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So You Have Your ARRA Funds for New Staff—Now What?

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Executive Summary

This paper describes several investigations that state commissions could pursue with staff hired with American Recovery and Reinvestment Act (ARRA) funds from the U.S. Department of Energy (DOE). These investigations would provide context to help state commissions make good decisions on utility-proposed generation and smart-grid projects that have U.S. DOE cost sharing or loan guarantees and help commissions increase the effectiveness of energy efficiency (EE) programs. For each class of investigation there is a discussion of necessary and useful staff skills.

Generation investigations could use a portfolio analysis (PA) approach. PA can guide generation investments in this time of increased planning uncertainty and risks to customers. A commission could investigate these questions:

1. Is the amount and type of planned generation plants and power purchases the appropriate mix for your state or region?

2. Is the generation planning process conducted by utilities in the state adequate to meet the challenges in the years ahead?

EE investigations could examine existing measurement, verification, and evaluation (MV&E) efforts and adjust EE programs to ensure that customers get the right amount of savings at the least cost.

1. If there are EE programs for the utility that go beyond merely educating customers, a commission could investigate the value of current spending by examining the MV&E that is currently conducted on EE programs.

2. If the EE investigation above shows poor performance for utility or third-party EE programs or if a utility has minimal EE efforts, a commission could investigate whether to impose a system charge (for example, one percent of retail revenue) to be spent by an independent entity on EE.

Commissions in almost every state will confront complex decisions on a variety of smart grid investments. By pursuing some of the 11 investigations outlined in this paper, a commission could increase the value to customers from smart grid investments.

The Appendix contains three potential information requests to utilities related to these investigations.

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So You Have Your ARRA Funds for New Staff—Now What?

I. Introduction

Is there a commission-established method for comparing power supply demonstration projects that have federal cost sharing with conventional generation? Are your utilities acquiring all the cost-effective energy savings available? Does your commission have a smart-grid plan that provides a framework for assessing utility proposals for smart-grid investments—or is it in a position only to react to these proposals? Due to state budget difficulties, many state commissions have not had the staff to conduct investigations on these and other key issues. In late 2009, however, the U.S. Department of Energy (DOE) announced one-time grants[1] of $0.76 to $1.69 million to state utility commissions so that they can hire new electricity staff to work on issues related to the American Recovery and Reinvestment Act (ARRA).[2]

Wise use of ARRA-funded staff can advance the goals of state commissions, help motivate employees, and create a permanent expertise infrastructure.

This paper discusses potential commission investigation regarding generation (Section A), energy efficiency (EE) (Section B), and smart grid (Section C). At the end of each section is a discussion of the skills related to the investigation. Three potential information requests to utilities related to these investigations are in the Appendix.

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[1] Grants are from Funding Opportunity Announcement; American Recovery and Reinvestment Act - *State Electricity Regulators Assistance*; Funding Opportunity Number: DE-FOA-0000100; Announcement Type: Amendment 000002; CFDA Number: 81.122; Amendment 2; (2009), select the "amendment 2" link at https://www.fedconnect.net/FedConnect/?doc=DE-FOA-0000100&agency=DOE.

[2] The full ARRA bill is available at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf.

II. Potential Investigations

A. Use of ARRA staff to conduct investigations on the planned generation mix

1. It is not an easy time for utilities and state commissions to choose among generating technologies.

Natural gas-fired plants were the easy choice for new sources of power in the 1990s. During this period, hardly any other types of plants were built in the U.S.[3] Gas plants have low capital costs and short construction times. They are a fully mature technology. They have relatively low emissions of criteria pollutants[4] and greenhouse gases (GHGs),[5] with few waste products. Until natural gas prices rose after 1999, gas plants had low costs and low risks.[6]

The period 2005 through 2008 saw a mix of new natural gas, coal, and wind projects. Coal and natural gas power plants comprised 4 and 47 percent of net capacity additions, respectively.[7] Wind projects, spurred by federal tax credits, made up most of the remainder. Wind power generation (MWh) grew 61 percent between 2007 and 2008.[8]

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[3] For the period 1990 to 2005, net additions to gas-fired capacity were 284,000 megawatts (MW) (nameplate). Total retirements for all technologies other than natural gas plants exceeded total capacity additions for this period. Calculated from U.S. EIA data: "1990 - 2008 Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860)," retrieved from http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html on Feb. 25, 2010.

[4] Criteria pollutants include mercury, sulfur dioxide, and oxides of nitrogen.

[5] Carbon dioxide (CO_2) is the primary greenhouse gas emission from fossil-fueled power plants. These plants also emit small levels of nitrous oxide (N_2O), methane (CH_4), and black carbon soot.

[6] Two thirds to three quarters of the levelized cost of a natural gas-fired power plant is the cost of the gas. Natural gas prices to U.S. power plants for the period 2000 through 2007 were 127 percent above the level for the period 1997 through 1999. Even though prices for the first 11 months of 2009 dropped from the high level in 2008, they were still 88 percent above the 1997-1999 level. From U.S. EIA at http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm. Data retrieved March 6, 2010.

[7] Net nameplate additions (MW) calculated from EIA-860, op. cit.

[8] Wind power went from 0.83 percent of total U.S. generation in 2007 to 1.34 percent in 2008. Calculated from U.S. EIA, *Electric Power Annual*, Table 2.1.A. "Net Generation by Selected Renewables by Type of Producer, 1997 through 2008" and Table 2.1. "Net Generation by Energy Source by Type of Producer, 1997 through 2008" (Jan. 2010), available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

Currently, there is an increased likelihood of federal regulation of CO_2 emissions from power plants. Under the U.S. Supreme Court decision in 2007, the Environmental Protection Agency (EPA) must address GHG emissions.[9] The U.S. House passed the Waxman-Markey cap-and-trade bill in June 2009.[10]

While more coal-fired capacity was added in 2009 than in 2008, the upward trend in new coal plants is unlikely to continue. Due to the economic recession and regulatory uncertainty (related primarily to federal climate change legislation), the third quarter of 2009 saw 14,915 MW of planned new coal capacity canceled, with only 4,605 MW proposed.[11]

2. State commissions can use portfolio analysis to help choose among new generating technologies.

Retail customers' bills will be affected for decades by the choices made for new power plants. There is a growing opportunity for state commissions to influence, and in some cases determine, the mix of generation technology and fuels for their states. A commission could open an investigation into the appropriate types of technologies for new power plants. The investigation could provide guidance to utilities even if a public utility planning process (sometimes referred to as an integrated resource planning or IRP process) already exists. The

[9] *Massachusetts v. U.S. Environmental Protection Agency*, 549 U.S. 497 (2007). The Congression Research Service summary is available at http://assets.opencrs.com/rpts/RS22665_20070518.pdf.

[10] The CBO estimated that the price of GHG allowances would rise from about \$15 per metric ton of carbon dioxide equivalent (CO_2e) of emissions in 2011 to about \$26 per mt of CO_2e in 2019 under the bill. The Congressional Budget Office's *Cost Estimate* regarding H.R. 2454, The American Clean Energy and Security Act of 2009 (June 5, 2009), is available at http://www.cbo.gov/ftpdocs/102xx/doc10262/hr2454.pdf. An allowance cost of \$26 per metric ton of CO_2 would add \$27 per MWh to the cost of power from an 11,000 Btu-per-kWh coal-fired plant and \$10 per MWh to the cost of power from a 7,000 Btu-per-kWh gas-fired plant. Under the provisions of the bill, allowance prices would likely rise after 2019. The cap on covered GHG emissions is 3% below the 2005 level in 2012, 17% below that level in 2020, 42% below in 2030, and 83% below in 2050.

[11] "Tracking New Coal-Fired Power Plants," Erik Shuster, National Energy Technology Laboratory (NETL), (Oct. 8, 2009), available at http://www.netl.doe.gov/coal/refshelf/ncp.pdf. In January 2009 there were seven coal projects "near construction." In January 2010 there was one. NETL defines "near construction" as follows: The "project has been approved; majority or all permits are obtained. Sponsor is contracting vendors and Engineering, Procurement, and Construction (EPC) contractors. Site preparation has begun." Over the same period, the number of plants under construction declined from 28 to 22, with eight plants completed.

investigation could also inform state legislative policy debates on renewable portfolio standards[12] and feed-in-tariffs.[13]

One way to assess which technologies are the best fit for a state is through portfolio analysis (PA).[14] In PA the basic steps are:

1. Develop an understanding of the attributes of different generation technologies; and

2. Assess how those technologies can fit together in a portfolio that best serves the public interest. PA accounts for the interactions among existing utility assets, possible additions, and potential future conditions.[15]

PA focuses on three aspects of generation planning:

1. **The uncertainties and risks related to generation decisions** – For example, new generation technologies share one or more of the risks pertaining to uncertainties concerning:

    a. Load growth and changes in load shape;[16]

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[12] For a description of renewable portfolio standards, see EPA's fact sheet at http://www.epa.gov/chp/state-policy/renewable_fs.html.

[13] See *What Is an Effective Feed-in Tariff for Your State? A Design Guide*, Adam Pollock and Edward McNamara, National Regulatory Research Institute, in press.

[14] Much of the following discussion derives from *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria*, Joe McGarvey, Ken Costello, R. Scott Potter, Michael Murphy, and Paul Laurent, National Regulatory Research Institute, February 14, 2007, available at http://nrri.org/pubs/electricity/07-03.pdf.

[15] For an example of a recent comprehensive use of portfolio analysis, see the Northwest Power and Conservation Council's (NWPCC) *6th Power Plan* (2010) at pages 6-1 to 6-47 and 10-1 to 10-31. Available at http://www.nwcouncil.org/energy/powerplan/6/Default.htm.

[16] "Load shape refers to the shape of the curve on a two-dimensional axis, in which the Y-axis displays demand, the X-axis displays the time of occurrence of that demand, and the values reflect the customer (or customer group's) load at each point in time. A city's load shape for a 24-hour period in August would show low levels from midnight until about 6 a.m., with load then growing to a peak by late afternoon, then gradually falling into the evening. A manufacturing firm with constant demand throughout the day would have a load shape consisting of a horizontal line intersecting the Y-axis at that demand level." From McGarvey et. al., op. cit. at 4.

b. The development, siting, and construction of the power plant and associated transmission;

c. Operating performance and dispatching of power plants;

d. Future legislation and regulations on air and water emissions and requirements for safely handling waste and other byproducts; and

e. The markets for power plant fuels and wholesale electricity.

Each kind of risk and uncertainty affects each technology differently.

2. **The multi-objective nature of generation planning** – PA for generation planning addresses more objectives than merely minimizing expected costs to customers or minimizing the risk of costly errors (judged in hindsight). By using PA, a state commission can address many competing objectives simultaneously. PA can also assess the effects of treating some objectives as constraints.

3. **The potential value of deploying an array of diverse generation technologies** – Heterogeneity can produce benefits when the differences are complementary. For example, in financial PA there are risk reduction benefits from purchasing oil stocks and airline stocks. If oil prices rise, the value of oil stocks goes up but the value of airline stocks goes down, because airline profits drop when their operating costs rise. Thus, a portfolio with both these stocks would have less risk than a portfolio with only one of these stocks.[17]

In using PA, state commissions can consider the following characteristics of each generating technology:

1. Load-service function
2. Time to construct
3. Cost to construct
4. Operational life
5. Fuel costs
6. Fuel dependability

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[17] There are also potential costs from excessive diversity. "The cost of excessive diversity—or diversity for the sake of diversity—can derive from the following sources: (1) lost scale economies resulting from the reduced operation of technologies (e.g., baseload plants) that require intensive use to exploit their full benefits on a power system; (2) transaction costs stemming from the acquisition and validity of information for generation technologies unfamiliar to the utility; and (3) additional capital and operating costs associated with configuring generating units to make them more flexible (for example, to handle alternative fuel sources or to interact complementarily with other generating plants)." Ibid at 66.

7. Plant dependability
8. Maturity of the technology
9. Externalities and regulatory uncertainty[18]

3. Potential commission investigations on generation choices

1. Is the amount and type of planned generation plants and power purchases the appropriate mix for your state or region?[19]

2. Is the generation planning process conducted by utilities in the state adequate to meet the challenges in the years ahead?

The second investigation could be opened after the first concludes.

4. Staff skills related to investigations into generation planning

For generation planning the most important expertise is in economics, public policy, and public utility regulation.[20] The second most important expertise is in long-term planning. Planning skills are related to long-term forecasting of demographics, technologies, and economic and social trends. While experience in generation or transmission planning is most relevant, planning skills from other areas, such as transportation, would be useful.

Experience in modeling utility transmission or generation systems, or engineering experience with generation equipment, would be important complements to the expertise of staff working on either investigation.

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[18] See ibid. at 7 to 16 for descriptions of these attributes.

[19] The portfolio analysis used in the investigations can be simplified if commission staff construct several internally consistent scenarios of future conditions. The analysis can then focus on the tradeoffs between the expected present value of utility revenue requirements (PVRR) and the risks from high PVRR under less likely scenarios. (PVRR is the sum of all customer bills discounted over the planning horizon—typically 20 or 30 years. The expected PVRR would be the weighted average of all scenarios and sensitivity analyses, with cases weighted by their subjective probabilities.) The analysis could include sensitivities for reductions in annual load growth of 0.5 and 1.0 and 1.5 percent, due to potential utility, state, or federal energy efficiency programs, including building codes and appliance efficiency standards. The analysis could also include sensitivities for new types of loads, such as electric plug-in vehicles.

[20] Expertise in public utility regulation includes regulatory theory and practice; understanding the current regulatory environment; interpretation and application of state and federal statutes and regulations; knowledge of state, regional, and federal policies regarding the regulated electricity industry; and principles of economics, rate design, and business management as they apply to electric utility companies.

If the region is served by a regional transmission organization or a federal power marketing agency, experience with the operations of these organizations also would be helpful, especially if either organization provides integration services[21] for intermittent renewable generation.

B. Use of ARRA staff to conduct investigations on cost-effective savings from energy efficiency (EE) programs

1. Advantages and disadvantages of EE as compared to building new power plants

Spending on energy efficiency (EE) ranges widely among states.[22] The range is so wide that, even given different circumstances, it implies that either the low-end utilities are doing too little EE or the high-end utilities are spending too much on EE. The reported savings from utility EE programs are growing.[23]

A comprehensive EE program would capture nearly all the cost-effective savings in the residential, commercial, agricultural, and industrial sectors.[24] Such a program would capture

[21] Integration services include contingency reserves and regulation- and load-following services. These services enable the system to increase or decrease available power to accommodate variations in wind generation due to changes in wind speed (or sunlight variations for solar generation).

[22] Average U.S. combined spending on EE and DR was 0.7 and 1.0 percent of retail revenues in 2007 and 2008, respectively. From U.S. EIA, Electric Power Annual, (Jan. 21, 2010) at 11; available at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfilees1.pdf. Oregon's two largest electric utilities spent 2.1 percent of retail revenues on EE in 2007 and 3.1 percent in 2009. For 2010, spending will be 3.85 percent for the largest utility and 4.85 percent for the second largest. (From tariff filings and Oregon Revised Statutes 757.612). This spending includes EE funding administered by Energy Trust of Oregon, the Oregon Dept. of Energy (for schools) and the Oregon Housing and Community Services Department (for low-income weatherization This spending does not include state or federal tax credits.)) "Massachusetts regulators have backed plans for the state's electric and natural gas utilities to invest roughly $2.2 billion in efficiency measures over three years. On the electric side, the plans set an energy savings target of 2.4% of electricity sales in 2012, reversing the overall electricity usage trend from growing roughly 1% per year to declining 1.4% per year." SNL Energy's *Electric Utility Report,* Feb. 8, 2010 at 8.

[23] Utility EE programs saved 67 and 86 million MWh in 2007 and 2008 respectively. EIA *Electric Power Annual* (Jan 21, 2010) at 81; available at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile9_6.pdf.

[24] If EE program implementation would result in long-term negative load growth, EE costs would be compared to the reduced costs at the most expensive operating plants. The

savings in lighting, space-heating, air-conditioning, ventilation, appliance, equipment, and industrial-process changes across all sectors. It would address different market segments—for example, whether a commercial or residential building is occupant-owned or rented. It would incorporate rate designs to encourage cost-effective practices by customers.[25]

The reported costs of EE savings are well under the costs of new generation.[26] The Electric Power Research Institute estimates that cost-effective EE and demand response (DR) programs could reduce annual U.S. electric load growth by up to one percent.[27] This load reduction does not include reductions from energy-efficiency standards for appliances and

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reduced costs would include the savings from plant retirements. Under positive load growth, cost savings include avoiding the need to build new power plants. Because the long-term rate of load growth is uncertain, expected cost savings will be a mix of savings under positive and negative load growth conditions.

[25] For a discussion of economically efficient inclining block and seasonal rates see "How to Induce Customers to Consume Energy Efficiently: Rate Design Options and Methods," Adam Pollock and Evgenia Shumilkina, National Regulatory Research Institute, (January 2010), *available at* http://www.nrri.org/pubs/electricity/NRRI_inducing_energy_efficiency_jan10-03.pdf.

[26] A study by the American Council for an Energy Efficient Economy (ACEEE) found that the reported costs for utility savings in 2007 ranged from $0.016 to $0.033 per kWh, down from a range of $0.023 to $0.044 per kWh in 2004. ACEEE, *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs* (Sept. 2009) at 1; http://www.aceee.org/pubs/u092.htm. The full report is free with registration. EIA estimates of MWhs saved and program costs for EE give average costs of $0.025 to $0.027 per kWh for 2007 and 2008, respectively. From U.S. EIA, *Electric Power Annual* (Jan. 21, 2010), op. cit. EIA cost estimates are not an independent check on the ACEEE estimates because EIA also uses utility-reported estimates of savings and costs.

[27] "EIA projects that peak demand in the United States will grow at an annual rate of 1.5% from 2008 through 2030. The combination of energy efficiency and demand response programs has the potential to realistically reduce this growth rate to 0.83% per year. Under an ideal set of conditions conducive to energy efficiency and demand response programs, this growth rate can be reduced to as low as 0.53% per year. These estimated levels of electricity savings and peak demand reduction are achievable through voluntary customer participation in energy efficiency and demand response programs implemented by utilities or state agencies." *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010–2030).* Electric Power Research Institute, Palo Alto, CA: Report 1016987 (2009) at 1. Available for free at http://my.epri.com/portal/server.pt?

equipment and energy elements of building codes. Savings from codes and standards are enabled by utility EE programs that provide the economies of scale needed to lower the costs for energy-efficient appliances, equipment, and building materials.[28]

Another benefit of EE is that it reduces risks by reducing the need for new power plants.[29] These risks are larger now because all generating technologies have substantial, albeit different, risks. EE savings are less risky because the power from one generation project equates to many EE projects. As long as there is no bias in the estimates of energy savings, the larger number of small EE projects reduces the variance in revenue requirements. Also, EE projects take less time to plan and build, so the risk of overbuilding is less.

A key disadvantage of EE compared to generation resources is the need to carefully measure, verify, and evaluate (MV&E) program performance. MV&E requires a comparison of energy use with and without the EE program.[30] An investigation of the MV&E of existing EE programs can help state commission improve EE programs.

2. Potential commission investigations of EE

Depending on the level of EE activity in a state, a state commission could open either EE investigation:

1. If there are EE programs for the utility's service area that go beyond merely educating customers, a commission could investigate the value of current spending by examining the measurement, verification, and evaluation (MV&E)

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[28] The processes for establishing appliance standards and building codes examine the costs and benefits of energy-using equipment and changes in building practices.

[29] For a good analysis of the risk reduction benefits of EE, see NWPCC (2010) at pages 9-1 to 9-26, op. cit.

[30] The issue of estimating energy use with and without financial incentives from an EE program is more important if cost effectiveness is judged by the utility cost test (sometimes referred to as the "administrator cost test"). This test has the goal of minimizing the PVRR (see footnote 19). If cost effectiveness is based on the total resource cost test, then estimating the effect of incentives on customer behavior is less critical. For a discussion of cost-effectiveness tests, see the National Action Plan for Energy Efficiency's (NAPEE's) *Understanding the Cost Effectiveness of Energy Efficiency Programs* (November 2008), especially pages 6-2 to 6-7; available at http://www.epa.gov/cleanenergy/documents/cost-effectiveness.pdf. The National Action Plan for Energy Efficiency (NAPEE) is a collaboration of state commissions, utilities, federal officials, and others to implement all cost-effective EE projects by 2025.

that is currently conducted on EE programs. Helpful guides for commissions on MV&E are available from the National Council on Electricity Policy[31] and the National Action Plan for Energy Efficiency.[32]

2. If the investigation above shows poor performance for utility or third-party[33] EE programs or if a utility has minimal EE efforts, a commission could investigate whether to impose a system charge (for example, one percent of retail revenue) to be spent by an independent entity on EE. [34] (See information Request #1 in the Appendix for how to assess the current level of spending). This investigation would also examine which EE programs should be changed or added.[35]

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[31] The National Council on Electricity Policy's *Eight Approaches to Enable Greater Energy Efficiency: A Guide for State Government Officials* (November, 2009). The report addresses how to finance EE programs, innovative approaches to EE program design, incentives for effective utility participation and measuring, and verifying electricity savings. Available at http://www.ncouncil.org/Documents/National%20Council%20EE%208%20Steps_web.pdf.

[32] Many helpful papers from NAPEE on the EE implementation are available at http://www.epa.gov/cleanenergy/energy-programs/napee/resources/guides.html.

[33] If a party other than the utility is implementing EE programs and the programs are ineffective, the party could be replaced with a different independent implementer. Having the funds spent by an independent entity avoids much of the concern about providing appropriate incentives to utilities to pursue EE. Proper incentives for the independent implementer are needed, but such incentives don't have as many complications as providing effective incentives for the utility. For a discussion of incentives for utilities see NAPEE's *Aligning Utility Incentives with Investment in Energy Efficiency* (2007), available at http://www.epa.gov/cleanenergy/documents/incentives.pdf.

[34] One way to reduce cost shifts by class is for the commission to apply system-charge revenues from each customer class to EE programs for only that class. Another way to reduce concerns on the part of large industrial customers about cost shifts from residential or commercial customers is to allow each large customer to apply all the EE funds collected from it over several years to its own cost-effective EE projects. If the customer does not spend the funds within a limited period, the funds would be available for use by other industrial customers or other EE programs. This process is referred to as "industrial self-direction of EE funds." The commission could reduce concerns about economic hardships imposed by the system charge on low-income households by assuring effective EE programs for renters and low-income homeowners.

[35] For an example of a comprehensive EE assessment see NWPCC (2010) at pages 4-1 to 4-23, op. cit.

3. Staff skills related to EE investigations

Rather than general skills in public utility regulation, specific experience in EE program design, implementation, and evaluation is necessary for the investigations above. If no candidate has all three types of EE experience, evaluation experience is preferable. If the investigation examines utility incentives for good EE performance, then public utility regulation experience is necessary. If increased funding for EE would require changes in state laws or rules, legislative or rulemaking experience would be helpful.

C. Use of ARRA staff to conduct investigations to guide smart grid investments

1. What is a smart grid?

On October 27, 2009 the federal government provided $3.4 billion of grants to 100 smart grid projects. The selected projects are in 49 states. Most of the projects include deployment of advanced meters. Many projects also will deploy digital monitoring devices and increase grid automation to increase efficiency, reliability, and security for distribution and transmission systems. Some projects will link advanced meters with devices in homes, such as smart thermostats, or with automated utility distribution substations.[36]

Smart grid,[37] including demand response (DR),[38] can be viewed as an interconnected system of information and communication technologies and electricity generation, transmission, distribution, and end-use technologies that will:[39]

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[36] See the U.S. DOE announcement at http://www.energy.gov/8216.htm. A listing of all the projects by state is available at http://www.energy.gov/recovery/smartgrid_maps/SGIGSelections_State.pdf.

[37] Smart grid includes advanced metering infrastructure (AMI) and advanced distribution operations (ADO). ADO increases real-time information and control of the distribution system (sensors, distributed intelligence, outage management capability, and distribution automation). ADO uses AMI communications to collect real-time distribution system information and improve operations. AMI also includes smart retail meters to record and communicate electricity use at intervals of a few minutes, a data-management system, and a two-way communications system. AMI communications are used to control loads (demand response or DR) through direct control of appliances or equipment or through customer response to information or price signals. Definitions adapted from "Designing for the Smart Grid" by Jerry Ramie in *Electronic Design* (January 7, 2010), available at http://electronicdesign.com/content.aspx?topic=designing_for_the_smart_grid&catpath=power.

[38] For a discussion of DR see NWPCC (2010), op. cit. at pages 5-1 to 5-12.

[39] The three elements of this view of smart grid are adapted from "Smart Grid Or Smart Policies: Which Comes First?", Lisa Schwartz and David Moskovitz, the Regulatory Assistance Project's *Issuesletter* (July 2009) at 1. Their view was adapted from Roger Levy and the Smart

1. Enable consumers to manage their usage;

2. Maintain and enhance delivery system reliability and stability, and

3. Enable the use of least-cost resources including reduced or shifted peak use, reduced distribution losses through voltage reduction,[40] intermittent renewable generation, and energy storage.

State commissions could investigate applications of smart grid (including advanced distribution operation (ADO), advanced metering infrastructure (AMI), and DR programs) that can:

1. Reduce the need to construct and operate peaking generation;

2. Reduce the costs of integration services for intermittent renewable generation by using load reductions and increases,[41] distributed generation, and energy storage technologies;

3. Reduce power losses in the distribution system;

4. Efficiently collect information to measure, verify, and evaluate EE and DR programs; and

5. Increase system reliability.

DR includes the following applications to increase system reliability or decrease capacity costs:

1. Direct control of customer equipment and appliances;

2. Customer price response to time-of-use metering;[42]

Grid Technical Advisory Project, Lawrence Berkeley National Laboratory. The *Issuesletter* is available at http://www.raponline.org/docs/RAP_IssuesletterSmartGridPolicy_2009_07.pdf.

[40] Voltage reduction is operating a utility distribution system in the lower portion of the acceptable voltage range (120-114 volts) to reduce power losses. Voltage reduction "saves energy, reduces demand, and reduces reactive power requirements without hurting the customer. … The NEEA [Northwest Energy Efficiency Alliance] study results indicate energy savings of 1 to 3 percent, a kilowatt peak-demand reduction of 2 to 5 percent, and a reactive power reduction of 5 to 10 percent. Approximately 10 to 40 percent of the savings are on the utility side of the meter." NWPCC (2010), op. cit. at pages 4-12 and 4-13.

[41] For how demand response can provide integration services to intermittent renewable generation, see the NWPCC (2010) op. cit. at pages 5-12 to 5-15.

3. Storage of heat or cold at customer sites, including utility-controlled electric hot water heaters; and

4. Integration of distributed energy sources including solar photovoltaics and batteries in plug-in electric vehicles (PEVs).

Beyond DR, other benefits of a smart grid include:

1. Reduced meter reading costs;

2. Reduced costs of disconnecting and reconnecting customers;

3. Reduced theft of power;

4. Improved outage detection and management; and

5. Distribution system automation to reduce power losses.

By themselves, the first three benefits listed above can pay for AMI.[43]

2. Potential commission investigations of smart grid

As an example of an investigation of smart grid issues, the Oregon Commission adopted the staff proposed 5-year action plan below on Dec. 8, 2009.[44] The Oregon staff proposed the plan on Dec. 3. 2009.

[Oregon Staff's Proposed] Smart Grid 5-Year Action Plan

The smart grid has the potential to provide net benefits on several levels: at the level of the electricity customer; at the level utility distribution system; and at the

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[42] For a discussion of time-of-use, critical-peak, and real-time pricing options see Pollock and Shumilkina, NRRI (January 2010), op. cit.

[43] Oregon Commission Order No. 08-245 in 2008 found that the projected operational cost savings from Portland General Electric's AMI plan made the plan "cost-effective" (at pages 9 and 10) without consideration of the benefits of "demand response, distribution asset utilization and outage management" (at pages 2 and 3). The order is available at http://apps.puc.state.or.us/orders/2008ords/08-245.pdf.

[44] Memo prepared for the Dec. 8, 2009 Oregon PUC Meeting; Maury Galbraith; "Staff recommendation to open a docket and use Oregon Electricity Regulators Assistance Project funds ARRA of 2009 to develop Commission smart grid objectives and action items for the 2010-2014 time period" (staff memo dated Dec. 3, 2009), at 3, available at http://www.puc.state.or.us/PUC/meetings/pmemos/2009/120809/reg3.pdf.

level of the regional transmission system. The [Oregon] *Commission should establish near-term objectives and mileposts to set regulatory expectations and guide utility decision making on smart grid advancement at each of these levels. The five-year action plan could also include a near-term smart grid vision statement. Staff recommends that the Commission open a docket, and use ARRA 2009 funding, to investigate and develop Commission smart grid objectives and action items for the 2010-2014 time period.*

Potential issues to address in the new docket include*:*

1. *What types of rate structures and services will be possible with the new meters and communication systems?* [See utility information request #2 in the Appendix for cost information that could be used in designing rates.]

2. *What are the expected energy savings from these rate structures?*

3. *Should rate structures and services be mandatory or allow customers to voluntarily opt in or opt out?*

4. *Does the Commission need to develop new standards to address equipment obsolescence?*

5. *Should new reliability metrics be developed to evaluate the performance of utility distribution systems?*

6. *Should the Commission direct each utility to file a smart grid transition plan with periodic updates?*

In addition to the subject areas above that were adopted for the Oregon investigation, state commissions could add or substitute the following questions to an order opening an investigation on smart grid:

1. How should utilities coordinate equipment investments, data management, and communication protocols for AMI and ADO?

2. What are the potential effects of PEVs on peak loads, load shape, and electricity sales, including an assessment of the effects with and without DR programs? (See utility Information Request #3 in the Appendix.)

3. Should the commission and utilities begin now to guide the times of day when battery recharging occurs in PEVs,[45] including whether or not mandatory tariffs and increased metering are needed for customers recharging PEVs?[46]

4. Who should pay for early adoption of DR equipment?

5. How should the commission address short-term net costs from voluntary or mandatory DR tariffs and equipment on low-income and renter households?

3. Staff skills related to smart grids and DR

Essential skills for smart-grid investigations include expertise in economics, public policy, and public utility regulation. Specific skills in microelectronics, including computing and telecommications engineering (hardware and software), would be helpful. If the primary focus of the investigations is planning smart grid investments, academic training in these fields could substitute for academic training in economics or public policy. Experience in public utility regulation is still essential.

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[45] The 2009 Ontario Reliability Outlook noted that:

"100,000 vehicles charging up at the same time would require the equivalent of a generating plant the size of the new Sithe Goreway facility … an 875-MW, gas-fired plant" (quoted in SNL Energy's Electric Utility Report, Jan. 4, 2010; at 20).

[46] "Doug Kim, director of Southern California Edison's PEV Readiness Program, says that 'while the utility estimates the adoption of about 400,000 PEVs by 2020 as a midlevel scenario, it is preparing to deal with as many as 240,000 PEVs by 2015 and 1.1 million by 2020 in its service territory'." From Energy News Data's *Clearing Up*, Jan. 4, 2010; at 12.

III. Conclusions

This paper describes several investigations that state commissions could pursue with the staff hired with ARRA funds from the US DOE. These investigations would provide context to help state commissions make good decisions on utility-proposed generation and smart-grid projects that have U.S. DOE cost-sharing or loan guarantees, as well as help commissions increase the effectiveness of EE programs.

Generation investigations could use a PA approach. PA addresses the current high level of generation planning uncertainty and risks to customers. EE investigations could examine existing MV&E efforts and adjust EE programs to ensure that customers get the right amount of savings at the least cost. Commissions in almost every state will confront complex decisions on a variety of smart grid investments. By pursuing some of the smart grid investigations outlined above, commissions can increase the value from these investments.

Necessary and useful staff skills vary with each investigation, but a basic understanding of public utility regulation is generally necessary.

There will not be enough ARRA staff to perform all the investigations outlined in this paper. If it is unclear which investigations would provide the most useful context for commission decisions, the commission could solicit public and staff input before opening investigations.

Appendix

Potential Information Requests to Utilities

1. Please provide estimates of the utility's funding of energy efficiency (EE) for 2009 and planned for 2010. For each year, please provide estimates of the energy (MWh) saved. Please provide information by program summed to customer class in a manner consistent with reports filed with the U.S. Energy Information Administration. Please indicate which program savings estimates are based on sampled metering data after measure installation.

2. Please provide estimates of the real-levelized long-run marginal cost (LRMC) per kWh to serve a typical whole-house air conditioning load for 25 years, including incremental transmission costs, applying the three assumptions below for wholesale prices for fossil fuels and power purchases and sales. Please provide comparable estimates of the LRMC for a kWh of residential electricity provided between the hours of 5 and 6 a.m., applying the assumptions below. Please include all documentation, analyses and operable Excel spreadsheets. All values should be in 2008 dollars.

a) An estimate using the utility's base-case forecast for wholesale power and fuel prices and future regulatory costs for air emissions;

b) An estimate based on the delivered wholesale natural gas costs of $6.00 per MMBtu, plus a cost adder of $20 per metric ton for CO_2 emissions from all fossil fuels, including the forecasted effects on wholesale power prices.

c) An estimate based on the delivered wholesale natural gas costs of $9.00 per MMBtu, plus a cost adder of $40 per metric ton for CO_2 emissions from all fossil fuels, including the forecasted effects on wholesale power prices.

3. Please provide any studies or estimates of the potential effects on monthly peak hour loads (MW) and sales (MWh) in your service area from electric plug-in vehicles (PEVs) for 2020 and 2030. If information is available, please provide these estimates with and without planned demand response programs. If such studies or estimates are not available, please provide any estimates of the likely sales of PEVs in your service area, by vehicle type. Please include all documentation and analyses for all estimates.