminent panel convened by the Copenhagen Consensus Center and that included an economics Nobel Prize winner reviewed the paper and ranked it number one among 85 separate submissions.[1] We believe the main reasons that this proposal was ranked number one includes: lack of power being a key development issue in Haiti and using best practices to address sources of past failures in Haiti by all major international donors. The proposed design provides incentives for performance and contains a credible approach to ensure sustainability.

Background

Haiti has the least developed power system in the Western Hemisphere. This is due in part to a weak institutional framework, where several actors interact in an unclear regulatory framework with a lack of strategic coordination and leadership. The Ministry of Public Works Transportation and Communication is the lead government agency in charge of the energy sector, as there is no dedicated Ministry of Energy. Decrees reorganizing the power sector published in January 2016 have called for the creation of a regulatory agency, however, as of the writing of this paper, these decrees have yet to be enforced. The electric utility, Electricité d'Haïti (EDH) runs more than 10 separate, unconnected distribution networks that have average technical, commercial, and collection losses (ATC&C) of 70 percent. These grids have daily blackouts that have forced most businesses and many households to install generators on their premises as a means of coping. Many observers consider the lack of power one of the most significant constraints to economic growth. Efforts have been made by multiple donors to improve the power system, including the US Agency for International Development (USAID), the Inter-American Development Bank (IDB), and the World Bank, but these attempts have been largely unsuccessful. Lack of success is the result of a failure to reform EDH, which in turn is a result of lack of political will and alleged corruption.

The interventions proposed in this paper would have a systemic effect in the entire country by reducing a key constraint to economic growth. Direct beneficiaries would include present customers of EDH, who will have access to higher quality power and would suffer less unscheduled blackouts. As the EDH units are strengthened, additional customers would be served. The government of Haiti would also benefit from a decreased need to subsidize EDH. The utility currently receives a US$200 million subsidy annually, a sum that amounts to 10 percent of annual government budget expenditures.

Proposed Interventions

We propose two types of interventions as part of a package of reforms:

1. **Interventions to improve the legal regulatory framework.** These would be in support of the ministry in charge of energy and a regulator that eventually will become autonomous and accountable. These interventions will initially support the corporatization of EDH and establish the basis for management contracts, leases, concessions and privatization of the different units of EDH. Adequate performance by the GOH during the first three years will trigger a continuation of the program. Potential donors would include USAID and other bilateral donors such as Canada and France. An upper bound for costs for five years would be US$20 million.

2. **Interventions to improve the efficiency of EDH.** These interventions will support the different units of EDH with technical assistance and equipment, mostly meters. It is envisaged that the different units will be managed through management

1. http://www.copenhagenconsensus.com/haiti-priorise/haiti-priorise-eminent-panel-findings

contracts with incentives for performances, leases, concessions, and that the Jacmel utility would be privatized. The IDB and World Bank, as well as bilateral institutions, could be potential donors. Estimated costs for a five-year program would be US$38 million.

The analysis conducted here is based on a 50 percent chance of success for the first phase of the program – intervention to improve the legal regulatory framework. Sensitivity tests show the expected economic net present value would still be greater than zero if the chance of success drops to 8 percent. Given that the investment in technical support of EDH is conditional on the success of the regulatory and legal reforms, the chance of success will not affect the financial viability of the project for EDH.

Benefits

The most difficult aspect of a project such as this is the estimation of benefits. For these interventions, we have estimated the potential reduction in ATC&C losses using data for a USAID-funded project that supported the energy distribution company in Kabul, Afghanistan (DABS). For the case of Haiti, we have assumed that the reduction in losses would take twice as long, ten years as opposed to five. For the economic benefits, we only valued the reduction in technical losses at the price paid by consumers.

Sustainability

Presently, GOH subsidies exceed US$200 million per year. If EDH is strengthened, those would be reduced very significantly and maybe would be eliminated, thus allowing the finance of the regulatory costs. Additionally, a small fee on the total revenue of the DISCOS (say 0.3 percent) would be sufficient to pay for the costs of regulation. Funding the regulator with fees is considered a "best practice" as it reinforces independence of the institution.

Key Milestones

Milestones for the proposed reform program are shown in Table 1.

Table 1 — Milestones for Haitian Electricity Reform Program

Target	Baseline	Year 3	Year 4 - 13	Year 14 – n
PPP units established	0	5 – 10*	No change	No change
ATC&C losses	70%	70%	Gradual reduction	25%

* Five would be the minimum and 10 the maximum. If the minimum milestone is not met, the program would be terminated.

Precedent

USAID and other donors have been successful in implementing programs like this in other countries. A USAID-funded study that analyzed Public Private Partnerships (PPPs) for infrastructure and concluded that they can only succeed if control is fully vested in new managers through management contracts, leases, concessions, or full privatization. A previous attempt by USAID to improve the operations of EDH failed when the GOH changed the proposed management contract to a purely technical assistance contract. Because of this poor performance, USAID significantly reduced programs supporting the power sector in Haiti and concentrated efforts in Caracol, where an on-going program has demonstrated that ATC&C losses can be reduced to under 10 percent if competent management is introduced. USAID is now developing the bidding documents to grant a 30-year concession for Caracol. Success with this would validate the institutional feasibility of the main recommendations of this paper.

Risks

Benefits and costs were estimated using conservative assumption. The main risk is that lack of political will and corruption can derail the interventions. Table 2 lists the costs and benefits of the intervention, assuming a 50 percent chance of success, a commercial loss target of 18 percent and a technical loss target of 8 percent.

Table 2 — IRR and NPV from Alternative Perspectives

Criteria	100% chance of success	50% chance of success
Economic NPV (ENPV) @ 12%	87 Million 2017 USD	40 Million 2017 USD
Economic IRR (EIRR)	18%	17%
Financial NPV (NPV) @ 12%	391 Million 2017 USD	195 Million 2017 USD
Financial IRR	28%	28%

Conclusions

The proposed project would be feasible from the financial and economic points of view. But feasibility depends most importantly on the willingness of the Government of Haiti to implement the proposed reforms. We have been informed that the President of Haiti accepted in principle the recommendations of this paper and that he has named a point person to further discuss next steps. This presents a golden opportunity to reduce or even eliminate a most significant constraint to economic growth. Successful implementation will also require excellent coordination by international donors.

USAID played a key role in introducing CBA in the agricultural and rural road sectors in Haiti. Additionally, USAID funded a training program for GOH officials that included financial, economic, and beneficiary analysis, and project design; as a result, Haiti now has a cadre of very well trained professionals in these areas. USAID should consider introducing CBA for power sector projects in Haiti and elsewhere as an intrinsic component of project design, as was done in the case of the Feed the Future Initiative.

Introduction

This paper deals with Cost Benefit Analysis (CBA) of a project designed to strengthen power sector regulation and improve the efficiency of Electricité d'Haïti (EDH), a state-owned utility.

It is important to note that the authors first had to design a project and then carry out the CBA. They did this using the experience of this paper's lead author in designing development projects at the World Bank, Inter-American Development Bank (IDB), and the US Agency for International Development (USAID). Designing projects like this is usually an iterative process that involves multi-disciplinary teams that include, inter alia, engineers, project design specialists, lawyers, financial analysts, and economists. Additionally, and most importantly, this would include a thorough process of consultation with the relevant authorities, officials of EDH, users, etc. Given resource limitations, only very limited consultations were carried out.

Economic development institutions follow a project cycle that begins with a strategy for the sector, identification, pre-feasibility analysis, feasibility analysis, project approval, and monitoring and evaluation. This CBA analysis was carried out using secondary data and represents the level of analysis that would be carried out at the identification stage. Results obtained indicate that a project to strengthen EDH and reduce generation costs would be viable from the economic and financial points of view. If a donor encountered similar results in the real world, the next step would be to fund the necessary studies to move the project through the project cycle. The greatest risks this project would face stem from a lack of political will, and possible corruption driven by those who benefit from the present system.

Several donors have been involved in a multitude of projects designed to improve the operations of EDH, but these projects have largely failed or have resulted in minor improvements given the level of resources expended. These projects have been somewhat timid in terms of the reforms or were weakened after approval because of political pressure. For example, a USAID-funded project to strengthen EDH initially contemplated a quasi-management contract, with incentives for performance, where the consulting firm would have significant control of EDH, including hiring and firing of staff. But eventually the Government of Haiti (GOH) converted this contract to technical assistance contract, where the consulting firm was limited in its role to providing advice to the management of EDH and supporting the procurement of some equipment. Improvements of efficiency under this contract were minor. Because of this poor performance, USAID reprogrammed more than $100 million originally intended for the power sector in Haiti, to other sectors in Haiti and to other countries. The USAID-funded program was one of a multitude of efforts by many donors, including also the World Bank and the IDB. It is alleged that a main reason for the failure of programs to strengthen EDH has been corruption and specifically that EDH officers benefit personally from commercial and collection losses.

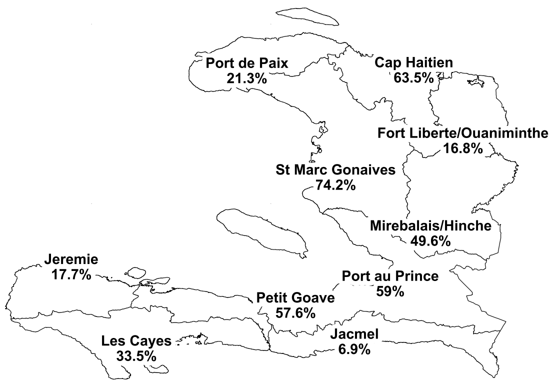
A more recent and very important initiative has been USAID's support for the Caracol Power Plant. USAID initially provided funding for the construction of 10 MW diesel-fired plant and distribution network. Afterwards, USAID funded a management team under the National Rural Electric Cooperative Association (NRECA) and now ATC&C losses are under 10 percent, and all other efficiency indicators also have improved. USAID also supported the analysis to estimate cost-reflective tariffs for Caracol. Presently, USAID is providing funding to develop the necessary bidding document for the award of a 30-year concession for the Caracol Power Plant. If successful, this would validate to some extent the main recommendation of this paper.

USAID has carried out financial analysis of a possible concession and this is being refined by a management-consulting firm hired by USAID. It does not appear, however, that USAID has carried out any cost benefit analysis (CBA) of a multitude of investments in the power sector. This contrasts with the USAID-funded rural road program and agricultural development programs in Haiti, which have been subjected to rigorous financial, economic, and beneficiary analysis.

Power Sector Background

Haiti has one of the least developed power systems in the Western Hemisphere. The electric utility, Electricité d'Haïti (EDH) runs more than 10 separate, unconnected distribution networks that are characterized by very large average technical, commercial, and collection losses (ATC&C) and by daily blackouts that have forced most businesses and many households to install generators on their premises; many observers consider the lack of power one of the most significant constraints to economic growth. As discussed above, efforts by multiple donors to improve the power system, including the US Agency for International Development (USAID), the Inter-American Development Bank (IDB), and the World Bank have been largely unsuccessful. Lack of success is the result of a failure to reform EDH, which in turn is a result of lack of political will and alleged corruption.

Figure 1 — Haiti Grids and the Associated ATC&C Losses



Installed capacity is about 320 MW, of which 260 comes from generators that burn liquid fuels and 60 MW comes from hydropower. This makes the country highly vulnerable to variations in petroleum prices. Of the 320 MW of installed capacity, only about 55 percent are available for generation (176 MW). There are independent power producers (IPPs) that signed power purchase agreements (PPAs) through direct negotiation rather than through competitive bidding procedures. EDH rates are on average around $0.30 per kWh, which is relatively high compared the average rates in the Caribbean. Even at these high rates, EDH requires more than $200 million per year from the Government of Haiti to enable it to pay for its obligations.

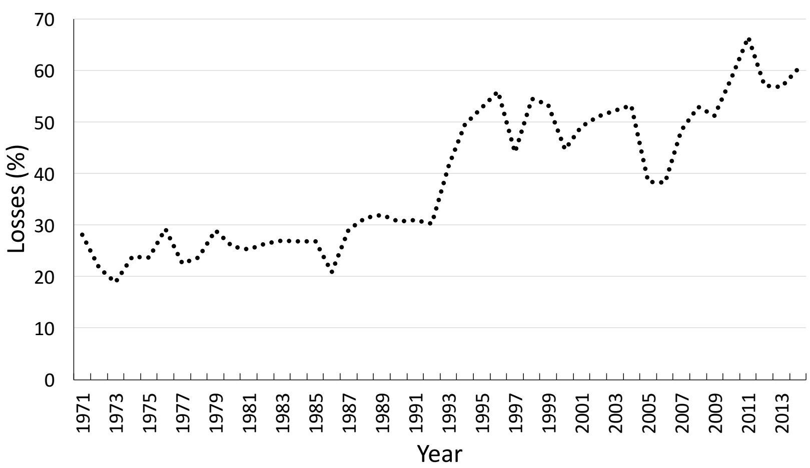
Haiti's power sector faces numerous challenges. Some of the main ones follow:

As discussed above, ATC&C losses are very high and have averaged in recent years around 70 percent of total electricity generated; commercial and collection losses account for 70 percent of total losses or around 49 percent of total energy produced.

The electrification rate is one of the lowest in the world. Only about 12 percent of the population is connected to the grid officially, while an equal percentage are connected illegally.

There are daily blackouts and customers receive only between 5-15 hours of electricity per day. Therefore, even small businesses and many households must have their own generators and/or batteries and this constitutes an important constraint to economic growth.

Figure 2 — Average Technical, Commercial, and Collection (ATC&C) Losses in Haiti by Year — World Bank (2017)



Context/Literature Review

Haiti's economic condition both influences, and is influenced by, its failing electricity market. Only 35 percent of Haitians have access to electricity through grids. In rural areas, that figure is 11 percent (World Bank, 2015). Per capita consumption of electricity in Haiti is significantly lower than other Caribbean countries, and is only two percent of the neighboring Dominican Republic (World Bank, 2015, p.5).

The inability to access electricity has serious implications for all Haitians, but is especially harmful for commercial and industrial enterprises. The lack of reliable electricity supply is cited by business owners as the most binding constraint to private sector development (World Bank, 2015, p.5). Businesses in Haiti also face some of the highest costs for electricity in the region, making it hard for them to operate competitively. Households also suffer from lack of available power and are forced to adopt coping strategies such as using small diesel generators to power household appliances, or burning kerosene oil for light. Those Haitians who do have access to electricity through grids face shortages and it is estimated that those with connections only have electricity for 5-9 hours a day (Worldwatch Institute, 2014, p.26).

Haiti's electricity sector is also a serious financial burden on Haiti's economy. EDH requires a transfer that averages US $200 million each year to cover operating costs. This is equal to 10 percent of the national budget or 2 percent of GDP (World Bank, 2015, p.68). EDH's significant financial losses are partly due to high levels of commercial and technical losses in the electrical grid, which prevent EDH from collecting revenue. If EDH could reduce technical losses sufficiently and improve the collection of payments for electricity that is consumed, it is possible that they could operate in a more financially sustainable way and reduce their burden on GOH. Reforming EDH could make other interventions on both the supply and demand side of Haiti's electricity market (which we discuss in other papers we have written as part of Haiti Priorise) more feasible.

Although it is hard to predict exactly how reform will play out in Haiti, there is a precedent of large benefits being achieved through power sector reform in other parts of the developing world. The reforms we propose are heavily inspired by the Kabul Electricity Service Improvement Program (KESIP) implemented by USAID in Afghanistan (USAID, 2017). Like Haitians, only 30 percent of Afghans have access to electricity. Before KESIP, commercial and technical losses were also very high—at around 60 percent—like Haiti. KESIP focused on reforming Da Afghanistan Breshna Sherkat (DABS), the national electrical utility incorporated in 2008. With a bundle of reforms that included commercialization of the utility, changes to the governance structure, installation of smart meters, changes to the procurement processes, performance management, and removing illegal connections, DABS saw AT&C losses drop from 60 — to 24 — in under five years. While it would be unlikely that Haiti would be able to replicate the exact success of KESIB, even a fraction of this level of improvement could make reform feasible.

Other countries have shown the potential benefits of power reform. Kozulj and Di Sbroivacca (2004) looks at electrification rates before and after sectoral reform in Argentina, El Salvador, and Peru and finds large increases in all cases. In interviews with colleagues at USAID, it was noted that reforms involving smart meters in Brazil, India, and other countries lead to significant drops in non-technical losses, in some cases by as much as 96 percent.

Theory

Power projects for existing markets can be classified in three types: policy and institutional reform projects, supply projects, and demand side projects. This CBA will be focused on a policy and institutional reform project designed to enhance the power sector policy and regulatory environment and to improve the efficiency of the main off taker of power, Electricité d'Haïti (EDH).

Benefits included in the evaluation of an electricity project fall under two broad categories: (i) reductions in the cost of supplying electricity and (ii) value of improved access to energy. For instance, if investment in generation results in replacing an inefficient power plant with a more efficient one, then the main source of benefit is the saving that results from efficiency gains. However, if the investment increases the total generation resulting in increased access or improved reliability, then the benefits will mainly result from the value of access or improved reliability for consumers. It is also common to have projects that result in both types of benefits.

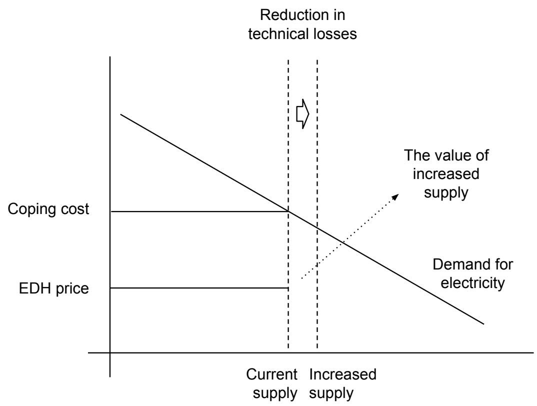
Institutional reform of EDH, if successful, can result in a range of benefits listed below.

- Reduction in technical losses.
- Reduction in commercial losses.
- Reduced market risk for IPPs resulting from financial stability of the off taker.
- Reduction in EDH operating costs (improved institutional efficiency).

Given the inadequate supply of electricity from EDH and the prevailing market trends in distributed generation for consumers of all classes, it is reasonable to assume that any reduction in technical losses should be valued from the perspective of consumers. A reliable estimate for the value of additional electricity in this case would be the coping cost of consumers per unit of electricity obtained from sources other than EDH. To estimate the value one needs to learn about how, on average, consumers of each class use solar panels, batteries, inverters, small diesel, candles, kerosene, or other sources of energy to cope with unreliable supply of power from EDH.

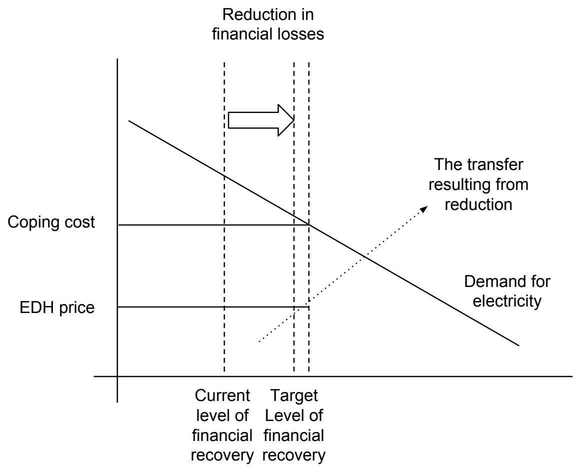
The reduction in technical losses could be valued higher than the market price of electricity if it results in expanding access to high-value consumers who are not currently served. However, due to lack of supporting data for a quantitative estimation of additional benefits, they are not included in the model.

Figure 3 — Impacts of Decreasing Technical Losses



A reduction in commercial losses would not, however, translate to such savings. Commercial losses reflect electricity that is consumed, but not paid for to EDH. Consumption comes at a value even if it does not translate to a financial payment to EDH. Therefore, a majority of what EDH gains from a reduction in commercial losses is a transfer away from consumers or resellers who do not pay for electricity. One could argue that the value of a unit of electricity consumed and not paid for can be on average lower than the value of a unit of electricity that is consumed and paid for. In other words, consumption will be at inefficient levels when the price is zero. This, however, can be ignored in this case since the difference is on the margin and anecdotal evidence reflects that a considerable share of commercial losses result from non-paying resellers of the electricity.

Figure 4 — Impacts of Decreasing Financial Losses



Reduction in commercial losses can result in financial independence and sustainability of EDH, and, in the long-run, reduce the risk for IPPs that EDH is unable to pay for the power. Such risk reduction would reduce the cost of generation from IPPs and the overall cost of electricity to the economy. This benefit is however not included in the model as its estimation process relies on weak evidence.

Overall, a reduction in commercial losses is treated as a pure transfer in this study, maintaining a conservative level of benefits. Similarly, reduction in operating costs of EDH is excluded from the analysis.

The main benefits of the project are a reduction in losses. In terms of CBA, Average Technical, Commercial and Collection losses (ATC&C) can be divided into technical and non-technical. A reduction in technical losses is clearly an economic benefit. In the case of Haiti, where there is excess demand for power, a reduction in losses would increase power available to consumers by, among other things, reducing the length and duration of blackouts. The entire reduction in ATC&C losses is a financial benefit for EDH. While a reduction in Commercial and Collection losses would likely result in a reduction of consumption by those users who would start paying for power, we assume in our model that revenue will not decline because there is significant unfulfilled demand in Haiti.

Calculation of Costs and Benefits

Introductory Comments

Financial vs. Economic Analysis

We have performed both economic and financial analysis. In this and other projects, we normally perform financial analysis from different points of view to ensure that all economic agents have adequate incentives to participate in the project. Financial analysis is also important to ensure sustainability. For the financial analysis of this project, we have included as benefits the entire reduction in ATC&C losses and the costs in direct support of EDH.

Economic analysis allows us to determine if an investment will be advisable from the point of view of the society. For the economic analysis of this project, we only included as a benefit the reduction in technical losses and as costs we included all the costs included in the financial analysis plus the costs of regulation. It is important to note that while some of the costs will be paid by foreign grants, we include these costs in their totality as they could be used to fund alternative investments in Haiti.

Sustainability

Proposed program envisages a combination of foreign expatriates and locals so that eventually there would be no or minimal requirement for expatriate support. Eventually, the regulator should charge fees to the regulated enterprises based on the value of power at the consumer level; this is considered a "best practice."

Investment Criteria and the Chance of Success

The analysis conducted in this model results in two streams of net cash (resource) flow. The first one is the financial net cash flow from the perspective of EDH and the second one is the economic net resource flow from the point of view of the country. The reduction in commercial and collection losses is not included as a benefit from the economic point of view as it represents a transfer. However, from EDH's perspective reduction in all ATC&C losses translate to increased financial earnings. The economic resource flow will also include the costs associated with the regulatory and legal reform that sets up the environment outside EDH during the first phase of the program. The benefits and costs of both net cash (resource) flows in the second phase of the program will depend on the chance of success. To estimate the expected investment criteria, we introduced a parameter called the "chance of success," which is shown as a in the formula and is used to adjust the costs and benefits of the second phase (C_2 and B_2, respectively). Alternative criteria can be reported using these net cash (resource) flow statements, including the net present value (NPV) and internal rate of return (IRR).

$$Expected\ NPV = \alpha B_2 - C_1 - \alpha C_2$$

In this formula, B_2 represents the benefits of the second phase, C_1 represents the costs of the first phase, and C_2 represents the costs of the second phase. Please note that the first phase itself has no benefits, as it is only about building the infrastructure to enable the environment for the second phase. In other words, the costs of the first phase are the costs associated with having the opportunity to conduct the second phase. Each of these criteria can be estimated for the financial net cash flow or the economic net resource flow.

Project Costs

We have carried out a CBA of a project that has two distinct sets of activities and two phases. In our proposed intervention, Phase I would last three years (years 0 to 2) and would develop the minimum conditions for the success of Phase II. Given all the past failures of donor-funded projects, if the Government of Haiti (GOH) does not demonstrate commitment to reform, Phase II would not be supported. The second phase is focused on supporting EDH units in charge of generation, transmission, and distribution of electricity. Table 3 details the assumptions behind the costs of each phase II by category.

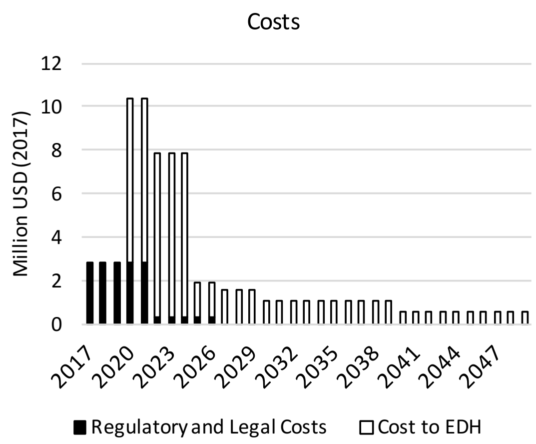
The cost assumptions are based on USAID programs funded in Haiti and in other countries. It is assumed that an international management consulting firm will be engaged in the beginning, so the costs include overhead and profit. The costs will later drop for both activities as the staffing composition transitions from international staff to local hires to ensure sustainability.

Table 3 — Costs across Time by Activity

Years	0-2	3-4	5-7	8-9	10-12	13-22	23-32
Regulatory and legal costs	2.80	2.80	0.3	0.3	-	-	-
EDH Support	-	7.6	7.6	1.6	1.6	1.1	0.6
Total cost	2.8	10.4	7.9	1.9	1.6	1.1	0.6

The flow of is also presented in the figure below.

Figure 5 — Costs over Time



Costs of Strengthening the Regulatory Capacity of the GOH

Significantly more private participation in the sector would likely be the main instrument to improve performance. To achieve this, it would be necessary to enhance the regulatory capacity of the GOH. It is estimated that a team of five expatriates during five years and five Haitians during ten years would be needed. We also consider that training under the National Association of Regulatory Utility Commissioners (NARUC) be provided. These foreign and Haitian professionals would lead the institutional reform of EDH and develop the privatization and concession terms for different units of the utility. It is envisaged that, given the small market in Haiti, the scheme used would be "regulation by contract" rather than more sophisticated market designs followed by most countries in Latin America.

Costs of EDH Support Component

In the past, USAID financed a project to strengthen EDH, but that project essentially failed. The main reason for the project's failure is that actual implementation did not follow the initial project design. USAID originally agreed to fund a quasi-management contract whereby a team of consultants would administer EDH with full powers to take management decisions, including developing a corporate strategy, and hiring and firing staff, as necessary. Eventually, because of political pressure, the contract was changed to a technical assistance type of contract where the consultants provided support to the management of EDH but had no power to take key management decisions. During this USAID-funded project, numerous issues were identified. The main ones were:

- Political interference. Several directors have been replaced after short tenures and many projects undertaken were not justified from the economic or financial points of view.
- Alleged administrative corruption. It has been alleged that EDH employees collude with clients to enable them to avoid paying for power consumed.
- Overemployment of unqualified staff. A significant proportion is unqualified and lacks sufficient basic knowledge to be able to benefit from training programs.
- Lack of knowledge and skills in information technology (IT). Lack of basic IT skills makes it very difficult to modernize billing and financial management.
- Poor donor coordination. Many donors implement programs in isolation, without considering what other donors are doing, thus wasting resources.

Given the problems discussed above, a classical investment project to support EDH, such as funding meters and Information Technology (IT), would not be very effective. Similar projects have indeed been performed recently with the support of the World Bank and did not lead to significant results toward reductions in ATC&C losses. We have performed the CBA of EDH activities under the basic assumption that the GOH will introduce greater private participation in the 10 units of EDH. Given that the different units have widely different levels of efficiency, as measured by ATC&C losses, the solutions for each would vary. We believe there is scope for a management contract with incentives for performance, leases, concessions, and full privatization. These options are very tentative and are presented for illustrative purpose. The next step would be to hold in-depth discussions with the GOH and potential donors. The options are summarized in the table below.

Table 4 — Proposed Management Structures

Publicly Owned & Managed	Publicly owned & managed	Publicly owned; managed by private firm under management contract with incentives for performance	Lease	Concession	Privatization
No technical assistance	Technical assistance to state managers; investment in technology including meters	Management contract with incentives for performance	Private firm operates & maintains; investment funded by public sector	Private firm operates & maintains; investment by private firm	Private ownership & management
	US-AID-funded project failed to improve performance of EDH	--Port Au Prince --Petit Goave --St Marc Gonaive --Cap Haitien --Mirabalais/ Hinche	--Les Cayes	--Fort Liberte --Port de Paix --Jeremy	--Jacmel

For this scheme to work properly, it is also necessary to reform the sector. Of most importance would be to establish an independent and accountable regulator.

Project Benefits

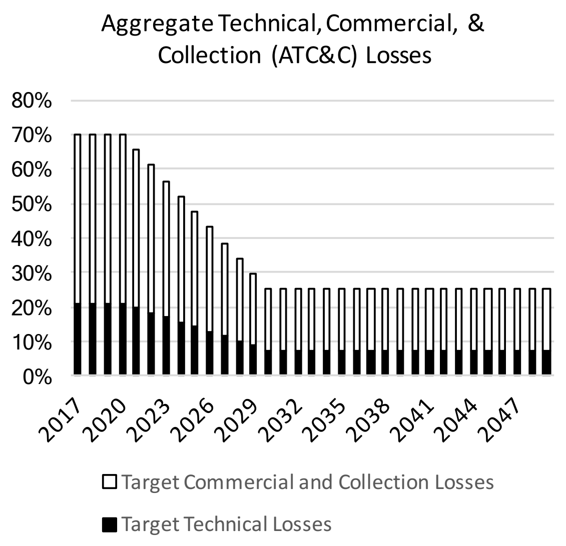
Estimating potential reductions in ATC&C is, obviously, highly speculative. We will use data from a USAID-funded project (KESID) with the energy distribution company in Kabul, Afghanistan (DABS) as a benchmark for estimating those reductions in losses in EDH. Before the USAID-funded project, losses in DABS were 60 percent, like EDH, and there was political interference, lack of trained staff, and many of the other problems faced presently by EDH. Below are the estimated losses in DABS (Kabul).

Table 5 — Estimated DABS ATC&C Losses

	Year 1	Year 2	Year 3	Year 4	Year 5
Losses	60%	53%	31%	28%	24%
Benefits	0%	7%	29%	32%	36%

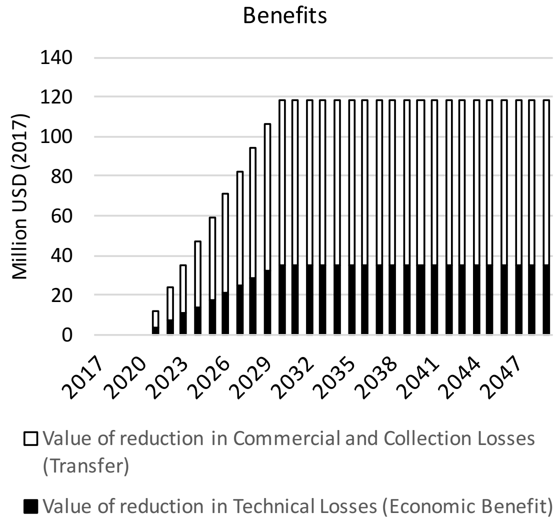
While improving the operation of DABS in a highly conflictive and corrupt environment was very challenging, it might be more difficult to achieve similar results in Haiti. Therefore, we will assume that the rate of improvement of the ten units of EDH will take twice as long as the improvement in DABS. Total losses in EDH would decline steadily from 70 percent to 25 percent in ten years starting in Phase II; technical losses would decline during the same period from 21 percent to 8 percent and commercial and collection losses drop from 49 percent to 18 percent. This drop is illustrated in Figure 6.

Figure 6 — Aggregate ATC&C Losses over Time



The reduction in losses are valued at US$0.30 per kWh. Knowing the amount electricity generated by EDH (875,000 MWh per year), the value of the averted losses is presented in Figure 7. Please note that this is a conservative estimate as it assumes no growth in generation.

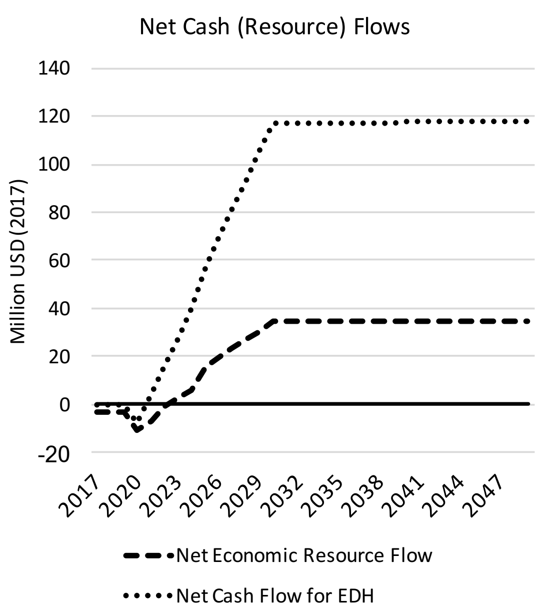
Figure 7 — Value of Averted ATC&C Losses



Summary of Costs and Benefits

The net cash (resource) flow is illustrated in Figure 8 based on 100 percent chance of success. Table 6 summarizes the investment criteria estimates under 100 percent chance of success, as well as 50 percent chance of success.

Figure 8 — Net Cash (Resource) Flow over Time



Please note that the IRR in Table 6 is estimated using the modified IRR function at 12 percent reinvestment and financing rates.

Table 6 — Summary of Investment Criteria

Criteria	100% chance of success	50% chance of success
Economic NPV (ENPV) @ 12%	87 Million 2017 USD	40 Million 2017 USD
Economic IRR (EIRR)	18%	17%
Financial NPV (NPV) @ 12%	391 Million 2017 USD	195 Million 2017 USD
Financial IRR	28%	28%

Sensitivity Analysis

The tables in this section summarize the sensitivity of the expected NPVs and IRRs (based on the chance of success) to various parameters. These parameters include the chance of success (Table 7), discount rate (Table 8), target for collection and commercial losses (Table 9), and target for technical losses (Table 10).

Table 7 — Sensitivity of Expected Results to Chance of Success

	ENPV	EIRR	FNPV	IRR
1%	(7)	5%	4	28%
8%	0	12%	31	28%
50%	40	17%	195	28%
70%	59	18%	274	28%
100%	87	18%	391	28%

Table 8 — Sensitivity of Expected Results to Discount Rate

	ENPV	FNPV
5%	142	559
10%	57	257
12%	40	195
15%	23	134
20%	8	76

Table 9 — Sensitivity of Expected Results to Target Level of Collection and Commercial Losses

	ENPV	EIRR	FNPV	IRR
7%	40	17%	244	29%
12%	40	17%	221	29%
18%	40	17%	193	28%
25%	40	17%	161	27%
30%	40	17%	137	27%

Table 10 — Sensitivity of Expected Results to Target Level of Technical Losses

	ENPV	EIRR	FNPV	IRR
4%	56	18%	212	28%
6%	47	17%	202	28%
8%	37	17%	193	28%
10%	28	16%	184	28%
15%	5	13%	161	27%

We may also wish to consider a scenario where multiple variables deviate from our estimates, a worst-case scenario so to speak, to see if the project is expected to generate a positive net benefit. Such a scenario can make the following assumptions:

- A target of 30 percent for commercial losses;
- A target of 15 percent for technical losses; and
- A 10 percent probability of success.

The results of this scenario are summarized in Table 11.

Table 11 — Results under the Worst-Case Scenario

ENPV	EIRR	FNPV	IRR
3	13%	40	28%

As one case see, the results are robust even under a conservative estimate with worst-case assumptions.

Conclusion

The proposed interventions would be highly beneficial to the Haitian economy. Using conservative estimates of costs and benefits, the economic NPV (ENPV) would be 40 million USD 2017 (assuming a discount rate of 12 percent). The greatest risks to reform is that lack of political will and corruption will impede the actions necessary to improve the efficiency of EDH. These risks are high, as past efforts by all main international donors, including USAID, the World Bank, and the IDB have failed. To mitigate that risk, we have proposed that donors impose strict conditions to fund the full program. Specifically, we believe that unless some key reforms are implemented during the first three years of the proposed program, all future activities will not be supported. The analysis was done without consultation with key stakeholders and could be considered less than what a donor would do at the identification stage in the project development cycle. The next step would be to discuss with the GOH, potential donors, and all other main stakeholders.

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The Challenges of New Electricity Customer Engagement for Utilities and State Regulators

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"The Challenges of New Electricity Customer Engagement for Utilities and State Regulators," *Energy Law Journal*, Vol. 38, No.1, 2017: 49-78.

The International Confederation of Energy Regulators (ICER) voted to award the authors the 2018 ICER Distinguished Scholar Award in the category of Next Practices.

Synopsis: Growing customer engagement has been a driving force behind transformation of the U.S. electric industry. It has triggered actions by both electric utilities and their regulators. The combination of technology, public policies, and economics should stimulate additional customer engagement in the future, although the jury is still out on how fast it will grow in retail electricity markets over the next several years. After all, the overall enthusiasm over electric customer empowerment may be "more noise than sound." To date, the vast majority of residential customers have exhibited much inertia, whether it is participating in retail competition programs or a new pricing scheme like time-varying pricing. Even with the hype over rooftop solar, an extremely small percentage of U.S. households have taken advantage of this technology. In any event, utilities will increasingly operate in an environment with a distinct line between engaged and traditional customers. They will face additional costs and risks. The major challenge for state utility regulators is to protect traditional customers while encouraging utilities to serve engaged customers. Regulators have various tools to achieve these objectives.

I. Customer Bifurcation

This article examines the profound implications for a wide range of utility and state regulatory practices that arise from the growth of "engaged" electric consumers compared to "traditional" consumers. "Engaged" consumers include those who actively seek out opportunitiesto manage their electric consumption for reasons that may range from simply cutting costs to environmental activism.[2] "Traditional" customers are those more likely to be comfortable with the status quo, and who may have little desire or incentive to seek out alternatives to the existing rate structure or utility provider.

A. Traditional Customers

Traditional customers essentially pay little attention to their electricity consumption and bill. They receive their bill and then pay for it without much scrutiny. They are satisfied with their utility service (both in terms of price and reliability) and, presumably, find spending much time on managing their usage, or seeking the least-cost option, is not worth the benefits that they expect to receive.

Traditional customers tend to have an "information" deficiency, high switching costs to change providers, or are just simply inert (i.e., once they make a decision, they stick with it and tend not to change their behavior, even when it seems they should). Their relative passivity may reflect the lack of

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2. One source classifies customers into three broader categories: traditional, active, and prosumers. Ont. Energy Bd., Staff Discussion

customer participation in new market opportunities because of inertia when new information shows that a customer would benefit. According to this perception, customers are irrational in not modifying their behavior.[3]

Instead, however, inertia may reflect rational behavior where a customer concludes that the benefits from switching to another supplier as highly uncertain or minimal. One noted example of customer inertia is the long distance telephone market, where the penetration of non-AT&T carriers progressed slowly, and several years passed before these carriers collectively were able to increase their market share above AT&T's.[4]

B. Engaged Customers

1. Increased Expectations of Some Utility Customers

A growing number of electricity customers expect more from their electric utility than in the past, just as consumers across a wide spectrum of industries have placed higher demands on other companies.[5] As expressed in one paper, "[e]lectricity is no longer just something the utility delivers to consumers. Consumers want more choice and control over their management of electricity. New unregulated entities are entering the market to meet consumer needs with new products and services."[6]

The quote implies that utilities must seek ways to provide value to customers other than traditional reliable service at reasonable prices. If they fail, as some analysts have predicted, they could face death-spiral-type consequences.[7]

One fundamental question relates to the source of customer engagement: Has it spawned from the emergence of new technologies and public policies, or has it initiated from the demands of customers wanting more from their utilities? An example of the first is entrepreneurs' desire to provide new distributed-generation technologies, because their costs have dropped to economical levels, even in the absence of consumers previously expressing their desire for them. An example of the second is the desire of customers for clean energy and real-time information, with the market responding by developing new technologies to satisfy these demands. It is probably true that customer engagement originated from both customers themselves and from the development of new, economical technologies.

It also makes sense to expect an interactive relationship between customer engagement and new technologies; namely, the increased penetration of new technologies will likely lead to the growth in customer engagement in controlling electric usage. This, in turn, can stimulate further technological developments, spiraling yet heightened customer engagement.

2. Engaged Customers Want Different Things

Engaged customers tend to better exploit increased competitive conditions and have access to

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Paper EB-2015-0043, Rate Design for Commercial and Industrial Electricity Consumers: Aligning the Interests of Customers and Distributors 12 (2016). Prosumers benefit from consuming cleaner electricity, reducing their utility bill, receiving satisfaction from producing their own electricity, and receiving payments from their utility for unused power. To avoid confusion with customer activism observed in regulatory proceedings, this article combines and re-labels active customers and prosumers as "engaged" customers.

3. Behavioral economics predict that real-world decision making is often inconsistent with consumer decisions that neoclassical theoretical models would suggest to be optimal or rational. Robert H. Frank, The Economic Naturalist: In Search of Explanation for Everyday Enigmas (2007); Richard H. Thaler & Cass R. Sunstein, Nudge: Improving Decisions about Health, Wealth, and Happiness 80 (2008).

4. James Zolnierek et al., Fed. Commc'ns Comm'n, Long Distance Market Shares: Second Quarter 1998 (1998). The analysts used revenues to measure market shares. As a policy matter, whether long distance telephone users would have been better off if AT&T's market share eroded faster over time is not at all clear. One could argue that, in view of the threats of Sprint, MCI, and resellers, AT&T faced enough competition to not act like a dominant supplier.

5. Consumers in general feel more empowered, are less tolerant of poor service, less loyal and more informed. For example, Uber has enhanced consumer expectations for the taxi industry by providing quicker service, lower prices at most times, and a more convenient payment method.

6. GridWise Alliance, The Future of the Grid: Evolving to Meet America's Needs 1 (2014).

7. Elisabeth Graffy & Steven Kihm, *Does Disruptive Competition Mean a Death Spiral for Electric Utilities?*, 35 Energy L.J. 1 (2014).

more information, new technologies and market developments. They place greater demands on utilities to provide (1) a wider array of products and services and (2) greater opportunities to control their electricity usage and the price they pay for electricity. Engaged customers tend to want one or more of the following:

- Real-time information and pricing so that they can better manage their usage;[8]
- The capability to save on electricity costs via time-varying pricing, demand response, and energy-efficiency initiatives;
- Clean energy as they are willing to pay more for electricity when produced from renewable energy, either by their utility or themselves;
- Exceptional, reliable, and resilient service (e.g., shorter and less frequent outages)[9] and power quality[10] as they assign greater costs to outages and other service disruptions;[11]
- The ability to self-generate (e.g., combined heat and power, micro-generators, rooftop solar) and other distributed energy resources (DER);[12] and
- Opportunities as "prosumers" to sell unused electricity at a "fair" price back to the utility.

Few engaged customers would want all of these things while most others would probably demand varying combinations. One customer may select a green tariff that requires him to pay extra for electricity produced from clean energy sources.[13] Another customer may prefer "fair" rules for self-generation, both in the price he pays for standby utility service and the price he receives for selling unused electricity back to its utility. A third customer may just want real-time information to better control her electricity usage. In satisfying all of these diverse demands, a utility would have to unbundle its services and possibly have to take more drastic actions. Each of these new activities costs money that regulators will have to decide how and from whom the utility will recover them.

Some customers want additional and better services from their utility than previously, just like they do from other companies. As remarked in one paper, "The last best experience anyone has anywhere becomes the minimum expectation for the experience they want everywhere."[14] Customers are increasingly being accustomed to more customer-centric service in other industries. The same paper commented that:

> Today's energy and utility customers are asserting more control by choosing particular providers and offerings, actively managing their consumption and making their voices heard directly through social channels, not just through regulators. In some cases, customers are even generating their own power. The utility industry is reaching a point where customers can behave more like partners with their utility, which can lead to new opportunities.[15]

8. One example is turning "big data" into useful information for customers to make decisions on a real-time basis.

9. Grid resilience has become particularly valuable in the East since super storm Sandy.

10. A "digital" world has heightened concern over the serious problems created by momentary disruptions in voltage or frequency. Utilities are unable to maintain perfectly constant voltage at all times, because many power quality problems are beyond their control. Lightning strikes, storms, motor-vehicle accidents, falling tree limbs, and can cause major power disruptions and surges. Customers may best deal with this problem by installing a surge-protection device, especially if they have appliances or equipment that are sensitive, expensive, or contain critical data.

11. One reason is that households use electricity for a wider range of activities, some of which have substantial value that would be lost with power outages or power-quality problems.

12. The spectrum of DER includes solar, wind, CHP, microgrids, storage, efficiency, demand management, and demand response. DER can benefit customers by making generation more flexible, transmission and distribution more controllable and resilient, allowing customers to become producers, and loads more interactive and dynamic. Even though technology will allow customers to become more self-sufficient, say, by installing a rooftop solar system, it is unknown how many of them actually would.

13. Some big U.S. corporations have begun to demand that the electricity they purchase from their local utility comes from clean energy sources.

14. IBM, The Digital Customer: Engage Customers as Individuals 4 (2016).

15. *Id.* at 2.

C. The Trend Toward Bifurcated Customers

Regulators and utilities should ask the essential question, What do electricity customers really want? That is, what value do customers receive from electricity? We can safely say that some customers expect less from their utilities than other customers. With confidence, we can also say that more customers will become engaged in the years ahead; we can only speculate, however, on the percentage that will and know exactly what they want.

Sure, almost all customers, when asked, would like to have highly reliable service, clean energy, and low prices.[16] But if asked what trade-offs they would prefer to make, customers would answer differently. Some customers may be willing to pay nothing for cleaner energy, as their preference is for the lowest-priced electricity. Alternatively, other customers would pay, say, 10 percent more for their electricity if it came from clean-energy sources.

The presumption that all customers are demanding more from their electric utility borders on hyperbole. Electricity customers, like customers of other products and services, are heterogeneous. Many customers want things to remain the same. Others want change, and technological developments have given them the opportunity to take more control with additional options. Bifurcation of utility customers based on their expectation for utility service seems like the right place to start in addressing policy alternatives for the future electric industry.

There are many reasons for why we should expect growing customer engagement over time. The first is economic: with likely cost reductions for self-generation and information-based technologies, more customers will exploit their benefits. A second reason is the availability of new technologies. We have seen the increased penetration of smart meters,[17] information/digital technologies, and Nest thermostats.[18] These have given customers the tools to automatically manage their electricity usage. Demographics also favor more engaged customers in the future. The millennials and other younger generations are technologically astute and have a reference point that differs from older customers in their expectations for utility service.[19]

Overall, when customers have more options to manage their electricity costs and make associated choices, it is likely that they will become increasingly engaged and set a higher standard for satisfactory utility service. This development has occurred across a wide spectrum of industries, and the electric industry should expect the same.

D. Caveats

As of today, the vast majority of utility customers are traditional and may continue to be so for the foreseeable future.[20] Because electricity costs are a small

16. One problem with consumer research is the discrepancy between what people say they believe and their actions. As a major flaw, a survey respondent may indicate a favorable disposition toward something, but would not be willing to pay anything for it.

17. Smart meters can provide two-way communications capabilities and other functionalities that facilitate the ability of customers to better manage their electricity usage. They can also, although rarely in the U.S., allow for time-varying pricing. Less than 4 percent of the over 50 million households in the U.S. with smart meters are on time-varying rates. Ahmad Faruqui, Brattle Grp., A Global Perspective on Time-Varying Rates 5 (2015). Time-varying pricing can bolster certain new technologies (e.g., energy storage), both inside and outside the home. The lack of interest in time-varying pricing probably reflects more than anything the preference of customers and regulators for the "stability" aspect of average-cost pricing.

18. Nest thermostats are an example of a technology that has provided customers with a positive experience even though they never expressed a prior demand for it.

19. The young generation place high demand on hand-held electronic devices. They also may likely demand real-time information to reduce their energy usage.

20. According to one report:

The number of electricity customers who use net metering increased exponentially from fewer than 7,000 in 2003 to more than 450,000 in 2013 … . Growth has continued in 2014, with more than 75,000 additional net metered customers reported through May 2014. However, despite this growth, in 2013 these customers represented only 0.3 percent of the more than 145 million electricity consumers in the United States.

Jenny Heeter et al., U.S. Dep't Energy, Pub. No. NREL/TP-6A20-61858, Status of Net Metering: Assessing the Potential to Reach Program Caps 1 (2014).

percentage of the average customer's income and total spending, it would be unsurprising if many or most customers decide to remain traditional for the foreseeable future.[21]

Another point is that compared to high-tech industries—a prime example is mobile phones—electricity is essentially a commodity with relatively few value-added features.[22] Unlike iPhones and other electronic devices, electricity lacks the special features that make it increasingly valuable to consumers over time.[23] A commodity, by definition, is a product that has little differentiation across markets. That is, it is fungible or interchangeable, no matter who produces it. Electricity seems to fit well within the definition of a commodity, although in the future it may transform into more of a value-added service.

As an opposing thought, one observation from history is that many if not most major technologies were not projected to have a disruptive effect (think of the airplane, the television, the steam engine, the computer, the laser, the mobile phone). These technologies initially were thought to have the ability to attract only a small minority of consumers, rather than a mass audience. But, of course the world has seen otherwise. It is conceivable that, in the years ahead, we will see a much radically different electric industry than what we can imagine today. One factor in this transformation could be innovations that turn customers into highly engaged participants. Presently, we can only speculate how the electric industry will evolve in terms of the number of engaged customers.

II. Essential Elements of Customer Engagement

The possibility that customers could never be worse off if they become more engaged is axiomatic to many. Consumer sovereignty says that each consumer is the sole judge of her own welfare; she does not have to buy from a specific supplier, and if she has choices, she can take her business elsewhere. A number of exceptions exist, however, such as circumstances in which individuals have incomplete or erroneous information or are unable to process rationally the available information. It is easy to imagine some customers processing the information they receive illogically or making decisions based on false, misleading, or incomplete information.[24] Customers might have to live with these decisions either on a temporary or a more permanent basis.[25] Engaged customers consequently need good information and act rationally in making decisions that guarantee to benefit them.

A. The Rationality of Customer Behavior

A strategy for engaging customers, or using the popular term—empowering customers—would have three broad components: the availability of unbundled

21. The average residential customer spends about 2.7 percent of her before-tax income on electricity. U.S. Bureau Labor Stat., Consumer Expenditure Survey at tbl. 1202 (2012). By reducing her electricity bill by 25 percent, for example, the average customer's real income would increase by only 0.675 percent.

22. As one observer has noted:

The electric utility industry provides a homogeneous product that has more in common with the natural gas and water utility industries than with telecommunications and the internet. The vast majority of electric consumers want reliable, clean, reasonably priced electricity, and little else.

Steve Huntoon, "POPS Is Here to Stay: Reports of Plain Old Power Service's Death Greatly Exaggerated," *Pub. Util. Fortnightly,* July 2016 at 82-83.

23. Peter H. Kind, Ceres, Pathway to a 21st Century Electric Utility 15 (2015).

24. Many customers fail to fully exploit the available information in making the best choice. Reasons include confusion and bounded rationality.

25. In many markets, customers have incomplete or erroneous information or are unable to process the available information rationally. The relevant question then becomes: Are these problems serious enough to warrant regulatory intervention? The typical societal response, at least in the U.S., is for government to supplement market forces in protecting consumers from inadequacies of their own judgments. We observe consumer protection laws, labeling and warnings, mandatory product standardization, and consumer reports. Two prominent features of poorly performing markets are: (a) companies have substantial market power and (b) consumers are ill-informed and inactive in changing companies when it would be in their interest.

products and services, adequate information, and enabling technology. Customer engagement is dependent on several factors, including (1) choice of value added services, (2) pricing options, (3) economical self-generation and demand response, (4) access to alternative electricity sources, and (5) real-time information.[26]

Consumers make decisions in a complex environment in which uncertainty, confusion, and transaction costs often prevail.[27] An apparent rational reason for why electricity retail consumers should switch from full-requirements to distributed generation (DG) status might clash with factors that make taking no action more sensible. The latter factors would include small expected benefits, uncertainty over actual savings, and high transaction costs.

The economics of customers switching to another provider (which an engaged customer would do) simply says that utility customers will search for a better alternative when they expect the gains to exceed the costs.[28] Gains can arise from lower prices and higher product or service quality; costs include transaction costs plus any perceived costs (e.g., lower service quality[29]) from switching suppliers. When utility customers feel indifferent about switching because of no discernible gains, they would tend to do nothing differently.

The puzzle to some observers is why do customers take no action when it seems that they should. The human tendency is toward "inertia," which some people would call laziness. Since contemplating whether to take new action requires effort and time, the opportunity cost for many customers can surpass their expected benefits. Unless the action offers clear advantages (e.g., large cost savings) in view of time constraints, other costs, and uncertainty over benefits, residential customers might decide to take no action. In other words, traditional customers, although seemingly exhibiting inertia, are acting rationally.[30] A policy goal of artificially stimulating more customer engagement through subsidies may therefore fail a cost-benefit test.

B. Value-Added Products and Service

Unbundling refers to the offering of separate prices to retail customers for individual components of electric service. For retail customers, these components may include energy, capacity, reliability, transmission, distribution, and ancillary services. Examples of more refined value-added services are billing services, enhanced grid management services, emergency operational services, metering services and data, and customer-sited energy storage.[31] Retail competition is a form of service unbundling where the utility sells and prices commodity electricity separately from the other components of electric services.

Customers would typically benefit if offered the choice between bundled services and unbundled services. Some customers, namely engaged customers, may opt for purchasing individual components of electric service—for example, enhanced reliability—if they are less costly than purchasing bundled service.[32] For others, like traditional customers with

26. N.Y. State Dep't Pub. Serv., Reforming the Energy Vision: Staff Report and Proposal (Case 14-M-0101) at 6-7, 12 (2014).

27. "Transaction costs" refer to the costs for customers to search out and negotiate with suppliers of different electric services.

28. This condition assumes that customers are risk-neutral. If instead they are risk averse, then even an expected net gain might not necessarily cause them to change their current situation. The reason is that switching providers involves an uncertainty over future electricity-bill savings and service quality.

29. One example is a decline in customer service. Customers of non-utilities might have fewer rights to complain because of poor service, relative to the rights they enjoyed as bundled sales customers of their regulated utility.

30. Frank, *supra* note 2.

31. Advanced Energy Econ. Inst., Toward a 21st Century Electricity System in California: A Joint Utility and Advanced Energy Industry Workshop Group Position Paper 23, 25, 30 (2015).

32. Enhanced reliability on a targeted basis through installation of equipment on a customer's site may be more economical than if the utility treats reliability as a public good by making large investments to increase reliability for all customers. The latter action presumes that all customers value higher reliability at least at the additional costs they have to pay, when in fact some customers do not. Targeted action allows individual customers to decide whether the benefits of increased reliability are worth the costs.

higher transaction costs, purchasing bundled service could be the preferred action. That is, traditional customers would tend to be content with basic utility service whereas engaged customers would more likely want enhanced services or value-added services.

Overall, the economic pressures for unbundling of retail services heighten whenever competitive conditions intensify.[33] As long as DG can compete with utility bundled service, those pressures will likely only grow in the future, especially as utility customers become more engaged. One lesson learned from the experiences of other public utility industries is that when existing regulatory and utility practices depart from market realities, reform becomes inevitable. Reform includes the unbundling of retail services and rational pricing.[34] Simply put, competition creates the stimulus for the unbundling of electric services.

C. Adequate Information

One feature of an efficient market is well-informed customers.[35] Such customers know the different products and prices of competing providers. These providers will tend to compete more aggressively, since they expect those customers to switch to those providers offering the best deals. Overall, knowledgeable consumers tend to shop around, demand price cuts, and mitigate the chances of market power. When, instead, customers are ill-informed, providers recognize that they could charge higher prices, not compete as aggressively, and still retain those customers.[36] If a provider knows that its customers are not seeking out the prices being offered by other providers even though those providers would offer a lower price, the incumbent recognizes that its customers might not know or care if they did.

Often in bifurcated markets, companies will price discriminate in favor of engaged customers, who by nature are more willing to shop around to get the best deal.[37] Because of the inertia exhibited by traditional customers, companies can charge them higher prices while suffering only a minimal loss in sales.[38] Later, we will discuss what customer bifurcation means for utilities and regulators in terms of ratemaking, the utility business model, and the role of utilities.

D. Enabling Technologies

Enabling technology allows most of the day-to-day deployment of the offered products to be automatic, lowering transaction costs for customers. One such technology, smart appliances, can automatically respond to price signals without customers taking any action. Limited access to information, high customer

33. The initial stimulus for the unbundling of utility services in the U.S. telecommunications and natural gas industries was the economic pressures from consumers who wanted the opportunity to purchase the lowest-priced products and services. In the natural gas industry, unbundled gas transportation was in large part a response to bypass threats by large retail customers and the associated problems of cost-shifting and stranded investments. From the perspective of local gas distribution companies, unbundling of the commodity and transportation services could prevent a customer from leaving the distribution system (i.e., bypass) and thereby contributing nothing toward the utility's fixed costs. Gas distributors have generally been agreeable to being only transporters for certain customers, since their profits are generally not tied to the amount of purchased gas they procure for their customers. This has not been true for vertically integrated electric utilities, which would lose profits from generating less electricity because of retail competition.

34. The pricing of value added services might depart from cost of service principles and instead be based on value of service and done through contracting with individual customers.

35. Engaged utility customers might need to understand how, how much, and when they consume electricity. The absence of such information precludes customers from managing effectively their usage.

36. Less-than-perfect information per se does not pose a serious problem since rational customers will expend only limited time and resources to acquire information justified by the benefits. In other words, well-informed customers can lack perfect information. George Stigler, "The Economics of Information," 69 *J. Pol. Econ.* 213, 215-16 (1961).

37. Examples are (a) shoppers who search online often get better deals than shoppers who only make purchases at retail outlets; (b) shoppers who search for coupons pay lower prices at grocery and other stores; and (c) car dealers offer lower discounts to buyers whom they know would purchase cars only from a single manufacturer, like Toyota, BMW, or Ford.

38. Different possible reasons exist for passivity, including inertia or lack of market opportunities. What the reason is has policy implications. For example, open access of transportation could mitigate the second problem while better information could address the first.

acquisition costs, and other transactional hurdles are obstacles to customer engagement. Enabling technologies can help mitigate these factors and transform customers from traditional to engaged.[39]

III. Challenges for Utilities and Regulators with Customer Bifurcation

A. Relatively Few Engaged Customers Can Trigger New Utility and Regulatory Practices

The prospect of more customer engagement in the future—even if it only involves the minority of electric customers—has already triggered actions by both electric utilities and their regulators. These actions will intensify in the future as the economics, technological developments, and public policy will move in parallel to place greater customer demands on utilities. As shown by recent events across several states, customer engagement has already driven change in the electric industry or at least sparked vigorous dialogue on various topics calling into question long-held utility and regulatory practices. These actions have occurred notwithstanding the fact that, as of today, only a small minority of retail utility customers are placing greater demands on their utilities.

This section focuses on how unprecedented utility-customer engagement is likely to affect both utility and regulatory practices in a transformed electric industry. Even though, as previously predicted, customer engagement may involve a minority of utility customers, its effect on the industry and its regulation could be profound. We have already observed in several states heated dialogue over net energy metering and rate design, each of which has originated from a small number of customers wanting to self-generate from solar technologies.

Heightened customer expectations come in various forms and derive from different sources. As previously discussed, engaged customers require certain things, like real-time information, unbundled services, and enabling technologies. Traditional customers generally want only reliable service at stable and reasonable prices.[40]

With increased diversity of customer desires and needs, utilities face a greater challenge in serving all customers: They must satisfy disparate customer needs. For regulators, the task is to make sure that utility actions are aligned with the public interest, which according to one definition is the aggregate, long-term collective economic welfare of engaged and traditional customers. The task for regulators is therefore to ensure that utilities serve engaged customers while also protecting traditional customers from cost-shifting and discriminatory practices. This means that they will have to grapple with new ratemaking issues and perhaps even revisit the regulatory compact that they have adhered to over the past several decades.[41] Regulators will also want to assure customers that they have access to new technologies by prohibiting utilities from erecting undue barriers.[42]

Utilities have always had customers with varying characteristics. Two noteworthy ones are the value customers place on reliable utility service and their responsiveness to price. The new engaged electricity customer has distinct demands and characteristics compared with traditional customers. Throughout its history, regulation segmented customers by how much electricity they consume; namely, residential, commercial and industrial classes. Clashes occurred over cost allocation across these classes. In the future, we should expect more discord within the residential class between engaged and traditional customers. Some observers label this as the "digital

39. As discussed later, new technologies can be both a blessing and a curse for utilities.

40. One perception of traditional customers is they demand only basic service from their utility, while engaged customers demand enhanced or value-added services. This begs the question of what distinguishes the two kinds of services. One might say that basic service reflects electricity as essentially a commodity, while enhanced services transform electricity into more of an overall service. Enhanced services can provide more personalized electricity service by increasing their value to an individual customer.

41. The oft-cited "regulatory compact" connotes an implied agreement between the utility and the regulator: The utility will provide affordable, reliable, universal service in exchange for the exclusive right to serve customers in a specific geographic territory at an authorized "fair" rate of return.

42. This section will later address these topics in more detail.

divide" that could become increasingly challenging for both utilities and regulators in the years ahead.[43]

B. Sticking to First-Order Regulatory Objectives

1. Continued Relevancy of Core Principles

Core regulatory principles applied for decades by state utility regulators include:

- Maximization of aggregate customer welfare: maximizing the value of new technologies to all utility customers, engaged and traditional; or maximizing what economists call consumer surplus;[44]
- No cross-subsidization funded by traditional customers: no cost shifting as a result of utility non-recovery of fixed costs from engaged (e.g., DG) customers;
- Rates include only prudent utility costs: economical investments for serving engaged customers;[45] and
- Reasonable utility returns from accommodating engaged customers: aligning utility returns with risk; this may require performance-based regulation (PBR) to encourage utilities to accommodate engaged customers.[46]

2. Dual Objectives for Engaged and Traditional Customers

Future regulatory actions will align with core regulatory objectives, irrespective of how the electric industry evolves. According to many observers, the ultimate objective of regulation is to maximize the long-term welfare of all customers collectively. Violating that objective would therefore jeopardize the public interest. Whereas in the past, regulators emphasized customer protection, in the future the focus will ostensibly shift to assure that (1) engaged customers receive the highest possible benefits from new technologies and (2) traditional customers receive protection from undue discriminatory and cost-shifting practices. This involves, among other things, utilities refraining from erecting excessive barriers to third-party providers and shifting costs to traditional customers. It also requires utilities to invest in those technologies that efficiently accommodate the desires of engaged customers.

C. Increased Demands on Utilities

Engaged customers will surely pose greater challenges for utilities. The major ones are:

- More refined unbundling of services and their pricing;
- Investments in upgrading the grid;[47]
- Better communications with customers (e.g., with social media);
- Customer demand for real-time information;
- Investments for greater generation diversity (e.g., clean energy technologies);
- Other investments (e.g., smart meters);
- Higher revenue and profit uncertainty;
- Erosion of monopoly status; and
- Heightened planning uncertainty (e.g., from customers switching from full-requirements to DG status).

The electric utilities' world becomes increasingly

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43. "Digital divide" is just a form of market segmentation where the separations of customers into two groups depends on their access to and use of the latest technologies that provide them with real-time information and other valuable services.

44. Consumer surplus measures the value customers received from a product or service minus the monetary and nonmonetary (e.g., search costs) outlays. With new technologies, consumer surplus, conceivably, could increase because of (a) reduced prices, (b) the availability of additional services (e.g., value-added services), (c) lower transaction costs for purchasing those services, and (d) an increase in the quality of service.

45. That is, investments pass a cost-benefit test.

46. A results-based regulatory model shifts the emphasis of regulation from the reasonableness of historically incurred costs to (say) the pursuit of long-term customer value. Regulatory incentive plans allow for shifting the focus from inputs to outputs, which is a fundamental change from traditional rate-of-return regulation. Especially appealing is the notion that a primary criterion for utility revenues is its relationship to the value that customers receive from utility service. Implementing such regulation to produce desirable outcomes poses serious challenges for regulators. Ken Costello, NRRI Report 10-09, How Performance Measures Can Improve Regulation (2010).

47. Grid modernization can benefit utility customers by mitigating cyber and other threats to the security of the electric grid, expanding new products and services, reducing barriers to new technologies, and improving overall economic efficiency and grid resilience.

complicated when customers have more choices and place additional demands upon utilities. Pressure on inflating utility costs derives from various sources: increased demand for clean energy, replacement of aging infrastructure, grid modernization, transition costs to accommodate more renewable energy, integration of new technologies, cyber security protection, public demands for improved "superstorm" response, customers' demands for higher reliability, and overall quality of service.

As a major challenge for utilities, with more customers adopting DG technologies, operation of the distribution network becomes increasingly complex. The distribution network must keep the system in balance and confine voltage and frequency levels within a tolerable band. It must also respect contingency limits, meaning no violation of a line's physical limit if some other line or generator goes out of service unexpectedly. The network carries out these basic functions by purchasing ancillary services. The operation of an interconnected electric network has to be monitored in real time to assure that: (1) production always matches demand and (2) power can flow across the network within established reliability and security constraints. By making these tasks more difficult, the integration of DG adds to utility costs. [48]

Regulators might want to consider allowing utilities more flexibility and leeway in their operations and service offerings. [49] The result is that utilities are better able to avoid a death-spiral-type scenario from DG penetration and other developments that challenge utilities' financial health.[50]

D. Broad Concerns

Regulators should ask the following broad questions in a bifurcated-customer world:

- What should we expect from utilities in accommodating new customer demands?
- Who should pay for new required investments, and how?
- What role should third-party[51] (e.g., competitive) providers play in meeting customers' new demands?[52]
- What restrictions and liberties should third-party providers have?
- How can regulators guarantee an economically

48. A Massachusetts Institute of Technology study on the future of the electric grid explains that low levels of DG penetration reduce load at the nearby substation, but high DG penetration could create excess load at the substation. The outcome is power flowing from the substation to the transmission grid, creating a reverse power flow that makes grid management more difficult by causing high voltage swings and other stresses on electric equipment. These potential strains on the distribution network will require utilities to undertake further capital investments in system upgrades, which might include distribution automation, system interoperability, data management and analytics, and cybersecurity to address new network dynamics. MIT Energy Initiative, The Future of the Electric Grid: An Interdisciplinary MIT Study 112 (2011).

49. An example of where companies have been successful in transforming their product line is the cable industry, which expanded its service offerings and competed in other markets, rather than expending substantial resources to compete with the satellite companies in the old product market. Cable companies went from being television-only providers to providers of internet and phone service, sold both individually and in bundles. In other words, customers are able to choose between buying separate services or a combination of services. Peter Kind, Edison Elec. Inst., Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business 14, 16 (2013).

50. A death spiral refers to an existential crisis whereby a utility has limited ability to raise its prices to sustain financial viability in response to adverse events. In a competitive environment by definition, individual companies have no control over the price and will experience financial disaster if they try to raise their price above the market price. In non-competitive industries, companies are able to exercise some control over the price they receive, but even then they can suffer lower profits when they try to price their product or service too high. Kenneth W. Costello & Ross C. Hemphill, *A 'Death Spiral' for Electric Utilities: A Hyperbole or a Reality?*, 27 Elec. *J.* 7, 7 (2010).

51. These non-utility providers can directly serve retail customers or utilities. They provide both technologies, products, and services. Non-utility providers play a crucial role in satisfying the demands of engaged customers. How utilities interact with them and what rules regulators establish affect what benefits these providers transmit to retail customers.

52. Experiences in other public-utility industries have shown that in a workably competitive environment, allowing non-utilities to provide services can produce significant benefits to consumers. The telecom industry is a good example where third-party providers played a valuable role in exploiting new technologies for the benefit of consumers.

level playing field between utilities and third-party providers who serve engaged customers?
- What barriers to consumer engagement exist today, and how can regulators mitigate them most economically?[53]

Proponents of electric utility transformation have emphasized customer welfare as the paramount objective. Throughout its history, utility regulation has given customers top billing. One contemporary complication is that technology and other factors have allowed customers to take more control, placing greater demands on utilities. Another complication is that the interests of residential customers have become diverse, requiring regulators to trade-off the welfare of some customers for the benefit of others. Customers who install rooftop solar and other DG facilities want standby service; on average, they have a lower load factor than other utility customers;[54] and they impose greater demands on the local distribution system (e.g., two-way electricity flow). Utility customers have also responded differently to new technologies, with some exploiting real-time information and others preferring clean-energy generation.

There is a legitimate concern that utilities might favor themselves or an affiliate, which violates the condition of a level playing field. Utilities might also obstruct those innovations that threaten their monopoly status or be indifferent to those innovations that largely have public benefits.[55] Regulators have to be vigilant to make sure that utilities are unable to erect artificial (i.e., undue) barriers to protect their financial interests at the cost of customer or societal welfare. These barriers can reduce the value of the distribution network, thereby obstructing the development of innovative value-added services that stand to benefit engaged customers.

E. Ratemaking

Ratemaking affects the ability of utilities to recover their costs, allocate costs between customer groups, and achieve predetermined regulatory/social objectives. These objectives include the financial health of utilities, the efficient use of electricity and the accelerated penetration of socially desirable, new and emerging customer-oriented technologies. Customer bifurcation increases the difficulty of ratemaking, especially in balancing the interests of different stakeholders. Especially relevant today, encouraging customers to self-generate may increase rates to full-requirements customers or jeopardize the utility's financial health.

1. Concerns in a Customer Bifurcated World

Analysts, stakeholders, and others have raised concerns about current ratemaking practices, especially as they relate to industry transformation and customer bifurcation. Some of those concerns stem from self-interest while others have more legitimacy from a public-interest perspective. Even in those jurisdictions not anticipating radical industry reform, utilities along with other stakeholders and their regulators are contemplating changes to long-standing ratemaking practices.

Current ratemaking practices have triggered several concerns as bifurcation of utility customers has become more prevalent:

- Financial harm to utilities from lower sales given the typical rate design of recovering most fixed costs through volumetric charges;
- Inappropriate rates and rate design for DG and full-requirements customers;
- Overpricing of surplus power (e.g., the net metering rate) from rooftop solar customers;
- Cost-shifting to full-requirements customers;[56]

53. They include limited access to information, high customer acquisition cost, and other transactional obstacles. Advanced Energy Econ. Inst., Creating a 21st Century Electricity System for New York State: An Energy Industry Working Group Position Paper 21-23 (2014).

54. Load factor is the average load divided by the peak load in a specified time period. Assuming other things held constant, the average cost for a utility to serve customers with higher load factors is lower than its average cost to serve other customers.

55. Public benefits are external to a utility and defined by economists as positive externalities. Examples include clean air and national security, which the country values but individual utilities in terms of their profitability do not. Investments in new technologies that reduce greenhouse gas emissions and lower the risk of harmful climate change can benefit society at large. Absent carbon pricing or similar policies (e.g., carbon trading), no direct financial compensation associated with those benefits exists, thus driving a wedge between the private returns that a utility realizes from innovations and the overall social return.

56. Cost shifting could involve the utility allocating DG-related costs to full-requirements customers. As another example, the utility could

- Deficient utility compensation to DG customers for the value they contribute to the utility grid, including standby and other grid services;
- Uniform prices across all time periods; and
- Under-exploitation of smart technologies for more economically rational pricing.

Examples of reformed rates that are under discussion in a number of states are straight fixed-variable-type rates,[57] real-time pricing,[58] revenue decoupling,[59] multi-year rate plans (e.g., price caps), surcharges for innovative investments, creation of a separate rate class for DG customers, cost-based standby rates, and performance-based rates for utilities.[60] As DG grows, regulators will ultimately have to reconcile how utilities recover their energy, and capacity/grid costs. Excessive reliance on the volumetric component of utility rates to recover both of these distinct costs will become increasingly contentious and likely unsustainable over time.[61] For those customers who want more control over their electric bill, time-varying pricing and demand rates become critical. The legacy of average-cost pricing will likely continue to unravel as distinctive customers' demands become more prevalent.[62]

2. Recovery of Costs for New Investments Dedicated to Engaged Customers

One topic under robust discussion relates to cost recovery and funding for expensive new investments, some of which are targeted at engaged utility customers. There are five aspects of cost recovery (e.g., rate-basing capital costs): timing of recovery, method of recovery, customers responsible for recovery, criteria for recovery, and the accounting treatment of costs. Each of these aspects affects the willingness of utilities to invest in technologies and services benefitting only engaged customers.

Regulators face two critical questions: Who should pay for new investments benefiting engaged customers, and how should utilities recover their costs? When a new technology benefits only some utility customers (e.g., customers willing to pay a premium for clean energy), the regulator would have to determine the responsibilities of separate customer groups. Should all residential customers bear the

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sell information and computer services to an affiliate installing rooftop solar systems at below-cost. Cost shifting is not necessarily anticompetitive. It always has the effect of raising the prices of regulated services. Yet it might have minimal effect on the unregulated market: It could simply allow the utility to increase its profits by cost manipulation, rather than predation or other strategies giving its affiliate an unfair advantage over competitors.

57. Larry Blank & Doug Gegax, "Residential Winners and Losers Behind the Energy Versus Customer Charge Debate," 20 *Elec. J.* 31, 31 (2014).

58. While studies on real-time pricing generally show that the benefits outweigh the costs, most of the benefits go to a small number of consumers who are relatively price-responsive. Thus, although some customers will likely benefit from such pricing, other customers will see higher bills. The fear of a large number of losers is a political obstacle to widespread adoption of real-time pricing.

59. Under revenue decoupling, the utility adjusts its rates between rate cases for sales deviating from some baseline level. One common structure is to annually adjust rates for a gap between actual sales and test-year sales per customer. If a utility's actual sales per customer over a specific period fall below the level embedded in existing rates, the utility could increase its rates to compensate for the revenue shortfall. This mechanism helps to stabilize a utility's revenues and earnings, causing it to be more indifferent to the level of actual sales and thus removing any financial harm from energy efficiency and distributed generation.

60. In a general sense, performance-based rates would ask: Are customers getting value for their money? Evaluation of utility revenues would consider outputs (e.g., reliability, penetration of DG, energy-efficiency savings) that benefit customers and society as a whole. The question then becomes, given utility outputs, what revenues should regulators allow utilities to earn? Performance-based rates can involve formal incentive mechanisms or simply rate adjustments by regulators based on their judgment of whether a utility performed exceptionally well or poorly. The latter approach is problematic if the regulators' decision takes place after-the-fact in an ad hoc fashion, rather than by applying upfront rules and criteria to the utility.

61. One reason is that utility rates to core (or full-requirements) customers would rise faster as more customers migrate to DG.

62. A hallmark of state utility regulation is the setting of prices based on embedded historical cost. This pricing methodology precludes customers from having to pay fluctuating prices, including higher prices during peak periods and other periods of tight supplies. Regulators have also expressed concern that some consumers would not shift load to lower-priced periods and thereby drive up the average price of electricity they pay and their utility bill.

risk of a new technology that benefits only engaged customers? As a "fairness" rule, customer groups who benefit the most should pay more of the costs. In some states, utilities recover the costs of new smart meters through the customers' distribution charges. Complaints have come from some customers who see little benefit from these meters.

F. New Utility Obligations and Functions

A radical regulatory response to changing technological, public policy, and market conditions could involve utilities adopting a new business model (to be discussed later in this article) that defines their new role, objectives, and strategies. The utility in a transformed industry would likely have different functions and obligations, including the separate treatment of engaged and traditional customers. Because of engaged customers, the regulatory compact between a utility and its regulators might have to undergo a major revamping. The utility may have less retail monopoly power, disrupting its geographical franchise; and the regulator might allow the utility's rate of return to float within a larger range, based on the utility's performance in serving engaged customers.[63]

Utilities can assume different functions in growing DG. They could provide additional services to DG customers. The services for DG and other engaged customers will include enhanced services that utilities did not provide previously. Regulators have discretion over what products and services utilities can sell. Their decision rests on what functions they envision utilities to perform. Three alternatives are "platform" operator ("traffic cop"),[64] service provider,[65] and "wires" provider.[66]

One alternative is for utilities to invest themselves in DG facilities and electric-vehicle recharging stations and rate-base them to earn a profit.[67] One concern with this approach is that all utility customers would pay for the investments even though the benefits would likely go to a relatively small number of customers, namely, engaged customers. Alternatively, utility shareholders could initially fund these investments and recover the costs from DG customers over time. A third option is for utilities to form an affiliate that provides DG services.

G. A New Utility Business Model

1. Rationales

Regulators might want to advance a new utility business model to deal with the bifurcation of customers. A business model focuses on the utility's products and services, their value relative to their cost, and how efficiently and effectively the utility creates, produces, delivers, and supports those products and services in their franchised area. A new business model can allow utilities to profit from offering distributed generation services or owning PV solar systems, while maintaining a competitive

63. Instead of utility profits dependent on sales and the dollar value of the rate base, under a transformed industry utilities may have to demonstrate greater customer value from their offerings to receive their authorized rate of return.

64. "Platform" refers to a system that supports interactions among multiple parties, and establishes a set of rules that facilitates transactions among multiple parties. A platform can increase innovation and competition by: (a) reducing transaction costs, (b) increasing transparency, and (c) enabling the enhancement of integration benefits that will grow as additional diverse suppliers and new technologies (e.g., storage, plugged-in electric vehicles) enter the market. Industry observers label this role of utilities as a "smart integrator," "facilitator," or "orchestra leader." *See, e.g.,* Rocky Mountain Inst., New Business Models for the Distribution Edge: The Transition from Value Chain to Value Constellation (2013).

65. Some utilities have already invested in solar PV systems to improve their earnings. Others are considering additional services to offer their DG customers.

66. Bill Dickenson & Phil Sharp, Aspen Inst., The Future of the U.S. Electricity Sector (2013); Bipartisan Pol'y Center, Capitalizing on the Evolving Power Sector: Policies for a Modern and Reliable U.S. Electric Grid (2013); Ronald L. Lehr, *New Utility Business Models: Utility and Regulatory Models for the Modern Era,* 26 Elec. J. 35 (2013); N.Y. State Dep't of Pub. Serv., *supra* note 25; Rocky Mountain Inst., *supra* note 63.

67. One socially desirable rationale for utility investments in electric-vehicle recharging stations is market failure; that is, the private sector, for whatever reasons, would under-invest in recharging stations. In a more facilitative role, a utility could help stimulate electric vehicles by expediting permitting and installation, in addition to offering time-of-use rates for electric-vehicle charging. The market-failure argument would seem to hold less for the DG market, which has attracted a large number of vendors, installers and other market providers.

marketplace that precludes them from having an unfair advantage from shifting costs to traditional customers.

The recent dialogue on the "electric utility of the future" has focused on whether the existing business model is sustainable, given the prospects for the rapid development of solar PV and other DG technologies, and customer engagement in general. A threat to utilities can start with sales losses to DG and, subsequently, an inexorable struggle to recover fixed costs from fewer customers. Price increases aggravate utilities' problem of yet more customers switching to DG.

2. Features of a Business Model Serving Both Traditional and Engaged Customers

The late management guru Peter Drucker commented that a business model should answer the basic questions: Who is your customer, what does the customer value, and how do you deliver value at an appropriate cost and at an acceptable profit? [68] A business model therefore concerns how a company (1) creates value for its customers through its operations, products and services and (2) generates sustainable operating and financial performance. For a utility, a business model focuses on its products and services, their value relative to their cost, and how efficiently and effectively the utility creates, produces, delivers, and supports those products and services in their franchised area.

The utility business model should have three qualities. First, it should adapt to new technological and market developments. This may require utilities to function as "platform" operators, in accommodating DG that technological advances have made economical to utility customers.

Second, a business model should continue to support core regulatory objectives, including cost-based rates, fairness across different customer groups, highly reliable service, and "just and reasonable rates." Notwithstanding major changes that are likely to evolve in the electric industry, long-held regulatory goals will still hold a high standing.

Third, the business model should satisfy predetermined broad social objectives (e.g., affordable electricity to low-income households, clean energy). Changed conditions might require a different business model in which utilities would have more opportunities to exploit the benefits for themselves and society from the improved economics of DG and other technologies. A utility can then take a more proactive role, rather than a defensive posture where they see new technologies as a threat to their financial viability.

The prime criterion in selecting the appropriate business model is that it should help to steer utility performance toward society's demands reflected through public policies, market conditions, prevailing technologies, and customer behavior and preferences. One desirable outcome would be to enhance efficient competition in the delivery of energy services to engaged customers over a newly formed (i.e., revamped) distribution-grid platform.

H. Exploiting Differences in Customer Preferences

Utilities can exploit customer differentiation of demands through smart technologies by offering individualized value-added services at a profit. They can behave like airlines, in other words, in differentiating their services to earn higher profit margins. Although reflecting discriminatory pricing, such action can enhance the utility's incentive to provide additional services for which engaged customers would benefit and be willing to purchase.

As an illustration, priority service is a form of product differentiation in which the market segments into different groupings. Those customers willing to pay higher prices gain higher priority in receiving the product or service. Priority service is an economical and arguably equitable rationing scheme for curtailing the situation of excess demand.[69] The theory of efficient rationing suggests that allocation should be according to customers' valuations of service.

68. Peter Drucker, The Practice of Management (1954). Electric utilities, in addition to satisfying their customers and shareholders, must also appease regulators/policymakers who dictate their broader social responsibilities. In the context of this article, the prime question relates to what business model would best maximize the long-term interests of engaged and traditional customers collectively.

69. Hung-Po Chao & Robert Wilson, *Priority Service: Pricing, Investment, and Market Organization,* 77 Am. Econ. Rev. 899 (1987).

I. Encouraging Innovation[70]

Utilities may have to become more innovative in serving engaged customers. Regulators can help by providing utilities with stronger incentives to adopt new technologies and undertake research and development (R&D).

1. The Benefits of R&D

The main benefit of R&D is to advance the current state of technology. R&D can play a critical role in nurturing new technologies during their initial stages of commercial application so that they become more prominent in the future. When a new technology becomes commercial, it can still benefit from further R&D to hasten its diffusion in the marketplace. Additional R&D and technology improvements will be critical for solar power and other new technologies to become mainstream by mid-century.

In the public utility space, technological change has the additional value of fostering policy objectives. For some industry observers, the absence of breakthroughs in energy technology will preclude major strides toward attacking global warming affordably.[71] R&D can also spawn new technologies that will particularly benefit those customers who want more choices, and control over their electricity usage and the price they pay. There is some concern that electric utilities are underfunding R&D.[72]

2. The Effect of Public Utility Regulation

Various features of public utility regulation affect how much and how utilities make R&D/innovation investments. They include the tightness of regulation, regulatory commitment, degree of information symmetry, cost recovery, allocation of the benefits, and risk incidence. Depreciation policy can help ensure recovery of invested funds over the economic life of the physical capital. When depreciation rates are too low, with depreciation stretched out over too many years, a utility may find it uneconomical to replace old equipment with new equipment. The costs could be particularly high in a dynamic environment in which new technologies offer large benefits to utility customers and society in general.

Another regulatory practice is to split the benefits of a new technology between utility customers and shareholders. This can boost the efforts of utilities to invest in R&D. Otherwise, the benefits to utilities may not justify the risks they would bear. A third practice is the regulatory commitment to R&D, reflected in guidelines, rules, or individual rate-case decisions, that can lower the risk to the utility and make R&D more attractive.

The economics literature has devoted relatively little attention to regulated firms' incentive to engage in R&D, and develop and adopt new technologies.[73] Nevertheless, the standard thinking is that regulation tends to make utilities cautious about innovating and taking risks. The presumption is then that utilities will fall short in their R&D activities and deployment of new technologies.

Utilities tend to underinvest in R&D and new

70. This section draws heavily on Ken Costello, NRRI Report 16-05, A Primer on R&D in the Energy Utility Sector (2016).

71. Varun Sivaram & Teryn Norris, *The Clean Energy Revolution: Fighting Climate Change with Innovation,* 95 Foreign Aff. 147 (2016). One view held by many economists is that accelerating R&D instead of increasing subsidies represents a better approach to making clean energy resources economical and acceptable in the long run. Another important action is to hold participants in the energy market accountable for the adverse effect of greenhouse gas emissions. By requiring companies to internalize emissions and their damage to health and the environment, clean energy should become more competitive with fossil fuels, in the process stimulating more R&D spending on clean energy.

72. Electric utilities have spent less on R&D in absolute dollars since the mid-1990s. One reason is that in responding to increased competition, utilities curtailed their internal R&D activities in addition to reducing their support for collaborative research managed by the Electric Power Research Institute. With increased competition, utilities could less easily pass through R&D costs to their customers and appropriability became more of a concern (i.e., new competitors could "free ride" on the benefits of R&D conducted by an individual utility). One study found that electric industry restructuring in the 1990s was responsible for an almost 79 percent decline in utility R&D expenditures. Paroma Sanyal & Linda R. Cohen, "Powering Progress: Restructuring, Competition, and R&D in the U.S. Electric Utility Industry," 30 *Energy J.* 41 (2008). The incentives for utility R&D have therefore changed negatively starting in the 1990s. It is not obvious why the movement toward competition would decrease R&D. Utilities might upgrade their R&D activities to improve their operating efficiency and better compete. On the other hand, they may scale down R&D costs as part of their strategy to manage costs.

73. Two publications do offer analysis of this topic: Elizabeth E. Bailey, "Innovation and Regulation," 3 *J. Pub. Econ.* 285 (1974); Stanford V. Berg & John Tschirhart, Natural Monopoly Regulation: Principles and Practice (1988).

technologies that have public benefits or threaten their monopoly status. Especially for the latter reason, regulators need to be vigilant that utilities do not "squash" those technologies that threaten their financial health but are in the interest of their customers. The consequences can be particularly harmful for engaged customers, who would likely benefit the most from those technologies.

An increasingly important function of public utilities will be to act as a conduit for filtering the benefits of innovations developed by third parties to retail customers. After all, most innovations that benefit utility customers had their beginnings outside the utility space. Utilities' ability and willingness to play the role of "innovation" adopter depend on regulators creating a favorable risk-reward balance.[74] If utilities believe that innovations will threaten their financial condition, they will be less inclined to deploy them for the benefit of their customers. As a cardinal rule, any company will find R&D/innovation financially attractive only when it expects profits to compensate for the risk it bears.[75]

Although the net effect of regulation on R&D/innovation is difficult to assess, the perception among industry observers leans toward the negative. The conditions required for non-regulated firms to innovate seem to be lacking for utilities. Specifically, why should a utility make an extra effort to innovate when most of the benefits will go to customers?

J. Removing Artificial Obstacles

To promote the public good, regulators need to distinguish between "artificial obstacles" and "natural obstacles." A natural obstacle is a customer's rational response to risk and customer uncertainty over the future economics of DG. An artificial obstacle could include regulatory rules that unduly discourage utilities from accommodating DG, entry barriers to DG providers, or distorted price signals to consumers that make DG less economically attractive. Regulators should always strive to mitigate artificial obstacles, which, by definition, derive from market imperfections or flawed regulatory practices, as long as the benefits exceed the costs of mitigation.

Mitigating natural obstacles, on the other hand, would invariably fail a cost-benefit test. Stakeholders often plead for regulators to eliminate obstacles that allegedly disfavor their preferred technology or source of energy. Frequently, these obstacles are simply normal market conditions whose elimination would involve a cost (e.g., via subsidies) greater than the benefits. One instance is overpaying DG customers for electricity they sell back to their utility. Such a practice would tend to result in overinvestment in DG as well as higher rates to non-DG customers.

IV. The Path Forward

Some states have aggressively fostered DER and smart grid technologies,[76] whereas others view them as having little or even negative benefits.[77] It seems reasonable to predict that a few electric utilities will undergo a major facelift over the next few years, while others will see only incremental if any change.

The overall question for state utility regulators is what actions they should pursue in view of these prospects for dramatic change in the electric industry.[78] Should they take the lead in proposing changes in utility operations and the business model, and

74. As an adopter, utilities do not have to be the creator of a new technology; they can simply acquire and use the technology for the benefit of their customers.

75. The inherent features of R&D pose challenges for a private for-profit company. It is expensive with costs commonly incurred several years before a company can reap profits or other benefits. R&D by nature is risky and success is difficult to predict. Innovations starting with R&D often require long lead times between basic science and commercial deployment. Competitors can also appropriate the benefits. New knowledge is especially appropriable, unless one has acquired patent protection. These features of R&D imply two things. First, companies are unlikely to innovate unless the payoff from successful innovation is substantial. Second, the market may under-allocate resources to R&D, providing a rationale for government funding.

76. The smart grid represents an information- and communications-based technology that gives utility customers the opportunity to better manage their electricity usage and participate in the management and operation of the grid in a more engaged manner. Paul L. Joskow, "Creating a Smarter U.S. Electricity Grid," 26 *J. Econ. Perspectives* 29 (2012).

77. States taking the most engaged positions to date are California, Hawaii, Massachusetts, Minnesota and New York.

78. States differ on the authority granted to utility commissions to initiate changes that would transform the electric industry. In several

how they regulate? Or should they wait longer to see what transpires in technology development, and regulatory and energy/environmental policies in other states and at the federal level? What are the costs of staying with the current utility business model and regulatory practices if radical changes occur?

At the other extreme, what are the costs of reshaping regulation and the utility business model when actual changes fall short of expectations? A misjudgment or error in selecting a business model is more likely with greater uncertainty of the future.[79] The public policy discourse so far has focused more on not doing enough than on going too far in reshaping the utility business model. Utilities and their regulators should consider the risks associated with both over-reacting and under-reacting to the expected changes for the electric industry.[80] Will an explosion in distributed generation be confined to a few geographical areas, or will it permeate across most states?

A. An Argument for Incremental Action

Each state faces unique economic and political conditions that would rationally lead them to pursue a different path for their electric utilities. Most states to date have favored incremental action in electric-industry transformation. This position reflects (1) hesitancy toward making major changes in a world of high uncertainty and (2) the willingness to learn (or the preference for learning) from the experiences of so-called leading jurisdictions.

Utilities and states do not have to be leaders in supporting new technologies and business innovations, especially those whose future values are in doubt. As "free riders," they can learn from the experiences, both positive and negative, of so-called leading jurisdictions. The followers can view activities in states like California and New York as a public good.[81] This posture seems rational in view of the highly uncertain future of most new technologies and the state of the electric industry.

To say it differently, a sensible approach is for regulators and other policymakers to hedge their decisions to account for uncertainty. A rational decision-maker would tend to respond to future unknowns by delaying major actions. To the extent that waiting reduces uncertainty, utilities may enjoy an "option value" from an investment delay owing to this uncertainty.[82] They might therefore prefer waiting for new information before making major changes. In other words, utilities and states do not have to be leaders in supporting new technologies, especially those whose future is in doubt.

A good case study of diverse state responses is the

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states, commissions see their role as narrow, restricted to enforcing any policy changes or other mandates established by the legislature.

79. Assume that the utility radically changes its business model to accommodate a high continuous growth in DG. If the actual growth fell far short of expectations, the costs of the transformation to the utility could be excessive and fail a cost-benefit test. Disappointing outcomes come from policies that assume a different state of affairs than what actually transpired. Regulatory practices and public policies can therefore fail not only because they move too slowly relative to prevailing technological and market developments, but also because they advance prematurely. The latter condition can occur when unfounded optimism about radical changes leads to investments and other costly actions that ultimately do not benefit either utility shareholders or ratepayers on whose behalf they were undertaken.

80. Type I and II errors are often applied by policymakers to evaluate the risks associated with a particular decision given that their projections of the future and other assumptions turned out to be wrong. A Type I error can result from society expending excessive resources on industry transformation when projections about new technologies turn out over-optimistic. A Type II error can result in society sticking with status quo policies when actual future conditions would have called for radical changes. A trade-off exists between a Type I and a Type II error: Reducing one type of error compromises the other. In the context of electric-industry transformation, utility customers can suffer losses from the wrong policy. Policies can encompass the utility business model, ratemaking, rules for fair competition, and financial incentives for clean technologies. For a general discussion of Type I and Type II errors, see William Mendenhall & James E. Reinmuth, Statistics for Management and Economics 323-33 (3d ed. 1978).

81. Cal. Pub. Utils. Comm'n, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (Aug. 14, 2014); N.Y. State Dep't Pub. Serv., *supra* note 25.

82. Option theory provides insights for decision-making by saying that when the future is uncertain, it pays to have a broad range of options available and to maintain the flexibility to exercise those options. Risk reduction can result from breaking major decisions into series of smaller decisions; that is, spreading decisions over time allows the regulator to respond to unfolding contingencies. Avinash K. Dixit & Robert S. Pindyck, Investment Under Uncertainty (1994); Robert S. Pindyck, *Irreversible Investment, Capacity Choice, and the Value of the Firm,* 78 Am. Econ. Rev. 969 (1988).

electric industry restructuring that occurred during the 1990s. Many observers believed that restructuring throughout the country was inevitable. In restructured states, a major obstacle was the divergent visions that interest groups held about the electric industry's future. There was no solidarity of views about the industry's future. For the other states, restructuring was not even a topic of discussion or stakeholders reached a consensus of "no change."

While a few states, such as California and New York, are proceeding boldly, most states have taken a more measured stance. Many questions remain before one can say with certainty that the electric industry will see a transformation over the next five to ten years. After all, many who are projecting change either have ideological (even bordering on a quasi-religious mission), or monetary interests in promoting such a path. Regulators/policymakers should therefore not accept these optimistic or rent-seeking claims for new technologies on face value but act accordingly to a future that may, but not with certainty, turn out much differently than what the consensus is forecasting today.[83]

This posture has implications for what course of action regulators should take today and in the immediate future versus waiting to see what transpires over the next few years. There is no denying that the prospect for big changes is a real possibility, if not imminent. Whether these changes will spread throughout the electric industry across most states depends critically on the changed behavior of retail customers from traditional to engaged.

B. Question of Future Customer Engagement

One particularly optimistic scenario is that many residential customers will invest in rooftop solar PV systems. It is plausible that only a small minority of households care enough about lowering their electricity bills to spend a large amount of dollars upfront or even allow a third party to make the investment and install a system on their rooftop. After all, the average residential household spends only about 2.7 percent of its before-tax income on electricity.[84] Experiences with retail choice have also shown that the vast majority of residential customers would prefer staying with their current utility rather than switching to a third party, even at the lost opportunity of lowering their electricity bill.[85]

V. Conclusion

Growing customer engagement has been a driving force behind transformation of the U.S. electric industry. The combination of technology, public policies and economics has made this possible, although the jury is still out on how fast customer engagement in retail electricity markets will proliferate in the coming years. To date, most residential customers have exhibited much inertia, ignoring opportunities to participate in retail competition programs or new pricing schemes like time-varying pricing. Even with the hype over rooftop solar, an extremely small percentage of U.S. households to date has taken advantage of this technology. [86] Notwithstanding this fact, this technology as well as others (e.g., smart meters)

83. Some analysts contend that the same condition accounts for both the recent push for distributed generation and support for retail competition in the 1990s; namely, that average cost exceeds marginal cost in both periods, meaning that utility customers can benefit from bypassing utility service (priced at average cost) and switching to another source (priced at marginal cost). Severin Borenstein & James Bushnell, Pub. No. EI @ Hass WP 252R, The U.S. Electricity Industry After 20 Years of Restructuring (2014). Because of this pricing discrepancy, it is difficult to know whether bypass improves net economic welfare (i.e., economic efficiency). The effect is cost-shifting between electricity customers, rather than real cost savings. Lost utility revenues, when exceeding avoided costs, typically pass through to remaining core customers in the form of higher rates. This contention basically says that customers want to avoid utilities' sunk costs by having the right to choose another supplier. The logical, if not politically palatable, remedy is to set utility retail rates based on marginal or incremental cost.

84. U.S. Bureau Labor Statistics, *supra* note 20.

85. Mathew J. Morey & Laurence D. Kirsch, Elec. Mkts. Res. Found., Retail Choice in Electricity: What Have We Learned in 20 Years? (2016).

86. At the end of 2014, the percentage of homes in the U.S. with installed rooftop-solar systems was about 0.5%. Half of these installations were in California alone. According to the U.S. Department of Energy, even if the annual growth of residential rooftop solar installations was 25 percent through 2020, electricity from this source would still be less than 1 percent of the nation's electricity supply. Energy Info. Admin., U.S. Dep't Energy, Pub. No. DOE/EIA-0035 (2016/8), August 2016 Monthly Energy Review (2016); Energy Info. Admin., U.S. Dep't Energy, Wind and Solar Data and Projections from the U.S. Energy Information Administration: Past Performance and Ongoing Enhancement (2016).

has triggered robust dialogue, and to a lesser extent actions by both utilities and state regulators, whether about ratemaking or the utility business model.

The attention given to the new electricity customer seems to overlook the fact that electricity is basically a commodity, and that the average residential customer may be satisfied with her electric service and the price she pays. Radical changes in customer behavior require electricity to be viewed more as a value-added service than a pure commodity. Also, because the amount an average customer spends on electricity is a small portion of her income, devoting additional effort to lowering the electricity bill may fall short of the expected benefits.

New customer engagement has triggered action by both electric utilities and their regulators. Even if a small percentage of electricity customers become engaged in the years ahead, utilities and their regulators will face increased pressure to modify their long-held practices. We have seen this already in net energy metering, where contentious debate has occurred notwithstanding the extremely small percentage of residential customers switching to rooftop solar technologies. Ratemaking is under intense review in several states partially because of the conflicting interests of DG and core customers. Regulators must decide how much they are willing to accommodate DG customers at the expense of other customers. Some states, including Hawaii[87] and Arizona, have already reached a triggering point where their recent actions have swung the pendulum away from rooftop solar to core customers. Other states are likely to follow suit in the future. This position reflects the concern that regulators have toward those customers who continue to purchase their entire electricity needs from the local utility.

The availability of unbundled products and services, and enabling technologies along with more timely information will all bolster customer engagement. Utilities will increasingly operate in an environment where a distinct line exists between engaged and traditional customers. This demarcation means that the dialogue over whether utilities should operate under a centralized or distributed business model is off-mark. Both models can coexist and perhaps each can benefit from synergy. Utilities will face additional costs and risks. The major challenge for state utility regulators is to protect traditional customers while eliminating any unreasonable barriers to engaged customers who want to exploit new technologies.

Customer bifurcation poses challenges for determining what role utilities should play, and the appropriate ratemaking and the business models under which they should operate. One big question is whether regulators should place more reliance on regulated utilities to innovate via robust incentives, or on third parties who are more entrepreneurial. After all, throughout their histories, electric utilities have displayed conservatism when creating or using new technologies and other innovations.[88]

Regulators will have to expand their interpretation of the "balancing act" to account for the disparate interests of traditional and engaged customers. They will likely emphasize the protection of traditional customers from cost-shifting and other utility activities benefitting engaged customers.

An opposing scenario is that since engaged customers are more sensitive to price and the quality of utility service, the natural inclination of utilities is to accommodate them by discriminating against traditional customers. This may seem at odds with the current utilities' positions on net energy metering, where they protest giving rooftop solar customers favorable treatment at the expense of other customers. More than anything, the utilities' chief concern is recovering their fixed costs. In the future, if more of their customers desire to switch to a third-party provider, utilities may discourage them through discounted or other forms of discriminatory pricing "funded" by

87. In 2015, the Hawaii Public Utilities Commission concluded that the retail rate net-metering credit is driving uncontrolled, undirected growth, and raising serious questions about cost shifting to non-solar customers. The Hawaiian Electric programs were capped at existing levels as of the release of the October 12, 2015, decision, and lower buy-back rates were instituted for new rooftop solar systems on each of the state's islands. Systems with existing retail rate net-metering deals will be able to retain them for the life of their contracts. One interpretation of the Commission action is that it reflects its belief that solar has become sufficiently competitive to require no additional assistance. Mark Dyson & Jesse Morris, *Hawaii Just Ended Net Metering for Solar. Now What?*, RMI Outlet (Oct. 16, 2015), http://blog.rmi.org/blog_2015_10_16_hawaii_just_ended_net_metering_for_solar_now_what.

88. The drive to radically change the telecom market came from unregulated companies, rather than the regulated companies.

traditional customers. Regulators may frown upon such actions, however, and oppose them as unacceptably discriminatory against those customers who continue to receive their total electricity needs from the local utility.[89]

In enhancing the benefits from customer engagement, regulators and other policymakers should provide utilities with better incentives to innovate and undertake R&D investments that are essential to the creation and dissemination of future new technologies. They should also make sure that utilities are not blocking innovations from reaching retail customers. Many of the new technologies that can benefit customers have their beginnings in the non-utility sector. If utilities erect barriers to their dissemination, customer engagement would likely experience a serious setback.

Finally, the experience to date is one where states have taken varying positions on electric industry transformation, of which customer engagement is a major driver. This diversity exemplifies the adage that states are "laboratories of democracy." Although some observers would disagree, sub-federal regulation has its merits in allowing different jurisdictions to decide what is best for them. Those states that remain hesitant are acting rationally according to option theory, which says that decision-makers should proceed cautiously in an environment of uncertainty. Although the U.S. electric industry is in a transition to something different, the future remains uncertain over the timing, nature, and magnitude of change. One source of doubt is the future spread of customer engagement.

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89. Some electric utilities in the past have offered special rates to discourage industrial customers from self-generating. Industry observers referred to them as "cogeneration deferral rates." As long as the utility is not charging below its incremental cost, according to the conventional economic argument, it is not uneconomical to offer a lower rate. There are three potential problems, however, with discount rates. First, they are definitely discriminatory: The only reason the utility is offering a special rate is that the customer has a "bypass" option [i.e., CHP production]; it is not because it is cheaper for the utility to serve that customer compared with other similarly situated customers. Price discrimination is often defensible, so cogeneration deferral rates are socially desirable under specific conditions. Second, there is a "fairness" issue of who absorbs the "revenue losses." A net-revenue shortfall requires that the CHP-potential customer would have continued to buy its electricity from the utility even in the absence of a rate discount. In this instance, any revenue losses would likely lead to higher rates to other utility customers. Third, discount rates could act as a barrier to CHP, stifling the long-term growth of the CHP sector. In fact, some opponents of discount rates argue that these rates are anticompetitive and in violation of the Public Utility Regulatory Policies Act. Cogeneration Coalition of America, Inc., *Petition for Expedited Investigation under Section 210 of the Public Utility Regulatory Policies Act and Issuance of Declaratory Order,* Docket No. EL87-34 (April 28, 1987).

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