3.6.4 Tariff for EV Charging at Third-party Owned Infrastructure

In cases where EVSE is owned by third-party energy service providers, service providers can recover cost of charging stations through various routes. Several utilities operate on a model wherein service providers pay charges for total energy usage at the station to the utility based on TOU or flat rate tariffs. Service providers are then allowed to set their own pricing mechanisms to charge EV end consumers as shown in figure below. Regulators usually place an upper limit on charging rates that are allowed to be charged to EV end consumers by EV service providers. Examples of rate structures being currently followed in various places:

Table 25: Examples on Charging Rate structures

Type of tariff	City / utility	Details of user fees by third party providers	
		Type	**Details**
Per unit based on charging duration	ActewAGL-EVCI Provider	Basic Monthly Plan $10 Per 1 Month(s)	• FREE use of Fast Charger • 0 FREE minutes use of Rapid Charger • $3.50 per 15 minutes thereafter
		Budget Quarterly Plan $25 Per 3 Month(s)	• FREE use of Fast Charger • 30 FREE minutes use of Rapid Charger • $3.50 per 15 minutes thereafter
		Value Half Yearly Plan $45 Per 6 Month(s)	• FREE use of Fast Charger • 90 FREE minutes use of Rapid Charger • $3.50 per 15 minutes thereafter
		Freedom Casual Plan $0 Per Month(s)	• No monthly fee • $2 per use of Fast Charger • $5 per 15 minutes use of Rapid Charger
Pay per hour	Canada	Standard Charging Station: • The rate for 240-volt charging is either at a flat fee of $2,50, regardless of the length of charge or at an hourly rate of $1, billed by the minute and based on the amount of time the vehicle is plugged in. • Parking area charging costs $1 per hour, billed by the minute excluding parking fees. For example, if a vehicle is connected to a station for three hours, charging will cost $3.00, even if the vehicle was completely charged after one hour. Fast Charging Station: • The price of the 400-V fast charging station its $10 per hour, billed by the minute i.e., based on the total time connected to the station, not the duration of the charge or the total energy transfer. • Charging station in a parking facility that charges fees, parking fees must be paid as they are not included in the charging cost	

Source: Department of Public Utilities, Massachusetts

3.6.5 Defining standards for EVSE operations and managed charging

CPUC VGI recommendations for improved managed charging:

The California Public Utilities Commission (CPUC) Energy Division, California Energy Commission (CEC), California Air Resources Board (CARB), California Independent System Operator (CAISO), and Governor's Office of Business and Economic Development (GO-Biz) in 2017 led a working group to investigate whether the CPUC should require a communication protocol or protocols for the Electronic Vehicle service equipment (EVSE) and associated infrastructure that IOUs support with ratepayer funding. The study also revolved around suggesting standard specifications which would enable managed charging.

The working group evaluated the existing communication protocols utilized to enable EV management use cases in an effort to understand whether one protocol, or a specific combination of protocols, is mandatory to enable Vehicle-Grid integration (VGI) economically and at scale. The group's work included:

- Evaluating the technical requirements
- Mapping those requirements to the existing communication protocols
- Functional and non-functional requirements
- Hardware requirements
- List of recommended communication protocols for enabling VGI / managed charging

Earlier in 2017, California Energy Commission produced the VGI Roadmap which identified three tracks to direct the state's efforts: (1) Determine VGI Value and Potential; (2) Develop Enabling Policies, Regulations, and Business Practices; and (3) Support Enabling Technology Development. The VGI Roadmap identified activities intended to "increase consistency across technologies to enable interoperability and to provide guidelines for product development, while allowing for variety in VGI products and services." The Roadmap also highlighted the importance of the use of existing, internationally-adopted standards where "a common standards format ensures compatibility among multiple technologies, eases adoption by customers and increases certainty for developers about the access their products will have and about how their technologies can work with others." In particular, it notes how existing communication standards will be required to send messages between the VGI resource, aggregators, utilities etc.

The Electronic Vehicle Charging Stations Open Access Act15 (SB 454; Statutes of 2013) gives CARB (California Air Resources Board) the authority to adopt requirements to ensure public charging stations in California have interoperable billing standards, including a transparent fee structure, and allow the use of multiple payment methods. Participation in the Working Group has facilitated CARB's development of proposed requirements for publicly accessible charging stations.

CPUC highlighted the following key recommendations for managed charging:

Table 26: Key outputs and recommendations from CPUC study[15]

Key outputs	Details
Categories of use cases for EVSE	• Participation through Price Programs: These use cases influence drivers' charging habits by changing the price of electricity and differentiate between off-peak and on-peak. • Demand Mitigation: These use cases attempt to curtail peak demand use by encouraging customers to charge during off-peak times. • Vehicle Two-Way Flow: These use cases can influence charging behavior and also allow EV drivers and business owners to use electricity from a car battery. This category includes vehicle to-grid, vehicle-to-home, and vehicle-to-building use cases. • VGI Services: These use cases allow actors to access VGI services (e.g., demand response or load management programs) through the use of telematics, building management systems, network service providers and other pathways.
Identifying the entities involved	The actors involved were specified to understand the various interactions involved: • EV Driver (EVD) – who sets the charging preferences • Power Flow Entity (PFE) – An offsite entity that is requesting or mandating VGI activities from other actors downstream. • EV Battery System (EVBS) • DC Power Converter System (DCPC) – The off-vehicle power converter that controls DC energy flow to or from the EV Battery System. • EV Supply Equipment (EVSE) • Energy Meter (EM) • Building Management System (BMS) – A collection of sensors and controls intended to automate management of energy flow and use at a site location or facility • Smart charging network
Requirements needed for EVSE managed charging	• Functional (specific processes and functioning of the VGI system) • Non-functional (scalability, response time, reliability, data integrity, and interoperability etc.) • Customer requirements (controlling, opt-in, opt-out) • Other requirements (viz. manual override by customer, disconnecting EV loads by utility during emergency)
Key functional requirements stipulated for VGI / managed charging	• Information for communication back to grid viz frequency, voltage, location etc. • Pricing and tariffs • Load Control: communication of information from utility needed to respond to demand response signals for specific event • Smart Charging: communication of information needed to schedule charging sessions • Monitoring: communicating information about the charging session, including timing and electricity consumed and dispensed. • Restart: communicating information to affect the start of a charging session, including when charging is interrupted, to avoid overloading the electric system.

[15] *https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442460144*

<table>
<tr><th>Key outputs</th><th colspan="2">Details</th></tr>
<tr><td>Communication protocols for managed charging</td><td colspan="2">Following communication protocols are widely accepted whereas several others could be currently in development phase:
• Institute of Electrical and Electronic Engineers19 (IEEE) 2030.5
• Open Automated Demand Response[16] (OpenADR)20 v2.0b
• International Organization for Standardization (ISO)21 15118 v1
• CHAdeMO22 (IEEE 2030.1.1) 5. SAE23 J3072, J2847, J2931, J1772
• Open Charge Point Protocol (OCPP)24 v1.6[17]
• Telematics[18]
• Charging Network Management Protocol[19] (CNMP)26 IEEE 2690
During this mapping process, it became clear that many communication protocols could support most, but not all, of the functional requirements. Details given in annexure</td></tr>
<tr><td rowspan="7">Hardware performance functionalities</td><td colspan="2">To identify the necessary EVSE hardware functionality that will enable the high-level communication needed to achieve many of the VGI use cases, following recommendations were given by the commission:</td></tr>
<tr><td>Functionality</td><td>EVSE Hardware / Physical Layer Description</td></tr>
<tr><td>Interoperability</td><td>Interoperable with IEEE 802.11n for high bandwidth wireless networking OR Interoperable with IEEE 802.3 for Ethernet connectivity for Local Area Network and Wide Area Network applications</td></tr>
<tr><td>Mitigate need for hardware modifications and onsite software upgrades</td><td>Remote update capability should be available for updating software without need for on-site presence
Functionalities should be software based</td></tr>
<tr><td>Support real-time protocol translation/encryption/ decryption</td><td>Processor and Internet Protocol stack must accommodate multiple communication protocols</td></tr>
<tr><td>Support the use of internet protocols for management and networking of EVSE</td><td>Compliance with Transmission Control Protocol/Internet Protocol and Internet Protocol v6, or its successor version(s)</td></tr>
<tr><td>Provide the physical layer when needed to allow for high-level communications between the EVSE and the EV</td><td></td></tr>
<tr><td>Other requirements</td><td colspan="2">External protocol converter can be connected to more than one EVSE and perform any communication requirements for all the EVSEs connected to it. Each EVSE communicates to the external protocol converter, which then communicates to a third party such as an EV service provider (EVSP), aggregator, or PFE</td></tr>
</table>

[16] OpenADR is sponsored by the OpenADR Alliance, which was formed in 2010 by industry stakeholders to standardize and automate utility demand response programs using an open software platform. More information is available at http://www.openadr.org/.

[17] OCPP is sponsored by the Open Charge Alliance, and offers a uniform method of communication between a charge point and a network operator or utility system. Version 2.0 is currently being finalized. More information is available at http://www.openchargealliance.org/

[18] Each automaker has its own method of implementing telematics, either using proprietary communication protocols or IEEE 2030.5.

[19] This IEEE standard, if finalized and adopted, would define communication between Electric Vehicle Charging Systems and a device or network services system to allow for monitoring, controlling, and communicating

Key outputs	Details	
	Domain	**Protocol**
Recommended communication protocols	PFE to EVSE	One or a combination of the following: 1. OpenADR 2.0b 2. IEEE 2030.5 3. OCPP 1.6
	EVSE to EV	One or a combination of the following: 1. ISO 15118 v1 2. IEEE 2030.5
	Vehicle OEM to EV	Telematics (using OEM proprietary protocols or IEEE 2030.5)

Source: CPUC

A few utilities and EVSE companies in Europe, especially in the Netherlands and Germany, have advocated for communications standards to allow interoperability and "e-roaming" between charging station networks, leading to the wide adoption of the Open Charge Point Protocol (OCPP) and Open Clearing House Protocol (OCHP) in many countries. This has resulted in a number of international projects, such as Ladenetz, a collaboration between municipal utilities in Germany and the Netherlands, universities, and private EVSE operators, and Hubject, a private company supported by German power companies RWE and EnBW. The multiple international programs within Europe cannot currently work together but European Union policymakers hope to unite these efforts with common standards.

For utilities to properly plan for EV-related system upgrades and take advantage of potential grid benefits, it is imperative that utilities know which residents own EVs and how they will be charged. There is no standard protocol for alerting utilities of new EV registrations or EVSE installations in most regions (including in 46 U.S. states). The United Kingdom, however, requires notification of one's local distribution network operator in order to claim rebates for EVSE installations. The program is implemented through authorized charge point installers in order to simplify the process for customers

3.6.6 Regulations enabling EVs to participate in demand response markets

Various jurisdictions in the US and Europe have developed regulatory frameworks for participation of demand response in ancillary services. With increasing share of renewable energy sources which are intermittent and unpredictable, and changing load-generation balance scenario, resources like demand response providing ancillary services to the grid would be expected to slowly gain importance.

Table 27: Demand response and aggregators

Commission /authority orders	Definition of Demand response and aggregators
FERC Order 719	**Aggregation of retail customers-** Each Commission-approved ISO and regional transmission organization must accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, and the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, where the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers
MISO provisions	"An Aggregator of Retail Customers (ARC) is an MP [market participant] sponsoring one or more DRRs [demand response resources] or LMRs [load modifying resources] provided by customers. An ARC can, but need not, be an LSE [load serving entity] sponsoring a DRR or LMR that is the retail customer of another LSE
Arkansas	Act 1078 of 2013 allowed the Arkansas General Assembly articulate a state policy authorizing the Commission to "establish the terms and conditions for the marketing, selling, or marketing and selling of demand response by electric public utilities or aggregators of retail customers [ARCs] to retail customers or by electric public utilities, aggregators of retail customers, or retail customers into wholesale electricity markets. As defined in the Act, demand response means "a reduction in the consumption of on-peak or offpeak electric energy by a retail customer served by an electric public utility ... relative to the retail customer's expected consumption in response to: (i) Changes in the price of electric energy to the retail customer over time; or (ii) Incentive payments designed to lower consumption of electric energy." The Arkansas Commission stated that it "considers DERs to include (but not be limited to) energy efficiency resources (EE), demand response (DR), smart thermostats, renewable resources and distributed generation (DG), including solar and wind technologies, storage technologies, including batteries and water heaters, and electric vehicles (EVs), all of which may be enabled, enhanced, and integrated into the grid by implementation" of advanced metering infrastructure (AMI).

Without aggregation, individual Distributed Energy Resources (DER)s can theoretically provide energy, capacity, and ancillary services at the ISO/RTO level or the distribution level, but in practice most of that potential will go unrealized due to a variety of barriers, including:

Table 28: Demand response market requirements

Key requirements for markets	Details
Minimum threshold	Load-modifying resources must be capable of shedding at least 1 MW of load in MISO suggesting that not all demand side resources can participate in ancillary services

Key requirements for markets	Details
Value proposition	The MISO markets currently have operating reserves far in excess of resource adequacy requirements. This means that load curtailments are rarely needed, and DR resources can expect very little market revenue. It also means that wholesale energy and capacity prices are consistently low, which reduces the revenue that DERs capable of injecting energy might hope to capture. As a practical matter, the transaction costs for market participation by a single customer (described above) will typically exceed any market revenues
Visibility of DERs	A utility needs to know what types of DERs have been installed, where they are, what distribution system services they can potentially provide, and their operational status. The utility will also need the ability to control the DERs or send dispatch signals to whoever controls the DERs in order to provide distribution system services when and where they are most needed

3.7 Country specific policies for enabling participation in ISO markets

3.7.1 United States

In the US, aggregation has focused pre-dominantly on obtaining demand response. Various regulatory provisions by the FERC pertaining to involvement of demand response are highlighted below:

Table 29: Regulatory provisions for demand response

Date	Particulars
2000 onwards till 2008	FERC approved proposals by several ISO/RTOs to allow wholesale and certain retail customers to bid demand response into the day-ahead and real-time energy markets, alongside generation
2008	FERC issued Order 719 requiring all ISO/RTOs to accept bids from demand response aggregators acting on behalf of retail customers
2016	Revision in Market Administration and Control Area Services Tariff (MST) to establish a framework for DER aggregations to participate in CAISO's real-time and day-ahead wholesale energy markets and ancillary services markets (the "DER program")

Source: FERC

In Nov 2016, FERC announced that each RTO/ISO will revise its tariff to define [DER] aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation.

[20] *https://www.cpuc.ca.gov/General.aspx?id=8314*

Case study- CAISO Demand response through aggregation

Retail electric customers in CAISO can bid on their own (if they meet all eligibility requirements) or rely on commercial entities known as "Demand Response Providers (DRPs[20]) or aggregators" who aggregate retail customers into a single bid or multiple bids. Bids that are accepted and dispatched by the CAISO will be awarded energy payments based on wholesale market prices. Customers who participate through a DRP/aggregator will be paid according to the terms and conditions of any contractual agreement between themselves and their DRP/aggregator.

A DRP/aggregator, in this case, is a commercial entity that provides demand response services such as assisting retail customers with strategies or technology to reduce their electric consumption and then providing the electric load reductions as a 'bid' in wholesale energy markets. As of Feb 2019, there are 15 registered[21] DRPs in CAISO markets.

The California Public Utilities Commission adopted Rule 24/32 in accordance with CPUC decisions D.12-11-025, D.13-12-029, and CPUC Resolution E-4630. In summary, Rule 24/32:

- specifies the roles and responsibilities of different entities involved in facilitating direct participation DR, e.g., the utilities and DRPs/aggregators,
- requires that the DRP sign a DRP service agreement with the utilities,
- specifies meter data access requirements.

Resources capable of providing demand response can participate in CAISO energy and ancillary markets as follows through aggregation[22]. Aggregation refers to a means of combining of multiple sub-resources, at single or multiple locations, into a single market resource that participates in ISO markets:

1. Proxy Demand Resource (PDR): enables third parties to bid demand response into the CAISO market independent of the load serving entity for load curtailment in wholesale energy and ancillary services markets
2. Reliability Demand Response Resource[23] (RDRR): A market participation model for reliability-based load curtailment, triggered only under emergency conditions

- RDRRs are not required to participate economically therefore day-ahead market participation is optional
- All uncommitted RDRR capacity must be offered as energy in the real-time market
- Only includes system emergencies viz. transmission emergencies on ISO controlled grid, mitigation of imminent or threatened operating reserve deficiencies, resolving local transmission and distribution system emergencies etc.

Following table provides key features of both products:

[21] *https://www.cpuc.ca.gov/General.aspx?id=6306*

[22] *http://www.caiso.com/Documents/PDR_RDRRParticipationOverviewPresentation.pdf*

[23] *http://www.caiso.com/Documents/ReliabilityDemandResponseResourceOverview.pdf*

Table 30: Key features of PDR and RDRR

Aspect[24]	Details
Requirements to be met by DRPs	Demand response providers must secure agreements for wholesale participation. They can aggregate multiple customers to provide DR to the ISO. A DRP must: • Have an agreement with the load serving entity (LSE) / distribution company who serves the demand responsive load • Execute a demand response provider agreement (DRPA) with the ISO • become a Scheduling coordinator or obtain the services of a a Scheduling Coordinator A Scheduling Coordinator is a scheduling agency which can be chosen by the market participants, that is approved by CAISO to provide the schedules on behalf of the DERs or DERPs. The SC is responsible for scheduling or maintaining the schedules of each of the participants and communicating the same with CAISO. It also handles the settlement processes.
Market participation[25] options	For PDRs, scheduling coordinator to provide: • Economic Day-Ahead & Real-Time energy bids • Economic Day-Ahead & Real-Time ancillary services (Spinning and Non-Spinning reserves) For RDRRs, scheduling coordinator to provide: • Economic Day-Ahead energy bids • Reliability real-time energy bids • RDRRs with day-ahead schedules and remaining capacity in real-time will not receive dispatch until operational conditions exist such that the resource is activated in the market.
Capacity & Aggregation Requirements	• Energy markets only: 100 kW minimum curtailment—must be sustainable for duration of bid. Ancillary Services: 500 kW minimum curtailment—must be sustainable for 60 minutes for Day-Ahead Regulation awards, 30 minutes for Real-Time Regulation awards, and 30 minutes for Spin/Non-Spin reserves. • Smaller loads may be aggregated to achieve minimum targets • Can bid load curtailment in 10kW minimum increments
Operating and bidding characteristics	Resource bids in as a supply resource; bid segments may be as granular as 0.01 MW Resource owner defines one start-up and one ramp rate
Scheduling	• CAISO will treat the **aggregation as a single resource**, regardless of the location of the individual DERs. • The **DERP has to disaggregate** CAISO's instructions to the DERs

Source: CAISO

3.7.2 Europe

EU directives have been focused on participation of aggregators through demand response. The following is an overview of various regulatory/policy provisions.

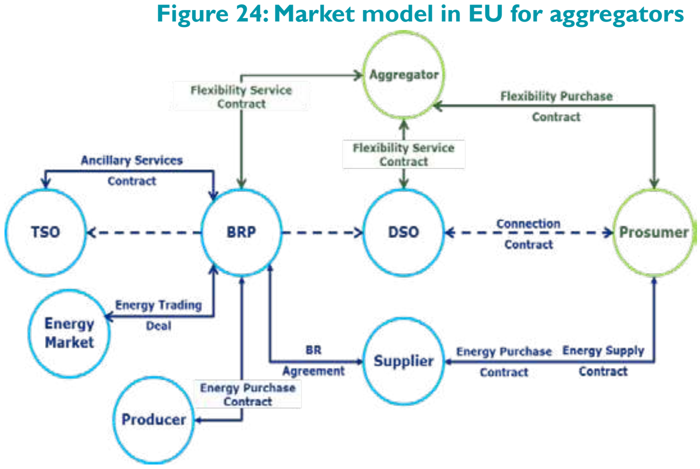
[24] http://www.caiso.com/Documents/ParticipationComparison-ProxyDemand-DistributedEnergy-Storage.pdf

[25] http://www.caiso.com/participate/Pages/Load/Default.aspx

Table 31: Regulatory and policy provisions for participation of aggregators through demand response.

Particulars	Details
Energy Efficiency Directive 2012/27/EU	Energy Efficiency Directive 2012/27/EU (EED) defines the term 'aggregator' as a "demand service provider that combines multiple short-duration consumer loads for sale or auction in organized energy markets"; definition includes only consumer loads and not the generation of energy. EU Member States shall ensure that transmission system operators and distribution system operators, in meeting requirements for balancing and ancillary services, treat demand response providers, including aggregators, in a non-discriminatory manner, on the basis of their technical capabilities. Network regulation and tariffs "shall not prevent network operators or energy retailers from making system services available for demand response measures, demand management and distributed generation on organised electricity markets, in particular: […] (b) energy savings from demand response of distributed consumers by energy aggregators." IEM directive facilitates final customers in providing balancing services to the markets
Directive on the internal energy market 2009/72/EC	Transmission system operators should facilitate participation of final customers and final customers' aggregators in reserve and balancing markets. Member States shall ensure the implementation of intelligent metering systems that shall assist the active participation of consumers in the electricity supply market. This should happen based on an economic assessment and where the roll-out of smart meters is assessed positively, at least 80 % of consumers shall be equipped with intelligent metering systems by 2020.12 IEM directive facilitates final customers in providing balancing services to the markets
Network codes	The Network Code on Electricity Balancing (NC EB) declares in Art. 10 the "facilitating [of] the participation of Demand Side Response including aggregation facilities and energy storage" to one of its general objectives of the balancing market. Furthermore, the Network Code contains that "the conditions for aggregation of Demand Side Response, the aggregation of generation units or the aggregation of both should be part of the terms and conditions for Balancing Service Providers Participation of demand side response has been identified as a primary objective of the balancing market

Figure 24: Market model in EU for aggregators



the basic market model prevalent in EU for aggregators is described in the illustration below:

- Aggregator is responsible for contracting with DSO to provide services, BRP for maintaining imbalances in real time

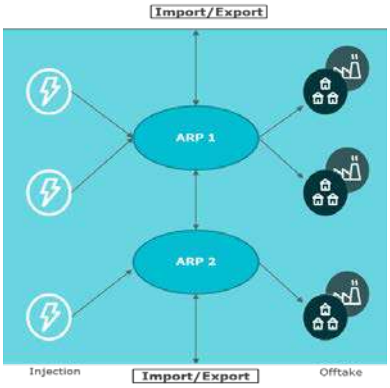
- BRP provides ancillary services in case of imbalance. It can manage its imbalances through other BRPs
- BRP can participate in energy markets to correct aggregator's portfolio in real time

Table 32: Case study – ARP in imbalance market

Case Study: Participation by ARPs in Imbalance market

- The responsibility of maintaining instantaneous balance between the load and generation lies with the TSO.
- Belgium has only one control zone and it is overlooked by Elia.
- To help maintain the balance between generation and consumption, Elia has balance responsible parties (BRP)
- For each access point there must be a designated BRP. A balance responsible party is also called an access responsible party (ARP).
- Either the supplier takes on the role itself or else it appoints an ARP which enters into a contract with Elia.
- ARPs are authorized under an ARP contract signed with Elia.
- Elia applies imbalance tariffs if a 15-minute time block imbalance is observed.
- ARPs can avoid imbalances by:
    - exchanging energy with other ARPs on the 'intraday hub'. In this case,
    - they submit their nominations to Elia before noon the following day;
    - importing or exporting energy for the south border on an intraday basis

Figure 25 Illustration of Import and Export by Access Responsible party (ARP)



An Imbalance occurs when there is a difference for one quarter-hour between the total Injection to the Elia Grid allocated to ARP's Balancing Perimeter and the total off-take from the Elia Grid allocated to ARP's Balancing Perimeter

Figure 26 ARP Balancing Perimeter for Injection and Off-take.

ARP is responsible to balance its perimeter on an quarter hour basis

- Day-ahead nominations of ARP must be balanced
- ARP pays an imbalance tariff if the final position of its perimeter is not balanced
- ARPs react on real-time imbalance tariffs to restore their perimeter balance
- ARP which also provide ancillary services has the right to offer ancillary services to Elia

In real time, the residual imbalance of the zone is solved by the TSO

- TSO will restore residual imbalances by activation of balancing services
- Balancing actions by TSOs are reflected in imbalance tariffs

The above mechanism allows for individual ARP/BRPs to balance out their portfolios in the imbalance market through a spectrum of DER and DR response programs.

Source: EU, Energy Efficiency Directive 2012/27/EU

4. An analysis of high EV penetration in distribution systems in the Indian context

4.1 Approach to Distribution network analysis

IA distribution network analysis was conducted to explore the effectiveness of managed charging towards avoiding distribution network impacts. The analysis used a case study approach centered on the Delhi based utility, BSES Rajdhani Power Limited (BRPL). At various levels of penetration of EVs and considering a varied charging profile, the analysis performed by NREL, USA has focused on impact of integrating EVs in the BRPL network and the possible resolution options including battery storages for mitigating the challenges. The report will be separately released and can be accessed by all in their official website. The GTG-RISE/ Deloitte analysis, presented in this Chapter focuses on analyzing the impact of network loading (at select feeders and transformers), at various levels of EV penetration scenarios in the next 10 years so that a prioritization strategy of rolling out charging infrastructure can be deployed by BRPL, having looked at the available margins and constraints in the network. The analysis also provides a mitigation plan, through active managed charging, that could be adopted by the utility, to further defer the investment requirement in augmentation of the network, for optimum utilization of the network and consumer investments and builds a strong business case for representation to Delhi Electricity Regulatory Commission (DERC) in enabling managed charging framework. c

For modelling the distribution network, EPRI's freeware distribution system simulator, OpenDSS, was used, integrated with a Python based time series load flow analysis. The distribution system of BRPL was modelled with appropriate load growth assumptions to identify when overloading may occur. An instance of overloading refers to a situation whenever the loading of any DT crosses 70% of the rated DT capacity. EV growth was assumed to be in line with the GOI's target of 30% EV penetration by 2030 compared to present levels.

A preliminary analysis has been carried out in the first step to understand approximate year in the future where each of the DTs are expected to get overloaded. Once the approximate year is determined, the next step is to consider slot wise loading data of the DT and undertake a detailed time series based load flow analysis to understand total number of slots in a year where each DT becomes overloaded and whether there is a scope for managed charging in those slots.

This analysis has been carried out in a two- step process:

1. Preliminary Analysis:

- For each DT, a sample day's time series data was created by taking the maximum load for each time slot.
- Selected maximum load for each DT has been broken down into two parts: Consumer load and EV load.
- It has been assumed that the net EV load in the base year of simulation (2019) is 165 kW (Corresponding to 50 E-Rickshaws) and the EV load grows at 30% CAGR to fulfil the target of 30% EV penetration by 2030.
- The cumulative load growth (EV and Consumer) is taken as 5%.
- In the base year, the spare capacity of each of the DT is calculated as the difference of 70% of rated capacity of that DT and actual loading of the DT.

- The EV load (165 kW) is apportioned to each of the DT as per their ratio of spare capacity in the base year.
- For each year in the future, the primary loading on the DTs has been calculated considering a 5% growth of load from the base year.
- For each year, loading and spare capacities of each DT is ascertained. The years where the loading of each of the DT crosses 70% of it's rated capacity is also noted down. The detailed slot wise loading analysis is then carried out prior to and post before and after around which (± 2-3 years) the slot wise analysis (main analysis) has been carried out for the determination of the manage charging hours and slots.

2. Main Analysis

- For each data, slot-wise projected loading data has been considered for the simulation. For all the DTs where data was missing for few slots, data cleaning has been done and synthesized based on statistical approaches and the missing data was constructed.
- Slot-wise load for each DT has been broken down into two parts, viz., Consumer Load and EV Load.
- It has been assumed that the net EV load in the base year of simulation (2019) is 165 kW (Corresponding to 50 E-Rickshaws). EV load grows at 30% CAGR to fulfil the target of 30% EV penetration by 2030.
- The cumulative load (EV and Consumer) growth is taken as 5% y-o-y.
- In the base year, the spare capacity of each of the DT is calculated as the difference of 70% of rated capacity and actual loading of the DT.
- The EV load (165 kW) is apportioned to each of the DT as per their ratio of spare capacity in base year.
- Considering the year of simulation, the primary loading on the DTs has been calculated considering a 5% growth of load from the base year.
- The loading obtained for the considered year of simulation has been apportioned in the ratio of consumer load and EV load (scaled from the base year using EV load CAGR and cumulative load CAGR)
- For each of the DT, slots with overloading instances have been identified.
- Identified overloading instances have been divided into two categories, viz., manageable and Non-manageable.
- All the manageable instances, for a particular DT, are those slots where overloading can be prevented by shifting the EV load (Total loading less EV loading <= 70% of rated capacity of DT) in that particular slot whereas Non-manageable instances are those wherein DT is overloaded even after shifting the EV load on the DT chosen.
- The year of overloading for each of the DT has been calculated as the year wherein this Non-manageable slots exceed/reach 30 instances.

- Each of the manageable instances have been plotted for the decision making of contracting time (in hours for managed charging).

For the purpose of our simulation, a feeder with presence of both Domestic and Commercial loads has been considered for the analysis.

4.1.1 Input data

1. Load data

Load on each DT **for the base year** has been considered as shown below. However, this load has been increased with a CAGR of 5% year-on-year. **Load data in the base year for two sample DTs have been shown below.**

Figure 27 Load data of Sample Distribution Transformer 1

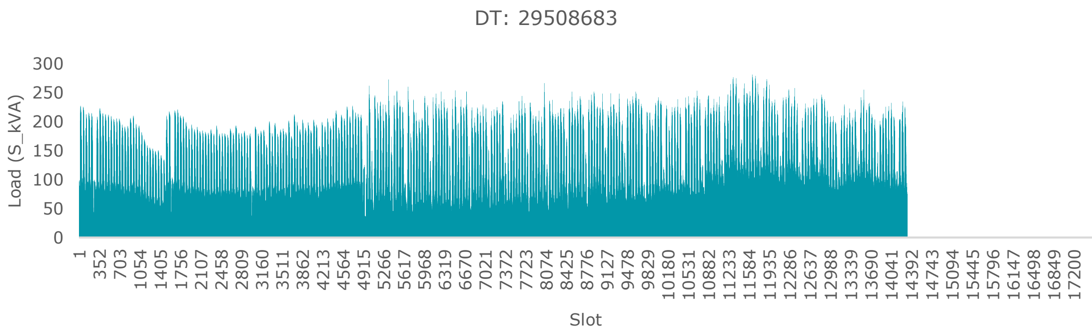
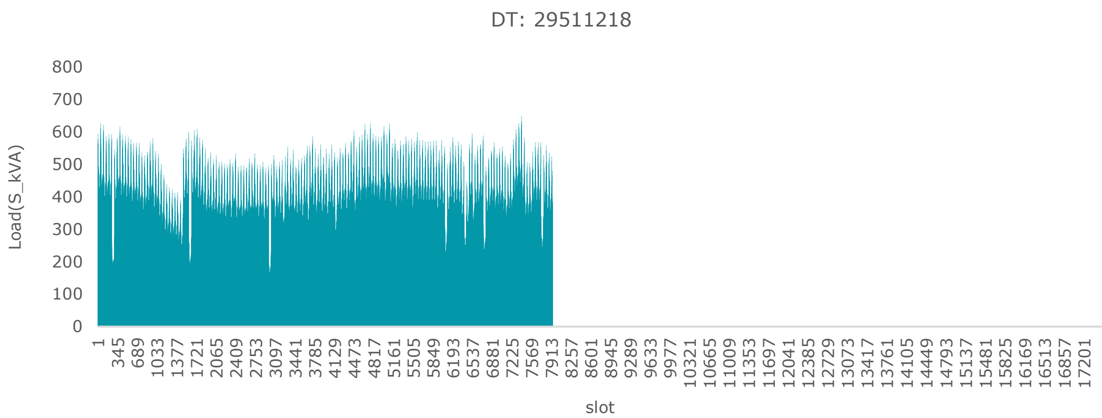


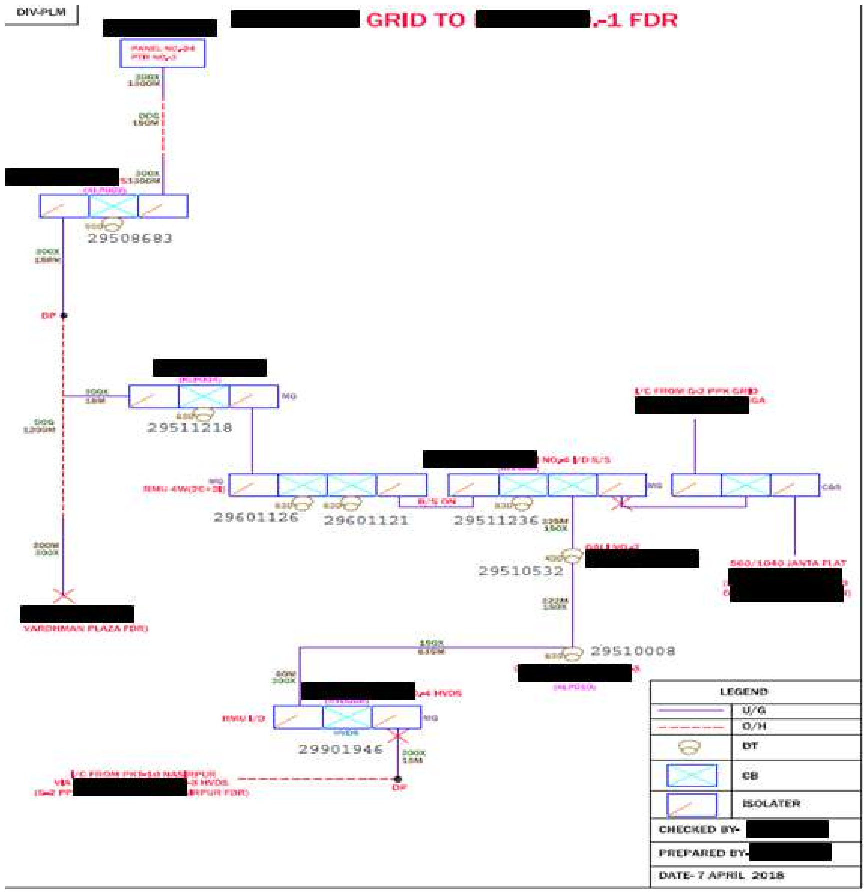
Figure 28 Load data of Sample Distribution Transformer 2



2. Single Line Diagram

The SLD of the network considered has been shown in the figure below:

Figure 29 Single Line Diagram of Dabri I feeder used for the modelling and simulation



3. Network parameters

For the load flow analysis, the line and DT parameters are highlighted below:

Table 33: DT and Line parameters

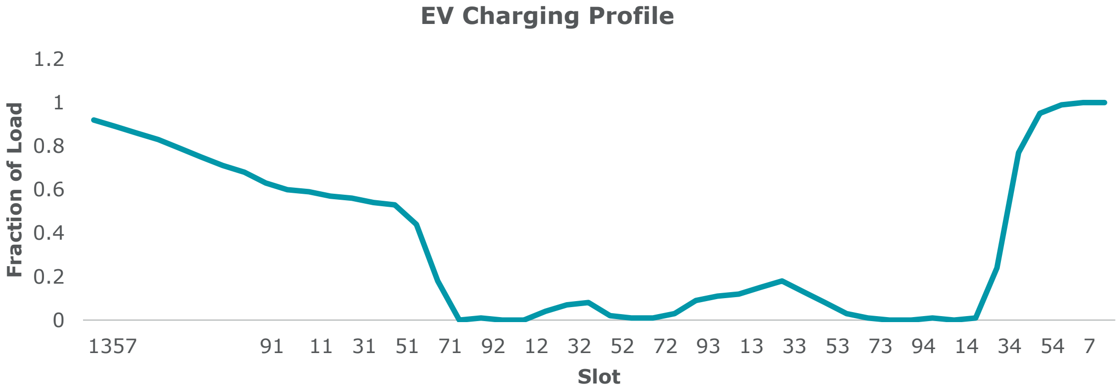
DT (Ratings)	Voltage Ratings	Z (pu)	R (pu)	X (pu)
990 kVA	11/0.4 kV	0.0484	0.01149	0.047
630 kVA	11/0.4 kV	0.0407	0.01151	0.039
400 kVA	11/0.4 kV	0.0399	0.01219	0.038

Line	kV	R (Ω/Km)	X (Ω/Km)
300x	11	0.13	0.093
150x	11	0.264	0.089
Dog	11	0.2792	0.02

4. EV charging profile

Following representative EV charging profile, as per actual observed profile at a sample node, is considered:

Figure 30: Representative profile of EV charging load



4.2. Key assumptions

- The rating for slow charging stations is 15 kW at a power factor of unity
- The rating for fast charging stations is 22.5 kW at a power factor of unity
- The spare capacity is apportioned in 1:3 ratio between fast and slow charging stations
- A DT has been considered to the overloaded when the DT is loaded >= 70% of its rated capacity for at least 30 hours/month

4.2.1 Results of the simulation

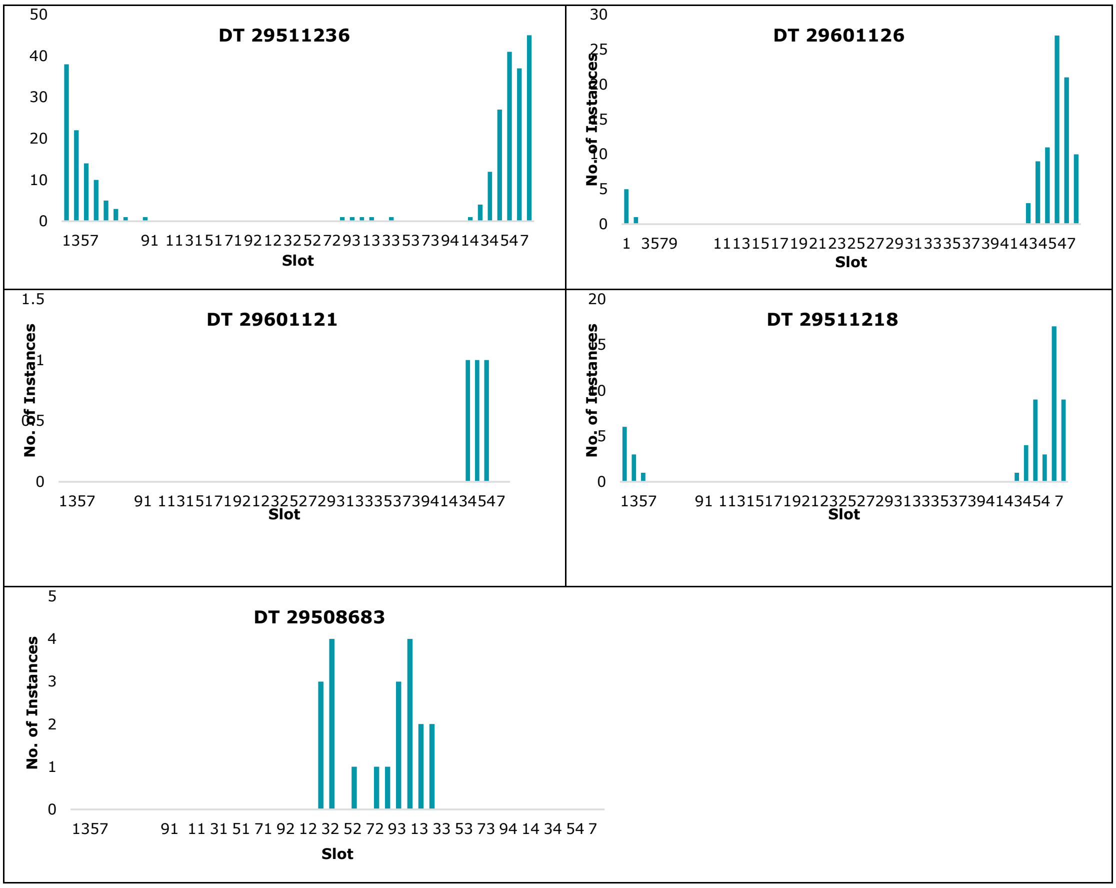
The definition of overloading considered in the analysis corresponds to the situation when at least 30 non-manageable overloading instances are observed for any given DT in a year. The years of overloading has been presented in the table alongside for each of the DTs as present in the SLD. It can be observed that one DT, 29510532 has not reached its overloading capacity until 2033, except that all the remaining DTs have reached their overloading capacity well before 2030.

Table 34: DT and Line parameters

DT number	Year of overloading
29601121	2019
29511218	2020
29510008	2021
29601126	2025
29508683	2029
29510532	>2033

In the following DT-wise graphs, all the manageable overloading instances have been plotted in a slot wise distribution prior to their respective years of overloading for the decision making of contracting hours of managed charging.

Figure 31 Slot-wise distribution of manageable overloading instances for the decision making of Managed Charging



From the graphs, manage charging hours for each DT are:

- **DT 29511236:** Slot 45 to slot 1
- **DT 29601126:** Slot 44 to slot 1
- **DT 29601121:** Overloaded in base year itself
- **DT 29511218:** Slot 45 to slot 1
- **DT 2958683:** Slot 23, 24 & slot 30 to slot 33 (Since, the overloading patterns are distributed, TOU based tariff could be considered for this DT)

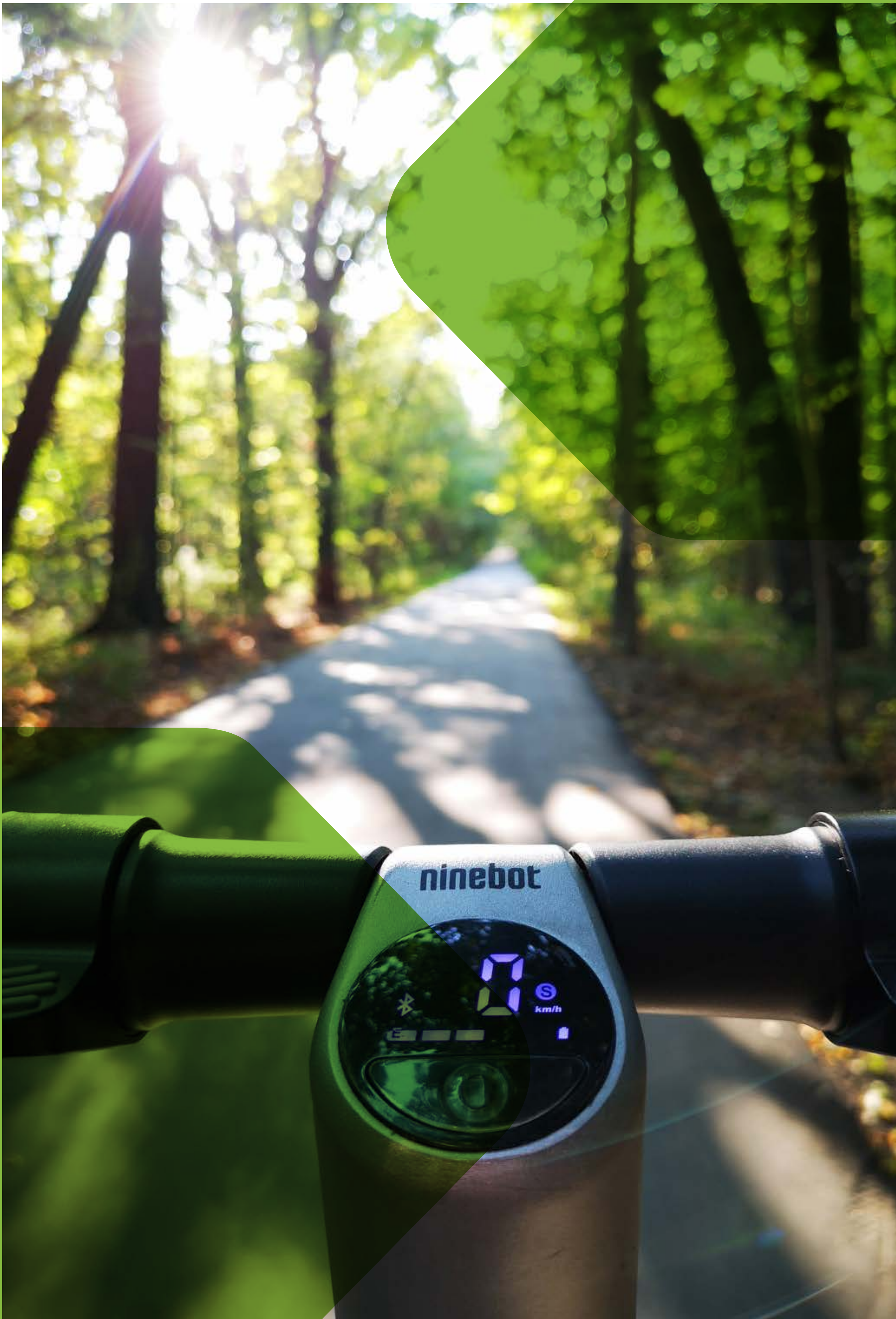
4.2. Key assumptions

- Based on the analysis, distribution system planning may benefit by considering at a 10-year planning horizon that is inclusive of consumer load growth, considering EV adoption. Capacity planning by utilities should be configured such that it addresses distribution system overloading, voltage and frequency fluctuations and any other network constraints in the future.
- It has been observed in this analysis that in the long run, the impact of EV charging could be substantial considering the gradual and steady move to EVs. Hence, distribution utilities should develop multiple system cost scenarioswith/-without storage systems and managed charging etc., to effectively design the network and address future load conditions instead of taking a 10-year time-

frame for deciding the network parameters including DT sizing etc.

- Power distribution utilities would have to undertake scientific modelling studies to understand potential growth of EVs in the long run and how it would lead to overloading of DTs and distribution lines. Significant business focus and priority should be given to EVSE as an additional load in the system and scenario planning-/-prioritization strategy needs to be developed for the following:
  - Peak load management
  - Reducing technical losses in the distribution system by controlled EV charging
  - Reducing system costs by enabling RE based generation sources to be utilized for EV charging instead of resorting to costlier conventional sources
- It is evident from the analysis that there is substantial scope for load shifting of EVs. To enable a framework for managed charging, utilities should initiate a dialogue and represent to concerned regulators for justification and subsequent introduction of managed charging practices, TOU tariff pricing, etc.
  - Managed charging can provide significant means to mitigate overloading of the distribution system at times of peak demand by modulating the charging rate of EVs and delaying the charge over a larger timeframe
  - There could be certain pockets where managed charging may not be attractive due to variations in EV charging profile by the users. Passive mechanisms like TOU tariffs can act as suitable incentive for users to shift their EV charging to off-peak periods.
- As observed from the above results, most of the DTs get overloaded before 2030, based on the overload criteria established (30 hourly overload instances in any month). However, it was observed that for the rest of the year, these DTs are usually loaded to the extent of only 40-50% or even lower. This could be a typical phenomenon for a city like Delhi. In such cases, augmentation of DTs may not be cost-effective. Hence, utilities need to analyze and model their respective load profiles and simulate scenarios to determine the most cost-effective solutions (given below) for managing EV load:
  - Active managed charging
  - Passive managed charging like TOU tariff structures-/-Demand Side Management incentives
  - Charging through distributed RE sources
  - De-congesting the network and-/-or charging through local Battery Energy Storage System (BESS) installations in the grid, etc.

This analysis has been carried out considering a lump load at a DT level. Analysis at a household/industry level using geographic information system (GIS) mapping could give more accurate results for the power distribution utilities due to precise accounting of losses. The voltage stability analysis could also be carried out when an analysis is carried at a household level for significant results. The same analysis can also be extended with the BESS for peak shaving. A sensitivity analysis could be carried out for different EV charging patterns to determine the best EV charging pattern for the network deferral.


ninebot
km/h

5. Gap assessment, recommendations and identification of enablers for development of EV charging infrastructure

5.1 Current gaps in India's framework

Table 35: Gaps in India's framework for developing EV charging infrastructure

Key Parameter	Detail and gap
Cost recovery through rate-basing "make-ready" infrastructure	Utilities in US are encouraged to invest in EV infrastructure through a range of legislative mandates such as for clean air and reducing overall emissions from transportation sector. Regulators allow utilities to undertake investment in "make-ready" infrastructure for EVSE integration as well as EVSE infrastructure itself and recover the cost through rate-basing. This allows utilities to undertake costly investment and socialize the cost of setting up "make-ready" infrastructure for EVs. Such a proactive approach creates an eco-system for setting up EV charging infrastructure. While several states in India have introduced EV policies, state utilities and regulators are yet to facilitate large-scale investments in "make-ready" infrastructure for EVs. A first step would be for regulators to encourage utilities to carry out such investments and provide pathway to cost recovery through rate basing.
Standardization	EV standards and technical specifications have increasingly moved towards standardization encouraging interoperability in developed countries. This helps create an EV ecosystem with adequate confidence from private players as well enables interoperability of equipment. While, there have been guidelines on technical specifications that have come up in India, institutions such as CEA and BIS shall have to further play a role in standardization on EVSE equipment.
Managed Charging Framework and functions	Utilities in advanced power markets with significant levels of EVSE penetration have focused on developing a managed charging framework so as to efficiently manage the additional stress on distribution system network on account of EV charging. This entails setting up various communication and hardware protocols to implement a managed charging framework as well as creating various incentives for consumers to participate in managed charging initiatives. While EV growth is still at a nascent stage in India, utilities and regulators will need to plan for implementing a managed charging framework with a long-term perspective. While absence of standardized protocols for EV managed charging is a major barrier in the Indian context, equally important is the fact that the managed charging landscape involves various stakeholders viz. utility, grid operator, aggregator, EV user, network operator, etc. and adequate coordination between everyone is required to formulate adequate systems and infrastructure which would function properly. The concept of aggregators is still being explored in India. Moreover, robust electricity grid and network infrastructure are vital for effective functioning of managed charging in India.
Demand Response Market	To take advantage of flexibility from managed operation of EV charging, ancillary markets in developed countries have provisions for demand response providers to participate in the ancillary market. This provides additional revenue stream to demand response sources and allows utilities to better manage its demand-supply position. The CERC has introduced a discussion paper on market-based procurement of tertiary services in India. Currently there is no established mechanism for demand response products in the ancillary market wherein aggregators can participate.

Key Parameter	Detail and gap
Pilots on managed charging of EVs	From the international case studies, it can be observed that many of the new technology related to managed charging of EV has been introduced first using a pilot platform. The results for these pilots are then used to carry out large scale deployment of technology. While standards and guidelines introduced in India do provide provisions for communication protocol between EVSE and other stakeholders, there has been no pilot initiative on large-scale managed charging pilots. Utilities and regulators across India need to take initiative on introducing pilot projects which can demonstrate the benefits of managed charging of EVs.
EV tariffs and incentives.	It has been observed that having dedicated tariffs and incentives for EV encourages adoption. While few states in India have taken EV policy initiatives, a large number of states are yet to introduce EV specific tariffs for public and home charging as well as incentives under state policies for purchasing EVs and setting up home and public charging stations.

5.2 Creating an enabling framework to support EV charging infrastructure

The following section delves into the various enablers which would influence increased adoption of charging infrastructure. Based on international benchmarking, these have been categorized as the following:

1. Policy and regulatory enablers
2. Technological enablers, and
3. Others, including collaboration and partnerships among utilities and other stakeholders in the EV value-chain

Understanding these levers is important in understanding the role that a particular regulator/government/utility can play in encouraging the deployment of EV charging infrastructure.

5.2.1 Policy and Regulatory enablers

1. Policy enablers

a. National / State level policy for incentivizing Distribution Utility investments in EV charging infrastructure: Through adequate support and enabling policies, power utilities should be incentivized to undertake capital investment in charging infrastructure to accelerate widespread transportation electrification and reduce dependence on petroleum. Recovery of capex could be done by rate basing them among all the electricity consumers instead of only consumers using EVs. Adequate policy mechanism should be in place to ensure that such investments are subject to regulatory jurisprudence to avoid unnecessary burden on concerned ratepayers. This, as illustrated below, is enabled through suitable policy mechanism in the state of California.

Section 740.12 of Senate Bill 350 of the state of California states that:

1. "The commission, in consultation with the State Air Resources Board and the Energy Commission, shall direct electrical corporations to file applications for programs and investments to accelerate widespread transportation electrification to reduce dependence on petroleum, meet air quality standards".
2. "The commission shall approve, or modify and approve, programs and investments in transportation electrification, including those that deploy charging infrastructure, via a reasonable cost recovery mechanism, include performance accountability measures and are in the interests of ratepayers

Furthermore, the Senate bill 350 also states that the California Energy Commission shall regularly carry out a prudence check of EVSE capital investment so that it is convinced that the same is reasonable to be recovered from all of the rate payers:-

"The commission shall revise data covering current and future electric transportation adoption and charging infrastructure utilization prior to authorizing an electric corporation to collect new program costs related to transportation electrification in customer rates. If market barriers unrelated to the investment made by an electric corporation prevent electric transportation from adequately utilizing available charging infrastructure, the commission shall not permit a additional investments in transportation electrification without a reasonable showing that the investments would not result in long –term standard costs recoverable from ratepayers".

b. Launch of Charge ready infrastructure programme by Distribution Utilities through policy initiative:

Utilities should plan and initiate investing in "make-ready" infrastructure wherein they would set up the necessary infrastructure required for EV charging service. This would enable development of EV charging infrastructure by ensuring electrical infrastructure is already provided at customer sites to support charging. "Make-ready" infrastructure may include components such as necessary transformer and transformer pads, new service meter, new service panel, associated conduit and conductor necessary to connect each piece of equipment, Smart Grid Devices, etc.

Case study of charge ready infrastructure program adopted by Southern California Edison is highlighted in Section 3.6.2

2. Regulatory enablers

a. Rate-basing of EVSE

Utility investments in infrastructure to support EVs, including system upgrades, dedicated meters, and workplace or public EVSE, could be funded by distributing the cost across all customers. This practice, although socializes the costs among all consumers, adds only a small amount to customer electricity bills. Regulators may encourage these investments due to their potential to increase utilization of the electric grid which would drive down effective rates for all consumers.

Detail case study of rate basing of investment in EV charging infrastructure have been highlighted in Section 3.6.1

b. EV Tariff structuring:

Time-of-use EV charging rates: A simple, but effective step for utilities is to implement time-of-use (TOU) rates, in which electricity prices vary over predetermined periods of the day. Typically, there are two or three rate tiers during a day, with prices also sometimes varying by season or on weekends. Costs would be higher (often by a factor of two or more) during peak demand times, but total average prices are typically designed to be revenue-neutral and reflect the marginal cost of electricity generation.

Details of TOU tariffs prevalent in various countries is highlighted in detail in Section 3.5.2

c. Electricity market structures:

Presence of market structures where EVs can provide demand response/ancillary services could provide substantial benefits to utilities/aggregators and EV owners alike.

Details of regulatory interventions in design of electricity market structures in other countries have been detailed in Section 3.6.6

d. Approval for technical standards for charging equipment in the case of managed charging:

Most countries have a national technical standards agency that either develops a standard or adopts a standard developed by an international technical agency for use in the country. This approval process often involves consultation with various other government agencies that look after fire safety, electric grid, etc. For instance, ASTAR in Singapore had been mandated by the government to develop a standard for EV charging in consultation with OEMs, the local utility and other stakeholders.

Case study of adoption of Technical standards for Managed charging by the California Public Utilities Commission (CPUC) is highlighted in Section 3.6.5

5.2.2 Technological enablers

1. Interoperability, communication and user experience:

a. Inter-operability

Several major efforts are needed toward improving the user experience of charging infrastructure by promoting interoperability between EVSE providers.

For EV users, interoperability, or "e-roaming," means that users can charge at any station with a single identification or payment method, and that all charging stations can communicate equally with vehicles. For this to work seamlessly, common standards for charging network operators must also be established. User roaming is accomplished through the widespread adoption of open standards, including the OCPP and Open Clearing House Protocol (OCHP), in various countries, which allow for efficient communication between charging stations, the grid, and back-end offices to ensure interoperability in operation and payment.

Ladentz, a government-sponsored collaboration among municipal utilities, universities, and private electric vehicle service equipment (EVSE) operators in Germany and the Netherlands, seeks to create a Europe –wide network of interoperable and user friendly charging stations.

In the United States BMW, Nissan, ChargePoint, and EVgo founded the ROEV (Roaming for EV Charging) projects to advance interoperability.

California is currently working on implementing the Electric Vehicle Charging Open Access Act, which focuses on customer interaction with the EVSE. The act applies to all electric vehicle service providers (EVSPs) operating one or more publicly available Level 2 or Direct Current fast Charger (DCFC) Electric Vehicle Supply Equipment (EVSE) installed in California. The act requires

- Publication of station locations on the Alternative Fuels Data Center (AFDC) website.
- Disclosure of all pricing before a charging event begins
- Charge points accessibility to everyone, including the ability to accept multiple forms of payments. Implementing these key features will enable broader access for customers.

Case study of guidelines for ensuring interoperability in EV charging infrastructure is highlighted in Section 3.6.5

b. Communication between EV charging stations

Communications among EV charging stations should be enabled so that users of EVs are suitably informed about availability, operating status, waiting time of various EV charging stations. A central cloud-based platform is necessary to undertake these activities. The centralized platform should enable data sharing and visualization so as to help drivers find and monitor the perfect-/-nearest charge point based on availability, operating status, waiting time, etc.

Case study of the same is highlighted in Annexure 7.

c. Communication between EV charging station and distribution utility

Communication system between EV charging infrastructure and distribution utility is vital for controlling-/-managing EV charging. Communication between the two ensures grid stability and more efficient system utilization, and can take on a variety of forms, including demand response, one-way controlled charging, or vehicle-to-grid.

The signals which utility would send to EVs and vehicle chargers combine messaging, or application, protocols (e.g., OpenADR 2.0, OCPP) and transport layer protocols, also known as network communication interfaces (e.g., Wi-Fi, cellular). Through a combination of network and messaging protocols, the utility can send signals and undertake controlled charging for particular locations as per requirement. Communication medium could range from Wi-Fi, AMI, Cellular networks, radio networks and Ethernet. Through this, the distribution utility can also input remote commands and remote firmware updates to the charging stations.

Case study of the same is given in Section 3.5.4

2. Modelling and simulation studies

With the anticipated growth of EVs as a widespread transportation choice, the incorporation of electric vehicle supply equipment (EVSE) will become a critical element of utility network planning. Selecting a site for EVSE installation will require consideration of a combination of factors. While every site is unique in nature and every EVSE host has unique set of priorities for installation, there are certain common physical elements that would characterize planning choices for any EVSE installation. Appropriate urban traffic and distribution network studies must be conducted in order to identify and establish key criteria which would enable utilities to ascertain suitable locations for siting of EVSE.

Case study of the same is highlighted in Section 3.4

3. Database management and notifications to utilities:

In order for utilities to properly plan for EV-related system upgrades and take advantage of potential grid benefits, it is imperative that utilities know which residents own EVs and how they will be charged. Maintaining a repository of such information would also aid them in planning for EV smart charging pilots.

The United Kingdom's Office of Low Emission Vehicles administers a grant for Chargepoint installers. The grant is set as a 75% contribution to the cost of one chargepoint and its installation and the grant cap is set at £500 (including VAT) per eligible vehicle. The OLEV requires Chargepoint installers to notify one's local distribution network operator (DNO) in order to claim rebates for EVSE installations as well as communicate for the purpose of installation completion.

4. Smart metering requirement:

Smart metering is an essential tool to track the electricity consumption and curb technical and commercial losses. They also enable real time monitoring of energy consumption in a particular period of time. The Government of India's (GoI) UDAY programme, launched in 2015, has mandated the deployment of smart meters with a phased timeline for curbing of commercial losses in distribution system.

Smart meters would also enable implementing of TOU rates for EV consumers and accurate monitoring of energy consumption over time.

5. Enabling Vehicle grid integration

RE penetration in the country is slated to increase in the future due to GoI's ambitious push for 175 GW of RE capacity by FY 2022. This would act as a wide opportunity for EVs in participating in the energy imbalance market by providing V2G services.

Typically, EVs have a residual value of 8-10% after 5-6 years. This can significantly increase if these residual batteries can be used as storage-based charging devices wherein they can be charged when power is cheapest and most abundant (for instance during high solar hours) and can be made to dispatch power back to the grid during periods of frequency imbalance through participating in the ancillary market operations. The demand-supply variability will largely be created during the day when solar peaks up and V2G services could be offered during this 6-7 hours of high solar time.

EVs can also participate in Demand side management programme by utilities. In the developed countries, participating of DR resources is generally through aggregators who provide DR services by aggregating smaller resources. Case study of the same has been highlighted in section 4.5.6

5.2.3 Others including collaboration and partnerships among utilities and

1. Cooperation with stakeholders

A key enabler for smart charging and other vehicle-grid integration aspects is collaboration between utilities and various stakeholders in the EVSE landscape. Such partnerships can give utilities valuable insights into new technologies and lead to new business models in this rapidly expanding field, as well as defray the costs (in money and time) of innovative new programs.

A number of utilities have already created partnerships and identified areas for collaboration to study and promote EVs. Table below highlights a few existing partnerships to date. As shown, existing utility partnerships include automakers, EVSE hardware and software providers, IT and software companies, research organizations, and governments at different levels.

Collaboration with the broader industry would also involve the following:

- agreeing on common standards for equipment interoperability and integration with existing smart grid platforms
- defining and developing point-of-sale payment standards to expand charger access
- ensuring proper charging access for all customers.

Potential Partners	Areas for Cooperation	Examples
Automakers	Smart Charging, aggregation, standards advocacy and adoption	• BMW and PG&E ChargeForward • ElaadNL with Renault in Netherlands • ROEV charging network project
Charging infrastructure providers	Connectivity, DR, V2G, open standards	• Siemens and Duke Energy VersiCharge • EVSE LLC and SCE workplace charging
IT/software companies	Charging optimization, security, aggregation	• HECO and Greenlots Battery DCFC • My Electric Avenue
Academia and research organizations	System modelling and simulation	• PJM and University of Delaware V2G • eConnect Germany Project
Local and state government	EVSE deployment, local modeling, outreach	• San Diego readiness study • Plug In BC (BC Hydro)
Central Government	Standards and R&D	• US Dept. of Energy • US Dept. of Energy - Edison Electric Institute MOU • Ofgem Electricity Network Innovation Allowance

2. Cooperation among peer distribution utilities

Some projects, such as deploying EV charging networks or creating smart charging standards, may require collaboration across jurisdictions and among multiple utilities. For instance, the Elaad Foundation, a partnership of the eight largest Distribution System Operators in the Netherlands, manages more than 3,000 public charging stations, maintains an international standard for public charge station interoperability, and continues to research smart charging technologies. Clever, a group owned by five utilities in Denmark, is the largest operator of EVSE in that country and has now expanded into Sweden, while 23 utilities in Norway have together opened a nationwide network of DC fast chargers under the Grønn Kontakt brand.

5.3 Summary of recommendations and roadmap

A phase wise roadmap for ensuring that the aforementioned enablers are attained gradually and progressively for development of EV charging infrastructure has been illustrated in the table below. The enablers have been classified into following three categories:

1. **Near term priority:** These are near-term priorities that can be tackled immediately or over the next 1-3 years through quick policy/regulatory measures and accelerated ongoing efforts.
2. **Medium term priority:** These are medium-term priorities that have been identified to be crucial and would play a pivotal role establishing a developed EVSE ecosystem. However, these would require considerable support and substantial policy, technology and/or infrastructure changes and stakeholder buy in.
3. **Long term priority:** These are complex initiatives requiring significant expertise to be built-up over a long period of time. Owing to the level of complexity, these long-term initiatives require transformational structural changes in policies, skill development, regulations, etc.

Table 36: Summary of recommendations and roadmap for utilities

Type of intervention	Policy	Regulatory	Technological	Collaboration and partnerships
Near term priority	• National / State level policy for incentivizing Distribution Utility investments in EV charging infrastructure • Launch of Charge ready infrastructure programme	Approving Rate-basing of utility investments in building EV charging stations and infrastructure	• Enabling inter-operability in EV charging stations • Enabling communication between EV charging stations • Undertaking modelling and simulation studies • Smart metering	Collaboration and partnerships amongst utilities and other stakeholders in the EV value-chain
Medium term priority		• Designing TOU tariffs for EV charging • Approval for technical standards for charging equipment in the case of Managed charging	• Enabling communication system between EVCS and distribution utility • Database management and notifications to utilities	Collaboration and partnerships amongst utilities and other stakeholders in the EV value-chain
Long term priority		• Designing electricity market structures for participation of EVs	• Enabling Vehicle grid integration