The Structure and Current Policy Drivers of THE ELECTRICITY SECTOR IN UNITED STATES

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Preface

Aside from being touted as the most complex machine on the globe, the United States' electricity grid is also a core component of the nation's economic backbone. With the current geopolitical shift in the global energy supplies, and an increased concern for climate change, it is of strategic importance, as well as of ecological value to decarbonize the power generation sector. Thus, as a major policy objective the United States federal government has enacted sweeping reforms to make this happen by a tentative date of 2050. With only 27 years between now and 2050, there are major obstacles that can potentially impede progress on this transition.

This work presents a summary of the current organizational and regulatory structure of the entire power sector, from federal jurisdictions to state regulation and the technical standards that govern its day-to-day operation. The discussion is developed further into the current regulatory issues that are of concern and finally a comprehensive analysis of the current policy drivers in the form of Inflation Reduction Act and Bi-Partisan Infrastructure Law, that are slated to bring about the transition towards decarbonization is presented. A keynote chapter in the end examines the effectiveness of current energy policy w.r.t to current issues presented earlier.

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I. Executive Summary

This work is an effort to analyze current issues facing the electricity sector in United States in reference to the ongoing transition towards decarbonization of the U.S. economy. The focus is to highlight regulatory issues that will not be solved through progress in technical areas. It seeks to evaluate the effectiveness of the current U.S. Government's energy policy towards the electricity sector to identify where improvements are required.

It is divided into four parts:

- Part A develops a thorough understanding of the organizational and regulatory structure in the U.S. electricity sector. The goal is to convey to the readers, the specific function and purpose of all the entities that are involved in the operation, working and regulation of the entire system.
- Part B builds on the ground created by the previous part to evaluate the technical Standards that govern the interaction of distributed energy resources with grid and introduces operational and planning standards promulgated by NERC. The goal is to educate the readers on the constraints that the power system must meet in its day-to-day operation.
- Part C takes the knowledge gained from Part A and Part B and explores further into the current regulatory and operational challenges that the power system faces in response to the ongoing DER transition. The goal for the reader is to form a perspective with some depth on each one of these issues.
- Part D is the concluding chapter that thoroughly inspects the government's current energy policy propagated through the Infrastructure Reduction Act and Bi-Partisan Infrastructure Law. The efficacy of this legislation in tackling some of the issues discussed earlier and in general is explored.

II. Organizational Structure of Electricity Sector in United States

The electricity sector of the United States of America is arguably the most complex organization governing the most technically sophisticated and interwind systems that exist on this planet.

This chapter aims to summarize the organizational structure of this system by dividing it into four components:

1 Industry Structure / System Operations
2 Utility Companies
3 Regulatory Landscape
4 Applicable Standards

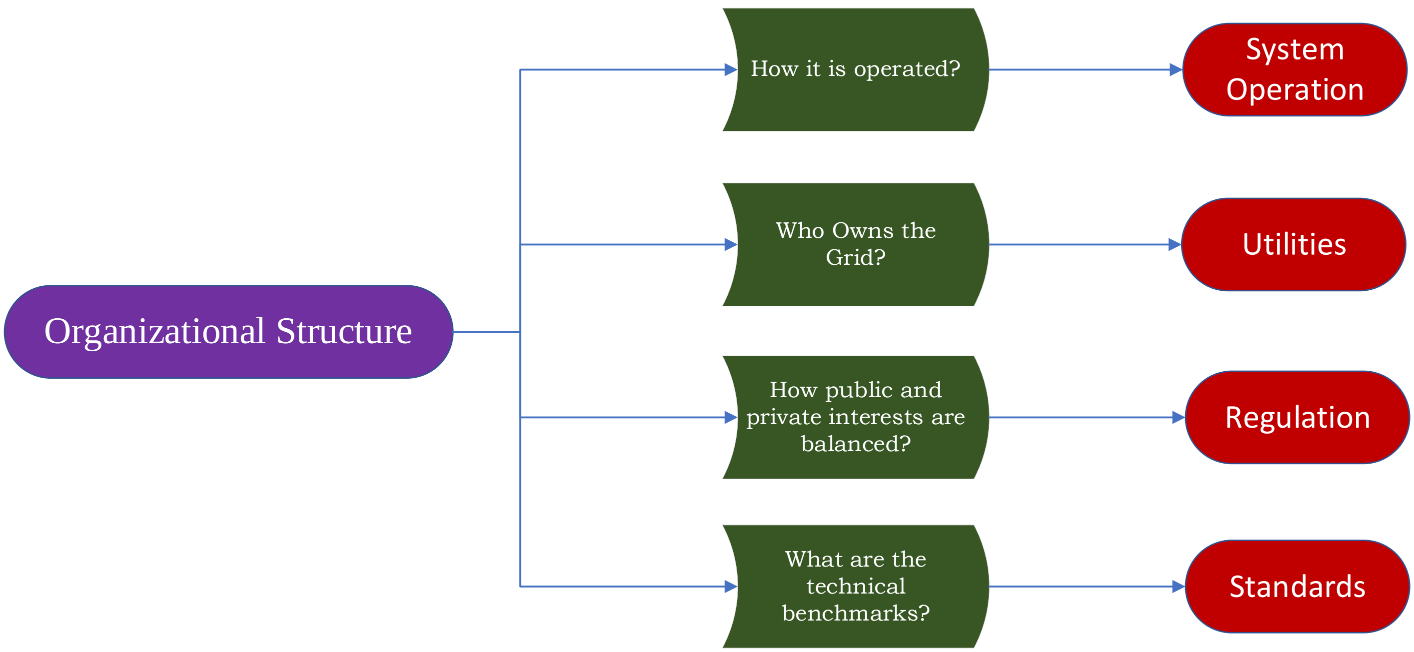

Figure 1: Four major components of the electric power sector

2.1 Industry Structure

The key to understanding the synchronous operation of the vast North American Grid is to breakdown the composition of entities and organizations that operate the various components of this grid and how the responsibility of system operation is divided between their jurisdictions.

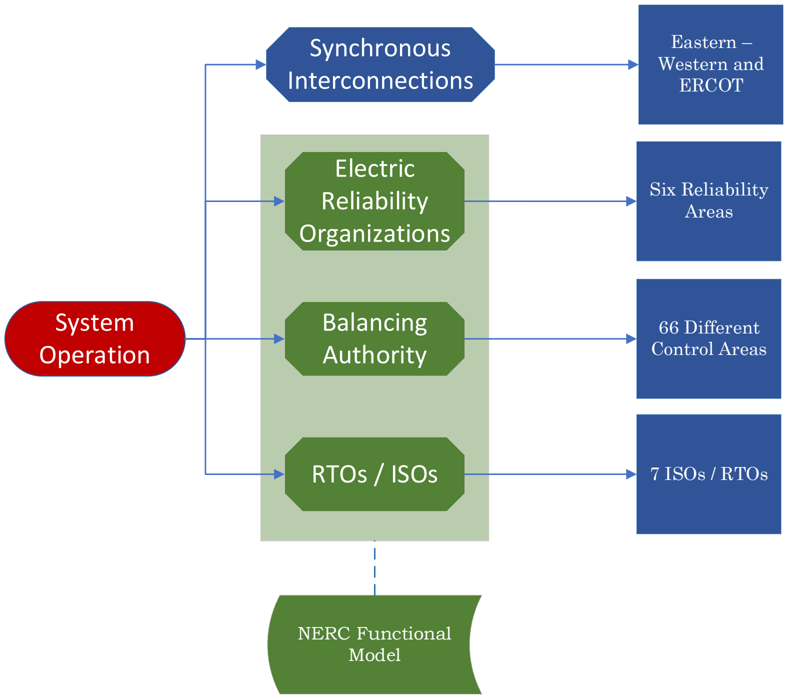

Figure 2: Entities and organizations involved in system operation. (NERC's functional model is discussed in section 5.3)

Independent Synchronous Grids

The North American Grid comprises of three independent AC synchronous grids, Eastern Interconnection, Western Interconnection, and the Texas Grid. These three are connected by DC interlinks for power exchange but largely operate independently.

Regional Entities

Within each synchronous grid, the North American Electric Reliability Council has demarcated six regional entities or Electric Reliability Organization (ERO) Enterprise, w.r.t to electrical boundaries of the grids. NERC oversees the regions to ensure consistency of delegated functions and enforcement of reliability standards across North America, while allowing for an appropriate degree of flexibility to accommodate regional differences [1]. According to functional model, regional entity is the 'compliance enforcement authority' in its respective area.

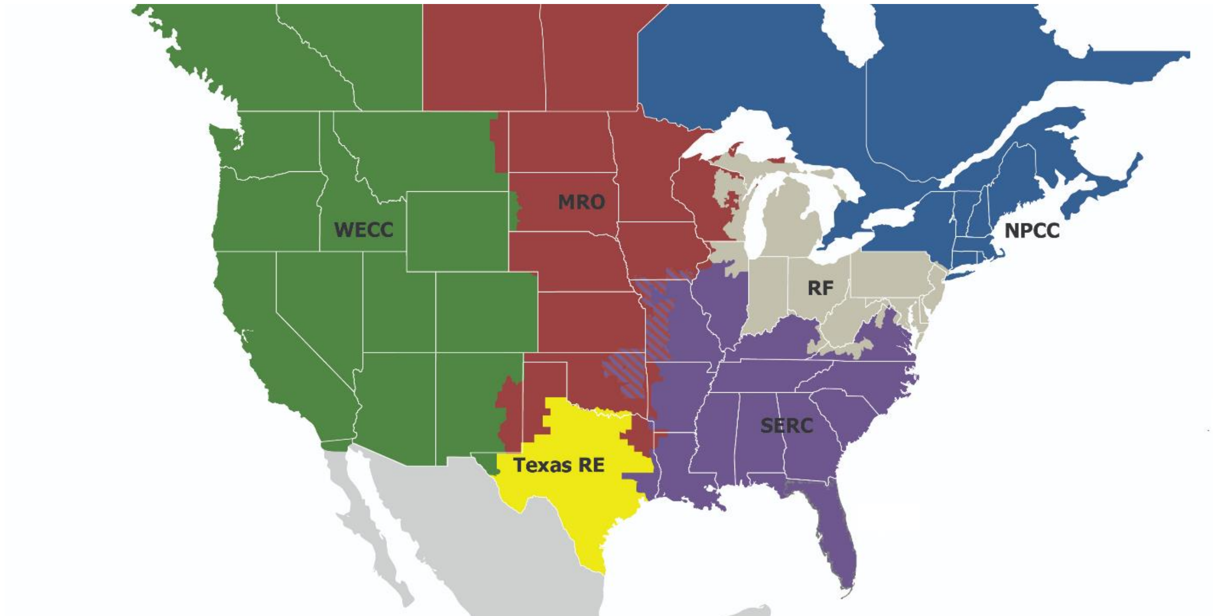

Figure 3: Six regional entities or EROs. [2]

Balancing Authority

A Balancing Authority maintains load-interchange-generation balance within its assigned area and supports interconnection frequency in real time. Currently there are 66 different balancing authorities, but this number may change in the future as two or more balancing authorities may be permitted by regulators to merge.

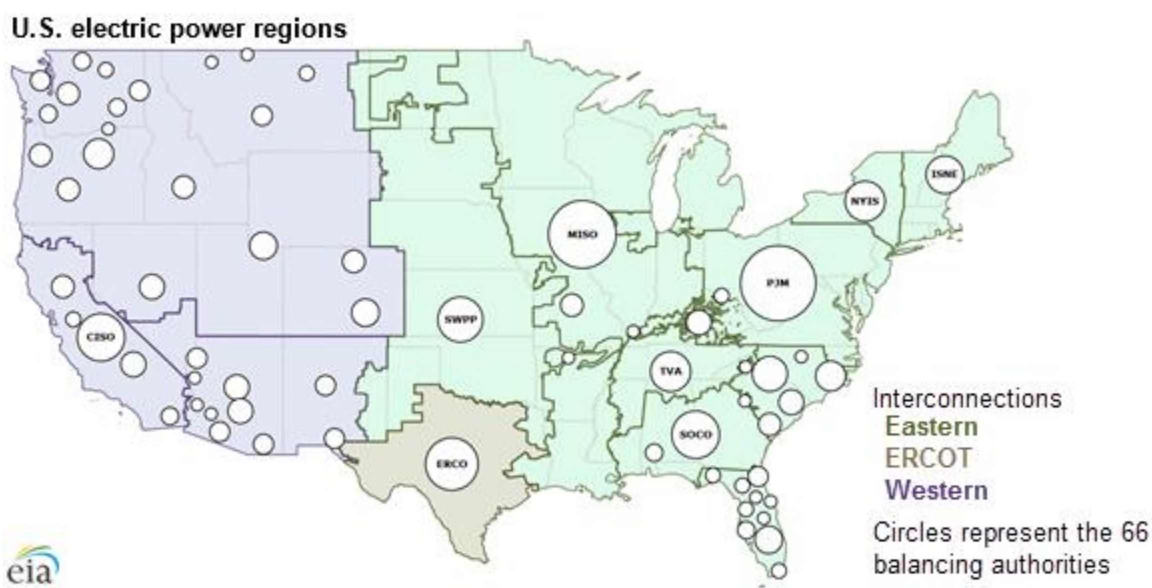

Figure 4: Balancing Authorities and synchronous interconnections. [3]

Independent System Operators (ISOs/RTOs)

ISOs and RTOs are responsible for real-time balancing of the bulk electric power being generated and consumed at any given time. Their job is to schedule generators for the day ahead market and commit the units as necessary during the daily operation. In addition to this function, they also serve as the common electricity market hub for all generators within their electrical boundaries. Currently, 7 of these exist and the FERC laws allow for creation of more, by the voluntary clustering of utilities.

An ISO/RTO can also be a Balancing Authority in its area.

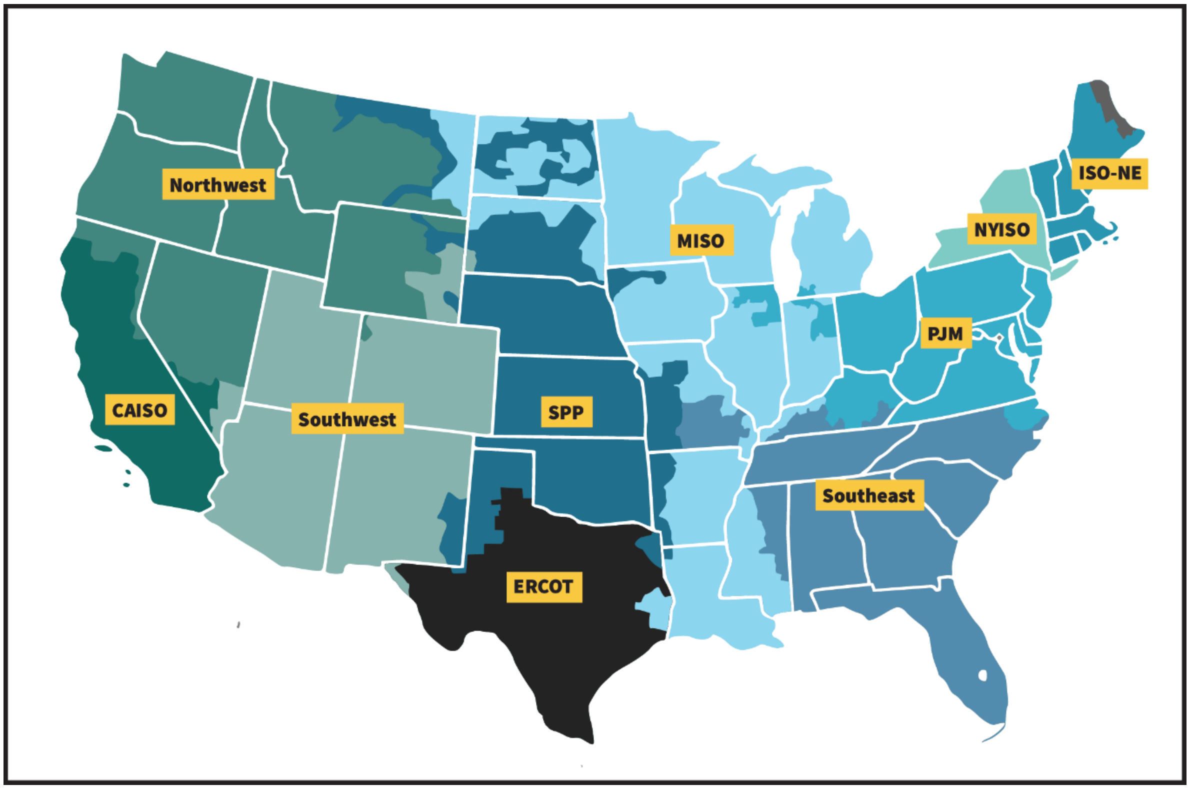

Figure 5: Excluding the power Markets of Northwest, Southwest, and Southeast, CAISO, MISO, PJM, NYISO, ISO-NE, SPP and ERCOT form the current seven ISO/RTOs. [4]

2.2 Utility Companies

As we saw in the previous section, individual utility companies can cluster together to form ISOs/RTOs and this develops our discussion further into the structure and types of these utilities. Primarily, in the United States, utilities can be of two types:

1. Investor-Owned Utilities (IOUs)
2. Public Utilities

Investor-Owned Utilities

This type makes roughly about 75% of the total distribution base in United States. They are private companies financed by shareholders equity and bond holder debt. They can also be holding companies. IOUs have formed a voluntary lobbying group called The Edison Electric Institute (EEI).

Public Utilities

The remainder 25% is served by public utilities. Their structure can take one of the below three forms:

1. Cooperatives
2. Public Utility Districts
3. City owned or Municipal Utilities

They are similar in terms of the fact that they are governed by elected officials but differ in terms of how the governing officials are elected. Cooperatives are governed by a council elected by customers of the utility. Public Utility Districts are governed by officials elected by voters within their service territory and Municipal utilities are governed by elected city councils or commissions.

In several places the above three have sometimes pooled together, with the motive of utilizing generation and transmission resources more efficiently to form Generation & Transmission Cooperatives or simply G&Ts. These are inherently corporations that have the authority to generate and contract on behalf of many small sized utilities.

The infographic below reflects this division:

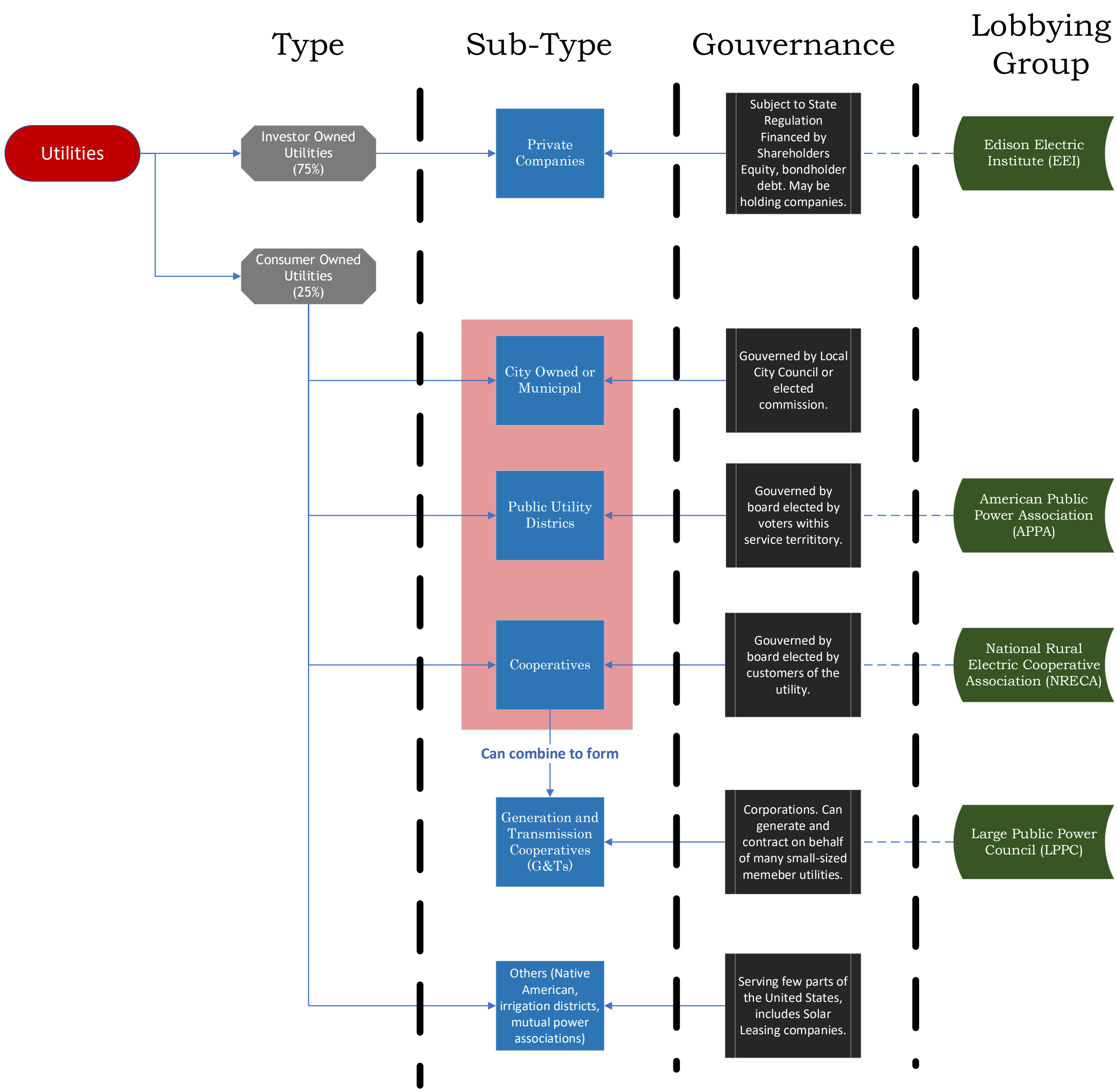

Figure 6: Governing structure and lobbying groups of investor-owned utilities and consumer owned utilities

2.3 Regulatory Landscape

After understanding the different entities that constitute our electric grid, it is important to clearly discern the jurisdiction of regulatory bodies over these entities.

General Principal

A very basic concept in the US Federal Law is the fact that, anything that escalates beyond the state boundaries comes under the control of federal government and all other things, which stay within the boundaries of a particular state are subject to state regulations.

State Vs Federal Regulation

With this concept in mind, we can infer that interstate transmission and distribution, as well as wholesale power purchase (at ISO hubs) is regulated by federal law and other things such as siting and location of power plants and environmental regulations can be left to state and local regulators. (More information in the assisting flow chart).

Federal electricity regulation is mostly promulgated by FERC or Federal Energy Regulatory Commission. Matters involving reliability are dealt by North American Electric Reliability Commission or NERC. NERC is a mandated subsidiary of FERC and by FERC regulation of 2007 it is mandatory to follow all applicable standards set by NERC.

On the other side of the picture, state and local regulation falls under the jurisdiction of Public Utility Commissions in the case of IOUs and/or elected councils in case of Public Utilities as we discussed earlier. Both follow relatively same regulatory framework, but the difference lies in the body that has the jurisdiction to promulgate the regulation over their respective class of utility. State regulation will be discussed further in Chapter III.

2.4 Applicability of Standards

Several types of standards are applicable in the electricity sector in the United States. Some of them are circulated and maintained by Federal Agencies such as NERC, EPA and OSHA. Others are maintained by private organizations such as ISO, NFPA and UL. Bulk of the standards applicable on the electricity sector originate from the IEEE or Institute of Electrical and Electronic Engineers. An approved IEEE standard would become an American National Standard or simply ANSI Standard.

Here, we will give a brief overview about each type of standard and a detailed discussion on standards applicable on DER interconnection and NERC's operation and planning standards will follow in Chapter IV and Chapter V respectively.

IEEE Standards

IEEE Standards form the bulk of the technical standards in this sector. Our focus will be on the IEEE 1547 series of standards that focuses on the interconnection requirements of DERs with secondary and primary distribution systems and talks about design and operation of microgrids as well as network studies required to evaluate the impact of DERs.

Another important standard is the IEEE 2030 series of standards, which deals with interoperability requirements for DERs between different vendors and manufacturers.

NERC Standards

NERC standards deal with network reliability such as transmission operations, facility interconnection requirements and reliability coordination requirements for generators willing to connect to the synchronous grid.

NFPA Standards

NFPA 70 or the National Electric Code is a widely accepted standard about construction of all types of electrical installation, fixtures and equipment. NFPA 70 is accompanied by NFPA 70E, Standard of Electrical Safety in the Workplace, dealing with safety requirements for all of the former. In the case of DERs both will apply on solar PV and battery storage system installations.

UL Standards

UL standards are equipment specific, referring to conformity of apparatus (protection relays, battery and panel enclosures and in our case, inverter devices) to defined requirements such as electric shock, fire risk and ingress protection.

ISO Standards

ISO standards relate to defined practices in organizational management structure. For our study ISO 50001 EnMS is applicable, which gives organizations a recognized framework for developing an effective energy management system. In the light of the current DER integration scenario, this could be helpful in an organizational context but not in terms of technical functionality.

EPA Standards

United States Environmental Protection Agency enforces toxic emission control standards for power plants through the Clean Air Act of 1990 and national emission standards for hazardous air pollutants (NESHAP).

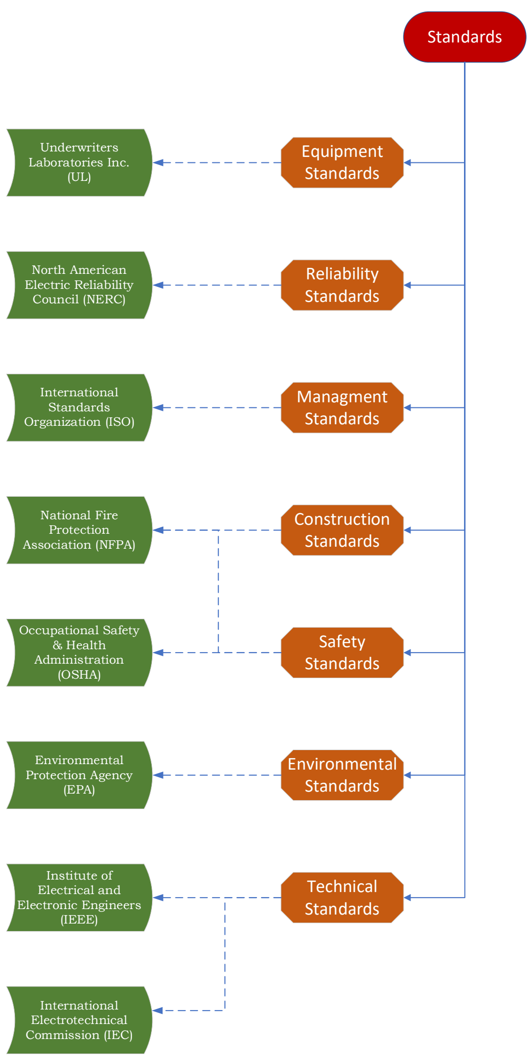

Figure 7: Different standards can be applicable on the power industry.

III. State Regulation

Drawing from the governing principal of the US constitution, the Federal Government and Federal Agencies will have authority over interstate matters and those, that stay within the borders of individual states will be dealt by their respective state authorities. Thus, state regulation has an important role in the overall regulatory landscape. Here, we must first ascertain the entities, that would fall under the jurisdiction of state regulation and the offices that would establish those regulations. Next, we will see what is being regulated, for the subject entities.

3.1 Entities Subject to State Regulation

State regulation primarily applies to Investor-Owned Utilities or IOUs, that comprise of about 75% of the total customer base. They may have limited jurisdiction over municipal utilities and/or cooperatives, where it is assumed that, since municipal utilities are themselves, governed by a local electorate, control over their policies through voting, is generally sufficient from a regulatory perspective. Same is true for cooperatives. Nevertheless, about 20 states do allow some oversight of municipal utilities by state authorities and about 30 of them allow oversight of cooperatives by state authorities [5].

In cases where large customers have access to high voltage transmission system, their utility charges may be almost entirely comprised of rates set by FERC for wholesale purchase of power. (State commission will still approve the contract beforehand).

3.2 Offices that Promulgate State Regulation

Excluding the elected boards or city councils governing COUs, state regulation is primarily promulgated by Public Utility Commissions or PUCs. Their procedures and organizational structure generally follow that of FERC. A typical PUC would consist of three to seven officials assisted in duties by professional staff [6]. Officials may either be:

1. Appointed by the governor and endorsed by the legislature.
2. Or elected by legislature or voters.

PUCs are represented by the voluntary lobbying group called NARUC or National Association of Regulatory Utility Commissioners. It represents the interests of State public utility commissions before the three branches of the Federal government and the Independent Federal agencies [7].

Aside from the PUCs, State Energy Offices have been given the responsibility of directing the overall strategic energy initiative for each state. They are the designated recipient of the Federal State Energy Program funding (SEP) administered by the U.S. Department of Energy (DOE) for each individual state. The SEP provides funding to states for enhancing energy security, advance state-led energy initiatives, and increase energy affordability, with the idea that these activities are tailored according to the unique resources and goals of individual states [8]. In most states this is an independent agency, separate from the regulator.

The SEP and other U.S. Government led initiatives were created as an offshoot of the Middle East oil embargo in the 1970s to pacify public concerns over energy security and the DOE was created to lead and administer these new programs.

3.3 Jurisdiction of State Regulation

Public Utility Commissions have the authority to regulate a range of affairs concerning IOUs and to a lesser degree, COUs, as discussed before. The state legislature has given them the legal authority to *regulate in public interest* and this is their guiding principle. Their role is discussed below:

Rate Determination

Chief responsibility of the PUC regulator is to determine an equitable rate billed to the customers. This rate must be sufficient to meet the revenue requirements of the utility including a reasonable rate of return on investment and at the same time, must be fair to consumers. Rate determinization is a complex process, particulars of which are beyond scope of this chapter, however they generally follow PURPA rate-making standards.

Generation Portfolios

To ensure reliability of the system and meeting environmental targets, a regulator may require the utility to meet a certain percentage of its generation portfolio from designated resource types, that are usually renewable energy sources. About half of the 52 states have active renewable energy portfolio requirements of some type. [6]

Some state energy offices also set portfolio standards for utilities to meet in the long-term. They may be tailored to each individual state's energy goals and strategic initiatives.

Resource Planning

Some state regulators require utilities to prepare long term resource plans or IRPs to guide the direction of their future investments in generation, transmission, distribution and demand side programs. The goal of the regulator here is to evaluate the different resource options on both supply and demand side to find the least cost option. It is expected that if all stake holders participate in the planning process early on, unproductive investments can be exposed earlier.

While all utilities do prepare them, the involvement of regulators varies state by state. Some have the authority to review and approve them formally, while others would just require them to be submitted.

Construction Permitting

State regulators have the authority to evaluate proposals for construction of new generation plants and transmission lines that pass through its territory. They key aspect here is, the state regulator will determine if the new project is actually 'needed or not'. The regulator will also scrutinize, if they can be built in a way, that minimizes negative externalities to the environment and local community. In some cases, this authority gives them veto power over multistate transmission projects, those that we discussed earlier, are under federal scope. This is however open to appeals to FERC under EPAct05, if the states fail to fulfill 'national interest' [5].

Energy Efficiency Measures

As with the generation portfolio requirements, some state regulators explicitly require utilities to reduce a portion of their demand through energy efficiency initiatives. State regulators have also set criteria for utilities to make investments in energy efficiency measures because customers would not otherwise implement them on their own.

Mergers and Competitive Activities

In economic theory, mergers or taking over of one utility by another utility are considered anti-competitive. The regulator in this case, may allow such mergers to happen, usually with specific conditions attached, if the case filer is able to prove that such merger would be in 'public interest' in a way that it will promote efficiency of service after the merger.

Some regulators may allow utilities to run 'associated' businesses like provision of energy efficiency services and installation of rooftop PV. The regulator would assume that if the utility is involved in this market, adoption of these products would be much faster, owing to confidence brought in by the utility. Other regulators may require such services to be offered only through separate subsidiaries, that will pay a royalty to the utility for use of its goodwill.

Capital Acquisition

In circumstances where a utility wants to raise more capital for investments in new infrastructure or any of its expansion projects, the state regulator must approve this capital acquisition. It may be through issuance of additional stocks or bonds. The regulator's perspective here is that the utility must raise this capital in a sustainable way and the cost of raising such capital must not be too high for the utility. Inevitably, because any investment made by the utility will be eventually recovered from the customers, so it should not be acquired at a higher upfront cost.

The regulator must also ensure that the utility is in a healthy financial state, with an acceptable debt ratio. Should a utility be required to raise capital on a short notice, like in an event of storm restoration, it must have access to this capital at a reasonable cost from the market. This is important for safe and reliable provision of service to customers.

Conflicting Affiliations

Regulators must ensure that any utility is not unfairly rewarding its own affiliate. This may occur in the case where a utility is deeply involved with some other organization by way of corporate links or shared ownership, and then pays its affiliate (that is not directly regulated) above market price on the shoulders of its own regional monopoly. The regulator has the authority to make sure that affiliates are not given an unjustified advantage over their competitors.

Service Quality Standards

Regulators have adopted service quality indices (SQI), such as the duration of outages in minutes/year or the speed with which the utilities respond to customer's calls and service requests. This is used to gauge the performance of the utility.

Technical Standards

Regulators also adopt standards that would endure that the customer receives an acceptable quality of electricity supply, such as the frequency deviation allowance and voltage stability thresholds and safety requirements. We discussed a number of these standards in Chapter 2. From the perspective of state regulation, they are mostly applicable to distribution systems and not on HV transmission system. The later being under the jurisdiction of FERC.

Environmental Justice

Multiple environmental standards and regulations exists at federal state and local levels. They are usually enforced and assessed by separate environmental agencies, however, since meeting these environmental standards come with some costs, for example, extra investment in pollution control equipment or water treatment requirements, the regulator is primarily tasked with apportioning these costs to different consumers and devising a way for the utilities so that they can recover these costs from their customers. This may be through direct rate increases approved by the regulator or in restructured states, passed on to electricity markets. Thus, their main job here is to be an economic regulator, rather than being an enforcer of environmental laws. In some states however, the regulators may explicitly require the installation of certain equipment that are necessary to meet environmental standards.

Regulators must also ensure that utilities are investing in low-pollution power generation such as wind and solar as a part of their long-term resource planning (IRP), that would serve in the best interest of the ratepayer. Their notion is that, since future cost of power generation billed to customers would be affected by its environmental impacts, the costs, risks, and feasibilities must be assessed now.

The infographic below provides a good summary of the distinction between federal, state and local authorities in the regulation of electric power industry.

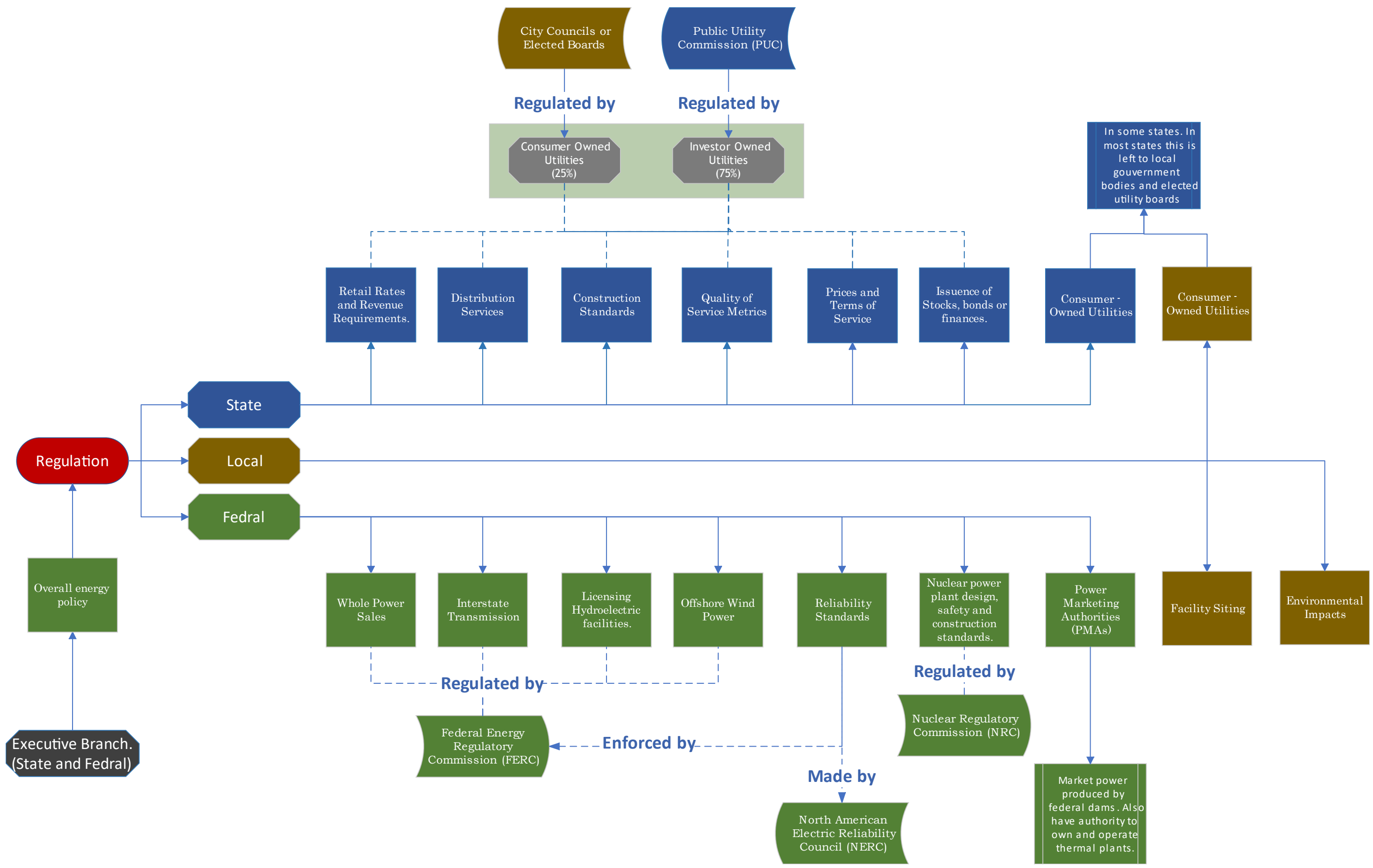

Figure 8: Distinction between federal, state and local regulation.

IV. Assessment of Technical Standards Applicable on DER Interconnections

The DER interconnection and smart grid operation landscape could fall under the scope of several widely accepted standards. If we break these down into six broad categories, we will find that:

- Majority of the technical specifications of distributed interconnection resources or DERs would under the umbrella of IEEE 1547 and IEEE 2030 series of standards. This includes battery energy storage systems as well as electric vehicles.
- Construction and installation criteria and requirements are primarily governed by NFPA's National Electric Code. NEC covers all types of electrical installation and hence would generally be applicable on DER installation.
- Safety considerations w.r.t to smart grid installations would fall under the scope of NFPA 70E and National Electrical Safety Code. Like the NEC, these two cover all types of electrical installation and hence would generally be applicable on any type of DER installation.
- Equipment and product conformity standards would be covered by Underwriter Laboratories (UL) Standards.
- Reliability and resiliency of DERs would generally be governed by NERC standards, if they are of sufficient capacity and seek to be interconnected to the bulk electric supply system. This would only be applicable for large DER sources. Additionally, individual control area operators would account for them regardless of DER penetration levels.
- There are several federal and local authorities governing environmental and land management regulations, but this is beyond the scope of this work.

A high-level overview is illustrated in the extended standards infographic and details follow through the chapter.

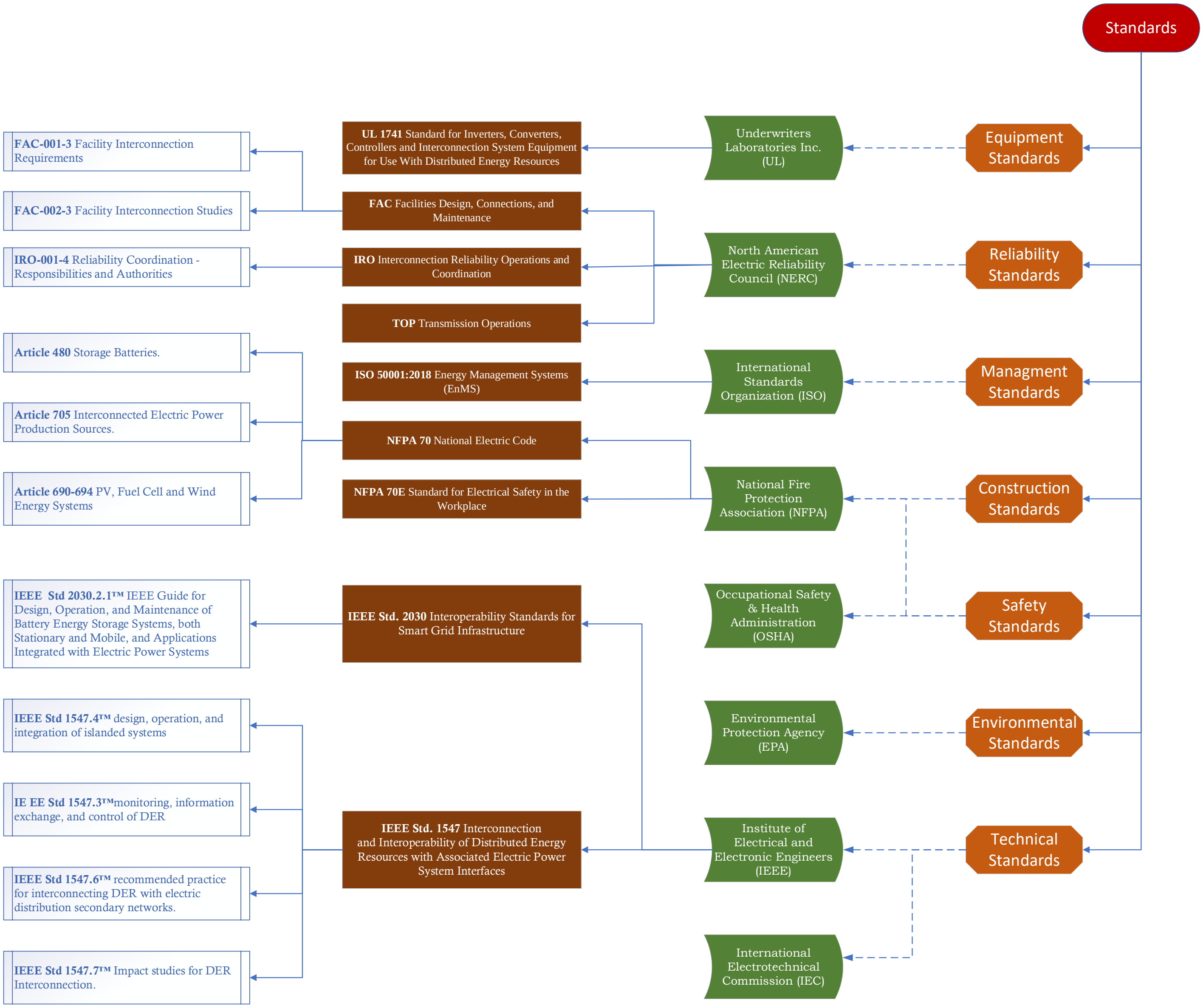

Figure 9: Summary of standards applicable on DER interconnections

4.1 IEEE 1547 Series

Std. 1547 provides a uniform standard for the interconnection and interoperability of distributed energy resources with electric power systems. Installation of DER on radial primary and secondary distribution systems is the main emphasis of this standard and requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection are presented. These requirements are universally applicable to DERs, whether it is a synchronous machine or any type of inverter/converter. IEEE 1547 is also cited in the Federal Energy Policy Act of 2005.

The IEEE 1547 has seven additional documents and some of those are discussed below:

IEEE 1547.2 – Interconnection of DERs

This document facilitates the use of IEEE Std 1547 by characterizing the various forms of distributed resource (DR) technologies and the associated interconnection issues. It applies to all DER technologies of aggregate capacity of 10 MVA or less at the point of common coupling (PCC) that are interconnected with an area EPS at typical primary or secondary distribution voltage.

IEEE 1547.3 – Monitoring and Information Exchange

1547.3 is intended to help stakeholders in DER installations, implement optional approaches for monitoring, information exchange, and control to support the operation of their distributed resources and transactions among various stakeholders and market players.

IEEE 1547.6 – Interconnection with Secondary Distribution

IEEE Std 1547.6 was specifically developed to provide additional information regarding interconnecting DER with distribution secondary networks. While all of 1547 is mandatory, 1547.6 provides additional recommendations and guidance in this regard.

IEEE 1547.7 – Interconnection Impact Studies

Increased adoption of distributed resources throughout distribution systems often results in the need to perform a distribution system impact study. This guide provides a common technical platform based on engineering knowledge to address study methods for performing DR-EPS impact studies.

4.2 IEEE 2030 Series

Interoperability is conceptually defined as ability of one manufacturers device to function harmoniously with another manufacturers device without compromising on functionality. Std 2030® provides approaches and best practices for achieving this interoperability in the smart grid environment.

Like the 1547, 2030 also has several additional documents:

- IEEE 2030.2 – Interoperability of Energy Storage Systems
  Std 2030.2 was specifically developed to address the interoperability of energy storage systems (ESSs) with electric power infrastructure. Implementing the IEEE 2030 smart grid interoperability reference model (SGIRM) approach, IEEE Std 2030.2 provides a framework for identifying and organizing the key information that is required to help assure that any given ESS can connect, and be interoperable, with the EPS to which it is connected.
- IEEE 2030.3 – Test Procedures for Energy Storage Systems
- IEEE 2030.5 – Smart Energy Profile Protocol
- IEEE 2030.7 – Microgrid Controllers
- IEEE 2030.9 – Planning & Design of Microgrids
- IEEE 2030.11 – Resource Management Systems (DERMS)

4.3 IEEE C2 - 2017 – National Electrical Safety Code

NESC is a globally recognized consensus standard that is intended to provide a practical standard of safe practices that can be adopted by public utilities, private utilities, state or local utility commissions or public service commissions, or other boards or bodies having control over safe practices employed in the design, installation, operation, and maintenance of electric supply, communication, street lighting, signal, or railroad utility facilities.

Generally, grid interactive customers or DERs do not fall under the legal jurisdiction of NESC beyond the point of common coupling unless they are operated by the utility itself, nevertheless NESC's practices are still beneficial to implement as the standard.

Since NESC standards are applicable universally to electric supply systems, we can reasonably conclude their applicability over DERs and microgrids in relevant installations of scale, particularly w.r.t its section 14 on storage batteries.

4.4 NFPA 70 – National Electric Code

National Electric Code is the widely accepted standard for installation of all types of electrical equipment. It gives you the criteria on what is the standard for installation of overhead and underground cables, conduits, transmission lines, generators, emergency power systems, feeder protection, grounding and so on. It is more like a construction standard that you would use when designing any new facility.

Articles of concern for us in DER integration are:

- Article 480 – Storage Batteries
- Article 690-694 – PV Fuel Cell and Wind Energy Systems
- Article 705 – Interconnected Power Production Sources

4.5 NFPA 70E – Standard for Electrical Safety in the Workplace

NFPA 70E primarily deals with employee safety while working on electrical installations for e.g maintenance of battery storage systems. It was developed as a separate document to satisfy safety requirements for OSHA as the original NEC did not have anything related to safety considerations for employees and employers. [9] NFPA 70E is applicable in all areas where NFPA 70: NEC is applicable. For our study, that could be while working on battery storage systems and PV installations.

4.6 UL 1741 – Standard for Inverters and Converters

UL 1741 titled “Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources” provides us the conformity standards for equipment or systems assembled from those equipment. Conformity standards can refer to protection from electric shock, enclosure impact bearing capability, water proofing, sound and noise levels and others specific to the type of equipment under consideration.

Scope of this standard covers all types of controllers, inverters, PV modules, interconnection system equipment and panel enclosures either being operated in grid-connected or grid-independent mode.

UL 1741 is applied in connection with IEEE 1547 and 1547.1 wherever grid-interactive applications are present, and it is presumed that all equipment installations would comply with NFPA 70: NEC and employees will be following NFPA 70E requirements when they handle that equipment. So, everything is interlinked here.

4.7 UL 50 – Enclosures for Electrical Equipment

This standard applies to enclosures for electrical equipment intended to be installed and used in non-hazardous locations in accordance with the provisions of the National Electrical Code for the United States. Enclosure types such as Type 1, Type 2 and so on are defined according to intended application.

This would be applicable on all panel and switch board installations for DER interconnection equipment.

4.8 NERC Standards

After the Northeast US blackouts of 1965, regional electric reliability councils were formed to promote reliability and efficiency of the interconnected power system. Shortly after words they joined together to form an umbrella group called NERC. Recently, by about 2006, due to the evolving complexity of the power system and everchanging landscape, the congress ruled that United States will no longer rely on voluntary compliance by participants, instead reliability requirements would be enforced. In response to this, FERC designated the NERC as the ERO or the

Electric Reliability Organization for USA in 2007. NERC standards were therefore enforced by federal authority of FERC. [5]

Categorization of NERC Standards

NERC standards are grouped into 14 categories as shown below:

Table 1: NERC Reliability Standard categories

Resource and Demand Balancing	BAL
Critical Infrastructure Protection	CIP
Communications	COM
Emergency Preparedness and Operations	EOP
Facilities Design, Connection and Maintenance	FAC
Interchange Scheduling and Coordination	INT
Interconnection Reliability Operations and Coordination	IRO
Modeling, Data and Analysis	MOD
Nuclear	NUC
Personal Performance, Training and Qualification	PER
Protection and Control	PRC
Transmission Planning	TPL
Transmission Operations	TOP
Voltage and Reactive	VAR

Compliance with NERC Standards

All bulk power system owners, operators and users must comply with approved standards. These entities are required to register with NERC through appropriate regional entity. NERC relies on regional entities for enforcement of standards and penalties in case of non-compliance.

V. System Operations and Planning as per NERC Standards

In Chapter II and Chapter IV we mentioned that, in North America, NERC has established very specific standards to govern the reliable operations of the bulk electric power system. In practice they are more than just reliability metrics, they in fact standardize every aspect of power system operation, from operating limits to coordination between different entities. This chapter will examine these standards in detail, but let's first look into the different time horizons of power system operation, which are of importance when interpreting NERC standards.

5.1 Time Horizons

Power system operation can be divided into four distinct timeframes. These time frames are referred to by NERC as Time Horizons. The four distinct time horizons are:

Long-term Planning:

A planning horizon of one year or longer. During this time period, entities will ensure that investments are channeled into most optimum generating resources and load forecasts to determine this generation rating must be accurate.

Operations Planning:

Refers to a time period from day-ahead up to months. It deals with generation and transmission changes that need to take place to accommodate seasonal variations in load and maintenance downtimes.

Same-day Operations (Economic Dispatch):

Refers to time period between one hour to the end of the day. It deals with unit commitment to supply the load in the coming few hours.

In restructured states where ISOs and RTOs have a competitive market where generators can bid their prices in real-time, economic dispatch is not required and it can be considered the same as real-time operation. This is true for most of the eastern United States.

Real-time Operations (Automatic Generation Control):

Refers to time period from the current instant up to one hour. These are the actions that needed to be taken at the current instant to balance the load with generation in real-time. A number of other actions needed to preserve the reliability of bulk electric power system are also performed in this time frame. [10] [11]

The four time horizons along with a contingency period, which can be considered as a subset of real time operation are illustrated below:

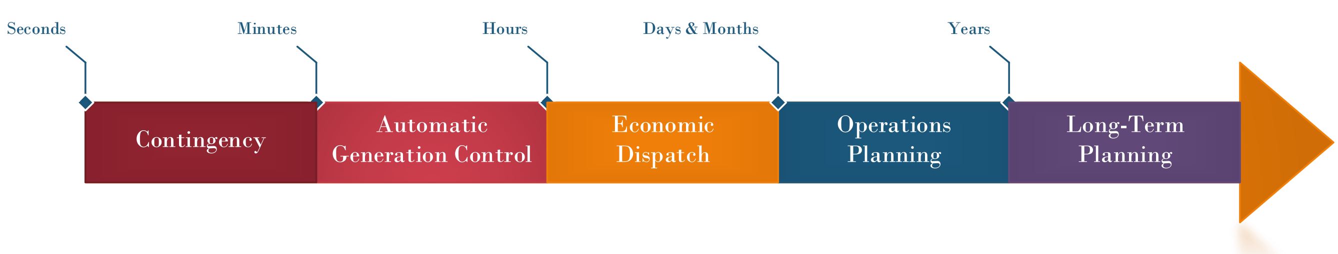

Figure 10: NERC's operational time horizons

5.2 NERC Standards in Different Time Horizons

Each requirement of a NERC standard is applicable on a specific time horizon that determines its applicability over a time period. Time horizons also determine the severity of violation, should it occur. For example, if a standard is applicable on real-time operations, its violation cannot be recuperated in the short period of time, so severity of standard violation is higher.

Figure 11 presents a summary of the most important NERC standards that are directly applicable on the operations of the bulk electric power system. Here we have omitted NUC, PER, CIP and PRC standards as they are not directly incident on power system operations.

We have added a category for contingency here to create a distinction between what is needed to be done under normal operations and when a contingency event occurs. NERC, however, treats this to be included in real-time operations.

5.3 The NERC Functional Model

The objective of the NERC functional model is to divide the tasks that are to be performed to ensure the reliability of the bulk electric power system between respective 'functional entities', hence each requirement of a NERC standard will apply to one or more than one functional entity.

It divides power system operation according to functional areas such as compliance enforcement, reliability assurance, transmission planning, operations, distribution provision, generator ownership generator operation, purchasing-selling and end user load serving. There are 18 distinct functional entities as per version 5.1 of the functional model:

1. Standards Developer
2. Compliance Enforcement Authority
3. Reliability Assurer
4. Reliability Coordinator
5. Balancing Authority
6. Planning Coordinator
7. Transmission Planner
8. Resource Planner
9. Market Operator
10. Transmission Operator
11. Interchange Authority
12. Transmission Service Provider
13. Transmission Owner
14. Distribution Provider
15. Generator Operator
16. Generator Owner
17. Purchasing-Selling Entity
18. Load Serving Entity

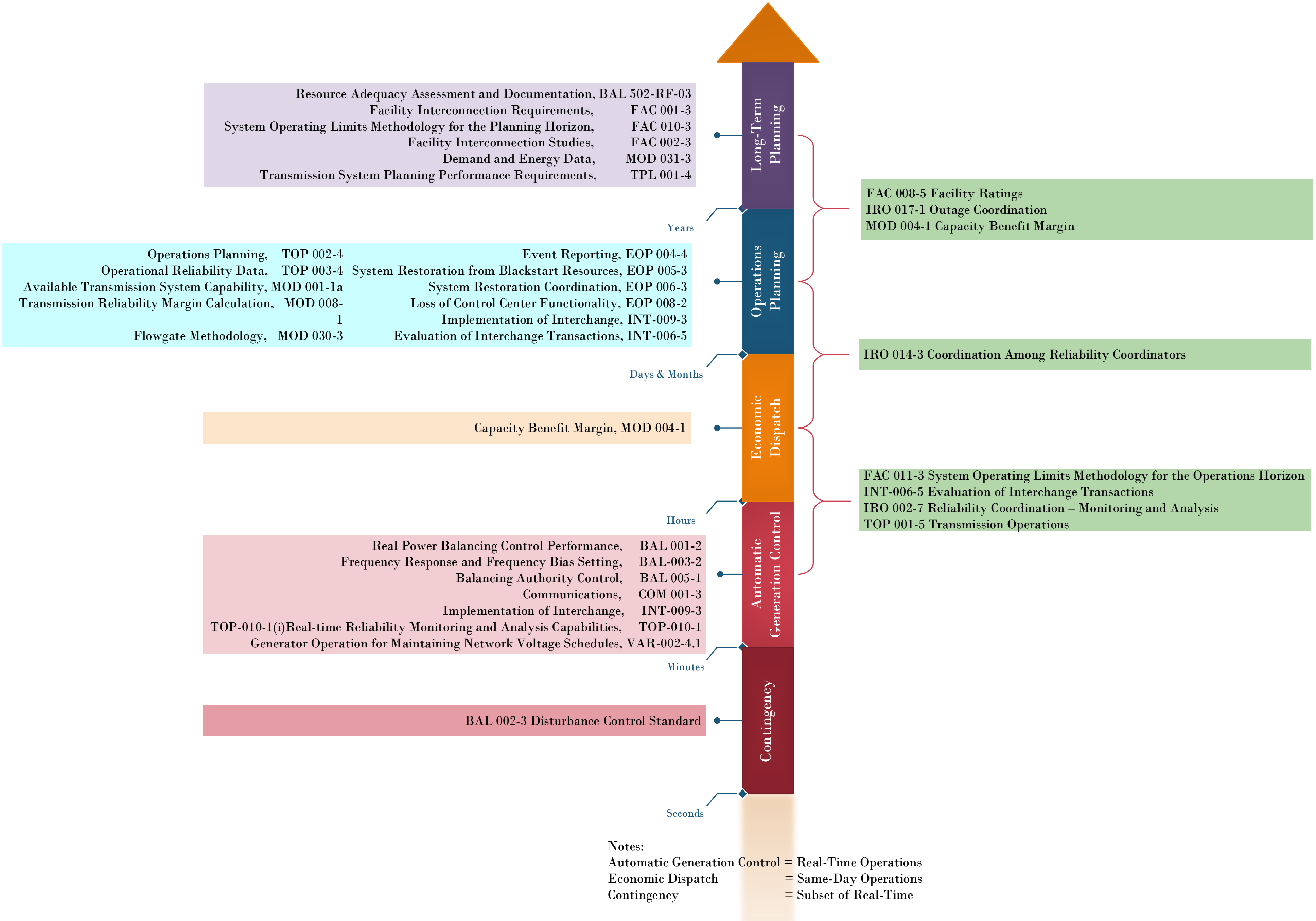

Figure 11: NERC standards and power system planning time horizons

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5.4 Summary of Important NERC Standards

A brief overview on the most important standards mentioned in the above chart is given below:

BAL 001-2 Real Power Balancing Control Performance

Defines the control performance standard (CPS1) and balancing authority ACE limit (BAAL) standards to control the interconnection frequency within defined limits.

CPS1 is the average of 1 minute frequency changes in one balancing area, divided by the same value averaged over the whole interconnected system in which the balancing authority operates. There is a detailed calculation process to arrive at both the CPS1 and BAAL value defined in this standard. Both these values should not exceed their defined limits.

BAL 002-3 Disturbance Control Standard

This standard applies to balancing authorities in an event when they encounter a contingency event. It states that the responsible entity, which could either be a balancing authority or a reserve sharing group, must try to recover its Area Control Error or ACE to pre-event value within the event recovery timeframe, if it experiences a balancing contingency event.

Responsible entities are required to maintain contingency reserves equal to or greater than the most severe single contingency event possible to happen within their area. This is simply the n-1 criteria. Should an event of that sort occur, contingency reserves must be restored to their pre-event values within the 'contingency reserve restoration period'.

BAL 005-1 Balancing Authority Control

Necessary requirements to record and report the area control error or ACE are given in this standard. Balancing Authorities are required to use frequency metering equipment with an accuracy of 0.001 Hz to monitor the ACE and the system must have a total uptime, greater the 99.5%. Data used to calculate ACE should be acquired every five seconds and if there is an interruption of more than 30-minutes, the reliability coordinator must be notified within 45 minutes.

Exchanges between two balancing authorities through tie-lines or dynamic schedules must be monitored through time-synchronized common sources.

BAL 502-RF-03 Planning Resource Adequacy Analysis

Establishes the 'one day in ten years' loss of load expectation principal and directs the planning coordinators to perform and document a resource adequacy analysis according to this criterion annually. Gaps between planning reserves calculated for one year and projected planning reserves for the next ten years must be identified.

TOP 001-5 Transmission Operations

Applies to balancing authorities, transmission operators, generator operators and distribution providers and establishes rules of coordination between these entities, so that instability, separations and outages can be prevented. Some data exchange requirements with entities are also mentioned in this standard.

Transmission operators and balancing authorities are placed at the top of the hierarchy, and are responsible to reliability of their transmission area and balancing authority area respectively. The former four entities, must comply with any operating instruction, given by the latter two entities, if it is safe and physically possible to comply. If they are unable to comply, the remaining three must be informed.

Transmission operators are mandated to determine system operating limits, their exceedances and operate to the most limiting parameter if there is a difference is SOL.

TOP 002-4 Operations Planning

This standard ensures that transmission operators and balancing authorities have plans to operate in the operations time horizon. It is mandatory for transmission operators to prepare an operational planning analysis for the next day that will evaluate if any of the SOLs will be exceeded with their transmission area during the next day operation. If the limits exceed, they should have an operating plan and concerned entities must be notified. These plans should be notified to the Reliability Coordinator.

Similarly, balancing authorities must also have planned that address:

- Expected unit commitment and dispatch
- Interchange schedules.
- Demand patterns
- Capacity reserve requirements.

Like the transmission operator, this plan must be reported to the reliability coordinator and all concerned entities, that will be impacted by these plans must be notified.

FAC 001-3 Facility Interconnection Requirements

The burden of determining interconnection requirements for generation facilities, transmission facilities and end-user facilities is placed upon the Transmission Owner. Generator owners can also document similar requirements for other smaller generators that wish to use their existing facility to interconnect to the transmission system.

IRO 014-3 Coordination Among Reliability Coordinators

Applies to reliability coordinators, (and remember they are the highest of all entities according to the hierarchy established by NERC) on how they should coordinate with other reliability coordinators during normal operations and in case of emergencies.

Each reliability coordinator must have specific operating procedures for notifications and passing other necessary communication to other reliability coordinators. An interesting aspect of this standard is that if one reliability coordinator interprets a situation to be an emergency, it must notify other impacted reliability coordinators and those identified must operate as if the emergency exists, even if they disagree on the existence of an emergency.

VI. Emerging Regulatory Challenges

As the electric power industry is becoming de-regulated and increasingly impregnated with distributed energy resources, the regulators task to arrive at a conclusion, that does justice between the consumers, utility and the general reliability and resiliency requirement of the electric power system is becoming a daunting task. This chapter attempts to discuss conflicting viewpoints on some of these issues that are a challenge for most regulating entities in the United States.

6.1 **An Equitable Net-Metering Policy**

The number of net-metering customers in the United States has risen by nearly ten folds between 2011 and 2021 [12]. This increase has been fueled by advances in technology leading to reduction in DER installation costs and favorable policies starting from the Energy Policy Act of 2005. The EPAct05 relegated the authority of making net-metering regulations to individual states, but the focal point was that, it mandated the states to consider adopting net-metering standards after a due process and it was required that each state reach a decision on this in writing [13].

Initially, net-metering was viewed as a simple administrative process that would roughly estimate the value of solar or any DG and since the number of participants and the exported kWh was small, the consequences of not doing justice between stakeholders, in-terms of over-estimating the value of DG were also small [14].

As mentioned previously, this is no longer the case. Both the customers and exported kWhs have increased and critics are arguing that net-metering fees paid to homeowners with rooftop solar for energy export, merely transfer the cost of utilities to customers without rooftop solar, instead of contributing to net benefits for the grid and ratepayers [15]. This criticism is valid for other DERs as well that benefit from utility paid incentives. The phenomenon is collectively being referred to as a 'cross-subsidy', where the ratemaking process allocates a utility's cost to all customers, but compensates only a few, that own DERs at a retail rate [16].

This arises from the fact that electricity rates typically consist of:

- Cost of building and operating generation plants including fuel costs.
- Cost of building and maintaining transmission and distribution systems.
- Cost of additional utility functions such as cost of meters, billing and administrative staff salaries.
- Return on investment for the investors.

The assumption is that these costs are factored into the per kWh energy price and levied equally on all consumers so that everybody, in its respective consumer class pays an equal share of generation, transmission, distribution and reliability services. Now, since the DER operator does not purchase electricity from the grid, this upsets the volumetric balance, because previously the per kWh rate was averaged over the total forecasted demand for all customers. Consequently, the utility will not be able to recover its fixed costs and over-time it will have to shift this burden on the remaining 'purchasers' by raising the per kWh price for all consumers. Also, a matter of fact here is that a DER operator still hinges on the reliability of the utility grid to meet its need when its own resource is unable to meet its load demand, but at the same time, avoids paying the fair cost of this reliability/off-peak service by purchasing very less electricity from the utility or in some cases ending up with a 'net-zero' bill.

Why it is Hard to Determine the Correct Compensation Rate?

An obvious solution would be apparent almost instantaneously is that regulators must abandon a DER compensation based on retail rate but settle at a lower price, and this is now the way forward, which we will discuss at some length in the coming sections, however it is not as easy as it may sound.

There are considerable challenges around determining the true value of DER benefits, for example:

1. Benefits derived from DER can change according to their penetration levels. Beyond a certain penetration level, the utility will start to face negative gain as it will have to spend in upgrading distribution infrastructure. One study suggests that upgrade to the distribution system will be required beyond a 20% penetration level [17].
2. There is a growing consensus that benefits of DERs tend to be time and location specific. Utilities may find it more expensive to generate electricity during certain peak hours of the day and may find it harder to supply far flung areas due to network losses [18].
3. In the electric power industry, generation for sale, which is what is the crux of net-metering is considered as wholesale power and is usually priced at a lower rate as compared to retail power, because it needs to be shipped to the customer and hence the cost of transmission and distribution will be added to it. Here, as the utility is responsible to 'redistribute' excess generation, argument is placed that DER exports should be treated at wholesale power rate and not at retail rate [18].
4. A new frontier on ancillary services rendered to the grid is emerging such as, voltage support, frequency ride through, demand response, peak shaving, volt-var control etc. Proponents argue that these are value added services that must be rewarded separately by the utility, however in contrast some countries like Germany have mandated DER inverters to be capable of rendering certain ancillary services [19]. FERC order 2222 also encourages market participation of DER aggregators and ancillary services [20]
5. There is frequent debate around how to value avoided costs from DG adoption, while it is straightforward to subtract the cost of kWh generated, how do you calculate the avoidance of fixed costs? For example, if the utility was about to replace a distribution transformer, but due to increased DER penetration, useful life of that same transformer was enhanced, and the asset replacement date subsequently deferred.
6. Further debate is over how would you quantify avoided externalities of environmental damage, where the utility is a major emitter of greenhouse gases and all the while, solar DG is contending to reduce the carbon footprint of the same utility and even going further by helping the utility reduce is environmental compliance and damage costs [18].
7. Since each state has different policies around net-metering, a unique amalgam of regulatory actions and policy changes makes it impossible to deal with net-metering in a uniform way. Some states can be more hospitable to net-metering while others like Kansas and Georgia might be less open [21]. Due to a variety of factors studies conducted in one state in a particular year cannot be extrapolated to all years in other states.

Solutions, Way Forward and Examples

Due to the many challenges associated with net-metering, many states and PUCs are rethinking the ways in which they are valuing their DG resources. While most states are moving away from feed-in tariffs and retail rates, the trend is shifting towards 'Value of Solar' rates and 'Avoided Cost' rates. Below, figure presents the conceptual distinction between these rate formulas.

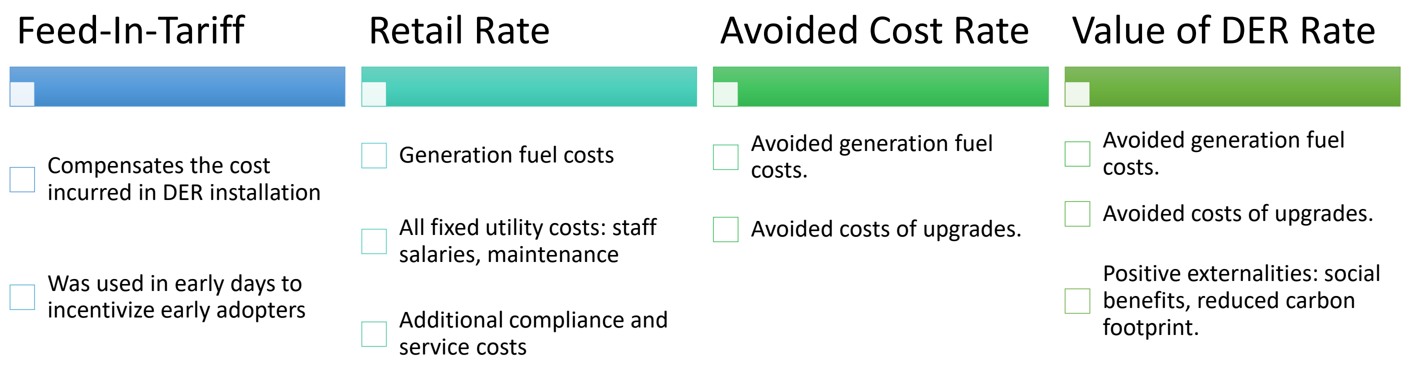

Figure 12: Types of DER compensation mechanisms

Avoided costs rate only reflects the additional costs that the utility would have to incur if all the DGs would stop generating, whereas Value of Solar rate adds a social and environmental benefit component to the avoided costs. Depending on a regulators assessment, a value of solar rate can be higher than the retail net-metering rate [17].

Let's now assess some examples of reforms from different States [22].

New York

New York has been widely accepted to be the leader in DER adoption. While the existing DER compensation mechanism is based on retail rates, the state has an ambition to transition towards a value of DER or value of solar rate which is based on the 'value stack' [23].

The value stack compensates DERs based on:

- Location Based Marginal Price of Energy
- Installed Capacity (ICAP)
- Environmental Value (E)
- Demand Reduction Value (DRV)
- Locational System Relief Value (LSRV)
- Market Transition Credit (MTC) or Community Credit (CC)

The value stack calculator is available on the NYISO's website [24].

Illinois

Illinois has been touted as the second-best US state by the Grid Modernization Index for successfully coordinating policy, consumers, and utilities towards grid modernization [25]. Prior to the Illinois General Assembly's Future Energy Jobs Act of 2016, DERs were compensated on a retail rate. However, the FEJA act is changing this landscape. Once DERs in a utility exceed 5% of the peak demand, the net-metering tariff is changed to a energy-only tariff based on locational and temporal value of energy provided to the grid [22].

Minnesota

The Minnesota Public Utilities Commission's 'value of solar energy' program provides a higher VOS rate for solar installations as compared to the retail rate because it adds the cost of avoided natural gas purchases, avoided environmental costs, avoided new power plant construction and transmission network construction for the next twenty-five years.

Thus, a contract between the customer and utility locks the solar value for twenty-five years and the utility owns the renewable energy credits generated by the customer in return [26]. In this way the customer gets a quick return on investment and the utility benefits in the long-run as in the future, utilities will pay a lower than net-metering after it is inflation adjusted. Remember that the value of solar was locked by contract for twenty-five years.

6.2 Bulk Transmission Construction

New transmission lines may be built to enhance the reliability of existing network, replace old aging infrastructure, to open new renewable energy corridors for the bulk transmission system, to resolve economic and policy issues or to facilitate functioning of energy markets. At any rate, numerous challenges plague this process.

Fragmented Industry Structure

Given the structure of US electric power industry and the way it is divided into IOUs and other cooperatives, most transmission lines are owned by individual utilities and in many cases, these regional entities may find no incentive in increasing the reliability of their nearby utility or to improve the transmission economics of adjacent areas. In the same way, there is no legal justification for state regulators to enforce cooperation on utilities by regulation. FERC has attempted to resolve this in part by the establishment of ISOs and RTOs that will be made responsible for regional transmission planning, but reliability issues persist [27].

Construction Permitting

Permitting and sitting approvals is also one of the most complex aspects of transmission line construction. Whenever a new transmission line is constructed, rights of way must be secured, where the line will traverse land, that can be publicly owned or privately owned. They may cross states, counties, and cities alike and can change land-use in their surroundings. A slew of local, state and federal laws govern this permitting process which makes it inherently slow and difficult. Typically states have veto power over, whether a transmission project should be constructed or not. The regulators will inspect the proposal based on 'need' as compared to other factors such as localized generation, demand response, environmental damage, etc. In this scenario, if the transmission line is in a 'corridor of national interest' contending parties can appeal to FERC but it too has limited authority to overturn local authorities [28].

Equity Financing and Cost Recovery

Now, due to reason discussed earlier it is being increasingly difficult to build and finance transmission lines. These days, third party and investor-owned transmission line projects have become sparse and most of the new projects are centrally planned. The challenge with centrally planned projects is that who will furnish the equity and how will the recovery costs be allocated? Usually, they are recovered from customer rate-base through regulated transmission charges, but this has its own shortcomings. Projects that will benefit one participant or regional utility will not always benefit the other region, that is for instance facing load congestion, on the same equal footing. The former, who is enjoying low market prices will object to paying for an inter region transmission project at the expense of other utility that will raise its own price [29].

6.3 Large Scale Adoption of EV Charging Infrastructure

Analogous to the exponential increase in net-metering customers, the sales of electric vehicles are also expected to increase by roughly four times, projecting into 2026 [30]. The darker side, however, is that EV charging infrastructure has not kept pace with this increasing demand of EVs. There may simply not be enough chargers, both within cities and interstate routes to facilitate rapid EV adoption [31]. This is in part due to the regulatory and market functioning challenges that are hampering the large-scale deployment of EV chargers.

Extent of Utility Involvement

The first critical regulatory challenge in EV charging industry is the extent of utility involvement in the EV value chain. The EV value chain is illustrated in the graphic given below. The utility can either assume the role of 'facilitator' where it will treat EVs as any other consumer load putting up a new connection request, or it can be an enabler where it will provide and develop the distribution network capacity necessary for charging stations, or it can be the full provider of charging services to end user. Where the utility owns the EV chargers and manages them itself [32]. The provider role can be extended into giving the utility the monopoly status of exclusive provider.

The question to be answered by the regulators here is, how much involvement and market power do you give to the utilities, (75% of which are investor owned) in the EV charging industry so that the market flourishes in a healthy state, promoting competition and at the same time encouraging investments [33].

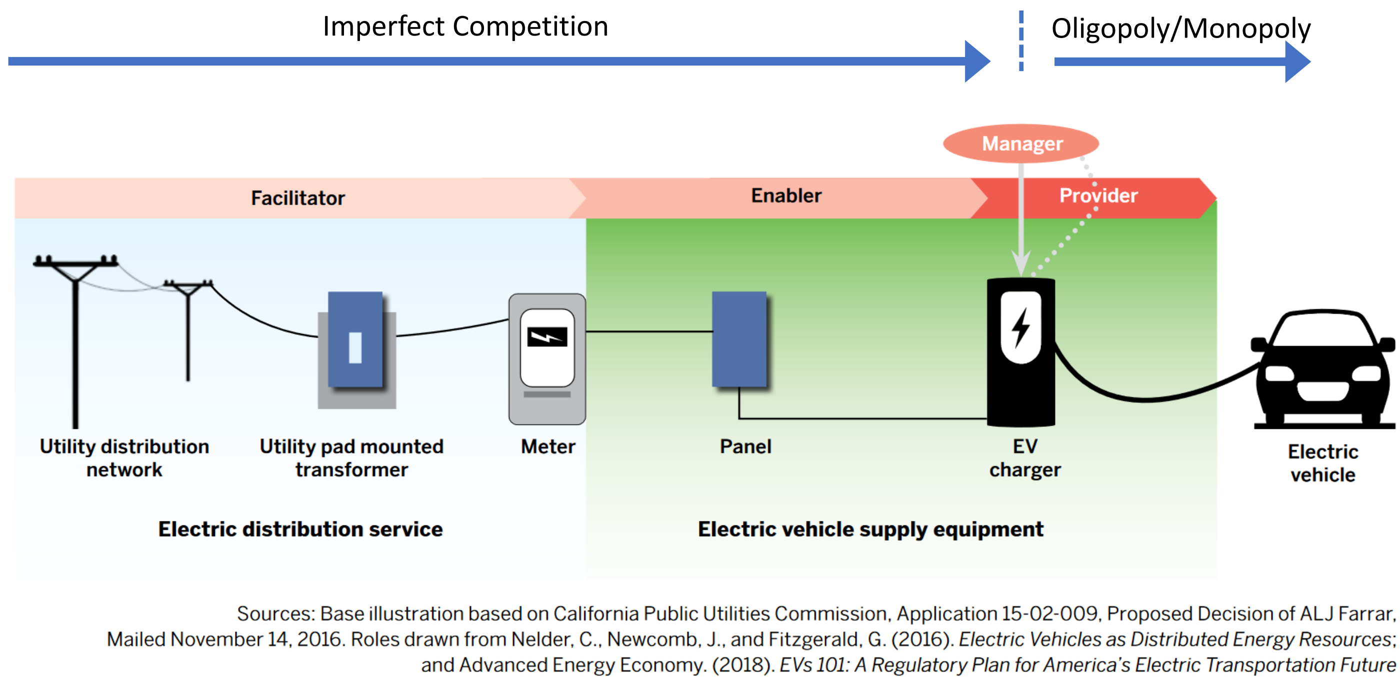

Figure 13: Role of electric utility in the EV's charging market.

States and their PUCs are divided on the extent of Utility involvement. Some states have adopted regulation that makes it possible for utilities to own and operate charging stations [34]. There are pros and cons in both approaches, which are summarized below. In the authors opinion, it is better to develop the EV segment as a separate market independent of utility influence.

Proponents of Utility Involvement

- Utilities can ensure safety, supervision and compliance of new charging points in a better way.
- State PUCs can have more authority on utilities as compared to private sector.
- Utilities can be forced to invest in underserved market segments, where private sector investment is not attractive.
- Utilities have more engineering knowledge of the distribution network, so they can plan expansion in a safe way.

Opponents of Utility Involvement

- Consumers can benefit from free market compitition between private firms.
- Private firms may be more accepting to implement new technology and approaches such as Time of Use pricing.
- Independent owners have a greater desire and incentive to promote efficiency.
- They can also take advantage of utility rebates in an enabler model.

EV Charging, a Service or Selling Electricity [34]?

State and federal regulations do not sufficiently clarify the role of EV chargers in the market. Some state regulators are still grappling with the fact that should be classify EV chargers as selling electricity or merely a service provider entity?

1. In some states like North Dakota, EV chargers can be considered an electric utility because they supply electricity and thus will be subject to the same regulation as utilities [35].
2. If you consider EV chargers as selling electricity then, some states have laws that restrict the resale of electricity bought from the utility. There are limitations on marking-up the price of electric power provided by existing utilities.

Nevertheless, the recent trend has been towards the States excluding EV charges from traditional utility regulation through affirmative legislative action. California, Virginia, Minnesota, New York, Hawaii and Maryland have excluded EV service providers from the definition of corporations or utilities.

The Pennsylvania Public Utility Commission adopted a policy in 2018 that EV providers provide a service and do not resell electricity. Another interesting decision is from the Kentucky Public Service Commission which determined that EV charging stations are themselves "consumers and end users of electricity" and that "they use purchased electricity to provide a specific service".

Should Utility Investment into EVs be Recovered from Ratepayer?

Another tricky question is where the states are pro-utility involvement, should the expense of utility investments put into enhancing the distribution infrastructure be levied on ratepayer or not. This would in effect come with the same argument of cross-subsidy that we examined for the net-metering case. An interesting example here is from the Vermont Public Utilities Commission. The VT PUC excluded EV service providers from its jurisdiction altogether, in the interest of promoting the industry, but noted an exception that "where a regulated utility seeks to develop public EV charging infrastructure and include the cost of that infrastructure in its rate-base". The commission would retain full jurisdiction over that infrastructure.

6.4 Resource Adequacy Planning in Presence of DERs

In the current landscape of energy transition, DER penetration is changing the way power systems of today must evaluate their 'firm capacity'. The intermittent generating patterns of wind and solar, make it a challenge to estimate the actual available capacity of solar and wind that can supply a load at any given time in power systems operation. In this part of our discussion on regulatory challenges, we will examine the breadth of this 'resource adequacy' conundrum and discuss the challenges it has for regulators.

'Resource Adequacy' is the ability of electric power system to produce sufficient generation to meet loads at all hours through a broad range of weather and operating conditions. Currently, in the United States their no fixed standard that everybody could follow to ensure resource adequacy. Although, NERC has adopted the Loss of Load Expectation principal in its BAL-502-RF-3 standard, balancing authorities, ISO and state regulators have the liberty to choose a different suitable standard [36] [37].

Technical Issues in Resource Adequacy Planning

Aside from intermittency of DERs, the resource adequacy problem continues to become more complex as the share of DERs increases across the power system. A recently publishes study highlights those challenges [36]:

1. ***Declining Capacity Contribution –*** As the share of DERs increases, their capacity value, that can be counted towards reliability decreases. While the first few additions of solar or wind would have a high contribution to capacity value, for example offsetting the peak summer afternoon spikes, as their share increases their capacity contribution would decrease as they are merely shifting the load peak to hours when the sun is not shining. This is called saturation effect. Historically simple probabilistic methods were able to capture capacity value at low penetration values, but high penetration ratios complicate this analysis.
2. ***Increasing Resource Interaction –*** Technological advances have made it possible to operate solar, wind and batteries in hybrid modes, in ways where they can complement or antagonize each other's effect. It is challenging to consider all these synergistic effects with accuracy in reliability calculations.
3. ***Climate Change –*** Climate change is altering the weather patterns that historical weather models based on past 20 to 30-year data would predict. This means that adequacy assessments done today can well falter tomorrow.
4. ***Renewable Droughts –*** In high penetration distribution systems, periods of low wind and solar, where there is no wind and solar for a few hours complicates reliability planning and doesn't help to eliminate the need of firm resources in the distribution system. A case study illustrated below highlights how a renewable drought can suddenly increase the demand for firm resources by a huge value, which would otherwise have been eliminated from this system if the resource adequacy metrics would have been followed, without considering probability of such events.

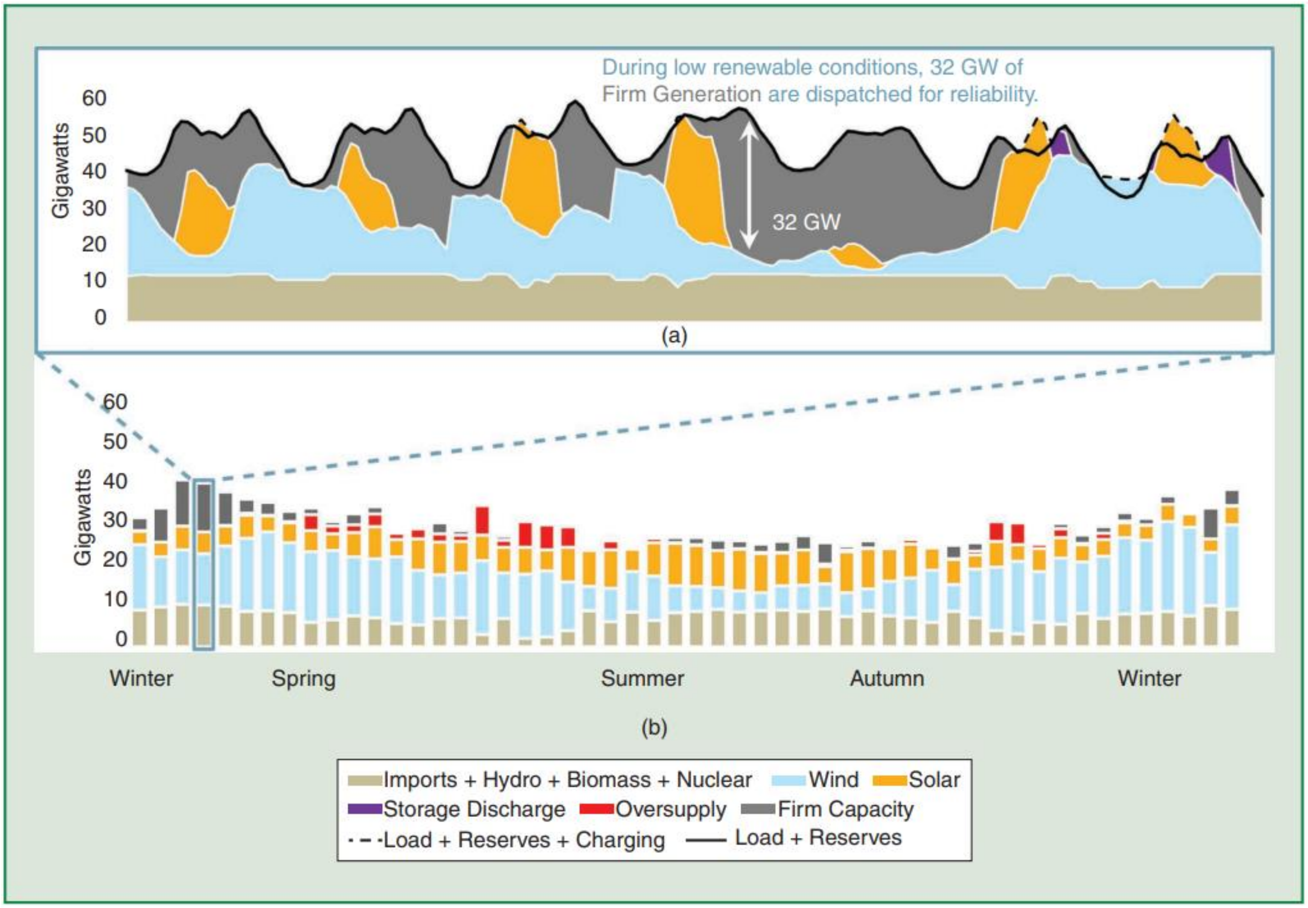

Figure 14: A sudden renewable drought in a simulated system increases firm capacity requirement.

5. *Social Behavior of Customer Base –* Some customers may be willing to allow utility to shed their specific loads, if done correctly this can be a firm demand response service, and the load can be excluded from adequacy planning, however it is difficult to predict and bind the customer's perception of this type of load curtailment.

Resource Adequacy Metrics

A variety of metrics to calculate and benchmark resource adequacy have been adopted in North America. They help system planners evaluate how much capacity is needed in the system and what is the share of each resource. Most common measures are summarized below:

- *Loss of Load Probability –* measures the probability that a system will not be able to meet its demand. It is computed over all states of the system. If for instance, two system states are not able to meet the demand, LOLP is the sum of probability of these two scenarios happening.
- *Loss of Load Expectation –* It measures the ability of a system to meet its demand by measuring the number of days a system will not be able to meet its demand. The NERC benchmark for this metric is 1 day/ 10 years loss of load expectation or LOLE. Some regions have adopted it as hourly loss of load expectation or LOLH
- *Planning Reserve Margin –* PRM is usually defined as the percentage by which installed capacity exceeds annual peak demand. A recent study criticizes PRM as insufficient to gauge resource adequacy, on account of not including each unit's individual contribution and each unit's individual probability of failure. It is still widely used [38].

The table below, published in the same study from 2016, summarizes the acceptability reliability/adequacy metrics across the United States.

Reliability metrics used by selected markets in the United States (adapted from Pfeifenberger et al., 2013; Western Electricity Coordinating Council (WECC), 2014).

	Regions	Metric	Target value
Probabilistic method	Southwest Power Pool	LOLH	2.4 hours/year
	ISOs/RTOs: PJM, MISO,[a] NYISO, ISO-NE, ERCOT[b]	LOLE	1 day/10 years
	NERC[c] regions: Midcontinent Area Power Pool, some SERC entities (e.g., Duke Energy Carolinas, Progress Energy Carolinas, Entergy), Florida Reliability Coordinating Council		
	APS[d]		
	BPA[e]	LOLP	5%[i]
PRM method	CAISO[f]	PRM	15%
	SCE&G[g]	PRM	12–18%
	PNM[h]	PRM	

Figure 15: Popular resource adequacy metrics

Resource Adequacy Planning Methods

Planning methods range from calculating simple plant capacity factors to more complex probabilistic and analytical models used to estimate the LOLP and LOLE. These metrics are eventually integrated into the integrated resource planning of utilities as directed by NERC's BAL-502-RF-3 standard.

Plant capacity factor and reserve margin are the simplest and most straightforward methods of predicting the real power available from a renewable source. Let's say, a 200 MW wind power plant is installed in a region with 800 MW peak demand. It raises the available supply in a region from 1000 MW to 1200 MW and hence the reserve margin is raised from 25% to 50%. However, once we estimate the plant factor of a wind power plant, we find that its average power output over a considerable length of time is only 40 MW. Therefore, only 40 MW is added to the supply and the reserve margin is calculated to increase to only 30%. The drawback here, is that plant factor does not take into account, when a wind plant is generating and when it is not generating. In that sense plant factor can be an overoptimistic prediction of the contribution of that wind power plant to supply adequacy.

To overcome this problem a study proposes a more robust probabilistic method to calculate the LOLE that capture the interaction of load and intermittent renewable generation in a better way [39]. It works by:

1. Estimating the LOLE of the system without DER contribution.
2. Forecasting renewable energy production and then subtract it from the demand curve of the system.
3. Determine the new LOLE to meet this residual demand.
4. Increase residual demand across all hours such that old LOLE is equal to new LOLE
5. Firm capacity contribution of DER is then equal to peak demand from old LOLE minus the peak demand from new LOLE.

A more complicated method based on ELCC or effective load carrying capacity is also proposed in [36] and one reference discusses the most current commercial methods employed by major North American utilities [40].

Regulatory and Structural Issues in Resource Adequacy Planning

Given the background presented in this booklet so far, it may not be surprising if our readers would already conclude that, solving all the technical issues will not necessarily lead towards a reliable electric power system. It is equally important to appreciate the fact that, where market forces fail to promote corrective actions, regulators must step in to enforce technical solutions. Our regulators therefore would face the following impediments as they build efforts to improve resource adequacy planning:

- *Agreement Over a Common Reliability Metric –* As discussed earlier, regions have not been mandated to adopt a single reliability metric, moreover one study from the National Academy of Engineering notes that there is significant concern over the fact that resource and energy adequacy is not being tracked accurately [41].
- *Compartmentalization of Regulatory and Planning Oversight* – As discussed earlier, state regulators retain authority over transmission, distribution, and generation construction, whereas FERC and NERC have authority over interstate reliability performance, this entails that some of the adequacy standards adopted by NERC will not be a legal binding on local generation. The same study noted that, in this connection coordination between FERC, NERC and NARUC is critical.
- *Regulator's Motivation and Knowledge –* We noted earlier that integrated resource plans at the central levels do exist in the United States, however the regulators have limited technical knowledge and sometimes for political reasons, limited motivation to ensure the accuracy of IRPs of large investor-owned utilities [42].

VII. Current Energy Policy Drivers

The president, congress, and federal agencies, such as the US Department of Energy, Department of Transport and State Energy Offices at the state level, make the laws and allocate investments from taxpayer money. This investment, coupled with the enacted laws, defines the direction of progress in the electricity sector.

Our readers may well at this point, predict that lawmakers in DC would be well aware of the renewable energy transition that is currently happening and would be keen to support it, however the Biden Administration's commitment is much stronger than merely being accepting of the current energy transition, compared to previous US governments. This new spirit is embodied by the current administration's Energy Targets, the Bi-Partisan Infrastructure Bill and the recent Inflation Reduction Act. The additive effect of these two acts comprises of an estimated $ 370 Billion of climate and energy related federal funding to meet the Biden Administration's net-zero goals [43], the largest of its kind in US history [44].

This chapter presents a summary of these two pieces of legislation in terms of the provisions that they have for the electricity and power sector.

7.1 Biden Administration's Climate Goals

Climate goals underscore the motivation behind the passing of BIL and IRA acts. These ambitious goal of net-zero emission by 2050 is set in the form of incremental targets [45]:

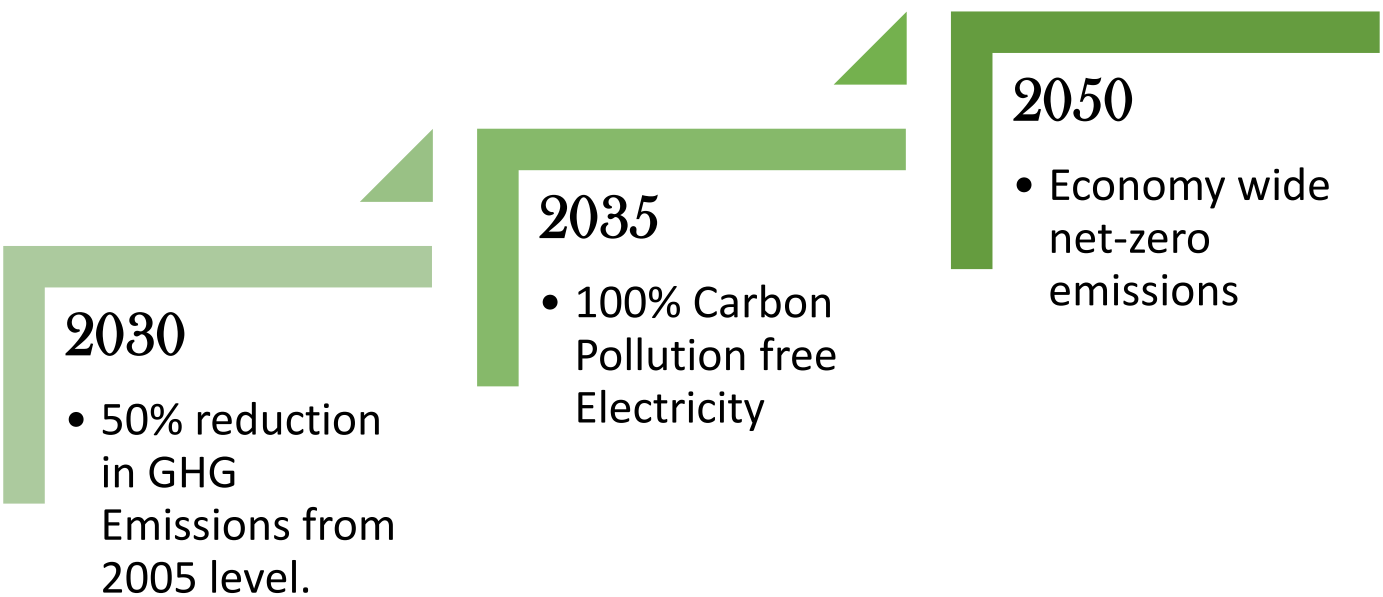

Figure 16: Biden administration's climate goals

7.2 The Bipartisan Infrastructure Bill

The Bipartisan Infrastructure Law allocates about $500 Billion for the improvement of transportation infrastructure, broadband, water supply networks, environmental protection, and clean energy grid over a 5-year period. Notable investments that concern the future of our electricity grid are as follows [46], and four of the most important aspects, that will shape the future of electricity grid are [47]:

1. *Network of EV Chargers* – $7.5 Billion for the development of a network of 500,000 EV chargers.

2. *Transit Electrification –* Another $7.5 Billion is allocated for electrification of large transit vehicles, esp. school buses and ferries.
3. *Transmission and Power Infrastructure Upgrades* – $21.3 Billion is allocated for construction of transmission lines, improvement of hydropower plants and providing support to existing nuclear reactors.
4. *Demonstration Projects* - $21.5 Billion is allocated for clean energy demonstration projects, such as hydrogen, carbon capture, grid-scale storage, and advanced nuclear reactors. This to test the effectiveness of new technologies in scale implementations and help commercialize and widespread deployment.

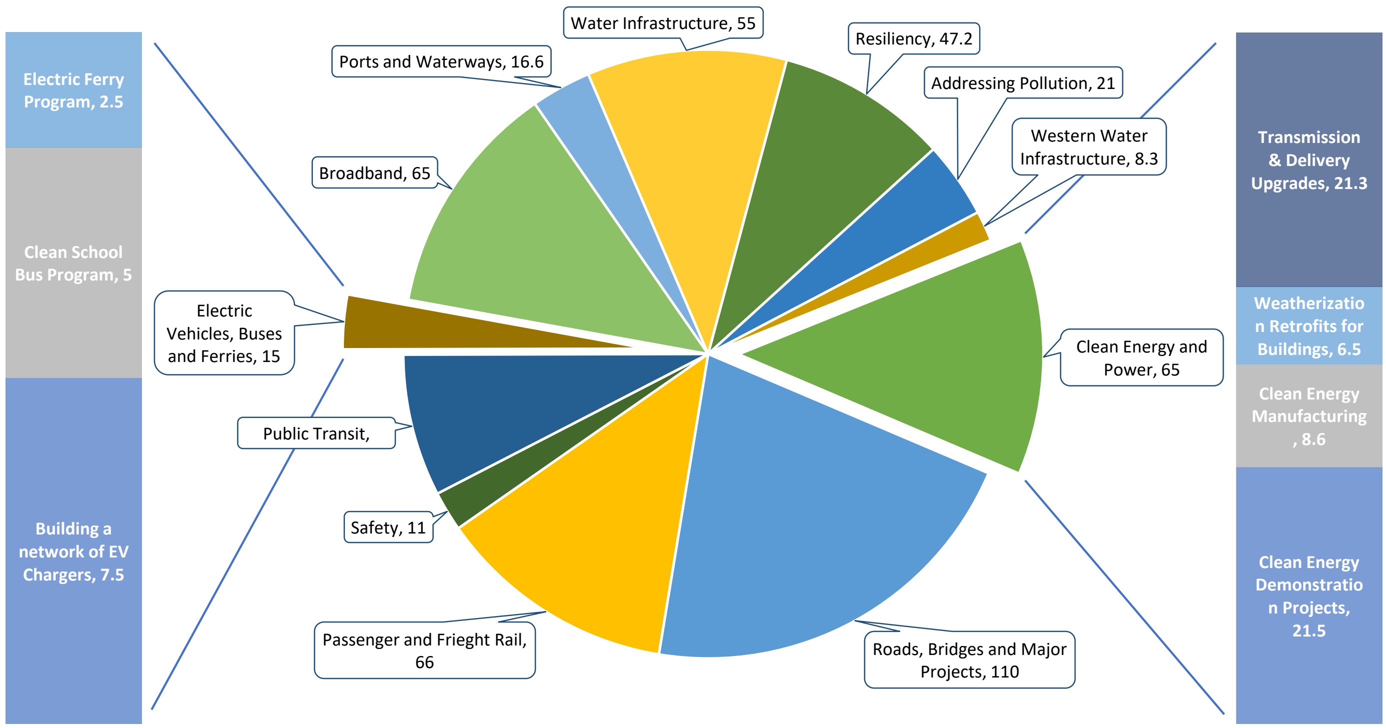

Figure 17: Notable Investments in the Bi-Partisan Infrastructure Law

7.3 The Inflation Reduction Act

The Inflation Reduction Act of 2022 builds on the spirit of the Bi-Partisan Infrastructure Bill but is inherently different in its mechanism. The BIL is almost wholly consists of grants and funds, whereas the IRA is only roughly 20% grants [43]. The IRA is in fact a law that aims to generate money primarily through IRS tax reforms, new corporate taxes and drug pricing reforms. This newly generated money will be channeled into tax incentives and loans for the energy, and health care sector. The focus within the energy sector will be clean energy initiatives, some of those we will discuss in detail in the coming sections. Here is a summary of this act's circular mechanism of making money and then giving it back into the clean energy sector. Congressional estimates also claim that this act will help in the reduction of budget deficit [48].

Figure 18: Inflation reduction act at a glance.

A summary of key incentives that will impact the electricity sector are as follows [49]:

Advancing and Deploying American-Made Clean Energy Technologies

Financing Deployment of Clean Energy Technologies

Clean Energy Production and Tax Credit	**Extended till 2024**
GHG Reduction Fund	**$27 Bn.**
Loans for Innovative Clean Energy Projects	**$40 Bn.**

Manufacturing to support clean energy transition

Loans for Energy Infrastructure Refinancing	**$250 Bn.**
Energy Project Credit	**$10 Bn.**
Manufacturing Production Credit	**Tax Credit**

Investing in Electricity Grid

Transmission Facility Financing	**$2 Bn**
Siting of Interstate Transmission Lines (Grants)	**$760 Mn.**
Wind Energy Transmission Planning	**$100 Mn.**

Clean Energy in Rural and Tribal Lands

Rural Electric Cooperatives (Grant)	**$9.7 Bn.**
Tribal Electrification Program	**$150 Mn.**
Renewable Energy in Rural Areas	**$1 Bn.**

Clean Vehicles

Clean Vehicle Credit	**$7,500 Once**
Second hand Clean Vehicle Credit	**$4000 Once**
Commercial Clean Vehicle Credit	**30 % Cost of Replacement**
Heavy-Duty Clean Vehicle Program	**$1 Bn.**
Domestic Supply Chain for Clean Vehicles	**$5 Bn.**

Investing in DOE Research Labs

Infrastructure improvement for National Labs	**$450 Mn.**
Other National Labs	**$ 1.55 Bn.**

Efficient Buildings & Homes

Lowering Energy Costs for Households

Residential Clean Energy Credit	**30 % Tax Credit**
Energy Efficiency Improvement Credit	**$3200 / year / house**
Energy Rebate Programs	**$9 Bn.**
New Energy Efficient Home Credit	**$5,000 / house**

Investments for Energy Efficient and Low Carbon Buildings

Updating Building Energy Codes	**$1 Bn.**
Energy Efficient Commercial Buildings	**Tax Reduction**

Effective Permitting for Infrastructure

Efficient Environmental Reviews	**$625 Mn.**
Permitting Improvement Steering Council	**$350 Mn.**
Establishing Environmental Quality Council	**$30 Mn.**

As you may have already noticed, not all of the funding is in the form of ready-made grants. Most of the funding is in the form of tax incentives and tax credits and big organizations are the major benefactors, particularly in the case of energy project credit, manufacturing project credit and infrastructure refinancing credit. Consumers will also benefit from tax incentives in the form of EV tax credits and efficiency upgrades to homes, such as heat pumps, water heaters, boilers, biomass stoves and insulation upgrades. New homes are also eligible for tax credits if they are energy efficient to incentivize builders to make housing more energy efficient.

There are however, some restrictions in place to unlock the full tax credits. For example, to get the full credit for EV, its battery elements must be local or come from a ‘favorable’ country and battery must be manufactured in North America. Manufacturing facilities will get the full credit, if they pay the prevailing wage to employees and conduct apprenticeship programs to develop new STEM labor force [50].

7.4 International Criticism to IRA Act

It is not surprising that the sweeping incentives for promoting American manufacturing of clean energy technologies and particularly of promoting the whole value chain of Electric Vehicle and battery manufacturing have been met with criticism from the EU counterparts on account of being termed as uncompetitive practices. The EU commission president criticized this strongly that this “buy American” approach leads to “discrimination” against EU companies as it will undermine their competitive edge [51].

VIII. Foreseeable Effectiveness of Current Policy

In this last chapter of our study, we will examine the Biden Administration's current energy policy, being propagated by the BIL and IRA and discuss the issues that may impede its course of action.

8.1 Accommodating EVs Charging Demand in Secondary Distribution

As discussed in section 7.3, the sweeping incentives aimed at substituting fossil-fuel based vehicles with electric vehicles will have far reaching consequences. We have already stated in section 6.3 that the sales of EVs will increase significantly in coming years. One study conducted by Rhodium Group estimates that the share of EVs across all light-duty vehicles could increase from 5 percent in 2021 to 57 percent in 2030 [52]. This directly entails that new charging infrastructure will be required and that will increase the load on secondary distributions systems. Local utilities providing power to new charging stations will need to ensure that they can support the increased load. This will require a huge capital investment to increase the capacity of transformers, secondary feeders and service laterals.

In the current policy landscape, defined by the IRA and BIL, investments and incentives have been allocated for the bulk power system and there have been measures to streamline their environmental permitting process, but there are no indications as to how individual investor-owned utilities would be encouraged to invest in their secondary distribution systems to support incoming charging load. This area is at best, being left to individual utilities to sort out by themselves in their IRPs. The same is true for the 500,000 public chargers goal stipulated in the BIL.

The bottom line is, you cannot operate an EV charger without the consent of your local electricity provider and at present, the financial incentive for utilities is not sufficient to warrant a vertically integrated investment and it is still not clear if the state regulators will allow its recovery to be included in the rate base.

8.2 Encouraging Deployment of EV Chargers

At this point, there are major gaps in road coverage of EV chargers, and this is a major drawback of owning an EV, that you cannot refuel it as often as you can refuel a fossil fuel car. The figure below represents these gaps [53]: One can easily see that there are large swaths of interstate highways that are still without adequate charging coverage.

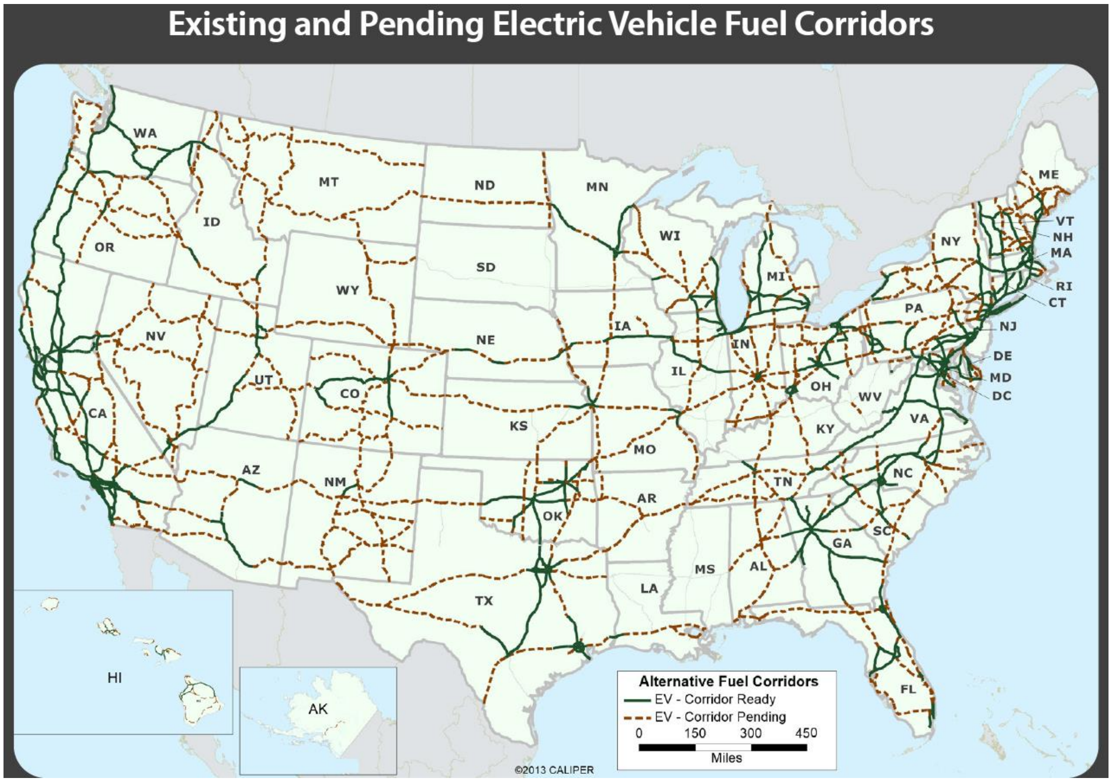

Figure 19: Existing and pending electric vehicle charging corridors.

While we stated earlier that the BIL aims to deploy 500,000 public EV chargers to cover these gaps, the limitation is that although the funding has been allocated, there are no specific guidelines on this topic in the BIL and IRA [54]. Most of the implementation has been left out for federal agencies such as the department of transportation.

The second limitation is that it must be understood that federal funding alone cannot completely alleviate the problem. Deployment of a more robust and dependable charging network will require a combination of public spending, utilities, and private charging owners. While third-party owners are looking forward to expanding public charging options, in many states the regulatory provision that would enable them to participate in this new market in a beneficial way are not yet mature enough. Further, the IRA and BIL funding is limited to federal agencies only. There are no provisions for private charging station owners except that a tax credit is available for properties hosting EV chargers, but that is limited to low-income and rural areas [49].

8.3 Catering to Peak EV Charging Demand

In addition to the capital investments required in T&D and distribution systems, it must also be noted that customer's EV charging behavior is expected to be identical to their daily routine. This entails that charging demand patterns will likely worsen the ramping and peak load requirements. On the other hand, if there is a charging load surge, utilities will most likely offset it by fossil-based peaking power plants. Hence the limitation, EVs are clean but the electricity used to power them is not clean and has already played a part in increasing emission in the complete supply chain. Avoiding this peak demand surge and ensuring that EVs are mostly charged through clean sources is a major obstacle to achieving a carbon free electricity generation sector.

Given that emission reduction is a primary target, a direct consequence of peak demand surges would be that utilities will be forced to shift or offset this demand to other times of the day where it can be effectively met through renewable sources [54]. For this to be effective:

- There must be attractive incentives for customers to convince them to charge at different times of the day, then they normally would.

- Utilities rate-making strategy should appropriately set peak and off-peak charges to create incentives.
- Aggregator models, recently permitted under FERC 2222 should be utilized to manage charging demand.

8.4 Limited Substitution of Critical Battery Minerals

As a strategic initiative, the IRA promotes the sale of EVs with batteries that have at least 80% market value of their critical battery minerals produced or processed within the US or in one of the free-trade partners. This measure has been widely criticized as being a market altering practice and has been termed as uncompetitive, as it will put EVs with imported batteries at a disadvantage as compared to those manufactured locally.

The goal is to promote extraction of minerals locally, but GHG emission and environmental damage incurred from extraction of virgin minerals is not considered. The incentives would mean that, it will be feasible to extract virgin minerals, that previously were not cost-effective to explore, either because of high energy costs or inaccessibility.

It must also be noted that the 80% mark is based on market value and not by mass component. Given the fact that recycled minerals will always be less priced as compared to virgin minerals, the yardstick of market value is disincentivizing recycling as manufacturers will be able to meet IRA conditions by just extracting new expansive minerals rather than having to go for the hassle of promoting recycling.

One study concluded that, across the three main battery chemistries, it will be challenging to meet the IRA's targets for lithium iron phosphate batteries and nickel cobalt manganese batteries [55].

8.5 Insufficient Incentives for Nuclear Energy

Proponents of nuclear energy would argue that to completely decarbonize the electricity sector, firm capacity is required to offset the variability from DERs. We could in one scenario argue that if policy sufficiently supports nuclear energy, this could be a viable 100% clean future generation mix, where nuclear and hydro would collectively meet baseloads and the remaining chunk could be derived from wind-solar-battery integration. To make this possible, new nuclear plants will have to be constructed and the policy should favor new plant construction.

Contrary to this pathway, nuclear power has historically been on the decline in United States. A total of 259 reactors were ordered by US utilities from 1950 – 2020. Out of those, a peak count of 112 were operational in 1990 and as of 2022 only 93 remain in operation. Out of those 93, only 28 remain competitive in their respective regional markets. Thus, the ratio of plants conceived and those that remain competitive is dismal [56].

Enormous capital cost is a major factor in discouraging investment in the nuclear sector. A study by a certain merchant bank says that a new nuclear buildout would cost 3 – 8 times more than unsubsidized wind and solar. A similar study by Bloomberg New Energy Finance estimates this factor to be as high as 5 – 13 times. Federal agencies such as the EIA have also concluded, in their published data of levelized cost of electricity that nuclear power costs exceed its value. In the new unbundled electricity markets, it is simply not possible for nuclear plant owners to recover their capital cost and, at the same time competitively clear the market auction.

Therefore, we seek to analyze under the prevailing policy landscape, if the current planned incentives are sufficient to achieve the net-zero electricity mark riding on the back of clean nuclear power.

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Both the IRA and BIL have collectively allocated about $40 Billion [43] for nuclear energy in the form of following incentives [57]:

Tax Credits Applicable on Nuclear Power	
Nuclear Power Production	**1.5 cents / kWh**
Clean Hydrogen (produced from nuclear power)	**$ 0.6 / kg of hydrogen**
Clean Electricity Production (technology-neutral)	**0.3 cents / kWh**
Clean Electricity Investment (for new plants)	**6 % of investment value**
Advanced Energy Project Credit	**$ 10 Bn. All inclusive**

Additional Funding for R&D	
Development of HALE Uranium Fuel Supply	**$700 Million**

Grants under BIL	
Civil Nuclear Credit	**$6 Billion**

Loan Authority	
Clean Energy Projects (For all types of projects including nuclear)	**$40 Bn. All inclusive.**

Figure 20: Incentives for nuclear power in the current energy policy

Given the current scale of initial investment required for new nuclear buildout, it can at best be concluded that the current policy direction is to prevent the current nuclear plants from retiring due to loss of competitiveness. These incentives are by no means sufficient to promote installation new plants. In contrast to the facts and figures quoted above, America's sole nuclear plant that is currently under construction in Georgia is already slated to exceed $30 Billion in construction costs [58], at times where the rise in costs is exceeding the pace of progress. This cost can easily dwarf any of the incentives available in the IRA and BIL. It is evident that the nuclear renaissance in the US is still a distant possibility.

With that said, in a 100% net-zero emission scenario it is no longer prudent to rely on nuclear baseload beyond 2030. The IRA and BIL will need to address this gap by placing more emphasize on clean sources that can be dispatchable, such as biogas, fuel cells, geothermal, pumped hydro, long-term storage, and demand response strategies. Our analysis has so far reflected that the current set of incentives deal with renewables in lumped form, whereas they should be a lot more specific between dispatchable and non-dispatchable resources.

In the long run, it should be expected that R&D will improve the dependability of dispatchable renewables, to an extent that they can fill the gap vacated by retiring coal and nuclear plants. While tax-payer dollar can temporarily bail out un-economic existing reactors, it cannot solve the problems of affordability, safety, waste and proliferation that are plaguing the industry. Therefore, a much more robust replacement strategy is required, that considers 'grid flexibility' with the same importance that policy makers give to 'firm capacity' [56].

8.6 Disincentivizing Natural Gas

The IRA introduces a methane emission fee starting in 2024, based on the amount of methane gas emitted from certain natural gas processing facilities. On the other side it also introduces a production tax credit (PTC) for production of clean hydrogen [54].

The objective is to drive a shift from natural gas consumption towards producing, transporting, and consuming clean and green hydrogen, however this poses unique challenges for both natural gas and electric utilities:

1. The cost of running the existing natural gas value chain will become higher so utilities, will have to find a way to repurpose their supply networks to cater to hydrogen distribution.
2. For the electric power sector, it would mean that peaking power available from fast ramping natural gas generators will become higher priced and their will need to be rapid shift to adapt natural gas generators to hydrogen generators to remain competitive.

This strategy of replacing natural gas with hydrogen and then incentivizing this transition through policy making is commendable, however critics would be quick to argue that sufficient technology to store, process and use hydrogen as a combustion fuel is still not mature enough to drive this transition to full substitution of natural gas. One recent study from Europe predicts that the hydrogen economy is currently in the R&D stage and may take up-to 2040 to realize its full potential [59]. Another slightly older study from 2012 also concludes that further improvements are required before hydrogen can effectively be used as an internal combustion fuel for transportation and power generation [60].

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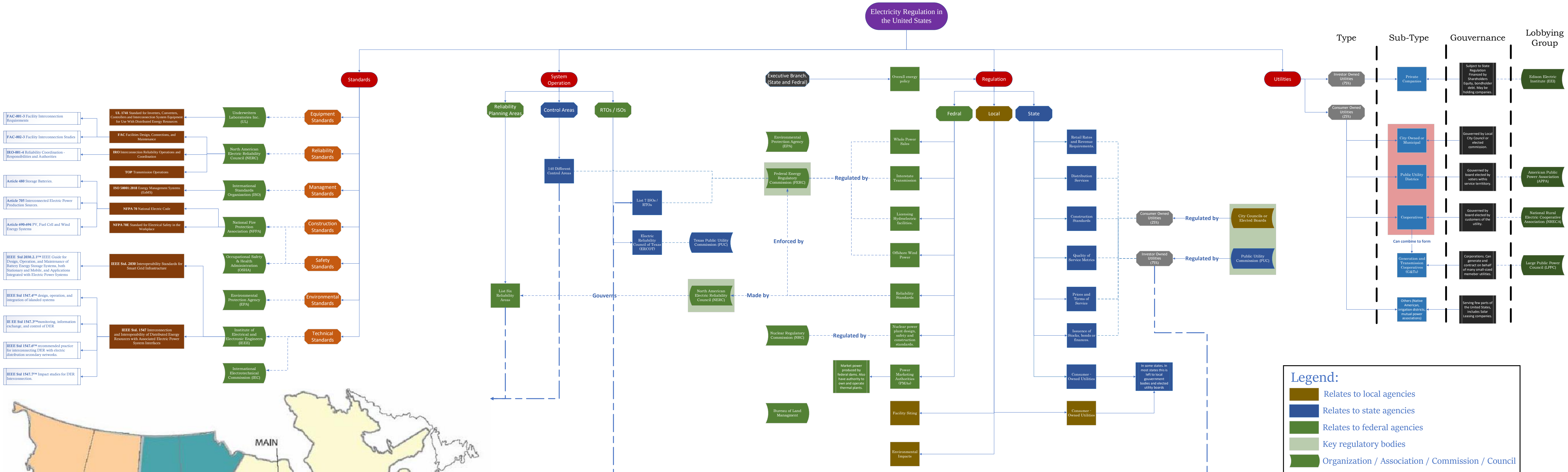
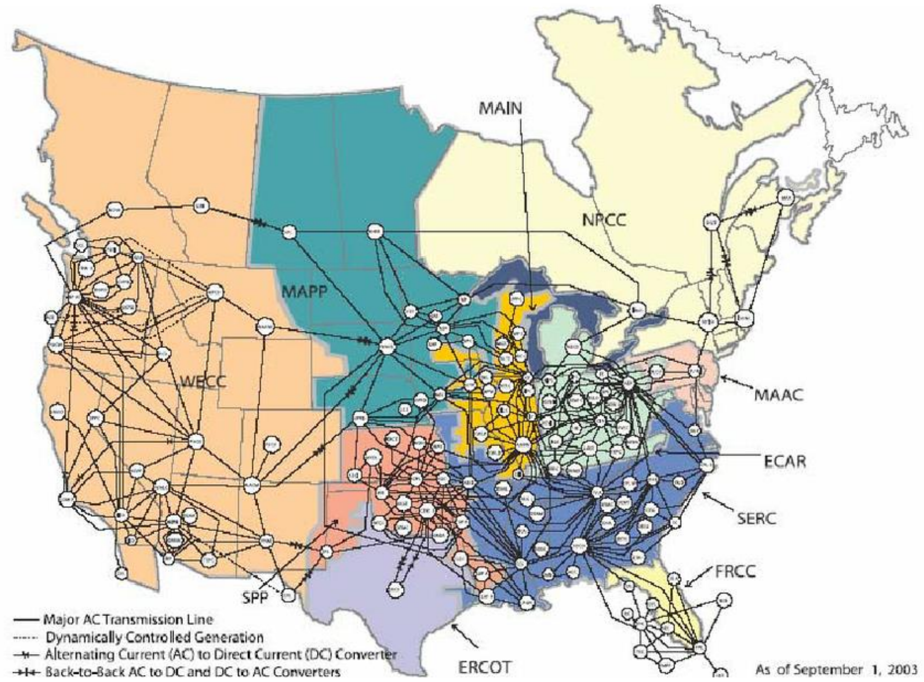
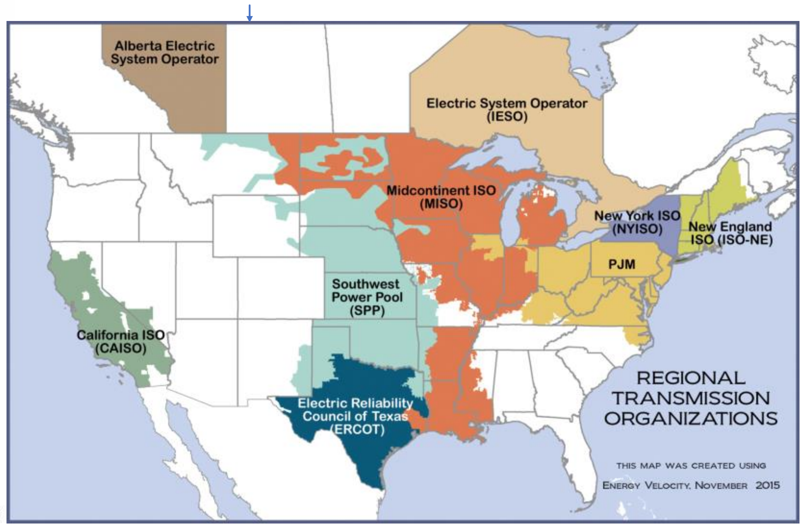
X. Appendix A

Summary of Organizational Structure





NERC reliability regions and control areas.



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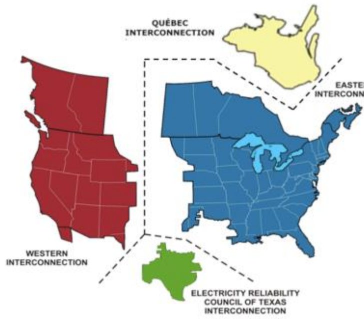

Synchronous Grids

Investor Owned Utilities (IOUs)