IAEE Energy Forum

Second Quarter 2016
International Association for Energy Economics

IAEE
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INTERNATIONAL ASSOCIATION *for* ENERGY ECONOMICS

CONTENTS

President's Message

Having started to write my Presidential Message, I received the news of another terrorist attack in the center of Ankara with several dozen innocent people waiting for a bus being killed and several dozen injured. An attack not of a much different nature than the strikes in recent months in Paris, Istanbul, Beirut, Bamako, Baghdad and Jakarta. I would like to convey my deepest condolences to the victims of the terror tragedies worldwide, and full solidarity to the families of the victims.

I do see a potential role for IAEE as a policy-neutral organization to make this world a better place. Let me explain. We make use of economic theory and principles to enhance the understanding of all aspects of energy production, transport and use. But economic alternatives often do not get implemented because of political reasons. In other words, our expectation from energy policy to be driven by energy economics is often not realized because of political interference. I therefore see the depolitization of energy as an essential element for world peace and welfare. Hence I would like to urge you to particularly question and elaborate on energy policies that are not in line with energy economics. We need to highlight these issues, discuss the problems with experts from all related disciplines to bring the depolitization of energy ahead. Energy sources, which have often been a trigger of international conflict, can serve as a means for international peace if energy policy decisions are depoliticized and based on economic grounds.

With this motivation I have been working to make IAEE grow in countries and regions with significant energy reserves where we don't have a member base. My trips to Pakistan, Egypt and Azerbaijan last year were part of this mission. Of these, Azerbaijan has materialized as a venue for the First IAEE Eurasian Conference to be held in Baku on August 28-31 this year. I would like to assure you that Baku is one of the safest places to which you could go and invite you to attend this new regional conference on the shore of the Caspian Sea with vast oil & gas reserves.

Before the Baku conference, we have Bergen expecting you for the 39th IAEE International Conference on June 19-22. I have the pleasure to announce that 723 abstracts were received for our Bergen conference, of which 65% have been accepted. Right before the Bergen conference, on 16-18 June, there will be an IAEE Summer School in Bergen on the topic of Financial Management of Energy Price Risk.

Before the Bergen summer school, we have a summer school on Electricity Markets and Regulation taking place on 25-28 May in Istanbul.

Our first conference this year was the 5th IAEE Asian Conference held on 14-17 February in Perth. With over 182 registered delegates Asia's energy challenges have been addressed. I would like to thank IAEE Past President and Conference Chair Peter Hartley for a very successful conference organization.

(continued on page 2)

Editor: David L. Williams

Presidennt's Message (continued from page 1)

Finally, I would like to congratulate Christian von Hirschhausen on his appointment as the new Editor-in-Chief of our journal, *Economics of Energy & Environmental Policy*. He will move into this position later this year.

Gurkan Kumbaroğlu

NEWSLETTER DISCLAIMER

IAEE is a 501(c)(6) corporation and neither takes any position on any political issue nor endorses any candidates, parties, or public policy proposals. IAEE officers, staff, and members may not represent that any policy position is supported by the IAEE nor claim to represent the IAEE in advocating any political objective. However, issues involving energy policy inherently involve questions of energy economics. Economic analysis of energy topics provides critical input to energy policy decisions. IAEE encourages its members to consider and explore the policy implications of their work as a means of maximizing the value of their work. IAEE is therefore pleased to offer its members a neutral and wholly non-partisan forum in its conferences and web-sites for its members to analyze such policy implications and to engage in dialogue about them, including advocacy by members of certain policies or positions, provided that such members do so with full respect of IAEE's need to maintain its own strict political neutrality. Any policy endorsed or advocated in any IAEE conference, document, publication, or web-site posting should therefore be understood to be the position of its individual author or authors, and not that of the IAEE nor its members as a group. Authors are requested to include in an speech or writing advocating a policy position a statement that it represents the author's own views and not necessarily those of the IAEE or any other members. Any member who willfully violates IAEE's political neutrality may be censured or removed from membership.

IAEE Mission Statement

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

We facilitate:

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

We accomplish this through:

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

Editor's Notes

As we noted last quarter the response to our call for articles on the electricity market was very gratifying. We conclude our coverage of that subject in this issue and hope you will enjoy reading it as much as we have putting it together.

Wilko Rohlfs and Reinhard Madlener discuss decision-making when irreversible investments under uncertainty in long-lived assets such as large-scale power generation units are in the focus. Multi-dimensional price uncertainty complicates modeling significantly, e.g., regarding state-dependent (endogenous) discounting and the consideration of technological progress. We show how real options modeling and portfolio optimization can guide decision-makers much better than standard discounted cash flow calculations.

Stanton W. Hadley and Shutang You study the generation and transmission expansion with a high wind power penetration rate in the U.S. Eastern Interconnection system. Results show that modeling more detailed information of wind variation among regions can improve the expansion result significantly.

Frédéric Babonneau, Michael Caramanis and Alain Haurie provide an introduction to ETEM-SG, a robust linear programming approach specifically designed for regional energy systems analysis. This model can be used to provide prospective analyses of the long-term (30 years and more) evolution of multi-energy regional energy systems in their transition to sustainability. The model assumes that this transition will occur in a smart city environment. It takes into consideration the constraints associated with intermittent and volatile renewable energy sources connected at the transmission and distribution networks.

Michael Toman and Govinda Timilsina posit that improved cross-border electricity cooperation and trade among South Asian countries could contribute to reducing many challenges the sector faces. Experience elsewhere indicates that cooperation can start with limited bilateral arrangements and then expand. Larger gains come from markets for cross-border power trade and effective regional institutions for managing transmission.

Silvia Pariente-David notes that the rapid penetration of renewable energy, driven by cost declines and climate policy, is creating stress on power systems, inducing costs not captured in the LCOE concept. The article reviews the different metrics to compare intermittent and dispatchable power generation technologies, and concludes that only a holistic approach can account for all effects of renewable penetration on the power system, therefore appropriately measuring renewable cost and value.

Nadejda Victor and Christopher Nichols discuss the dependence of the U.S. power sector on water makes electricity generation exposed to weather variability in some regions. Changes in the future electricity generation mix will have important implications for water use. We analyze how shale gas availability affects water usage in the U.S. power sector, investigate whether CO2 mitigation policies would improve or magnify electric sector water reliance and what generation technologies will likely to be deployed under water constraints.

Raul Bajo-Buenstado and Marin Garcia study the impact of the policies that promote wind generation on the power market. In particular, they focus on the effect on both the generation capacity mix and electricity market prices and provide some policy recommendations that should be taken into account to allow a smooth transition from a fossil-fuel based grid to a sustainable and reliable one.

Kuang-Chung Hsu and Zhen Zhu look at how the M&A activities in the U.S.oil and gas E&P sector responded to the low oil price environment during the last year. Their results suggest that lower M&A activity was correlated with lower oil price and provide some conjectures regarding motivations for M&A and suggest M&A activity may pick up as the low price environment stabilizes.

Nigar Muradkhanli analyses the role of natural gas in the energy infrastructure of Germany. With the Energiewende, Germany has made a substantial decision to move towards a sustainable energy supply over the long term, determining renewable energy as the main source of the future energy supply. He proposes an answer to the question – how the role of natural gas would be changed in the energy mix of Germany following Energiewende?

DLW

CONFERENCE OVERVIEW

Energy: Expectations and uncertainty
- Challenges for analysis, decisions and policy

Energy systems are becoming increasingly interdependent and integrated, raising the importance of changes in resources, markets, technology, policy, environment and climate. Methods, analyses and results that take explicit account of uncertainty and expectations from an economic and decision-making perspective will be highlighted.

The objectives of the Conference are to contribute to a better understanding of the role of expectations and uncertainty in energy, economic and environmental systems along these dimensions, and to place these topics within the broader themes of energy economics generally addressed by the Association.

PRESENTER ATTENDANCE AT THE CONFERENCE

At least one author of an accepted paper or poster must pay the registration fees and attend the conference to present the paper or poster. Authors will be notified by 2 March 2016 of the status of their presentation or poster. Final date for speaker registration fee, extended abstracts and full paper submission: 15 April 2016.

Multiple submissions by individuals or groups of authors are welcome, but the abstract selection process will seek to ensure as broad participation as possible. Each author may therefore present only one paper or one poster.

CONFERENCE VENUE

The conference is held at the Norwegian School of Economics (NHH), the leading national centre for research and education in economics and business administration.

NHH offers a two year MSc in Energy, Natural Resources and the Environment - an example of NHH's focus on energy economics.

NHH and Norway provide a perfect environment for the conference. As a country endowed with great natural assets, Norway has achieved a good track record of developing these for economic gain, whilst preserving its environmental capital.

For further information about the venue please see www.nhh.no.

Bergen is an international city packed with history and tradition, a small-town with charm and atmosphere. Bergen is an excellent starting point for exploring the Norwegian fjords, voted the world's most unspoiled tourist destination by the National Geographic.

www.VisitBergen.com

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NHH

SNF

PRELIMINARY PROGRAM

MONDAY 20 JUNE

9.00 am - 10.30 am: Opening Plenary Session

Energy and environmental policy formation in an uncertain world
Einar Hope, Professor, NHH (Presiding)
Confirmed speakers:
Dominique Ristori, Director General for Energy, EU Commission
Yi Wang, Professor, Chinese Academy of Sciences, People`s Congress of China
Eldar Sætre, CEO, Statoil

11.00 am - 12.30 pm: Dual Plenary Session

1. Energy and the economy: Sensitivity and expectations
Thomas Sterner, Professor, University of Gothenburg (Presiding)
Confirmed speakers:
James L. Sweeney, Director of the Precourt Energy Efficiency Center, Professor, Stanford University
Rick van der Ploeg, Professor, Research Director of the OxCarre, University of Oxford
Christoph Böhringer, Professor, University of Oldenburg and Centre for European Economic Research(ZEW)

2. Petroleum market fundamentals and risks
Klaus Mohn, Professor, University of Stavanger (Presiding)
Confirmed speakers:
Amrita Sen, Chief Oil Analyst, Energy Aspects
James L. Smith, Professor, Southern Methodist University
Paul Stevens, Professor, University of Dundee, Chatham House, the Royal Institute of International Affairs

TUESDAY 21 JUNE

9.00 am - 10.30 am: Plenary Session

Technological change and energy in transport
Gunnar S. Eskeland, Professor, NHH (Presiding)
Confirmed speakers:
Michel Derdevet, Member of the Executive Board, ERDF
Benjamin Schlesinger, President, BSA Energy

1.30 pm - 3.00 pm: Dual Plenary Session

1. Institutional investors and the energy sector
Espen Henriksen, Professor, UCLA Davis (Presiding)

2. Gas, Russia, and European markets
Arild Moe, SRF, Fridtjof Nansen Institute (Presiding)
Confirmed speakers:
Tatiana Mitrova, Head of Department, Russian Academy of Sciences
James Henderson, SRF, Oxford University
Klaus-Dieter Borchardt, Director, EU-Internal Energy Market

WEDNESDAY 22 JUNE

1.00 pm - 3.00 pm: Dual Plenary Session

1. Financial aspects of power markets
John Parsons, Professor, MIT (Presiding)
Confirmed speaker:
Norman C. Bay, Chairman of FERC
Mar Reguant, Assistant Professor, Northwestern University

2. In the aftermath of Paris: What has happened, and what to expect
Gunnar S. Eskeland, Professor, NHH (Presiding)
Confirmed speakers:
Scott Barrett, Professor, Columbia University
Bård Harstad, Professor, University of Oslo
Ottmar Edenhofer, Professor, Potsdam University

3.30 pm - 5.00 pm: Closing Plenary Session

Strategies for the Energy Sector under Uncertainty: Round table discussion among business leaders
Karel Beckmann, Editor-in-Chief, Energy Post (Presiding)
Confirmed speakers:
Christian Rynning-Tønnesen, President and CEO, Statkraft

PRE-CONFERENCE WORKSHOPS

- *Capacity markets and security of energy supply*
- *Future of utilities – utilities of the future*

Sunday 19 June

IAEE SUMMER SCHOOL

Financial Management of Energy Price Risk

Thursday 16 June - Saturday 18 June

PHD DAY

- *Special PhD session*
- *Enhancing academic presentation skills workshop*

Sunday 19 June

For more information, please visit
www.iaee2016nhh.no

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Economics of Energy & Environmental Policy

Dear IAEE Member,

I am very pleased to announce that the IAEE has, at the end of an extensive search and review process, selected a new Editor in Chief for our journal, Economics of Energy and Environmental Policy (EEEP). A committee of senior IAEE members under the leadership of Vice President for Publications Anne Neumann was established pursuant to the selection process approved by IAEE Council during the Antalya Conference. The other members were Ricardo Raineri, Olvar Bergland, Christophe Bonnery, and Lori Shell.

IAEE Members will have seen the widely placed notices that the position was going to be vacant later this year when current Editor-in-Chief Jean-Michel Glachant completes his term. The notice attracted complete applications from thirteen highly-qualified individuals, including a cover letter, CV, recently published peer-reviewed work of their own, and statements on their vision for leadership of EEEP and management philosophy. All the members of the Search Committee reviewed all thirteen applicants' materials and scored them in accordance with four agreed criteria: (1) research in energy and environmental economics, (2) experience in peer-reviewing and their own publication record, (3) leadership and management experience, and (4) networking skills and outreach. The scores were compiled, and the entire committee, in view of the scores, agreed to conduct structured 45-minute interviews with the three top-scoring candidates, who were provided questions in advance to answer and focus the discussion. One of the five Committee members opted out of the interview process for valid reasons, and the remaining four Committee members held calls with the three leading candidates.

The Members of the Committee have indicated that the choice among the three finalists was very difficult in light of their superb credentials and articulate presentation of their vision for EEEP. In the end, the Committee was unanimous in their judgment that the next Editor in Chief for EEEP should be Christian von Hirschhausen, an IAEE Member from Germany, effective in September.

This result was provided to the IAEE President by the Search Committee in December, 2015, who promptly asked Council to approve or reject the resulting nomination by an email vote. All the votes cast were in favor of the Committee's recommendation.

As President for 2016, I join the other officers and council members in thanking the Search Committee for their dedicated work in making this difficult selection, and share their confidence that Christian von Hirschhausen will advance EEEP's status among professional journals focusing on the energy and environmental economics. We owe a great debt of gratitude to Jean-Michel Glachant for his work in launching the journal and guiding it through its sometimes difficult early years.

EEEP is, by its nature, a journal that focuses on policy issues that link two controversial areas of public policy -- energy and environment -- and applies the tools of economic analysis to yield new judgments and recommendations. It is therefore natural that the articles published may themselves be interpreted as taking controversial positions or favoring controversial outcomes. This should never be interpreted as a bias or a policy position of IAEE, EEEP, or its Editors, who are committed to striking a healthy balance among the topics addressed, methods of analysis employed, and perspectives espoused by the authors, and to judging submissions first and foremost for their quality of writing and analysis. I join the Search Committee, the Members of the Council, and you, the loyal members of IAEE, in congratulating Christian von Hirschhausen in being selected to lead EEEP in maintaining such standards in service to the entire association and, indeed, to the broader public interest in good energy and environmental policy as seen from an economic perspective.

With all best wishes,

Gurkan Kumbaroglu
IAEE President

How Technological Choices, Existing Portfolios, and Multi-Dimensional Price Risk Affect Power Generation Investments

By Wilko Rohlfs and Reinhard Madlener

Fossil-fueled power plants with high efficiencies are typically large-scale and long-lived projects (40-60 years of lifetime plus substantial construction/lead times). These attributes incur high upfront - and more or less irreversible - investments, which result in risky and long-term business undertakings. Price projections and estimates of the progress of new and existing technologies need to be considered in the decision-making process. And although continuous plant maintenance and retrofitting enables the preservation (or, due to technical innovation, even a slight increase) of the conversion efficiency over a plant's lifetime, the main process remains unaltered. Hence, the pre-investment decision with regard to the input fuel to be used for conversion into electricity is crucial for the entire lifetime of such a power plant.

Wilko Rohlfs is a Research Associate at the Institute of Heat and Mass Transfer, RWTH Aachen University, Germany (currently on leave at MIT, USA). Reinhard Madlener is a Full Professor of Energy Economics and Head of the Institute for Future Energy Consumer Needs and Behavior (FCN), School of Business and Economics / E.ON Energy Research Center, RWTH Aachen University, Germany.Madlener may be reached at rmadlener@eonerc.rwth-aachen.de

Power generation units vary in their technical, economic, and environmental characteristics. Cash flows generated from the operating of a power plant are a result of a technology-specific mix of inputs and outputs, and they are dependent on expenditures for fuel, carbon emission permits, and revenues from electricity sales, all of which are themselves dependent on their respective price. As a consequence, different types of power plants (in our research, gas- or coal-fired, with or without carbon dioxide sequestration, as well as onshore and offshore wind) exhibit different capital expenditures and differ with regard to the specific combination of the underlying commodities. This combination can be viewed as a portfolio of real assets. Importantly, the prices of the underlying commodities are correlated with each other, and the price development in deregulated markets is usually highly uncertain.

DECISION-MAKING UNDER MULTI-DIMENSIONAL PRICE UNCERTAINTY

Decision-making with respect to long-lived irreversible energy investments under uncertainty calls for multi-dimensional models that are able to account for the unknown price trajectories of all the different prices of the underlying commodities (fuel input, CO_2 permits, and electricity output). Figure 1 depicts some possible future development paths of the electricity price and the correlation between the coal and electricity prices for possible future states. In the analysis, trend and volatility values for the commodity prices are derived from the price trajectories for Germany reported in Nitsch et al. (2010).

For such scenario analysis, deterministic approaches are commonly used that assume a constant rate of change for each price; these price trends are then varied within a realistic range to check for the robustness of the model outcomes (Ventosa et al., 2005). More sophisticated approaches for dealing with price uncertainty make use of stochastic models, which can be classified according to Möst & Keles (2009) into those that

- use stochastic processes for electricity prices, commodity prices, and other uncertain parameters (such as hydro inflows, solar irradiation, or wind distributions);
- enable scenario generation and reduction;
- allow the stochastic optimization of investment decisions, including short- and mid-term electricity generation planning and long-term system optimization.

Commonly employed stochastic net present value (NPV) approaches enable a comparison of the expected value of the different technologies in each state, from which the technology with the highest expected rate of return can subsequently be chosen. Although this decision process can be seen as a kind of optimization, it is nevertheless a static approach that does not account for

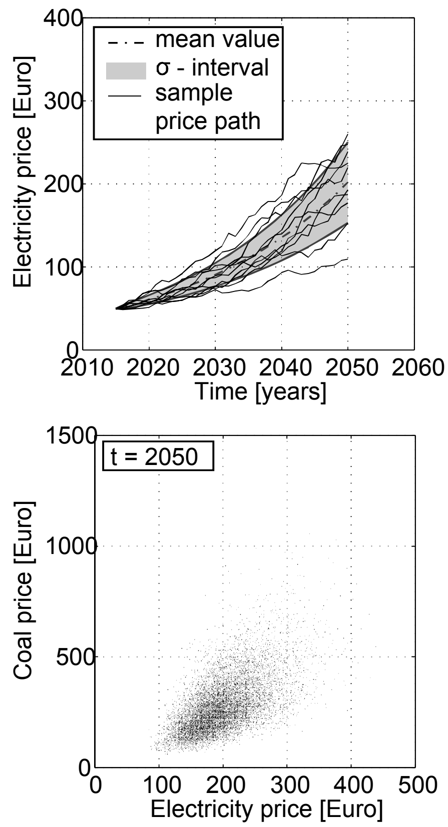


Figure 1. Sample paths of the price development (upper plot) and correlation between two assets (coal and gas) in t = 2050 (lower plot), both calculated by Monte Carlo simulation (Source: Rohlfs & Madlener, 2014a).

(net) economic gains accruing from a delaying of the investment decision (and investing only if prices are developing in a favorable direction). In contrast, real options-based (RO) models (originally developed by Black and Scholes (1973) and Merton (1977) for financial options) can include this value of waiting (McDonald and Siegel, 1986), thus optimizing the decision process also over time (Dixit & Pindyck, 1994). In recent years, the application of RO models to decision-making processes in the energy sector, especially for investments in new power generation infrastructures, has increased considerably (for a literature review, see, e.g., Martínez Ceseña et al., 2013).

In a recent study by the authors, a generalized RO model has been developed that, in contrast to more conventional RO models used, accounts for multiple commodities by correlated stochastic price paths with a combined evaluation of an arbitrary number of available technologies.

HOW TO DISCOUNT FUTURE CASH FLOWS OF MULTI-DIMENSIONAL INVESTMENT OPTIONS

The discount rate is one of the most important parameters in economic analysis of investments with a very long lifetime, and one that can drastically affect the expected value of an investment. A more sophisticated choice of the discount rate than a practitioner's rule of thumb accounts for the technology-specific project risk profile (that itself results from the technology-specific combination of the underlying commodities), provided that these show different but correlated price uncertainties. Thus, a combination of commodities (i.e., cash flows generated from expenditures and returns) leads to a portfolio of commodities, or assets, in which the uncertainty can vanish if the commodity price risks are uncorrelated, similarly to the standard mean-variance portfolio theory of Markowitz (1952, 1991). Consequently, risk becomes endogenous, as a technology-dependent measure used for risk-adequate discounting – in the sense of the classical capital asset pricing (CAPM) model of Sharpe (1964) and Lintner (1965) – and requires a technology-dependent discount rate. However, this endogenous discounting faces two main complications, namely, time-dependent risk structures and inter-temporal correlations of asset prices. Both aspects will be outlined in the next two paragraphs.

First, assuming constant values of key parameters (e.g., growth rate and volatility) for the stochastic processes of the underlyings (i.e., asset prices), the risk of the prospective returns becomes time-dependent if the ratios between input and output quantities are fixed. For the desired dynamic optimization of the investment strategy, the RO approach is well suited, as it incorporates the value of waiting. Nevertheless, multi-asset option models typically assume that, once the investment has been made, the share of the different underlyings will remain constant over time, which leads to a time-invariant solution. However, in the case of power plants, the technology chosen defines the input and output quantities as well as the ratio between them for the entire lifetime of a plant. Such a constant ratio between the input and output quantities couples the prospective returns directly to the ratio between the asset prices. This, however, clashes with the unequal growth rates predicted for the prospective prices, which cause a strong time-dependency in the ratio between the various input and output cash flows, and thus also cause time-varying levels of uncertainty.

Second, the evaluation of uncertain cash flows gained at different times is more complex in comparison to the evaluation of stocks in a financial portfolio. Due to strong correlations of subsequent returns, a separate valuation of the resulting cash flows remains inaccurate. The following example illustrates the problem. Let us suppose that an uncertain cash flow in period 1 takes the value of either 100 or 200 (for simplicity, with the same probability). Due to uncertainty, a risk premium would be required, reducing the expected utility to below the utility of the average cash flow of 150. In period 2, the same cash flow might be gained, but due to a temporal correlation, the cash flow is 100 if the cash flow of the previous period was 200, and vice versa. A segregated treatment of the two periods would again require a risk premium. However, by evaluating the cash flows jointly, the associated risk vanishes if the time between the two cash flows is sufficiently short. This simple exercise illustrates how intertemporal correlations between different cash flows preclude the use of simplistic discounting methods when combining risk-discounting with time-discounting.

HOW EXISTING POWER PLANT PORTFOLIOS INFLUENCE THE OPTIMAL INVESTMENT DECISION

In a recent study, we have developed and applied a multi-dimensional model with time-, technology- and state-dependent discount methodology (Rohlfs and Madlener, 2014a, 2014b). The generalized model proposed also enables, for example, an examination of the influence of new investments on existing power plant portfolios, as is shown by Rohlfs and Madlener (2014a) and illustrated in Figure 2. The figure depicts an estimated probability for the deployment of different generation technologies. The probability is based on technological specifications and price projections up to 2070. Price projections for electricity, coal, natural gas, and carbon permits were calculated based on the predictions of the so-called German Pilot Study 2010 (Nitsch et al., 2010). The technologies considered comprise hard coal (HC), hard coal integrated gasification combined cycle without (HC-IGCC) and with carbon capture and storage (HC-IGCC-CCS), combined gas and steam power plant without (COGAS) and with CCS (COGAS-CCS) as well as onshore wind (OW). In the remainder of this article, we summarize the findings of the above mentioned study (Rohlfs and Madlener, 2014a, p.125).

In a first step, we have employed the classical NPV model as well as the RO approach to identify the influence of the different aspects of the RO model (e.g., value of waiting, multiple available technologies, and existing power plant portfolios). For an investment in a new power plant today, the NPV is highly negative, rendering an investment economically very unattractive. When tracking the decision into the future, a significant increase in the probability of investing in coal-fired power plants was found (beyond 2020), and for later time periods also the probability of coal-fired power plants equipped with CCS increases. However, if an investor has the choice of building one of the power plant technologies available right away, then the dominance of one technology strongly reduces the probability of investments in other technologies.

With the value of waiting in the decision process, the expected value (RO value) increases above the expected NPV, although the investment decision is delayed. It is interesting to note that the value of waiting also reshapes the probability distribution of the expected values and, consequently, the associated risk. While for the classical NPV decision rule, the probability distribution of future NPVs is more or less Gaussian-shaped, the probability of the value of waiting is strongly asymmetric. The asymmetric shape reveals a steep gradient (decreasing probability) for expected values below zero and a long tail for positive expected values. Consequently, the probability of falling below the desired rate of return, i.e., a negative expected value, yields a strong reduction if the value of waiting is considered as well.

Accounting for the value of waiting also impacts the choice of an investor when the new investment is viewed against an existing power plant portfolio. Because systematic risk between new and existing projects can be mitigated, the resulting volatility diminishes, leading to a reduced value of waiting and thus to an earlier investment. Owing to the hard coal power plant's dominance, this effect has the most significant impact on investors who already have gas-fired power plants in their fleet of generation units.

A further advantage of using the proposed RO model was revealed in a sensitivity analysis, which showed that the decision process is less influenced by the choice of the discount rate if the value of waiting is considered, compared to the classical NPV decision rule. Thus, the value of waiting enables a more robust estimation of the probability of future investments.

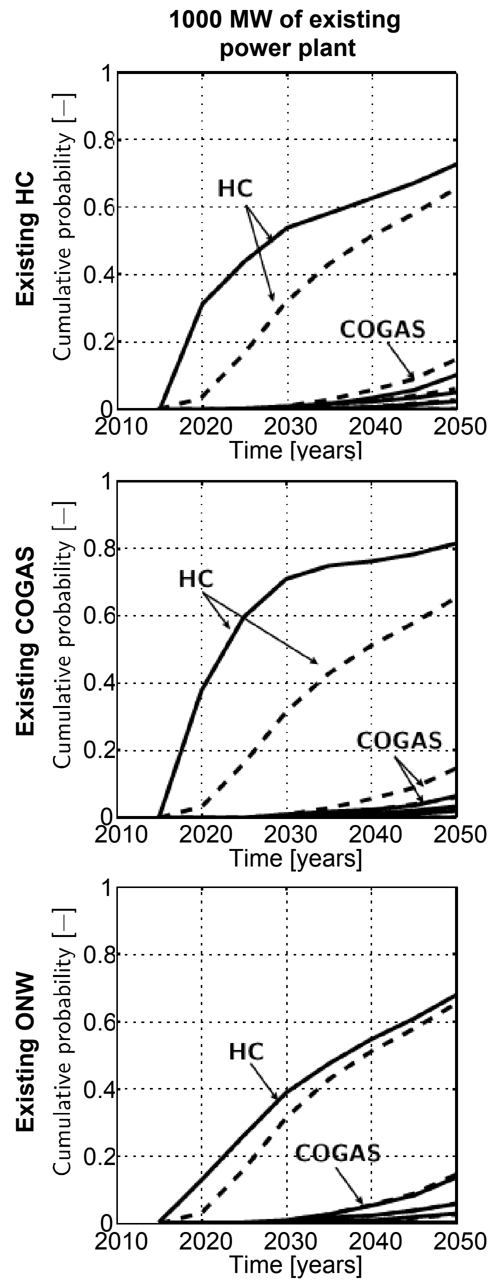


Figure 2. Influence of existing power plants on the investment decision when taking the value of waiting into account. The dashed lines indicate the investment decision for the case of no pre-existing portfolio. (Source: Rohlfs & Madlener, 2014a).

Economic decision-making models for long-lived investments are very sensitive to the assumptions made with regard to the prospective price developments and, as such, can never accurately predict the future. Evidence is provided by the struggling electric utility companies in Germany that are suffering from the high share of subsidized renewables with priority dispatch and the rapid nuclear phase-out. However, economic modeling itself provides useful insights, broadening a decision-maker's horizon and sharpening an investor's sensitivity to crucial parameters and effects. By tackling questions related to the "correct" way of discounting and the influence of portfolios in the decision process, the RO models developed in recent years enable such powerful and potentially useful insights.

See References on page 18

KENICHI MATSUI

Kenichi Matsui, 77, passed away in Tokyo on February 23, 2016 after a year of illness.

He was passionate about nuclear energy and he had recently undertaken to write a book on the subject. He strongly believed that nuclear was the most important energy source to reduce the CO_2 emissions and he made it his last mission to provide for a better understanding of nuclear energy and enlighten people. He was particularly aiming at non-experts in Japan. IAEE members who attended the IAEE International Conference in 2013 in Daegu, Korea may recall his witty enthusiasm and stimulus talk at the dual plenary on nuclear.

He graduated from Tokyo University, College of Arts and Science in 1963 and received his Ph.D in Political Science from the Waseda University in 2005. He Joined The Institute of Energy Economics, Japan (IEEJ) in 1966 and worked extensively in the international scene. He worked with the German Institute of Economics (1969-70), the Long Term Energy Assessment Unit at OECD (1973), the ESCAP (1978-79) and for the UN Conference on New and Renewable Sources of Energy (1981-82).

His dedication and contribution as Chair of the APEC Expert Group on Energy Data Analysis (EGEDA) for over 20 years, established a firm foundation for the APEC member economies to tackle a variety of energy related policy challenges and issues, with better energy data.

After working for the IEEJ for 28 years, he became Professor of Ryukoku University at the Faculty of Intercultural Communication in 1994. During his academic career, Professor Matsui served many public roles including being a founding member and president of The Japan Society for Intercultural Studies and president of Japan Association of Private University Libraries. He retired from the Ryukoku University in 2007 and returned to IEEJ as Councilor until full retirement in 2014.

Not only was he a very active member of the IAEE, he served as President in 1995, and received the Outstanding Contribution to the IAEE Award in 2009. He published numerous books on energy, including among other titles, “Energy Questions!” (NTT Publishing Co., 2010) and “Overcoming Fukushima Nuclear Incident” (Energy Forum, 2011).

Matsui-san has been my mentor ever since I joined the IEEJ. He used to tell me wittily that forecasting can be done using a French curve and that the ability of running models and getting plausible results does not define us as experts. He strongly believed that it was far more important to understand the surrounding situations or causal relations and to be able to use the analyses to induce intriguing and intellectual debates.

While working with him at the IEEJ, one of my first tasks was to organize the IAEE International Conference in Tokyo, Japan in 1986. At that time it was to coincide with IEEJ’s 20th Anniversary. This year, IEEJ is celebrating its 50th Anniversary and Matsui-san had been invited to provide a special lecture as a part of the event.

The void is big and we all miss his guidance.

Condolences may be sent to the family at iaee@edmc.ieej.or.jp

Yukari Niwa Yamashita
Board Member, Director
The Institute of Energy Economics, Japan (IEEJ)

Influence Analysis of Wind Power Variation on Generation and Transmission Expansion in U.S. Eastern Interconnection

By Stanton W. Hadley and Shutang You

Stanton W. Hadley and Shutang You are with the Oakridge National Laboratory. Hadley may be reached at hadleysw@ornl.gov **This work was supported primarily by the U.S. Department of Energy. This work was also supported by the Engineering Research Center Program of the U.S. National Science Foundation under NSF Award Number EEC-1041877 and the CURENT Industry Partnership Program.**

INTRODUCTION

Bulk power system expansion problems can be divided into three categories: generation expansion [1, 2], transmission expansion [2-4], and generation-transmission co-expansion [5]. Power system operation is subjected to influences from stochastic factors, such as forced outages, load, renewables and fuel cost variations. With the increase of renewable penetration rates, the stochastic features of wind and solar are becoming major uncertain factors of power systems. As studies predict that U.S. could have around 27% of its electricity coming from renewables by 2030 [6], their fluctuations need to be considered in not only the operations stage, but also the planning stage.

It has been widely accepted that co-optimization generation and transmission expansion can obtain better expansion results and more investment savings [7]. This co-optimization process involves multiple years of detailed market simulation for an accurate assessment of expansion plan candidates. Since renewable variation in different regions has significantly increased interface flow and energy exchange between regions, the expansion co-optimization should consider renewables output variations in the temporal and spatial dimension. This article investigates how wind power variation will influence generation and transmission expansion in the U.S. Eastern Interconnection (EI) system.

METHODOLOGIES

Generation and transmission expansion aims to maximize the social welfare or minimize the total cost, which is comprised of the expansion cost, the operation cost, and the emission cost over the planning horizon. The breakdown of the objective function is shown in Table I.

Cost category	Cost items in the objective function
Expansion costs	Generation built cost
	The transmission expansion cost of all interfaces
Operation costs	The fuel cost
	The varying operation and maintenance cost
	The value of lost load
	Fixed operation and maintenance cost
	The wheeling cost of transmission lines
Emission cost	The emission cost

Table I. Constitution of the objective function in expansion planning

The objective function is the net present value of the sum of all of the system's cost items over the planning horizon. In addition, it is important that the expansion planning formulation does not inappropriately consider the end of the planning horizon to be the 'end of time'. Without considering the 'end-year effects', the expansion plan would select to build generators with low build costs in the last several years, even if their marginal generation costs are high, so that the average cost in the horizon would be low. To reflect the 'end-year effects', the last year of the horizon is repeated an infinite number of times [8] and it is reflected in the modified discount factor of the end year.

A practical expansion plan should also satisfy various planning and operation constraints. Constraints considered in this expansion planning problem are described in Table II.

Constraint category	Constraint items	Constraint descriptions
Expansion constraints	Maximum expansion constraint for generation	Due to resource limitation, the number of generator expansion in each region should be within its upper limit.
	Maximum expansion constraint for transmission	Due to the right-of-way limitation, the number of expanded interfaces should be within its upper limit.
	Integer constraint	The number of built generators and interfaces should be integers.
	Expansion speed constraint	Due to the construction resource limitation, the annual expansion speed of generators and transmission lines should be within their upper limits.
Operation constraints	Power balance constraint	In each region, the sum of generation output, unserved demand, and interface interchange should equal to the demand for all regions within the planning horizon.
	Capacity discount	Capacity discount considering the forced and maintenance outages
	Regional reserve capacity constraint	The reserve capacity of each region should be larger than a pre-determined level for regulation and contingencies.
	Interface capacity constraint	The power flow of each interface should be within the maximum transmission capacity.
	Wind resource constraint	The output of wind turbine generators is restricted by the available wind resource.
Other constraints	Regional renewable portfolio constraint	In those regions with renewable portfolio constraints, the percentage of renewables in the total installed generation capacity should be higher than a pre-determined value.

Table II. Constraints in expansion planning

The U.S. EI multi-regional dataset comes from Charles River Associates [9]. This dataset partitions the EI system into 25 regions and the interfaces between adjacent regions as shown in Figure 1 [10]. The load profile is represented by 20 load blocks per year. The EI multi-regional dataset and

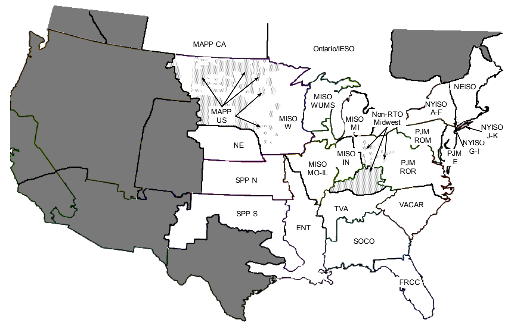


Figure 1. Regions of the U.S. EI system (EI includes all regions in the east) [11]

the generation and transmission expansion problem are modelled in PLEXOS [8]. The planning horizon is from 2015 to 2030. Five developed cases with different number of wind blocks (representing different detail levels of wind modelling) are developed as shown in Table III, which is followed by further graphical descriptions.

Figure 2 shows the wind capacity factor of the SPP_N region in three datasets: 1) hourly; 2) 20 Block; 3) 40 Blocks Non-Synchronized. It shows that the output profile of the 20-Blk Case is very smooth compared to the raw hourly data. The 40 Blocks Non-Synchronized Case preserves some wind power variation information since it splits each original block into two blocks with equal number of hours that represent high and low wind in half. The total amount of wind power available in each combined high and low wind scenario block remains the same under all three cases.

In the 40-Blk-NonSync Case, it is assumed that the wind in all regions is highly correlated. In other words, high wind is supposed to happen simultaneously in all regions, as does low wind. This phenomenon can be seen from the wind blocks of three regions in the 40-Blk-NonSync Case shown in Figure 3.

Case Name	Number of wind blocks (modelling detail levels)	Case Description
20 Blocks (20-Blk)	$N_{S_W} = 1$	• The base case has 20 load blocks in each year • Wind is the average value in each load scenario
40 Blocks Non-Synchronized (40-Blk-NonSync)	$N_{S_W} = 2$	• Splitting each load block in two equal number of hours • Average of high wind in a half and average of low wind in the other half (*wind data are not synchronized across regions*).
40 Blocks Synchronized (40-Blk-Sync)	$N_{S_W} = 2$	• Determining hours of high and low wind capacity factors based on the weighted average system-scale data in each of the 20 load blocks • Synchronizing wind, solar, and load to the average of the region's values in those hours
80 Blocks Synchronized (80-Blk-Sync)	$N_{S_W} = 4$	• Breaking each load block into four quartiles based on the weighted average system-scale data in each of the 20 load blocks • Synchronizing all regions' wind, solar, load, and fuel prices to those hours
160 Blocks Synchronized (160-Blk-Sync)	$N_{S_W} = 8$	• Breaking each load block into eight sub-blocks based on the weighted average system-scale data in each of the 20 load blocks • Synchronizing all regions' wind, solar, load, and fuel prices to those hours

Table III. Description on the developed cases

However, in reality the half periods with high wind output in one region do not totally overlap with those in another region due to weather and geographic factors. Typically, nearby wind regions have more synchronicity on wind output levels, while further ones have less. Using the time series generation method in Section 3, the 40-Blk-Sync Case is able to capture the correlation degree of wind output between regions. The wind variation in three regions represented by data in the 40-Blk-Sync Case is shown in Figure 4. In the 40-Blk-Sync Case, the hourly solar, load, and fuel price data are also synchronized with the wind data to form their 40 synchronized blocks for LT expansion planning. In this way, the wind, solar, load, and fuel prices keep their synchronization in the 40-Blk-Sync Case.

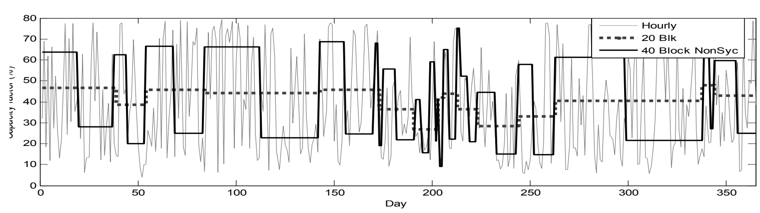


Figure 2. Wind variation representation of SPP_N in the 20-Blk Case and the 40-Blk-NonSync Case

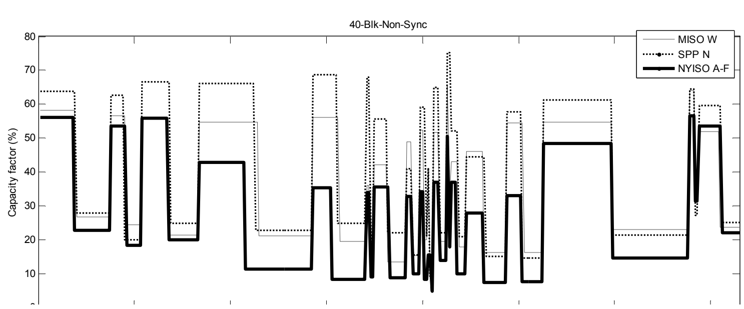


Figure 3. Wind blocks of four regions in the 40-Blk-NonSync Case

Similarly, wind blocks in the 80-Blk-Sync Case and the 160-Blk-Sync Case are developed. The wind variation in three regions represented by data in the 160-Blk-Sync Case is shown in Figure 5. It can be seen that more blocks will capture more information on regional wind resources, especially in peak load periods during summer.

RESULTS AND ANALYSIS

The expansion results of the five cases are summarized in Table IV. It can be noted that the planning results of Case 40-Blk-Sync is between that of Case 20-Blk and Case 40-Blk-NonSync. Since Case 20-Blk only includes one wind output block (i.e., the average wind output) in each load block, it overestimates the capacity of wind power and underbuilds transmission capacity. Compared with 40-Blk-Sync, the 40-Blk-NonSync Case underestimates the capacity value of wind power since it assumes all regions' wind power is at the high or low half simultaneously, which also leads to more transmission expansion. The 80-Blk-Sync and 160-Blk-Sync Cases add less wind than 40-Blk-Sync but more transmission. This is because the two cases modelled higher wind peak generation blocks, which need more transmission capacity to export. In the meantime, modelling lower wind blocks reduces wind power's capacity value, thereby reducing wind power expansion in the planning result.

Figure 6 shows the transmission expansion over the planning horizon of the five cases. It can be seen that using more detailed wind blocks will make the transmission expansion more dispersed in space. Particularly, compared with 20-Blk, both 40-Blk-Sync, 80-Blk-Sync, and 160-Blk-Sync have smaller transmission expansion on the interface MISO_IN to PJM_ROR.

Table V shows the expansion of gas and wind generation capacity in PJM_ROR and SPP_N. Figure 7 shows the energy flow in 2030 for the Case 20-Blk and Case160-Blk-Sync. It can be seen that in the 20-Blk Case, a large proportion of import energy to PJM_ROR comes from wind in SPP_N. When detailed wind blocks are incorporated (such as in Case 160-Blk-Sync), PJM_ROR relies more on its local gas generation.

In addition, it can be noted from Figure 7 that the annual energy flow of almost all interfaces in 160-Blk-Sync increase except for those on the major wind power delivery corridor: SPP_N – MISO_MO_IL – MISO_IN – PJM_ROR. This indicates that detailed wind blocks will increase the energy exchange frequency and amount between adjacent regions, while decreasing the economy of enforcing transmission networks to transmit a large amount of wind power through a long distance.

For comparison, Figure 8 shows the annual energy flow of the not-co-optimized case (which optimizes generation and transmission expansion separately). It can be seen that this expansion result chooses to expand the interface between MISO_W and PJM_ROR. In fact, expansion of this interface requires high investment, making the whole expansion plan uneconomic.

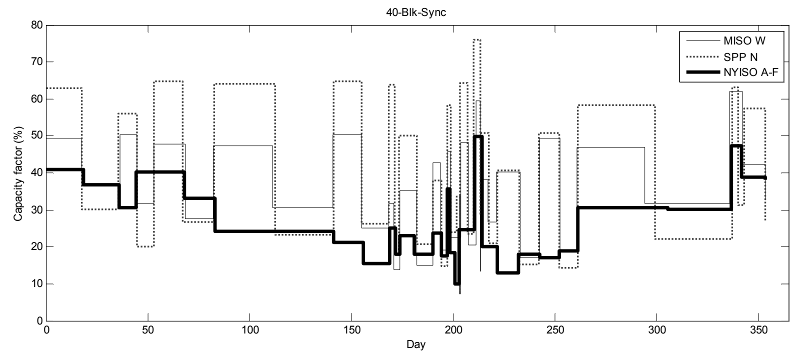


Figure 4. Wind blocks of four regions in the 40-Blk-Sync Case

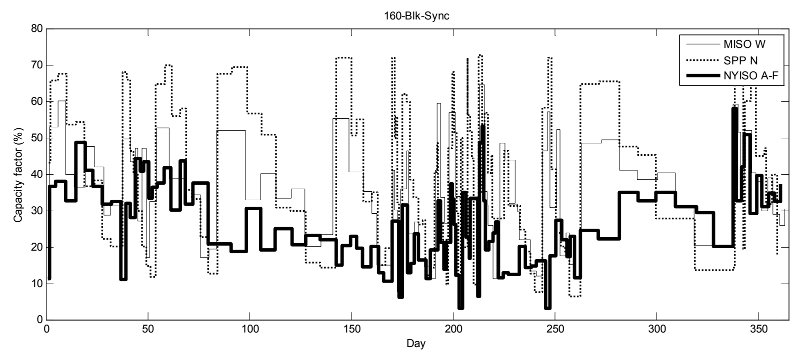


Figure 5. Wind blocks of four regions in the 160-Blk-Sync Case

Expansion results	20-Blk	40-Blk-NonSync	40-Blk-Sync	80-Blk-Sync	160-Blk-Sync
Wind Candidates Built Capacity[a] (GW)	262	218	223	221	218
All Gen Built Capacity (GW)	407	373	381	380	378
Wind Capacity in 2030 (GW)	304	260	265	263	260
Wind Generation in 2030 (TWh)	917	768	783	776	766
All Gen Build Cost (NPV) (billion $)	649	595	603	601	598
Trans Build Cost (NPV) (billion $)	20.2	26.1	22.1	22.5	25.0
Emission in 2030 (million ton)	305	365	358	362	368
Fuel Offtake 2030 (million GBTU)	17.1	18.2	18.1	18.1	18.2

Table IV. The expansion result summary of the five cases

[a] Excluding wind power that has already been decided to build.

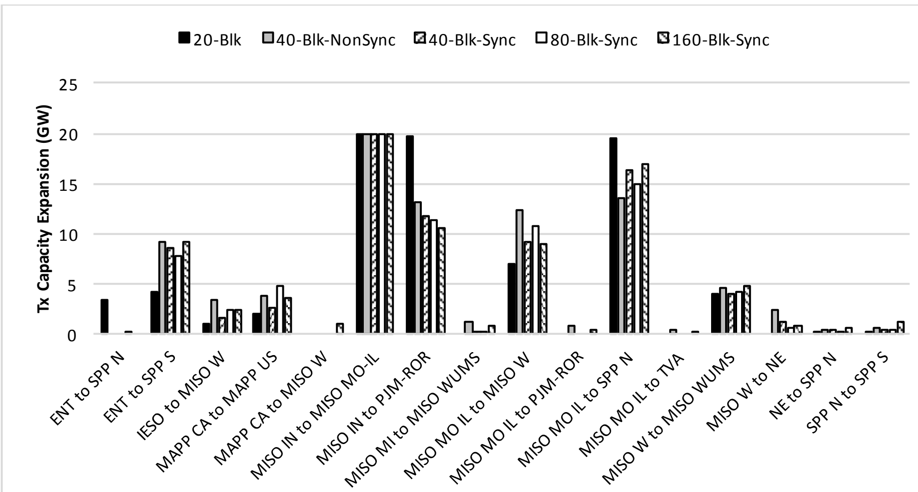
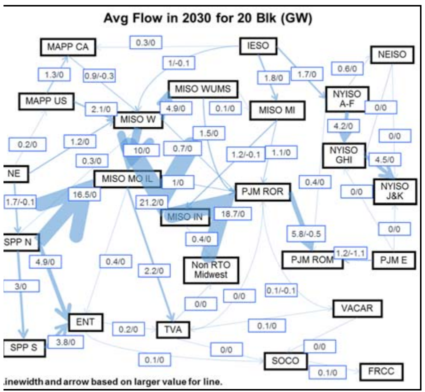


Figure 6. Transmission expansion over the planning horizon in the five cases

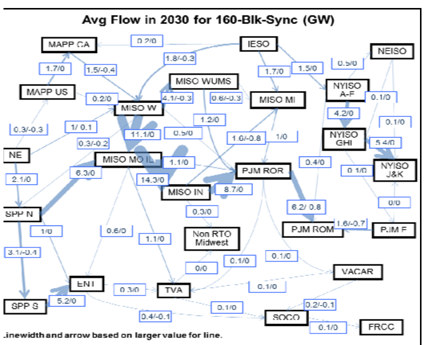
Expansion Results	20-Blk	40-Blk_NonSync	40-Blk-Sync	80-Blk-Sync	160-Blk-Sync
PJM_ROR Gas Combined Cycle Built (GW)	6	12	15.5	16	17.5
SPP_N Wind Built[a] (GW)	76.8	37.4	41.0	37.4	37.4
PJM_ROR Net Interchange	153 TWh Import	82 TWh Import	78 TWh Import	69 TWh Import	61 TWh Import

Table V. Expansion of gas and wind generation in Region PJM_ROR and SPP_N
[a]Excluding wind power that has already been decided to build.

In order to quantify the accuracy improvement through the proposed scenario generation method, the long-term expansion result is compared with the short-term simulation result for each case. The long-term simulation applies economic dispatch based on the blocks generated in the expansion planning model, while short-term simulation uses unit commitment and economic dispatch based on the chorological hourly data. The LT-and ST comparison result is shown in Table VI. It can be noted that there are always gaps between the short-term and long-term results. This is because long-term expansion uses the aggregated blocks that omit some information in the hourly data. In addition, it shows that Case 160-Blk-Sync has the smallest difference between long-term and short-term simulations, indicating that the operation simulation in Case 160-Blk-Sync is closest to short-term realistic operation. Therefore, on the basis of more accurate modelling of the system operation, the expansion co-optimization result obtained in Case 160-Blk-Sync is more reasonable.



(a) Case 20-Blk



(b) Case 160-Blk-Sync

Figure 7. Annual energy flow of Case 20-Blk and 160-Blk-Sync. Width of arrow indicates amount of flow.

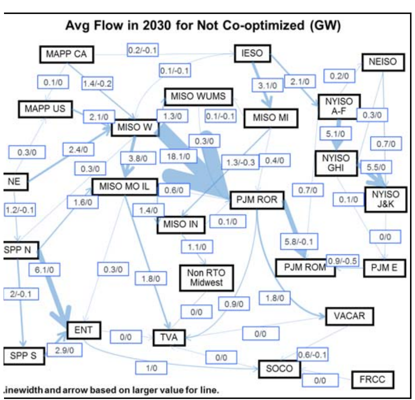


Figure 8. Annual energy flow of the not-co-optimized case

CONCLUSIONS

In this paper, U.S. EI system generation and transmission expansion is co-optimized considering wind power variation. The result shows that more detailed information of wind variation among regions significantly improved expansion results. Some additional findings in this study are:

(1) Incorporating more-variable wind (i.e., the temporal diversity) in the scenarios instead of more averaged wind in long-term planning will decrease the optimal wind expansion capacity and make transmission expansion more dispersed in space.

(2) Incorporating the spatial diversity of wind speed through synchronization will slightly increase wind generation and transmission expansion. However, this increase caused by the spatial diversity is less significant than the decrease when considering more detailed wind temporal diversity. In addition, detailed wind scenarios will reveal that it may be less economic to expand transmission networks to transmit a large amount of wind power through a long distance in the EI system.

Results	LT/ST	20-Blk	40-Blk-NonSync	40-Blk-Sync	80-Blk-Sync	160-Blk-Sync
Generation cost (NPV billion $)	LT	47.9	55.0	54.4	54.9	55.2
	ST	60.3	61.9	60.0	59.7	59.5
Emission cost (NPV billion $)	LT	42.8	51.0	50.0	50.5	51.3
	ST	50.9	52.6	52.5	53.1	53.2
LT-ST Gap		18.36%	7.48%	7.13%	6.57%	5.52%

Table VI. LT and ST simulation results in 2030

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A Systems Approach to Regional Energy Modeling with Smart Grid Integrated Distributed Energy Resources

By Frédéric Babonneau, Michael Caramanis and Alain Haurie

INTRODUCTION

It is now well recognized that the drive toward sustainable development can be facilitated by adopting smart energy systems relying on the interface and co-optimization of the cyber and physical layers modeling the Electricity Cyber Physical System (CPS). Regional energy systems will be profoundly transformed by the increasing penetration of intermittent and variable renewable energy (VRE) sources connected at transmission (e.g., wind farms) or at distribution (e.g., rooftop PV panels) networks. At the same time, the advent of grid friendly flexible loads (FLs) and distributed energy resources (DERs) including variable speed drive powered CHP micro-generators [5], heat pumps [9], and electric vehicles [6,12], will provide new options to develop demand response and provide distributed system services. VRE will impose new operational requirements, but, fortunately, FLs and DERs provide new opportunities to optimize power systems through the provision of fast reserves and dual use of accompanying volt/var control devices (PV inverters, EV chargers and the like). Under these circumstances, FLs and DERs can significantly improve operational and investment efficiencies.

Frédéric Babonneau is with Ordecsys and EPFL, Switzerland; Michael Caramanis ia with Boston University, Boston, USA. and Alain Haurie is with Ordecsys, Geneva Switzerland. Haurie may be reached at ahaurie@ordecsys.com.**This work has been supported by QRNF (National Research Fund of Qatar).**

Grid operators (GOs) and agencies entrusted with planning sustainable development at the regional level, for example those in charge of developing territorial climate energy plans in Europe (e.g., in France, Germany or Switzerland), or those promoting the development of smart cities in the Gulf region (e.g., Lusaï in Qatar or Masdar in Abu Dhabi), must cooperate to redesign the local energy system. To succeed in the transition to a non-fossil fuel based renewable energy future, new designs should embrace the generation as well as the consumption sides (see Mathiesen et al. [11]) through the adoption of Smart Energy Systems (SESs). This requires investments in a number of appropriate infrastructures including smart electricity grids, smart thermal grids (district heating and cooling), smart gas grids and other fuel infrastructures. There is, therefore, an urgent need to develop a new planning framework based on a Systems Analysis approach at the regional level capable of capturing the synergies of SESs with smart grid integrated DERs (e.g., OSeMOSys [7]).

ETEM-SG provides such a framework. It has been designed to integrate within a computationally efficient Linear Programming framework explicit constraints on reactive power compensation, secondary reserves, electric vehicle (EV) charging, and variable loss of life of network assets such as transformers. In this respect it complements the model listed above and provides a more precise assessment of the potential offered by SESs in fostering extensive penetration of VREs.

ETEM-SG: A LINEAR PROGRAMMING MODEL FOR REGIONAL ENERGY SYSTEM PLANNING

DERs can be thought of as small, albeit numerous agents acting in a distributed fashion. For example, the owners of EVs may have the option to participate in demand response programs controlling the charging of their vehicles by local computer intelligence that synthesizes EV owner preferences (e.g., desired departure time) and GO information communicated through the smart grid cyber layer. Typically, GO information will be indicative of the marginal cost of electricity at different times and grid locations. A local on-board computer will be programmed to optimize the charging of the battery in response to GO communicated dynamic prices. Load aggregators may facilitate this process. Since each EV is a very small consumer, it can be thought of as a price taker whose charging decisions have no influence on the price. In fact, it can be shown that, under reasonable conditions, the optimal decisions taken by many small optimizing agents reacting to marginal cost based dynamic prices are consistent with the decision the GO would take to minimize system cost, if it were able to directly control the charging of classes of EVs (See [1]). Indeed, the introduction of smart controllers may facilitate the implementation of socially optimal marginal cost pricing of electricity.

Linear programs have been used with success to discover marginal cost based prices of electricity that prevail at different times of the day and different seasons in the year. Linear programs have also been used with considerable success to develop a systems analysis of the long-term evolution of the whole energy sector in a country or a region (see in particular TIMES [8] [3] or OSeMOSYS [7]). ETEM-SG is a linear programming model, designed for the prospective analysis of regional energy systems (see [2]) that is very similar to TIMES. The energy system is driven by price-quantity bids for energy (or energy services) by market participants, and by the price of energy imports. The model takes into account all possible energy and technology options, at the levels of extraction, generation, transformation and usage of primary and final energy forms. Each technology is characterized by a date of availability (if it is a new technology), a life duration, an installed capacity, which can be increased through investment, and an operating strategy. Three categories of costs are considered, investment cost linked to capacity increase, maintenance cost linked to installed capacity, and operation cost linked to the operating process. These costs enter in the definition of a total discounted system cost, which is used as a performance criterion in the associated linear program. The model can account for global emissions of local pollutants (NOx, VOCs) and of GHG (CO_2, CH4). ETEM-SG is used to analyze the path of energy transition at a local/regional level. A particular feature of ETEM-SG is its ability to take into account the constraints and optional strategies and preferences of smart power systems at the distribution level.

MODELING OF SALIENT DISTRIBUTION NETWORK COSTS, BENEFITS AND DYNAMICS

In ETEM-SG the electricity production sector is modeled with special care devoted to distributed energy resources (DER) - EVs/PHEVs, heat pumps, solar panels and the like - , the management of demand response and system ancillary services, such as secondary reserves and reactive power compensation. ETEM-SG uses a simplified representation of the transmission system. Centralized conventional generators and wind farms are connected to a high capacity transmission network that is approximated by a single congestion free ”infinite” bus. The production of wind generators incurs no variable cost. The distribution network is modeled by n radial distribution feeders connected to the ”infinite” bus. Each feeder bus hosts: (i) demands corresponding to conventional inflexible loads (e.g., lighting), which consume “reactive power” depending on a constant power factor, (ii) flexible loads (typically EV battery charging, variable speed drive heat pumps for space conditioning), and (iii) PV generation. EV battery chargers and PV inverters can provide reactive power compensation, as needed, when they have excess capacity, for example when the sun does not shine enough to fully utilize the DC to AC inverter of the PV facility or when the EV battery is not charging at the charger's capacity. During a given time-slice, flexible loads create value (or utility to their owners) by providing a service such as space conditioning that maintains inside temperature within a comfort temperature zone, increasing the state of charge of the EV battery and the like. Although in principle other types of reserves can be also modeled, we focus on secondary reserves made necessary by renewable generation and uncertainty in conventional loads and generation. The reserves required by the system operator can be provided by conventional centralized generators but also by the flexible loads, in particular by the PHEV/EVs. When the apparent power flowing through a feeder's transformer rises close to or exceeds its rated capacity, the transformer's life degrades rapidly contributing to distribution network's variable costs. High apparent power flow is also associated with high distribution line losses. Reactive power compensation decreases the apparent power flow providing significant cost reduction through lower energy losses and transformer life degradation. In addition, requiring less reactive power at the infinite bus, reduces further the grid opportunity cost associated with the provision of reactive power compensation at the substation. The production of energy by conventional generators is associated with a marginal cost corresponding to the short run marginal costs of the marginal generator. The linear program determined flexible load and DER capacity allocation among real power, reactive power and reserves that minimizes grid costs and participant costs minus benefits, subject to load flow, voltage, energy balance and reserve requirements constraints.

ILLUSTRATION WITH ETEM-SG

An implementation of ETEM-SG has been realized, taking a region of Switzerland as a case study. The region, called “Arc Lémanique” regroups the cantons of Geneva and Vaud. Three aggregate feeders are modeled corresponding to the grids of the three main operators, SIG in Geneva, SIL in Lausanne and Romande-énergie in the Vaud canton. We compare two scenarios to illustrate how smart energy systems can foster penetration of VREs, by allowing FLs and DERs to provide secondary reserve, reactive power compensation and demand response at different levels. The first scenario assumes that EV batteries and heat pumps can be used to satisfy reserve requirements while in the second scenario this option is not available. Both scenarios assume the same demand for energy services, like transport and space heating, the same prices for imported energy, including electricity and the same stringent emissions reduction objective that corresponds to the official “New Energy Policy” defined by the Swiss Federal Energy Board [15]. In these simulations we assume a reserve factor of 0.5 to cover wind generation, a system reserve of 0.2 to cover load and a power factor of 0.93 associated with reactive power consumption by conventional loads of 0.35 KVar for each 0.93KW that they consume.

The results of simulations, performed for a 2025-2050 planning horizon, show that smart grid integration of FLs and DERs would facilitate VREs penetration.

Figure 1 shows higher VREs penetration in Scenario 1, i.e. 63% of total electricity generation in 2050 from wind turbines (E08) and solar panels (E07), compared to scenario 2 with only 41%. This increase is essentially due to a stronger penetration of wind units.

This is permitted by the exploitation of flexible loads, providing secondary reserve as shown in Figure 2. Note that the 41% observed when smart systems are not fully used is close to the current practice, which recommends a maximum 30-40% share for VREs.

The other production technologies are gas combined-cycle power plants (E0F), gas turbines (E0E) and hydro power plants (E01 and E02). We notice that imports, assumed to be carbon free in this exercise, are needed in scenario 2 to satisfy the emissions reduction constraint. These imports come from Europe and other regions of Switzerland as we don't distinguish them in the model.

We notice in Figure 3 that in both scenarios EVs penetration (TES) is much needed to reach the GHG emissions reduction objectives. The share is even higher in scenario 2 to compensate VREs reduction. Other cars are hybrid (THY) and diesel (TE1) vehicles. In the residential sector, the situation for heating is very similar in both scenarios with investment in heat pumps technologies (i.e., around 20% of the heating sector). Finally, we observe that when smart systems are considered (scenario 1), flexible electricity demand from heat pumps and electric vehicles reaches around 21% of total electricity consumption in 2050.

CONCLUSION

When modeling local/regional energy systems, in a smart grid or, more generally, smart city environment, it becomes very important to represent the constraints, costs and capabilities that are present in distribution networks. With ETEM-SG, local/regional energy and environment planners have the possibility to propose coherent scenarios for the massive penetration of VRE power generation accompanied by the development of smart grid operations, permitting demand-response, distributed reserves as well as distributed reactive power compensation, and the like. The model is currently being tested on case studies of the Arc Lémanique region, in Switzerland, the region of Doha in Qatar, and the non-interconnected regions of the French islands (la Réunion, Corsica, etc.). The first implementations have shown the model's ability to exploit the new potential for efficiency improvement provided by smart grid integration of distributed energy resources. In particular, the scenarios demonstrate the contribution of smart grid integrated flexible loads and distributed energy resources to the efficient adoption of solar and wind generation.

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The Benefits of Expanding Cross-Border Electricity Cooperation and Trade in South Asia

By Michael Toman and Govinda Timilsina

The South Asia region is comprised of nations with (i) rapidly growing energy demand, (ii) significant seasonal complementarities in their energy demands (see Figure 1), and (iii) large but unevenly distributed primary energy electricity generation potential across countries and seasons. The region's national electricity systems face several challenges. Electricity supplies have not kept pace with demand and are frequently interrupted. At the same time, there is underutilization of available generation capacities due to fuel supply shortages and price controls. Electricity shortages not only impose hardships on households, but also hinder business activity and new investment in the economy. Electricity generation and transmission shortages also have stimulated use of energy-inefficient, costly and pollution-intensive power sources, including both aged and highly polluting coal-fired generation plants, and diesel generators operated both on the grid and by end-users. Government bailouts of electricity suppliers in serious financial distress put a serious weight on already-stressed government budgets.

Michael Toman and Govinda Timilsina are with the Development Research Group of The World Bank. The research summarized here was the result of major analytical inputs from (in alphabetical order) Touraj Jamasb, Jorge Karacsonyi, Rabindra Nepal, Musiliu O. Oseni, Michael G. Pollitt, Anoop Singh, and Luca de Tena Diego. World Bank colleagues including M. Iqbal (Bangladesh), Rabin Shrestha and Jie Tang (Nepal), Anjum Ahmad (Pakistan), and Yannis Kessides contributed valuable advice for the implementation of the project.

See footnotes at end of text.

Effectively addressing these challenges requires accelerating national-scale efforts to improve the technical efficiency of power systems, the economic efficiency of power markets, and the financial sustainability of electricity generators and distributors. Our research shows that further steps toward greater electricity sector inter-connection and power trade among South Asian countries can make important contributions to alleviating the many challenges noted above.

Table 1 provides a summary of key quantitative findings from the research.[1] Our analysis indicates that increased regional electricity integration and trade could generate, on average, cost savings on the order of about $9 billion per year relative to the status quo, which has very limited cross-border trade and even less investment coordination. The present value of the net cost savings from expanded electricity cooperation and trade over 25 years (2015 – 2040) is almost $100 billion (using a social discount rate of 5%). The present value of fuel and other operating cost savings exceeds the present value of the net increase in generation and interconnection investment costs to facilitate increased inter-connection and trade by more than 5-to-1.

These numbers are conservative in that we have focused only on the direct cost savings in the electricity sector, without attempting to assess the knock-on effects of lower electricity costs and more stable supplies for overall economic growth in the South Asia region. Nor have we attempted to calculate the potentially substantial economic and health benefits of reduced local air pollution. A larger and more integrated grid also can better absorb increases in intermittent renewable sources (solar and wind) without raising concerns about grid stability.

The net cost savings come primarily from large savings in fossil fuel costs

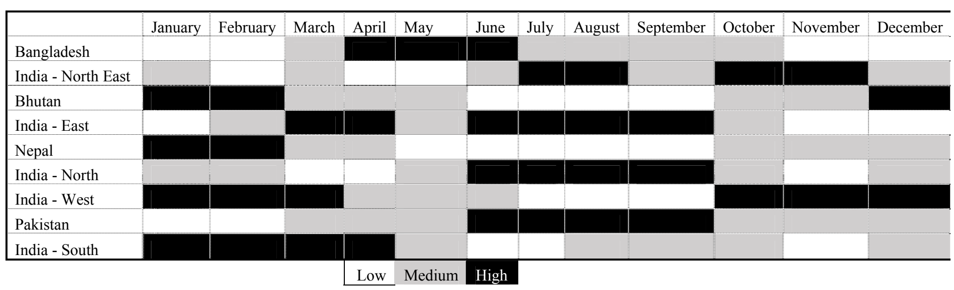

Figure 1: Seasonal complementarity in monthly electricity load profiles across South Asia

Source: Timilsina et al. (2015)

Total savings in electricity supply costs during the 2015-2040 period, relative to baseline	US$222 billion (undiscounted) and US$97 billion (discounted at 5%)
Changes in countries' total installed electricity generation capacities by 2040 relative to baseline (GW)	Afghanistan (+4), Bangladesh (-11), Bhutan (+9), India (-35), Nepal (+52), Pakistan (-13), Sri Lanka (-1); Net regional change = +5*
Changes in regional installed electricity generation capacities by 2040 for different technologies, relative to baseline (GW)	Hydro (+72), Coal (-54), Gas (-6), Wind (-7); Net regional change = +5*
Changes in cross border and inter-grid transmission capacities relative to baseline (GW)	Net increase in cross-border transmission capacity (+95) Inter-grid capacity in India (-37)
Reduction of regional power sector CO_2 emissions, relative to baseline	8%

Table 1. Key Findings from Analysis of Gains from Increased South Asia Electricity Integration and Trade

* Total generation capacity changes only marginally relative to baseline since the demand trajectories are assumed to be the same with and without increased cooperation and trade.

due to expanded regional availability of hydroelectric power, as well as benefits from cross-border trading between higher-demand and lower-demand areas at different seasons in a year (and, to some extent, in different hours of the day). The ability to greatly expand regional hydroelectric capacity with an integrated regional scale market is a key gain from regional cooperation and trade, since high levels of hydroelectric development in Nepal and Bhutan in particular are not economic without access to power export markets. The table also shows that with expanded regional electricity cooperation and trade, there are major shifts in the types and locations of generation investments.

The region is expanding interconnections and increasing cross-border power flows.[2] However, progress is slow. An assessment of the experiences provided by several electricity cooperation initiatives, in developing and developed countries, provides a number of conclusions relevant to electricity cooperation in South Asia:[3]

- Effective cross-border institutional arrangements do not automatically require the establishment of a single cross-national regulatory body, but can rely on increased coordination among national regulatory mechanisms. The main challenge is the degree of willingness of sovereign countries to agree to common rules with working enforcement mechanisms. Agreements for expanding regional transmission capacity are key to the expansion of cross-border power cooperation and trade, as are mechanisms for ensuring that contracts for cross-border trade are honored. Trust building around regional electricity cooperation and trade is possible even among countries with a history of conflict. Cross-border power cooperation and trade can start with a small number of countries and discrete projects to expand interconnection. Such arrangements then may expand and deepen cooperation over time.
- While less formal regional cooperation arrangements can provide significant benefits, more fully integrated systems and the establishment of competitive regional power markets very effectively facilitate expansion of electricity cooperation and trade. In this context, the role of well-functioning regional institutions for effectively managing more integrated power systems – especially transmission – cannot be over-emphasized.
- Decisions by domestic power sector regulators affect pricing, investment recovery and market entry and thus incentives to invest, especially for expanding private sector participation. This implies that improvements in domestic power sector performance through regulatory and institutional reforms also contribute significantly to improving regional inter-connection and trade.

To increase cross-border electricity cooperation and trade in South Asia, an important first step can be to encourage specific cross-border power projects based on the specific circumstances involved, including projects involving private sector participation. The economics of specific projects will depend on availability and comparative costs of generation capacities, and the possibilities for joint benefits from expanded cross-border interconnection. Individual projects can be achieved with relatively simple rules for governing and operating the interconnections, and mechanisms for account settlement with respect to power transactions.

As bilateral trade increases, expanded participation by third parties also can grow. One such example is efforts to expand power trade between Nepal and Bangladesh with India as a transit country. Beyond that, market-based power trading can grow through participation by other countries' suppliers and purchasers in India's rapidly developing power exchanges, and eventually in the development of region-wide exchanges. This level of electricity cooperation can bring significant benefits in terms of incentives to produce and price power efficiently and flexibly. However, it would require additional efforts to harmonize access rules, develop protocols for grid management, and establish fair and non-discriminatory transmission charges. Deeper levels of regional electricity market integration also will require additional and harmonized reforms in national electricity markets.

Footnotes

1 Timilsina et al (2015) reports on the analysis behind these numbers.

2 Recent progress includes the completion of a 500 MW India-Bangladesh transmission line; significant progress on the construction of the first Nepal –India 400 kV transmission link (Dhalkebar-Muzzafarpur), and an agreement between Bangladesh and India for a 7,000 MW transmission line through Bangladesh that evacuates hydropower from North East India for Bangladesh and other parts of India.

3 See Oseni and Pollitt (2014) and Singh et al (2015).

(References continued on page 30)

The Cost and Value of Renewable Energy: Revisiting Electricity Economics

By Silvia Pariente-David

Silvia Pariente-David is an Energy Consultant to the World Bank and Advisor to the Center for Mediterranean Integration. She may be reached at sparientedavid@gmail.com

See footnotes at end of text.

COP21 concluded in Paris late last year, with an agreement that was broadly hailed as a diplomatic triumph. And renewable energy (RE) is the grand winner. Many countries had already announced ahead of COP21 that they were transitioning their power systems to 100% RE by 2050, and even earlier if possible. Market data indicate that the trend is already underway, with 60% of capacity additions being RE last year according to IRENA. The IEA, in its annual RE Medium-Term Market Report, projects additions of 700 GW of RE over the next five years. The most important reason for the growing market trend is the RE cost decline in many parts of the world due to sustained technology progress, improved financing conditions and aggressive expansion in emerging markets. This is all happening at a time of low oil prices, so this time it seems that RE are here to stay.

If this trend continues, this is indeed very good news, as it implies that the decarbonisation of the power system needed to implement the Paris agreement may not be so costly for the economies and may not need subsidies. But is this really true? Concerns are increasingly being voiced on the costs induced by the growing RE penetration, the so-called "hidden costs".

What is the right cost metric?- The equipment cost decline has been spectacular in the last couple of years. The MESIA's MENA Solar Outlook 2015 reports that "installation cost of utility-scale solar PV power plants have fallen from roughly $7 000/kW in 2008 to less than $1 500/kW in 2014". However, it is now well known, even to non-energy experts, that the initial investment cost is not a good measure to assess the competitive positioning of RE technologies and indicate whether they will deliver electricity at an affordable price to consumers. The "capital cost" metric does not capture the fact that RE generating plants usually operate less hours than a conventional plant, and therefore cannot be used to compare different power generating technologies.

Comparison is usually done based on the levelized cost of electricity (LCOE). LCOE is the per-kWh cost of building and operating a generating plant over its financial life. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and utilization rate for each plant type. It is a convenient metric to compare different power generating technologies, as it allows comparison of plants with different cost structures and utilisation rates. LCOE can also be regarded as the minimum cost at which electricity must be sold in order for a project to break-even.

The declining trend has been as steep for RE LCOE as for capital cost, with declines of 66% for PV and 30% for wind in the last five years. In some cases, the LCOE is even lower than the price offered by conventional power plants—this is when grid parity is reached. In January 2015, the tender for the second phase of Mohammed bin Rashid Solar Park in Dubai was awarded to the lowest bidder for US$0.06 per kWh for a 25-year fixed contract, which was then the lowest solar price ever achieved worldwide[1]. Lower LCOE prices have been reported since then in the U.S. and in Germany.

The fallacy of LCOE- LCOE analysis has shortcomings and comparing technologies using that metric is misleading, as shown by Joskow[2]. The use of LCOE is flawed because it treats all kWh supplied as an homogeneous product with a single price. Specifically, traditional levelized cost comparisons fail to take account of the fact that the value of electricity supplied is time and location specific. Moreover, the LCOE metric does not take into account that electricity supplied by conventional plants and by RE plants is not the same product. Since the output of wind and solar PV is driven by natural processes, there is no guarantee that it will be available when the consumer needs it, whereas electricity from conventional power plants can, most of the time, be produced on demand. A kWh produced from conventional power plants is firm, one by RE is uncertain. LCOE ignore the costs of backing up intermittent renewables and of the networks required to integrate them.

Grid integration costs- Integrating wind and solar power or other variable RE into power systems causes costs elsewhere in the system. Examples include distribution and transmission networks, short-term balancing services, provision of firm reserve capacity, a different temporal structure of net electricity demand, and more cycling and ramping of conventional plants. These costs are often called "hidden costs" or "grid integration costs". Typically, "integration costs" are of three types: grid costs, balancing costs and the "adequacy costs" or "utilization effect on conventional power plants". There is no agreement on whether the third type should be accounted as part of integration costs; it is discussed in the next section on merit-order effects. Integration costs will vary substantially according to the amount of penetration of variable RE, the power system structure and its flexibility. The flexibility of a power system is its ability to cope with the stress resulting from sudden and unpredictable variations in availability, which is characteristic of renewable energy. Grid integration costs can vary from zero (or even negative when the production of RE matches perfectly the demand profile) to estimated values of around $15/MWh[3].

The merit order effect- RE penetration affects the revenues and margins of conventional power plants by lowering average wholesale electricity prices and peak prices and by reducing the volume of electricity produced by thermal plants. Wholesale prices fluctuate between zero when renewables are at the margin (or even negative when low demand coincides with a very high level of wind for instance) and the variable cost of fossil fuel-fired plant when the latter are at the margin.

In a merit order based on marginal cost, RE plants will be dispatched first as they have a zero marginal cost. As the RE capacity increases, conventional fossil fuel power plants move to the right of the merit order curve and their utilisation is substantially reduced. In Spain, effective operations of CCGT fell from over 4000 hours in 2008 to less than 1000 hours in 2014. Not only they do not recover their fixed investment costs[4], but also they risk being decommissioned if they run too few hours to cover their fixed O&M. However, those plants are needed to provide the system flexibility required to integrate a high level of RE. An issue for electricity systems is how to provide adequate compensation for this flexibility. Capacity mechanisms have been introduced in some European countries to remunerate that flexibility and avoid conventional power plant closure. However, capacity payments tend to create an oversupply of power generating capacity, further depressing prices. This affects negatively both the value of RE and of conventional plants.

System costs- As emerges from the discussion above, there is a complex and intricate relationship between prices, RE costs/values and conventional plant profitability. A high level of RE capacity tends to depress wholesale electricity prices. This implies lower revenues for conventional plants, which tend to be decommissioned or mothballed. This in turn reduces power system reliability and flexibility, which decreases the ability of the power system to integrate a high level of renewables. This vicious circle needs to be broken to find an economic equilibrium that optimises the RE contribution. What is needed is a holistic approach to power system analysis and planning.

The metric needed is an approach that integrates all these costs and derived effects of the RE penetration to determine the optimal mix of plants to meet electricity demand at lowest cost, while satisfying the climate change and other policy objectives. This is the "total system cost" approach which focuses on the total cost of the power system, rather than trying to allocate some of the cost components to specific technologies, or part of the power system, in order to be able to compare the technologies on the basis of LCOE.

Planning the future power system needs to integrate the flexibility requirements, but flexibility requirements also need to be incorporated in operating decisions. The power system does not always operate as planned. Extreme weather, unanticipated outages and other factors can result in the system operating outside of planned conditions. Generally, the system is robust enough to handle most departures without problems. For more severe departures from planned conditions, the re-dispatch of generating resources is a major tool for the system operators. Although the prevailing thinking is that RE plants run whenever available, curtailing existing variable RE units for reliability reasons could be helpful at times; but it adversely impacts the economic performance of such resources and is politically challenging. There are suggestions that RE could provide ancillary services and contribute to market balancing, mimicking conventional generation, but the cost may be high and it would affect RE market value. Building RE capacity to remain idle while waiting to back each other up and provide flexibility as needed is difficult to justify economically. The long-run challenge is to put in place market arrangements—both market design and operating practices-- that recognize the value of flexibility, by remunerating flexible plants adequately, and guarantee sufficient revenues for investment to take place without permanent state intervention.

The "system cost" approach provides the right metric to measure RE costs and market value, but it is a little complicated for the layman. Either we need to better educate the public, or design a simple metric that everybody can understand.

Footnotes:

[1] Source IRENA Press Release April 8, 2015- Cost-Breakthroughs Make Solar and Wind the UAE's Most Competitive Energy Sources

[2] Joskow, Paul. "Comparing the Costs of intermittent and dispatchable electricity generation technologies", MIT-CEEPR Working Paper (revised February 2011). A short version appears in the *American Economic Review Papers and Proceedings 2011,* 101(3):238-241, May 2011.

[3] Some estimates are given as % of LCOE, with a range of 10-40%

[4] In general, CCGT plants were financed on the assumption that plants would operate around 4,000–5,000 hours a year (46–57 % load factor).

IAEE/Affiliate Master Calendar of Events

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

Date	Event, Event Title and Language	Location	Supporting Organization(s)	Contact
2016				
April 24-26	9th NAEE/IAEE International Conference *Energizing Emerging Economies: Role of Natural Gas & Renewables for a Sustainable Energy Market and Economic Development*	Abuja, Nigeria	NAEE NAEE/IAEE	Wumi Iledare *wumi.iledare@yahoo.com*
June 19-22	39th IAEE International Conference *Energy: Expectations and Uncertainty Challenges for Analysis, Decisions and Policy*	Bergen, Norway	NAEE	Olvar Bergland *olvar.bergland@umb.no*
August 28-31	1st IAEE Eurasian Conference *Energy Economics Emerging from the Caspian Region: Challenges and Opportunities*	Baku, Azerbaijan	TRAEE	Gurkan Kumbaroglu *gurkank@boun.edu.tr*
September 21-22	11th BIEE Academic Conference *Innovation and Disruption: The Energy Sector in Transition*	Oxford, UK	BIEE	BIEE Administration *conference @biee.org*
October 23-26	34th USAEE/IAEE North American Conference *Implications of North American Energy Self-Sufficiency:*	Tulsa, OK, USA	USAEE	David Williams *usaee@usaee.org*
2017				
June 18-21	40th IAEE International Conference *Meeting the Energy Demands of Emerging Economic Powers: Implications for Energy And Environmental Markets*	Singapore	OAEE/IAEE	Tony Owen *esiadow@nus.edu.sg*
September 3-6	15th IAEE European Conference *Heading Towards Sustainability Energy Systems: by Evolution or Revolution?*	Vienna, Austria	AAEE/IAEE	Reinhard Haas *haas@eeg.tuwien.ac.at*
2018				
June 10-13	41st IAEE International Conference *Security of Supply, Sustainability and Affordability: Assessing the Trade-offs Of Energy Policy*	Groningen, The Netherlands	BAEE/IAEE	Machiel Mulder *machiel.mulder@rug.nl*
September 19-21	12th BIEE Academic Conference *Theme to be Announced*	Oxford, UK	BIEE	BIEE Administration *conference @biee.org*
2019				
May 26-29	42nd IAEE International Conference *Local Energy, Global Markets*	Montreal, Canada	CAEE/IAEE	Pierre-Olivier Pineau *pierre-olivier.pineau@hec.ca*
August 25-28	16th IAEE European Conference *Energy Challenges for the Next Decade: The Way Ahead Towards a Competitive, Secure and Sustainable Energy System*	Ljubljana, Slovenia	SAEE/IAEE	Nevenka Hrovatin *nevenka.hrovatin@ef.uni-lj.si*

1st IAEE
EURASIAN CONFERENCE
Energy Economics Emerging from the Caspian Region:
Challenges and Opportunities
28-31 August,2016
Baku - Azerbaijan

Energy Economics Emerging from the Caspian Region:

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The 1st IAEE Eurasian Conference will take place in Baku, Azerbaijan between 28 and 31 August 2016, and will focus on energy economic issues of the Caspian region.

Oil and gas producing countries in the Caspian region have experienced rapid economic growth over the last decade under high energy prices, while they are suffering today from cheap oil. Does the Caspian region have the potential to become an important energy supplier for European and global markets under reduced prices? What are the oil & gas price dynamics and expectations? What is the economics of unlocking the rich oil and gas reserves of the Caspian region? What are the diffusion prospects for alternative and renewable energy projects under low energy prices in the region? How can regional energy security be assured? Answers to these questions and many others will be sought in Baku under many exciting sessions featuring lively discussions with renowned international speakers.

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We are pleased to announce the Call for Abstracts for the 1st IAEE Eurasian Conference,

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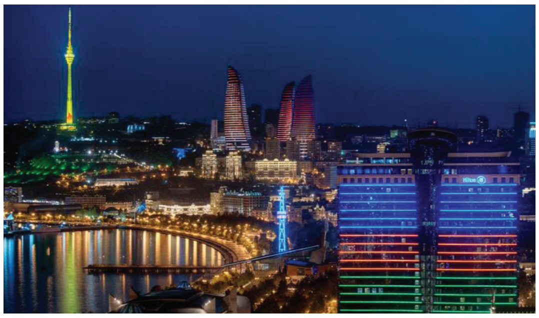

The deadline for receipt of abstracts for Concurrent Sessions is **Friday March 25, 2016.**

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The abstract must be no more than two pages in length and must include the following sections:

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c. Results: Key and ancillary findings

d. Conclusions: Lessons learned, implications, next steps

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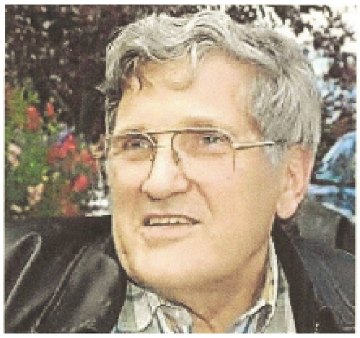

ARLON REX TUSSING, A REMEMBRANCE

Arlon Tussing passed away on January 15. I met Arlon in 1973 when I started my congressional fellowship on the staff of the U.S. Senate Energy Committee. The “energy crisis” resulting from the Arab Oil Embargo started shortly after I arrived and we were off to the races. Arlon was the Committee’s Chief Economist and was an island of serenity, indeed of wisdom, during that crazy period.

Arlon is among the most intelligent people I ever met. But Arlon also was a memorable character who delighted in courageously attacking the then-conventional wisdom. In fact, delighted is not quite accurate, he felt compelled to do so. He was a free thinker; he once told me his intellectual forefathers were Milton Friedman and Karl Marx —and that was accurate!

I can think of three important events that involved the IAEE. For the 1981 IAEE conference in Houston, I invited Arlon to participate on a panel where he would give a talk on natural gas markets. You may recall that interstate pipelines had signed take-or-pay contracts with gas producers above $10 an MCF despite the fact that price the gas was sold to consumers was far below that. The idea was that there was a lot of cheap old gas that would “subsidize” the higher priced contracts and keep pipeline throughputs high. Of course, the throughputs were what pipeline tariffs were based on, and what their profits depended on.

Arlon understood, before just about anyone else, that this practice was commercially unsustainable, and would lead to no good. And he said so during his talk. In Houston in November, 1981, he told the audience that the natural gas pipeline industry should tell their producers “I can’t take, and I won’t pay, so sue me!”

That was a call to insurrection, to the barricades, and the audience, populated heavily by Houston pipeline and producer company economists, was incensed! This took real courage, which Arlon had to spare. But it got the message across. I would bet that anyone who attended that conference still remembers Arlon’s presentation.

For the 1982 IAEE conference in Denver, I invited him to present a talk on the future of world oil markets. Arlon again did not disappoint. He and Sam van Vactor predicted that the long run equilibrium oil price was about $15 a barrel in $1982, at a time that oil was selling for over $40. Again, the oil industry participants were scandalized, and angry. Again, Arlon was courageous and right. But he had ticked off so many IAEE members that it took until 2007 before he was elected a Senior Fellow of the USAEE.

Third, for the 1992 conference in Houston, I worked with Cathy Abbott to have him debate Jeff Skilling from Enron, who was then promoting an exciting natural gas futures contract. The confrontation was wonderful to watch and Arlon did well, as usual.

But Arlon’s career was much more impactful than solely his energy career. He was extremely important to creating the framework for developing the oil and gas riches of Alaska, and sharing them with their indigenous population. Alaska is permanently different, and much better off, than most oil rich states, and countries, and Arlon had an extremely important role in establishing this. Please see the websites below to get a feel for what he accomplished. He will be long remembered and sorely missed.

Mike Telson, Senior Fellow (USAEE)

http://www.adn.com/article/20160119/maverick-economist-arlon-tussing-shaped-alaska-energy-policy
http://www.legacy.com/obituaries/insidebayarea/obituary.aspx?pid=177384516
https://books.google.com/books/about/An_Arlon_Tussing_Sampler.html?id=6ANBPwAACAAJ
http://dor.alaska.gov/Portals/5/Docs/PressReleases/RSB%20Fall%202014%20highres%20page.pdf

Shale Gas Availability, CO_2 Emissions, Electricity Generation Mix and Power Sector Water Use: EMF 31 Scenarios Results for the U.S.

By Nadejda Victor and Christopher Nichols

Nadejda Victor is with Booz Allen Hamilton and Christopher Nichols is with the Department of Energy-NETL. Victor may be reached at nadejda@bah.com

See footnotes at end of text.

The U.S. electricity sector is responsible for 38% of energy-related CO_2 emissions and for 45% of total water withdrawals for power plant cooling[1]. Depending on the electricity generation mix to meet future demand, power sector water usage could be enlarged or reduced. Within the past decade, coal power plants were the dominant source of electricity generation in the U.S. and in 2008 coal plants accounted for 67% of water withdrawals and 65% of consumption for thermoelectric power plants[2]. Natural gas power plants are less water intensive: for the same year, gas plants accounted for 4% of power plant freshwater withdrawals and 9% of consumption[3]. Nuclear reactors, however, require more water to produce the same amount of electricity than fossil plants with an equivalent cooling system as they are thermodynamically less efficient: in 2008, nuclear power plants produced 21% of the freshwater-cooled electricity, but accounted for 27% of all power plant freshwater withdrawals, and 24 % of consumption[4]. The water intensity of renewable energy technologies varies: some concentrating solar power plants consume more water per unit of electricity than the average coal plant, while wind farms use basically no water. Geothermal and biomass power plants also have water intensities in the range of nuclear or coal.

Nuclear and coal, on average, are the most water-intensive thermoelectric power plants. Carbon capture and storage (CCS) escalates the amount of water used if CO_2 is captured through absorption with amine solvents[5]. Furthermore, the additional power used to capture and sequester CO_2 lowers the plant's output, thus raising the amount of water used per unit of energy generated. Changes in water use from electricity generation is vulnerable to weather variability and, in turn, changes in water consumption for electricity generation affect the availability of water in other sectors of the economy. Taking into account challenges to U.S. electric power reliability, it is crucial to understand how future energy and carbon mitigation policies could impact electricity generation water usage.

We explored the relationship between shale gas availability, CO_2 reduction policies and water use in the electric power sector. We applied a multiregional MARKAL model and the publicly available EPAUS9r2014 database[6]. The original EPAUS9r2014 database was modified in line with the Energy Modeling Forum 31 (EMF 31) scenarios: EMF Reference or Baseline (Reference); High U.S. Shale Resources (High Shale); Low U.S. Shale Resources (Low Shale); Technology Performance Standard (TPS)[7]; TPS with Low Shale Resources (TPS Low) and Modeler Choice[8]. Our Modeler Choice scenario is TPS that includes additional costs for water withdrawal treatment and an upper bound on water consumption (TPS Water Constraints). We assumed that future additional water withdrawal treatment costs start in 2020 at $0.05/kgal. We estimated an upper bound on power sector water consumption by each region assuming a 35% reduction by 2050 at the national level and with different rates of water consumption decrease in different regions that are based on mean absolute percentage deviation of "Counties At-Risk" in the particular region[9].

CO_2 EMISSIONS MODELING RESULTS

In 2007–2013 U.S. electricity generation CO_2 emissions have fallen more than 15%, while system-wide CO_2 emissions have decreased only by 10% (Figure 1). Although CO_2 reduction could be assigned to the economic downturn, the continuing decline after 2010 suggests that increased availability of natural gas, and the transition from coal to natural gas has also contributed to the CO_2 decline. This trend continues in the short-term future in all scenarios since natural gas continues to replace coal-fired plants. By 2020 electricity generation CO_2 emissions are 20% below 2005 level in the Reference scenario, 27% in High Shale, 16% in Low Shale and 40% in TPS scenarios. After 2020-2025 power sector CO_2 emissions increase and are only 7%-15% below 2005 by 2050 in the scenarios without CO_2 constraints. In TPS scenarios CO_2 emissions are 48% below 2005 levels in 2050.

Total energy system CO_2 emissions are 12% below 2005 levels by 2020 and increase afterwards in the Reference scenario. By 2025, CO_2 emissions in the High Shale scenario are 15 % lower than 2005. The Low Shale scenario shows the lowest CO_2 reduction in the short-term (11% by 2020). Total system-wide CO_2 emissions in the Reference and Low Shale scenarios have a similar trend: decrease in 2005-2025,

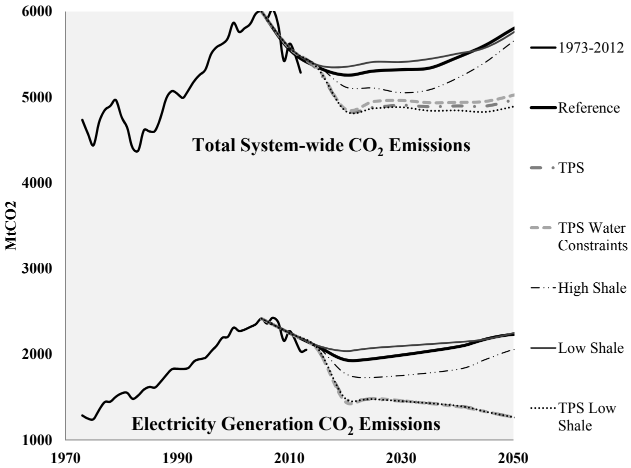

Figure 1. Total CO_2 Emissions and Electricity Generation CO_2 Emissions: Historical and Projections

stabilization in 2025-2040 and increase afterwards up to 2005 level by 2050. In the High Shale scenario natural gas supply affects CO_2 only in the short and medium-term and total CO_2 emissions by 2050 are merely 2% lower than in the Reference scenario. In TPS scenarios CO_2 emissions are only 16-18% lower than in the Reference case by 2050. Thus, the level of CO_2 abatement in electricity generation sector is higher than total energy system CO_2 abatement; so as long as there are no CO_2 constraints in other sectors, the model expands only electricity CO_2 reductions.

ELECTRICITY GENERATION MIX MODELING RESULTS

In 2005, coal provided 46%, nuclear power around 19%, natural gas nearly 20% of all electricity. Renewables (including solar, wind and large hydro) about 12%. Natural gas has been a strong competitor for power generation since 2006. In 2012, coal power plants produced a little more than 39% of all electricity, down from 46% in 2005[10]. In 2005-2050 electricity generation grows annually by 0.6% in the Reference scenario. The highest growth rates of electricity generation (1% annually) can be observed only in the High Shale scenario (Figure 2). All other scenarios show electricity generation lower than in the Reference scenario (the lowest level can be observed in TPS scenarios with annual growth rates of 0.4%). The low electricity demand in the TPS scenarios is a result of efficiency improvements and switching from electricity to other fuels. In addition, electricity co-production in industrial CHPs is higher in the scenarios with CO_2 constraints in the electricity generation sector because those emission sources are not covered by the modeled policy.

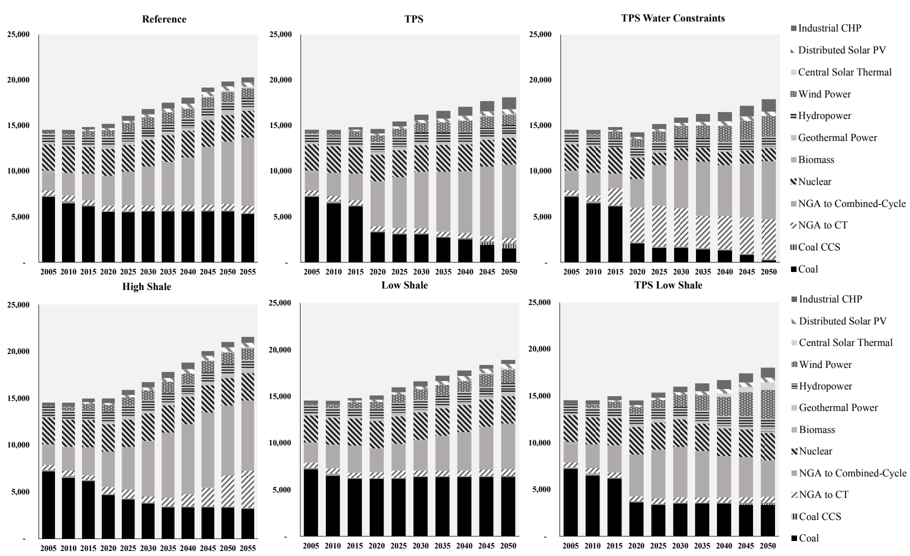

Figure 2. Electricity Generation Mix by Technologies and by Scenarios (in PJ)

In different scenarios, electricity generation technologies are various, though the share of generation from renewables are similar with the exclusion of TPS Low Shale (27% renewables by 2050) and TPS Water scenarios (21% renewables by 2050). Shale gas availability plays an important role in the future electricity generation mix in scenarios with or without CO_2 constraints in the electricity generation sector. The highest share of electricity generation from coal can be observed in the Low Shale scenario and the highest share of natural gas is in the High Shale scenario. In the TPS and TPS with water constraints scenarios most conventional coal plants that remained active through 2050 in the Reference and Low Shale scenarios, are gradually retired and replaced by natural gas power (combined cycle and combustion turbine plants). In the TPS scenario about 30% of the remaining coal facilities are retrofitted with CCS technology by 2045.

Rapid deployment of natural gas combustion turbines can be observed in the TPS scenario with water constraints in 2020 and later, though power plants with CCS do not deploy during the modeling period. Thus, in TPS scenarios, in place of the retired coal facilities, the model implements natural gas combined cycle or natural gas combustion turbines (depending on presence of water restraints as burning of natural gas in combustion turbines requires very little water and natural gas-fired combined cycle systems require water for cooling) or renewables (in case of shale gas limitation).

Furthermore, in the TPS scenario with water constraints, conventional nuclear plants are retired more rapidly and the model relies primarily on natural gas that replaces not only coal, but nuclear too. Solar and wind do not significantly contribute in electricity generation in the TPS Water Constraints scenario in comparison to the TPS Low Shale scenario.

ELECTRICITY GENERATION WATER CONSUMPTION AND WITHDRAWALS MODELING RESULTS

The water consumption figure reveals that shifts to less water-intensive technologies for electricity generation could be observed only in the TPS scenario with water constraints (Figure 3). In the Low Shale and Reference scenarios water consumption is correspondingly 20% and 25% higher by 2050 than in 2005. In the High Shale scenario water consumption is 8% higher and in TPS scenarios without water constraints water consumption in the electricity generation sector is about the same as in 2005 by 2050. Thus, CO_2 constraints encourage a decrease in water withdrawals in the generation sector in all TPS scenarios relative to the Reference scenario. At the same time, electricity generation water withdrawal in the Reference scenario drops 20% by 2020 relative to 2005 and stays about the same in 2020-2050. The reason is that existing coal power plants with once-through cooling systems are replaced by power plants with recirculating cooling systems that have a higher water consumption but lower water withdrawal. Water withdrawal in the Low Shale scenario is the highest across all scenarios (though 12% lower than in 2005) as less natural gas power plants can be deployed.

Coal plant retirement and the associated cooling system replacement play a major role in water withdrawal reductions in the scenarios with CO_2 constraints. Replacement of old facilities also increases generating efficiency and consequently decreases withdrawal. The shift to low water-use renewable power (wind or solar) can be observed only in TPS scenarios with water constraints and in the TPS scenario with Low Shale assumptions. The TPS Low Shale scenario does not show that withdrawal is lower than in TPS or High Shale scenarios as replacement of coal plants is limited by natural gas availability. In addition, CCS retrofits in the TPS Low Shale scenario are associated with higher levels of withdrawal.

By 2050, relative to the 2005, power generation sector water withdrawals decrease by 12%, 21% and 32%, respectively, in the Low Shale, High Shale and Reference scenarios. In the TPS scenario with water constraints, the trend toward more water-efficient technologies and cooling systems results in a 98% withdrawal reduction by 2040. Water withdrawal reductions in the TPS and TPS Low Shale scenario are 46% and 34%, respectively, by 2050. Thus, water withdrawal and consumption generally are lower in the scenarios with CO_2 constraints.

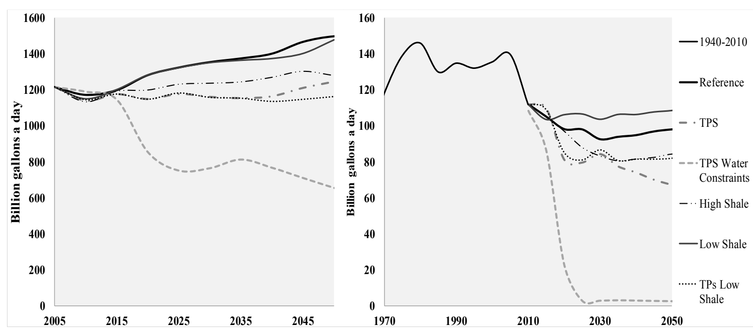

Figure 3. Water Consumption (left) and Water Withdrawals (right) in Electricity Generation Sector by Scenario.

The significance of electricity generation sector water demand depends to some extent on local conditions or on how much water is locally available and what water alternative uses would be. The greatest growth in water consumption in the electricity generation sector in the scenarios without water constraints is expected in West South Central, South Atlantic and Pacific regions or in the regions that are already experiencing intense competition over water. By 2050, in the scenarios without CO_2 constraints, water withdrawal drops in New England, East North Central, South Atlantic and Mountain regions in response to decreased electricity generation and replacement of once-through cooling systems by recirculating systems (Figure 4).

Thus, the response of power sector water consumption at the regional level is complex: in the scenarios with a CO_2 policy and without water constraint, national power sector water consumption is about the same as in 2005. At the regional level, water consumption could decrease, increase or stay the same in response to the replacement of inefficient existing conventional coal plants with higher efficiency natural gas combined cycle plants. These fluctuations occur at different times for each scenario, depending on the rate of conventional coal plant retirement and shale gas availability and each CO_2 emissions constraint scenario has an exclusive impact on total electric sector water usage at the regional level.

Regional water withdrawals remain at a generally static slope throughout the model horizon in New England, South Atlantic, West South Central and Pacific regions in the scenarios without water constraints. In the five other regions, if CO2 constraints take effect, water withdrawals are lower than in the reference scenario.

Future water demand in the electricity generation sector will be affected by the increase of electricity demand and by the power generation mix. The demand and generation mix projections vary, they are highly uncertain and depend on many factors, including market and economic conditions, energy policies, resource availability, technologies deployment and environmental regulations.

Though CO2 emissions reduction policies do not increase water withdrawals in the power sector in the TPS scenarios, water consumption over the model time horizon first slightly decreases, and then increases because CO2 constraints drove the replacement of existing thermoelectric power facilities cooled by once-through systems with more efficient facilities that decrease water withdrawal but increase consumption.

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Market Consequences of Wind Generation Promotion: Towards a Rational Energy Policy

By Raul Bajo-Buenstado and Maria Garcia

INTRODUCTION

Policy makers in many advanced countries have shown an increasing concern about environmental problems associated with fossil fuel use. This fact is reflected in multiple and well-known policies, such as the Renewable Electricity Production Tax Credit (PTC), Renewable Portfolio Standards (RPS), and Feed-in-Tariffs, among many others. In general, the goal of these policies is to promote clean generation technologies by increasing the presence of renewable resources in the capacity mix.

This policy makers' "renewable obsession" is definitely good news for society. The promotion of clean generation resources undoubtedly has a positive effect on welfare via environmental gains. Modern societies need a solid presence of renewable resources as a way to demonstrate commitment to combat climate change as well as to achieve other celebrated environmental goals. The trouble comes when emotional and political motives, rather than a reasonable and well-planned energy and electricity policy, surround the "green policies" debate. If so, we are at risk of ignoring some other market consequences.

Following this concern, we want to point out that even though an increase in renewable resources is desirable from an environmental point of view, market participants' incentives are not innocuous to a renewable resources promotion. In particular, we want to focus on some potential consequences that an increase in wind generation is expected to have on both the generation capacity mix and on market prices.

Due to the aforementioned policies, wind penetration has been rapidly increasing in many countries and regions, and it is still projected to rise in the near future in many of them. For instance, as shown in Figure 1, the installation of both onshore and offshore wind turbines in the European Union experienced a steady increase over the last decade. A similar story holds for the USA, where the penetration of wind has been especially intense in states such as Texas and Iowa, as shown in Figure 2.

Following this rapid increase in the share of wind capacity in the energy mix, some markets experienced notorious changes. Possibility the most salient consequence was the existence of negative prices in MISO and Texas ERCOT[1] that, as expected, have had (and will have) a "displacement effect" on current generation capacity. This displacement effect takes place in the context of an increasing concern about the resource adequacy problem (or "missing money" problem).

This notorious "negative prices" effect originated by the promotion of wind, together with some other consequences discussed below, lead us to raise the question of whether the promotion of wind generation capacity may also jeopardize some of the goals that policy makers set during the privatization wave in the nineties and to additional concerns regarding the resource adequacy problem. If that is the case, we argue that the so-called "green policies" must be articulated with some other policy measures to incentivize a rational, reliable and well-designed electricity market.

WIND PENETRATION AND THE EFFECT ON THE GENERATION MIX

Most countries and regions rely on more than one fuel/source to generate electricity. Thus, the generation capacity mix is usually divided into two main types of generators, namely, base load generators and peak load generators. The first group typically includes nuclear and coal-fired generation, while the second group typically includes natural gas (combine cycle and gas turbine) and oil-fired generation. How does the introduction of an

María García is a Planning and Control Manager at Repsol UK Ltd, Edinburgh (UK). **Raul Bajo-Buenestado** is a graduate fellow with the Center for Energy Studies at Rice University's Baker Institute and a Ph.D. candidate at Rice University's Department of Economics, Houston (TX). The opinions expressed do not necessarily reflect those of Repsol UK Ltd. Raúl Bajo-Buenestado may be reached at raulbajob@rice.edu

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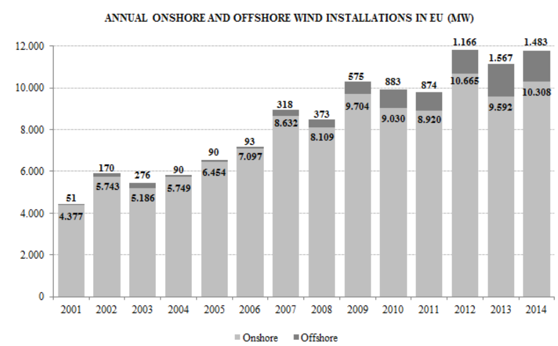


Figure 1
Source: EWEA

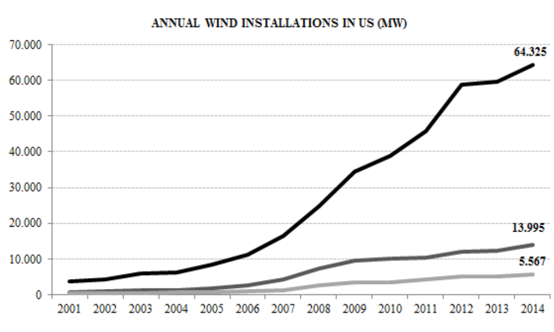
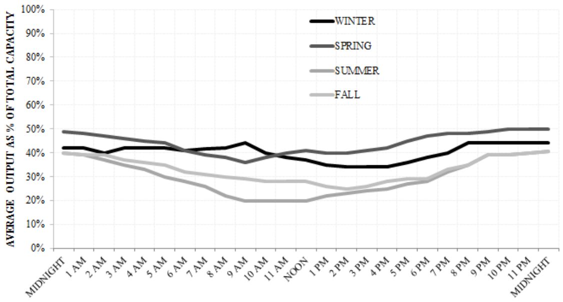


Figure 2
Source; EIW



Note: These profiles are based on ERCOT data for 1996-2012.

Figure 3. Source: Electric Reliability Council of Texas

intermittent resource (wind) affect the base load and the peak load generators?

To properly answer this question, let us take into account the following considerations. First, according to some recent empirical evidence from the Texas ERCOT market (see Figure 3), wind usually blows at night, precisely when the demand for electricity is low. In the absence of wind generation, base load generators (coal and nuclear plants) would typically have enough capacity to satisfy night demand. However, during windy nights, wind turbines will be online, taking market share from base load generators. If wind penetration is high enough, and considering that the marginal cost of wind generation is nearly zero, during windy nights market clearing prices will be close to zero, making production non-profitable for coal-burning power plants and nuclear plants.

Second, in some countries wind production receives a subsidy per kWh generated. For instance, in the U.S. the so-called Production Tax Credit (PCT), which is imposed at the federal level, currently grants $0.023/kWh to wind producers. This implies that wind generators are willing to bid even below zero, since the subsidy will guarantee that production is profitable for them as long as they are plugging power into the system. If so, power generation will be even less worthy for coal-fired plants and nuclear plants, since these power plants will incur negative profit.

Third, peaking generators, such as gas-fired turbines, have low shut down costs and are able to come online in 30 minutes. Therefore, when a peak in demand is anticipated, these plants are likely to be ready to generate power. This is not true for coal and nuclear plants (base load). For these types of plants, shut down and ramp up costs are high, that is, it is not cheap, nor easy nor quick, to turn them on. As a consequence, these plants face the tradeoff of staying online 24/7, as is the case for nuclear plants, at the risk of not covering variable costs if the wind is blowing (and even getting negative prices in the presence of subsidies), or shutting down whenever the wind is blowing, which makes these plants incur cooling down and ramp up costs.

Therefore, and according to Peter Hartley[2], due to both the intermittent nature of wind and the fact that wind generation satisfies base load demand (night demand), an increase in wind generation is likely to discourage investment in base load generation (coal and nuclear capacity) and encourage investment in natural gas capacity. This effect is further enhanced by (current) low natural gas and oil prices.

WIND PENETRATION AND THE EFFECT ON PRICES

The promotion of wind generation is also likely to have an effect on the electricity market price. The key question is whether this impact is positive or negative for consumers. Again, we shall consider the following issues to properly address this question.

The marginal cost of wind generation is zero (or near to zero). This implies that whenever the wind is blowing, electricity prices will be low, and even negative as it was the case in Texas ERCOT and MISO, due to the presence of subsidies and coal plants' shut down costs (see footnote 1). But, what happens if the wind is not blowing?

If our previous argument is correct, nuclear and coal-burning power plants are likely to be displaced over time in favor of peaking plants (natural gas generation and oil-fired generation) as wind generation penetrates the market. As a consequence, if the wind is not blowing, the "market clearing fuels" are likely to be natural gas and oil, which are more expensive than coal and uranium (nuclear production). In other words, the electricity market price will be subject to high jumps, whose size is the difference between the marginal cost of wind generation (zero) and the marginal cost of natural gas. Moreover, these jumps will move according to the pattern of wind, which is unpredictable.

Hence, a greater presence of wind turbines will leave electricity prices subject to two sources of variation. First, subject to jumps created by wind patterns. Second, subject to the fluctuations of oil and natural gas prices in the global energy markets. Moreover, as Riesz, Gilmore and MacGill[3] point out in a forthcoming article, in a high renewable market the proportion of revenue earned during extreme pricing events would need to increase significantly in order to maintain reliability. Hence, according to them, a significantly high market price cap will be also required. An increase in the price cap will add further variability in market clearing prices, since power prices will skyrocket during scarcity events. Considering these facts, we expect that a promotion of wind turbines will produce a significant increase in the volatility of electricity market clearing prices. Whether or not this is a desirable feature is a question that we leave to readers.

Finally, in regions in which wind is likely to blow mostly at night (e.g., Texas), some other generation resources will be necessary to back up production during the day, when the wind is less likely to blow. If so, and considering the displacement effect of wind capacity on base load generation, natural gas and oil power plants will play a prominent role during peaking demand hours. This will not only increase price variability for consumers, but it may also lead to an increase in average consumer prices, especially in markets with relatively high price caps (as is the Texas ERCOT case).

INSIGHTS FROM RECENT TEXAS ERCOT MARKET'S PATTERNS

The Texas ERCOT market provides some relevant insights on how the promotion of renewable resources (with a focus on wind) is likely to affect the power sector. The Texas ERCOT market has traditionally relied on two main sources of electricity generation, namely coal and natural gas. However, as shown Figure 1, the penetration of wind capacity has been increasing significantly over the last decade in Texas. Favorable wind conditions in some regions within the state (such as West Texas) and generation subsidies are two key elements that explain this pattern.

Following this high wind penetration, and in the presence of the PTC, the Texas ERCOT market has experienced some notorious changes. First, as discussed by Huntowski, Patterson, and Schnitzer (see footnote 1), the frequency of negative hourly prices in the ERCOT West zone increased from about 1% in 2007 to over 9% in 2011. Second, as a consequence, wind capacity has discouraged investment in coal-burning power plants. This effect will be exacerbated as a result of the implementation of the recently released Clean Power Plan act, which further pushes the reduction of coal-burning power plants. In fact, recent ERCOT projections[4] show that the only fossil fuel burning capacity additions will be based on gas turbine and combined cycle plants.

With the expansion of the South Texas nuclear generation station cancelled in 2011 and the expansion of the Comanche Peak nuclear power plant suspended since 2013, and with no promising future to restart these projects due to low gas prices, the Fukushima accident alert, and regulatory hurdles, it seems that Texas ERCOT tends towards a generation mix based on renewable resources and natural gas. Unsurprisingly, ERCOT reckons that these changes could increase electricity prices by up to 16% in 15 years (see footnote 4).

THE "IRRATIONAL" ENERGY POLICY IN SCOTLAND

According to our previous analysis, in the context of heavily subsidized wind generation, base load capacity is likely to be displaced. The market will have an incentive to invest in peaking plants, such as natural gas turbines and oil-fired plants, as a way to back up the increase in intermittent generators.

Even though the market tendency is to displace coal and nuclear plants, representatives of the Scottish Nationalist Party (SNP) at Westminster are willing to exacerbate this effect. In fact, according to a recent article by Simon Johnson[5], SNP ministers are using their control of the planning system to promote the construction of additional wind farms while blocking the construction of a new generation of nuclear. These political interventions are taking place at the same time that the closure of coal-fired plants, such as Longannet, and nuclear plants, such as Hunterston and Torness, are planned for the next year.

SNP members understand that investing in green generation is good for Scottish citizens. However the remaining question is, how do policy makers plan to back up production if it happens that there is no wind? It seems that SNP members are avoiding this question. In fact, as Gary Pender states in the aforementioned article, the lack of replacement of the coal-fired and nuclear generators will eventually lead to Scotland to transition from a being a net exporter to being a net importer of electricity. Paradoxically, electricity imports from neighboring regions may come from even dirtier technologies, and at a higher price.

CONCLUSIONS: AN ENERGY POLICY THAT MAKES SENSE

Current environmental challenges are pushing policy makers towards the adoption of policy measures that promote investment in renewable resources such as wind turbines. Undoubtedly, these policy measures are important in modern societies, in order to guarantee minimum environmental standards to future generations. However, this goal cannot compromise current and/or near future energy security and grid reliability. In other words, thoughtlessly "green legislation" that does not consider market consequences, and that does not envision a smooth fuel transition, should not be implemented by any means.

The real challenge for policy makers is not only to promote renewable resources, but also to guarantee a smooth transition from a fossil-fuel based generation mix to a less-carbon-dependent, reliable and sustainable grid. For that purpose, in our opinion, a rational energy policy should consider simultaneously the following points.

- Maintain well-articulated incentives that promote investment in renewable resources, while preserving market competition.
- Increase the thermal efficiency of existing coal plants, which could potentially result in significant reductions of CO_2 emissions. In addition, policy makers should also incentivize the investment in "top-notch" coal plant technologies, such as Carbon Capture and Storage (CCS). According to a recent report by the IEA[6], fitting CCS to a power plant requires additional capital investment for the CO_2 capture and compression equipment, the transport infrastructure as well as the equipment associated with storage. We argue that the right policy and funding mechanisms are needed to help CCS to turn profitable projects such as the Petro Nova porject in Southwest Houston[7].
- Incentivize the investment in safer, out-of-risk nuclear plants. According to Goldstein and Pinker[8], given the current state of the art, without nuclear power "the numbers needed to solve the climate crisis [...] do not add up". Nuclear generation is a carbon-free option, but given the (justified) social alarm created by the Fukushima accident further efforts are necessary to guarantee 100% safe nuclear generation in current and projected plants.
- A well-planned capacity market that sets the revenue adequacy requirement considering not only overall system needs and system existing capacity, but that also considers the negative correlation between intermittent production and market demand. If necessary, the regulator should make a distinction between off-peak and peak demand (net of wind), setting different resource adequacy standards for different periods.
- Study the implementation of "capacity portfolio standars" that take into account not the least-cost generation units but also the least-pollutant generation units. Such "capacity portfolio standars" should be set taking into account also the climatological patterns and the evolution of the renewable resources state of the art. If necessary, the regulator should increase the percentage of "thermal-generation" reserve margin in such a way there is enough thermal generation capacity to satisfy peak load in the worst expected "no-wind period" scenario.

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The Recent Oil Price Decline and M&A in the U.S. Oil and Gas E&P Sectors

By Kuang-Chung Hsu and Zhen Zhu

Kuang-Chung Hsu is Assistant Professor of Economics at the University of Oklahoma and Zhen Zhu is the Dr. Michael Metzger Chair and Professor of Economics at University of Central Oklahoma. Zhu is also Consulting Economist with C.H. Guernsey & Company in Oklahoma City.

See footnotes at end of text.

INTRODUCTION

Slightly more than a year ago, crude oil prices started to decline from about $100 a barrel to the current level of around $30. The O&G industry did a self-destruction due to the widespread use of new technologies in drilling and production, thus leading to surging production and low prices. Contributing factors also include lower demand due to the slowdown in developing economies, especially China along with OPEC implementing a strategy of keeping oil prices low in hopes of driving U.S. shale producers out of business. A year has passed since the start of the oil price decline, and the prospect of higher oil prices in the near to medium term does not look bright. During the low price environment in the past year, U.S. domestic production did not slow down much, world oil demand was still weak, and major OPEC countries did not cut production to boost prices in order to maintain their market share. In the meantime, low cash reserve oil producing countries such as Venezuela needed to generate more production to fill their budget hole resulting from low prices. All of these paint a bleak picture for oil prices in the next couple of years.

Low oil prices have no doubt fashioned a difficult situation for the U.S. oil and gas industry. For example, 83% of the 129 publicly traded companies on the Oil & Gas Journal list of 150, reported net losses for the 2nd quarter of 2015[1]. The price of oil is also perceived to provide a harsh environment for the O&G E&P sector as it worsens balance sheets of the E&P companies, reduces their borrowing base, and weakens the liquidity of many lower rated E&P companies. In addition, low oil and gas prices decrease the asset values of the E&P companies, lowering the return on drilling programs. However, the E&P companies cannot simply stop their drilling program to respond to low prices. Faced with the shrinking asset base and trapped by the low liquidity, many E&P companies may look to raise capital by selling non-core assets.

On the other hand, low oil and gas prices may provide an excellent opportunity for the cash-rich companies and private equity funds to find bargain prices, to build up their reserve assets by buying up some assets available for sale by less well-to-do companies, and in some cases, simply buying up some companies at the brink of bankruptcy due to low liquidity.

In our earlier article[2], we presented some stylized facts about the U.S. oil and gas E&P sector's M&A activities and postulated some factors behind the M&A activities. Our evidence suggested that the oil and gas prices, especially the oil price, were behind the M&A activities in the longer term, even though production helped to shape M&A wave patterns at the individual shale level. That article, however, was written before the oil price decline in the last quarter of 2014. In this article, we look at how M&A activities in the U.S. oil and gas E&P sectors responded to the low oil price environment during the last year.

OVERALL M&A ACTIVITIES

Figure 1 plots the overall M&A transaction count for the sample period (2013:1-2015:8). Prior to October 2014, the start of the oil price decline, the number of M&A transactions fluctuated around an average value of 50 transactions per month. Oil prices during the period stayed relatively stable, hovering around $100/Bbl. However, when oil prices started to decline in the last quarter of 2014, the number of M&A transactions declined at the same time.

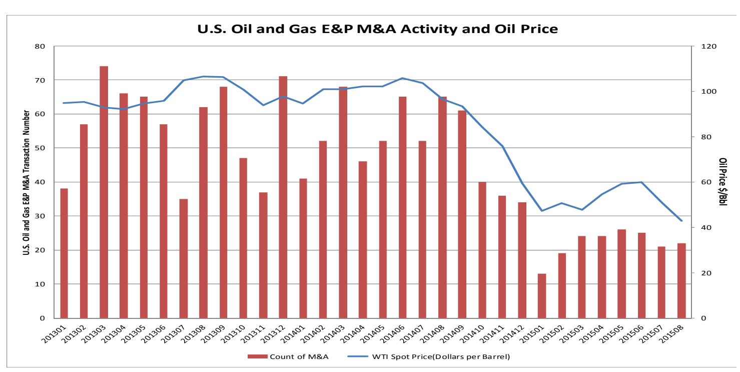

Figure 1.

A closer look at the relationship between oil prices and M&A activities suggests that for the short period prior to the oil price decline, there was little connection between the oil price and M&A on the monthly basis, while for the period of declining and lower oil price, the oil price – M&A connection was high. This can be observed from the scatter plot below (Figure 2) and the correlation statistics from Table 1.

Figure 2 shows that for the sub-period of the stable

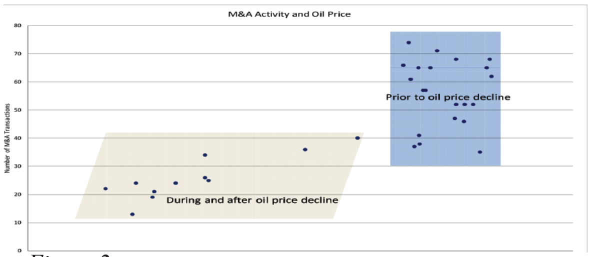

Figure 2.

and high oil prices (prior to October 2014), M&A fluctuated and was not closely related to oil prices. Howver, the declining oil price was accompanied by a decline in M&A activities. The correlations between oil prices and overall M&A activities along with some sub-categories of M&A in Table 1 suggest that there were little significant correlation between oil prices and M&A activities prior to oil prices declinimg, but the correlation between oil prices and the M&A categories increased substantially with the exception of the traditional M&A activities.

The traditional M&A definition refers to the combination of the businesses to form a new business entity (Merger) or one business acquiring another business (Acquisition). In the E&P industry, M&A activities are defined more broadly to include transactions in specific O&G assets such as acreages and other properties and royalties. In our data set, about 8.3% of the total 1462 transactions were traditional M&As. 35% of all transactions were related to acreages, 54% were related to acreages and other assets, and only 2% were transactions related to royalties. Table 1 shows that M&A in the traditional sense is not quite related to oil price, but the oil price decline caused the selling and purchase of the acreages/assets/royalty to decline significantly.

	Correlation With Oil Price		
	2013:1 to 2015:8	2013:1 to 2014:9	Post 2014:9
Traditional M&A	0.27	-0.12	0.28
Acreages	0.76	0.03	0.66
Property	0.82	-0.04	0.79
Royalty	0.08	-0.23	0.32
Total M&A	0.82	-0.04	0.87

Table 1: Correlation of M&A Activity with Oil Price

GEOGRAPHICAL M&A PATTERN

Figure 3 shows the M&A pattern for each of the eight regions. In general the M&A activities slowed down and the pattern changed in most of the regions when oil prices started to decline. An exception may be for the region of Ark-La-Tex. A statistical test in Table 2 reveals that the average number of M&A transactions was significantly lower in the period of lower oil prices after October 2014.

Region	Up to 2014:9	After 2014:9	t for mean difference
Ark-La-Tex	2.89	3.00	-0.147
Eastern	5.43	2.45	3.03*
Gulf Coast	10.67	4.73	5.75*
Gulf of Mexico	3.00	1.40	3.15*
Midcontinent	10.90	4.20	5.41*
Multi Region	3.52	2.56	1.41
Permian	7.75	3.45	3.85*
Rockies	10.43	5.09	4.14*
Total	53.67	24.73	8.15*

One-tail critical value at 5% is 1.77.

*First period sample mean is statistically significantly higher than the second sample mean.

Table 2: Test for Differences in Transaction Number Up to and After Sept 2014

DIFFERENT MOTIVATIONS FOR M&A DURING HIGH AND LOW PRICE ENVIRONMENTS

There are differences in the motivations for M&A in the oil and gas E&P sector when prices are at high or low levels. When oil and gas prices are high, the return to investment is perceived to be high. Therefore, E&P companies are willing to invest in acreages/assets in order to position themselves for future exploration and development, as development of the E&P program and gaining reserves are the key to the future of an E&P company. The selling companies are usually those who entered and acquired acreages early in the development of the production area. Higher oil prices increase the value of those holdings and enable them to sell the acquired assets at premium prices, which helps them to raise capital for their cap-ex programs. As production in an area starts to ramp up, there would be heightened interest in acquiring acreages/production assets. This can be seen to explain some wave patterns in the M&A activities in the E&P sector.[3]

When oil and gas prices are low, firms are motivated for M&A due to different reasons, depending on their circumstances. Well-capitalized E&P companies are well positioned to take on lower prices and pay bargain prices to acquire assets. For other strong balance sheet companies, especially those integrated oil companies, a low price environment creates an opportunity to reposition their business.

Lower oil and gas prices may also force companies that are in tight cash position to refocus their business on their core assets. Shedding non-core assets may help them become more concentrated and reinvest in their core businesses. Low oil and gas prices could also raise defaults. For example, a recent report by Moody's Investment Service reveals that oil and gas companies have accounted for five of the twelve corporate defaults in the third quarter of 2015.[4] Investors are more cautious in taking on new debt offers in the E&P sector, further exacerbating the tight credit condition. Some E&P companies may have to liquidate their assets.

M&A ACTIVITIES MAY INCREASE IN THE NEXT YEAR OR TWO

So far, the M&A activities in the E&P industry are still very low compared to historical values. There

Figure 3.

could be several reasons for this. The low activity may reflect the market's perception of price uncertainty. When price uncertainties are high, investment in the form of the M&A will be dampened. This is certainly consistent with standard financial theories. At present, oil prices are around the $30 range. There is still an uncertainty regarding the direction of the price movement. While there is a possibility that prices may inch higher and pass the $50 mark, the more recent oil price movement to below $30 is still a sign that the market fundamentals are rather weak.

There are reports that the fall borrowing base redetermination has not changed the bases much, which may not be all bad news to the E&P companies who are usually highly leveraged. However, as the banking industry is under increased pressure from regulators to reduce exposure to the oil and gas industry, and the oil and gas industry continues to face difficulties brought by the lower oil and gas prices, it is just a matter of time before credit conditions worsen substantially for the oil and gas E&P companies. Should the oil and gas price continue to remain low for another one or two years, we expect the M&A activities in the E&P sector to climb significantly.

Footnotes

1 See D. Stowers and L. Bell, "2Q revenues drop 35%, income plummets," O&G Finance Journal, November 2015.

2 "Merger and Acquisition Activities in the U.S. Oil and Gas Industry", K.C. Hus, M. Wright and Z.Zhu, IAEE Energy Forum, 2nd Quarter, 2014

3 For more discussions, see K. Hsu, M. Wright and Z. Zhu, "What motivates the M&A activities in the U.S. oil and gas E&P sector?" working paper, 2015.

4 See U.S. corporate default monitor – third quarter 2015: Default rate to hit four-year high during 2016," Moody's Investors Service. October 2015.

5 See M. Adams, "Fall redeterminations leave companies to fight another day," Oil & Gas Finance Journal, November 2015.

CONFERENCE OVERVIEW

North America, if not the United States alone, is expected by many to soon be energy self-sufficient. Horizontal drilling, coupled with hydraulic fracturing, reversed the downward trend in production of both crude oil and natural gas. As a result, the lower-48 US will be exporting natural gas by the time we meet in Tulsa. The debate over crude oil exports from the US will likely still be raging, and is likely to be an element of the 2016 US Presidential election. The production turnaround has shaken world energy markets, and the operation of our energy markets produced substantial reductions in CO_2 emissions through economic substitution from coal to natural gas in power generation. When we add advances in renewables and the promise of industrial-capacity battery systems, the potential for North American energy self-sufficiency appears to be on the near horizon. So, the focus of the 34th USAEE/IAEE Conference will be to provide a constructive and collegial forum for extensive debate and discussion, based on solid research and evidence, to facilitate deeper and broader understanding of the implications of this transformation for North America and the rest of the world.

The Tulsa conference will bring together business, government, academic and other professionals to explore these themes through a series of plenary, concurrent, and poster sessions. Your research will be a significant contribution to this discussion. Speakers will address current issues and offer ideas for improved policies taking full account of the evolution of the North American energy sector and its implications for the rest of the world. The conference also will provide networking opportunities for participants through informal receptions, breaks between sessions, public outreach, and student recruitment. There also will be offsite tours to provide a direct and close-up perspective on Oklahoma's dynamic energy landscape.

Tulsa became known as the Oil Capital of the World at the turn of the twentieth century, and, for a time, Oklahoma was the number one oil producer in the world. The first oil field waterflood was carried out in Oklahoma in May 1931, and the first commercial hydraulic fracturing was performed in Oklahoma in 1949. More recently, Oklahoma companies have led the way with the application of horizontal drilling and hydraulic fracturing techniques to commercialize the vast shale gas and oil resources in Oklahoma and across the country.

Cushing, Oklahoma is the pricing point for the most active commodity futures contract in the world, home to nearly 80 million barrels of crude oil storage, and is the junction for numerous crude oil pipelines collecting and moving crude oil from around the Mid-Continent and Canada to refining centers. The influence reaches from the wellhead, through the midstream, to the refinery and beyond.

In addition to Oklahoma's long-standing role in oil and gas, it is the fourth largest generator of wind energy in the country. The State has five hydroelectric projects, including a rare pump storage facility.

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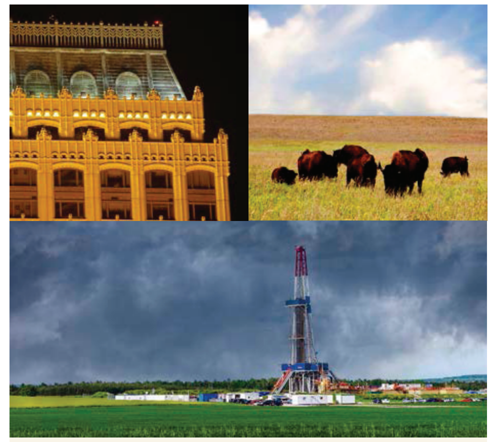

TOPICS TO BE ADDRESSED INCLUDE:

The general topics below are indicative of the types of subject matter to be considered at the conference. A more detailed listing of topics and subtopics can be found by clicking here: http://www.usaee.org/usaee2016/topics.html

- US oil and gas exports
- Energy Demand and Economic Growth
- Energy Research and Development
- Non-fossil Fuel Energy: Renewables & Nuclear
- Energy Efficiency and Storage
- Financial Markets and Energy Markets
- Political Economy
- OPEC's role in a changing energy world
- Energy Supply and Economic Growth
- Energy and the Environment
- International Energy Markets
- Energy Research and Development
- Public Understanding of and Attitudes towards Energy
- Other topics of interest include new oil and gas projects, transportation fuels and vehicles, generation, transmission and distribution issues in electricity markets, etc.

34TH USAEE/IAEE NORTH AMERICAN CONFERENCE CALL FOR ABSTRACTS

We are pleased to announce the Call for Abstracts for the 34th USAEE/IAEE North American Conference, *Implications of North American Energy Self-Sufficiency*, to be held October 23-26, 2016, at the Hyatt Regency Tulsa, Tulsa, OK, USA.

CONCURRENT SESSIONS

There are two categories of concurrent sessions: 1) current academic-type energy economics research, and 2) practical case studies involving applied energy economics or commentary on current energy-related issues. This latter category aims to encourage participation not only from industry but also from the financial, analyst and media/commentator communities. In either instance, papers should be based on completed or near-completed work that has not been previously presented at or published by USAEE/IAEE or elsewhere. Presentations are intended to facilitate the sharing of both academic and professional experiences and lessons learned. It is unacceptable for a presentation to overtly advertise or promote proprietary products and/or services. Those who wish to distribute promotional literature and/or have exhibit space at the Conference are cordially invited to take advantage of sponsorship opportunities – please see www.usaee.org/usaee2016/sponsors.html Those interested in organizing a concurrent session should propose a top ic and possible speakers to Professor Ron Ripple, Concurrent Session Chair (ron-ripple@utulsa.edu) Please note that all speakers in organized concurrent sessions must pay speaker registration fees and submit abstracts.

CONCURRENT SESSION ABSTRACT FORMAT

Authors wishing to make concurrent session presentations must submit an abstract that briefly describes the research or case study to be presented.

The abstract must be no more than two pages in length and must include the following sections:

a. Overview of the topic including its background and potential significance
b. Methodology: how the matter was addressed, what techniques were used
c. Results: Key and ancillary findings
d. Conclusions: Lessons learned, implications, next steps
e. References (if any)

Please visit http://www.usaee.org/usaee2016/PaperAbstractTemplate.doc to download an abstract template. All abstracts must conform to the format structure outlined in the template. Abstracts must be submitted online by visiting http://www.usaee.org/usaee2016/submissions.aspx. Abstracts submitted by e-mail or in hard copy will not be processed.

Student Poster Session

The Student Poster Session is designed to enable students to present their current research or case studies directly to interested conference delegates in a specially designed open networking environment. Abstracts for the poster session must be submitted by the regular abstract deadline and must be relevant to the conference theme. The abstract format for the Poster Session is identical to that for papers; please visit http://www.usaee.org/usaee2016/PaperAbstractTemplate.doc to download an abstract template. Such an abstract should clearly indicate that it is intended for the Student Poster Session – alternatively that the author has no preference between a poster or regular concurrent session presentation. Abstracts must be submitted online by visiting http://www.usaee.org/usaee2016/submissions.aspx. Abstracts submitted by e-mail or in hard copy will not be processed. Poster presenters whose abstracts are accepted should submit a final version of the poster electronically (in pdf format) by August 19, 2016 for publication in the online conference proceedings. Posters for actual presentation at the conference must be brought directly to the conference venue on the day of presentation and must be in either ANSI E size (34in. x 44in.) or ISO A0 size (841mm x 1189mm) in portrait or landscape format.

Presenter Attendance at the Conference

At least one author of an accepted paper or poster must pay the registration fees and attend the conference to present the paper or poster. The corresponding author submitting the abstract must provide complete contact details—mailing address, phone, fax, e-mail, etc. Authors will be notified by July 7, 2016, of the status of their presentation or poster. Authors whose abstracts are accepted will have until August 19, 2016, to submit their final papers or posters for publication in the online conference proceedings. While multiple submissions by individuals or groups of authors are welcome, the abstract selection process will seek to ensure as broad participation as possible: each author may present only one paper or one poster in the conference. No author should submit more than one abstract as its single author. If multiple submissions are accepted, then a different author will be required to pay the registration fee and present each paper or poster. Otherwise, authors will be contacted and asked to drop one or more paper(s) or poster(s) for presentation.

The deadline for receipt of abstracts for both the Concurrent Sessions and the Student Poster Session is Thursday, **May 19, 2016**.

STUDENTS

In addition to the above opportunities, students may submit a paper for consideration in the Dennis J. O'Brien USAEE/IAEE Best Student Paper Award Competition (cash prizes plus waiver of conference registration fees). The paper submission has different requirements and a different deadline. The deadline for submitting a paper for the Student Paper Awards is June 21, 2016. Visit http://www.usaee.org/usaee2016/bestpapers.html for full details.

Students are especially encouraged to participate in the Student Poster Session. Posters and their presentations will be judged by an academic panel and a single cash prize of $1,000 will be awarded to the student with the best poster and presentation. For more details including the judging criteria visit http://www.usaee.org/usaee2016/postersession.html

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Natural Gas as a Bridge Fuel into a Sustainable Future for Germany

By Nigar Muradkhanli

Nigar Muradkhanli is a doctoral student at the Freie Universitat Berlin. She may be reached at nigar.muradkhanli@fu-berlin.de

EUROPEAN GAS SUPPLY SECURITY

The last decade has seen several changes in the European energy sector, mainly in the context of gas market. The use of natural gas in Europe is increasing, driven by industrialization and urbanization. Given the increasing demand for natural gas together with decreasing domestic production it is expected that Europe will import 80% of its natural gas by 2030 [1]. The strong dependence on gas imports means that measures for ensuring security of gas supply are vital. It should be noted that natural gas is more climate-friendly compared with other fossil fuels as it produces less CO_2 [2], which strengthens its significance in the energy mix. Twenty four percent of the energy used by the European Union (EU) countries is produced by natural gas.

EU has a common energy policy including ensuring the functioning of the internal energy market, security of supply, promoting energy efficiency, renewables and the interconnection of transmission grids. It is one of the objectives of the EU energy policy to ensure security of energy supply in the Union, however the most decisive issues on security of supply are determined on a national basis [3]. The guidelines, issued by the EU set the frame within which the member states conduct their individual energy policies. Diversification of supply sources and distribution routes, strong bonds with supplier countries, long-term gas supply contracts, safe supply infrastructure, reliable storage facilities are among these policy measures.

NATURAL GAS IN GERMANY AT A GLANCE

Germany is one of the largest countries in the EU. The country shares borders with Denmark, Poland, the Czech Republic, Austria, Switzerland, France, Luxembourg, Belgium and the Netherlands.

The main source of energy in Germany is oil, although its use has declined over the past decade. Germany does not have much domestic oil resources and relies largely on imports to meet demand. The country has a flexible oil supply infrastructure, consisting of pipelines and import terminals. The domestic market is liberalised and characterised by a large number of players.

Natural gas makes a solid contribution to energy supply in Germany, being the second most important primary energy source of the country's energy mix. Germany's gas reserves are the fourth-largest in Europe, following Norway, the Netherlands and the United Kingdom. Germany is one of the biggest gas markets of Europe. The country uses an extensive system of pipelines for the import of natural gas and its distribution around the country. Germany's geographical location at the heart of Europe strengthens its position in the European gas market as an important natural gas transit hub. Significant amounts of gas are transported across Germany to the other EU countries. The total length of the German gas network is more than 510,000 km [4]. Germany's future plans include using the gas pipeline network as a composite system in which natural gas, biogas as well as hydrogen and synthetic methane produced from renewable energy are combined to form one huge energy source [5].

The German gas market is characterised by a large number of private operators in the areas of networks, storage operations and gas trading. The leading entity for natural gas security in Germany is the Federal Ministry for Economic Affairs and Energy (BMWi). BMWi is responsible for natural gas legislation and for emergency response coordination at the national and the EU levels. Germany has made significant progress on following the EU energy policy. The federal government completed a natural gas security Risk Assessment, the key finding of which is that the security of supply situation in Germany is reliable and safe. The Risk Assessment states that the standards required by EU regulation have been fulfilled and the available market-based instruments are generally sufficient for securing supply [6].

The natural gas storage facilities in Germany also make a significant contribution to energy security. Germany has the largest gas storage capacity in Europe and the fourth-largest in the world. The natural gas storage facilities of the country could theoretically cover approximately a quarter of Germany's annual demand, thus compensating for any short-term supply disruptions. In addition, 13.9 bcm of storage capacity is under development [6].

Natural gas production has been declining in Germany since the beginning of the century. The government forecasts that local production will continue to decline over the next 20 years, as resources are further depleted. Due to the fall in domestic production the country currently could cover only 10% of its consumption by own reserves. It makes Germany highly dependent on imports of natural gas. The country obtains 90% of overall gas demand from other countries via pipelines. According to the figures of Arbeitsgemeinschaft Energiebilanzen e. V. (AGEB), in 2014, 38% of imported gas was supplied by Russia, 22% by Norway, 26% by the Netherlands and the remaining 4% by other countries [4].

Russian imports account for about 35% of Germany's natural gas demand. However, the current Russia-Ukraine political conflict remains of concern. Diversification of supply routes providing Germany with gas has been improved, particularly with the opening of the Nord Stream pipeline, which added 55 bcm to import capacity. Following the commissioning of the Nord Stream pipeline, natural gas imports from Russia to Europe via Ukraine have dropped. Around 50% of Russia's gas exports to Europe still come via Ukraine [7].

Interconnection with other countries is also improving. The Caspian region has been a focus of the European gas consumers for the last decade. The discovery of the Shah Deniz (SD) in Azerbaijan, one of the world's largest gas-condensate fields, raised expectations that the Caspian region would play a role in the provision of gas to Europe. The International Energy Agency (IEA) estimates that the Caspian region's proven and recoverable natural gas reserves are about 7% of the world's reserves [8]. The region's proven gas reserves only tell part of the story, the prospects for further discoveries remain huge. The Trans Adriatic Pipeline (TAP) is designed to transport natural gas, extracted from the second stage of the SD field in Azerbaijan, via Greece and Albania, and across the Adriatic Sea to Southern Italy, and further to Western Europe. Initial pipeline capacity will be 10 bcm per year with the possibility of further expansion to 20 bcm per year. TAP's landfall in Italy provides multiple opportunities for further transport of Caspian natural gas to some of the largest European markets including Germany. It is a new prospective source of supply for Germany to be provided from 2019 onwards [9; 10].

The LNG market has steadily expanded in Europe over the past decade. Despite LNG supplies to Europe falling due to competition with Asia and South America, it is expected that LNG deliveries could satisfy up to 24% of European gas demand by 2020 [11]. Germany has no LNG infrastructure, as gas is fairly supplied by the existing pipeline network, but it has plans for LNG terminals, being important as an alternative method of gas deliveries. The federal government encourages market participants to purchase regasification capacities in LNG terminals in other countries. Germany provided 2 bn-euro financial guarantees to E.ON for the development of the Canadian Goldboro LNG export project. It is for the purchase of 5 mn tonnes (8 bcm) of LNG per year for two decades. In addition, E.ON is desirous of buying stakes in other LNG export projects in East Africa, South America and the Mediterranean using the government-backed guarantees [12]. Both E.ON and RWE have access capacity at the Dutch Gate terminal. It should be noted that the government of Germany had guaranteed only pipeline projects in the past.

THE ENERGIEWENDE – WAY TO THE FUTURE BASED ON RENEWABLES

With the adoption of the Climate and Energy Package by the EU in 2009, promotion of renewable energy became a distinct element of climate policy. German policy makers have taken a substantial decision to move towards a sustainable energy supply over the long term. The Energy Concept, adopted by the Federal Government of Germany in September 2010 determined renewable energy as the main source of future energy supply.

Perception of the risks of nuclear energy has been significantly changed in Germany after the Fukushima incident. In June 2011, the Bundestag determined by a large majority that, by the end of 2022 Germany will fully terminate the generation of power by German nuclear power plants (NPP). Accordingly, it adopted a second package to accelerate the steps towards energy transition. The second Energy Package, commonly known as the Energiewende, aims a fundamental transformation of the energy system of Germany. The main goal of the Energiewende is a low-carbon energy sector achieved by supporting renewable energy, grid expansion, and energy efficiency [13].

As a result of the termination of the eight NPPs, Germany moved from being a net energy exporter to a net importer for half a year [6]. The energy which was planned to be provided by the closed nuclear plants is to be compensated by the other sources of energy, so why not by natural gas? As nuclear capacity is phased-out, natural gas can promote an easy path to a low-carbon power sector.

Germany has large resources of hard coal and lignite. Hard-coal production and consumption in Germany is declining, but lignite production is successful, providing a major source of energy to the country. Germany has made a decision to phase-out subsidies for domestic production of hard coal and to decommission all hard coal mines by 2018. It is obvious that Germany needs a cleaner alternative to coal generation, if the government intends to meet its 2020 GHG emissions reduction target of 40% without much of its nuclear fleet.

In fact, natural gas can provide a spare source of electricity supply in the medium term. The role of natural gas in the electricity supply mix of the future will determine its significance for the Energiewende. As the electricity generated from renewable sources varies depending on weather conditions and season, natural gas-fired plants can play an important role in offsetting such fluctuations.

CONCLUDING REMARKS

External factors such as transforming the global gas market, the shale gas boom in North America, the political crisis in Ukraine, emergence of new pipeline projects, LNG projects development, increasing renewables and efficiency measures and other factors have affected the European natural gas market, including Germany and its future gas market development. The capacity lost by the withdrawal from nuclear energy must be replaced by additional power plant capacity. Gas plants may be needed to replace coal generation if Germany is to meet its further emissions reduction targets, as natural gas is more climate-friendly compared to other fossil fuels. As the electricity generated from renewable sources varies depending on weather conditions and season, natural gas-fired plants can play an important role in offsetting such fluctuations. All these facts show how important natural gas is for Germany. I see promotion of local gas production, greater access to global gas markets, strengthened bonds with potential new suppliers as important factors at Germany's current energy stage. Germany is very successful in diversification and expansion of its energy supply system in comparison with other countries, one of the main reasons of which could be the country's technological development. German gas infrastructure companies are expanding internationally, innovating and diversifying. In all cases gas in its role as a transitional fuel will continue to be important for the foreseeable future. Natural gas would be the bridge fuel into a sustainable energy future for Germany.

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NIGERIA

Mayowa Adejare
University of Ibadan
NIGERIA

Adewunmi Adekanmbi
University of Ibadan
NIGERIA

Adegbola Adekemi
University of Ibadan
NIGERIA

Fadekunayo Adeniyi
Quaint Global Energy Solutions Ltd
NIGERIA

Olatunji Adesiyan
University of Ibadan
NIGERIA

Richardson Adesuyi
University of Ibadan
NIGERIA

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University of Ibadan
NIGERIA

Aban Afghani
SAUDI ARABIA

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University of Ibadan
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Saudi Aramco
SAUDI ARABIA

Leena AlShohail
King Faisal Center for Research
SAUDI ARABIA

Fahad Al-Sulaiman
KFUPM
SAUDI ARABIA

Kingsley Amakiri
Emerald Energy Institute
NIGERIA

Felix Amieye Ofori
Energia Ltd
NIGERIA

Andreas Andreou
CYPRUS

Fredrick Ani
Emerald Energy Institute
NIGERIA

Olubiyi Anifalaje
University of Ibadan
NIGERIA

Abraham Atotse
Emeral Energy Institute
NIGERIA

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Solchaga Recio y Asociados
SPAIN

Agyro Avgoustaki
ESCP Europe Business School
UNITED KINGDOM

Oluwadamilola Ayanniyi
University of Ibadan
NIGERIA

Chigozie Valerie Azikiwe
Nigerian Elec Reg Comm
NIGERIA

Ayodele Babafemi
Emerald Energy Institute
NIGERIA

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Prosperia, d. o. o.
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HGA
USA

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University of Ibadan
NIGERIA

Olaide Dotun-Otunla
University of Ibadan
NIGERIA

Michael Doumpos
Technical University of Crete
GREECE

Philip Doyle
Reverve Energy
IRELAND

Adebayo Nurudeen Durodola
Centre for Petrol Energy Econ Law
NIGERIA

Lawrence Ebelebe
Emerald Energy Institute
NIGERIA

Aseimo Ebikena
University of Ibadan
NIGERIA

Winifred Egbeama
University of Ibadan
NIGERIA

Agbene Ejigah
Emerald Energy Institute
NIGERIA

Amaka Ejilofor
University of Ibadan
NIGERIA

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EGYPT

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NIGERIA

Etuk Eno-Obong
PPPRA
NIGERIA

David Enwere
Emerald Energy Institute
NIGERIA

Birol Erguven
Limak Energy
TURKEY

Samson Fadeyi
University of Ibadan
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Olasupo Fadinu
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Olusola Fatoki
University of Ibadan
NIGERIA

Carlos Finat
ACERA AG
CHILE

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Audencia Business School
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E Cube
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Paris 1 Panthéon Sorbonne
FRANCE

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Scheweitzer Engineering Lab
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Ted Hall
EOG Resources
USA

Usman Hariratu
University of Ibadan
NIGERIA

Marcus Hartley
Northern Economics Inc
USA

Adela Holasova
CVUT v Praze
CZECH REPUBLIC

Martin Holmsten
Energy Lawyer
FINLAND

Bolaji Ibrahim
University of Ibadan
NIGERIA

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University of Ibadan
NIGERIA

Chinyere Ikedi
University of Ibadan
NIGERIA

Elizabeth Ikpema
University of Ibadan
NIGERIA

Jeremiah Ishaya
Emerald Energy Institute
NIGERIA

Zubairu Ismaila
University of Ibadan
NIGERIA

Mbaeri Ijeoma Jacinta
Energy Comm of Nigeria
NIGERIA

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Ernst & Young s r o
CZECH REPUBLIC

Anietie Jeremiah
Emeral Energy Institute
NIGERIA

Argun Karacay
Ewe Holding
TURKEY

Faith Kayode
University of Ibadan
NIGERIA

Alfiya Kazikhanova
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PPPRA
NIGERIA

Erkin Kilinc
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TURKEY

Yalcin Kiroglu
Mars Energy
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Toluwalope Kolawole
University of Ibadan
NIGERIA

Kyriaki Kosmidou
Damaskinou Georgakou 3
GREECE

Andreas Koutsoulides
CYPRUS

Sharon Kow
Energy Market Company
SINGAPORE

Stepan Kratochvil
CVUT v Praze
CZECH REPUBLIC

Benjamin Kuba
Emerald Energy Institute
NIGERIA

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HK Univ of Science and Technology
HONG KONG

Folake Lawal
University of Ibadan
NIGERIA

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CEA
FRANCE

Anthony Livanios
Energy Stream CMG GmbH
GERMANY

Javier Lopez Prol
Wegener Ctr for Climate and Gobal
AUSTRIA

Nwobi Lucy
University of Ibadan
NIGERIA

Alexandra Maragkogianni
GREECE

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Ifo Institute
GERMANY

Naoko Matsuo
Inst for Env and Safety Studies
JAPAN

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Università di Bologna
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Ben Meiselman
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SPAIN

Olubukola Moronkola
University of Ibadan
NIGERIA

Obinna Muoh
PPPRA
NIGERIA

Yasmin Yashodha Narandaran
Sunway University
MALAYSIA

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Dauphine
FRANCE

Liliy Carol Nnabuife
University of Ibadan
NIGERIA

Chibuzor Nwabue
University of Ibadan
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University of Ibadan
NIGERIA

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University of Ibadan
NIGERIA

Rotimi Ogunmola
University of Ibadan
NIGERIA

Afolabi Ogunnaike
Wood Mackenzie
USA

F K Ohuche
Central Bank of Nigeria
NIGERIA

Lolo Ojaraida
Emerald Energy Institute
NIGERIA

Alochukwu Okoli
Emerald Energy Institute
NIGERIA

Emmanuel Okoro
NIGERIA

Abimbola Okunade
University of Ibadan
NIGERIA

Alo Oladapo
University of Ibadan
NIGERIA

Olatunde Olasunkanmi
University of Ibadan
NIGERIA

Oluwaseun Olorunfemi
University of Ibadan
NIGERIA

Job Abiodun Olorunshola
Central Bank of Nigeria
NIGERIA

Adrot Olubode
University of Ibadan
NIGERIA

Niyi Aluko Olubukola
University of Ibadan
NIGERIA

Bamgbala Olusola
University of Ibadan
NIGERIA

Fatunde Oluwafunmilade
University of Ibadan
NIGERIA

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Univeristy of Ibadan
NIGERIA

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University of Ibadan
NIGERIA

Ayansina Omolola
University of Ibadan
NIGERIA

Yewande Omoloye
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NIGERIA

Linda O'Mullane
AUSTRALIA

Odin Oroghene
Emerald Energy Institute
NIGERIA

Enetomhe Otsemobor
Lafarge Africa PLC
NIGERIA

Oluwagbohunmi Owolabi
University of Ibadan
NIGERIA

Adeyemi Adetunji Oyeleye
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Adewale Oyinlola
University of Ibadan
NIGERIA

George Papadakis
GREECE

Theodoros Papadopoulos
GREECE

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Ecofys Germany GmbH
GERMANY

Brian Payne
Chevron Hong Kong Ltd
HONG KONG

Sigit Perdana
Univ of Western Australia Business
AUSTRALIA

Kuroghefa Peregba
University of Ibadan
NIGERIA

Karlo Persolja
Borzen Power Mrkt Op d o o
SLOVENIA

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Ogbuji Reginald
University of Ibadan
NIGERIA

David Reiner
Univ of Cambridge
UNITED KINGDOM

Ricardo Renedo Williams
Budapest Univ of Tech and Econ
SPAIN

Peter Roscoe
Climate Change Economics Ltd
UNITED KINGDOM

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PPPRA
NIGERIA

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University of Ibadan
NIGERIA

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University of Ibadan
NIGERIA

Joshua Sokoya
University of Ibadan
NIGERIA

John Sorde
Emerald Energy Institute
NIGERIA

Manolis Souliotis
Kanari and Eleftheriou Venizelou 1
GREECE

Spyros Spyrou
GREECE

Colin Stonehouse
Ames Associates Pty Ltd
AUSTRALIA

Sherzod Taschpulatov
CVUT v Praze
CZECH REPUBLIC

Fabunmi Temitoyosi
University of Ibadan
NIGERIA

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University of Ibadan
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GREECE

Dimitris Tsoukakis
GREECE

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University of Ibadan
NIGERIA

Udeme Umoren
Emerald Energy Institute
NIGERIA

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University of Ibadan
NIGERIA

Lukman Wahab
University of Ibadan
NIGERIA

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RISC Advisory
UNITED KINGDOM

Jacob Wellman
University of Bristol
UNITED KINGDOM

Hakan Yilmazkuday
FIU Dept of Economics
USA

Andreja Zelenic Marinic
Elektro Maribor d.d.
SLOVENIA

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IFP School
FRANCE

Yu Peng Zhang
China Univ of Mining and Tech
CHINA

Constantin Zopounidis
Technical University of Crete
GREECE

Mark B. Lively, a deeply-experienced consulting engineer to the energy industries, and a Member and long-time officer with the National Capital Area Chapter of the USAEE, died suddenly at his home in Gaithersburg, Maryland, on Thursday, March 3rd. Mark was well known to virtually every member of the NCAC over the last 25 years as he seldom missed a monthly luncheon, collected the luncheon fees in his role as so-called "Treasurer-for-Life" for more than a decade, and was always ready to engage with other members on a wide range of substantive energy and economic issues. He will be sorely missed.

Mark was a 1969 graduate of the Massachusetts Institute of Technology with a BS in Electric Engineering, and obtained a Masters Degree in Industrial Management in 1971, also from MIT. After five years with American Electric Power, and 15 years with Ernst & Young Utilities Consulting, Mark established an independent consulting practice in 1992 through which he offered expert advice, testimony, and analysis to a host of major clients around the world. He specialized in electricity and gas utility rate design modelling and cost-of-service analysis. In addition to his constant and active participation as a member of the NCAC, Mark was also a member of the Institute of Electrical and Electronics Engineers, and Sigma Xi, the Scientific Research Society. His creative approach to energy economics was reflected in more than seventy-five published articles and filed testimonies. His warm approach to his many friends and unselfish willingness to take on any task that needed to be done helped to set a tone within the NCAC that led to the organization's remarkable recent growth and success, and seems likely to survive him for many years to come.

Mark leaves his wife Tracy Gross Lively, two sons and a daughter, and four grandchildren.

Slovenian Association holds Second Meeting

Slovenian Association for Energy Economics (SAEE) had its second meeting on 25th of January, 2016. It was held In memoriam of Ms Irena Praček, long year President of Slovenian energy Agency, that has passed away suddenly and much too soon in the end of the year 2015. Ms Praček was also a member of SAEE.

Due to its dedication to Ms Praček and also because of the guest speakers from IAEE that were participating, this meeting bears a significant impact for all the members and other people that were involved. After the introductory remarks and concluding some formalities Ms Jezernik, the President of SAEE and Mr Kumbaroğlu, the President of IAEE opened the main part of the meeting. At that point SAEE was awarded a plaque as an official Affiliate of IAEE, the round thirtieth Affiliate. SAEE prides itself on being a member of an IAEE family, especially when taking into account all the dedication and support received in the process of forming – from all the founding leaders of SAEE, Energy Chamber of Slovenia, other participant of the energy sector in Slovenia and the IAEE itself.

The SAEE was proud that professor dr. Gürkan Kumbaroğlu, President of IAEE and the President of Turkish Affiliate of IAEE, professor dr. Georg Erdmann, Past President of IAEE and the president of German Affiliate of IAEE, professor dr. Carlo Andrea Bollino, Past President of IAEE and the president of Italian Affiliate of IAEE and Mr. David Williams, Executive Director of IAEE all responded the invitation to participate on the meeting. Their long year experience and knowledge promised an interesting event and for that reason, also other people from energy field in Slovenia were invited to the event.

The main theme began with the topic The Role of energy industry in EU and the World, presented by Mr Erdmann. The presentation was complemented with the presentation of Mr Martinec, former president of Energy Industry Chamber of Slovenia, on the role of Energy sector in Slovenian economy.

The presentations continued with Mr Bollino and his lecture on the Cost Assessments of European environmental policy.

The speakers did not leave nearly 40 present listeners empty handed, as they presented interesting and up to date information and proceeded into leading open discussions with the audience.

As the meeting was ending all the guest speaker collaborated in round-table discussion on good practices of IAEE Affiliates, trying to widen the options and opportunities for Slovenian Affiliate.

If we summarize the responses, we can conclude that the meeting meet all the expectations of the participants and presents a new momentum for further activities of the SAEE.

Tina Strukelj
General Secretary

From the left: Mr. Williams, Dr. Kumbaroğlu, Ms. Štrukelj, Ms. Jezernik, Mr. Martinec, Dr. Bollino, Dr. Erdmann.

Gurkan Kumbaroğlu, President of IAEE, presenting the Certificate of Affiliate to the President of SAEE, Ms. Jezernik,


5TH IAEE ASIAN CONFERENCE
MEETING ASIA'S ENERGY CHALLENGES
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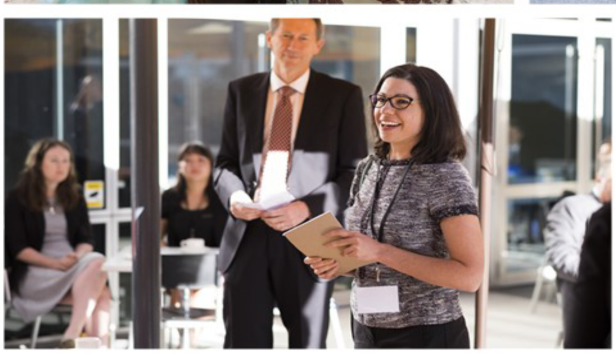

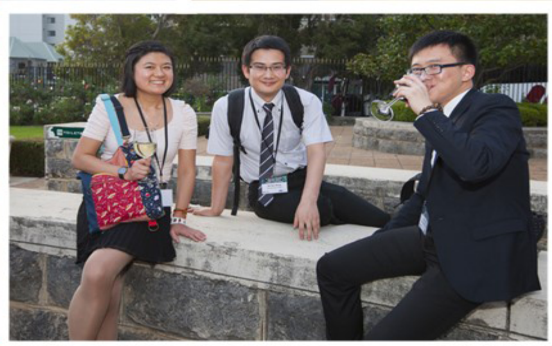


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The 5th IAEE Asian Conference

The 5th IAEE Asian Conference was held at The University of Western Australia Business School from 14-17 February 2016. The theme was "Meeting Asia's Energy Challenges." Over 182 delegates registered to attend the conference sessions, while many additional people attended ancillary conference events. In particular, the Breakfast by the Bay panel discussion on electricity industry reform attracted many individuals from the Perth business, government and consular community.

More than 55 students attended from around the world. Overall around 70% of attendees were from outside Australia, around 10% from other Australian states and the remaining 10% from Western Australia.

The conference was generously supported by 13 organisations and firms. The major sponsors were EY, UBS and Woodside. Other sponsors were Alinta Energy, ATCO Australia, Broadspectrum, City of Perth, UWA Energy and Minerals Institute, Hogan Lovells, Monadelphous, Paladin Energy, Perth Energy, and Shell.

Plenary sessions focused on some of the implications of forecasted substantial energy demand growth in Asia over coming decades. There is much discussion of the role of China in this respect, but conference attendees also heard about the potential for substantial demand growth in India and Southeast Asia. Other topics covered included possible changes in the Asian market for LNG, disruption in electricity markets as a result of technological change, financing infrastructure investments in the energy industry in Asia, the future of nuclear power, energy taxation and subsidies, geopolitical implications of growth in Asian energy demand and how international political developments could affect Asian energy demand growth, and some of the environmental implications of growing Asian energy consumption and use. Conference delegates also heard a presentation on the then newly-released BP Energy Outlook for 2016, and a very thoughtful address from the Minister for Energy in the West Australian government on the interplay between economic analysis and real-world policy formulation.

One of the themes of the conference was the difficulty in predicting where the future energy market was heading. Opinions were divergent on a range of topics. Throughout the conference, there was debate over whether an effective Asian LNG hub would be developed, and if so, where. While the increasing role of spot trades was recognised, some doubted that an effective hub would be developed within the next ten years. At the same time, others were confident that a hub would emerge in Singapore, Tokyo or Shanghai.

There was also debate over the future price of gas in the Asian region. Some saw an oversupply of gas with the commencement of new LNG facilities, including gas that was not yet contracted by an end user. Others saw the price recovering somewhat in the medium term.

A student was assigned to each room where Plenary or Concurrent sessions were held to make sure that the AV equipment worked appropriately and to ensure that speakers stuck to their allotted times. We invited these students to mention the highlights of the presentations that took place in their room. We received responses from four of them.

Sigit Perdana, who is originally from Indonesia, said that his favourite presentations were about the 35 GW Electricity Project in Indonesia and Energy Subsidy Reform in Indonesia, both given by Dr Agung Wicaksono. He found the presentation on the 35 GW Electricity Project very timely and relevant in the context of developing countries, mostly in Asia. The presentation focused on issues of financing and developing infrastructure and encouraging investment while promoting the use of alternative energy sources.

"I think this presentation highlights the fact that developing countries, through the example of Indonesia, will still be heavily dependent on non-renewable energy for raising the proportion of the population with access to electricity," Sigit said. Sigit also found the discussion of energy subsidy reform very informative. The presentation did not only inform about the phase out of subsidies. It also discussed how the Indonesian government reallocated the funds to stimulate renewable energy production and utilisation.

Sigit emphasised that he found these presentations interesting not purely because he was Indonesian and his own research is about Indonesia. "The speaker spoke very clearly, supported his comments with informative slides, and was really involved with the audience," he said.

Xing Shi said that his favourite speaker was Professor Peter Newman. His topic was "disruptive innovation in energy" which combined energy with Xing's research interest in innovation. Xing commented that, "I do believe that disruptive innovation in energy will reshape the world substantially, both economically and politically."

Vanessa Juliana said that she really enjoyed the closing plenary session the most. She said, in particular, that having an industry perspective on the current energy market was very informative to her.

Kelly Neill said her favourite presentation was by Ky Cao, Managing Director of Perth Energy. He spoke about problems in Western Australia's electricity market. He pointed out that government intervention is extensive. The main electricity supplier, Synergy, was created by the merger of two government-owned utility companies, and continues to receive government subsidies. In Ky Cao's judgment, Synergy is operating inefficiently, leading to higher electricity costs in WA.

Kelly added that the plenary session on nuclear power also was great. "We heard about Australia's potential as a uranium producer, as well as shifting public opinions in the country," Kelly said. "We also learned about challenges in Japan, one of the major consumers in the region, and about developments in nuclear technology and new installations in China."

CALENDAR

March 31 - April 01 2016, Argus Media China Russia Oil & Gas 2016 at The Regent Beijing, 99 Jinbao Street, Dongcheng District, Beijing, 100005, China. Contact: Phone: +65 6496 9922, Email: yuanchang.yu@argusmedia.com, URL: http://atnd.it/40416-0

04-08 April 2016, Energy Business Management Course at to be determined. Contact: Phone: +31 (0) 88 1166837, Fax: +31 (0) 88 1166899, Email:bakker@energydelta.nl, URL: https://www.energydelta.org/mainmenu/executive-education/executive-master-programmes/executive-master-of-gas-business-management

05-07 April 2016, South-East European Exhibition on Energy Efficiency and Renewable Energy at IEC,Tsarigradsko shousse, Sofia, 1000, Bulgaria. Contact: Phone: 0035932960011, Email: mk@viaexpo.com, URL: http://atnd.it/32002-0

05-07 April 2016, Argus Biomass 2016 at Hilton Park Lane, 22 Park Lane, London, W1K 1BE, United Kingdom. Contact: Phone: 02077804352, Email:tomas.bavington@argusmedia.com, URL: http://atnd.it/42194-0

05-07 April 2016, South-East European Forum on EE, Renewable Energy and Smart Cities at IEC, Tsarigradsko shousse, Sofia, 1000, Bulgaria. Contact: Phone: 0035932512900, Email: office@viaexpo.com, URL: http://atnd.it/39856-0

11-13 April 2016, International SAP Conference for Utilities at World Forum, Churchillplein 10, The Hague, 2517 JW, Netherlands. Contact: Phone: +4401212003810, Email: l.jersova@tacook.com, URL: http://atnd.it/45357-4

11-13 April 2016, 8th Annual Wind O&M Dallas 2016 at Westing Galleria, 13340 Dallas Parkway, Dallas, TX, 75240, United States. Contact: Phone: UK, Email: 02073757565, URL: http://atnd.it/46404-0

11-13 April 2016, International SAP Conference for Utilities 2016 at The Hague, Netherlands. Contact: Phone: +441212003810, Email:info@tacook.com, URL: http://bit.ly/1J1WLSb

12-14 April 2016, International SAP Conference for Oil and Gas 2016 at The Hague, Netherlands. Contact: Phone: +441212003810, Email:info@tacook.com, URL: http://bit.ly/1TZUho2

12-14 April 2016, Sustainable Nuclear Energy Conference at Nottingham, United Kingdom. Contact: Phone: +4401788534489, Email:snec@icheme.org, URL: http://atnd.it/28214-0

12-14 April 2016, International SAP Conference for Oil and Gas 2016 at World Forum, Churchillplein 10, The Hague, 2517 JW, Netherlands. Contact: Phone: +4401212003810, Email: l.jersova@tacook.com, URL: http://atnd.it/45115-4

13-14 April 2016, Power and Electricity World Asia 2016 at Pullman Central Park, Jakarta, Indonesia, Central Park, Jl. Letjen. S. Parman Kav. 28, DKI Jakarta 11470, Indonesia. Contact: Phone: 65 6322 2769, Email: mildred.ang@terrapinn.com, URL: http://atnd.it/36414-0

14-15 April 2016, International SMR and Advanced Reactor Summit at Twelve Hotel and Residences Atlantic Station, 361 17th Street NW, Atlanta, GA 30363, United States. *Contact: Phone: 020 7375 7528, Email: jfurness@nuclearenergyinsider.com, URL: http://atnd.it/46401-0*

18-20 April 2016, Platts 31st Annual Global Power Markets Conference at Wynn Las Vegas, 3131 Las Vegas Blvd, South, Las Vegas, NV, 89109, United States. Contact: Phone: 857-383-5733, Email: christine.benners@platts.com, URL: http://atnd.it/41671-0

18-20 April 2016, Master Class LNG Industry at Barcelona, Spain. Contact: **Phone: +31 (0) 88 1166827, Fax: +31 (0) 88 1166899, Email:portena**@energydelta.nl, URL: https://www.energydelta.org/mainmenu/executive-education/specific-programmes/master-class-lng-industry-lng-training-course

18-22 April 2016, International Gas Value Chain Course at Amsterdam, The Netherlands. Contact: Phone: +31 (0) 88 1166826, Fax: +31 (0) 88 1166899, Email: sanders@energydelta.nl, URL: https://www.energydelta.org/mainmenu/executive-education/introduction-programmes/international-gas-value-chain

19-20 April 2016, Solar & Off-Grid Renewables West Africa 2016 at TBC, Accra, Ghana. Contact: Phone: +44 (0) 207 871 0122, Email:marketing@solarenergyevents.com, URL: http://atnd.it/40286-0

24-27 April 2016, ICEED 43rd International Energy Confernce (Invitation Only) at Boulder, CO, USA. Contact: Phone: 303-442-4014, Fax: 303-442-4014, Email: iceed@colorado.edu, URL: www.iceed.org

25-26 April 2016, Smart Water Systems at Holiday Inn Kensington Forum, 97 Cromwell Road, London, SW7 4DN, United Kingdom. Contact: Phone: +44 (0) 20 7827 6140, Email: vtrinh@smi-online.co.uk, URL: http://atnd.it/42159-0

26-28 April 2016, Clean Energy Summit at Twickenham Stadium, Whitton Rd, London, TW2 7BA, United Kingdom. Contact: Phone: +4402078710122, Email: jandrews@solarmedia.co.uk, URL: http://atnd.it/46066-0

27-28 April 2016, Argus Asian Petroleum Coke 2016 at Courtyard by Marriott, Mumbai, Opposite Sangam BIG Cinemas, CTS 215, Andheri - Kurla Rd, Hanuman Nagar, Andheri East, Mumbai, 40. Contact: Phone: +6564969977, Email: ashrafe.hanifar@argusmedia.com, URL: http://atnd.it/43373-1

27-28 April 2016, Oil & Gas Supply Chain Compliance Houston 2016 at Houston Marriott West Loop By The Galleria, 1750 West Loop South, Houston, 77027, United States. Contact: Phone: +4402031418700, Email: info@hansonwade.com, URL: http://atnd.it/41878-0

28-28 April 2016, Energy Storage Summit at Twickenham Stadium, Whitton Rd, Twickenham, TW2 7BA, UK. Contact: Phone: 207 8710 1257, Email:cgonthier@solarmedia.co.uk, URL: http://atnd.it/45607-0

09-11 May 2016, Argus Rio Oil Conference 2016 at Sofitel Rio de Janeiro Copacabana, Avenida Atlântica, 4240, Copacabana, Rio de Janeiro, CEP 22070-00, Brazil. Contact: Phone: + 1 713 360-7586, Email: giuliana.braga@argusmedia.com, URL: http://atnd.it/46331-1

09-11 May 2016, Argus Rio Oil Conference 2016 at Sofitel Rio de Janeiro Copacabana, Avenida Atlântica, 4240, Copacabana, Rio de Janeiro, CEP 22070-00, Brazil. Contact: Phone: + 17133607586, Email: giuliana.braga@argusmedia.com, URL: http://atnd.it/46331-1

10-11 May 2016, Argus Europe Bitumen 2016 at Fairmont Ray Juan Carlos Barcelona, Av. Diagonal, 661-671, Barcelona, 08028, Spain. Contact: Phone: 02077804352, Email: tomas.bavington@argusmedia.com, URL: http://atnd.it/42191-0

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