STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

AMEREN ILLINOIS COMPANY	**)**	
d/b/a Ameren Illinois,	**)**	
Petitioner	**)**	
	)	**Docket No. 12-0244**
Smart Grid Advanced Metering	**)**	
Infrastructure Deployment Plan	**)**	

DIRECT TESTIMONY ON REHEARING OF COLIN MEEHAN ON BEHALF OF THE CITIZENS UTILITY BOARD AND THE ENVIRONMENTAL LAW AND POLICY CENTER

CUB-ELPC Exhibit 3.0RH

August 24, 2012

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. Please state your name and business address.

A. My name is Colin Meehan and my business address is 301 Congress Avenue, Suite 1300, Austin Texas, 78701.

Q. By whom are you employed?

A. I am employed by the Environmental Defense Fund ("EDF") as a Clean Energy Analyst.

Q. What does EDF do?

A. EDF is a non-profit organization whose mission is to preserve the natural systems on which all life depends. Guided by science and economics, EDF strives to find practical and lasting solutions to the most serious environmental problems. Consistent with EDF's general strategy, I work with key stakeholders to set specific environmental performance criteria for smart grid deployment and develop regulatory reforms and new electric sector business models to create market opportunities for entrepreneurs with innovative energy technologies and services and transform traditionally conservative utilities into agents of change.

Q. Where is EDF currently engaged in smart grid design and deployment activities?

A. As my colleague, Miriam Horn stated in her testimony during the initial proceeding on this case, EDF is engaged in a number of the leading smart grid deployments across the nation, beyond Illinois. In Texas, EDF is a founding partner of the research consortium Pecan Street Inc., which oversees the nation's most comprehensive smart grid pilot project, where we have been deeply involved in the design of Austin's future energy system and the intensive analysis of those elements that have already gone online. In addition, our Texas work includes efforts to

change market rules to allow more access to electric markets for distributed resources such as demand response and distributed renewable energy. In Austin we have been working with the local utility (the 9th largest municipal utility in the country) for several years to meet aggressive energy efficiency and renewable energy goals established in its long-term plan. Our work currently includes helping them implement an innovative "Value of Solar" rate that compensates distributed solar installations at a level that includes their value in offsetting grid management and infrastructure costs in addition to the conventional avoided costs.

The EDF energy team has also brought performance-based ratemaking to Duke's service territory in North Carolina, through our work to make the Save-a-Watt program a reality. In California, where Investor Owned Utilities ("IOUs") statewide are obligated to deploy smart grid technology under a 2009 statute, EDF helped shape the California Public Service Commission's ("CPUC") planning requirements; designed an Evaluation Framework for Smart Grid Deployment Plans[1] (the "EDF Scorecard") which CPUC regulators used to evaluate the California utilities' plans; and has been tasked by the Commission to work with utilities and other stakeholders to develop stronger metrics for smart grid success. In addition, EDF has been involved in transmission planning and/or market design in the California Independent System Operator ("CAISO"), the Electric Reliability Council of Texas ("ERCOT") and has contributed to proceedings relevant to the adoption of advanced grid technology and the integration of intermittent renewables at the Federal Energy Regulatory Commission.

[1] Herter, O'Connor, Navarro, *Evaluation Framework for Smart Grid Deployment Plans: A Systematic Approach for Assessing Plans to Benefit Customers and the Environment* (June 2011), available at http://www.edf.org/sites/default/files/smart-grid-evaluation-framework.pdf

Q. How are you involved in the work currently going on in Texas for EDF?

A. I am actively involved in the design as well as the deployment and resulting analysis of most of the current smart grid activities in Texas. This includes developing and analyzing economic, policy and reliability implications of various smart grid strategies in order to identify opportunities to maximize both economic and environmental benefits.

Q. What is your role in the energy sector in Texas?

A. At a state level I serve on the Board of Directors of the Texas Renewable Energy Industries Association and lead the coordination among NGOs, the clean tech sector and other stakeholders around renewable energy policy at the state Legislature. In addition I am a Research Associate in the Webber Energy Group at the University of Texas at Austin, where I specialize in emissions analysis of wholesale power markets and the connection between bulk power emissions, renewable energy and smart grid deployments. I have published papers on this topic in the Proceedings of the American Society of Mechanical Engineers and the U.S. Association of Energy Economists. In Austin I serve as vice chair of the City of Austin's Local Solar Advisory Committee, which is tasked with providing the Austin City Council with recommendations to enable and accelerate the deployment of distributed solar generation throughout the city. I have also served on Austin Energy's Public Involvement Committee, which provided recommendations to the utility for their rate restructuring process.

Q. Have you ever provided expert testimony before a legislative body?

A. Yes. I have provided testimony multiple times before the Texas legislature on smart grid topics including renewable portfolio standards ("RPS"), solar rebate programs,

distributed solar technologies, energy storage regulations, demand response, building efficiency and energy conservation.

Q. Have you ever provided expert testimony before a state Public Utilities Commission?

A. Yes. I have provided testimony multiple times before the Texas Public Utilities Commission on a range of smart grid and renewable energy topics, including resource adequacy, demand response, RPS, energy storage, smart grid pilot projects, distributed renewable energy and wholesale electric markets.

Q. Have you participated in any other industry groups relating to the smart grid?

A. Yes. I have also worked with ERCOT in several stakeholder working groups including the Long Term Study Task Force and the Demand Side Working Group.

Q. Please describe your relevant work experience.

A. Before joining EDF, I worked as an energy settlement analyst and nodal market implementation expert for the Lower Colorado River Authority, which provides wholesale power and demand response services to rural co-operatives and small municipal utilities through central Texas. I have also worked as a wholesale energy analyst for ICF International, where I analyzed the economic impact of renewable energy and energy emissions policies such as the Regional Greenhouse Gas Initiative. My biography is attached to this testimony as CUB-ELPC Exhibit 3.1 RH.

Q. Why does EDF, a non-profit organization, regard smart grid deployment as a policy priority?

A. In the coming decades, the U.S. electric industry is poised to invest trillions of dollars in technology that will transform our electric system from a 19th century network to an integrated, digital, automated 21st century network with radically different capabilities. Those investments have the power to transform the way we generate and consume electricity, moving us from a reliance on fossil fuels to clean,

renewable, domestic energy resources. We view such a transformation as essential to mitigate warming.

The smart grid is an enabler. Incorporating information technologies into the grid can enable enormous efficiencies across the entire system, real-time management of demand, and the interconnection of far more variable renewable and distributed generation, storage and plug-in electric vehicles ("EVs"), thus reducing costs and vulnerability to volatile fuel prices while improving reliability and empowering customers to be market participants, earning new revenues from selling both supply and demand into energy markets.

Smart grid investments, however, must be intentionally planned with attention to what is possible – a low-carbon, efficient, flexible, reliable, cost-effective, clean energy system that is open to innovation. EDF is engaged in smart grid because good smart grid policy is essential to the emergence of a clean, secure energy system.

Q. How can these investments support broader Illinois energy policy?

A. Advanced metering infrastructure ("AMI") deployments cannot be thought of in a vacuum. Instead, they are part of a broader smart grid and, more generally, energy strategy for the impacted region. By deploying smart meters in a thoughtful, strategic manner, it is possible to unlock a range of important economic and environmental benefits.

Q. Are there specific policies that this deployment will benefit?

A. The RPS provides guidance on renewable energy generation in Illinois. The Illinois Energy Efficiency Portfolio standards also sets goals to reduce energy delivered and peak demand. To meet these mandates, there will need to be a significant increase in the construction of renewable resources in the State.

Q. Can you please describe how you anticipate a strong AMI roll-out would impact the RPS?

A. AMI, combined with the right pricing and regulatory policies, can deliver significant benefits to customers. Effective deployment increases the transparency and interoperability of the overall grid system. In addition, an effective deployment, specifically in the Ameren service territory, will unlock vast untapped demand response potential in the heavy manufacturing and agricultural sectors, prevalent in Southern Illinois.

Q. In what capacity are you testifying in this proceeding?

A. I am testifying as a witness for the Citizens Utility Board ("CUB") and the Environmental Law and Policy Center ("ELPC"), because CUB, ELPC and EDF share a common goal: to maximize the consumer and environmental benefits from the deployment of new energy infrastructure, such as the investments that Ameren Illinois ("Ameren") described in the revised Deployment Plan (the "Ameren Plan"), filed for rehearing on June 28, 2012.

Q. Why are you testifying instead of Ms. Horn, who testified in the previous hearing?

A. Ms. Horn was unable to travel to Springfield for medical reasons. EDF, and its partners CUB and ELPC, feel strongly that this is an important proceeding to ensure that the Advanced Metering Infrastructure ("AMI") investment contemplated in the proposed plan maximizes the benefits to both consumers and the environment.

Q. Were you familiar with this case and the Ameren plan prior to being asked to participate as an expert in this case?

A. Yes. The EDF energy team works collaboratively, and I have been actively involved and engaged in the important work going on in Illinois.

Q. What documents have you reviewed in preparing this testimony?

A. I've reviewed the testimony filed by Ameren, including both the original Advanced AMI plan (the "Original Ameren Plan") and the subsequently amended Ameren Plan. In addition, I have reviewed CUB/ELPC's testimony filed in the original hearing; the final order in 12-0089 and CUB's testimony in that case, Ms. Horn's testimony, the ComEd AMI Plan, and the final order in 12-0298, including ComEd's AMI Plan; and Mr. Chris Thomas's testimony and the final order in 11-0772, the ComEd performance metrics case. I have also reviewed Mr. Thomas' testimony that is being submitted as part of this re-hearing.

Q. What is your conclusion?

A. The Ameren Plan expands little on the Original Plan and does not provide the necessary details to ensure that projected benefits from the AMI deployment will be realized and that these benefits will outweigh the costs of the deployment. Specifically, the Ameren Plan does not provide substantive detail in a number of key areas necessary to determine the ultimate effectiveness of the deployment.

Q. What are some of those key areas?

A. One is the Ameren Plan's cost benefit analyses for energy efficiency measures, demand-response activities, and the enabling of greater penetration of alternative fuel vehicles. A second is how consumer benefits from smart grid AMI will be enhanced. A third is the Ameren Plan's enumeration of milestones and metrics for the purposes of creating a roadmap to successful AMI deployment. This is not an exhaustive list of areas where the Ameren Plan lacks detail.

II. THE AMEREN PLAN PROVIDES INSUFFICIENT DETAIL TO DEMONSTRATE BENEFITS AND DOES NOT INCORPORATE THE MILESTONES AND METRICS NEEDED TO CREATE A PATH TO SUCCESSFUL DEPLOYMENT

Q. Does the Ameren Plan adequately demonstrate the benefits of it energy efficiency, demand-response and alternative fuel vehicle measures?

A. No. In Dr. Faruqui's testimony, he identifies a $3 million incremental investment in Demand Response, with an expected benefit of $406 million. However, he does not, nor does the Ameren Plan, detail the utility actions that will be taken to realize this return through the tools and technologies made available by the deployment of AMI.

Dr. Faruqui also identifies $24 million of benefit from energy efficiency, with a $2 million incremental investment. Again, however, there is no explanation in the plan how Ameren will realize these benefits through the deployment.

In addition, Dr. Faruqui identifies $151 million in benefits from the deployment of electric vehicles, with an incremental cost of $13 million. Dr. Faruqui also includes an additional $11 million in benefits from carbon reductions connected with the reduced vehicle emissions from the use of electric vehicles. As above, there is little information on how Ameren will ensure that these benefits are realized by its customers through the AMI deployment.

Q. Does the Ameren Plan include any additional funds to ensure that consumer benefits are realized?

A. Yes. The revised Ameren Plan includes an additional $23 million in costs for customer engagement and to support customers in realizing these benefits. However, there is no detail as to how Ameren will decide how to spend these dollars, what types of organizations they will contract with for that outreach, or how they'll make decisions on funds deployment..

Q. Does EDF disagree with Dr. Faruqui's assertions that smart grid can potentially be beneficial?

A. No. EDF has worked with Dr. Faruqui on a number of analyses relating to the potential benefits of smart grid deployments and the dynamic pricing they enable. For example, Ms. Horn referenced Dr. Faruqui's *"Tao of Smart Grid"* as an important analysis of the benefits that can be derived from a well- planned smart grid deployment.

Where Ameren's submission falls short is in its lack of details on how the plan, and the attendant benefits, will be realized specifically in the Ameren service territory. Without that substantive detail, it is impossible to determine whether the enormous potential benefits will actually be realized.

Q. Does the Ameren Plan provide annual milestones that are sufficient to development a roadmap to a successful deployment?

A. No. The Ameren Plan states that several of its significant milestones and timelines remain unknown.[2] Then, as discussed in the previous testimony of Miriam Horn, the Ameren Plan enumerates a list of milestones that are not tied to a goal, date or timeline.[3] For example, one of the Ameren Plan milestones is the "number of customers signed up for peak time rebate tariff."[4] It does not, however, provide an ultimate goal of how many customers should be signed up for the tariff, nor does it detail a timeline to arrive at that goal. It is hard to see how, without annual goals, Ameren's required yearly report will track and quantify progress.

Q. What are the benefits of including additional metrics in a plan?

[2] *See* AIC Ex. 2.2RH at Section 5.3.3.
[3] *See* AIC Ex. 2.2RH at Section 7.3, listing that its milestones will be comprised of: (1) percent of support system installed, (2) percent of 2-way network installed, (3) number and percent of AMI meters installed, (4) number of customers able to access the Web Portal and Web Portal usage statistics, (5) number of customers eligible for peak time rebate tariff, (6) number of customers signed up for peak time rebate tariff and (7) number of customers on PSP, RTP, or other real time rates.
[4] *Id.*

A. The current plan includes only the statutorily-required metrics from EIMA. However, as demonstrated in California and also in the recent Commonwealth Edison ("ComEd") filing, the inclusion of additional metrics or trackers increases the transparency of the implementation and provides key insights into its successes and required adjustments over time. By measuring progress continuously, Ameren, the ICC and stakeholders will be able to quickly identify challenges and leverage analytical frameworks to improve year by year decision-making.

Q. What metrics and trackers do you believe would lead to significant benefits in this case?

A. I believe that the trackers that were included in the final ComEd filing provide a strong foundation to evaluate the efficacy of the deployment. Through analysis, and a concurrent continuous improvement process, the likelihood of delivering the expected benefits are significantly increased. (A list of the metrics included in the final ComEd filing, with revisions to reflect Ameren's Plan, is attached to the testimony of Chris Thomas as CUB-ELPC Exhibit 2.2 RH.)

Q. Why is a well-defined plan important to increasing the likelihood of delivering the benefits associated with an AMI deployment?

A. An appropriately implemented AMI deployment is an important factor in unlocking the broader benefits of smart grid for electricity consumers. However, it does not provide those benefits in and of itself. Instead, it is vital that the AMI deployment plan be part of a broader smart grid strategy and roadmap that lays out both the expected benefits for consumers and the path the utility is going to take, including investments and activities across its network and business, to ensure those benefits are realized.

Q. Does the Ameren Plan include this type of roadmap?

A. No. The Ameren Plan does include information on the development of a Project

Management Office that has specific functionalities, but does not provide a detailed roadmap that links actions and outcomes, all targeted at delivering on the broader promise of smart grid for its customers. Without this type of roadmap, it will be very difficult to ensure that the benefits that are promised can actually be delivered.

III. LEVERAGING LESSONS LEARNED FROM THE CALIFORNIA SMART GRID DEPLOYMENTS

Q. Have you analyzed utility AMI deployment plans before?

A. Yes. In Texas I have worked with the transmission and distribution utilities in the competitive market footprint of ERCOT to develop plans and support customer outreach during and after AMI deployment. I have also worked with Austin Energy, the University of Texas and Pecan Street Inc. on the deployment of AMI and other metering equipment used to monitor home energy usage within the Mueller Energy Internet Demonstration Project. Outside of Texas, I worked on the EDF team that engaged with both the CPUC and California IOUs to develop smart grid deployment plans, including standards for identifying and quantifying the environmental benefits of smart grid. I also worked on the EDF team that developed the EDF Scorecard. In addition, I remain engaged in the process by which EDF is helping to develop environmental metrics before the CPUC.

Q. Why was EDF an appropriate party to evaluate AMI deployment plans to maximize environmental benefit?

A. As an independent nonprofit organization working towards environmental outcomes, EDF could provide an objective viewpoint. EDF also possessed the requisite technical expertise in energy policy, prior smart grid deployments and data analysis to engage the stakeholders.

Q. How did EDF engage with utilities in California to develop their smart grid

deployment plans?

A. California Senate Bill ("SB") 17 required that California IOUs submit Smart Grid Deployment Plans by July 1, 2011.[5] Since early 2010, EDF, through mutual agreement, have worked closely with San Diego Gas & Electric ("SDG&E") staff to embed environmental considerations throughout its smart grid deployment plan and to develop a methodology to determine the associated costs and benefits – including emissions reductions. EDF helped SDG&E to improve their plan's cost-benefit analyses, evaluating and helping to improve SDG&E's methodologies before the PUC.

Q. How did EDF specifically improve SDG&E's cost-benefit analysis?

A. EDF worked with SDG&E to estimate the benefits of smart grid. This included the benefits of avoided emissions of greenhouse gases, sulfur dioxide and particulate matter from its proposed smart grid enabled programs and technologies. EDF and SDG&E considered peak load reduction, load shifting, integration and management of centralized and distributed renewable generation to meet the California 33% renewable portfolio standard ("CA RPS"), and integration of electric vehicles.

Q. Did EDF's engagement with SDG&E's cost-benefit analysis add value to the analysis of how smart grid benefits are realized?

A. Yes. EDF was able to leverage the knowledge gained in its work with SDG&E to distinguish benefits from smart grid investments from those derived from other utility programs, such as meeting the CA RPS or energy efficiency programmatic goals. To avoid double-counting of benefits, we drew on existing research on what the smart grid makes viable. For example, CAISO estimates that a 20% CA RPS is attainable without a smart grid, but a 33% CA RPS will require a smart network to

[5] See SB 17 (Padilla, 2008).

manage intermittency and multidirectional power flows. With this objective assessment, SDG&E ascribed a CA RPS benefit to smart grid equal to the difference between the 20% and 33% RPS; that is, the benefit associated with smart grid is achievement of an additional 13% CA RPS.

Q. What was learned about how the environmental benefits of EV are calculated in the California context?

A. In the case of electric EV integration facilitated by smart grid, emissions benefits were calculated as the avoided gasoline combustion emissions associated with the conventional cars EVs displace, taking account of fleet average fuel efficiency changes due to California-specific and federal standards. The growth in utility grid-based emissions from the EV load was netted out of the benefit calculation.

Q. How did this initial collaboration between EDF and SDG&E add value to the smart grid deployment process?

A. As discussed above, EDF's initial engagement with SDG&E yielded new techniques for demonstrating the benefits of smart grid deployment. These new techniques were of immediate practical value to the utilities as they developed their plans for filing with the CPUC. The collaboration also increased all of the parties' understanding of how calculations involving specific technologies, like EV discussed above, can take changing state and federal standards into account. These discoveries led EDF to develop the scorecard framework it subsequently used to evaluate utility smart grid plans.

Q. What is the EDF Scorecard that was used to evaluate smart grid plans in California?

A. The EDF Scorecard is an evaluative framework designed to assess how well smart grid deployment plans would meet core purposes identified by the CPUC, and is adaptable to other jurisdictions. These purposes included that plans must consider

costs and benefits across the entire system and provide evidence that smart grid investments are reasonable. A deployment plan should also follow statutory policy requirements, including RPS, energy efficiency portfolio standards and state and federal goals for EVs and distributed generation. In addition, plans should serve to develop a baseline against which to measure each utility's smart grid progress.[6]

Q. How was the EDF Scorecard used to engage with utilities in California to develop their smart grid deployment plans?

A. EDF announced its intent to grade each utility plan and submit the results to the CPUC. Once SDG&E and Pacific Gas & Electric ("PG&E") learned of the EDF Scorecard, they requested, and received from EDF, early feedback on draft elements of their plans. EDF's comments to SDG&E advised greater focus on meeting the environmental considerations per the CPUC guidance (D.10-06-047) on what should be contained in the deployment plans. In particular, we focused on the role of smart grid in meeting state environmental policy.

Q. What did engaging in the EDF Scorecard process achieve for the utilities and the smart grid deployment process?

A. Engaging in the scorecard process allowed the utilities an opportunity to receive critical feedback on their plans, with an eye towards environmental benefits and smart grid performance, before they were submitted to the CPUC. We suggested that SDG&E directly discuss in its plan the regulatory requirements it must meet in the upcoming decades, linking those challenges to potential smart grid solutions. We made specific recommendations about the smart consumer and smart market sections of the SDG&E plan, including expanding the discussion to include enabling time differentiated rates for storage, electric vehicles and small distributed

[6] *Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System*, R. 08-12-009, CPUC, June 28, 2010 at 4.

generation, as well as sale of distributed energy sources into the CAISO market. In addition, we asked that SDG&E identify and commit to develop comprehensive environmental metrics with EDF and other stakeholders, and to identify needs for data gathering and analyses to be taken or planned for in the near term to report these metrics in plan updates. EDF also provided feedback to PG&E, including suggesting the utility supply more information to build an environmental baseline to help guide future deployments.

While SDG&E and PG&E did not ultimately take all of EDF's suggestions, the outcome of our collaboration was a more clearly articulated vision of the smart grid's role in helping the utilities meet state environmental policy goals.

Q. How did EDF engage with the CPUC and the California IOUs to develop metrics to track smart grid performance?

A. In December of 2010, a CPUC decision about smart grid deployment planning identified several "non-consensus" environmental metrics and required the utilities to continue work with interested parties to develop additional metrics "for consideration for inclusion in the July 2011 deployment plans."[7] Following on that decision, EDF worked closely with SDG&E to help calculate the environmental and economic benefits from smart-grid enabled programs, developing metrics for avoided emissions of greenhouse gases, nitrogen oxides, sulfur dioxide and particulate matter. Utility programs considered included peak load reduction, load shifting and integration of centralized and distributed renewable electricity generation and electric vehicles. Having quantified the emissions reductions these programs would

[7] *Administrative Law Judge's Ruling Seeking Comments on Proposed Interim Metrics to Measure Progress by Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company in Implementing a Smart Grid,* R. 08-12-009, CPUC, December 29, 2010 at 3 (implementing *Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statutes of 2009*, R. 08-12-009, CPUC, June 24, 2010, where the CPUC declined to adopt metrics and ordered continued investigation of them, at 84).

achieve, EDF then monetized those benefits using existing and forecasted emissions allowance prices. These allowance prices are indicative of what the utility would have to spend to avoid emissions or purchase allowances.

Q. What is the status of these environmental metrics?

A. The CPUC ordered technical workshops where EDF, the utilities and other stakeholders could develop a consensus around environmental metrics.[8] The first workshop took place on August 21, 2012.

Q. What are some of the lessons learned from engaging with other stakeholders in the evaluation of AMI deployment plans and metrics?

A. As discussed above, collaboration between EDF, the CPUC, utilities and other allies in evaluating AMI technologies increased the collective knowledge base of the parties. It also created new tools that were employed to calculate and monetize the environmental benefits of smart grid technology. This both provided utilities and other actors with data to pursue environmental benefits and helped utilities map the least-cost path to meet state and federal clean air standards. Utilities were able to create better plans earlier in the process. The collaborative process also created buy-in from stakeholders. Approved plans also provided the utilities with some degree of regulatory certainty.

Q. Why is it important that the broader community be engaged in the development of a plan?

A. As was noted above, many of the benefits that can be derived from AMI deployments require engagement by a diverse group of stakeholders to ensure that they are realized. I have found that where stakeholders are engaged throughout the process,

[8] *Adopting Metrics to Measure the Smart Grid Deployments of Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas and Electric Company*, R.08-12-009, CPUC, April 24, 2012.

from planning through implementation, the likelihood of successfully attaining those benefits can be increased. Metrics that, for example, merely count the number of a particular device installed, only measure the performance of the installation team. This may not capture the promise of smart grid in terms of customer and environmental benefits. A more collaborative process can allow stakeholder to have input and inform a set of objective, rational measures of success.

Q. What additional principles can be used in determining what kind of collaborative process is appropriate to develop goals and metrics in the context of AMI plans?

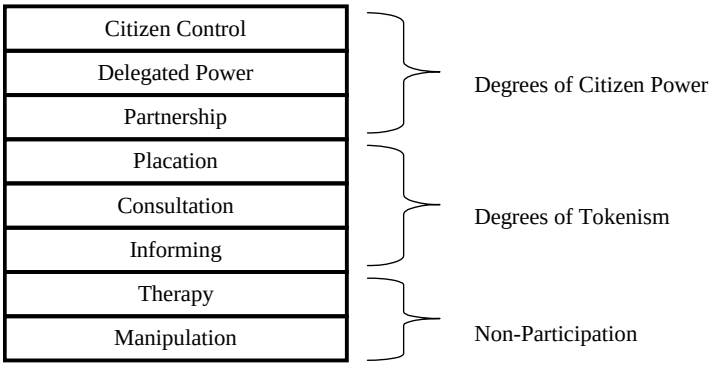
A. When contemplating a process to establish goals for investments in AMI and other grid modernizations, and the associated metrics for measuring progress toward and attainment of them, EDF believes that the first step is to establish broad goals to focus all stakeholders toward a common vision. To be fully inclusive, those goals should consider goals focused on the customer community, including historically disadvantaged segments of society. To define these goals, a broad spectrum of community stakeholders must be at the table as fully empowered participants.

EDF believes that the creation of safe settings for meaningful, collaborative, consensus-building is necessary because all stakeholders are not inherently empowered equally.[9] In the context of smart grid, empowered participation in

[9] There is a well-developed scholarly literature on what makes for open, honest and effective collaboration. For examples, see Judith Innis' work on "communicative" planning processes from UC Berkeley. Also, as show below, Arnstein (1969) describes a hierarchy of participation in community planning. Science-led planning can limit the public to various degrees of tokenism. "Meaningful" participation requires a citizenry empowered with the understanding necessary to critique the scientific bases of decisions.

developing a common vision necessarily will require stakeholders to have some technical expertise. For stakeholders lacking this expertise, the collaborative process can enable their participation by facilitating access to technical experts.[10]

Environmental metrics should be built upon the existing code and state tradition and include both economic measures of the cost-effectiveness and the cost-benefit of avoiding measurable quantities of well-defined regulated pollutants. Clarification on the logistics of collaboration will help stakeholders plan and organize resources. When deciding to allocate scarce, yet potentially significant resources of time and staff, most resource-limited stakeholders must consider the (high) opportunity costs of engaging in collaboration. To help to inspire full and determined engagement, collaborative processes should specify what decision strategies will be used and how outcomes will be incorporated over time into regulatory code and utility practice.



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[10] See, Marsh, Eric. Office of Environmental Policy Innovation. U.S. Environmental Protection Agency. Washington, D.C. (Discussing cross-cutting lessons from their study of a decade of documented participatory processes conducted by the EPA, "Often, data credibility depends upon whether the data can be produced or confirmed by an outside source…Without outside expertise, groups with non-technical backgrounds can be significantly disadvantaged in their ability to participation effectively in decision-making…EPA has made strides to improve in this area, however, by enabling participants in multi-stakeholder processes easier access to technical experts.") (Internal cite omitted.) 6th Biennial Conference on Communication and Environment. Aepli, M-F., Delicath, J.W., and S.P. Depoe, Eds. Center for Environmental Communication Studies. University of Cincinnati. July 27-30, 2001. Pg. 157.

IV. DEVELOPING A PROCESS IN ILLINOIS FOR AMEREN THAT WILL LEAD TO THE CREATION OF A SUCCESSFUL AMI PLAN

Q. Can a collaborative AMI development process add value in Illinois?

A. Yes. While the specific events that occurred in California cannot necessarily be duplicated in Illinois, I believe a process that involves stakeholders can lead to a more effective AMI plan for Ameren. This was also suggested by Miriam Horn in her previous testimony and also by CUB and other parties.

Q. What type of process would you recommend?

A. I would recommend that the Commission order Ameren to engage in a stakeholder-driven plan development process that is facilitated by an independent third party. This builds on, and is consistent with, the legislative requirements in the EIMA that each of the participating utilities work with the SGAC to develop milestones and review progress to date on an annual basis.[11] The process should also contemplate the principles for process development and stakeholder engagement discussed above.

Q. Who should convene this process?

A. I believe that the SGAC should convene the process, but that it should be open and inclusive of stakeholders beyond those that were included in the legislation.

Q. What would the purpose of the process be?

A. The collaborative process would focus on developing a robust AMI deployment plan with Ameren that included the requisite level of detail to ensure successful delivery of the benefits of smart grid for its customers.

Q. What would the outcome of the process be?

A. The process would culminate with the issuance of a report that is drafted by the SGAC, in partnership with the independent facilitator. This report will then be

[11] *See* 220 ILCS 5-16-108.6(c)(4).

presented to the Commission, along with an updated version of the Ameren Plan.

V. DELIVERING SMART GRID BENEFITS IN NON-URBAN ENVIRONMENTS

Q. Are there unique geographic attributes to the Ameren service territory?

A. Yes. Based on the map and deployment-by-region information provided in Ameren's plan, it appears that the service territory includes a mixture of urban, suburban and rural areas.

Q. Do you believe that it is more difficult to deliver benefits in this type of mixed service territory?

A. No. We have been involved in multiple planning and deployment processes in service territories with a similar population mix. Specifically, we have seen strong initial results in deployments for some of Texas' leading rural electric co-operatives.

Q. Can you please describe the deployment in Texas rural electric co-operatives?

A. Due to the regulatory framework in Texas, electric co-operatives are not required to submit plans to the Public Utilities commission. However a member-elected board runs these utilities and rate-based infrastructure investments must be approved by that board. In Texas, Pedernales Electric Co-op ("PEC") and Bluebonnet Electric Co-op ("BEC") have demonstrated through pilot programs and initial deployments that well planned AMI deployments can provide substantial benefits for rural customers. Both utilities participated in a "Virtual Peak Power Plant" pilot program aggregating over 300 rural electric co-operative residential customers to provide 845 kW of peak power capacity. This impact demonstrates the capability in rural regions to reduce the need for investments in additional peak capacity generation, thus reducing the need for future rate increases. Additionally pilot participants benefited directly from measured and verified reductions in energy consumption of

up to 17% in some participating households, which we estimate to result in approximately $200 in annual savings per residential customer.

Q. Does this conclude your direct testimony?

A. Yes, it does.