September 8, 2014

To: U.S. Department of Energy Office of Energy Policy and Systems Analysis
Submitted via electronic mail: QERComments@hq.doe.gov

Re: **Electricity Transportation, Distribution and Storage in the West; formal comments**

Sempra Energy, on behalf of its subsidiaries, San Diego Gas and Electric Company (SDG&E), Southern California Gas Company, (SoCalGas) and Sempra U.S. Gas & Power[1], supports the U.S. Department of Energy's (DOE) efforts to promote electric safety, reliability and affordability and appreciates the opportunity to comment on DOE's public meeting regarding electricity transportation, distribution and storage in the west. DOE's support in coordinating synergies among federal agencies and driving innovation through its role as a convener will be invaluable in supporting stakeholders in meeting the goal of providing safe, reliable and affordable energy, as further discussed in our comments below.

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Key Questions from the Department of Energy with responses provided by Sempra Energy.

1. Where is the nation's electricity TS&D system headed?

   The way homes and businesses get their energy is being revolutionized thanks to new technological innovations and a greater concern for the environment. Customers have different priorities than in the past and need to be provided with an array of safe and reliable energy service choices. This includes customer access to a balanced energy supply, including renewables, support for clean vehicle use and convenient refueling stations to keep new vehicles on the road. The energy revolution will result in increased reliance on distributed energy resources and renewables sited at both the transmission and distribution level which will change the load shape and create new integration needs to ensure adequate reliability and power quality while also increasing the importance of price signals that encourage customers to use energy at times that mitigate the need to add new conventional generation resources.

   These changes create the need for an updated and unbundled rate design at the state level that accurately reflects the services utilities provide to customers. Such a rate design will likely be different for customers that invest in new distributed energy technologies than for traditional bundled utility customers and will need to take into account the costs that are avoided by utilities when services are provided to the grid through distributed energy resources. Price signals need to ensure that all customers, including customers with distributed generation (DG), have incentives to use electricity at times with lower demand and refrain from using electricity at a time of peak demand, based on the actual cost consequences of these decisions. Such a rate design would encourage economically efficient demand response and energy efficiency, while also leading to new distributed energy technology market opportunities, new opportunities for consumers, reduced emissions, and new energy technologies (such as energy storage) that will address over-generation scenarios in the future.

[1] Sempra U.S. Gas & Power, LLC is not the same company as the California utilities San Diego Gas & Electric Company (SDG&E) or Southern California Gas Company (SoCalGas), and Sempra U.S. Gas & Power, LLC is not regulated by the California Public Utilities Commission.

As market penetration of intermittent resources continues to grow, failure to adopt rate designs that reflect accurate price signals regarding the costs utilities incur to provide services to customers could result in significant market uncertainty for utilities, customers, and potential vendors of new technologies and services. This kind of uncertainty would stifle economically efficient investments, while inaccurate price signals would encourage economically inefficient investments by customers and utilities, and cause cross-subsidies to grow. The result is increasing bills of customers that may not have the financial ability to make a distributed energy resource investment, which is obviously unfair.

2. What kind of policies and planning can encourage reduction of transmission and distribution system vulnerabilities (e.g., cyber/physical attacks, weather, fire) on near-, medium- and long-term horizons?

   SDG&E believes that proper planning is key to reducing the vulnerabilities and the impacts to the grid and consumers due to cyber/physical attacks, weather, fire and other natural disasters. In addition, policies that promote physical and cyber security around critical transmission assets will play a key role in protecting the grid against attacks. SDG&E believes that the proper federal agency to deal with cyber and physical security issues is the FERC, working through the North American Electricity Reliability Corporation (NERC).

   Cyber and Physical Attacks:

   In order to reduce system vulnerabilities to cyber or physical attacks, it is important to have a strong policy framework in place that leverages multiple industry frameworks and best practices, and standards. Regular collaboration with recognized industry experts, consultants, private companies and local and federal government entities aids to better understanding of existing and potential system vulnerabilities. A strong awareness program is a key component in reducing vulnerabilities. DOE can play a strong role in providing a forum for such collaboration. Stakeholders and the federal government have an interest in protecting the nation’s electric grid from attack, either physical or cyber, which necessitates co-operation, coordination and the willingness to reach jurisdictional agreements. The industry would be poorly served by overlapping and possibly contradictory policies, rules, standards, requirements or frameworks.

   With regard to the electric transmission grid, FERC has promulgated standards developed through a collaborative process by NERC that set forth minimum protections against cyber threats that apply to all utilities that own and operate facilities that are critical to the reliable operation of the Bulk Electric System. These standards are backed up by a rigorous framework of self-certification, compliance audits and reviews and enforcement. Rules governing protections from physical attacks are currently in development and the first version of those standards will be in effect soon.

   SDG&E believes that with regard to the development of rules and standards, for various federal agencies with an interest in developing mandatory and enforceable standards for cyber or physical security, it would be best that such efforts take place within the existing FERC/NERC process. This would allow DOE and other federal agencies to leverage the collaborative process already in place with clear jurisdiction and authority granted by congress to FERC and NERC in this area.

DOE and the Federal government should encourage, support and facilitate collaboration among the intelligence community, sector-specific agencies such as FERC and NERC and owners and operators of critical infrastructure regarding the creation of a threat and intelligence taxonomy, guidelines for designation of covered critical infrastructure, standards, best practices and enforcement so that jurisdictional conflicts are avoided.

One area where DOE could provide leadership is the development of a common methodology or taxonomy for labeling threats and intelligence. Sempra Energy and SDG&E recommend the establishment of a common methodology or taxonomy to provide a single framework for sharing threat information among public, private and government organizations. Organizations could use the common framework to collect, share and prioritize threat information in a way that provides broad value. DOE, working in collaboration with FERC, NERC, the Department of Defense, the intelligence community and the private sector, could facilitate the development of such a taxonomy that could apply broadly across critical energy infrastructure, or potentially across sectors.

The threat and intelligence taxonomy should provide enough information so that a local analyst can understand the accuracy and confidence of the threat information, the impacted infrastructure, recommended actions, and any other relevant information. Threat scores should utilize either a quantitative or qualitative measure, or both. Our preference is for a numerical scoring mechanism which can map to a schema of critical, high, medium, low, and informational.

For such a taxonomy to be useful, however, government agencies and the private sector must also develop protocols and mechanisms to share such intelligence. DOE could assist in the development of such information sharing guidelines.

Along similar lines, a common approach should be adopted for incident reporting and the approach should consider developing an automated process for incident management. The output of the incident reporting process should include sufficient information to determine whether there was a gap in controls or whether a control failed. DOE could, working with the FERC, NERC DoD, DHS and intelligence and law enforcement agencies, facilitate the development of incident reporting for the electricity sector.

Further, Sempra Energy and SDG&E recommend a program that incentivizes third parties to develop secure solutions and penalizes third parties for poor security practices. Third party services and products that are insecure are one of the most significant gaps in the security of critical infrastructure. Another possibility would be for DOE and the federal government to develop a certification program of some type that would provide greater visibility as to the security of various third party providers of service. With the industry moving to cloud based services, requirements and standards should exist for addressing third party risk.

Weather, fire and other natural events

The challenges to the reliable delivery of electricity that result from various natural events (e.g. weather, fire, and earthquake) vary significantly from region to region in the country. Certain areas are more prone to tornados while others face severe winter storms, or severe winds. Some, like California, must deal with earthquake events. Wildfires are also frequent and a cause of significant damage in some areas.

San Diego is a region that faces the risk of catastrophic wildfires. At certain times of the year, wind-damage to electric infrastructure that ignites a wildfire may occur. This occurrence can not only disrupt electricity service but can lead to significant property damage and most importantly, loss of life. Unfortunately, SDG&E has had significant firsthand experience in responding to the threats that wildfires pose. Within the last decade, the San Diego region, and SDG&E have been the victims of several such wildfires. These wildfires, or rather firestorms, driven by high winds, have led to lives lost and have caused billions of dollars of damage. Fortunately, these events are relatively rare due to system protections and weather monitoring/forecasting put in place by SDG&E. More typically, wildfires that damage electric transmission and distribution infrastructure predominantly pose the real risk to providing reliable electricity service in the dry southwest. In SDG&E's view, we can improve the resilience of the electric grid to wildfires through preparation and situational awareness.

SDG&E's fire risk research on these wildfires seeks to determine what conditions (combination of humidity, fuel, wind etc.) create a high risk of catastrophic wildfires. Among other things, when it sees these conditions, SDG&E takes operational steps to reduce the risk based on this research. In high fire risk areas automatic reclosers are turned off to reduce the risk that a line with a fault could create a spark that could ignite a fire. In addition, when weather and system conditions reach a certain level, certain lines may be de-energized to protect public safety and prevent a downed or damaged power line from potentially causing a fire. During high risk periods, SDG&E pre-deploys certain assets and personnel in order to respond to problems as they arise. SDG&E fire risk indicator research has become an essential tool in operating our electric grid in a safe and reliable manner.

SDG&E has also undertaken steps to fire harden its facilities in high risk fire areas, including switching wood poles to steel and replacing conductors with heavier gauge conductors.

SDG&E implemented a very rigorous vegetation management program that resulted in an over 10-fold reduction in tree-related outages on the system. SDG&E maintains a comprehensive database of over 455,000 trees that could impact our system. This data includes tree location, species, growth rates and pruning history.

Many miles of electric infrastructure traverse federal lands that are at risk for wildfires. In order to reduce the risk of, and the impact wildfires have on the electric grid, many utilities will undertake efforts to "fire-harden" their infrastructure. These improvements, which are designed to increase the likelihood that the infrastructure will survive a wildfire, as well as reduce the likelihood that the electric infrastructure is the source of the fire, require various permits by federal agencies with stewardship over these areas.

DOE can assist with this process by coordinating federal agency response to requests for approval of infrastructure improvements related to reducing the risk and impact of wildfires. These requests should be given expedited treatment. While environmental review of such improvements is often necessary, it should be done in as timely a fashion as possible with recognition of the fire risk reduction purposes the improvements serve.

Further, DOE can help with the response to wildfire risk by assuring that federal agencies are aware of the critical nature of the electric grid, and the need to protect this infrastructure. Often wildfires involve land that is held by multiple federal agencies, such as the Bureau of Land Management, U.S. Forest Service, National Park System, Department of Defense, and the Armed Forces. DOE could work with these agencies to assist them in understanding the importance of key electricity infrastructure threatened by wildfire, and ensuring that protection of these critical facilities is factored into land agencies' response priorities.

In SDG&E's experience, preparedness and situational awareness are key-to reducing the risk from weather related events and other natural disasters. DOE should focus on those weather related events that cover a wide geographic area crossing state boundaries or affecting transmission facilities that are critical to the Bulk Electric System. DOE might also consider organizing response exercises where a simulated response to a wildfire can be evaluated. Following such an exercise, DOE could facilitate evaluation and planning to address the lessons learned.

DOE can also help by funding research into the impacts of extreme weather and disaster events, and how they impact the power grid. Such knowledge would assist electric utilities as well as federal, state, and local agencies in planning for such events. In addition, funding for the development of warning tools, like SDG&E's fire risk indicator research, which provide sufficient warning to allow utilities and others to begin undertaking operational changes, including pre-deploying personnel, equipment and replacement parts, in anticipation of the event would be welcome.

DOE should support the electric utilities' efforts for mutual aid support to respond to such events. DOE could facilitate the utilization of military airlift capabilities by developing a protocol that would, in anticipation of a need, arrange air transport of personnel and equipment for utilities so that these resources can be deployed more quickly and recovery efforts undertaken sooner.

Additional recommendations include the issuance of government-provided Wireless Priority Service and Emergency Communication priority services for incident responders, including electric utility and telecommunication provider personnel seeking to restore this critical service. The opportunity exists to develop and implement a "common access" card (government issued) that provides the following organizational benefits:

- Authorized Emergency Responder – Assistance to key personnel to bypass security checkpoints;
- government background checks for response personnel where required;
- access to private and government facilities used for incident response; and
- authorization for Priority Data and Telecommunication Services.

The government should establish "common criteria" to be used to develop local, regional and national emergency response plans related to the recovery of the electricity grid.

3. How can the federal government remove limitations/obstacles to siting needed transmission lines?

   The energy industry faces tremendous uncertainty. Where will the power consumed by customers in the future be produced? To what degree will demand depend on distributed resources or central station resources? Will transmission lines continue to be needed in regions with coal-fired generation? And if coal-fired generation resources will be replaced by natural gas or renewable resources, where will they be located? This uncertainty is increased by inaccurate price signals in utility rates and uncertainty as to whether, and if so when, those flaws will be corrected. Complicating this is uncertainty and delay associated with environmental review of proposed utility upgrade projects.

   The intersection and crossover of federal and state jurisdiction creates obstacles to siting transmission lines and results in a costly process of meeting requirements, which often overlap or are inconsistent. There are many cross-jurisdictional issues that create barriers for siting and construction of transmission lines, and many different agencies which have responsibility over the permitting process. Questions often arise about which group has responsibility for which part of the process.

   One approach to increasing efficiency is to consistently apply or expand the federal government's designation of portions of federal lands as "energy corridors". Section 368 of the Energy Policy Act of 2005 directs the departments of Agriculture, Commerce, Energy, Defense and Interior to designate corridors for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities on Federal lands. If these corridors can be pre-established as allowing transmission lines as a permitted use on portions of federal lands, one of the major obstacles to siting needed transmission lines would be removed.

   In addition, increased coordination across jurisdictions (federal, state, county, city) is needed. Multiple layers of regulation exist, and there is little consistency between these layers, which makes doing business difficult and increases overall cost. In California, state law requires local and county governments to accommodate electric transmission line corridor designations in their every five-year general plan update. Federal funding and/or coordination to accommodate and connect federally designated Section 368 corridors during these updates could provide a more comprehensive solution.

   The communication between the independent operator (CAISO), state regulator (CPUC) and the federal regulator (FERC) should be coordinated to leverage and expedite the siting process. The Energy Policy Act of 2005 already has a backstop in place that would allow FERC to consider an application to issue a permit to construct a proposed transmission line if a state withholds approval for more than one year, or cannot consider the interstate benefits of a proposed project located within a national energy corridor. Should a state's withholding of approval or even denial of a proposal interfere with the development of a robust transmission grid, SDG&E believes that action by the federal government would be appropriate to expedite putting needed facilities in place.

These issues require clarity and a more efficient review approach. Regulatory certainty on timing of reviews would also facilitate construction and financing of projects. The Department of Energy can aid in this process by supporting the need for regulatory certainty and coordination between regulatory agencies.

4. How will changes in the resource portfolio affect transmission needs, operation, and reliability?

   Changes in the resource portfolio will affect transmission needs, operation, and reliability and pose a major challenge for maintaining and increasing reliability in the face of increased grid complexity and managing technologies at different levels of maturity as illustrated in the specific examples below.

   Installation of photovoltaic panels (PV) and use of electric vehicles (EV) are often clustered in specific locations, but not necessarily on the basis of the locational value[2] or cost associated with interconnecting these resources. In addition, these cost considerations are not reflected in rate design for residential net energy metering and other customers. Utility scale solar and wind are interconnected to the transmission system at 69 kV and above. There are some medium voltage (12 kV for SDG&E) connected PV systems, however, the majority of small systems (< $5kW_{ac}$) are connected at secondary voltage levels.

   Large systems, (>10 MW_{ac}) are typically located in the rural areas of our service territory where there is available land. However, the distribution and sub-transmission system is often weak in those areas and system upgrades are frequently required to support installation of these systems. To help balance load intermittency, DOE might consider policy and/or monetary assistance for implementation of energy storage systems that could assist in avoiding costly transmission system upgrades while at the same time strengthening the grid.

   Utility scale systems, (>50 MW_{ac}) are being developed near each other in areas supportive of the specific technology, such as windy areas and desert areas. This requires new large transmission infrastructure to deliver the power to the load center often hundreds of miles away.

   Furthermore, as the penetration level of solar increases the impact to the daily load profile changes, particularly on shoulder months, with the daily peak moving to between 6 and 8 pm when solar generators are no longer producing energy. This increases the diurnal ramp rates on generators to match generation and load. DOE might consider economic incentives applicable to emerging technologies, such as energy storage, to alleviate the daily peak concerns by "load shifting" energy that was produced during off-peak hours.

   As renewable penetration rises, the creation of negative pricing also has a negative impact on the dispatch of fossil and nuclear resources. Today, SDG&E's Palomar Combined-Cycle plant is being operated as a load following resource as opposed to a base load unit.

[2] Locational value is defined as a node in the grid where the addition of DER may provide grid benefits.

As ISO, transmission, and distribution operations become more closely integrated, increased coordination and interaction will be required. Overall, an integrated view and perspective on operations system-wide (transmission and distribution) will be needed.

Information technology (IT) and communication investment will be a very important part of the grid of the future. Methods need to be developed to deliver, aggregate, assimilate, and provide information to customers. Grid operators will have to incorporate the tools and technology needed for the next generation of consumers. These consumers will have expectations that differ from today's consumers.

Technology systems must be able to accommodate an increasingly complex grid, including data management and two-way communication. Information and energy will flow bi-directionally; there will be a mixture of local generation assets at the edge of the grid and large-scale renewable generation that may be remotely located.

With distributed energy storage, aggregation of local loads and generation will become possible, ranging from very small localized aggregation to larger (community-based) aggregation. The grid may also need to move from a radial system to a more opportunistic, networked system (for some locations), which will require significant investment. There will be a very large, complex group of stakeholders involved in the grid, including homeowner associations, state utility commissions, city governments, and others. System planning needs to be considered on a long-term time scale, within the context (needs/requirements) of particular communities. DOE can facilitate the utilities' need for adapting to changing technologies by supporting objective research as to the real costs and benefits of distributed resources, particularly when those resources are intermittent and may require back-up generation or other resources to compensate. Key questions include what are the true, tangible benefits and what are the true costs and burdens placed on the system. DOE can also continue its support for the development of new technologies, including electricity storage technologies that may provide solutions to the issues raised above.

Please also refer to our response to number one above.

5. Are regulations needed to incentivize desirable characteristics for the future grid?

   There is a need for more accurate price signals to trigger demand response and create incentives for demand to occur in ways that minimize the need to incur additional transmission and distribution costs to address renewable and distributed energy resource issues.

   The Department of Energy's Sunshot Program has a goal of $1/Wdc and $1.35/Wdc for commercial and residential PV installations by 2020 respectively. Additionally, California's governor has indicated that the 33% by 2020 goal Renewable Portfolio Standard (RPS) is a floor, not a ceiling, and California's goal to reduce greenhouse gases may result in higher levels of renewable development. These scenarios bode well for additional solar, wind and other renewable deployment in or adjacent to SDG&E's service territory where penetration levels are already doubling approximately every two years.

Existing rate designs create significant incentives for customer adoption of solar. In California, the CPUC will adopt a new net energy metering (NEM) rule pursuant to AB327 once a cap on participation under the existing NEM tariff has been reached. At the DOE Sunshot goal levels, the levelized cost of electricity is in the $0.06-0.07/kWh range. While this will be much lower than the $0.18/kWh future average bundled utility rate, distributed solar NEM customers receive reliability and power quality services from utilities which are not currently considered in determining the NEM credit for residential NEM customers.

These goals are driven by state and federal policies for carbon free generation sources and energy security. Some customers want some level of control over their electricity generation choices and their bills.

There is a need to promote new regulatory frameworks that

- Provide adequate flexibility to offer products and services customers want and need now and moving forward;
- provide more accurate price signals and cost causation in utility rates;
- tie regulatory strategy and framework to utility business goals and objectives; and
- rethink the customer relationship and the role of utilities (e.g., traditional vertically integrated versus service based).

DOE can support the development of regulations that incentivize desirable characteristics for the future grid by funding research and by collaborating with industry leaders to explore potential new regulatory frameworks and other incentives for utilities to make the long term investments required to bring these desirable characteristics to the future electric grid. DOE could assist in facilitating an ongoing discussion about the changing utility business model and the regulatory changes needed to accommodate that change. In addition, DOE might consider carefully examining Federal policies designed to incentivize new investments by third parties to ensure that these do not rely upon uneconomic rate designs that in the long run are not sustainable and have the potential to undermine the very foundation upon which the future electric grid is based.

6. What is the future role for Canadian imports, and how will they affect generation and transmission needs in the United States?

   No response.

7. What limits the value that distributed energy resources provide to the electric system? Can these challenges be mitigated? If so, how?

   Currently, retail price signals, particularly for residential customers, fail to provide incentives for Distributed Energy Resources (DER) to be installed in a manner where it will produce more energy when needed, and provide price signals that would encourage innovation in Distributed Resources (DR), DG and other DER technologies. Utility rate designs must be updated to reflect the services utilities provide to customers that invest in DER so they pay for the services they receive and have price signals that empower them to use energy and obtain those kinds of services in the least costly manner.

Installation of PV and utilization of EVs are clustered in specific locations, but not necessarily on the basis of the locational value or cost associated with interconnecting these resources, the values for which are not reflected in rate design for residential NEM and other customers.

To mitigate these challenges there needs to be a discussion regarding rates, as rates are intended to recover the cost of utility investments from customers based on the services customers receive from their utility.

Customers that invest in new technologies like distributed solar generation use the grid in new ways.

- They now only receive some of the services they used to receive (standby, reliability and power quality services); and
- They may also be able to create unique grid benefits depending on location.

In order to allow for long-term growth in the distributed solar market and other new technologies, it is necessary to update utility rate design to recognize these new uses of the grid. Rates must provide accurate unbundled price signals for the services utilities provide customers and must compensate customers with new technologies for the benefits created for the grid. Otherwise, customers that cannot afford new technologies will have to pay for the services provided to customers with new technologies. This impact is exacerbated by an outdated rate structure that is a legacy of the energy crisis (CA-AB1X).

Accurate price signals will maximize economic efficiency in long-term planning. To the extent DER subsidies are necessary, they should be clear and transparent, not hidden in the intricacies of utility rate design.

DOE can help address this by supporting objective research as to the real costs and benefits of distributed resources, particularly when those resources are intermittent and may require back-up generation or other resources to compensate. Key questions are what are the true, tangible benefits and what are the true costs and burdens placed on the system. Such objective information would be useful to policy makers at all levels of government. Additionally, DOE can support research into the actual levels of the hidden subsidy that various rate designs and other regulatory frameworks cause, and their impact on consumers. Currently many distributed resources are relying upon hidden cross subsides imbedded in rate designs that result in real economic costs and loss of economic efficiency. Again, such research would be valuable as policy makers explore incentives to support distributed generation in an economically efficient and cost effective manner.

A significant limitation on the value of many distributed resources is their intermittency and their inability to be dispatched or otherwise match output with demand. DOE research that would improve on these two traits would help reduce the limitations of distributed generation.

8. Should the regulatory compact be redefined to accommodate the future role of the utility, and if so, how should the benefits of the grid and that of distributed generation be addressed?

The regulatory compact should not be revised in ways that deprive utilities of a reasonable opportunity to earn a fair return on their investments or needed investments to support the transition the industry is undergoing. As utilities are confronted with the obligation to support new technologies they must be allowed to charge for the services they provide to owners of those new technologies; customers who do not benefit should not have to pay for these services. Without cost fairness, the regulatory model will impose a cap on the extent to which new technologies can be pursued based on the tolerance of other customers to pay for the services that are provided to DER customers in de-coupled states and the extent the regulatory model provides utilities with a reasonable opportunity to earn a fair return in non-decoupled states. To the extent the regulatory compact is revised, changes should ensure that utilities are able to continue to have a reasonable opportunity to earn a fair return as the kinds of services they provide, and the technologies change over time.

For an environment that encourages new services to develop, it will be necessary to create the right conditions which include steps to:

- Establish a new pricing structure to allow customers to see and analyze the costs and benefits of various products or services, and to ensure customers pay for what they receive.
- Upgrade the electric grid to allow for the two-way flow of electrons and to maintain reliability to match increased amounts of intermittent renewable power.
- Provide customers with clear, simple information about energy products and services – from smart thermostats and appliances to energy-efficiency and demand-response opportunities.
- Research and pilot programs that ensure a broad understanding of customers' diverse preferences and needs, and whether the existing industry structure can meet them.
- Encourage private development and research into emerging technologies, such as energy storage, and reward those efforts with long term utility contracts. This will shelter the utility from unnecessary technology risk while at the same time ensuring price competitiveness.

DOE and other policymakers must recognize that shareholder investments made to provide service to existing customers must be recovered to honor the regulatory compact. It is not just or reasonable to expect those costs to be shifted to customers without DER. Distributed generation that relies on such cost shifting is by its very nature uneconomic.

9. Will the future utility need to coordinate transactive customers, distributed generation, and microgrids?

The utility of the future may own and/or coordinate transactive customers, distributed generation and microgrids and provide support services (reliability, balancing, capacity, etc.) to customers that make these kinds of investments in enabling technology.

The price transparency that currently exists in the wholesale markets will be needed at the customer level in the retail markets. Customers must know what they are buying.

Utilities of the future must be allowed to accommodate sustainable services with various energy commodities. There will be greater integration of gas, electric, thermal, and water energy, as appropriate, to support sustainable cities (in a holistic utility-city environment[3]).

A pricing methodology that is acceptable to the customer and encourages needed infrastructure investment as well as supporting investments in distributed energy resources by customers, third parties, and utilities will be needed.

10. Can storage be incorporated into the system to maximize its benefits? If so, how?

Storage, which is one type of DER, can be incorporated into the system to maximize its benefits at both the transmission and distribution levels to address operational issues presented by increased penetration of intermittent renewable resources. The type of benefits that storage/DER may provide is dependent upon a number of factors.

Locational benefits are enhancements to the system (i.e., increased capacity, voltage regulation, increased stability, deferment of projects) due to the addition of a DER/DG project in that specific location on the system. While all DER/DG may provide capacity/enhancements in a broader sense (LCR, etc.), projects that require significant system upgrades are a planning liability, and may not provide local benefits. To provide locational benefits the DER must meet these four requirements: 1) it must be installed in the right place, 2) at the right time to avoid utility capacity upgrades, 3) of the right size to meet the need and 4) provide physical assurance; a guarantee of performance to ensure the needs are met.

An optimal location would be one which provides one or more of the system enhancements mentioned above while requiring little to no system upgrades and reduced local capacity requirements in addition to an increase in the life cycle of distribution equipment by reducing loading on the equipment. This is optimal because the goal of DER integration is to avoid doing the very same upgrades we would have done anyway - just to accommodate a DER project. This would effectively double the investment required, and be a detriment to ratepayers.

Optimization would identify those locations where storage as well as DER/DG can fit seamlessly into the system, without the need for significant upgrades. This may be done via exhaustive locational analyses, resulting in specific installation sites, or via high-level “optimization zones” which would identify broader areas where DER would have a greater chance of success. The identification and labelling of these “optimization zones” would be general in nature, and would not ensure that every project that attempts to connect in said zones would find an optimized location.

[3] The concept of sustainable cities is one where an integrated view of energy, communications, water, transportation and waste treatment drives development to minimize environmental impact and improve quality of life.

In addition, the utility may choose to perform some system enhancements in targeted areas with the hope of attracting DER resources. This would be done to meet capacity/reliability needs through a combination of utility investment and DER installations. The hope is that a minimal infrastructure upgrade in conjunction with the appropriate resource request for proposal (RFP) would accomplish goals that would normally require a much larger traditional infrastructure project. Given the unique characteristics of each location, the optimization should result in deployment of a DER technology that meets the needs. However, the choice of technology would likely not be the same in all locations.

11. Should transmission and distribution be compensated in electricity sales, services provided, or some combination thereof?

    Transmission and distribution should be compensated on the basis of the services provided in a way that provides utilities a reasonable opportunity to earn a fair return on their investments in infrastructure.

12. Is there a forcing function for changes in the regulated utility business model (e.g., regulation, technology financial markets, etc.)?

    Please refer to number eleven above.

13. How important is it to develop a national architecture for how all the components of the electrical system will function together?

    DOE and the federal government should support the development of a national architecture but should leave it to the industry and the marketplace to develop it. There is much innovation needed to bring about the future grid and government efforts to develop a "national architecture" may stymie that innovation. Rather, DOE and other government policymakers should allow the industry to evolve an architecture and develop protocols that will facilitate the needed interoperability and communications to enable the future electrical system to function in a cohesive and complementary manner.

14. Should the federal government develop a sectoral roadmap for the electricity sector?

    If the federal government decides to develop a sectoral roadmap for the electricity industry, regional differences need to be taken into account. Additionally, the utility sector is evolving rapidly and the process of developing an overly rigid roadmap may result in a less efficient pace of development.

    Regulatory clarity is needed to help utilities plan and respond to changing technologies. Current rate cases are cumbersome and take too long; they do not allow utilities to be nimble and react to changing market conditions or customer expectations. Utilities and other stakeholders need certainty regarding the rules around cost recovery in order to make investments in grid modernization. In addition, incentives are needed to encourage the right types of investments, such as investment in innovation and efficiency.

As new participants enter the market, there will be a need for infrastructure and technology accountability. If a new participant provides services to customers and then leaves the market, there will be questions about how services to those customers are handled and who is accountable for providing those services. If the utility is required to pick up the services, consideration of how the utility will be fairly compensated for taking on this burden must be undertaken. Utility regulators, working with the utilities and stakeholders need to address these issues now so as to avoid confusion by utilities, customers and new participants regarding their rights and obligations.

To the extent that a roadmap is developed, the roadmap needs to include policies conducive to new business model formation. The roadmap needs to provide enough detail to be useful; therefore, it should be completed at the regional, state, or company level. The roadmap should provide clarity on the path forward and help facilitate an orderly transition to the future grid. The roadmap should be stakeholder-driven but developed through frank, open discussions with all stakeholders to make sure all perspectives are taken into account. Furthermore, the roadmap should integrate with federal greenhouse gas reduction policies such as the Clean Power Plan and should include recognition of early adopters like California and ensure that regulations are complementary, not overlapping or conflicting.

15. What are the respective roles for industry and government in addressing cyber security issues related to an increasingly complex generation system?

    Please refer to response to question number two above.

16. What changes to the electricity TS&D system would help enable lower-carbon, more energy efficient energy production and use?

    Please refer to response to question number four above.

17. What technologies or policies would reduce direct energy loss from the electricity TS&D system?

    While energy losses from the system are important, the primary focus instead of the question posed should be energy efficiency of the end loads. For example the Institute of Electrical and Electronics Engineers (IEEE) estimated that networked gadgets waste 400 terawatthours per year and “That's equivalent not only to the consumption of any number of large countries, but also to more than 100 mid-sized coal power plants and all their emissions.”[4] To address this problem, DOE should focus policy and assist in the development of technologies that minimize the energy of end use devices, similar to Energy Star and power consumption of devices in standby mode.

[4] Levitan, Dave. IEEE Spectrum. Networked Gadgets Waste 400 Terawatt-Hours of Energy Every Year. 7/3/2014. Web. 9/8/2014. http://spectrum.ieee.org/energywise/consumer-electronics/gadgets/networked-gadgets-waste-400-terawatthours-of-energy-every-year.