THE ICER CHRONICLE

A FOCUS ON INTERNATIONAL ENERGY REGULATION

EDITION 3, MARCH 2015

The ICER Chronicle

Edition 3, March 2015
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I. Foreword

This, our third edition of the ICER Chronicle, is once again packed with interesting material. The articles chosen by the Editorial Board for this edition range from core regulatory issues (such as infrastructure investment, incentive regulation models and smart grids) through to latest policy developments (Europe's "Energy Union" concept) and a business strategy approach to sustainability.

The Chronicle is not only aimed at the world's electricity and gas regulators, but also policy makers, academics, consultants and professionals with an interest in energy regulatory affairs. Through its pages we aim to share good practices, leading edge thinking and novel approaches to challenges faced by energy regulators which can begin to inform other policy and practices in other jurisdictions.

The Chronicle is a bi-annual online publication of the International Confederation of Energy Regulators (ICER). ICER itself was created in Athens in 2009 at the fourth World Forum on Energy Regulation (WFER). ICER aims to enhance collaboration between energy regulators on issues affecting energy regulation globally. It also seeks to enhance the understanding of policy makers in governments on the role of energy regulation in respect of broader energy policy. ICER is a truly international organisation and depends on the commitment and contributions of energy regulators internationally, and on a number of other bodies where the public interest issues of energy policy play a significant role in their activities. The ICER Chronicle, for example, is produced by its Working Group 4: Regulatory Best Practices led by NARUC, the U.S. state-level regulatory association.

The 6th World Forum will take place in Istanbul in May 2015 (www.wfer2015.org) where ICER will present three reports on innovation in regulatory practices in the areas of regional market integration; regulation and investments in new technologies; and consumer protection and empowerment. The winners of two ICER Distinguished Scholar Awards will be announced in Istanbul at WFER VI to those candidates. In this and other ways ICER works to foster new approaches and to develop good practices from which all regulators (and ultimately energy consumers) can benefit. A further example is the ICER Women in Energy (WIE) initiative which aims to unlock the full potential of women in energy regulation.

As always, we welcome your feedback on the Chronicle. Should you have an original article you think would be of interest for future editions of the Chronicle, please submit it to chronicle@icer-regulators.net.

Lord Mogg
ICER Chairman

II. Welcome from the Editorial Board Chair

On behalf of ICER Working Group 4: Regulatory Best Practices, I am excited to share Edition 3 of the ICER Chronicle. The Chronicle is a means to further promote ICER's goals of enhanced exchange of regulatory research and expertise. If you missed previous editions, please visit: http://www.icer-regulators.net/portal/page/portal/ICER_HOME/publications_press/ICER_Chronicle/Archives

The Chronicle is published biannually in order to share information among international energy regulatory agencies and beyond. If you haven't received this subscription directly, you can join our list-serve by emailing chronicle@icer-regulators.net.

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. The deadline for consideration for inclusion in the next edition of the Chronicle (Edition 4) is August 3, 2015.

Finally, I would like to thank the dedicated members of our Editorial Board. They thoughtfully reviewed all submissions and assessed those that are particularly interesting and timely to the global regulatory community.

Sincerely,

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Many thanks to the following support staff who contributed to the design and development of the Chronicle:

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Ms. Natalie McCoy, Secretary General, CEER
Ms. Una Shortall, Deputy Secretary General, CEER
Ms. Anh Tran, ICER Secretariat, CEER

III. Women in Energy (WIE) Story Telling

Our WIE story telling section shares stories by women in energy regulatory authorities from around the world. These authentic, personal stories reflect the richness and diversity of our global network of energy regulators. But geographical and cultural boundaries fade when people connect through story telling.

Our two latest stories come from the Republic of Serbia (Ms Brkic-Vukovlajak) and from the United States of America (Ms Denise Parrish).

Interested in joining Women in Energy – the ICER International Network?

Connect with regulatory peers from across the globe

Share professional experiences

Benefit from our webinars and mentoring programme

The ICER WIE network is open to all staff (men and women) of ICER's energy regulatory authorities. It's free to join! Visit http://bit.ly/ICERWomenInEnergy

Are you a woman in energy with an inspiring story to share?

Due to repeated requests to widen our WIE story telling, ICER is pleased to open the story telling to all women in the energy sector (both within and beyond energy regulatory authorities).

To share your WIE story, visit the Chronicle section of the ICER website www.icer-regulators.net or contact us at chronicle@icer-regulators.net to learn how to submit your story.

For inspiration, check out the WIE story telling section of the ICER website.

Many thanks to all our story tellers.

Una Shortall
Chair of the ICER Women in Energy Steering Group

Women in Energy Story Telling: from the Republic of Serbia

Milica Brkic Vukovljak

Milica Brkic Vukovljak, has more than 10 years of experience in the Serbian energy sector. She worked in Serbian national transmission system and market operator for seven years mostly in the market department as an allocation manager. She has a Certificate of Completion from the Florence School of Regulation 2014 course. She works for the Energy Agency of the Republic of Serbia in a technical department after Serbian TSO. She is a mother of twins and she is on PhD studies.

A few days ago I was in a hospital because of some terrible allergy, waiting for my anti-histamine vaccine. A very nice doctor, a woman, was polite and asked a lot of questions. When she realised that I work for the Energy Agency she asked me if I was the one responsible for possible increases in energy bills? She was trying to explain how people in Serbia do not have enough money for energy prices to be in line with European energy prices. I said ok I agree. I explained that we need money to buy energy after the floods that struck our country in spring 2014(as we were importing 800MWdaily during summer). I asked her is it is better that we take loans from the EU and International Monetary Fund and have lower salaries or have a higher price for energy and the same salary and then decide how we use the energy and how we spend our salaries? (The alternative is taxes on salary and cheap energy). “In this case you convinced me”, she said. That’s my job!

Turning Challenges into Successes

The biggest challenge that I have faced was at the beginning of my career. After graduating from university and having already international experience in the power system world (Germany, Slovenia…), I applied to work for PE EPS who had advertised vacancies. I was faced with an unbelievable reality. All the open positions (for power system dispatchers) required men only. I was confused. Two years later, I worked in PE EMS (the Serbian public enterprise for electricity transmission system and market operator) along with dispatchers. My point is: diplomas have no gender! If you have worked hard enough to earn it, you have to believe in yourself and to try maybe a few times more to get where you want to be. After I got a job I shared my sad story from the beginning.

The biggest project that I worked on was from 2006 until 2009 on the allocation of transmission capacity on Serbian borders. I was part of a team that was creating rules, coordinating with colleagues from Unicorn (Czech Republic), in making an auction office platform named DAMAS for capacity allocation, and afterwards creating a joint auction on the Serbian borders with the Hungarian and Romanian Transmission System Operators (TSOs).

Balancing Life

This is a challenge even today. I am a proud mother of three year old twins, Jana (a girl) and Luka (a boy). I am doing PhD studies at the University of electrical engineering in Belgrade and I have finished a regulatory course at the Florence School of Regulation (in Italy) last year. So work -life balance is an everyday challenge.

The Benefits of Exchange

The main benefit of the ICER Women in Energy (WIE) network is sharing experiences and knowing that you are not alone, that there are a lot of great women in energy.

WIE can help attract talented women to the energy sector. If you can promote other successful woman in energy and they tell their true career and life stories, then talented young women can live their dreams knowing that they can be one of them.

My Success

Being open-minded, having self-confidence and being a really hard worker.

I also feel I was in the right place at the right time. I had a chance, when there was no deregulation process in Serbia, in 2003 to visit the Slovenian faculty's energy department and attend the Balkan summer school. This gave me my first insight in energy policy and the energy market.

In the Energy Agency of the Republic of Serbia half of the technical department are women, which has proven to be a good source for learning from each other. I believe we can benefit from sharing our experiences.

I wish that we have the same opportunities as men do. When you are going for a job interview gender should not be taken in to consideration. In Serbia sometimes there is a problem for young women to be hired because they may be planning to have a family one day. It is thought to be better to hire young men instead, because men will not be going on maternity leave.

My Advice

Never give up! Believe in yourself! Work hard!

Women in Energy Story Telling: from the United States

Denise Parrish

Ms. Parrish has worked in utility regulation for more than 37 years. She is a manager and working rate analyst who enjoys teaching about regulatory matters. She has worked for four regulatory agencies and two consumer advocate entities. She is currently the Deputy Administrator at the Office of Consumer Advocate, Wyoming Public Service Commission. She is a past chair of the NARUC Staff Subcommittees on International Relations and Accounting & Finance. She is a member of the NASUCA Tax and Accounting Committee, a member of the ICER Virtual Working Group on Consumers, a founding member of ICER's Women in Energy and works with ERRA's Tariff/ Pricing Committee. She is thankful that her husband is her biggest supporter.

Turning Luck Into Success

It was late winter in 1977. I was an underemployed college graduate with an accounting degree. I had moved back home to live with my parents and look for work. When the call came to interview with the Michigan Public Service Commission, I asked around… what does it do? Utility regulation, I was told. It must do more than that, I responded. That can't possibly be full time work.

In April, 1977 I began what has *so far* been a 37 year career in utility regulation. I was hired with a group of other young recent college graduates. The majority of them were women as there was a policy of trying to offer equal opportunity employment in the work force of state government. We became friends, hanging out socially and growing professionally. Some of the group decided to study to become Certified Professional Accountants (CPAs). I decided I wanted to focus on my new job. I was single and focused. I took piles of reading material home at night and tried to learn about this strange new world of regulation that I had just entered. Any time I could break away from my office, I sat through hearings, learning the special language of energy regulation; learning how important it is to have good communications skills; and learning that in the end it is all about the money -- and professional relationships.

Flash forward to 1991. I have now worked in three different states but have maintained a career in utility regulation. I have had good bosses and bosses that were tolerated. Some were men and some were women. My abilities and interest grew under all of them. Some were mentors (whether they knew it or not) and I am very grateful to them for the lessons they taught me. The best of my bosses forced me to work on matters about which I knew nothing, knowing that I was capable of learning if forced to do so. I tried to be a good employee by not disappointing. I was raised to work hard and do my very best. I hoped that my best was good enough.

In 1991, I was offered a new job at the Wyoming Public Service Commission as the Chief Accountant/Chief Rate Analyst – a fourth state in which I would work in regulation. I took the job but I was not fearless about it but was instead fearful. I was nervous knowing that people would turn to me for advice and training and wondered if I was really prepared to take on such responsibilities. But, I was ready for a change and jumped in with both feet. My talents had been underutilized. I had now gone from being a small fish in a big pond to a big fish in a small pond. I worked hard. I was given more responsibilities over the years. I made myself a go-to person. I built professional relationships, many that still exist 20+ years later.

The Benefits of Exchange

I became active in the National Association of Public Utility Commissioners (NARUC), helping to author technical recommendations and white papers, not just attending but participating in meetings, and making both male and female friends from states around the country. I was able to learn from the experience of others I met, and did not have to reinvent the wheel with each new issue. I contributed to the work of a larger group of regulators, finding that working together was often more effective and efficient that working alone.

Fast forward to the 2003. I received a call from a colleague running a training program for new regulators wondering if I knew anyone who can teach basic regulatory accounting at her training program. The notice is short and I rack my brains to think of someone. I tell her I'll let her know. I relay the story to my husband at lunch that day. He stares and me and asks if I'm kidding, right? Really, you didn't get it? *She was asking you if you would be willing to come teach*. Looking back, I don't know if that was true or not. But two weeks later, I was on a plane with my first ever power point slide deck. More than ten years later, I continue to go back annually to my alma mater and talk to new regulators. It is an absolute honor. It is also my duty to help others learn about this crazy world of regulation, after looking back at all the people who have helped me.

The next year brings even more surprises. Sitting in my office one winter morning, I receive a phone call asking if I would like to go to Nigeria and talk to the Nigerian Communications Commission. A colleague from across the country has committed to go but circumstances intervene and he can't. A last minute replacement is sought and I have been recommended. I explain that I don't even have a passport. *(Perhaps the recurring dream that I have had over the years about landing in an overseas location without a passport is now explained.* My advice: everyone should get their passport and keep it current.) I call my husband and ask if he has a problem if I go to Nigeria. *Sure, why not,* he says, *can you find it on a map?* We haven't been married long enough for him to know that I am serious and not kidding. I spent Easter of 2004 in Abuja, my first trip overseas.

Never Stop Learning

Fast forward to today. I have been to 23 countries, not counting the USA, and have regulatory friends around the world. Much of my vacation time is spent attending regulatory conferences, but when that conference is in Abu Dhabi or Athens or Bishkek or Budva, why not? I find myself saying Wow, how lucky am I? Each one of these trips has enhanced my personal and professional life. I learn a little something about regulation with every presentation I prepare. I learn something about regulation every meeting or conference I attend. I have brought ideas back from overseas that immediately became part of a recommendation before my own regulatory agency. My Christmas card list now includes addresses in Budapest, Kiev, Kishinev, Abuja, Toronto, and Quebec. My passport is full but my mind has been opened.

Looking back to that fateful interview in 1977, have I figured out yet what regulators do? Not completely, since every decade – or even every year – brings new challenges that have never been imagined. Sure, it is still economic regulation where the interests of owners and customers are balanced. We still want utilities to provide safe, adequate, and reliable service at affordable prices. The mission remains the same. Yet, after thirty-seven years, I can say there is still a lot to learn and resting on my past successes is not on option.

My Success

Would any young female college graduate with an accounting degree have been acceptable to fill the job of a novice staff auditor working on fuel surcharges back on that fateful day in 1977? Probably, and it was by the luck of the draw that I happened to be the one who was hired. Did I turn that luck into success through hard work and commitment? Yes, but I can't imagine doing anything else. It wasn't always an easy career but it is one I look back upon with pride and a sense of accomplishment.

Being a woman got my foot in the door. Being a strong-willed person who happens to be a woman kept my career moving forward. Hard work and persistence brought me success. Hanging out with my women regulatory friends from around the world brings me satisfaction.

Considering a career in regulation? C’mon in. Let me show you the basics and we’ll learn the rest together.

IV. Integrated Distribution Planning – An Idea Whose Time Has Come

By Paul Alvarez

Reprinted with permission, Public Utilities Fortnightly

For decades now, most states have required Investor-Owned Utilities (IOUs) to file periodic plans describing least-cost, least-risk approaches for meeting anticipated future loads. Though many restructured states have replaced “Integrated Resource Planning” with “Procurement Planning”, the goal is essentially the same: complete a public process to help assure regulators (and other stakeholders) that low-cost electricity will be reliably available to customers when needed. More recently, integrated resource planning (IRP) has also been used to accomplish other ostensibly worthwhile goals, such as renewable portfolio standards, with as little cost and risk to customers as possible. To date, integrated resource plans have focused almost exclusively on electric generation options, including consideration of related issues such as transmission and demand-side management potential, capabilities, and costs.

This article proposes and evaluates the idea of applying integrated resource planning principles to distribution grid modernization. Using IRP goals, processes, and characteristics as a guide, readers will recognize the potentially significant value of Integrated distribution planning (IDP) in reaching future customer, community, and societal goals in the most cost-effective and low-risk manner possible. We’ll begin by looking at the changing role of distribution grids and modern distribution grid investment characteristics. We’ll also consider a potential framework for an IDP process and its likely value to community planning and development stakeholders.

The changing role of distribution grids, associated investment characteristics, and the need for IDP

As the roles that distribution grids (and utilities) will be asked to play in the future evolves, the characteristics of required investments (and planning) will (should) change too. Before the recent grid modernization gold rush, the capital a utility might request for its distribution grid in a rate case might have amounted to $100 per customer. Today, a utility’s comprehensive grid modernization proposal might amount to $2,000 per customer *or more*. Historically, customers demanded that distribution grids reliably accommodate 1-2% load growth annually; today, stakeholders are demanding that distribution grids meet a variety of customer, community, and societal goals, each presenting its own challenges and many in conflict with others:

- Accommodate ever-greater customer choice, including self-generation, electric transportation, microgrid, payment, and pricing options
- Maintain or enhance reliability, including reduced vulnerability to cyberattacks and severe weather
- Increase the energy efficiency of the distribution grid
- Remain economically viable/maintain low capital costs while holding rates down during times of falling sales volumes

If the dramatic changes in distribution grid and utility roles aren’t enough to prompt a new approach to distribution planning, perhaps the uncertainty associated with future customer technologies is. How might convenient, cost-effective energy storage change the distribution grid and utilities? What about the connected home and the internet of things relative to demand response and real-time pricing? The timing and extent of customer generation and electric vehicle adoption? These ‘known unknowns’, not to mention the ‘unknown unknowns’, threaten to make IRP modeling look simple by comparison.

Also consistent with resource planning, grid modernization presents a dizzying array of design alternatives presenting different types and levels of attractiveness depending on one’s priorities (cost reduction, risk reduction, reliability, flexibility, environmental impact, customer choice, etc.). Smart meter communication network choices alone probably number in the dozens, each with its own pros and cons on a variety of measures:

- Build a dedicated network or buy network services from available service providers?
- Support the use of meters as home energy management gateways? Or leave to private sector?
- Make customer usage data available in near real time? For individual queries or ‘en masse’?
- Provide communications infrastructure for multiple utilities/services? Or for other city services, from Police and Fire to Parks & Recreation and Facilities Management?

These issues are summarized in the table below. Readers familiar with the integrated resource planning process will recognize the similarities to “Modern Distribution Investment” characteristics right away.

Characteristic	Historical Distribution Investments	Modern Distribution Investments
Investment Requested	Small ($100 per customer)	Large ($2,000+ per customer)
Investment Objective	Reliably accommodate 1-2% annual load growth	Accommodate a variety of customer, community and societal goals
Future Operating Environment	Highly certain	Highly uncertain
Design Alternatives	Few	Many

Table 1: Distribution Investment Characteristics, Historical vs. Modern

Potential Framework for an Integrated Distribution Planning Process

Having made the case that a new approach to distribution planning is long overdue, a framework for an IDP process is presented for consideration. Like resource planning, most communities will be well-served by updating an IDP periodically, perhaps every 3 years. The proposed IDP development framework includes visioning, roadmapping, and business planning.

Visioning. In the visioning step, stakeholders are encouraged to take a 15-20 year view of a community’s distribution grid and utility while answering several questions:

- What roles will our distribution grid and utility play in our community’s economic and environmental sustainability?
- What economic and technical developments in customer technologies (generation, storage, loads, controls, microgrids, etc.) are likely?
- What is the value of customer choice relative to developments in customer technologies?
- What economic and technical developments in grid technologies are likely?
- What threats (weather, cybersecurity, economic) are our grid and utility likely to face?
- What changes in distribution grid and utility capabilities are we likely to need?

The answers should be captured in a document which translates educated guesses into potential and desired future states for a community, its (electric) energy needs, and associated grid/utility capabilities. 'Collaboratives' formed to develop a grid vision in several states (in particular Illinois, Kentucky, and New York) are a step in the right direction, but as one-time events without further role or responsibility, their value is limited. Ideally, a grid vision is periodically updated and serves a specific purpose: to help stakeholders prioritize focus areas to develop in more detail as part of a grid modernization roadmap.

Roadmapping. With agreement on a vision, the IDP takes shape in greater detail through roadmapping. Roadmaps consist of short-term (1-4 years), moderate term (5-10 or so years) and long-term (beyond) outlines for the evolution of a community's grid and utility over time. Ideally, roadmapping should include some high-level cost estimates to assist with prioritization and trade-offs. In summary, it specifies the methods by which a community plans to achieve as much of the vision as possible with as little cost and risk as possible. While a vision may be aspirational in nature, a roadmap is much more practical. Ideally, the roadmap specifies objective performance metrics and target values for each timeframe, offering a yardstick by which to measure progress toward the vision.

	Short Term	**Moderate Term**	**Long Term**
Resiliency	Catastrophic event: 100% restoration in 5 days	Catastrophic event: 100% restoration in 4 days	Catastrophic event: 100% restoration in 3 days
Reliability	99.96%	99.98%	99.99%
Customer Efficiency*	Average head-end voltage 120v/circuit	Average head-end voltage 117v/circuit	Average head-end voltage 114v/circuit
Capital Efficiency	Callable demand response should be at least 3% of peak	Callable demand response should be at least 6% of peak	Callable demand response should be at least 10% of peak
Customer Choice^	Accommodate distributed generation capacity of up to 50% of minimum recorded demand per circuit	Accommodate distributed generation capacity of up to 100% of minimum recorded demand per circuit	Accommodate distributed generation capacity in excess of 100% minimum recorded demand per circuit
Economic Sustainability	Distribution rates in lowest 50% of utilities	Distribution rates in lowest quartile of utilities	Distribution rates in lowest decile of utilities

Table 2: Sample Roadmap Metrics, Target Values, and Time Frames

* With no increase in customer voltage complaints

^ While simultaneously achieving the reliability targets

Roadmap development is also the part of the IDP process in which stakeholders should agree upon other specifications, strategies, and features, including secondary goals and requirements. These can be captured in what is known in product development parlance as a *requirements document*. Some examples include:

Requirement	Rationale
Two financially sound suppliers shall be secured for each technology component	Interoperability keeps selected suppliers on their toes and reduces obsolescence risk
Proprietary/niche solutions shall be avoided in favor of open-standard, proven solutions	Reduces obsolescence risk, demands pragmatic design choices, and encourages competition for utility and customers' business
Increased customer choice (rate options, self-generation, energy management, etc.) has value and should be considered in business plans	Helps maximize the flexibility inherent in grid modernization designs and better prepares the grid for an uncertain future
All purchases should be warranted by their suppliers for at least 5 years	Transfers some economic risk from communities to suppliers
Distribution rate increases should be kept to no more than 1.5% annually	Ensures cost-effective capability prioritization and supports community economic development

Table 3: Sample Components of a Requirements Document

In summary, the roadmap provides the goals, objectives, strategies, and requirements utilities (and other stakeholders) can use to guide business planning.

Business Planning. A business plan puts meat on the bones of the short-term component of the roadmap, providing details on costs, capabilities, benefits, schedule, and fit with the priorities established in the vision and roadmap. The business plan is technology and supplier centric, including a great deal of RFI and RFP work. As this is a utility's area of expertise, the bulk of business plan work falls to it. But stakeholders must remain actively involved, ensuring business plans are consistent with the vision and roadmap, maximize bang for the buck, and incorporate post-deployment activities critical to capability optimization. It's particularly important that business plan, capability, and technology choices do not constrain future options or inhibit roadmap/vision attainment. A strong business plan incorporates all of the following components at a minimum:

- A business case with a positive customer NPV (the present value of direct economic benefits exceeds the present value of capital and related operations and maintenance spending)
- Details of new capabilities and their relative contributions to roadmap metric achievement
- An implementation project plan detailing deployment schedules, monitoring and control procedures, organizational changes, and other activities designed to ensure anticipated capabilities are delivered within budget in a timely manner
- A detailed post-deployment action plan illustrating how the utility plans to optimize the direct economic, environmental, and customer choice benefits of new capabilities through innovation, operational change management, and customer programs.

The Potential Value of Integrated Distribution Planning

Customers, communities, and utilities all stand to benefit from an ongoing IDP process and associated updates.

Customers. "Average" customers stand to gain more than others from an IDP process. While low -income customers are represented by consumer advocates, and large commercial and industrial customers have the motivation and wherewithal to advocate their positions, the average customer's interests are not well-represented in today's litigious rate case and grid modernization proceedings. It's possible an IDP process could better address typical customer needs, wants, and priorities. It's also likely a formal IDP process would deliver greater economic, reliability, and customer choice benefits per dollar for the average customer.

Communities. Grid modernization stakes are high. A community's grid will have a disproportionate impact on its future economic and environmental sustainability. While advocates of the environment and distributed generation are typically well-organized and focused, the plates of elected local and state officials are full and focused on short-term issues. Grid modernization merits a place at their tables. In some states and communities, legislators are guilty of abandoning critical grid planning activities to utilities. At the other extreme, well-intended but under-informed grid legislation can pre-empt any IDP process and its potential benefits entirely. A formal IDP process, by virtue of its "many heads are better than one" nature, is likely to deliver greater community value per dollar than either "hands off" or "hands on" legislative approaches.

Utilities. It is understandable that utilities – both for profit and nonprofit – would prefer to maintain complete control over grid investment choices. But the reality is that the choices utilities are making today will affect customers and entire communities for decades. This, in addition to the fact that customers and communities ultimately pay for these investments, makes it highly appropriate that decision rights be shared. But after giving it some thought, utilities will likely recognize a prudent motivator for sharing decision rights beyond 'it's the right thing to do': risk management.

In environments characterized by significant future uncertainty, the likelihood that decisions made today will be correct is very small. By holding tightly to decision rights, utilities increase the probability that their choices will be second-guessed -- quite possibly to their economic detriment – in the future. If choices made today are likely to be judged in the future, better that the choices be made with the documented input and support of stakeholders. Looking back from some future date, utilities will reduce stranded asset risk by being able to categorize grid modernization decisions as "community" choices rather than utility choices.

An IDP process also reduces customer satisfaction risk. As it is impossible for utilities to satisfy all stakeholders, it is difficult for utilities to be perceived as anything but an enemy of all stakeholders. A properly-executed IDP process forces stakeholders to educate themselves, compromise, and agree upon future directions. An IDP process could take the guesswork regarding "what's best for our community" out of utility and/or regulatory hands. In an IDP process, a utility's role shifts from bad guy to subject matter expert/consultant/educator. Consider the significant difference in the following phrases:

- "Here's what we propose to do."
- "If the community agrees it wants to prioritize <u>(fill in the blank)</u>, there are really 3 ways to go about it. Here are the pros and cons of each approach."

This article has illustrated the need for IDP, presented an IDP process strawman for consideration, and described the potential value propositions of IDP for customers, communities, and utilities. It is quite possible IDP would result in better grid investment choices than a utility acting on its own, but there is another critical aspect to maximizing customer and community return on grid investments: ongoing utility operations. Unlike traditional grid investments, in which there is a fairly direct correlation between grid investment and customer value (reliability), modern grid investments generally deliver new capabilities. The optimization of those new capabilities is far from assured. In fact, optimizing those capabilities to their fullest extent requires extensive utility program, operations, and policy changes that are not necessarily encouraged (and in fact are often discouraged) by traditional ratemaking practices and regulation. (For example, my teams' primary and secondary research indicates that about 1/3 of the direct economic benefits in an optimized smart grid deployment stem from energy conservation.) The RIIO model being implemented in the U.K., the New York PSC's "Reforming Energy Vision" docket, and Maryland's "Utility 2.0" initiatives hold promise, and communities considering grid modernization investments are strongly encouraged to consider changes to regulatory and governance models as part of IDP. But that is a subject for another day . . .

Paul Alvarez leads the Wired Group, a consultancy helping clients unleash the latent value in distribution utility businesses. A veteran of the utility industry as both insider and consultant to regulators, advocates, associations, and suppliers, he has led comprehensive, unbiased evaluations of large smart grid deployments for utilities and regulators. He has served as a subject matter expert on smart grid, demand response, distributed generation, and regulatory and ratemaking reform before many US state regulators. Author of *Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment,* he is also an adjunct professor at the University of Colorado's Global Energy Management Program and Michigan State University's Institute for Public Utilities. He is scheduled to serve as the keynote Policy program speaker at the SmartGridEvent 2015 in Brussels on June 3rd, delivering "Lessons Learned from US Smart Grid Deployments: An Unauthorized Account".

V. The Development and Application of an Incentive Regulation Model – a Balancing Act

By Roar Amundsveen and Hilde Marit Kvile

1. Introduction

Norway has 147 distribution system operators (DSOs) serving a population of about 5.1 million people. The DSOs are institutional monopolies that are regulated by the Norwegian Water Resources and Energy Directorate (NVE), which is a directorate under the Ministry of Petroleum and Energy. One of NVE's mandates is to promote efficient energy markets and cost-effective energy systems, and since 1997 revenue cap regulation has been one of the means to achieve this. As many other regulators, NVE has applied benchmarking methods to evaluate the companies' performances as part of the revenue caps calculation.

In general, the literature of regulation contains detailed descriptions of models for optimal prices, different regulatory schemes from cost-of-service to high-powered incentive schemes, benchmarking models etc. However, there are less descriptions of how regulators actually develop regulatory models. This may be too detailed to be part of the literature, but may also be regarded as internal regulatory matters that should not become public.

The Norwegian regulatory model is transparent in the sense that all data, assumptions and calculations are published, and it is possible to check all results in retrospect. This model is therefore an ideal case study in order to highlight the importance of the regulator being aware that every element in the model will affect the companies' incentives, and how it affects the incentives. By presenting the regulatory model for the Norwegian DSOs we will discuss this process of balancing incentives.

Implementation and development of a sustainable regulatory regime depends on several factors. It is important to have an appropriate legal framework with clear and defined objectives. The legal framework of the regulation of the electricity distribution companies is based on the Energy Act from 1990[1]. One of the main objectives of the Energy Act is to ensure that transmission and distribution of electricity are accomplished in a socially rational manner. The incentive regulation of DSOs is one tool to achieve this goal. It is important to acknowledge, however, that incentives can only influence some of the behaviour of a company. To create an efficient regulatory framework, there is need for direct regulations and compliance monitoring as well.

The means of the revenue caps are described in a legal regulation based in the Energy Act; the revenue caps shall cover costs and depreciations and give a reasonable return on invested capital over time, given efficient operation, utilization and development of the grid. NVE develops the regulatory framework given the objectives of Acts and regulations. The calculation of allowed revenue and revenue caps is stated in one of the legal regulations based in the Energy Act, but the benchmarking model is not described in a legal regulation. Still, when NVE changes elements in the benchmarking model, this is treated similarly to changes in the regulatory model. We ensure a proper communication with the industry and other stakeholders, and publish suggested changes on public consultations. NVE regards a credible regulatory practice over time as an important success factor. It is important that the industry regards the regulator as reliable, transparent, predictable and non-discriminating. Thorough communication on the regulatory model and fast and consistent case proceeding over time are factors to achieve this.

2. The Regulatory Model for Norwegian DSOs

2.1 Allowed Revenue

For each DSO i, NVE calculates allowed revenue yearly. Allowed revenue is the tariff base for the company. The formula is:

$AR_i = RC_i + PT_i – VOLL_i + TL_i$

AR_i is the allowed revenue and RC_i is the revenue cap. PT_i is pass-through costs; they are considered to be outside of company control[2]. It is important for the regulator to acknowledge that all not costs are controllable by the companies. $VOLL_i$ is value of lost load. This mechanism was introduced in 2002 and calculates the socio-economic cost due to power interruptions. For every interruption, the VOLL is calculated by cost functions, and the value depends on the type of customers that is affected, duration and time of the interruption. Deducting VOLL from allowed revenue makes sure companies regard socio-economic cost of interruptions as any other cost in the company.

TL_i is a mechanism for removing time lag for investments. This is included because the costs used in calculating the revenue cap are two years old (e.g. 2011-data for 2013-revenue caps). These are the most recent data NVE has available when calculating ex-ante revenue caps. Using two-year-old capital cost in the revenue cap may give disincentives for investments. This has been a general challenge in regulation, and over the years, regulators have applied different solutions to increase incentives for investment. One example is an adjustment for investments that is calculated based on previous investments. From 2009, NVE removed the time lag on capital entirely by introducing this TL mechanism. When NVE calculates allowed revenue for 2013 (in Dec 2014), we know the capital costs for 2013. The difference between these capital costs 2013 and the values for 2011 (that were used calculating revenue caps for 2013) are added (or deducted from) to the allowed revenue. This means that companies can include estimated capital costs from investments in the tariff base already from the year of the investment. It also means that for the first two years of an investment, the capital is not benchmarked.

The allowed revenue is compared to the actual revenue from tariffs. Excess revenues must be paid back to the consumer through lower tariffs; deficits may be collected from consumer through higher tariffs. A large part of the incentives for cost efficiency comes from the revenue cap model, but due to the introduction of VOLL and TL a significant part of incentives for investments and quality stems from the determination of allowed revenues.

2.2 Revenue caps

The revenue cap is the main element entering the calculation of allowed revenue. The revenue cap formula is:

$$RC_i = (1-\rho)\cdot C_i + \rho \cdot C^*_i$$

RC_i is the revenue cap, ρ is a scalar between 0 and 1. C_i is the cost base and C^*_i is the cost norm. The cost base is calculated from the company's own costs, and the cost norm is calculated based on other companies' costs. The calculation of the cost norm will be described in section 3.

Operation and maintenance costs, network losses, VOLL and capital costs are included in the cost base. Capital costs are calculated as depreciations and calculated return on the regulatory asset base (RAB). The RAB is based on book values by 31.12 from the company's accounts. The return is a regulatory rate of return calculated from a WACC model. A further description of this is found in Langset and Syvertsen (2013). All costs are updated every year.

Using both cost base and cost norm implies a sharing of risk and profit between the company and their customers, and the size of ρ decide the strength of the incentives for cost efficiency. When $\rho = 0$, we have a cost plus model with no incentives for cost efficiency. $\rho = 1$ is a pure yardstick model where the companies' revenues are completely independent of their own costs, giving very strong incentives for cost efficiency. Setting a reasonable value for ρ will depend on for instance quality of data and trust of the model. The ρ in the Norwegian model is set to 0.6 in the legal regulation. When the model was introduced in 2007, this increased the incentives for cost efficiency from the previous model.

3. The Cost Norm

The cost norm is calculated in three stages. Choices in one stage can create challenges in other stages and weaknesses in one stage can be reduced in other stages.

1. DEA model
2. Adjustment of DEA scores due to heterogeneity in operational environments
3. Calculation and calibration of cost norms

For NVE, DEA has been the main methodology in the calculation of revenue caps since 1998, but other methodologies such as COLS and SFA have also been used in analyses and in model development. Kittelsen (1994) recommended NVE to use DEA because there was limited information about the properties of the production function. In the beginning, the industry regarded the benchmarking model as "a black box", but today the industry is quite confident in the use of DEA.

3.1 Stage 1 – The DEA model

NVE's approach when choosing variables for a benchmarking model is that the variables must be conceptual, intuitive, significant and feasible. NVE applies a DEA model with one input and three outputs.

3.1.1 Input

It is possible to define inputs as quantities or as monetary values, e.g. as man-years or labour costs. Quantities are useful if factor prices are unknown. Monetary values require that factor prices are known, or they have to be identical for all the companies. An advantage with monetary inputs is that it is possible to summarize different inputs into one aggregated input. A company can for instance choose to use its own employees, which would be reflected in the total wages. Alternatively, the company can choose to buy this service in the market that is reflected in the cost of services. These two alternatives, or the combination of them, can contribute to the same level of output. The ideal combination can depend on the local market situation.

In the Norwegian model, we have chosen monetary inputs, and we have chosen to add all costs into one input. We regard the benefits of this approach as greater than the loss of factor prices not being equal. The total cost is similar to the cost base[3] and is the sum of:

- operation and maintenance cost (OM),
- cost of energy losses,

- value of lost load (VOLL),
- depreciations and
- regulatory rate of return[4] on regulatory asset base (RAB)

We think it is important that all types of costs are reflected in the input. Companies face trade-offs between the different costs. They can choose to increase maintenance and thereby delay a capital investment. They can choose to build more underground cable to reduce interruptions in the supply. If the regulator chooses to treat the different cost elements differently, it may give incentives to favour certain costs. E.g. if capital is not benchmarked it gives incentives to reinvest too early or too expensive (gold plating effects).

Calculating capital costs is in our view one of the most challenging issues; how they are calculated has a strong effect on incentives for investments. In the Norwegian model, the regulatory asset base (RAB) is the book values from the companies' accounts. The advantage of using book values is that it reflects what the companies actually have paid for their assets, and all companies have to follow the same accounting rules. However, using book values means that the input is affected by the age of the assets. Two companies can have exactly the same assets, costs of loss, OM and VOLL, but if one company has older assets than the other, the capital costs, and therefore the total cost, will be lower. The DEA results will therefore reflect both inefficiency and the age of the assets.

It has been a critique to the regulation model since 2007 that the model gives disincentives to invest in a time where the need for investments is large[5]. In the long run, all companies must invest and the age effect will disappear. However, NVE has recognized the challenge companies face when large parts of the cash flow comes towards the end of an asset's lifetime, and have therefore introduced mechanisms in the third stage of the calculation of the cost norm to reduce some of the age effect in stage one. This illustrates how changing one detail in one end can change incentives in the other end.

3.1.2 Output

NVE has chosen three outputs in the model; number of customers, length of high voltage network and number of substations. In theory, we prefer exogenous outputs. We use an input minimizing DEA model where the companies should minimize their input given the output. Then it is unfortunate if the companies are able to influence the level of the outputs. However, even if length of network and number of transformers may seem endogenous, other direct regulations imply that they in reality are not. The DSOs have an obligation to connect all customers and producers that demand it, and investments of new grid are basically driven by the external factors of supply and demand. This shows how direct regulations work together with incentive regulation.

3.1.3 Constant Returns to Scale - CRS

In the DEA-model NVE assumes constant returns to scale (CRS). This is often used in incentive regulation because even if the true technology is variable returns to scale (VRS), using CRS gives incentives to change the scale of the firm to optimal size. Size is regarded as a choice of the company.

3.1.4 Average data in the frontier

The revenue caps are calculated yearly, and the benchmarking analysis is also updated with new data every year. This is advantageous since changes in costs will influence the revenue relatively quickly. However, NVE has experienced that some cost elements may vary considerably over the years. This may affect the frontier of the benchmarking model, and the industry interprets frequent variations in the frontier and as the model being unstable, unreliable and unpredictable. This undermines the industry's trust in the regulatory model. NVE regards it is an advantage to have a more stable frontier, so we calculate the frontier as an average of data over five years where each company is evaluated with yearly data against this frontier. This also gives incentives for the efficient companies to improve their efficiency. If they can improve their performance compared to their 5 year historical average, they can achieve a DEA score higher than 1.

3.2 Stage 2 - Correction for operational/environmental environments

It is important to consider differences in relevant operational environments in the benchmarking model. In Norway, it is also stated in the legal regulation that this issue has to be addressed. NVE has derived geographic variables by employing Geographic Information System (GIS) analysis. The basis for this analysis is data containing the geographical coordinates of the network for each DSO. We combine the geographical network data with several thematic maps, which describes the environmental conditions in which the network is located. By applying this technique, we have produced numerous environmental variables that we tested in the model, together with structural variables that describe the conditions of a company. The variables that were tested were based in theory or from feedback from the industry.

Many of the geographical variables are strongly correlated, which will cause problems in a linear regression model. To be able to include more aspects of a geographical condition, NVE applied factor analysis on some of the most correlated variables, creating two different composite variables. Altogether, there are five geographical variables, or Z-variables, in the model, capturing conditions like coastal-, city-and forest environment as well as network availability (distance to roads).

Different methods have been suggested for adjusting the DEA scores for differences in environmental variables, and Coelli et al (2005) describe some of them. NVE introduced a two-stage procedure in 2010 where the DEA-scores from the first stage[6] were regressed on the Z-variables. With this approach, every company with values on their Z-variables would get their DEA score adjusted upwards. But some companies may be compared to peers that have even worse conditions, therefore NVE implemented an improved stage 2 regression from 2013. In this, the independent variables are not the Z-variables themselves, but the *difference* in the Z-variable for the DSO and its' "shadow company" (The point on the frontier that they are compared to) from stage 1 (Amundsveen et al, 2014). Companies can have their DEA result adjusted upwards or downwards.

3.3 Stage 3 - Calibration of the cost norm

When we have adjusted the DEA results in stage 2, we multiply the DEA result with the company's cost base to calculate the cost norm. When the cost norms are calculated, only the most efficient companies will have a cost norm that equals (or is larger than) their cost base. There are several factors that may limit companies' ability to achieve a reasonable rate of return in this model, and the main factors are the use of book values which leads to delayed cash flows and uncertainty of the results related to measurement error and lack of comparability. NVE's response to this has been to calibrate the cost norm in stage 3 so that the sum of cost norms equals the sum of cost in the industry. This implies that the industry as a whole will receive the regulatory rate of return calculated by WACC. A company with an average DEA result will receive the regulatory rate of return (RoR), a company with higher than average DEA result can receive higher RoR, a company with lower than average DEA result will receive lower RoR.

In the calibration of the cost norms, we calculate the difference between cost base and cost norms for the industry. This difference is distributed back to the industry based on each company's share of the RAB. Using the RAB as a distribution factor reduces the problem of the age effect in stage 1. In stage 1, a high RAB is unfavourable; in stage 3 it is favourable.

In this stage some of the uncertainty that follows the use of any model, is reduced. One may say that the regulator gives all the inefficiency in the industry back to the companies, but since they share a given size of the total revenue caps and the analysis is repeated every year, there are strong incentives for each company to reduce costs. In order to maintain a given level of RoR a company has to keep up with the development of the "average company". The large number of the companies limits the effects of cartelisation.

4. Discussion and conclusion

There is a difference between a regulatory application of benchmarking and the theoretical and empirical research. In our view this is due to the fact that regulators have a wider set of goals and considerations than just applying performance measurement for improved efficiency. Based on our experience, a successful regulatory model has to find a reasonable balance between incentives for efficiency, quality of service and investments. It is also important with a reasonable distribution of efficiency gains between companies and their customers. Further, the overall total effects in the regulatory model are more important than for example the application of the ideal text-book model. It is also important to recognize that it is limited what economic regulation alone can achieve. Therefore it is crucial to apply direct regulations that define rights and obligations. Other factors like data availability and legal issues may also prevent regulators from applying "text -book" solutions. Due to asymmetric information, the regulatory model should reward companies that choose the optimal solutions. Last, but not least, the regulator has to convince stakeholders to trust a long term sustainable regulatory framework that gives the possibility to earn a reasonable rate of return and that will be adapted to future changes in constraints and environments.

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[1] http://lovdata.no/lov/1990-06-29-50

[2] These are property taxes and tariffs paid to other regulated network operators. In addition, the companies are allowed to cover some of their research and development (R&D) costs directly in the allowed revenue. In this way, NVE incentivize R&D among DSOs.

[3] In the input of the DEA we also include capital that have been financed through contributions. This is because these outputs are included in the companies' data.

[4] We use the same WACC model as in the cost base

[5] NVE has assumed the need for investments (for DSOS) to be 4 000 mill NOK per year the next ten years. In 2012 the total book value in the distribution level for the industry is 34 000 million NOK

[6] We corrected the DEA results for bias using bootstrapping. This approach is described in Edvardsen (2004), and partly meets the criticism of serial correlation of DEA-scores by Simar and Wilson (2007).

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VI. Advancing Strategic Sustainability for the Electric Power Industry

By Jessica Fox

Sustainability is historically considered a “fluffy” issue of interest to a passionate few. The issue could not compete for the time and attention of company CEOs, and certainly had little relevance to busy Chief Financial Officers (CFOs) responsible for their company’s financial success. For many decades, the issue has been relegated to a communication task on how to promote a “green” image around environmental and sometimes social issues. But, in the last 10 years, sustainability has increasingly become a business strategy with many companies not only bringing the issue to the attention of their CFOs, but adding a full C-level position committed to the issue: the Chief Sustainability Officer (CSO).

Socially Responsible Investments (SRIs) are growing in size and performance, and financial markets are increasingly using environmental and social measures alongside economic metrics as factors in determining investment risk for a company. International reporting efforts such as the Global Reporting Initiative, Dow Jones Sustainability Indexes, and Carbon Disclosure Project are encouraging transparency on sustainability-based issues, and a nascent but active non-profit group based in San Francisco, the Sustainability Accounting Standards Board, is hoping to ensure a new requirement of the United States Security and Exchange Commission to include sustainability metrics as part of annual financial filings. The momentum is strong and is pushing companies to consider their strategy, risk, and performance on a wide variety of issues that sit under the increasingly massive sustainability umbrella.

The Electric Power Research Institute (EPRI) formally initiated its sustainability research in 2008 with the formation of the Energy Sustainability Interest Group. Beginning with only 12 companies discussing office recycling practices, it has since become the largest sustainability-focused group of its kind in the electric power industry. With more than 40 companies participating today, participants work collaboratively to share knowledge, experience, and information across the power industry to stay informed on the sustainability topics most important to electric utilities and their stakeholders. Demands for increasing the scope of research have moved EPRI’s interest group well beyond providing a forum for sharing, and have led to a multi-year suite of collaborative scientific research. Today, EPRI produces research results, decision making tools, and executive workshops to advance sustainability in the electric power sector, and the experience is beginning to inform other sectors.

What are we talking about?

A 2013 EPRI survey found that nearly 60% of responding electric utilities identified sustainability as either a top or very high priority. The respondents cited several reasons for placing a premium on sustainability, such as managing operational and regulatory risk, improving corporate reputation, and supporting core company values. These responses reflect how sustainability can put a company in a better overall position to reduce exposure to risk and liability from stakeholder protests or shareholder resolutions. With lower social risk, a company may be financially stronger. But, even with the recognized value of having a high-level commitment, many companies still struggle to understand what sustainability really means.

While the general definition of sustainability—the management of resources to ensure the long-term well-being of people and the planet—has served well for inspired contemplations, it has done little to inform specific action and decisions. The fundamental challenge is moving an idea into application; transplanting a philosophical concept that may enjoy another decade of pedantic discussion, into a business boardroom where decisions need to be made NOW. As companies work to understand their position, the conversation must begin with defining the issue.

Companies must pinpoint a definition of sustainability—a concept that is now widely understood to include environmental, social, and economic components—and then make often difficult choices about how to pursue it. Many companies are committed to sustainability in a broad context, but need to define specific commitments and determine how to make it real. Getting more sophisticated, fact-based, and strategic about sustainability allows for more effective communication about why certain decisions are made. In the electric power industry, these discussions are complicated by the fact that their core mandate is to provide safe, affordable, reliable electricity – a product that the world depends upon.

One Size Does Not Fit All

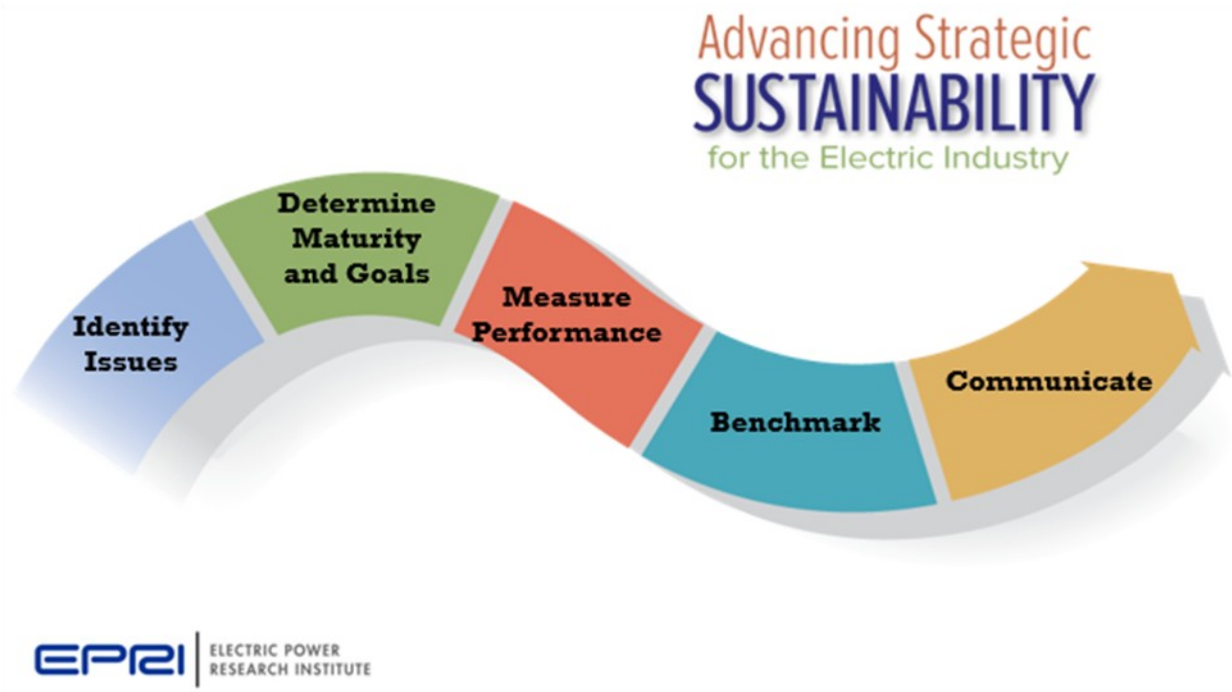
Because there is no blanket definition for sustainability, advancing corporate strategies is not simple. What constitutes sustainability for an electric utility depends on many factors. For instance, any comprehensive approach will naturally include a measure of greenhouse gas emissions. Yet there are vast differences in emissions among power companies that only distribute electricity verses those that are responsible for generation, transmission, and distribution. Location also matters. There are different environmental conditions depending on where a company is located. For example, in the Midwest and Southeast, water availability is less of a concern than in the West where drought is more common. There's not a one-size-fits-all approach to sustainability.

Complicating matters even further, efforts to improve sustainability in one area—whether it's environmental, social, or economic—may impact sustainability in another area, requiring constant balancing that is unique to each company. For example, an initiative to reduce greenhouse gas emissions may cause electricity prices to rise, making it more difficult for a company to meet their affordability mandate.

A Systematic Approach

EPRI provides a wide range of tools, research, and opportunities for collaboration that electric utilities can use to chart their own course and develop comprehensive sustainability strategies. To that end, the group supports five key steps in a sustainability strategy: identify issues, determine maturity and goals, measure performance, benchmark, and communicate (Figure 1).

Figure 1. The five steps in a sustainability strategy



The first step, Identify Issues, refers to the sustainability issues that are most relevant and important to an electric utility and its stakeholders. A recent EPRI report (3002000920) identified the 15 most material sustainability issues facing the electric power industry based on input from hundreds of electric utilities, government agencies, academic institutions, and environmental organizations. Grouped under the environmental, economic, and social pillars of sustainability, the issues include skilled workforce availability, greenhouse gas emissions, and water availability (Figure 2). Several companies have already used the study to identify high-priority issues. EPRI plans to issue a follow-up report outlining ways that electric utilities can address these issues.

Figure 2. This diagram shows the 15 material sustainability issues for the electric power sector organized into the three pillars of sustainability. Electric utilities face the challenge of achieving sustainability goals while fulfilling the core mandate of safe, reliable, and affordable electricity.

The next step, determine maturity and goals, involves an assessment of progress in various sustainability issues. After identifying issues, companies determine sustainability maturity levels by answering “where are you now,” “where do you want to go,” and “how will you get there.” Last year, EPRI unveiled a pilot version of the Electric Power Sustainability Maturity Model, which allows electric utilities to gauge their maturity level with respect to four of the material issues: greenhouse gas emissions, water availability, energy affordability, and energy reliability (see EPRI report 3002002302). A full version of the model incorporating all 15 material issues is anticipated for 2016.

The general philosophy behind the model is the need to understand where you are, before you can pick your next steps - any road will do if you don’t know where you are going. To apply the model, EPRI runs expert-facilitated workshops to help companies accurately determine maturity, define goals, and identify concrete actions to achieve those goals. The model provides an at-a-glance dashboard of current maturity across various material issue (Figure 3). After assessing the current maturity on specific issues, EPRI suggests specific actions a company could do to achieve their goals.

Electric Power Sustainability Maturity Model

Maturity Level	Water Availability	GHG	Affordability	Reliability
5	0.20	0.00	0.14	0.10
4	0.33	0.14	0.57	0.37
3	0.58	0.28	0.75	0.65
2	0.92	0.55	0.82	0.79
1	1.00	0.86	0.86	0.83

Legend	
>= 0.70	Level achieved or exceeded
>0.50 < 0.69	Major progress
>0.30 < 0.49	Some progress
<0.29	Little or no progress

Figure 3. Example Results Dashboard for EPRI's Electric Power Sustainability Maturity Model.

An objective assessment of an electric utility's progress toward sustainability must include a rigorous way to measure and track performance—which is why metrics are a focus of EPRI's work in 2014 and 2015. "Am I using CO2 equivalent per gigawatt-hour? Am I measuring water consumption or withdrawal? Do I care about the community that uses the water?" EPRI research is identifying the "right" metrics for the electric power industry to quantity material issues, based on the purpose of the metric measurement (informing stakeholders, predicting future performance, comparing with peers, etc).

In concert with measurement is benchmarking, which allows electric utilities to compare sustainability achievements with their peers. Under a collaborative agreement, EPRI will assume operation of the industry-wide benchmarking effort started by Tennessee Valley Authority in 2010. This initiative collects performance data for specific metrics and allows organizations to see where they stand relative to their peers through a process that builds company-specific information. (For more information, see www.utilityenvironmentalfootprint.com.)

EPRI's fifth focus area is communication—how electric utilities broadcast sustainability efforts to external audiences. This can happen through corporate social responsibility reports and voluntary disclosures to reporting organizations, such as the Global Reporting Initiative, the Carbon Disclosure Project, and the Sustainability Accounting Standards Board. The amount of effort required to track and interact with these and other reporting organizations is substantial. EPRI research is informing these external reporting organizations and gaining a better understanding of the costs, benefits, and current practices associated with participating in various disclosures. This research aims not only to inform what the reporting agencies request of companies, but also to provide a legitimate basis for why electric utilities issue certain disclosures.

Giving Meaning to Sustainability

With the momentum building in sustainability research, EPRI recently hired its own first Chief Sustainability Officer, Anda Ray, to drive EPRI's sustainability research strategy. At the core of EPRI's research is crafting a more precise, measurable definition of sustainability for the electric power sector. The research ensures that all aspects of the work—whether it's identifying material issues and metrics or assessing costs and benefits—are based on facts and sound science. At the same time, the research aims to provide a framework to translate the electric power industry's collective lessons into customized sustainability strategies that fit the unique situation of each electric utility. Goals and targets, maturity levels, disclosures, and properly balanced decisions will always be individual propositions. Providing the tools to help electric utilities with these tasks will continue to be the focus of EPRI's sustainability research for the foreseeable future.

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VII. Bulgaria – the Island of Non-Liberalization

By Anatas Georgev

Seven years after the accession to the EU, the energy market in the Southeast European country is still heavily regulated

The political will in the EU was to liberalize the markets for electricity and natural gas in all member-states as of July 1, 2007. Bulgaria, which joined the EU on January 1, 2007, had to be no exclusion. However, the electricity (and gas) markets in the country are still heavily regulated and only as much as 3000 clients, none of them households, are currently able to freely change their electricity supplier. A new deadline is coming soon – all energy markets in the EU have to be fully liberalized and coupled by the end of this year. Meanwhile, in Bulgaria, there is still no visible end date for the first stage of liberalization.

Liberalization or Planned Economy?

The current market model in Bulgaria is based on two segments. The first one is regulated, based on production quotas and regulated prices for the whole power-market chain – from the generation of electricity in large conventional plants, through the administratively-set feed-in tariffs for the growing number of renewable energy capacities, through the wholesale price of electricity and down to the end prices for households and small businesses. The second segment is the liberalized market, where all non-household consumers have the right to choose an alternative supplier.

In a well-structured European power market, the national regulatory authorities should have less pricing obligations related to energy prices and regulate mostly the grid infrastructure prices. In Bulgaria, the current legislation defines an all-embracing role for the regulatory body, which sets power production quotas, wholesale prices, RES feed-in tariffs, end-user prices, and grid prices.

Unfortunately, the EU-level energy policy imbalances have been aggravated in Bulgaria. It is extremely difficult to combine the policy objectives for a fully liberalized electricity market in Europe, defined with Directive 2009/72/EC and the whole Third Energy Package, with the objectives for the support of specific energy resources through the obligations in Renewable Energy Directive 2009/28/EC. However, the RES directive itself offers a viable solution – to support green energy through administratively-set feed-in tariffs, or through market-based tradable green certificates. Bulgaria, for example, chose the feed-in tariffs model, which aggravated the delay in the local market liberalization, while neighboring Romania is successfully implementing the green certificates model. Another difference between the two neighboring markets is the presence of an experienced power exchange operator in Romania – OPCOM, while Bulgaria still struggles to found its own energy exchange.

The planned economy feeling in the Bulgarian power market is further strengthened by the constant will of several successive governments to lower the regulated power prices, which is fully supported by the national regulatory authority – the State Energy and Water Regulatory Commission (SEWRC/DKEVR). There were 5 (five!) resignations of the SEWRC's Chairmen in one year – 2013, followed by a unanimous resignation of the 6 other members in the commission. The sense of a strong political dependence of the SEWRC is supported by several suggestions by different energy ministers that prices should be lowered with a given number (e.g. 5%), strictly followed by the respective regulatory decisions. It seems, that the Ministry of Economy and Energy, its 100% subsidiary Bulgarian Energy Holding (owner of about 60% of the generating capacity in Bulgaria), and the regulatory body speak with the same voice and maybe take instructions from one place.

The Strength of the Contracts

The liberalization of the power market becomes even more complex, when all the current long-term contracts are taken into consideration. As part of the modernization of the national energy system, the Bulgarian public supplier and incumbent company NEK has concluded two 15-year contracts with large TPPs generating electricity from local lignite coal. One of the power-purchase agreements (PPAs) was concluded with the American company Entergy (later on replaced by the Italian Enel and then by the current US-based ContourGlobal) for the rehabilitation of the TPP Maritsa East 3 (908 MW). The second contract is with AES for the construction of a new TPP with a capacity of 670 MW. In addition to this, some of the capacities in the state-owned TPP Maritsa East 2 are also tied with a PPA to NEK. And last, but not least, there are long-term contracts with renewable energy producers for duration of 12 to 25 years for a total capacity of about 2000 MW, most of them photovoltaics. Also, NEK and the end suppliers (CEZ Electro Bulgaria, EVN Bulgaria Electricity Supply and Energo-Pro Sales) should purchase with priority the efficiently produced electricity from cogeneration plants at industrial sites and district heating plants, which have a combined capacity of over 1300 MW.

The maximum winter consumption of Bulgaria in the coldest days of January is about 7500 MWh per hour and the lowest consumption, usually in April, is about 2500 MWh per hour. With a total installed capacity of 14000 MW and priority purchasing of the electricity from capacities of over 5000 MW, the local market could not be opened efficiently. The challenge is aggravated by the strict contract conditions and the legislative requirements to purchase this electricity production and to include it in the mix of the regulated market. Thus, when consumers choose a new supplier of electricity, the first effect is that there is not enough capacity to offer them real alternatives and the second one is that the “expensive” energy, generated through PPAs and feed-in tariffs should be distributed to a lower number of buyers. In order to solve this multiple-layer equation, the government, the regulatory commission, the generators, and the suppliers at both segments of the market should coordinate swift transition of all current contracts in order to let the national market meet its EU-obligations.

The Green Energy Conundrum

Renewable energy is becoming a problem for liberalized markets not only in Bulgaria. The European Commission has published several communications in the last 2 years, suggesting that RES support should be changed for new projects in order to reflect the new market situation. However, the current contracts should not be changed one-sidedly and retroactively, but with the support of the RES sector itself.

In 2009, when the RES Directive was enacted, still the situation looked quite different than in 2014. The economic and financial crisis had just started, but it was not included in the initial assumptions of the pre-directive analyses. Also, no one expected the Chinese PV manufacturers to catch-up so quickly, in combination with the sudden fall of the PV modules prices. The shale gas boom was not expected so soon, and the carbon prices were headed to their peak with no change of the situation in sight. Now, several years later, we can see what happened, but only in the rear-view mirror. Statistical data were not quick enough to show that actually the green energy market is over-investing, which could lead to higher prices for local consumers. The industrial consumers were hit hard with high energy prices in comparison to their competitors overseas.

In Bulgaria, the green electricity was generously supported with high feed-in tariffs until 2012 and the national renewable energy action plan had a conservative view on their rise through 2020. Actually, the plan predicted, that Bulgaria should have about 303 MW PV capacities and 1256 MW of wind capacity in 2020 in order to meet its 16% national target in the RES directive. The actual numbers in 2014 are strikingly different. The negative effects are spread throughout the energy mix: higher end prices; priority dispatch and purchase of RES power; lowering the production of conventional sources, including nuclear; increasing the share of generation in the regulated mix; etc.

One of the possible solutions is to sell the green energy (or at least internationally-accepted green certificates from it) at the regional and EU markets. In order to do this, there should be a serious refurbishment of the national legislation, followed by a consensus on the renegotiation of current contracts. Unfortunately, it seems that this is not an immediate priority for the current parliament and government. Moreover, the European Commission itself is not actively coordinating or supporting this process, even if their experts provided a short consultancy trip in the spring of 2013, pinpointing in a written most of the shortcomings in the Bulgarian energy market. It is now clear for many stakeholders in Bulgaria, that the support and expertise of the EC and other international institutions from the World Bank Group are needed in order to reshuffle the legislation, the regulatory framework, and the governance of the Bulgarian power sector.

Independence for The Regulators

The administrative capacity of the Bulgarian national regulatory authority SEWRC will be one of the largest hurdles in the further liberalization of the energy market. The commission is responsible for the licensing, pricing, control, and dispute resolutions in 4 sectors – electricity, natural gas, water, and central heating. It has about 120 employees and an insufficient budget for its activities – about 1.9 million EUR per year. Both the low remuneration levels and the public perception for the quality of work of the SEWRC stop experts from joining its work force. Meanwhile, its tasks have been increased with the enactment of the Third Energy Package and the decision of Bulgaria to implement the Independent Transmission Operator (ITO) unbundling model in both electricity and gas markets. Now the commission has to certify and monitor the activities of both the national gas ITO – Bulgartransgas, and the electricity one – ESO.

The capacity of the commission and its independence have been questioned by the market monitoring reports of DG Energy. They considered that it has an insufficient budget for proper regulation of all 4 sectors and reminded that there had been interference of the decision-making process from the government on many occasions. According to the DG Energy's reports, a key factor for the liberalization of the Bulgarian energy market will be the strengthening of the SEWRC's administrative capacity, combined with a sufficient level of independence from the government.

Further on, the obligations of the SEWRC have to be reconsidered and maybe it has to be seriously restructured. A new market monitoring department there will be very much needed in the process of market opening. Also, many stakeholders have proposed the energy and water sectors to be regulated by different entities in order to strengthen the power sector regulation.

And last, but not least, some experts suggest that a separate dispute-resolution body is needed in order to process about 12000 complaints each year. Such ombudsman service, introduced for example in the UK, has shown very good results. In Bulgaria the positive effects may come from both lower costs and more free time for the specific regulatory obligations of the commission.

A new selection and appointment procedure will be needed as well. Currently, the 7 members of the SEWRC, including its Chairman, are appointed by the Council of Ministers with no formal nominations or selection procedures. There is a strong opposition now to this practice, suggesting the election of members of the national regulatory authority from the parliament after public nominations and hearing procedures in order to guarantee the transparency of the process, the independence from the executive power, and the high professionalism of the regulatory commission members.

Energy Island or Part of the Inland?

Ultimately, the paradigm of the national energy policy has to be changed. Many national analyses of different governments and state-owned companies considered Bulgaria as an energy island and not as part of the common EU market. For instance, the decisions to start the construction of NPP Belene and the decision to build a new nuclear capacity at NPP Kozloduy are based mainly on the assumption, that the regional energy consumption will rise and that Bulgaria will be the only (and the first) country to satisfy it. Also, the decision-makers obviously believe, that Bulgaria may keep its prices the lowest in the EU even after its market is fully integrated into the regional one and the European one.

Even if this sounds well for the Bulgarian voters, who have the lowest income in the EU, this may not be the case anymore. The coupling of national energy markets and the further integration within the EU actually means that all producers and consumers will share the same marketplace. A true market may not have different prices based only on the nationality of its consumers – it may be segmented, but based on preferences and needs of its participants. Therefore, the concept of an “island” in energy terms is not only wrong, but extremely dangerous for all the stakeholders in the national energy market. The European Commission has its tools to make the liberalization happen in Bulgaria – through political pressure, European Court procedures, or otherwise. It is only a matter of time when this will happen. After this is done, it will be late for Bulgarian producers and consumers to catch-up. The preparation has to start now and it is already years behind schedule.

The Road Ahead

The time to act and change the Bulgarian energy system is now. There is a set of actions, which have to be implemented in order to guarantee the timely and less harmful transition from fully regulated to fully liberalized prices. Some of the actions may and should include:

- a political will for transparent, timely, and predictable changes in the power sector;
- a clear message to all consumers and producers what are the current challenges and what are the possible solutions;
- calculating and agreeing on the current financial imbalances in the sector with a clear schedule how to overcome them;
- public consultations sector-by-sector and in general in order to pinpoint and challenge each of the current problems;

- introducing market measures, such as tradable green certificates, in order to give more opportunities for the liberalization of bilateral contracts;
- reforming the current model of PPAs with the participation of the private partners in order to include them in the supply side of the liberalized market;

These are only part of the needed solutions. The full list may be defined only through an enhanced discussion between all stakeholders and with the active participation of the government – mainly as a moderator. The current problems should be tackled in coordination and the process has to start immediately.

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VIII. Ad hoc regulation of a merchant interconnector: maximizing the benefits for grid users

By Guro Grøtterud, Lamis Aljounaidi, Antoine Dereuddre, Adrien Thirion

How the French and British national regulatory authorities designed a tailor-made framework to enable maximized benefits for grid users from private-funded 1000 MW HVDC interconnector, speeding up necessary investment.

Introduction

In a context where interconnector capacity is lacking, ElecLink Ltd., a firm planning to develop a merchant interconnector between France and Great Britain applied for an exemption before the national regulatory authorities (NRAs) of these two countries, Commission de Régulation de l'Energie (CRE) and Ofgem. Although generally, interconnectors in Europe are regulated, European legislation provides the possibility for merchant investment. CRE decided and Ofgem to investigate whether and under which conditions this merchant investment could contribute positively to the power system and to consumer welfare.

This paper explores the ad hoc solution developed by the NRAs. After examining the benefits of interconnectors, we study whether ElecLink may generate costs for grid users, and if so whether these can be compensated. We will then look at the concrete measures that were taken by the NRAs to maximize net benefits for grid users while taking into account the specificities of the project [DEC]. We will then explain why merchant interconnectors should not become the standard approach for cross-border transmission investment.

What is ElecLink?

ElecLink Ltd is a joint venture between investment fund Star Capital Partners (51%) and Eurotunnel Group (49%). The latter owns and operates a submarine railway tunnel between France and Great Britain. ElecLink's project is to build, own and operate an electrical interconnector between the transmission grids of the two countries, passing through the existing infrastructure of the tunnel. The HVDC interconnector would have a capacity of 1000 MW, which represents a 50% increase compared to the maximum capacity currently available between the two countries (2000 MW), and it would be commissioned in late 2016.

In France, the regulatory framework for interconnector investment is set by national and European legislation. Currently, all regulated interconnectors are developed by Réseau de transport d'électricité (RTE), the national transmission system operator (TSO). ElecLink's situation is however different from RTE's. In particular ElecLink does not receive regulated revenues from grid tariffs. In order to adapt applicable regulation to its particular situation, ElecLink requested an exemption [PC] from parts of the framework normally applicable to interconnectors – possibility which is given by European legislation under certain conditions [REG]. In particular, ElecLink wanted to allocate up to 80% (800 MW) of the interconnection capacity through up-to-twenty-year contracts. ElecLink requested that this exemption be applicable during 25 years.

Which benefits are expected for grid users from interconnectors?

The European energy sector faces and will face several challenges in the coming years, in particular integration of variable renewable energies, the completion of a competitive single market and, potentially, security of supply issues and increased electricity prices. Sufficient grid flexibility would contribute positively to address these challenges.

Currently, the European electricity system is a zonal system where each country is constituted of one price zone. The interconnections between zones are often bottlenecks, i.e. limiting commercial and physical flows between the zones whereas there is less congestion inside the zones. Interconnections are therefore particular points of attention as concerns the flexibility of the European grid. In particular:

Interconnections provide the possibility to optimize the generation pattern and thus to decrease overall generation costs at European level. Interconnections allow for importing electricity from the lower price areas to higher ones, generating overall lower retail prices. Such flows generate social welfare in both the importing and the exporting country in addition to the congestion rent. As concerns France and Great Britain, power prices may differ significantly. In 2013, the spot price was higher in GB than in France 84% of the time, with an average price difference of 20€/ MWh [MRI] during these hours.

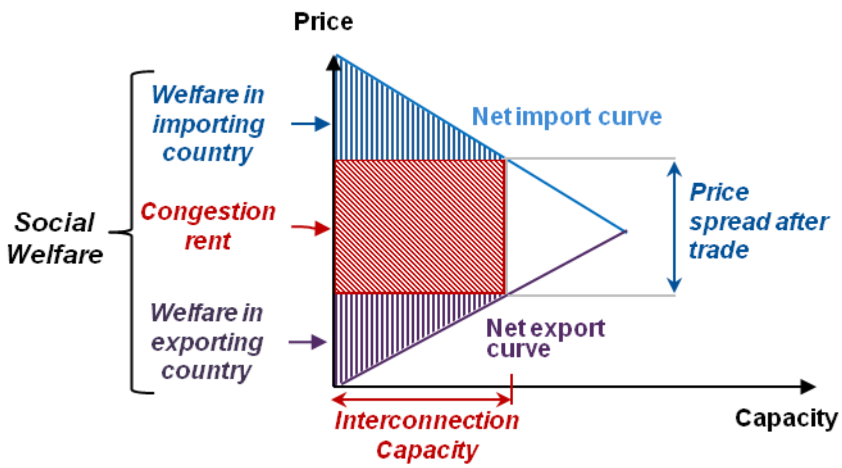

Figure 1: Welfare generated by a cross border exchange. Net import (export) curve represents price variation in the importing (exporting) country when the cross border exchange increase. The social welfare is split between net welfare for the importing country, for the exporting one, and congestion rent.

Interconnections contribute to integrating variable renewable energies. Generation surplus in one country may be exported instead of being reduced, potentially replacing less green generation in the importing country. Avoiding reducing variable renewables is key in a context of high political ambitions for their development, as their growing part in national final gross consumption increases the difficulty of the challenge.

In addition, interconnections support the security of the European system both on short-term, through balancing energy exchanges and on long-term, as a complement to peak generation facilities available in the zone to cope with high consumption phases. As such, interconnections can avoid excessive investment in peak generation, in particular if demand schemes differ between interconnected countries.

Last, interconnections can be used as a vector to promote competition, by facilitating the entry of new players in national markets. Competition stimulates decreased costs and prices for generation and retail offers in the interest of end consumers.

Historically, the European grid was constituted by national grids that were interconnected for

TSOs' mutual assistance emergency situations. Today, the role of interconnectors has extended from a sole emergency tool for avoiding blackout to an answer to the four abovementioned issues. In this new context, current interconnection capacities prove to be insufficient and massive development is needed. To this aim, several European and national initiatives have been set up, with regulated investment by national TSOs as a general rule.

Can ElecLink play a role in this context?

Would ElecLink substitute regulated projects? Would it generate costs for grid users without compensation?

Before considering the regulatory framework to be applied to ElecLink, CRE and Ofgem examined whether the projected interconnector could be useful for grid users, i.e. whether the overall impact for grid users would be negative or positive. Indeed, ElecLink should only be encouraged to realize its project if the impact was positive.

The NRAs first examined the impact of the Eleclink project on the feasibility of planned regulated investments. 2013 figures (see above) seemed to indicate that further interconnection capacity was necessary between France and Great Britain. However, RTE had, together with British counterparts, two new regulated interconnector projects between the two countries. These consisted of submarine DC cables totaling 2000-2400 MW interconnection capacity [PCI]. If ElecLink were to substitute one of these projects, it would result in reduced regulated revenues. Such reduction would potentially be reflected in increased grid tariff paid by grid users and in particular consumers – without any additional social welfare being created, compared to a situation without ElecLink. This possibility was however ruled out, as according to RTE, ElecLink's project does not change the validity of the regulated projects [PC]. ElecLink will add to, and not substitute, RTE's projects.

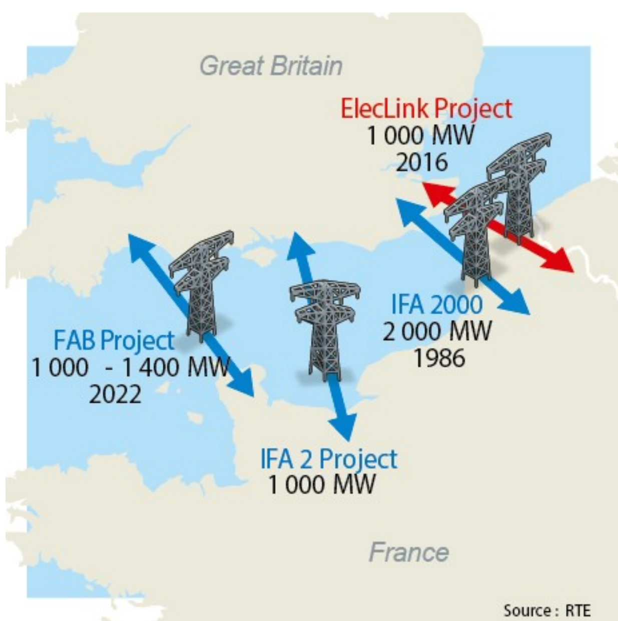

Figure 2: Existing and planned interconnectors between France and Great Britain, with capacity and (planned) commissioning date

Second, the NRAs looked at the costs that the new investment might generated for grid users. Indeed, the connection of any asset to the transmission grid may generate congestions. These are solved by grid reinforcement or by other actions such as redispatching of generation. The costs occurred are covered by the TSO [ACCESS] and ultimately by the grid users, in particular the consumers. In addition, even if no regulated projects are substituted by a merchant project, the additional project will cause interconnection capacity prices to decrease. The resulting loss of regulated congestion rent is ultimately suffered by grid users, and therefore constitutes a negative externality.

Negative externalities might reach considerable amounts (whether the investment is regulated or merchant), and even outweigh the positive externalities such as social welfare and increased security of supply expected from a new interconnector. Unlike the national TSO, which is in charge of the whole grid, a merchant investor has no reason to take such costs into account in its business plan.

Therefore, both positive and negative externalities of ElecLink were examined. Calculations provided by ElecLink were analyzed and compared to figures provided, on CRE and Ofgem's request, both by the national TSOs (congestion costs) and from London Economics (social surplus), a consultancy firm who, on CRE's and Ofgem's request, provided analysis of particular parts of ElecLink's request. Findings showed negative externalities below 100 M€, whereas the positive externalities exceeded 550 M€. Although it is impossible to perfectly forecast future externalities and although these externalities depend on several external factors, the probability for a positive sum of externalities is overwhelming.

This conclusion led CRE to further consider the framework to be set up for ElecLink, in order to allow the realization of the forecasted positive impact.

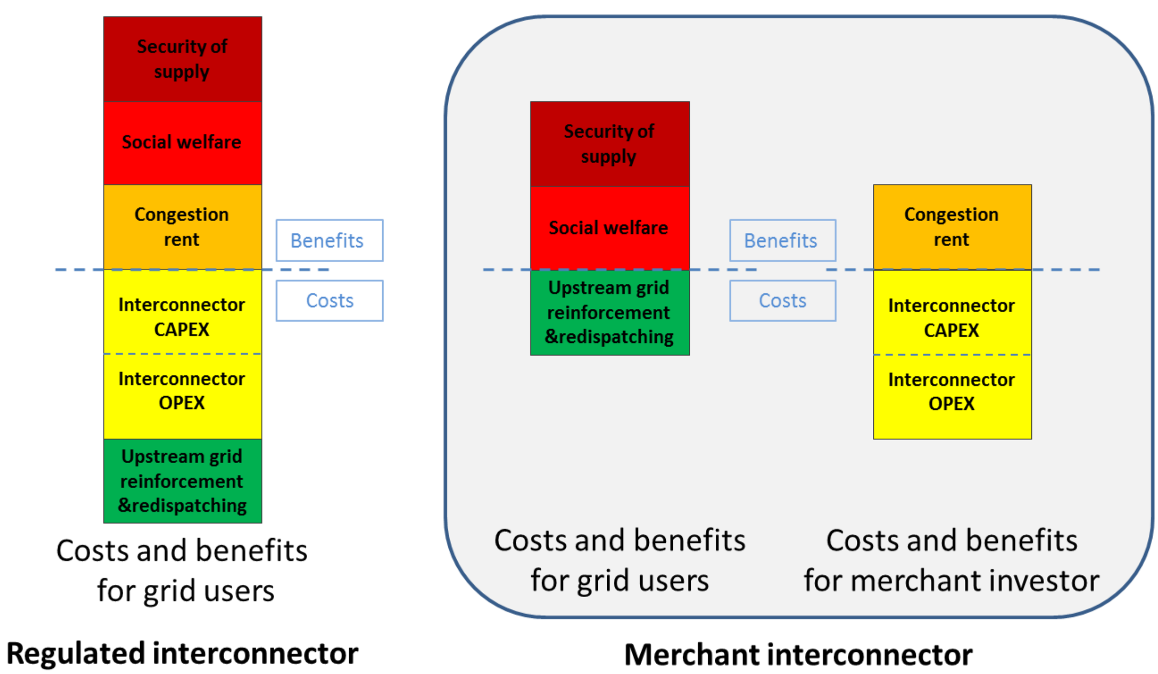

Figure 3: Distribution of costs and benefits of an interconnector for grid users.

How to make the investment possible…

ElecLink will own and operate one single asset: the ElecLink interconnector. ElecLink will depend solely on the interconnector's revenues to pay its operating charges, service its debt and possibly pay taxes and distribute dividends.

Interconnectors derive their revenues from selling cross-border capacities. The revenues are thus closely related to the price differential between the markets they connect. Yet, capacities on European interconnectors are only sold for periods, not exceeding year ahead. Income from such products is particularly sensitive to variations of the price differential, and would thus depend on:

- The evolution of electricity demand in France and Great Britain and other relevant markets over the next 25 years
- The evolution of the generation mix and production costs
- The evolution of interconnection capacity between relevant markets over the same period

Forecasts for these elements vary considerably, depending on, amongst others, the development of renewable energy, energy efficiency measures, the future of nuclear production, the cost of energy products (gas, coal, fuel, etc.) and the success of other interconnector projects. Revenues from short term products are thus "uncertain and stochastic" as qualified by London Economics.

However, before deciding to provide debt financing, creditors test the ability of the projects to pay them back under extreme hypotheses. One such hypothesis is that uncertain revenues are not realized. Therefore, creditors request to "have a significant portion of project revenues covered by long-term contracts". As a result, ElecLink requested the possibility to enter multi-year capacity contracts for up to 80% of its capacity.

The need for project finance and, subsequently, multi-year contracts, was confirmed by London Economics. Therefore, the the NRAs considered necessary for the project to be realized that capacities could be allocated through up to twenty-year long capacity contracts.

…while protecting the interests of consumers…

On regulated interconnectors in Europe, capacities are not allocated for more than a year ahead. Therefore, before allowing ElecLink to allocate up to twenty-year long capacity contracts, it was necessary to examine the impact of this exemption from harmonized European rules may have on the electricity market and thus, ultimately, on consumers. Indeed, although interconnectors generally contribute to enhanced competition, capacities locked in for a very long period could have the opposite effect. Diminished competition is expected to increase market power and thus retail prices.

Therefore, CRE and Ofgem considered that ElecLink should not be allowed to sell more multi-year capacities than what is necessary for the bankability of the project. ElecLink requested to sell up to 80% of the capacity, i.e. 800 MW, as multi-year capacities. However, the project's need was to secure a certain level of revenues. The NRAs therefore decided to complete ElecLink's suggested limit by setting a maximum amount (which is kept confidential) for income from multi-year capacities).

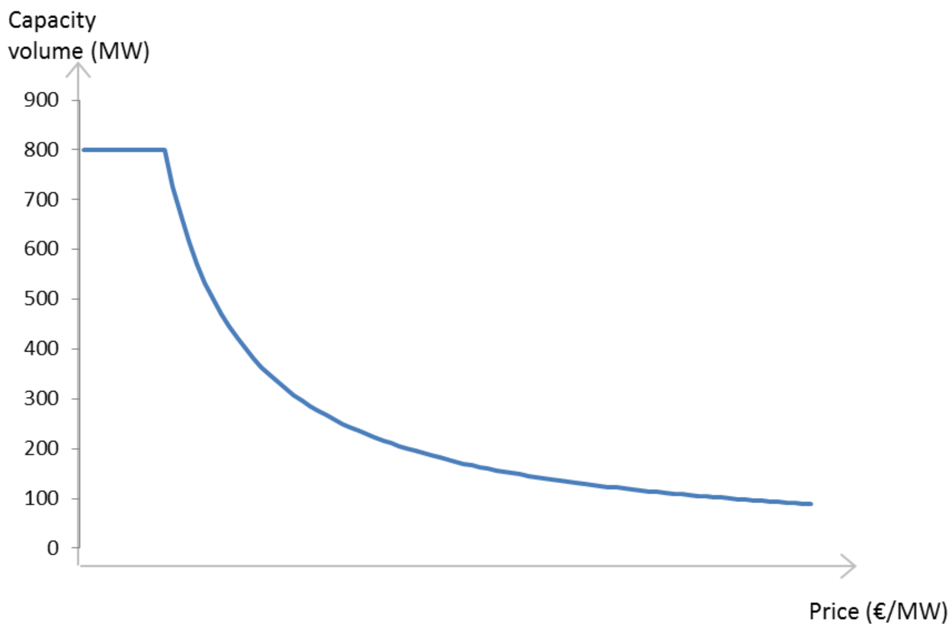

Figure 4: Maximum capacity volume allocated through multi-year capacity contracts, depending on resulting price.

Moreover, if one market player holds a too large amount of allocated multi-year capacities, it could impact competition negatively, in particular if the concerned market player is already in a dominant position in the importing market. Basing on a competition study provided by London Economics, CRE decided to apply the following rules to multi-year capacities:

- Maximum 20% of the interconnector capacity, i.e. 200 MW, may be allocated to a market player with more than 40% market share in the importing market;
- Maximum 40% of the interconnector capacity, i.e. 400 MW, may be allocated to any market player in any direction.

Finally, smaller players must be able to be eligible at least for smaller and/or shorter capacity products.

…and maximizing social welfare

Efficient use of the interconnector

Best practices to efficiently manage the existing and future cross-border infrastructures are currently developed and implemented at European level. Although an exemption has been granted to ElecLink , the major part of these best practices, shall also apply. Indeed, the abovementioned benefits generated by an interconnection highly depend on the operator's capacity management and the market players' capacity use.

One of these best practices is Market Coupling, which was implemented between France and Great Britain in February 2014. Market Coupling consists in fully optimizing the use of the interconnection: optimal flow is calculated based on information from the electricity exchanges (bids and offers) and TSOs (available interconnection capacity). This contributes to avoid situations where the highest price zone exports to the lowest price zone, or where the interconnection capacities are not fully used although the prices in the two connected countries differ. Such situations resulted in 2013 in a loss of welfare of 20 M€ [MRI] and illustrate how capacity management influences interconnector benefits for the grid users. ElecLink must to implement this pan-European optimization tool, otherwise the benefits expected from its interconnector would be undermined.

Moreover, ElecLink must implement measures to avoid capacity withholding to guarantee availability of all unused capacity to the market at all times. Together with the Market Coupling, such measures guarantee efficient use of the ElecLink interconnector and prevent any possibility to affect market prices.

Making all capacity available at all times implies in particular that ElecLink has to apply Use-It-Or-Sell-It (UIOSI) and netting. UIOSI means that when a capacity holder does not want to use its long-term rights, the capacity is made available to the market at the day-ahead timeframe, while netting means that when calculating day-ahead capacities in one direction, nominated capacities in the opposite direction are taken into account to maximize available day-ahead capacity.

Thus, ElecLink must respect current best practices. However, these may change over time to adapt to new challenges of the European market. It is therefore key for the regulator to be able to intervene on ElecLink's capacity management rules during the whole exemption period (25 years). If not, there would be a risk of inefficiency, distortions, and thus a brake to move forward. To cope with this issue, a two-step approach has been chosen:

- An overall frame including high level principles has been defined by the NRAs, this applies for 25 years;
- Capacity management rules to be redrafted when necessary. These are submitted to regulatory approval and shall be adapted to evolutions of the overall market design while respecting the high level principles. This allows the NRAs to control that the rules adapt correctly to new challenges.

Sharing the profits with grid users

According to European legislation, revenues resulting from interconnection capacity allocation are to be invested in increased interconnection capacity or availability of existing capacities. ElecLink requested an exemption from this, allowing it to keep all the revenues from its activities.

Fundamentally, ElecLink's revenues will come from congestion rents derived from electricity price spreads between two market zones. London Economics' analysis suggests that revenues may be higher than predicted by ElecLink, and exceed the total costs of the project, including depreciation and cost of capital. Moreover, the downside risks to the project are not such as to justify that ElecLink keeps all the revenues in all circumstances.

Excess profits may be considered as a form of economic rent. Generally, such economic rent is considered to be tamed by market competition when possible or, when impossible, by regulation [TIPR].

Although it is necessary that ElecLink receive revenues from congestion rents, excess profits should be used as foreseen by European legislation. Therefore, the NRAs designed a profit sharing mechanism that works as follows: profits exceeding a certain threshold are distributed, in equal shares, to national TSOs in France and GB and will be used in line with European legislation, i.e. reinvested in interconnection capacities in the interest of grid users. The sharing threshold (which is kept confidential) is consistent with a reasonable internal rate of return, taken into account all the risks taken on by ElecLink.

Moreover, once the sharing threshold reached, ElecLink may keep part of the excess profits. Indeed, if none of the exceeding profits were given to ElecLink, it would probably stop its activity once the sharing threshold was reached. In order to incentivize ElecLink to maintain an optimal interconnector capacity and limit the risk of compromising operation of the interconnector, the NRAs decided that ElecLink would keep 50% of the revenues exceeding the sharing threshold.

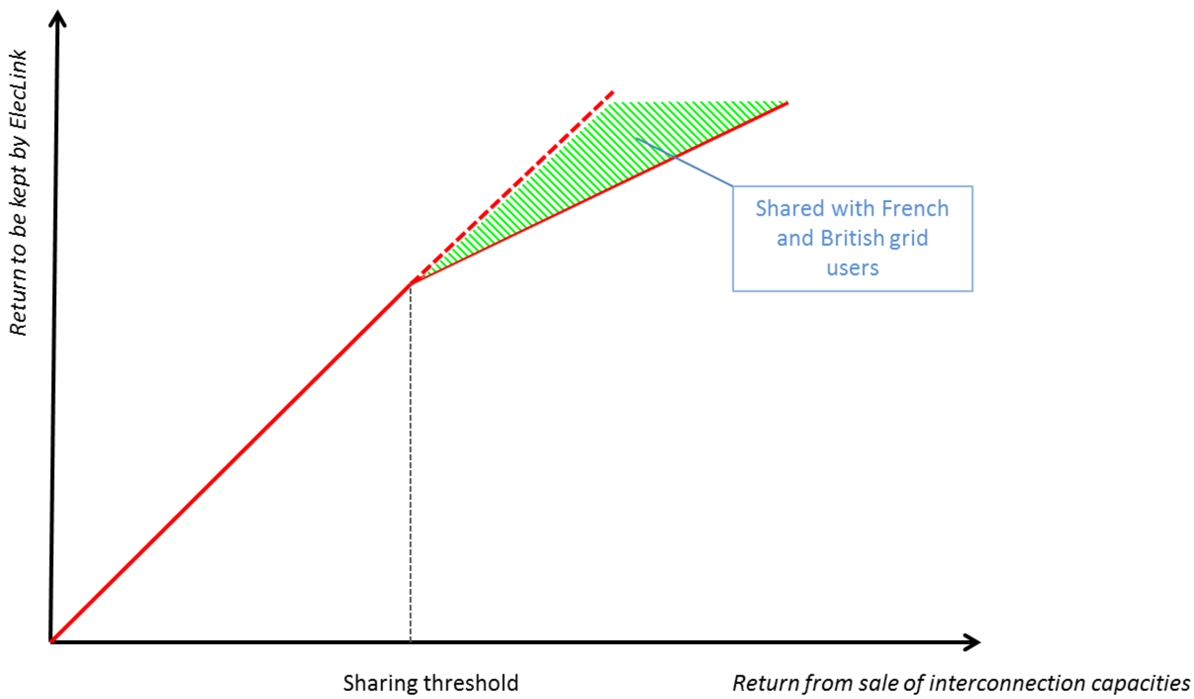

Figure 5: Sharing mechanism designed by CRE and Ofgem

The limits of merchant investment

As we have seen, merchant lines, as a private initiative, may be useful to complement regulated transmission operators' investments and to play a part in speeding up the completion of European integrated markets. Currently, several incentives are developed on European and national level in order to increase regulated investment. Could these be replaced by merchant investment as the standard approach for transmission investments?

Optimal interconnection capacity depend on whose point of view is considered : society or a merchant investor.

- From the society's point of view, optimal interconnection capacity is reached when additional capacity would fail to generate enough social welfare to recover the costs of the project.
- From a merchant investor's point of view, optimal interconnection capacity is reached when additional capacity would fail to generate enough congestion rent from price spreads to recover the costs of the project.

At first, adding interconnector capacities increases total congestion rents. However, increased interconnection capacity tends to decrease the price differential between the concerned electricity markets. This means that above a certain capacity, total congestion rents begin to be adversely affected by increased interconnection capacity.

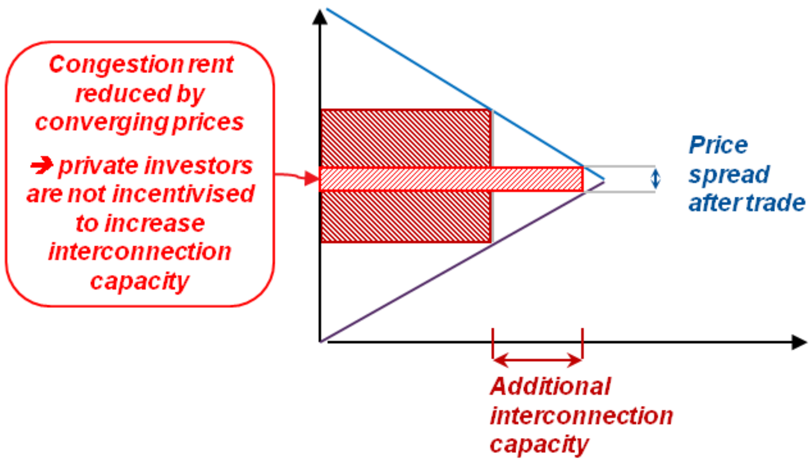

Figure 6: Eventually, total congestion rent decreases with increased interconnection capacity

Merchant investment will not allow for reaching optimal interconnection capacity, as the investor only takes into account the congestion rent, but none of the positive externalities (welfare in importing and exporting countries):

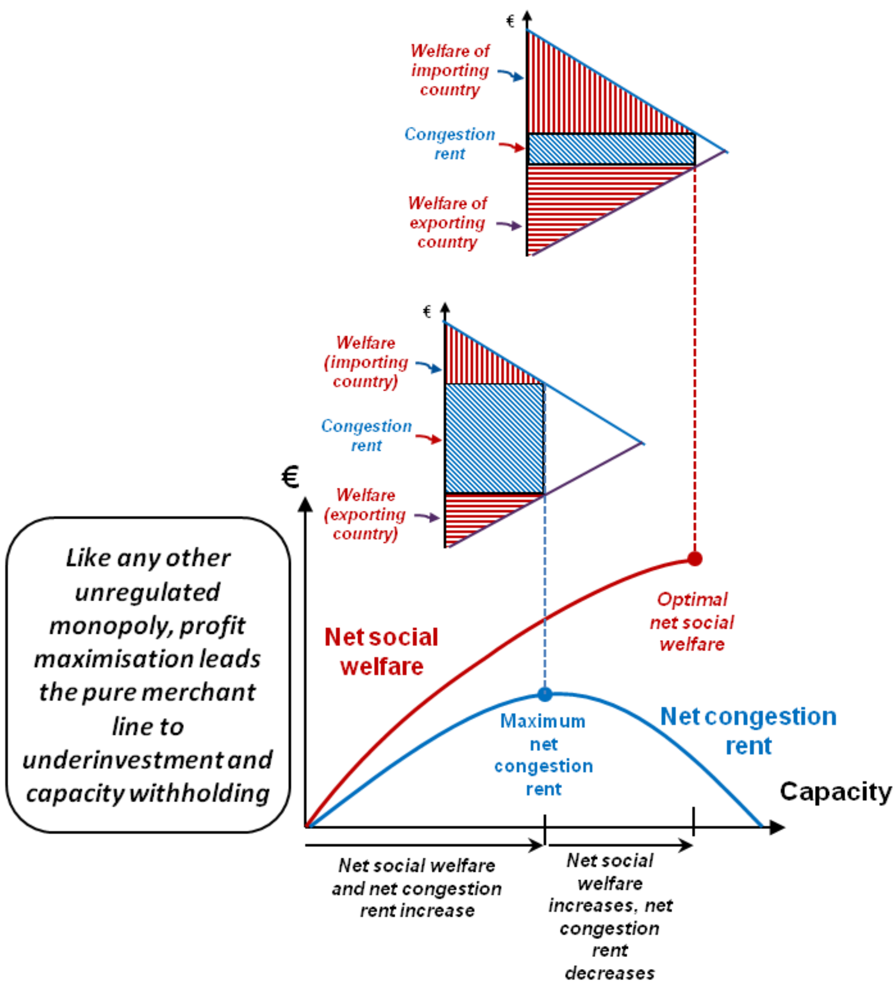

Figure 7: Net social welfare: congestion rent + exporter welfare + importer welfare - interconnector costs
Net congestion rent: congestion rent - interconnector costs

This means that under a pure merchant line scheme, there is an inherent incentive to undersize the interconnection capacity in order to maximize profits, leading to suboptimal capacity and potential adverse effects for the electricity market.

As a consequence, although merchant lines may be useful as a complement to regulated investments this should not become the standard approach for transmission investments.

Conclusion

Although interconnection investment is generally regulated in Europe, the example of the ElecLink interconnector shows that merchant investment may contribute positively to interconnection capacities in the interest of consumers. This is particularly the case where regulated investment is not (yet) sufficient: in ElecLink's case, the merchant interconnector adds to regulated investment and thus accelerates the necessary interconnection capacity increase.

However, this tool is to be handled with care. First, merchant investment does not allow for reaching the societal optimum of interconnector capacity. Second, the potentially important negative externalities of a merchant project need to be taken into account by the regulator before allowing the project to go on. Eventually, an ad hoc regulatory framework needs to be developed. While allowing bankability of the project, such a framework needs to take into account the specificities of the project and of the two interconnected markets. In this aim, a solid cooperation between concerned regulators and detailed exchanges with the merchant investor are key to success.

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Adrien Thirion, Guro Grøtterud (foreground), Lamis Aljounaidi (background), Antoine Dereuddre

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IX. Regulatory Roadmap for the Development of Smart Grid in Mexico

By Héctor Beltrán and Paola Madrigal

The development of the Smart Grid in Mexico is in its early stages. Currently there are three public entities working together for the implementation and deployment of the Smart Grid in Mexico: the Ministry of Energy, the electric utility, and the Energy Regulatory Commission. Until recently, the Commission did not have specific authority relating the Smart Grid. However, after the Energy Reform that took place on December 20, 2013, the Commission has been established as one of the responsible entities for promoting the development and deployment of the Smart Grid in Mexico, through a suitable regulatory framework. Furthermore, Mexico is going through a transition period from a vertically structured power industry to a deregulated market, as a result of the Energy Reform. Within this context, the Commission launched a project with the objective of developing a Regulatory Roadmap (RR) to define how an appropriate regulatory framework should be developed in order to support the Smart Grid. This RR involves several topics relating the Smart Grid and integrates them as a whole to develop the most convenient strategy for the Commission and Mexico. It takes into consideration international experiences to identify the key success and failure factors, with special attention to Smart Grid implementation experiences in countries that have a similar electricity sector structure to Mexico's. Therefore, the RR has been considered as a basic tool to establish the regulatory strategy for inclusion of the Smart Grid. The first step to develop the RR was to establish the vision and pillars of the Commission. Afterwards, in order to identify the current state of the power grid for the inclusion of renewables and the Smart Grid, a SWOT analysis was carried out. Finally, as a result of the research and the analysis, a set of specific recommendations regarding the key aspects for a successful implementation of the Smart Grid was provided to the Commission.

The aim of this paper is to share the experience of the Commission in developing the RR as well as some of the most important results obtained.

Overview: Current Landscape of the Electric Sector in Mexico

Until recently, the electricity sector in Mexico was vertically structured and the public utility, the Federal Electricity Commission (Comisión Federal de Electricidad-CFE), was in charge of all the activities related to the supply chain of the industry: generation, transmission, and distribution. On December 20, 2013 several legal conditions related to the energy sector were reformed, including the electric power industry. In order to establish an electricity market in Mexico, the industry is currently going through a transition period from a vertically integrated structure with a monopoly to a deregulated market open to competition.

As a result of this reform process, the Energy Regulatory Commission (Comisión Reguladora de Energía-CRE) gained considerably more authority, including the establishment of the regulatory framework, permits, methodologies, etc. related to both electric and hydrocarbons sectors. Within this context, one of the new authorities granted to the Commission is: "To issue norms, directives, and other administrative dispositions relating to Smart Grid and Distributed Generation, attending the policy established by the Ministry of Energy (Secretaría de Energía-SENER)." Before the energy reform, the Commission didn´t have specific authority related to the Smart Grid. However, under the current scheme, the Commission is the responsible entity for promoting the development and deployment of the Smart Grid in Mexico, through a suitable regulatory framework. This framework must consider not only the deployment of the Smart Grid, but also the renewable energy target established by SENER in the National Policy, which is set at 35% of the electric energy generated using clean energy resources by 2024[1]. In this matter, the Smart Grid can be considered as one of the enabling factors for the deployment of such clean energy resources (mainly renewables).

Smart Grid status in Mexico

In April 2014, a National Smart Grid Task Force Group (NSGTFG) was established with the leadership of SENER, gathering specialized staff from CFE, CENACE (National Center for Control of Energy) and CRE. At this time, the NSGTFG is comprised of federal entities only, however, in the short term, one of the goals is to consider the interaction with the rest of stakeholders such as academia, industry, project developers, consumer advocates, etc. The main objective of the NSGTFG is to collaborate and support the implementation and deployment of the Smart Grid in Mexico, considering the different roles and responsibilities of each of the members. Before the establishment of the NSGTFG, members had been working on developing their own vision of a Smart Grid.

SENER outlined its vision in the National Energy Strategy[2]. Its highlights were: increasing reliability, safety, sustainability and efficiency of power plants, transmission and distribution infrastructure, structuring and consolidating a set of programs, projects and actions that will lead to the development of a strategy for the development of a Smart Grid in Mexico. The National Energy Strategy considered that the Smart Grid could boost the integration of renewable energy into the grid and thus to reduce the impact on the environment.

On the other hand, CFE developed a Smart Grid Roadmap draft. The objectives of this roadmap were to: enable the client with better information to manage their consumption, optimize the use of existing infrastructure, manage the automated operation of the network, facilitate the integration of renewable generation, and develop processes aligned with interoperability and cybersecurity requirements.

Finally, CRE recognized that an appropriate regulatory framework was needed in order to develop a Smart Grid. Considering this, CRE developed a RR that enables the establishment of a regulatory strategy to support the deployment of a Smart Grid, based on an analysis of the best international practices and lessons learned, and at the same time considering the current landscape of the electricity sector and the Smart Grid in Mexico. The RR was developed by CRE, with the support of ESTA International under funding by the US Trade and Development Agency (USTDA). It is worth mentioning that prior to the Energy Reform of 2013, while CRE had no clear authority to work on Smart Grid issues it did decide to launch the RR project at that time. Nevertheless, the information and recommendations obtained by CRE in its RR maintain their value in this new energy scenario, since we focused on the role of a strong regulator having authority in the matter. The rationale used in developing the RR was to give an answer to the question “what a Regulator should do?” instead of answering the question “what a Regulator can actually do?” By focusing on this, CRE is in a great position to implement its RR since the Energy Reform now gives CRE explicit authority to issue all necessary regulation related to Smart Grid.

Efforts: A Regulatory Roadmap

The main purpose of the RR project was to provide a tool to define how an appropriate regulatory framework should be developed in order to support the Smart Grid in Mexico. One of the most important values of the project is that it considers several topics relating the Smart Grid and integrates them as a whole to develop the most relevant strategy for the Commission and Mexico, considering the international experiences to identify the key success and failure factors with special attention to Smart Grid implementation experiences in countries that have a similar electric power structure to Mexico's. Likewise, it considers the current landscape for the electricity sector and the Smart Grid in Mexico.

Considering its objectives, the RR encompasses seven tasks, as shown in Fig. 1. The topics addressed in the roadmap include the following: review of international developments, identification of regulatory and market barriers and how to overcome them, assessment and identification of opportunities for private investment, assessment of environmental and development impact, economical analysis and implementation plan. Each topic has a specific objective and corresponds to an individual task.

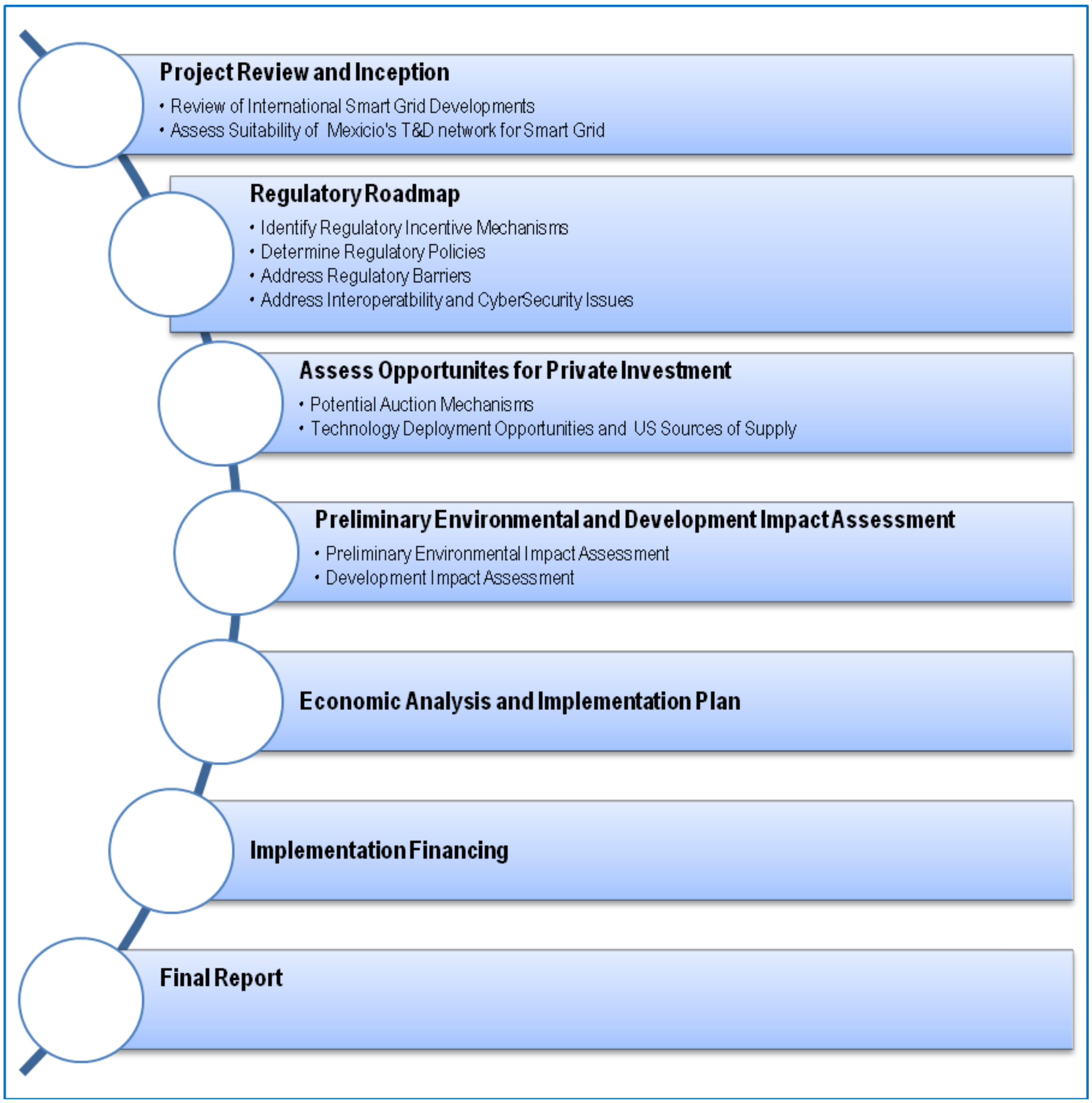

Figure 1. Tasks of the Roadmap.

The approach established by ESTA International to develop the RR was based on an extensive research of the best international methodologies. The process consists of the following seven stages: vision, pillars, timeline, baseline, analysis, functions, metrics, and assessment, as shown in Fig. 2. Such stages included the following activities: identify the drivers and pillars of smart grid, determine the time phase for each desired goal, review the current regulatory state regarding Smart Grid, perform regulatory gap analysis, and identify potential policies that will be needed as well as the incentive mechanisms.

The methodology followed by the ESTA/CRE team included the following activities: detailed information request questionnaire, face to face meetings with the entities involved in the development of the Smart Grid in Mexico, such as: SENER and CFE, review of industry best practices in countries with a similar power structure as Mexico´s, such as: a Ministry of Energy, a single regulator, and single utility. The process can be applied to regulatory, policy, and technology roadmapping.

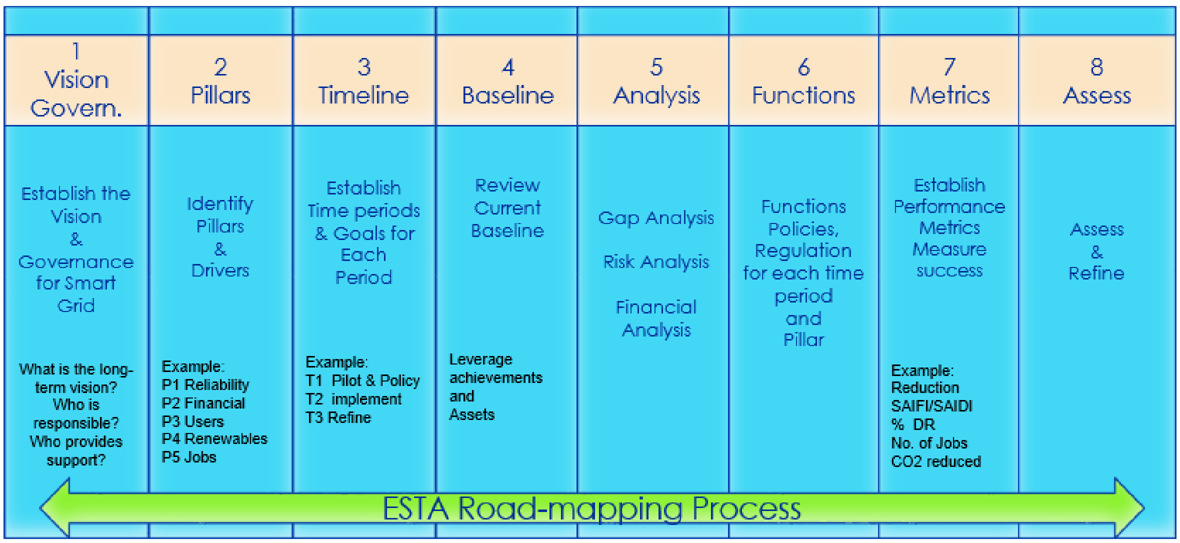

Figure 2. Approach for roadmap development.

Vision and Pillars

As shown in Fig. 2, the first step followed by CRE was to define its own vision related to the Smart Grid. According to the ESTA international roadmapping methodology, the vision statement is a succinct articulation of the goals and objectives of Smart Grid for the nation or an entity engaging in Smart Grid. The vision is established by reviewing the overall objectives at national and regional levels. It embraces governmental objectives as well as policy and energy acts. It addresses current as well as future challenges. It serves as the beacon for Smart Grid planning and deployment.

In general terms, the vision established for CRE can be articulated as: "Support Smart Grid implementation in the Mexican Electrical Energy Sector by developing a Regulatory framework supporting energy policy making made by SENER; fostering technological implementation made by CFE; giving certainty to existing and new private developers to participate in new markets; and empowering consumers to protect their privacy and optimize their energy usage."

Along with the vision, the pillars for CRE were established according to its objectives and corresponded to: consumer empowerment providing information security and education programs to optimized energy usage; adherence to SENER's policies related with energy fuels and climate change; attracting private sector participation into the renewable energy sector; and support and facilitate CFE to carry out Smart Grid programs aligned to energy policy. Fig. 3 shows, both the vision and the pillars for CRE.

For the implementation process, several specific objectives and targets were defined, along with their expected timeframes. In general, in the short term, CRE expects to set the foundation for the most urgent actions identified in the roadmap. In the medium term, CRE expects to develop the basis to achieve the ultimate goal of renewable energy in Mexico, stated by the national policy. In the long term, it is expected that the actions taken will facilitate the achievement of the national policy goals.

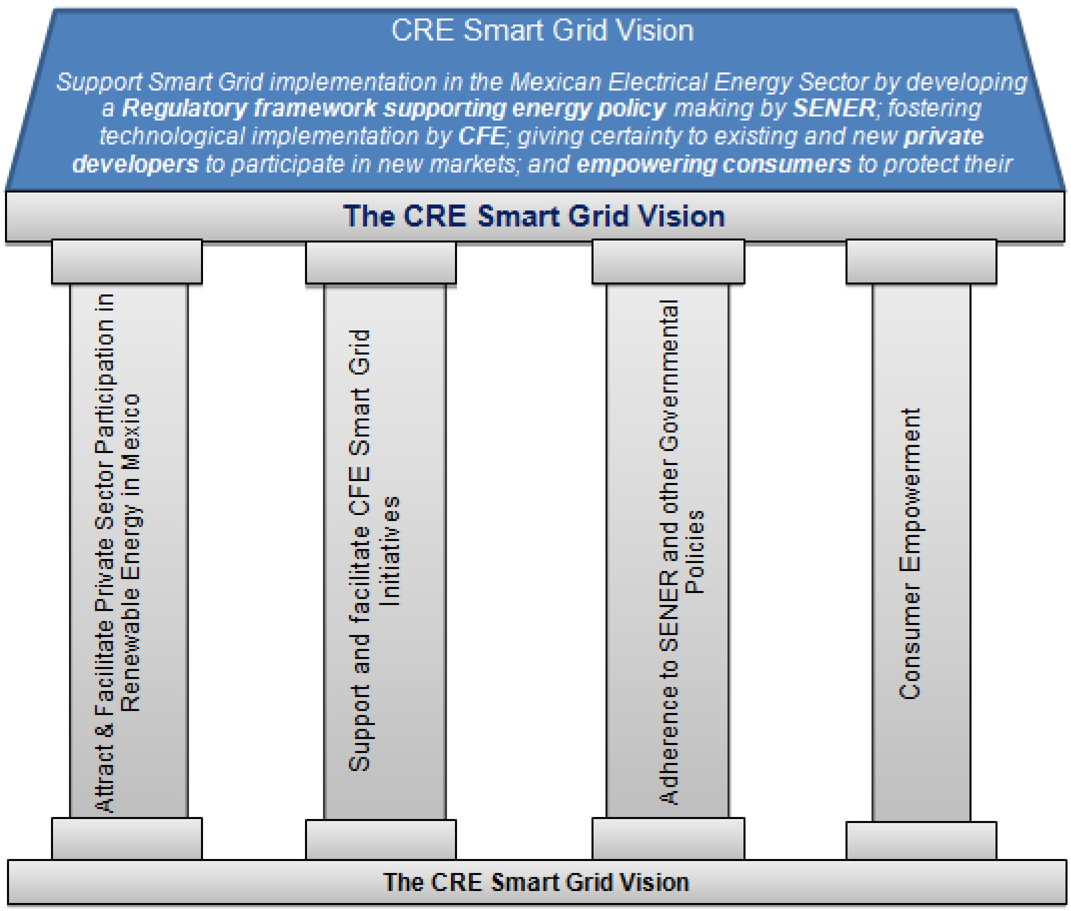

Figure 3. CRE Smart Grid vision and pillars.

Initial General Assessment: SWOT Analysis

Once the vision, the pillars and the targets were defined, the next step consisted of a general assessment of the following main topics: the power sector in Mexico, the nuances of the power sector to accept renewable generation, an analysis of the current authority of the regulator, and an analysis of the Mexican authority structure in the energy sector. The objective of this review was to establish the initial approach considering all the key elements of the electric power sector in Mexico to implement Smart Grid. To do so, all the information gathered was used to develop a SWOT (strengths, weakness, opportunities and threats) analysis of the Mexican power sector for implementation of Smart Grid. The SWOT analysis applies to both renewable energy and Smart Grid, although its main focus is on the first one. Below are summarized some of the factors identified through the SWOT analysis.

The identified strengths of the Mexican power grid that are consider as factors that can facilitate the development of a successful renewable resources program are:

1. Knowledgeable and skilled staff.
2. Availability of marginal costs.
3. Experience with 1,300 MW of wind generation.
4. Advance short-term load forecasting system.
5. Strong power grid with a 400 kV backbone transmission system.
6. Significant hydro generation which can dampen intermittency effects.
7. Existing interconnection study process.
8. Modern national and regional control center with advanced applications.
9. Development and testing of precision monitoring by synchro - phasors technology.
10. Automatic Generation control function to manage intermittency and variance of renewable resources.
11. Utilization and availability of ancillary services and reserve monitoring.
12. Large and diverse geography providing ample natural fuel for renewable resources.

In the same manner, the weaknesses of the Mexican power grid that may present challenges and impact the full realization of benefits from renewable sources and smart grids were defined and are summarized as follows:

1. Occasional overloads on the bulk transmission system.
2. Inadequate reference price for energy and ancillary services.
3. Absence of defined transmission expansion indexes.
4. Absence of defined Competitive Renewable Energy Zones (CREZ).
5. Under-developed regulatory and oversight process specific to integration and monitoring of utility scale renewable resources.
6. Absence of a tariff for interconnection of renewables with clear rules and compliance measures.
7. No mechanism for identifying viable and serious projects.
8. Current interconnection handbooks are not specific to any particular renewable technology.
9. Little experience with planning and operating utility scale solar technologies.
10. Needed training and formal processes to address increased complexities in planning and operation and increased risk introduced by integration of renewable energy sources.

A well-designed and implemented renewable resources program can provide a number of opportunities to benefit the power grid. The opportunities identified are:

1. Environmental and greenhouse gas reduction.
2. Increased asset utilization.
3. Alleviate and eliminate known congestion on the transmission system.
4. Defer or eliminate new investments in transmission infrastructure.
5. Reduce technical losses.
6. Potential for creation of useful micro grids areas.
7. Early retirement of old, polluting and inefficient power plants.
8. Creation of Competitive Renewable Energy Zones (CREZ).
9. Create opportunities to export renewable power to the U.S. and other countries.

Finally, the threats that can be created with a renewable resources program that does not provide the proper regulation and adequate oversight are:

1. High network upgrade costs.
2. Potential for the need to increase retail rates.
3. Increased need for subsidies by the Mexican Treasury.
4. Possible degradation in transmission system performance.
5. Possible degradation in under-voltage and under-frequency load shedding.
6. Emergence of new forms of congestion in previously non-congested areas.
7. Potential for local over-generation conditions.
8. Increased need for curtailment of renewable resources.
9. Increased overall operating costs.
10. Increased need for ancillary services, especially regulation.

The results from the SWOT analysis were combined with site visits, meetings, and discussions with SENER and CFE, as well as examination of documents in order to provide a set of recommendations useful for CRE. Such recommendations involve the following areas: regulation to enhance the operation of the electric power system, regulation to benefit the development of renewable resources, regulation to benefit end users and improve satisfaction, regulation to share costs and benefits of Smart Grid, regulation to protect end user information and privacy, among others. The recommendations were specified considering: the recommendations for the regulator, for the Ministry of Energy and for the electric utility. Below are summarized the main recommendations provided to the regulator.

Recommendations

The following suggested recommendations were identified specifically for CRE within the Mexican energy context:

1. CRE should support the creation and execution of a multi-party planning process for Smart Grid planning and implementation.
2. CRE should require that all power sector actors, in collaboration with the industry and with existing standards bodies, adopt and publish standards for Smart Grid, building on successful experiences in other countries.
3. CRE should develop and articulate its vision of third-party involvement in the retail Smart Grid.
4. CRE should develop regulation and establish rules that recognize the increasing reliance of the Mexican power grid planning and operation on third-party renewable resources such as hydro, wind, solar, biomass, etc., with varying characteristics.
5. CRE should develop regulation and establish rules requiring more reliance on third-party supplemental resources such as demand response, energy storage facilities, and back-up natural gas generation resources.
6. CRE should make legislative recommendations to encourage Smart Grid investment through informed tax and investment policy.
7. CRE should support SENER in developing proposals to legislation to remove any barriers to interconnection of Smart Grid suppliers.
8. CRE should require the utility to make “no regrets” Smart Grid investments that emphasize detection of outages, poor power quality, distribution transformer conditions before failure, etc.

9. CRE should oversee development by the utility of “plug and play” technical standards for Smart Grid devices to enable consumer involvement.
10. Provide additional consumer billing information, including potentially providing selected consumers with innovative and expanded billing information such as that offered by a number of providers that contract with utilities.
11. At CRE’s direction, the utility should consider contracting with a Smart Grid platform provider for a large scale trial.
12. CRE should consider promoting demand response options to price sensitive consumers to participate in energy and ancillary service markets.
13. CRE should consider pricing options and incentive mechanism for end-use consumers to attract small-scale renewable resources (capacity payment vs. energy payment).
14. CRE should develop regulation to encourage distributed resources in population areas (Distributed Generation, Energy Storage, Appliances, and Electric Vehicles).
15. CRE, in cooperation with other authorities, should begin introducing new rate structures: a Smart Grid requires “smart rates”.
16. CRE should begin publicizing Smart Grid impacts on consumer outages in areas with significant Smart Grid penetration.
17. CRE should plan and execute consumer education programs to introduce the benefits of Smart Grid initiatives.

All recommendations are discussed in depth within the RR exploring specific actions that CRE should undertake. In this paper, we only present the main summarized outcomes of Task 2 but it is worth saying that the RR includes an environmental impact analysis, a financial analysis as well as explorings some finance source opportunities. In elaborating the RR in 2012, Mexico lived a milestone in the Smart Grid Arena by gathering the main government stakeholders involved (SENER, CRE and CFE) for the first time in an institutional meeting to discuss Smart Grid actions for the first time. After many isolated efforts, we can ensure that Mexico is now using a national joint effort to deploy Smart Grid technologies and CRE is particularly pleased in considering its RR as one of the fundamental pieces needed for fully implementing the Smart Grid in Mexico.

Conclusions

As a result of the Energy Reform, CRE was granted with new powers and authority. Among those powers, CRE is now responsible for issuing all necessary regulation for promoting the development and deployment of the Smart Grid in Mexico. In an effort to develop the most appropriate strategy to support the Smart Grid, CRE launched a project in order to develop a roadmap. CRE’s RR has to be understood as a regulatory strategy to move forward with the Smart Grid actions in Mexico by providing certainty to all stakeholders involved. CRE will be responsible for addressing stakeholders’ agendas following the guidelines of a transparent, fair and equal treatment.

The base of the RR is the vision and the main objectives of the entity. Once this has been established, an overall assessment of the electric power sector was carried out, in order to identify the key elements through a SWOT analysis. As a result of the analysis and other efforts, a set of recommendations were developed in order to guide the regulator on some of the actions that must be carry out.

One of the main advantages of the RR is that consists of a tool to develop a custom made strategy. It is valuable to learn from international experiences considering both failure and success stories. However, CRE strongly believes that such experiences have to be studied within particular energy contexts getting rid of the idea that a “copy-paste answer” is suitable for all cases.

CRE shares its work to provide other Energy Regulators with some guidance when starting a regulatory journey to develop smart grids in their countries. The lessons shared encompasses the transition from a power sector controlled by a state monopoly to an unbundled and open-to-competition market. Finally it is important to say that a review of the legislative authority of energy regulators with respect to smart grids is important due to the lack of regulatory incentives which has been identified as one of the main barriers not only in Mexico but around the world in implementing smart grids. It is always important to bear in mind that a smart grid will need smart regulation.

Current Status

National Smart Grid Task Force Group

By the end of 2014, the (NSGTFG) had developed a working plan in which established the activities of the group for the next two years. Based on those activities and the main topics identified, nine different subgroups were created to work on the following topics:

1. Implementation strategies.
2. Regulation.
3. Renewable sources.
4. Smart Grid benefits.
5. Entailment with academy.
6. Proposals, evaluation and follow up of projects.
7. Entailment with the industry.
8. Funding and investment.
9. Inter-institutional collaboration.

The objective of the subgroups is to coordinate the development of the assigned topic, through a collaborative effort that involves SENER, CFE, CRE, and CENACE. In the coming months, the NSGTFG is expected to start with its activities and a set of quarterly meeting have been already scheduled in order to present the progress in the above mentioned topics. Particularly, CRE is responsible to develop topics 2 and 9.

Smart Grid RR: Next Steps

Now that the first stage of the activities is done, CRE is looking to move forward by sorting the 91 recommendations obtained from the RR. CRE acknowledges that all recommendations are important but it makes little sense to charge ahead without a priority list in which the most urgent actions are defined and planned.

With this in mind, CRE organized a summit focused on the implementation of its RR. This summit took place in Mexico City on February 24th, 2015. It involved the participation of around 140 representatives from government entities, academia, industry, consumer advocates and other stakeholders.

The event was comprised by two main parts. In the first one, authorities from SENER (Undersecretaries of Electricity and Energy Planning) and CRE (Chairman) presented the most recent activities developed in Mexico regarding Smart Grid and discussed the main challenges for its implementation.

The second part of the event was focused on obtaining a priority list for the 91 recommendations obtained from the RR. For this purpose all participants were gathered into 6 different working groups:

1. Regulation
2. Public Policy
3. Renewable Energy
4. Consumer issues
5. Energy efficiency
6. Power System operation

The aim of each group was to sort the most urgent actions to move forward with the implementation of Smart Grid, proposing timeframes to assess the progress in every topic.

As a result of the summit, CRE obtained valuable information from the stakeholders regarding the main challenges and possible adjustments to the Recommendations obtained from the RR that should be considered in order to develop a suitable regulatory framework for the implementation of the smart grid in Mexico. Based on such results, CRE is currently developing the action plan to establish the regulatory measures that will be taken for implementing the smart grid. With this Summit, CRE endorses its commitment of developing the necessary regulation based on an open, transparent and consensus-based process.

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X. Increasing Consumer Choice – The Potential Impact of Prosumers on Electricity Market Regulation

By Carmen Wouters, Carolyn Vigar and Katelijn Van Hende

1. Introduction

Over the last century, the electricity supply system of industrialised countries has evolved from small direct current electricity grids that served a local consumer base in the early 1900s, to a centralised alternating current electricity grid where electricity is generated in large centralised power plants to be transmitted and distributed through the network to end-consumers[1]. This trend of upscaling arose from the increasing population and interconnection of the system. Liberalisation marked a second system reform that introduced competition in several sections of the supply system. Although a general trend of increasing global energy consumption is assumed, following increasing levels of urbanisation and industrialisation, in some industrialised countries with liberalised electricity markets, a decline in end-consumption can be observed[2].

In Australia, demand has fallen with an average of 1.8% annually between 2009-2010 and 2013-2014 and is forecasted to continue declining[3]. Economic and other incentives coupled with access to information and technology are providing consumers with electricity supply choices. Electricity consumers now have avenues through technologies such as rooftop photovoltaic (PV) cells to become both producers and consumers of electricity. The emergence of the prosumer, with the related trend towards decreasing dependency on the central electricity grid, will challenge systems of electricity industry regulation that are based on a centralised electricity supply model [4].

Unsurprisingly, the liberalisation model of the 1990s in southern and eastern Australia was designed for the electricity supply model which existed at that time. At its inception, the National Electricity Market (NEM) was typified by large-output base load generation generally located at a distance from major load centres, which provided electricity to consumers via transmission and distribution networks.

Although the trends in Australia are the immediate focus of this paper, the challenges of alternative technologies to existing systems of regulation are relevant wherever the electricity supply system has been liberalised. From the 1980s onwards, many countries around the world such as the United States, the countries within the European Union, Australia and some east-Asian countries, started to deregulate their electricity markets to remove vertical integration to allow for competition and efficient investment[5]. While a driving philosophy behind these reforms was often to reduce the direct involvement of governments in the electricity sector, experience across the globe has demonstrated that regulation of the electricity supply industry resulting from these reforms has increased[6]. These systems of regulation are premised on prevailing technologies; so that the emergence of new technologies necessitates regulatory reform.

This paper considers the impact of new technologies on consumer behaviour and the potential consequences for network regulation. While liberalisation of the electricity supply industry can be viewed as a precondition to these new technologies becoming available to consumers, it may be that these new technologies will ultimately undermine not only the system of regulation that was implemented for the purposes of liberalisation, but the financial viability of network businesses. A new model of regulation and network ownership may ultimately result from these trends. This paper argues that as a result, the Australian electricity sector may in future be reregulated.

2. Decentralised technologies and increased consumer awareness in Australia – making the shift possible

A changing consumer paradigm

Decreasing electricity demand stems from several trends at the low voltage end-consumer level in the distribution system of the conventional network. Especially residential consumers – responsible for about 30% of the total energy demand in Australia – have the ability to access new mature decentralised energy technologies[7]. Awareness of and access to these technologies is not only reducing consumer dependence on electricity networks, but is in some cases also enabling prosumers.

Three preconditions for a widespread uptake of decentralised technologies can be identified:

- availability of decentralised technologies is increasing;
- consumers have more information regarding electricity supply alternatives; and
- incentives to adopt an alternative approach exist.

The existence of these preconditions enables residential consumers to implement initiatives to reduce their peak demands, increase the reliability of their energy supply and decrease their dependency on centralised network energy supply.

Availability of decentralised technologies

Decentralised generation and storage units refer to small-scale technologies that are typically implemented at or in close proximity to the premises of end-consumers in the grid[8]. They are implemented at the low voltage distribution level in the central grid and will generally be limited to about 10 kW in installed capacity at the residential level[9].

Various forms of decentralised technologies exist. These can be energy generation technologies that are either based on intermittent renewable resources such as sun and wind, or dispatchable units such as combined heat and power units[10].

Decentralised technologies are gaining increased interest around the globe speeding up their technology learning curves and decreasing their investment cost[11]. As technologies such as batteries and PV units mature and the demand for these technologies increases, unit price reductions may make these technologies more attractive and accessible to end-consumers.

Economists argue that the most significant potential gains from electricity restructuring stem from changing the way investment and consumption decisions are made[12]. In the United States electricity market for example, technological changes and increasing fuel prices have made it economic to generate with smaller units and integrate separate utility systems into larger regional networks that increase the size of the market[13]. Decentralised generating units have a major benefit in that they balance and control local supply and demand while exploiting, to a high degree, locally available energy resources[14]. The intermittency of renewable sources can be offset in residential settings by recent developments regarding electric storage, leading to increased autonomy of self-supply of households[15]. With rising electricity costs and network reliability issues, for some consumers investing in these technologies is increasingly attractive [16]. Decentralised energy technologies will enable residential consumers to decrease their peak load and increase the elasticity of their demand, reducing both their energy cost as well as their dependency on the central grid[17].

Information and awareness

For the adoption of decentralised technologies, consumers need to have adequate information and awareness regarding technologies available in the market and how to access them. Furthermore, in order for consumers to make a conscious shift towards decentralised technologies, they need to understand their own consumption behaviour.

While consumers in the past had little or no opportunity to respond to price signals (as the cost of producing electricity fluctuates by hour or even by minute), deregulated electricity markets often include incentives to implement consumer price responses, such as giving the consumers a free choice of producer or a guarantee of origin as implemented in the European Union[18].

Typical residential electricity loads in Australia show morning and evening peaks and significant seasonal differences between peak consumption during winter and summer times[19]. Since the current payment structure of residential consumers in the NEM is based on usage [kWh], householders are unlikely to link the peaks in their own demand to the need for peaking generators in the central generation portfolio on only a few occasions throughout the year. Similarly, network investment to ensure reliability during peak times increases network service charges for consumers.

Regulatory change to increase consumer awareness and responsiveness to network pricing is already occurring. The Australian Energy Market Commission (AEMC) undertook a review in 2012 which is resulting in the Power of Choice reforms[20]. The AEMC's review is premised on electricity market efficiency increasing through better demand side participation (DSP). Better informed consumers enable a use of DSP tool to make more informed consumption decisions [21].

The current reforms proposed through the review include altering distribution network pricing principles to improve consumer understanding of network tariffs[22]. The AEMC has released a draft amendment to the National Electricity Rules (NER) which will require distribution network service providers to base network tariffs on long run marginal costs of providing a network service (NER Amendment)[23].

Incentives

The experience in Australia with the installation of rooftop PV units demonstrates that support schemes such as feed-in tariffs or governmental subsidies increase the accessibility of decentralised technologies[24]. These incentives can be financial, related to energy security or arise out of sustainability considerations.

Financially, governmental support schemes such as subsidies and available feed-in tariffs in the market will make the investment in decentral technologies more attractive to end-consumers due to the potential of income creation. With regard to the NER Amendement, a desired result is to reward consumers through reduced tariffs where the consumer adopts technologies or consumption patterns which reduce dependence on the grid[25]. Current network tariffs largely average costs across the consumer base and thereby consumers with low demand profiles effectively subsidise consumers with higher and peakier demand[26].

Greater consumer awareness of the impact of consumption patterns enables an appreciation of the financial consequences of reducing network demand. Investing in decentralised generation units such as household rooftop PV-battery systems might be a solution for consumers to level out demand profiles and reduce dependency on high electricity prices in the grid or high capacity payments[27]. Other actions may also provide consumer incentives. For example, electricity distributors in Queensland, Australia, are proposing to restrict and even prohibit residential consumers to export rooftop PV electricity to the central grid[28]. Other Australian network operators may follow this initiative as the highly successful rollout of residential rooftop PV units is necessitating significant network infrastructure upgrades[29]. This will potentially increase the interest of residential consumers in investing in batteries to complement their rooftop PV units and in this way exploit a continuous advantage of the energy generated by the sun.

When viewed from an energy security perspective, consumers in several regions in the NEM experience frequent power outages due to severe wind and weather events[30]. This additionally motivates consumers to invest in decentralised technologies to secure their energy provision and increase the reliability of their energy supply by not solely relying on the central grid.

Lastly, sustainability and climate change awareness is growing amongst the residential population which is another driver for the uptake of renewable, efficient and sustainable decentralised energy technologies such as a combination of PV and batteries.

3. Prosumer Trends – Challenging network regulation

Deregulation in Australia – precondition for consumer choice

The NEM has operated in southern and eastern Australia since 1998[31]. A fundamental technical component of this market is the interconnected 'national grid'. This grid is made up of transmission and distribution networks of the participating jurisdictions joined together by interconnectors. The NEM participating jurisdictions are South Australia, Tasmania, Victoria, New South Wales, the Australian Capital Territory and Queensland.

The networks which comprise the national grid are variously owned by private and public sector corporations. In the 1990s, Victoria and South Australia privatised their network businesses while other jurisdictions such as Queensland and New South Wales currently retain the network businesses in government ownership. Regardless of the ownership structure, all network businesses operating in the NEM are subject to regulation under the National Electricity Law (NEL) and the NER.

A key component of this regulatory system is the economic regulation of network businesses. Regulated network costs comprise around 50% of the national average electricity price[32]. From the outset of the NEM, it has been recognised that the network businesses would be subject to economic regulation to ensure an efficient supply of electricity to consumers. Regulatory resets of revenue or price caps occur periodically against a framework set out in Chapters 6 and 6A of the NER.

Economic regulation – a model premised on a broad consumer base

The Australian Energy Regulator (AER) is responsible for the economic regulation of all network businesses participating in the NEM. The economic regulation of network services by the AER involves the classification of those services as either 'direct control network services' or 'negotiated network services'[33]. The provision of the core network service of transmitting electricity from the point of generation to an end-use consumer (including via interconnected networks) is a direct control network service. The regulation of direct control network services involves the AER applying a building block approach to determining either revenue or price caps for a network business for a regulatory period (generally five years)[34].

The AER is required when performing or exercising an economic regulatory function or power to perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the national electricity objective[35]. This objective states:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*
>
> *a) price, quality, safety, reliability and security of supply of electricity; and*
> *b) the reliability, safety and security of the national electricity system.[36]*

In addition, the AER is required to take into account the revenue and pricing principles set out in section 7A of the NEL when exercising a discretion in making a distribution determination or a transmission determination relating to direct control network services.

An unstated premise of economic regulation under the NEL and NER is that there is a broad consumer base from which to recover the transmission use of system charges and distribution use of system charges. While historically this premise has been true, technological changes and the existence of incentives for consumers to explore alternatives to traditional electricity supply challenge the degree to which network service providers can rely on there being a secure consumer base from which to recover the costs of network service provision. This in turn calls into question the principles which underlie the economic regulation of these businesses.

For example, the revenue and pricing principles indicate that a regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services and complying with a regulatory obligation or requirement or making a regulatory payment[37].

By utilising a regulatory asset base (RAB) to determine network tariffs and revenues, the regulatory model reflects the significant sunk costs of network businesses through capital investment in their networks. These capital costs are not recovered directly from particular consumer segments that utilise particular assets, but are recovered through charges applying across the consumer base according to the volume of electricity consumed.

4. Potential Regulatory impact of prosumers

Regulatory assumption of a broad consumer base

The AER is required to have regard to the RAB adopted in any previous distribution determination or transmission determination. The RAB locks in the sunk costs of network service providers on the assumption that the consumer base will continue to pay for services provided by serviceable assets regardless of their economic age. This is a workable assumption provided that there is a broad base of consumers from which to recover these costs.

A reduction in either the amount of electricity being taken by consumers or the consumer base will mean that these sunk costs will need to be recovered on the basis of lower consumption or from fewer consumers. The same is true for operational expenses (opex) incurred by network service providers, which may have a limited ability to be varied to reflect services to a smaller consumer base. This is particularly the case where the reduction in consumer numbers are spread throughout a network service provider's network area, thereby, precluding the provider from discontinuing services to specific parts of its network area.

Revenue and pricing principles discordant with emerging paradigm

Similarly, the revenue and pricing principles indicate that a regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The ability to efficiently invest in network upgrades or augmentation is premised on having a sufficient customer base to recoup these capital costs. Attention is already being given to the meaning of efficient investment in an environment with diminishing demand for network service either through reduced consumption or decreasing consumer base. For example, the AEMC has released a framework for reconsidering efficient investment in transmission networks by aligning the levels of investment with customer expectations in respect of network reliability[38].

The revenue and pricing principles also require that a price or charge for the provision of direct control network services should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates. Trends towards decreased reliance on network services may alter the risk profile of network businesses over the medium and longer term.

As examined above, there are costs of network businesses which will be built into the revenue caps which need to be recovered from the consumer base as a whole. If the consumer base has diminished, then each consumer pays proportionately more for network services. There is a risk that this will reach a critical point where the consumer base is unable to meet these costs (particularly if the consumers remaining are those least able to cope with rising network costs or to afford alternative technologies allowing them to reduce their dependency on network supply). This result increases commercial risk for network business as the certainty of achieving a commercial return is undermined.

The system of economic regulation for network businesses is not well attuned to the changing dynamic evident in the electricity supply industry toward less dependence on network services. The revenue and pricing principles are premised upon recovery of capex, opex and a commercial return across a broad consumer base, which may not continue to exist. Ultimately, the revenue and pricing principles may be inconsistent with the achievement of the national electricity objective as networks are required to provide a similar level of service reliability to a diminished consumer base, which cannot afford the cost of the service. The long-term interests of consumers, therefore, will not be met.

Adoption of decentralised technology may alter governments' role

Ultimately the regulatory impacts of the trends identified will depend on the degree of decentralisation which occurs. As a general proposition, a significant decrease in the consumer base for network services will make the costs of those services unsustainable. Increased network costs are likely to highlight financial incentives to adopt decentralised technologies and accelerate the trend away from network dependence.

Should there be sufficient adoption of decentralised technologies then the service provided by the distribution network may be one of providing a backup supply in the event of local supply failure (rather than being a universal service). There may be an inability in the remaining consumer base to support this service in a manner which enables service provision on a commercial basis by network operators. This will necessitate further adjustment to the regulatory system and perhaps even a reinstated role for government to ensure that back-up network supply is available in the event of failure in a decentralised technology system.

5. Conclusion

Regulatory systems premised on particular technologies will always be challenged by the emergence of alternative technologies. This is evident with respect of uptake of decentralised technologies. Consumers are increasingly able to access technologies to decrease their dependence on electricity supply networks and control their consumption behaviour. The preconditions for increasing uptake of decentralised technologies lie in the maturing of these technologies, increased consumer awareness and incentives such as financial support schemes. These preconditions are apparent and residential consumers are choosing to install decentralised technologies to reduce their network consumption, allowing them to become in some cases prosumers of electricity.

Regulatory challenge brought about by technological change is not a new phenomenon either in Australia or elsewhere. Clearly though a consumer-led shift away from the electricity supply network on the basis of increasingly accessible decentralised technologies is not catered for in the current system of NEM regulation. Consequently amendments to the NER are already being pursued [39].

A systemic shift of this nature may require a fundamental review of the role of electricity networks and ultimately a re-evaluation of the assumptions which underlie the current system of network regulation. This could be the start of a debate on whether ultimately future electricity markets will transition from their current deregulated form towards a reregulated form. As indicated earlier, most electricity markets in the developed world have moved towards deregulation since the 1980s. The developments described in this article may well put this model under pressure and precipitate a new era of electricity market reregulation.

The described trend may provoke a debate on the role of governments in providing reliable and safe access to electricity. Future research should investigate consumer patterns taking account of the rise of prosumers and identify potential pathways for electricity markets to transition towards future smart energy systems, where consumers will play a more active role.

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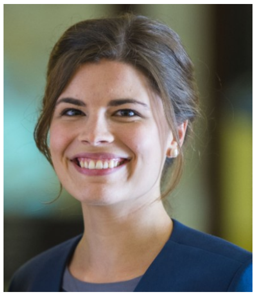

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XI. Advantages and Barriers to the Creation of a Pan-European Balancing Market

By A. Zani, G. Migliavacca, D. Burnier de Castro, T. Esterl, H. Auer

In the last decades, the integration of different national power markets in Europe is leading to the creation of a common day-ahead exchange area, the so-called Internal Electricity Market (IEM). In fact, after coupling the national day-ahead markets, it becomes important to reflect on the opportunity to integrate the markets that are closer to the real time, most notably the balancing markets. Actually, the necessity to create an integrated European balancing mechanism is clearly stated in the ENTSO-E Network code on Electricity balancing (NCEB) [1].

This paper aims at investigating the opportunities created by the integration of electricity balancing markets. The work described in this paper, carried out in the framework of the EC FP7 project eBADGE [2], analyzes advantages and barriers in sight of the creation of a Pan-European Balancing Market. After a short description of the European regulatory context (section I), an in-depth description of barriers and criticalities to the creation of a Pan-European balancing market is presented (section II); then, a scenario analysis is carried out in order to quantify possible benefits deriving from a common balancing market between Italy, Austria and Slovenia (section III); conclusions are shown in section IV.

The European Regulatory Context

Currently, the European energy policy is based on the three pillars, namely: (a) integration of intermittent renewable generation, (b) security of supply, (c) creation of a pan-European IEM. Regarding the process of integration of the national electricity markets, the European Council (4 February 2011) fixed some reference dates for the completion of the IEM (by 2014) and the connection of all member-states that are now electrically isolated from the rest of the EU (by 2015). Up to now, the attention for the creation of the IEM was concentrated on the integration of national Day-Ahead Market (DAM) with the implementation of the market coupling mechanism.

Anyhow, also the integration of market closer to real time could bring important benefits to the system: the third energy package and Directive 96/92/EC [3] clearly “moves” in this direction by creating the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators (ENTSO-E) with the obligation of the latter to elaborate network codes on the basis of framework guidelines formulated by the former.

One of these is the Network Code on Electricity Balancing (NCEB)[1], presently still in draft, that proposes a phased approach to fostering cooperation amongst balancing areas through the creation of “coordinated Balancing Areas”, seen as “a cooperation with respect to the Exchange of Balancing Services between two or more Transmission System Operators”.

The level of cooperation within and between Coordinated Balancing Area will increase as time passes, up to a situation in which the final target of a single pan-European market based on a Common Merit Order list is achieved. In the NCEB an important space is dedicated also to all potential providers of Balancing Services (like demand side response, energy storage and intermittent sources), in order to create a level playing field for all possible market participants.

However, nowadays national balancing markets have really different characteristics that need to be harmonized in order to allow the progressive integration process. Currently the NCEB focuses on setting rules for a minimum harmonisation between the European countries.

This context motivates the FP7 research project eBADGE, led by Telekom Slovenije (main coordinator) and cyberGRID (technical coordinator) and encompassing 13 partners including the Austrian and Slovenian Transmission System Operators APG and ELES, the Slovenian market operator Borzen, the German ICT provider SAP and several research institutions. Aim of eBADGE project is to propose an optimal pan-European Intelligent Balancing mechanism also able to integrate Virtual Power Plant Systems (VPPs), thought as aggregations of a variety of entities located in the distribution sector - like distributed renewable generation, demand response capabilities and storage resources - into a clean energy asset acting like a conventional peaking power plant.

Barriers and criticalities to a pan-European Balancing Market

Nowadays, the great diversity of ancillary market designs among its Member States represents an important barrier to the set-up of a cross-border trade of ancillary services and to the development of a fully integrated IEM. The diversity of procurement schemes for ancillary services across Europe has to be taken into account when developing cross-border balancing schemes. According to selected design parameters, balancing markets can be analyzed as shown in Figure 1. While the multinational design variables have yet to be designed, the national balancing market parameters need to be harmonized for successful implementation of cross border balancing in a way to ensure secure balancing and to enhance global welfare. The challenge of defining these parameters and of defining the degree of harmonization is to specify them in an intelligible way, but to let room for national technical requirements and specifications.

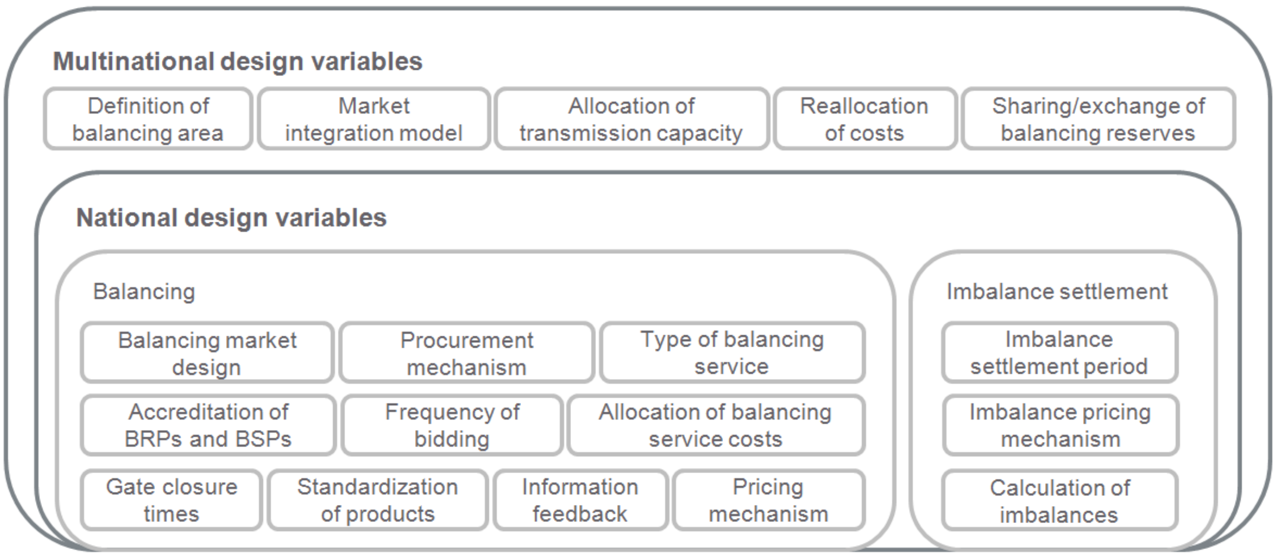

Figure 1 – Selected design variables for analysis of national balancing markets [10]

One parameter is the selected market architecture. There are different market architectures for the integration of European balancing market and thus, for cross-border procurement of balancing energy and, as seen in TABLE I, they have different pros (+/++) and cons (-/--). The starting point is a national balancing market without any exchange of balancing energy bids.

The cross-border BSP (Balancing Service Provider) – TSO (Transmission System Operator) concept is followed by two gradually enhanced cross-border TSO-TSO balancing market architectures (considering different principles of bid exchange). The most advanced market architecture coincides with the so called 'Target Model' being consistent with the overall framework defined in the ACER and ENTSO-E documents [5][6].

The balancing market within the control zone of a single TSO (national model) is organized based on the following subsequent steps for procuring and – in case of activation – balancing services from different Balancing Service Providers (BSPs) fulfilling the prequalification criteria: (i) Procurement of balancing capacity, (ii) Procurement of balancing energy and (iii) Activation of balancing energy of selected BSPs. For the first two mentioned steps above ((i) & (ii)) separate tenders exist and the corresponding bids are split for upward and downward regulation. Well defined standard products can be offered by BSPs to the TSO that clears the market in the corresponding national market place for procurement of balancing energy.

In the cross-border BSP-TSO concept it is foreseen that Balancing Service Providers (BSPs) can offer balancing energy bids not only to the Transmission System Operator (TSO) in their own control area, but also to other TSOs in neighboring control areas. This offer of balancing energy bids by a BSP to a TSO has to be accepted by the 'own' TSO in the control area where the BSP is located. In case of activation of these kinds of balancing energy bids a cross-border balancing energy exchange takes place as long as there is sufficient cross border transmission capacity available at the point in time when it is actually needed.

The bilateral/multilateral market-based TSO-TSO balancing model with surplus exchange is a further development of the previously described national approach. The aim of such a balancing market model is that the involved TSOs exchange some surplus balancing energy bids based on predefined criteria. It is important to note that the exchange is restricted to surplus balancing energy bids only. The determination and procurement of balancing capacity is carried out separately by each of the TSOs. Hence, no exchange of balancing capacity among the TSOs exists and also no reservation of cross-border transfer capacity is needed to enable the exchange of balancing capacity. However, a cross-border exchange of surplus balancing energy bids is only feasible if sufficient cross-border transfer capacity is available in case of activation.

The bilateral/multilateral market-based TSO-TSO balancing model with common merit-order list with unshared bids can be interpreted as an intermediate step next to the so-called "target model". Moreover, this approach can deliver valuable experience before implementing the "target model". The challenge of the TSO-TSO balancing model with common merit-order with unshared bids, however, is to find criteria or a set of criteria determining both balancing energy bids need and need not to be shared among the different TSOs (=unshared bids). Exchanging balancing energy bids on a common function and, in case, activation of some of these balancing energy bids finally results in cross-border balancing energy exchange. This balancing energy exchange, however, is feasible only if there are sufficient cross-border transmission capacities available.

The "target model" is a fully integrated TSO-TSO balancing model with common merit order, where all bids of the Balancing Service Providers (BSPs) are shared on common function. The procurement of balancing capacity bids and balancing energy bids is conducted by the connecting-TSO. Then, each TSO will forward the procured balancing energy bids to the common function, cross-border exchange among the TSOs balancing capacity is only optional hence, the

	Cross-border BSP-TSO model	Bilateral / multilateral TSO-TSO model without common merit order	Multilateral TSO-TSO model with common merit order - lower degree of harmonization	Multilateral TSO-TSO model with common merit order - high degree of harmonization
Economic allocation efficiency	--	-	+	++
Short/medium term applicability in practise	++	+	-	--
Support of VPPs as BSPs	--	--	-	+
Harmonisation needs of neighbouring balancing markets	--	-	+	++
Market compatibility / competition / transparency	--	-	+	+
Social welfare / system cost (global optimum)	--	-	+	++

procured balancing capacity bids remain on national TSO level. Therefore, a reservation of cross-border transmission capacity is not obligatory. Also in this model a cross-border exchange of balancing energy is feasible only if sufficient cross-border transmission capacity is available.

Table 1. Comparison of the different cross-border balancing market concepts [10]

The balancing markets in Austria, Slovenia and Italy (AIS) and the need for harmonization between them were analyzed, within the project eBADGE, according to the design variables in Figure 1. The first dissimilarity between the three countries is the balancing market design. The dispatching system is the same in Austria and Slovenia (self-dispatch system on portfolio basis), but different in Italy (central dispatch system). Many details in the Network Code on Electricity Balancing implicitly assume a self-dispatch balancing market design. For central dispatch markets an exceptional regulation is in place. The optimization algorithm of the central dispatch model takes simultaneously the balancing requirement as well as the internal congestions into account. The balancing resources have to be mandatory offered in Italy, whereas in Slovenia the balancing capacity is procured by bilateral contracts. In Austria the market-based mechanism of a tendering process is used. The manual Frequency Restoration Reserve (mFRR) balancing service of the three countries is indeed according to the operation handbook of the ENTSO-E [4], but the mFRR differs in some parameters as for instance regarding the time to full activation (10 minutes in Austria, 15 minutes in Slovenia and Italy). At least some of these differences have to be harmonized for the cross-border market opening of balancing energy. A first step for the harmonization would be an adaptation of the gate closure times – day-ahead, intraday, balancing energy, capacity allocation and favorable the (imbalance) settlement time unit – as different gate closure times make the cross-border provision of balancing energy nearly impossible.

Scenario

In order to carry out a quantitative assessment of the benefits that could be extracted from an integrated balancing market, models of both the present mechanism and the “target” model were developed and run, with a particular focus on a region encompassing Austria, Italy and Slovenia. The conclusions that can be drawn on the obtained results are not limited the studied region, being extendable to other European regions.

As shown in Figure 2, the eBADGE simulator represents both Austria and Slovenia with one only equivalent zone, while Italy is split into six zones (corresponding to the Italian day-ahead market zones). As presented in previous section, and extensively in [4], settlement and clearing approach of these three nations are really different: in Austria and Slovenia the clearing of balancing energy market is mainly done without network constraints; different approach is taken in Italy, where the network has to be taken into account because its characteristics limit the field of action of real time markets. This is the reason why Italy is modeled thought a zonal representation, while Austria and Slovenia are seen as single zones.

Figure 2- Model of the power system [Modelled zones: Austria (AU), Slovenia (SL), North-Italy (IT-NO), Centre-North Italy (CN-IT), Centre-South Italy (CS-IT), South Italy (SU-IT), Sicily (SI-IT) and Sardinia (SA-IT).]

The studied scenarios refer to a period between the 1st march 2012 and the 31st July 2013. This timeframe was chosen on the basis of TSO's input, that affirm that in this period the regulatory context has been stable in all the involved nations).

Analyzing the rules for switching from secondary to tertiary bids in each nation, a great complexity and inhomogeneity has been observed. For our modeling purpose, simplifying assumptions have been adopted in order to keep the complexity within a range that can be dealt with in our model:

- Austria and Slovenia: secondary reserve is called for activation if the actual imbalance is lower than a given threshold, otherwise tertiary bids are used.
- Italy: a similar rule has been adopted, the only difference being that the threshold is not fixed a priori, but it is a function of the daily peak load (typically 2% of it).

It order to assess which benefits could subsist for the Italian power system in case of a common balancing market with Austria and Slovenia, two different scenarios have been defined:

- A Base Case scenario (BC), simulating a situation in which each nation has to solve internal imbalances only with local resources; in order to implement this scenario NTC values have been imposed equal to zero;
- A Common Balancing Market scenario (CBM), simulating a situation in which balancing resources may be exchanged.

A comparison between the results of the BC and CBM scenarios was performed in terms of costs and energy flows.

Costs results are presented in Table II and Figure 2.

Table II. Balancing Costs [M€] for each nation

Scenarios	Nation			
	Austria	*Slovenia*	*Italy*	*Total*
BC	3.5	37.3	137	177.8
CBM	5.2	20.2	54.2	79.7

It can be observed that if a common balancing market is created total dispatching costs decrease for both Slovenia and Italy. Different results for Austria -most likely because the cheapest Austrian generators are used to cope with imbalances in Italy and Slovenia, while more expensive generators are used in order to face Austrian imbalances - imply higher costs for this country.

In any case, costs increases in Austria are lower than the savings that can be achieved in Slovenia and in Italy; in particular, in Italy, costs for secondary and tertiary activation amount to 137 M€ if imbalances are solved only with local generators and this value decreases to 54.2M€ in case a common balancing market is implemented, with a saving level up to 60%. It has to be noticed that this estimation corresponds to an optimistic case in which no internal network constraint is violated. The presence of internal constraints could make it necessary to resort to less optimal solutions and reduce this saving level. So, the presence of a strong transmission network is an important prerequisite for allowing a cross-border balancing market to function efficiently.

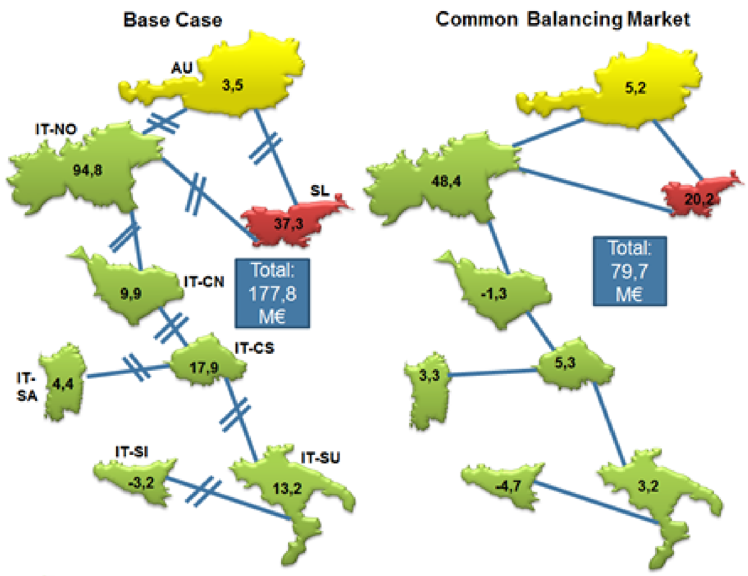

Figure 3—Comparison of costs-savings for the two scenarios (M€)

Analyzing in detail the results for the different Italian macro-zones we observe the following:

- The North macro-zone is in line with the general trend, with saving around 48%
- The Center-North macro-zone registers optimal results passing a cost of 9.9M€ in the BC scenario to a benefit of 1.3M€ in the CBM scenario.

Another important result to analyze is the level of energy exchanges between the modelled macro -zones. Figure 3 reports the results for the CBM scenario.

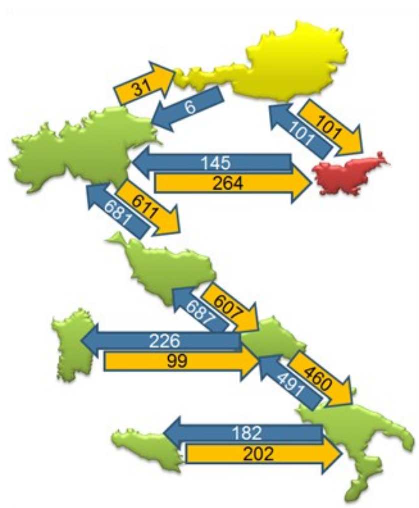

Figure 3—Energy exchanges [GWh] between zones in CBM scenario.

Considering that, in the studied period, the total imbalances that occur in all the Italian zones amount to 6286 GWh, if we compare this figure with the resulting exchanged energy, equal to 3894 GWh, we conclude that volume of exchanges between macro-zones amounts to 77.8 % of the total imbalances that occur in the system. This result highlights the benefits in terms of integration of balancing system.

It can be seen that the exchanges between north Italy and Austria stay quite low: this apparently unexpected result can be justified with the weak interconnection level between the two countries.

Moreover, the level of exchanges between continental Italy and Sardinia or Sicily could be overestimated in our scenarios. In fact, in order to maintain a sufficient level of security of supply in a weakly interconnected system as well as for reasons related to reactive management, some local units are called to operate also if their costs are higher than those of other units. For these reasons, both in the day-ahead markets and in the balancing markets, weakly interconnected macro-zones tend to exploit local resources. The solution of our model does not take into account all these characteristics and thus we think that the import figures for Sardinia and Sicily could be overestimated.

Conclusions

The work presented into paper highlights that the way towards a harmonized regulatory framework is difficult, as shown by an in-depth study carried out within the project eBADGE. Different “intermediate” market architectures for cross-border procurement and activation of balancing capacity and balancing energy are possible, requiring a progressive harmonization of several balancing market design variables. A starting point would be an adjustment of the gate closure times, as different gate closure times make the cross-border provision of balancing energy nearly impossible and standard products for the balancing markets have to be available.

Moreover, using the balancing market simulator developed by eBADGE, an estimation of cost saving potentials in case of implementation of the “target model” is provided. The results are encouraging: 60% cost savings were registered with respect to a situation where each country manages balancing with local resources. However, these results should to be evaluated more in detail, taking into account network constraints inside each zone.

Finally, it must be stressed that a common management of the balancing resources is only possible if accompanied by a real integration of the European balancing markets. Anyhow, big steps toward a true harmonization of the markets regulation have still to be carried out: the three analyzed markets are currently strongly non-harmonized, having different gate closure times, considering different kinds of products and implementing different dispatching models. Great efforts should be taken also in this direction. Otherwise a future coupling process could lead to market distortions.

Acknowledgements

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