The Alliance for Transportation Electrification (the Alliance) is pleased to submit the following comments in response to the Notice of Inquiry dated September 24, 2018, in the above-captioned proceeding.

The Alliance is a broad and diverse coalition of about 40 organizations overall in many states across the country, including utilities (30) both investor-owned and publicly-owned, auto manufacturers, EV supply equipment (EVSE) firms, and related trade associations and other non-profit organizations involved in electric vehicles. The Alliance’s overall goals are to engage with state commissions and other agencies to encourage a collaborative and open approach to accelerate the deployment of EV infrastructure, complement the private/competitive market by supporting an appropriate utility role, and promote interoperability and open standards in all parts of the EV ecosystem.

This Notice of Inquiry sets the stage for Illinois to join other forward-thinking states in a global transformation that will improve the lives of millions through cleaner air, more enjoyable driving, and lower transportation costs. State and local governments are making the commitments necessary to bring EVs to the emerging majority of vehicle owners, while the automotive industry is investing billions in new models. The Alliance appreciates the opportunity to provide comments in response to the Notice of Inquiry and we look forward to continued participation in this important endeavor.

Energy Efficiency

The Alliance believes that the increased adoption of electric vehicles (EV’s) should have no direct impact on the regulatory policies and incentives regarding energy efficiency measures. Those measures should continue to be evaluated under the traditional framework of portfolio analysis and cost-benefit methodologies that have traditionally been used for all sectors – residential, commercial, and industrial. As in other regions and states of the country, the Alliance believes that certain energy-efficiency measures will continue to be judged to be cost-effective and constitute minimal risk as demand side management resources under most scenarios used in long-term planning.
The questions posed appear to be directed at the question of the efficiency of conversion of primary energy to the end use of energy by the consumer, in this case the driver of an EV compared to the traditional driver of an internal combustion engine (ICE) relying on fossil fuel. In fact, the Alliance believes that we should be using a broader framework when examining overall energy usage, and especially the conversion of primary energy on a BTU basis in final use, taking into account losses along the path of conversion such as transmission losses for electricity (estimated to be about 7 percent) and refinery losses during the process of refining crude oil to gasoline (estimated to be about 10 percent).

In fact, EPRI has recently conducted such analyses in its U.S. National Electrification Assessment (USNEA) which was published in March of this year, when it examined a number of electrification cases in the economy, and most notably the transportation electrification use case which it states offers the most immediate potential. EPRI concluded that, under reasonable assumptions of electricity generation with NGCC (natural gas combined cycle) plants and the losses mentioned above, that the “pump to wheels fuel consumption” would be one third to one quarter that of an efficient ICE engine when considering the entire energy conversion chain (specifically, the end use of an EV would be about 12 MMBtu, while that of an ICE engine would be 41 MMBtu). In addition, the battery electric vehicle (BEV) would produce no emissions, either CO2 or tailpipe emissions, at point of use, while even an efficient ICE vehicle would continue to produce significant amounts of emissions.

Accordingly, the Alliance believes that there is a significant efficiency gain to be achieved in primary to final energy usage by moving from ICE vehicles to battery electric vehicles. The metrics for these efficiency gains, of course, are not the same as have been used to measure traditional energy efficiency improvements over the past two decades, and we believe that new approaches and metrics must be developed to measure these improvements. Moreover, the Alliance realizes that Illinois still has significant amounts of fossil generation in its generation mix, especially in the Illinois basin, which should be addressed together with its significant zero carbon nuclear generation fleet. We believe that the Commission needs to take into account the characteristics of the generation mix in Illinois, and how it varies by season, by hour, by location, and by fuel price variation over a period of time, along with any public policy preferences imposed by the state on this generation mix. In general, the Alliance believes that the shift toward lower carbon sources of generation will continue to accelerate in Illinois, the Midwestern region, and throughout the country for a variety of economic and environmental factors.

Regarding the likely increased load generated by EV’s in the future, it is difficult to make accurate estimates at this time due to the low levels of penetration of light and heavy duty vehicles in Illinois and other states. Many of the projections are performed on a global or national basis, since the EV market is increasingly becoming a global market for both the final vehicle, the batteries, and other parts of the supply chain and that fact that China and the EU are moving more quickly than the United States in the path to adoption. And many of the projections vary considerably in the rate of hockey-stick type growth over the next 10-15 years, although nearly all projections set forth very significant growth trends based on the publicly announced plans of major auto OEM’s and the expected decline in battery costs. If we refer to the BNEF projections cited in the introduction of the NOI, namely 11 million EV’s sold in 2025 and 30 million in 2030, it is reasonable to assume that the U.S. market should account for about 2.5-3 million units and 7 to 8 million units of those global sales. If so, it is not unreasonable to
assume that Illinois should be able to achieve annual sales of EV’s of about 90,000 to 100,000 units by 2025, and 250,000 to 300,000 units by 2030. While the registered base of EV’s in Illinois today only amounts to about 15,000, this would constitute a significant ramping up of sales growth of light-duty EV’s especially in the ten-year period from 2020 to 2030. A registered base of 700,000 to 1 million EV’s by 2030 in Illinois is not an unreasonable assumption given likely national growth rates. And the Alliance expects that medium and heavy duty vehicles, including metro transit buses and school buses as well as commercial delivery fleets, to increase at a significant pace in Illinois and the Midwest as well.

Regarding the increased load attributable to EV’s and EVSE, net of ongoing energy efficiency measures, it is too early to make reasonable projections for specific utilities in Illinois. More work needs to be done on a utility and state-wide basis to understand these overall impacts from transportation electrification, and then to translate these effects in to more specific impacts on the distribution system. We do have the overall national analysis done by EPRI in the USNEA, in which it modelled four different scenarios out to 2050, and the impacts on total final energy (in all cases a decrease), electric load, natural gas, and economy-wide impacts on CO2 emissions. For increased electric load, the impacts ranged from a 32 percent increase for the Reference Case, to a 52 percent increase for the Transformation Case. That latter scenario translates in to an annual net load increase of about 1.8 percent out to 2050. But, again, these projections included economy-side forecasts of electrification across several other use cases besides the electrification of transportation, and therefore those should be adjusted accordingly.

Grid Reliability and Resilience

We will attempt to answer these questions one by one, but first one needs to define more precisely the definitions of “reliability” and “resiliency” of the electric system at the distribution level. We will define “resiliency” in the more traditional sense of SAIDI and SAIFI, namely measuring how reliably the distribution system can deliver adequate power as measured by duration and frequency of outages, while maintaining system adequate frequency regulation and voltage controls. Resiliency, on the other hand, refers to the ability of the distribution system to both respond to and recover from an external event that attempts to disrupt the reliable operation and delivery of electric power to customers. Resiliency metrics therefore deal with the adaptability of the system, and importantly the time and effort required to recover from such an event – whether it be a natural disaster, or a cybersecurity type of event.

A. In general, the adoption of EV’s should have no significant impact on grid reliability and resiliency. These should be regarded as another demand side resource, and specifically as a distributed energy resource (DER) that can provide benefits both to the end-use consumers as well as the distribution grid;

B. The key issue for grid management is to encourage and adopt charging practices which avoid the increase of peak loads on the grid at certain points during the day. This management is termed grid-to-vehicle charging practices. Part of this involves tariff changes that provides the right price signal to the consume through a tariff or time-of-use rate, either on a whole home or separately metered basis. Another part involves general customer education on how to carry out “smart charging” and how to use the functionality in the electric vehicle, and how to use tariffs and rates to gain as much economic value as possible while benefiting the grid;
C. Additional grid infrastructure to accommodate EV’s should have no direct impact on these issues; these investments in capital additions to the distribution system should be regarded as any other asset. One key issue is what sort of longer-range planning is necessary by the utility, to be reviewed by the Commission, to guide such investments;

D. Many types of new technologies can be used to manage these new loads created by EVSE, and certainly EVSE can enable technologies such as demand response and perhaps increased distributed storage in the future. The questions here primarily revolve around both the increased cost associated with such technologies, as well as the rate design issues to be reviewed and approved by the Commission. And, of course, the threshold issue is how much of this charging will be grid-connected to the utility in the first place (as opposed to Level 1 charging not necessarily connected to the grid, and subject to potential load management techniques).

E. No, vehicle to grid (V2G) capabilities are desirable under a range of circumstances for grid management, but not necessary either for the EV owner or the utility, especially in early stages of adoption.

F. As stated above, it is desirable for the distribution utility to have both access to the location of the EVSE, and basic information on the type of charger in order to both plan for grid improvements (e.g., potential transformer or other transformer upgrades) and operate the grid efficiently. At low penetration rates, this is not as serious an issue as at higher penetration rates. However, even with the low penetration rates and pilot programs by the utility to test out certain charging infrastructure, it is important for the utility to have full access to the data generated by the EVSE funded by utilities, on a royalty and IP free basis, in order to assess consumer behavior and impacts on the grid.

G. Cybersecurity is an important and complex topic, and as with any other DER introduced in to the distribution system, the utility and vendors must address these issues seriously and provide adequate security to mitigate the potential risks of these systems. As a general matter, any new device or system introduced in to the system poses an increased security risk to the security of the distribution system in terms of both IT and OT security. Utilities and vendors should be vigilant about such risks, should adhere to the current engineering standards for such equipment and systems, and go further by adopting best practices that try to anticipate future threats and malicious actors that may attempt to intrude in to EVSE and grid integration systems for DER’s in general. Let us offer a few more specific comments here:

1. Utilities have faced similar cybersecurity challenges when adopting advanced meters or AMI which include remote control of distributed devices over the past decade, and there are valuable lessons learned here that may be applied to the increased deployment of EVSE for electric vehicles;

2. While NERC-CIP standards apply at the bulk electric system level, developed by NERC and overseen by FERC, no similar mandatory standards exist for SCADA and OT equipment at the distribution level, both for the assets owned by utilities and the supply chain and vendors with whom the utilities procure from;
3. But the overall framework created at the bulk electric system may be useful for the ICC and other state agencies in Illinois when overseeing the cybersecurity measures taken by utilities, and the overall resiliency of the grid in the event of such contingencies;

4. If the regulated utilities are required to report or consult with the Commission on a regular basis, the measures adopted to mitigate these risks should be included in such reporting;

5. Finally, the Commission realizes that the vigilance about cybersecurity measures extends not just to the regulated utilities, but also to some of the new industries active in this EV space, namely the automotive sector, and the IT industry involved in autonomous and semi-autonomous vehicles. While these industries are not regulated by the Commission, they have extensive experience in cybersecurity and other measures which may offer useful guidance especially with higher EV penetration levels.

Barriers

There are many barriers as well as benefits with more rapid adoption of EV’s and the accelerated deployment of EV infrastructure. On behalf of the Alliance, I have written on this topic in more detail in several articles and papers. Probably the most thorough explanation of some of these issues are in the recent paper published by Lawrence Berkeley National Laboratory (LBNL) in August of this year: “The Future of Transportation Electrification: Utility, Industry and Consumer Perspectives.” This paper brought together different perspectives on these issues by me (Philip Jones), Jonathan Levy of EVgo, and Jenifer Bosco of the National Consumer Law Center. We would refer you to these essays for a more detailed discussion of some of the many challenges here, as well as the many potential benefits and opportunities. But let me attempt to highlight and summarize a few of the major issues, first on the barriers side and then the benefits; again, I will try to follow the questions posed, as well as some additional thoughts:

A. Consumer awareness: this is one of the largest barriers to greater EV adoption, namely a general lack of awareness of the EV market and specifically how many and what type of light duty EV’s are available to drive today. In addition, consumers are generally unaware of the significant number of future EV’s – both PHEV’s and BEV’s – that have been publicly announced by the auto OEM’s to enter the market in North America soon. Even in the expanding market for EV’s in California, our largest market, surveys have shown that less than one-half of all surveyed consumers can name a specific EV. The Alliance believes the “driving is believing”, and that it is critical to try and get consumers in an electric vehicle through a ride and drive or similar event;

B. Education and outreach: this issue is related to the above, but involves the broader issues of educating not only consumers, but also the automobile dealers who are not adequately trained to sell EV’s and lack the basic knowledge of types and locations of charging infrastructure. In particular, the Alliance has observed the local automobile dealerships have become a real obstacle, in general, to the increased adoption of EV’s (although a small number of dealerships, maybe 10 or 15 percent, do a good job in EV education and sales, most of them lack such training and awareness). But this lack of knowledge also extends to utilities themselves and their employees, employees of corporations and large organizations (which may have workplace charging), and others in the potential EV ecosystem. Utilities with best practices are addressing
these issues in a variety of ways, including enhancing web portals to provide both general and specific information to its customers, working more closely with automobile dealers, working more closely with cities, counties and other non-profit organizations, and of course working directly with the auto OEM’s to engage in such issues. The Alliance believes this is both a consumer barrier and a regulatory issue. We believe that the O&M costs associated with a well-designed program for consumer awareness and education, with appropriate limits and oversight by the Commission, should be categorized as “above the line” and included in the total revenue requirements.

C. Range anxiety: this has proven to be a major obstacle to most consumers when they are surveyed about a potential purchase of an EV, but is less of a concern for drivers with access to private parking because of significantly increased range for fully electric vehicles (now typically capable of about 250 miles as compared to 90 miles for the first generation of EV’s) as well as a large number of plug-in hybrid vehicles (PHEV’s). Such PHEV’s are capable of 30 to 50 miles on a fully charged battery, along with a small gas tank fueling a 4-cylinder internal combustion engine, can together achieve a range of 450 to 500 miles. Accordingly, such vehicles may need only a single Level 2 charge per day. That said, many drivers do not possess control of a parking space and will rely on public charging. For these EV drivers, as well as for drivers of fully electric vehicles who drive long distances including between cities, the concerns are legitimate. That is why when certain surveys have been conducted by Plug-in America and other consumer facing EV groups, the single most important reason that people mention for not purchasing an EV is the lack of adequate charging infrastructure deployed and in the ground. They are afraid of running out of “fuel” (namely the kWh in a fully charged battery), and being stranded on the side of a busy road or highway.

D. We will address these regulatory issues later in the ratemaking section, but the Alliance strongly believes that a substantial number of DC fast charging stations located both along highway corridors as well as in dense urban areas (perhaps along with public facing Level 2 chargers) is a key to resolving these anxieties. The Alliance believes that utility ownership and control of such DC fast charging stations is preferable in this early stage of market development.

E. Economic barriers: there are several economic barriers to greater adoption of EV’s and more EVSE infrastructure today. The first obstacle is the relatively higher cost of an EV compared to an ICE engine. Although battery costs and other supply component costs have been rapidly declining, the reality today is that the cost of an ICE vehicle is lower than that of an EV. Several projections, however, point to a “tipping point” in the early 2020’s when the upfront purchase cost of an EV will become roughly similar to that of an ICE vehicle, although technological changes and improvements will affect both types of vehicles. However, on a total cost of operating (TCO) basis, the EV will increasingly compete with the ICE vehicle, and will likely become cheaper to own and operate as a vehicle in the next several years, if not today for some vehicles. In addition, potential EV owners will incur additional costs to install at least some portion of the make-ready costs and Level 2 home charger (depending on the utility program, and the type of rebates or incentives offered) in order to do home charging, where over 80 percent of the charging has been done to date.
There are multiple solutions to these barriers that have been and are being worked on actively by auto OEM’s, vendors, utilities, and other EV stakeholders. They include continued cost reduction efforts by the auto OEM’s to bring the upfront purchase price of an EV down, including efforts by battery developers to lower costs while increasing range. They include the continued offering of various incentives for the purchase of an EV, including an extension and lifting of the cap (for those auto OEM’s who have reached the cap this year) for the federal tax credit, continued state and local tax incentives for both the purchase of an EV as well as potentially to non-utility developers of EVSE infrastructure. Of course, these financial and tax incentives have to be well calibrated and structured in the context of overall fiscal policies, but they are critical at this stage of market development to accelerating change.

In addition, utility programs can be very effective in addressing many of these economic related barriers, such as assisting new EV owners/ratepayers with some cost sharing of the initial infrastructure building out at the residence, as well as accelerating the building out of public facing EV infrastructure that addresses their concerns about range anxiety and adequate public charging stations within their neighborhoods and cities.

F. Prioritization of barriers and needs: while the basic answer to this question is yes, the more complicated answer is that this answer depends on the overall posture that the Commission, likely guided by the Legislature and perhaps the Governor, wants to take on these issues. The Alliance certainly believes in a proactive role for the Commission to play in this space, and urges this Commission to issue definitive policy guidance or direction for the regulated utilities, and all stakeholders, to follow in pursuing these objectives. Yet the Commission needs to allow the regulated utilities, as well as the multiple non-utility third parties, local governments, vendors, and potential host sites, to put forth their own plans and priorities for accelerated deployment of EV infrastructure. For the regulated utilities, increasingly good long-term planning – most likely on a 5 and 10 year basis to start – has become vital to good planning and sound asset management, and this should be encouraged by the Commission. The prioritization of needs and requirements can take place within the context of those distribution level planning efforts, as well as the requirements for asset management consistent with reliability and resiliency needs. Regular or annual reporting can be a means to achieve this, as well as a robust and ongoing stakeholder process, preferably led both by the Commission staff and regulated utilities, that addresses these issues through meetings, workshops, and exchange of information. In addition, the utility should be encouraged to engage in more detailed planning around both decarbonization goals as well as accelerated EV adoption and other DER’s by developing a “Pathway to 2030” type study. Examples of other utilities who have developed such plans, which are both forward-leaning as well as quite tangible in terms of the near term (namely 2030, instead of the longer range aspirational goals of 2040 or 2050), include the Pathway studies of National Grid, Southern California Edison, and the low-carbon pathway study by the Southern Company.

G. Commission as a facilitator: while not having direct regulatory control and oversight of all players in the EV ecosystem (such as auto OEM’s, most non-utility third party providers, IT solutions providers for autonomous EV’s and so on), Commissions, besides having explicit control over the regulated IOU’s, can play an important facilitation role within the state of Illinois. The ICC has already shown strong leadership in technology and grid modernization issues for the state in convening the Next Grid Illinois proceeding and series of working groups,
which have assessed a number of technologies such as EV’s and EV infrastructure and their impact on the evolving grid. The Commission can continue to play this role in the future by bring together the various state agencies such as the Illinois EPA including both the clean air office and the state energy office, the Illinois DOT, as well as other agencies as well as the multiple stakeholders in the EV ecosystem – auto OEM’s, vendors, environmental NGO’s, local governments and many others. The key point is to achieve good coordination and information sharing, consistent with the statutes and rules in Illinois, in a transparent way.

H. Lack of consistent planning and a roadmap: as stated above, it is important first for the utilities regulated by the ICC, and other non-jurisdictional utilities, to develop specific plans and roadmaps (“Pathways to 2030” is one approach) for the acceleration of EV infrastructure in their service territories. Based on those pathway studies, the Commission and other state agencies should be able to use those analyses and data to build a broader, more comprehensive state-wide plan that can guide state decision-makers and other EV stakeholders on the best pathways forward. The MJ Bradley study done in 2017 for the state, commissioned by the NRDC and the Sierra Club, was a good start for a state-wide assessment, but more detailed studies should be done by the utilities in a broader stakeholder process to develop specific plans which can result in program development, rate design and tariff proposals, and other tangible actions.

Benefits:

Again, as stated above, I would refer both to the LBNL essays cited above, as well as the MJ Bradley study done in 2017 to understand better the benefits that are created by increased adoption of EV’s in Illinois (and regionally and nationally), as well as the acceleration of EVSE deployments. There are significant economic and environmental benefits associated with this significant transformation of both the automotive/transportation and electric power industries, together with the positive contributions to be made by the IT industry in developing autonomous vehicles as well. We highlight and summarize several of these benefits below. At the same time, the Alliance strongly supports the development and adoption of new cost-benefit methodologies that reflect more broadly not just the electricity impacts, but the energy conversion impacts of this transformation.

A. Benefits of reduced GHG emissions: today, Illinois ranks about fifth in the nation in the annual emissions of carbon dioxide – about 219 million tons of CO2 according to the 2015 data from the EIA. About 71 million tons can be attributed to the transportation sector, which as of 2015 was roughly equal to the emissions from the electric power generation sector, and since then has probably surpassed those amounts. Accordingly, the more rapid adoption of EV’s – both light duty vehicles as well as diesel-powered medium and heavy-duty vehicles – should play a significant role in reducing such emissions. If the BNEF projections are roughly accurate, and some of the penetration rates cited turn out to be correct for EV’s on the road by 2030, the move toward electrified transportation could play a significant role here. In addition, as zero and low carbon resources become more cost-effective such as solar and wind, and as the public policy support for zero carbon nuclear generation is continued, the power generation mix will move toward a lower emission path, and complement the environmental progress that will be made in the transportation sector;
B. Disadvantaged neighborhoods and environmental justice: historically, some of the neighborhoods and communities that have been most affected by air pollution, such as SO\textsubscript{x} and NO\textsubscript{x}, have been the low-income and disadvantaged communities located near both large stationary sources of pollution, as well as major highways, ports, and industrial areas with significant numbers of diesel-powered trucks and automobiles travelling through them. The electrification of transportation over time should play a significant role in helping to improve air quality in these disadvantaged communities, and thereby provide tangible public health benefits to the residents of these communities, including potentially senior citizens and children who may suffer from asthma or other health concerns. With properly designed programs such communities and constructive engagement with these communities, the utilities have a unique and important role to play in helping to provide EVSE to such disadvantaged communities.

C. Lower electric rates for consumers: several studies have analyzed the data and scenarios of higher EV adoption, under various assumptions for smart charging programs and tariffs that encourage EV owners to move charging to off-peak. Such studies also include the impacts of more efficient utilization of the distribution grid, as well as higher kilowatt-hour sales of electricity for the utility. If these programs are properly design and implemented, and avoid increasing peak loads during the day, these programs should result in lower total revenue requirements for the utility, which should result in lower rates for all customers in all rate classes. This could be result in a positive outcome both for the EV owners, who will enjoy both lower fuel costs due to electric costs compared to gasoline costs as well as the lower total cost of operations (TCO) – as well as positive rate benefits for the non-participants as well;

D. Grid integration benefits: as more EVSE is deployed at the edge of the grid, it should enable more technologies, such as demand response (DR) and potentially distributed storage, to be integrated more easily in to the distribution grid of the future. While it is difficult to project specific benefits and quantify those benefits today, the Next Grid Illinois proceeding is assessing many of those potential benefits of new and emerging technologies which may be deployed in the grid over the next decade. EV’s and EV infrastructure will constitute a key building block for such distributed architecture and infrastructure in the future.

E. Economic development benefits: the Alliance believes that there are significant benefits of economic development from the support given to a robust and strong automotive and transportation industry in Illinois, the Midwestern states, and throughout the United States. As stated earlier, the automotive industry is global in its structure and its supply chain including the key component of battery design and manufacturing. China and the EU are both significant potential competitors in this emerging EV marketplace, and today China has developed the leading EV market in the world. The economic development benefits for Illinois and other Midwestern states are potentially significant and can be quantified in terms of state GDP, personal incomes, taxes generated, and other factors. While the Commission is primarily designed by statute and rule to be an economic regulator of utilities in Illinois, it is certainly permissible for the Commission to take economic development factors into account when reviewing tariffs and programs submitted to it by the utilities. Moreover, the Commission is a body created by the Legislature and is certainly attentive to the legislative direction provided by potential bills in the areas of environmental protection and decarbonization measures, economic innovation, and the development of a modern grid.
F. Cost benefit methodologies: this will be a critical issue for the Commission to decide as utilities file petitions to initiate EVSE programs and ultimately seek to recover costs in utility rates (above the line) or from shareholders (below the line). This is a complex and challenging topic, but needs to be addressed quickly in order to provide solid policy guidance for both the utilities who file and the EV stakeholders who will intervene in such cases. A number of tests have been used to date, including the Ratepayer Impact Measure (RIM) test, the Utility Cost Test (UCT), the Total Resource Cost (TRC) test, and perhaps the Societal Cost Test (SCT). The Alliance believes that that a variety of tests can be used for analysis and reference during a file, and while a RIM test has been used by several utilities in jurisdictions, it will never be sufficiently robust and broad to incorporate all of the benefits and costs that have been cited above. An SCT approach may be more appropriate for a state that has a specific goal of decarbonization and a preferred pathway to achieve this, but some of the decisions in pricing carbon and other “environmental or public health” public goods are considered to be too subjective by some intervenors. Recently, EPRI has commissioned a study from the Brattle Group, led by Ahmad Faruqui, Ph.D., to try to develop another “middle ground” approach that combines elements of both the TRC and SCT methodologies that utilities and Commissions could use to evaluate these proposals. While still being developed and vetted, the Alliance believes that this approach (it is being called a Holistic Value Test) has merit, and we urge the Commission to give this methodology due consideration either in this NOI or in a future proceeding which examines the costs and benefits of electrification for light duty vehicles and medium/heavy duty vehicles such as buses.

EV Charging Infrastructure

The Alliance believes that the utilities should first engage in such detailed analyses of their specific distribution grid for their service territories and likely number of customers to adopt EV’s, and therefore our comments here will be at a higher level. The utilities, in consultation with the EV infrastructure firms, other vendors, and EV stakeholders, make a good-faith effort to estimate the types of charging infrastructure that will be required – ranging from residential, to workplace, to DC fast charging stations – to achieve the goals of Illinois by 2030. While the Commission should be most concerned about the public facing charging infrastructure to be deployed – namely, the DC fast charging and the non-resident Level 2 public charging – the Commission should encourage a “portfolio approach” that includes all types of charging including workplace and residential charging since they are important components of a comprehensive plan. The Commission should take into account two foundational studies that have been conducted to date – namely, the MJ Bradley study done for the state of Illinois in 2017, as well as the NREL study published in September, 2017 done on a national basis that uses that methodology to estimate the necessary infrastructure to accommodate the needs and range of EV owners (“National Plug-In Electric Vehicle Infrastructure Analysis”, September, 2017, by NREL for the USDOE, Office of Energy Efficiency and Renewable Energy). The projections of EV’s in the fleet by the MJ Bradley may be somewhat on the higher side (1.2 million EV’s by 2030 for Illinois), while the projections in the Central Scenario of the NREL study nationally may be considered to be more conservative (15 million EV’s nationally by 2030, which may translate into a range of 600,000 or 700,000 EV’s for Illinois depending on their distribution). We will now address some of the specific questions posed in the NOI.
1. Assessment of the necessary charging infrastructure by method and source:

a. As stated above, we believe that the NREL methodology for infrastructure needs constitutes a sound basis for Illinois-specific analysis. The MJ Bradley study can be used as a supplement;

b. It is difficult to develop a precise and consistent ratio of PEV’s in the fleet to the required number of DC fast chargers and public-facing Level 2 chargers and ports. These needs will vary by type of business use case (a light duty vehicle case, a shared transportation network company case in an urban area, an intercity highway corridor use case, and so on). And the need for stations and ports will vary widely by location and geographic area – namely, cities, towns (or suburban areas), rural areas, and interstate corridors;

c. Suffice it to say that the NREL study, under what we view as a fairly conservative “Central Scenario” called for about 8500 DC fast charging stations, or about 27,000 ports, by 2030. We are far short of that number today nationally, and certain far short of that number in Illinois;

d. The Alliance believes that, due to this large and growing infrastructure gap in Illinois and other Midwestern states, that utilities and others in the EV ecosystem need to work collaboratively to make a concerted push – starting today – to attempt to fill this gap;

e. The Alliance believes that the utilities regulated by the Commission, as well as other non-jurisdictional utilities, have a vital role to play in kick starting the EV infrastructure market, and helping to transform this market in an accelerated way;

f. It is difficult to describe precisely the rate at which the public infrastructure should grow, especially if it is led by utilities together with the vendors. Due to the regulatory process, utility rate cases and accounting petitions tend to come to the Commission for review in a concentrated way, and there the capital and O&M investments will be lumpy. Accordingly, it is probably not appropriate to try to develop a smooth-line average investment amount for this over the next ten years. But the Alliance urges the Commission to consider both the rapid growth in EV sales over the past couple of years, in the range of percentage increase in the high 20’s to mid-30’s, and especially to look forward to the next 3 to 5 years in particular, and what is expected to be hockey-stick type growth;

g. The Alliance believes that the overall size of the EVSE market will be substantial, and that there will be ample room for both utility and non-utility companies to participate in the growth of this market. We believe that the utilities, as stated above, should play a leading role in developing this nascent market, but we do not put forward a number of total charging stations or percentage of market for the utilities versus the non-utility companies. There will be a number of business models that are developed as the market is transformed.

2. Costs of installation and EVSE:

The costs of the installation will vary significantly depending on the type of end-user (residence, commercial, Level 2 public, and DCFC), the price and terms of real estate, the amount of trenching needed, panel upgrades need, and a host of other factors. Moreover, the costs of
installation will vary depending on the cost of living and electrician costs in either the city (more expensive), the town (less expensive), and rural areas (less expensive). Averages can be made for state-wide purposes and for the purposes of regulatory tariffs and establishing the level of an average customer contribution (for installation), and the average level of a rebate to the customer (for both installation costs and the purchase of EVSE). The Alliance urges the Commission to explore these cost-related issues in more depth in a further workshop type setting, since the utilities and EVSE firms and vendors can produce more specific numbers based on the above factors. For illustrative purposes only, the Alliance will offer below several reference cases from other states, broken down by type of charging infrastructure.

a. Residential charging costs: we refer to the Avista pilot program in Washington which began in 2017, which is the based on the own and operate model. Avista requires a certain level of customer contribution and offers a rebate. The level of residential costs of installation has varied from $452 to $3271 per unit, with an average cost of about $1,370. If one adds the average EVSE cost of $1,048, that brought the total cost to about $2,440. Key factors in the cost differential are whether or not 240V service is available, whether or not a panel upgrade is necessary, the amount of trenching necessary (not common), and total circuit distance. In its report to the Washington UTC, Avista cited to an INL study which found wide cost variations by geography in the country, stating that the averages for Los Angeles for $1,828, for Atlanta at $775, and for Seattle at about $1340. Therefore, the Commission should expect a similar variation among urban and geographic locations in Illinois, with probably the Chicago metro area being the most expensive, while other cities and towns (and rural areas) should have lower costs.

b. Commercial charging costs: of course, these installations are more expensive due to their scope and size, amount of trenching, and other factors. One of the key differentiating factors is whether the unit can be wall mounted (cheaper) or pedestal mounted (more expensive). The average cost of installation per customer was about $7,860 per unit, while the cost of the EVSE was about $4,860, resulting in a total cost of about $6,000 with average ports being 2.1.

c. Level 2 public charging costs: the costs cited above for commercial customers can be generally referenced for these L2 public charging stations, although the location and design (perhaps together with DC fast charging stations in combination) will play a large role in the actual costs;

d. DCFC, or DC fast charging stations: the total cost of DC fast charging varies widely by type of charger (generally, 50 kw capacity with both CCS and CHAdeMO connectors as dual ports with a Level 2 EVSE as back-up), but increasingly 150 kw capacity chargers), location (intercity highway in rural area, or dense urban area), need for trenching and other construction work, need for circuit upgrades, and cost of real estate. Accordingly, the use of averages is not instructive here; instead, discussing these installations by sub-categories and location is more useful. Avista found the range of costs in the Spokane and Pullman (close to a major university, WSU) areas to be in the $100,000 to $150,000 range, including all direct and indirect costs. Avista encountered several challenges in trying to site its proposed 7 DCFC installations, prove a viable business case in the early years due to lower expected utilization, and develop the right price method per the tariff that could be approved by the Commission.
However, these costs will certainly be higher for certain parts of Illinois, and certainly in the Chicago metropolitan area; the Commission will have to rely on its regulated utilities to develop appropriate cost estimates for DCFC. Many lessons have been learned at this utility and many others around the country as they have developed these DCFC stations on a pilot program basis, and there. Again, the Alliance urges the Commission to engage with the utilities and vendors and ask for more detailed cost and technical information on DC fast charging. We also urge the Commission to examine closely the difficult use cases for DC fast charging, based on either kWh charging (perhaps in the $0.23 to 0.40 range), or time-based charging for revenues, and how the expected lower utilization rates in the early years make this difficult on a stand-alone basis. Instead, the Alliance urges the Commission to regard DCFC as one measure in a “portfolio approach” to EVSE that can be considered and assessed using a cost-benefit analysis for the entire portfolio of measures.

3. Public chargers in densely populated areas:

The short answer is yes, and with the advent of higher capacity DC fast chargers (going from 50 kW to 150 kW and perhaps further), this may generate a better use case in a dense urban area. We will not offer further details here, since this is a complex area of both siting, location, public policy, and the greater penetration of TNC’s (transportation network companies) based on EV’s. Such charging stations could be sited to serve the needs of people who live in multi-unit dwellings, such as apartment buildings, where it is difficult to persuade the landlord, or other tenants, to install a charging station in the garage. This application may also be appropriate for disadvantaged communities (DAC’s), or low income communities, in which either a garage is not available, or a curb-side location at the residence is not permitted.

4. Ownership of charging stations:

As stated above, the utility should be allowed the option to own and operate a portfolio of charging stations and EVSE, and should be provided a robust role in the planning and operation of these network management systems. Any rules either prohibiting or constraining a utility role in this area should be addressed and resolved, so that they can fully participate in this infrastructure deployment. How strongly to encourage the utility participation in this area should be left to the Legislature, Commission, and other state decision-makers. The Alliance believes in a strong utility role for a number of reasons, some of which are stated above.

The utility must plan for and manage the “grid of the future” which is becoming increasingly complex with more DER’s and two way flows of power. Both for planning purposes and operational reasons, the utility should have the ability to have full “situational awareness” of how EVSE loads and other DER’s are being sited and operated. They should also have full access to the data, on a royalty free basis, from the EVSE in order to be able to gauge consumer behavior and ascertain if EVSE loads are being shifted from potential peak times to off-peak hours, while maintaining the reliability of the system. In addition, we believe that the utilities have the financial resources and size to be able to accelerate EVSE deployments and scale things up quickly.
In addition, utilities have the obligation to serve when a customer requests service for an EVSE or DER (the principle of universal service), if these applications are going to be an essential part of the future grid as we believe they will be. Finally, we believe that interoperability and open standards are going to be vital for greater adoption and an improved consumer experience in the future as scale of EVSE increases. While there are several proprietary network management systems being deployed on the back-end of infrastructure today, the Alliance believes this is the wrong approach. Utilities have more of an ability to insist upon open protocols and interoperability, as Electrify America has done in Phase 1 of its national ZEV investments in Illinois and around the country, and they can insist on these protocols in the RFP process with vendors.

However, several business models are possible as well, and some utilities have chosen, at least initially, to pursue a make-ready approach to building out infrastructure to the stub, and allowing the customer or host site to purchase the EVSE (perhaps with a rebate) and handle other BTM (beyond the meter) installation and operational issues. This can be a viable model as well, although the Commission should measure and assess the implementation of these models (especially with a rebate, which is funded from general utility revenues including non-participants in EVSE) against the goals set by the Commission either on a utility-specific or statewide basis. Other business models are possible as well, including certain partnerships with host sites such as municipalities and local government organizations.

5. Why DCFC chargers are necessary:

Refer to the above sections. In short, they are necessary to address the serious concerns of “range anxiety” of potential EV consumers, and to be part of a viable portfolio approach of charging infrastructure that meets the needs of all classes of customers, including potentially the low-income and disadvantaged communities as well.

6. Other utility service options:

The Alliance believes that most EVSE infrastructure costs, rate design, and public policy issues should be dealt with openly in a tariff filing in a process chosen by the Commission. We prefer the process to be more collaborative in nature, especially at the outset of pilot programs, rather than immediately going to litigation although the Alliance realizes that ultimately that parties will intervene more formally in a general rate case on cost recovery issues. The Commission may be referring to other possible tariff options to address specific use cases, such as the beneficial electrification of school and transit buses and whether a separate tariff class needs to be created to address the charging infrastructure needs of those end users. That may well be the case, but the Alliance believes that the decision to create such tariff categories should be left to the utility, following a stakeholder process.

7. Building code considerations:

The Alliance will not address in detail this issue, since the jurisdiction over building code issues are generally handled at the city and local government level, and sometimes through a state-wide building council or similar organization. The Alliance, however, believes that the recent
building code for EV-ready infrastructure adopted by the City Council is a good one, and should be a model for cities in Illinois going forward.

8. Ordinance changes:

Again, we will not address in detail for reasons similar to the building code considerations stated above.

9. Other municipal codes:

Again, we will not address these issues in detail.

10. Technical standards and protocols:

As stated above, and the essay referenced in the LBNL paper, the Alliance strongly believes in promoting interoperability and open standards or protocols, especially on the back end of the network management systems that connect the cloud-based network to the specific charging station in the field. We believe that Open Charge Point Protocol (OCP) is the best available protocol in the marketplace today, which is administered currently by the OCA (Open Charge Alliance). While this is emerging as the most common protocol recently in the EVSE industry and was adopted by Electrify America for its national investment network, not all utilities and EVSE firms have adopted this protocol. And other proprietary networks have been developed and deployed as well.

In addition, we believe that the interoperability of charging station systems on the front end need to be addressed quickly. Currently, the Alliance believes that the charging experience for a new EV owner is too complex, fragmented, and burdensome for convenient charging at public facing stations. There is no national standard or protocol that allows free roaming among proprietary networks, and instead EV owners must sign up for several different charging systems with a membership card. Networks don’t necessarily share easily this information among themselves. Recently, certain EVSE firms have negotiated peer-to-peer (PTP) agreements bilaterally for themselves to share such information, and this is a step in the right direction. Yet another attempt at an open platform that would allow e-roaming in Europe is called OICP (Open InterCharge Protocol), being developed by one company. The Commission should address these e-roaming among networks, billing compatibility, and ease of consumer use through the development of common and open platforms, as much as possible.

Ratemaking issues

Generally, the ratemaking issues should be addressed in specific utility filings, and the utilities are best prepared to develop such tariffs and programs for review by the Commission, depending on their medium and long-term planning for deployments and capital asset management including EVSE and other DER’s. Utilities should bear the burden of proof in a Commission proceeding, whether it be an open meeting item or in a general rate case (GRC), and should work with the EV stakeholders in a robust and constructive process prior to filing. Accordingly, the Alliance will not devote many comments to these two sections (Ratemaking and Regulatory Treatment of EV’s) at this time. But we look forward to a further process in this proceeding in
which we can engage in more detail on these issues, since they will be utility-specific and fact-specific to the circumstances at the time.

1. Dynamic rates: yes, in general, they are a good and necessary idea for most utilities in providing incentives to consumers to move the EVSE load to an off-peak hour. This is especially true in a state like Illinois, in which at least the northern part of the state can participate in real-time energy markets (with PJM) and garner benefits from time variations in pricing. But generally, in the RTO states, it is easier to develop TOU rates and make them effective, and provide discrete benefits to the consumer. In some of the vertically integrated states, such as Washington and Oregon where there is not a large difference in off-peak and peak wholesale prices and no RTO/ISO to operate a real-time energy market, it is more difficult for the utility to develop meaningful TOU rates. Yet the rate structures developed by Georgia Power, which were approved by the Commission, have proven to be effective and deliver real benefits to EV drivers. The benefits to the consumers, of course, are the lower prices usually in the night-time hours in the per-kWh price of electricity in which they can further lower their electricity costs. This improves even more the price comparison between the gasoline for an ICE vehicle, and the electricity during off-peak for charging the battery of an EV.

2. Treatment of capital as rate base: The Alliance, as stated above, believes that the capital investments for EVSE should be treated in a similar manner as any other prudently incurred investment for capital in the distribution grid infrastructure. There is no persuasive reason to categorize this differently from other types of either investments in intelligent devices in the T&D networks (such as those in smart grids, or capacitors, or other advanced equipment on the lines and poles). Investments in EVSE should be regarded as another form of a distributed energy resource (DER) that is both dynamic and flexible in the sense that it can accommodate other forms of innovate uses in the future that may provide tangible benefits to the customer and the utility, such as DR and distributed storage. From an accounting standpoint, the Commission should follow the normal accounting practices for such capital investments that are included in the asset management plan (once deployed) of the utility, and therefore should be classified as “electric plant” according to the normal definitions of FERC and the Commission.

Regarding the breakdown between O&M and capital expenses, the Commission should review such a division of funding in the petition from the utility, and assess it in the usual manner it would for any other project or investment in the distribution grid. For example, expenses for education and outreach activities should be regarded as an O&M expense, while investments in make-ready to the meter or EVSE location (electric wiring and any upgrades, trenching expenses to that location, etc.) should be regarded as a capital expense, along with any associated equipment associated with communications devices (e.g., commercial WiFi networks in a mesh network that carry signals from the DC fast charging station to the equipment on the utility pole).

The Alliance also believes that Commissions should consider capital treatment, with a return, for the rebates to be offered to customers and end-users as part of the overall tariff or program meant to incentivize greater EV adoption. Not many Commissions have moved in this direction as of today, and the Commission needs to consider the public policy guidance it has received from the legislative bodies, in terms of statutes and intent language, as it makes decisions on this particular point.
Many Commissions have approved utility petitions for EVSE cost recovery using deferred accounting, since the first programs for EVSE are usually pilot programs over a two or three year period. Such accounting treatment allows the utilities to avoid regulatory lag, and begin receiving cost recovery quickly after its investments for the “return of” its capital investments as well the “return on” such expenditures. Such expenditures are reviewed under normal rules in a future general rate case proceeding on prudency grounds.

3. Other rate design options:

There are a number of rate design options of utilities that have been approved by other State Commissions. As stated above, a number of states like Georgia, New York, California, Maryland and many others have earlier approved some sort of dynamic pricing with a TOU rate, either a whole-home TOU rate or an EV-only TOU rate. In addition, several utilities have been able to secure approval for tariffs that provide some sort of “demand charge mitigation or holiday” for customers that wish to deploy DC fast charging especially. For example, Southern California Edison has received approval for an “economic development tariff” that lowers the demand charge for the first five years of a project while increasing the volumetric rate at the end of ten years. Portland General Electric (PGE) has received approval for a similar approach from the Oregon PUC, although it is not called an economic development tariff and is instead included under existing rate structures (in commercial and industrial rate classes) with the intent to reduce the impact of demand charges in the early years of a DC fast charging station.

Continued on next page.
Regulatory Treatment of EV’s

We have covered most of these questions in the above. Yes, for regulatory purposes of classification as electric plant and cost recovery, the Alliance believes that utility investments in these grid-edge capital assets should be treated in a similar fashion as other assets. Many of the EVSE already include DR capabilities, and distributed storage can be added as a complement or addition in the future, if proven to be useful and cost-effective. The normal allocation of costs between capital expenditures and O&M expenses should be followed using the principles of regulatory accounting, and these costs should be carefully reviewed by the Commission. The above applies just to the assets deployed and operated by the regulated utility. For the non-utility third party provider who is not subject to direct economic regulation, the Commission does not exert direct regulatory authority over such firms, and the location, price, and terms of charging for the consumer will be determined in a commercial manner. However, as stated above, there are a variety of ways in which the market can develop in the near future, and the Alliance advocates a strong utility role which could include other ways of working in partnership with host sites, local government, and EV infrastructure firms. In addition, the utility may choose a preferred list of EVSE providers for its residential or commercial or workplace charging program, and develop a working relationship with the vendors in this manner. If the utility uses overall ratepayer funding and develops the RFP and chooses the vendor, the Commission will assert its authority over the utility (and not the vendor) if any changes to the program are to be made, or if any compliance filings or reporting requirements are necessary.

Respectfully submitted,

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