The Value of Flexibility: Application of Real Options Analysis to Electricity Network Investments

by

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1 Abstract

This thesis assesses electricity distribution network investment decision-making methods using a three-step approach, to explore the possible value of flexibility. By applying a simple quantitative framework to an illustrative distribution network decision, it finds that current methods that fail to consider flexibility can result in higher cost investments and lost value.

First, it presents the recent developments in the electricity sector and outlines how the current state of network planning is no longer fit for purpose.

Second, it proposes a flexible design approach for electricity network investments, and determines the value of this flexibility by developing a simple model and applying real options analysis.

Third, it identifies the practical challenges to effectively implementing a flexible design methodology, before proposing recommendations for electricity utilities and regulators.

The proposed flexible design methodology found that building in flexibility through Non-Wire Alternatives provided a greater Expected Net Present Value than current robust techniques using traditional investments. This thesis confirmed that the value of this flexibility increased as uncertainty over future electricity demand increased.

This thesis finds there is a strong case that the use of a flexible design approach can increase the cost-effectiveness of network investment decisions. However, there remains significant uncertainty regarding key parameters that determine the value of these cost savings. As such, this thesis concludes with a discussion of evidence gaps and priorities for future research.

2 Acknowledgments

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4 Introduction and Motivation

The electricity system is undergoing rapid change. Governments and regulators have been slow to respond, and this is resulting in unnecessarily costly electricity network investments.

There is an opportunity to embrace and direct these developments, in a way that is beneficial for the electricity system and for consumers. This thesis explores one such topic, building flexibility into the planning of electricity distribution networks through distributed energy resources (DERs) as non-wire alternatives (NWAs).

In 2014, the New York State Public Service Commission (PSC) directed the Department of Public Service to develop and issue a Benefit-Cost Analysis Whitepaper addressing the components and application of a benefit-cost analysis (BCA) in the context of the Reforming the Energy Vision Initiative (REV). The REV envisioned a dynamically managed electric distribution system to provide the greatest benefits at the lowest cost. In particular, the PSC explained that system efficiency and benefits could be improved, and costs reduced, by leveraging opportunities to harness DERs. They recognized that the BCA methodology can ensure that technologies are subject to consistent and accurate consideration and that ratepayer funds are employed in the most efficient manner (New York State Department of Public Service, 2015).

However, there were some concerns that the 'optionality' of DERs (referred to as NWAs when they are used in place of a traditional investment) were not being suitably valued for consideration against traditional investments in the BCA. This meant that flexible investments were undervalued, and potentially higher cost investments were made (New York Battery and Energy Storage Technology Consortium Inc., 2018).

Subsequently, the PSC announced that utilities should consider the option value of NWAs, but declined to act to formalize this at the time due to additional work needed. In particular, New York State Department of Public Service and New York State Energy Research and Development Authority (NYSERDA) outlined in their Energy Storage Roadmap, that utilities should develop a methodology that details how optionality valuation should be performed and provide examples using past NWAs (Department of Public Service and New York Energy Research and Development Authority, 2018). This thesis outlines an approach to option valuation for electricity networks, and provides an example case study.

The remainder of the report is structured as follows:

- **Section 5** outlines key attributes of electricity systems, and introduces some of the major changes underway resulting in a distribution system that is not fit for purpose, but which also offers new opportunities for utilities to address customer needs.
- **Section 6** reviews current approaches to distribution network planning.
- **Section 7** introduces the concept of flexible design and discusses how this can be applied in electricity networks.
- **Section 8** explores a case study where a flexible design approach is used and applies real options analysis to value flexibility.
- **Section 9** concludes this body of work and proposes recommendations for regulators and utilities to apply.

5 Key attributes of electricity systems

In this chapter we discuss the characteristics of electricity systems, recent developments that are reshaping these systems and implications for network planning. We discuss how new technologies, particularly distributed generation and storage, and changing consumer preferences and roles, are challenging the current system and planning processes. We also identify the opportunities they pose for unique, low-cost solutions to network needs, if leveraged appropriately.

Finally, we outline the key questions that result from these changes and present what will be addressed in this thesis. The focus of this work is US electricity distribution networks; however, lessons will be drawn from other jurisdictions and are noted accordingly.

This chapter is structured as follows:

- **Section 5.1** discusses the characteristics of electricity systems and current challenges.
- **Section 5.2** outlines major changes underway in the sector.
- **Section 5.3** discusses the impacts these changes have on electricity network planning for utilities and regulators.

5.1 Characteristics of electricity systems

Electricity systems are complex networks typically comprised of centralized generators, such as coal, hydroelectric or nuclear power plants, linked using extensive transmission and distribution networks to end-consumers including households, commercial and industrial users.

Electricity network investments are long-lived, capital-intensive investments which are inherently 'lumpy' (MIT Energy Initiative, 2016). A 'lumpy' investment refers to an investment characterized by large infrequent outlays, rather than continuous or recurrent investments of a smaller scale (discussed further in 7.2). The physical nature of the system and considerable cost reductions enabled by economies of scale, mean that investments often occur to meet demand that is forecast to be achieved years into the future. Once networks are built it is almost impossible to make fundamental alterations, such as to reduce capacity or footprint. Investment decisions are made far in advance to allow time for permitting and building, and are therefore built to satisfy future needs, as best they can be anticipated.

Investment occurs to meet the peak demand, as due to the nature of the network there is limited flexibility to invest in the network just for those peak hours. Any investment made is available all the time, even if it is not being utilized. Therefore, rather than periodically expanding network capacity to meet increasing peak demand, as has been the case previously, there are many occurrences when it may prove favorable to shift electricity demand from the peak to other periods.

Investment costs need to be recovered, and are generally passed through to consumers via tariffs and charges that are approved by regulators. The costs that need to be recovered in the electricity sector include energy, network and policy costs. That is, costs relating to the generation of electricity, the transmission and distribution to end-consumers, and any other objectives that governments may stipulate, such as emission reduction objectives (for example renewable portfolio standards). For this reason, there is significant focus by regulators to keep costs as low as practicable to minimize distributional impacts.

5.1.1 Attributes and drivers of electricity demand

Electricity demand is the key determinant of network investment. The primary drivers for electricity demand are economic activity and population growth.

A major source of demand resulting from population growth is driven in part by weather patterns, in particular, large cooling and heating loads, with 87 per cent of U.S. households cooling their homes with air conditioning, and 35 per cent of homes using electricity as their primary heating source (U.S. Energy Information Administration, 2019b). Conversely, energy efficiency and changing demographics (such as the shift to city living) reduces per capita energy usage. The National Renewable Energy Laboratory (NREL) outlines that significant efficiency improvements over the last decade have caused the growth of electricity consumption in buildings to slow (National Renewable Energy Laboratory, 2018).

Increased economic activity and population growth also leads to an increase in electrification of other industries, such as transport. A rise in electric vehicles (EVs) will see a shift in primary energy source for the transport industry, and could be a significant driver of future energy demand. NREL forecasts that electrification has the potential to significantly increase overall demand for electricity, with the possibility of widespread electrification leading to historically unprecedented growth (absolute year-to-year change), as presented in Figure 1.

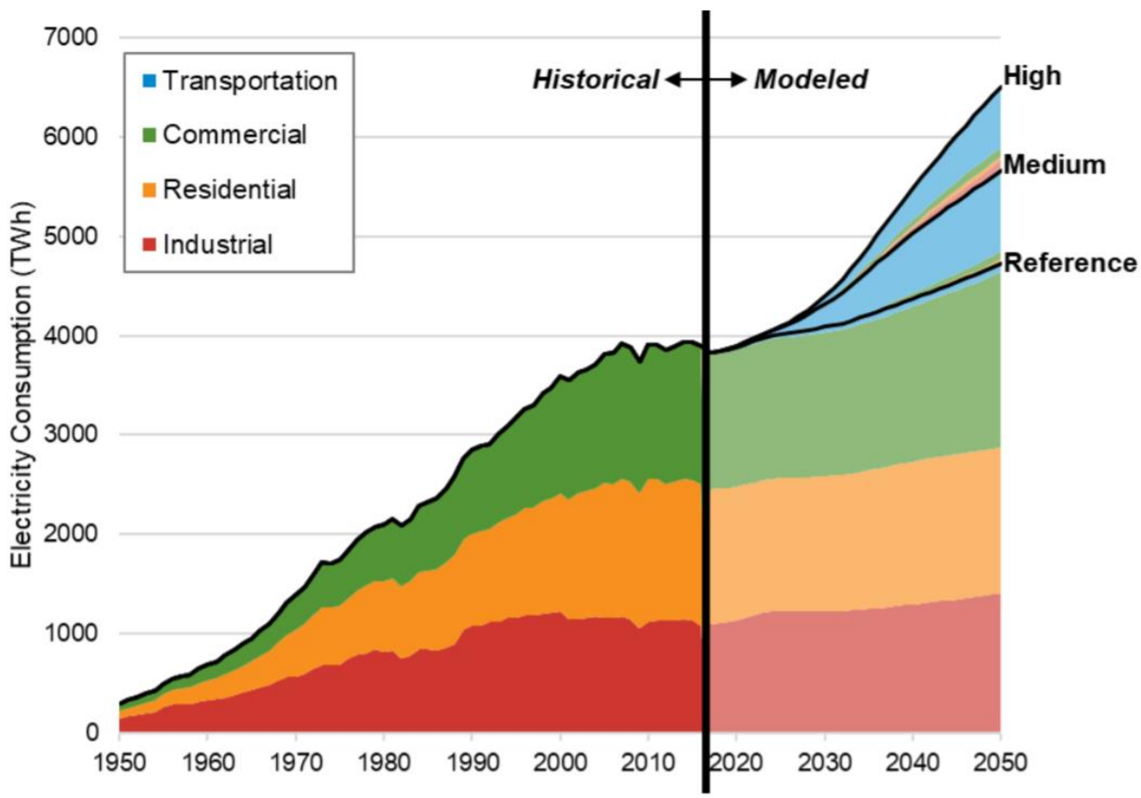


Figure 1: Historical and projected annual electricity consumption (National Renewable Energy Laboratory, 2018).

In the industrial sector, electricity consumption has a more complex history. Following World War II, population growth and economic expansion drove electricity consumption, primarily through the growth of electricity-intensive processes. However, more recently the US economy has seen a shift away from electricity-intensive manufacturing industries to a service-based economy.

It is apparent that over the last several decades energy use has changed significantly. While some areas experienced growth rates significantly lower than projected, other areas have seen rapid increases. As the economy continues to shift, consumer preferences change, and new technologies become available, there will be continuing impacts on electricity demand and consumption patterns. Each of these areas introduce different sources of uncertainty that increase the challenge of forecasting energy demand.

5.1.2 Challenges in forecasting electricity demand

Since the industrial revolution, electricity demand tracked with gross domestic product (GDP). However, more recently electricity demand has decoupled from this, largely from the decline in the energy intensity of GDP due to the shift to a service economy, increase in energy efficiency and behavioral changes, increase of electrification (more efficient way to meet energy needs), and a shift to renewables (McKinsey & Company, 2019).

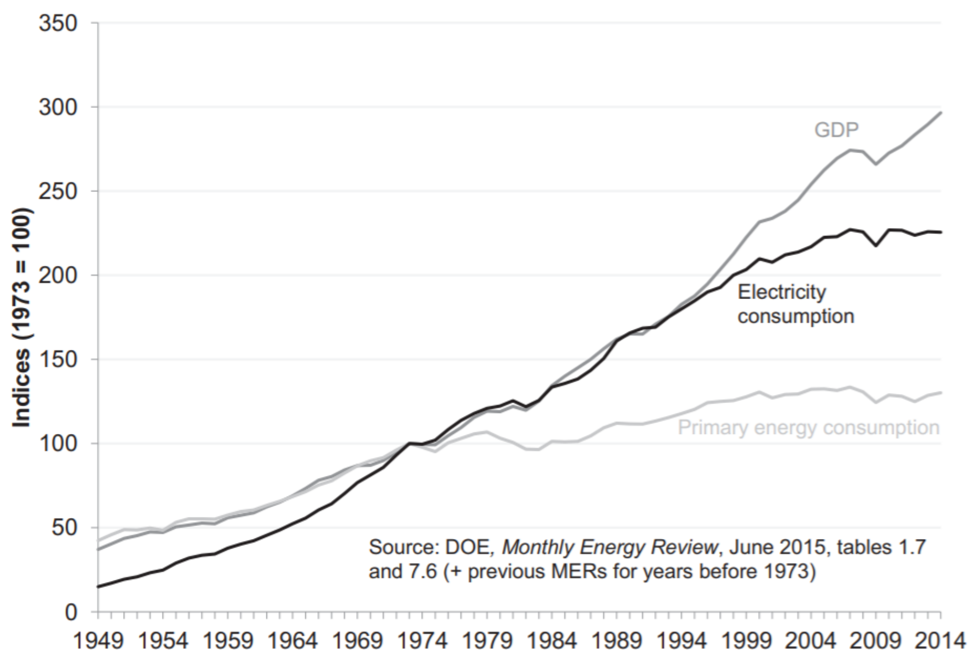


Figure 2: US Inflation-Adjusted GDP, Primary Energy Consumption, and Electricity Consumption (Hirsh and Koomey, 2015).

This separation has increased the uncertainty of electricity demand projections. The uncertainty in electricity demand has a flow on effect to network planning, as the electric grid is built to meet locational peak demands.

Analysis by the Rocky Mountain Institute using Federal Energy Regulatory Commission (FERC) data shows that planners have over-forecast electricity demand by one percentage point for each year of their forecast from 2005 to 2015, excluding 2009 and 2010 to reduce impact of the recession (Rocky Mountain Institute, 2017). Figure 3 identifies the percentage that a utility's forecasted peak varied from realized peak from 2005 to 2015, as well as the capacity-weighted average highlighting the impact of netting over/under estimates of demand, and the increasing trend of overestimating demand.

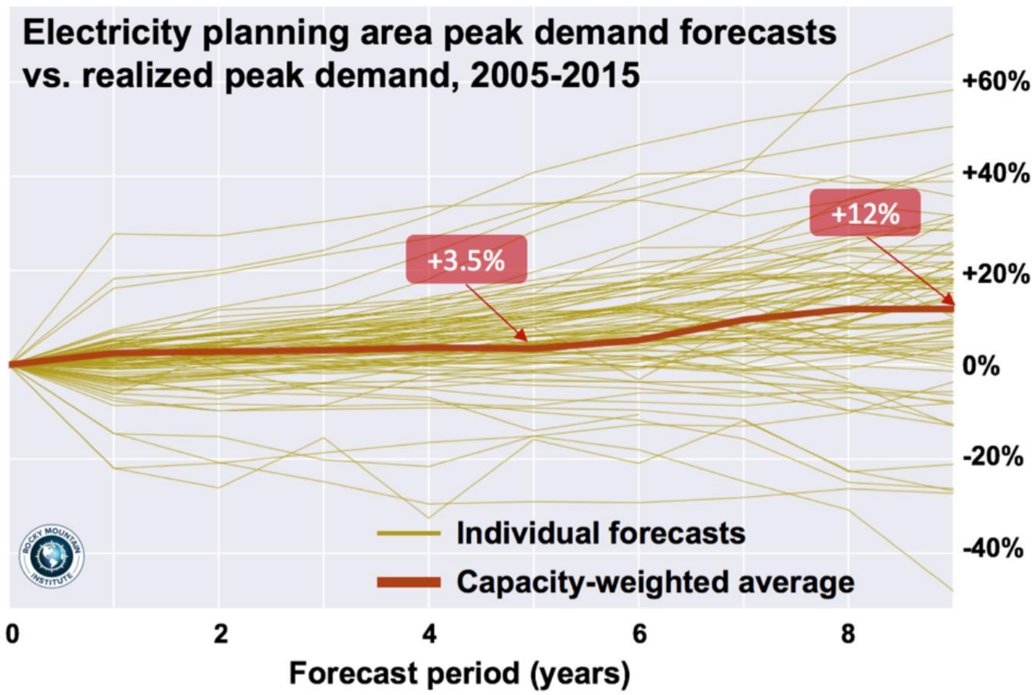


Figure 3: Electricity planning peak demand forecasts variation from realized peak demand from 2005-2015 FERC data analysis by Rocky Mountain Institute 2017.

This trend of overestimating demand, or alternatively forecast demand not materializing, means networks are underutilized. Consequently, the investment schedule was not optimal, and are likely to have incurred unnecessary costs.

Furthermore, policy, technology and consumer preferences impact what energy is used for, and how it is consumed. Predictions around these three areas are extremely challenging and have huge sources of uncertainty around them that further exacerbate planning challenges.

The only certainty is that energy must be generated somewhere and how, and be sent to consumers via some means. The following section outlines how electricity is delivered to consumers, and highlights some key changes that we are currently observing.

5.1.3 How electricity is delivered to consumers

Electricity is typically generated at large power plants located close to major demand centers ('load') in order to reduce electricity losses and costs of transmission. Electricity is transmitted through a vast network of high-voltage alternating-current power ('transmission') lines over long distances to minimize electricity losses. On reaching the distribution network, the electricity voltage is reduced to a lower voltage before it is distributed to end-users for consumption, as shown in Figure 4.

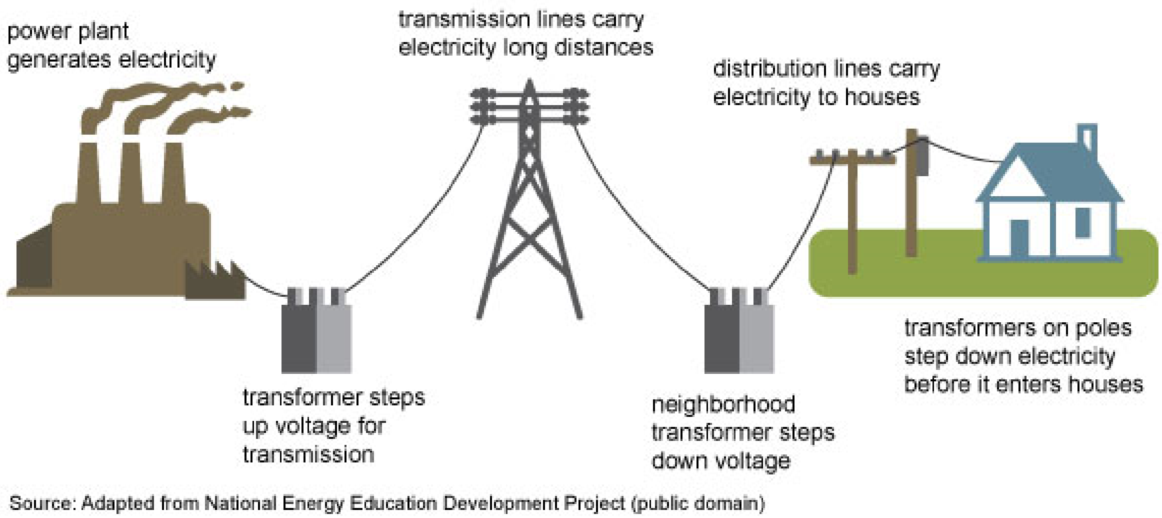


Figure 4: Electricity generation, transmission and distribution (U.S. Energy Information Administration, no date).

The focus of this thesis is on the distribution network. The distribution system consists of multiple large planning areas, where utilities may have hundreds of substations that connect and deliver energy from the transmission system, to serve thousands of different distribution feeders (wires), which ultimately serve the hundreds of thousands to millions of customers a distribution utility may have (Electric Power Research Institute, 2015).

It is not economically feasible to store electricity in large amounts and so, supply and demand must always be balanced to prevent equipment damage and black-outs (Kassakian *et al.*, 2011). This is a challenging task for system operators, who must vary the supply of electricity to meet minute-to-minute changes in demand and variable output of renewables, such as solar and wind. The large number of agents involved in the electricity system, including thousands of suppliers and millions of users, compounds the complexity of managing the electricity network.

Once electricity is generated, the electrical energy must be delivered from generation-source to the end-user. This is done through electricity networks (or 'grid') which include the transmission and distribution systems. These networks are subject to physical laws and constraints, as conductors and transformers heat up as current passes through them, causing resistance and losses in the form of waste heat.[1] Conductors and transformers must be kept below specified temperatures and the voltage and

[1] This was a contributing factor to the 2003 North East power outage, where overloaded lines sagged due to the heat from excessive current (increased resistance), and arced to surrounding trees. Protective relays detected the excessively high current and disconnected the line, transferring current across other lines. These other lines did not have sufficient capacity and their overload protection disconnected them, causing a cascading failure (U.S-Canada Power System Outage Task Force, 2004).

current must be maintained within tight bounds, to protect equipment and minimize risk of catastrophic failures (MIT Energy Initiative, 2016).

The interaction of the power balance with these physical network constraints creates unique values of electricity at different points and times in the network. The cost-efficient trade-off between the total system costs for planning and operation, and the costs associated with losing energy supply requires that rules are developed to coordinate operational decisions in a manner that minimizes risk of failure for a given total system cost. In practice, operating limits set to satisfy physical constraints may simply reflect the risk aversion or incentives for the regulator and/or system operator, such as aversion to blackouts for both economic and political reasons, and may differ from optimal operating limits (MIT Energy Initiative, 2016).

As technological developments provide new opportunities for how electricity is generated, delivered, and consumed, it is necessary to review the approach to system planning to consider changes in the optimal trade-off between costs for planning, operation and supply loss. The following section outlines some of the recent developments in the sector, which will be followed by a discussion of traditional approaches to electricity regulation and network planning in Section 6.

5.2 Recent developments in electricity systems

Historically the objectives of policy and regulations directing the planning and operation of electricity systems was to ensure reliable electricity was delivered to consumers while minimizing cost.

Recently, a further policy objective has emerged, reduced carbon dioxide emissions, which has fundamentally altered the electricity generation mix, and has had a significant impact on the electricity system. There are necessary cost-benefit tradeoffs, and a balance that must be achieved between these three policy objectives, presented in Figure 5.

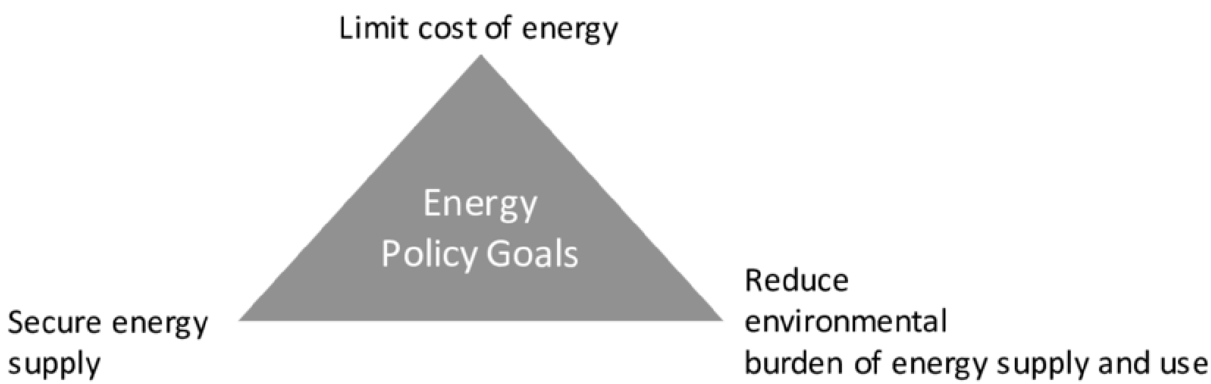


Figure 5: The energy policy "trilemma" (Schmidt, Schmid and Sewerin, 2019)

5.2.1 The green revolution in electricity generation

The last decade has seen rapidly accelerated change in the energy system, with previously expensive renewable technologies like solar and wind generation, now competing with traditional alternatives at scale. This has been the outcome of long running policy support aligning with rapid reductions in technology costs. Since the late 1970's, the U.S. federal government has supported the deployment of renewable energy through accelerated depreciation, and since the 1980's, tax credits for investment or production. All states provide tax credits or other incentives for investment in low-carbon energy. At the end of 2018, 29 states had legally binding renewable portfolio standards requiring utilities to procure a minimum percentage of energy from designated renewable sources, while eight states had nonbinding renewable portfolio goals (Kassakian *et al.*, 2011; U.S. Energy Information Administration, 2019c).

Government funding for research and development and direct subsidies have supported technology advancements, driven capacity investments, and reduced technology costs. These reduced costs have facilitated increased production and scale of variable renewable technologies, which drive further cost reductions. This cycle, of reduced costs driving capacity investments leading to further reduced costs, occurs because of "learning rates" (discussed further in 7.4.3) and is presented in Figure 6 and Figure 7.

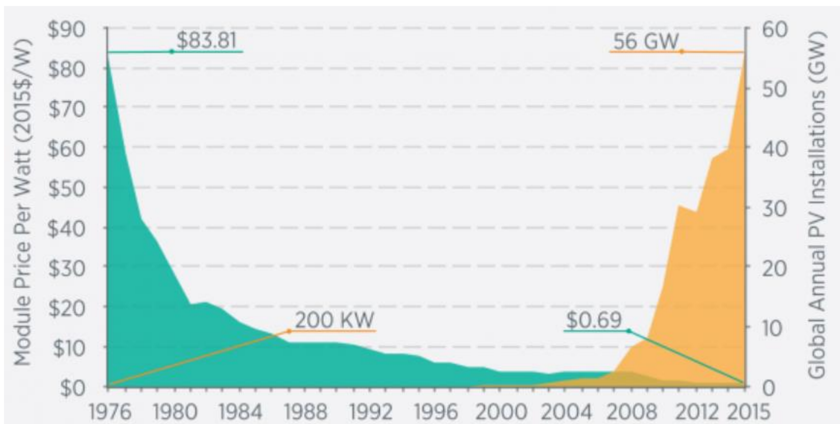


Figure 6: Solar module cost decline and annual photovoltaic capacity installation (Office of Energy Efficiency and Renewable Energy, no date).

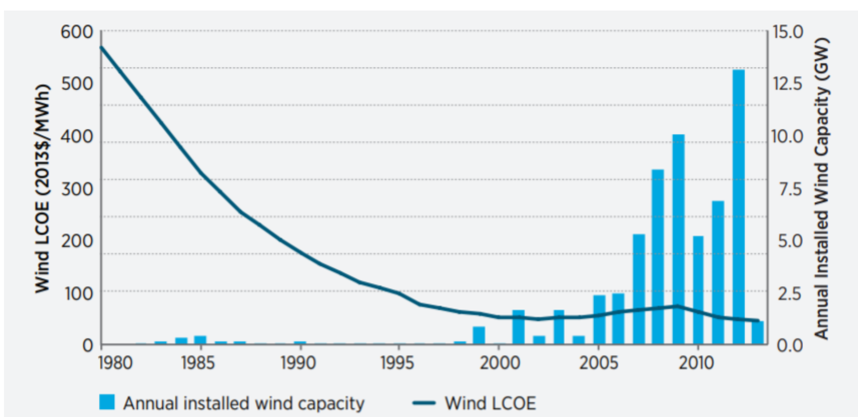
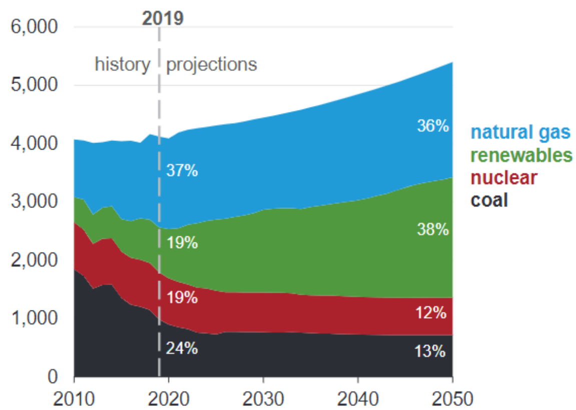


Figure 7: Wind levelized cost of energy decline and annual installed capacity (U.S. Department of Energy, 2015).

In 2020, the proportion of generation from renewables is projected to be 19 per cent, and this is expected to increase to 38 per cent by 2050 (Figure 8, left). The proportion of planned new generation capacity being added from renewable sources, in particular solar and wind, is significantly greater than 'traditional' sources (gas, coal, and nuclear) with substantial retirements occurring for coal generators from 2020–2024 (Figure 8, right). This highlights the rapid change that is underway in the electricity generation system.[2]



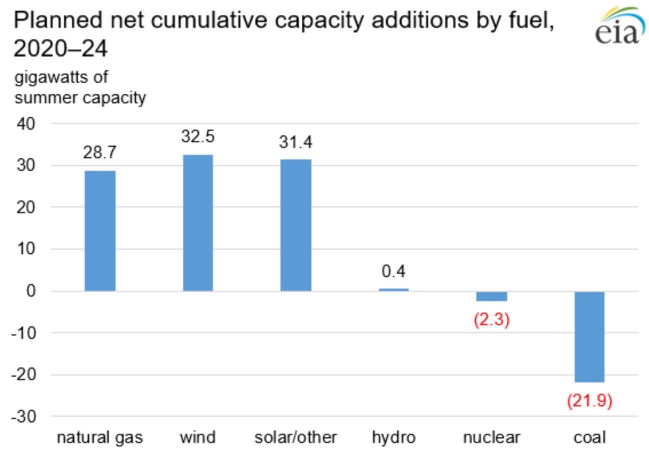


Figure 8: Left- Electricity generation from selected fuels (AEO2020 reference case, billion kilowatt-hours) (U.S. Energy Information Administration, 2020a) *and Right- planned net cumulative capacity additions by fuel* (U.S. Energy Information Administration, 2019a).

This transition to large-scale renewable generation sources will see many renewable generators located far from existing load centers in order to utilize the best resource locations, and will necessitate expansion of the transmission system (Kassakian *et al.*, 2011). This has significant impacts on current network expansion planning and regulation for the transmission network, however these impacts will not be covered in this thesis.

This section has outlined changes that are occurring in the electricity generation and transmission ('bulk') systems. However, we are also seeing significant changes in the distribution system.

Increased penetration of renewable generation in the distribution system, such as uptake of rooftop photovoltaics, are posing challenges for the design and operation of these networks. This may raise costs for many consumers if the current approach to network planning and distributed energy resource integration is not changed.

The following section discusses the significant changes that are occurring in the distribution and demand-side environment, in particular the rapid uptake of distributed energy resources.

5.2.2 The rise of Distributed Energy Resources

The distributed nature of renewable energy technologies is a fundamental change from the centralized generation system of the past. In particular, this has major implications for the distribution system, as small, geographically disbursed "Distributed Energy Resources" (DERs), such as solar photovoltaics (PV)

[2] It is important to note that renewable generation often has a lower utilization in comparison to 'baseload' power generation (essentially the power plants that can run all the time such as coal or nuclear) due to impact of weather patterns on electricity output. This means a larger capacity of renewables may be required to offset the exit of a baseload generator of smaller capacity.

or battery storage systems, are located within the distribution network. These DERs can be located on the grid (with a direct connection to distribution network), or customer sited, such as within households.

DER installations in the United States have increased significantly due to a combination of technology advances, cost reductions, and state energy policies (Federal Energy Regulatory Commission, 2018b). This growth is expected to continue as costs reductions are supported by factors such as customer desire for self-supply, environmental considerations and declining installation costs. As distributed resources are increasingly adopted, traditional consumers are transitioning to "prosumers"– agents that consume energy at some times and produce it at others (MIT Energy Initiative, 2016).

In 2016, DERs accounted for about two per cent of the installed generation capacity in the US, but distributed solar PV accounted for 12 per cent of new capacity additions. DER deployments in 2016 reached 30 gigawatt (GW), significantly more than the net capacity addition of central generation at 19.7 GW. On a five-year basis, DER is estimated to grow almost three times faster than central generation. as shown in Figure 9 (Navigant Research, 2016).

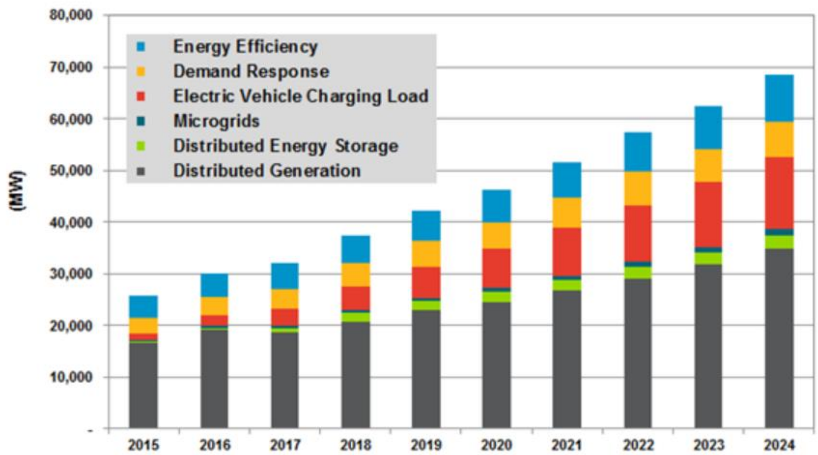


Figure 9: DER deployment by technology in the United States (Navigant Research, 2016)

Customer-sited DERs typically act as a demand-offset, where the distribution system operator cannot see, or is not aware of, the resource and its generation. This is also termed "behind the meter" (BTM) generation, and in this situation, the resource reduces the households load and often changes the load profile. In some circumstances, the DER can feed energy in excess of household consumption at a point in time, back into the network.

These characteristics create challenges for the system operator for several reasons.

Firstly, network operators plan electricity networks based off forecast peak load and BTM generation limits the operators ability to see *actual* household demand and understand usage profiles. This is fundamental for the operator to accurately model the power system, which is critically important for power grid operations and planning, particularly given the highly complex and interconnected nature of the power system (NERC, 2017).

Secondly, this change in consumption pattern has drastically changed the demands on the electricity system. The uptake of rooftop solar is significantly depressing observed demand during daylight hours as presented in Figure 10 (over page). This is presenting the risk of over generation during the day, as well as placing greater demand for fast-start/ramping generation, which are used to balance supply and demand. These ramping and balancing activities are more challenging with high levels of DERs, as they may require resources located in the bulk system (generation and transmission systems) as well as distribution system, which may not be visible or able to be controlled by, the system operator (NERC, 2017).

Finally, excess energy that is fed back into the grid from customer-sited DERs can create two-way flows on circuits that are not designed for this. These flows can cause voltage oscillations and other power system impacts that could increase the frequency and duration of outages (CPUC Smart Inverter Working Group, 2014). These are not new challenges for networks, for instance, PJM[3] has been facing reverse power flows to the transmission system as a result of DER output since before 2012. In the period of January to March 2012, there were more than 350 instances of negative loads of 10 megawatt-hours (MWh) or more (Federal Energy Regulatory Commission, 2018a). This highlights the significant operational and planning implications that distribution networks can have on the bulk power system.

A higher penetration of DER will require more accurate forecasts of power withdrawals and injections by load and of DERs embedded in lower voltage networks. This is forcing the need for greater oversight of the distribution network. This is particularly important as greater amounts of DERs actively participating in wholesale markets potentially without distribution network oversight, will make control harder at the distribution network (MIT Energy Initiative, 2016).

At the same time, DERs present an opportunity to optimize the future electric supply, by locating supply direct at the load, reducing costs associated with congestion and losses, and by allowing for incremental and lower-risk planning decisions in face of significant uncertainty.

[3] PJM is a regional transmission organization serving parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

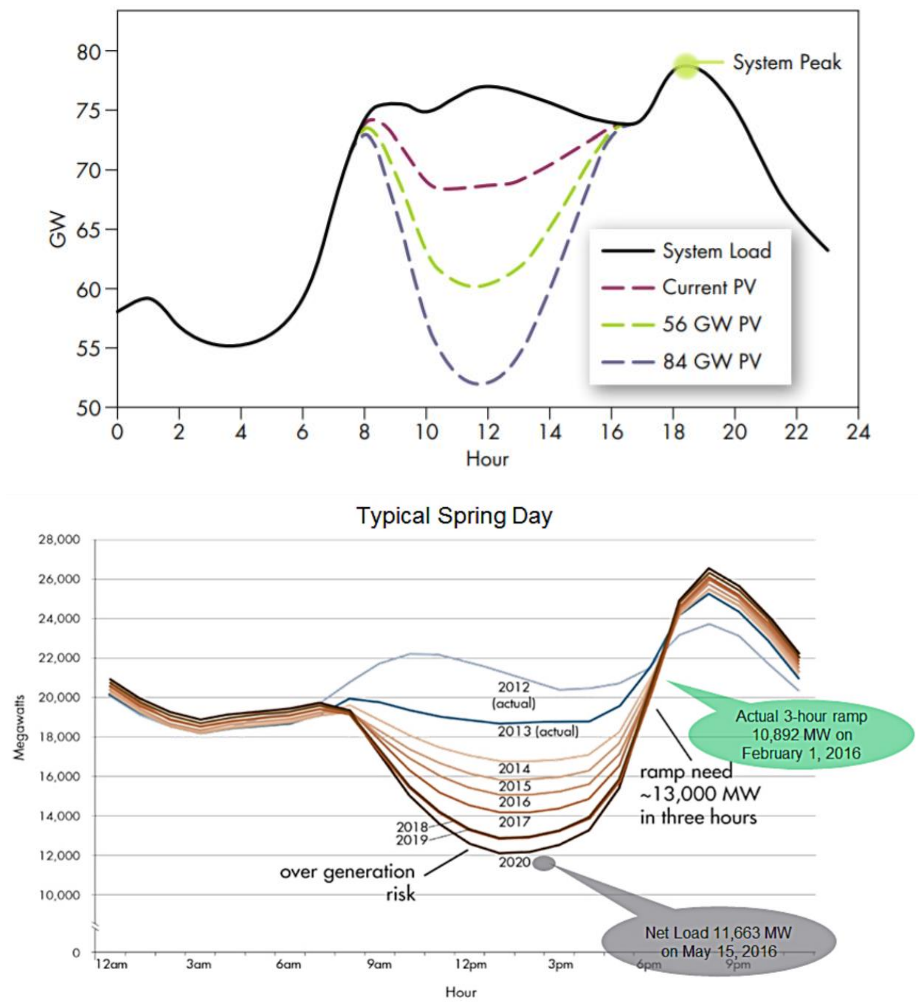


Figure 10: Changing load profile, top showing impact of increased solar photovoltaics, bottom showing changing profile from 2012–2020 in California (California ISO, 2016)

Demand profiles will continue to be impacted by consumer preferences, in particular the uptake of DERs, and adoption of emerging technologies. These trends and future advances, increase the complexity of managing the distribution system and forecasting future capacity and operational needs, to address developing user preferences.

5.2.3 Consumer preferences will have an increasing impact on the distribution network

The challenges for the electricity sector created by DERs are likely to be compounded by other technology developments in the near future. In particular, the wide-scale uptake of electric vehicles (EV) creates a risk that the ratio of peak to average demand will increase and thus further reduce capacity utilization and also risk increased electricity rates to fund underutilized network capacity (Kassakian *et al.*, 2011). However, the U.S. Energy Information Administration currently projects moderate growth of EV's out to 2050. They also identify that growth is heavily dependent on government policies, which introduces significant uncertainty (U.S. Energy Information Administration, 2020a).

EV's can have similar impacts on the network as prosumer households, as sometimes they are a load and draw from the grid, and at other times can be behind the meter supply either satisfying household demand or feeding back into the grid. EV's may present a large increase in energy demand, but, if policy is implemented mindfully, there is an opportunity to utilize this asset in a way that is beneficial for the grid.

Additionally, households and end-consumers are increasingly able to respond to price signals, either by investing in DER or by reducing demand during periods when the value of the reduction is greater than the value of energy delivered to the consumer. This, in part, is driven by the increase in advanced metering, which has increased substantially from 2007 to 2017, reaching a penetration rate of 50 per cent (Federal Energy Regulatory Commission, 2019).

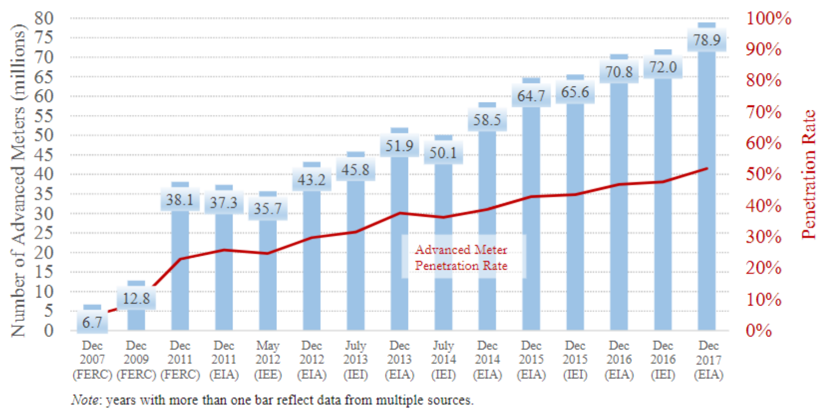


Figure 11: Advanced meter growth 2007–2017 (Federal Energy Regulatory Commission, 2019)

The potential for operators to leverage their consumers to respond to system needs is considerable, and has been driven in part by the wide-scale implementation of advanced meters and appliances; move towards more cost-reflective pricing; roll-out of demand response and efficiency program; and the development and implementation of DERs.

These trends create challenges for the planning and operation of the system. In particular, as investments and decisions are occurring in a more decentralized fashion, the distribution network can no longer be on the periphery of planning and policy decisions.

System operators and regulators, are starting to realize the efficiency gains that can be achieved by engaging end users, and providing incentives to contribute to the optimization of power system operation and planning across the short, medium and long-term

There is particular interest in increasing the efficacy of investment decisions, by better coordinating the large range of technologies and participants that are both impacting, and also providing new solutions to, system operation.

The sector is facing significant challenges, resulting from a combination of rapid developments in the sector, and a technical and regulatory framework that is designed for a system that in reality no longer exists. Despite exacerbating some challenges, many of these developments present new solutions, but require a policy framework that supports and leverages these opportunities appropriately.

5.3 Implications for Network Planning

Traditionally, investments have been made in the transmission and distribution network to meet peak demand. The network is reinforced when existing grid capacity is insufficient to ensure that extreme conditions can be met. This “fit and forget” approach was relatively effective and cost-efficient in the context of conventional centralized power systems (MIT Energy Initiative, 2016), however is no longer appropriate in a distributed power system.

Three aspects of electricity demand that are important to consider in system planning include:

1) height of peak– networks are traditionally built out to meet peak demand
2) length of peak– typically, the narrower the peak, the lower the utilization of the network. Under certain circumstances it may be possible to shift the demand using a battery
3) profile– which refers to the load demanded at each point in time over a day or season, and is inherently influenced by the height and length of peak energy demand

However, as the system demand becomes increasingly peaky (Figure 10), the network will be reinforced to a level that may only be reached for a very short time. This increases network costs to meet a peak demand that will only occur for a short period each year. This may be inefficient and unnecessarily costly as the network is underutilized, and further increases costs for consumers.

While traditionally the only way to meet increasing demand was to expand or reinforce network capacity through grid investments, such as substations, poles and wires, it is now possible to utilize DERs. These can be specific technologies, including battery storage systems, or programs to encourage changes in consumer behavior, such as demand management programs, which can shift load and/or reduce peak, to reduce network costs while retaining reliability. These solutions are referred to as Non-Wire Alternatives (NWAs), and are receiving greater attention as the changing demand profile is making network planning more complex and expensive.

These changes in the electricity system have significant implications for the future operation and regulation of electricity systems, which will affect the businesses operating electricity networks and regulators providing oversight.

5.3.1 Implications for Utility Businesses

Energy demand forecasts made decades into the future are inherently uncertain. The planning horizon for distribution network investments extend far into the future. For example, most distribution planning processes occur with a five to 10 year planning horizon, however looking several decades ahead is not unheard of (Fletcher and Strunz, 2007).

This uncertainty is exacerbated by new developments. For example, the growth of energy efficient appliances saw a large reduction in energy demand, despite increased electrification occurring through a rise in the number of houses with electric heating/cooling. The uptake of DER has also drastically changed household consumption patterns. Network operators have not adequately accounted for these developments previously in developing their demand projections, and cannot be assumed to do so in future.

Forecast accuracy is less important for bulk system planning if planners under-forecast as much as they over-forecast, as identified in Figure 3. However, this is not the case for distribution networks, where the network is built to meet needs at a certain location, and limited interconnectedness means that under-estimates in one distribution network and over-estimates in another do not cancel out. Therefore, uncertainty in electricity demand can have a disproportional impact on distribution networks.

Furthermore, distribution networks tend to overestimate demand, as the value of lost load (discussed in 6.4.2) produces asymmetric risk (Dyson and Engel, 2017). This tendency and increased demand uncertainty, has the risk of greater investment costs for assets that will be underutilized, unless changes are made to distribution planning practice.

In addition, a higher penetration of DERs will be accompanied be new service providers and business models, as consumers call for more opportunities to engage and be compensated for doing so. The active participation of DERs in the power system provide additional options for the provision of electricity services, which distribution and transmission network operators may be able to utilize if appropriate regulatory frameworks are introduced (MIT Energy Initiative, 2016).

While significant changes are occurring that impact the operation of the distribution network, regulators and the public are applying greater scrutiny to network investments. In particular, regulators have recognized there are new options available to meet network needs, such as through NWAs, and are requiring businesses to look at these to ensure lowest cost investment is occurring, such as in New York State as outlined previously.

5.3.2 Implications for Regulators

We are at the start of what will be a dramatic shift in electricity regulation. As outlined in previous sections, the changes in consumer preferences and uptake of new technologies is drastically changing the supply and demand landscape, and along with the emergence of new agents and business models, is forcing a shift in how regulation occurs.

Regulators are facing increased pressure to ensure reliability, security of supply (with no or minimal interruptions to electricity supply), energy efficiency, affordability and predictability (that is, long-term market certainty). This is being driven by rising energy prices and higher consumer awareness; increased adoption of DER and integration of renewables; growing reliance on demand response; and infrastructure investment recovery. Greater consumer choice and access, diverse competitive threats and market environments are also radically shaping today's energy marketplace (Accenture, 2016).

In response to growing pressure from consumers to keep prices low, and to modernize the grid, regulators have looked to alternate ways that allow or require utilities to meet consumer needs at least cost, while taking advantage of the changes underway. In particular, regulators have recognized there are new cost-competitive options available to meet network needs (NWAs), and are requiring businesses to look at these to ensure lowest cost investment is occurring.

Previously NWAs were considered too expensive or were not at required scale, to be suitable for network investments. However, regulators are beginning to encourage, and in some cases mandate, network utilities to consider NWAs when looking at network investment decisions. NWAs are projects that allow utilities to defer or avoid conventional infrastructure investments by procuring DER that lower costs while maintaining or improving system reliability.

For example, as part of the Reforming the Energy Vision, the New York Public Service Commission published an Order Adopting Regulatory Policy Framework and Implementation Plan, which envisions a future electric industry that incorporates and uses DER and dynamic load management.[4] A subsequent Guidance Order required utilities to identify specific areas where there are impending or foreseeable infrastructure upgrades needed in their initial Distributed System Implementation Plan, such that NWAs could be considered and so that DERs could potentially be used to avoid infrastructure investments or provide operational and reliability benefits.[5]

However, DERs and traditional network investments are fundamentally different. The shift to allowing DERs for network investments has considerable impacts on utility businesses and their planning and decision frameworks, as well as substantial changes to how regulation should occur in this new paradigm.

5.3.3 Considerations for the interactions between business and regulation

There is a fundamental dichotomy between the planning of DER and network investments. Deployment of DERs by end users are not regulated in the same way as utilities. For example, DERs are typically much smaller and can be deployed very quickly, while network investments require longer-term decisions and planning, and are scrutinized through a thorough regulatory process.

Network operators are regulated under different regulated pricing frameworks, which has a significant impact on their decisions. Under cost recovery pricing, there is little incentive to care about the ex-post (after the fact) efficiency of their investment decision. However, if prices are set in advance based on a calculation of some efficient level of network investment, then there is greater incentive to consider the costs and conditional probabilities (MIT Energy Initiative, 2016).

Traditionally, policy makers have controlled the expansion of the power system through stringent regulatory controls. Despite the liberalization of the wholesale electricity market, most jurisdictions experience policy decisions which fundamentally shift the investment horizon (MIT Energy Initiative, 2016). These include renewable energy schemes, regulated rule changes that impact market operation, or direct intervention through support of or direct investment in generation assets (such as NYS announcement of 1,500 MW energy storage target for 2025 through the REV). Interventions by governments and regulation changes outside of a transparent process, significantly impact risk and investment certainty.

In addition to this, investments in distributed resources is occurring without necessarily being pushed by regulatory decisions, driven by consumer desire for autonomy, decarbonization and bill reductions. Now there are increasing numbers of people actively engaged in the market, and many more potential

[4] CASE 14-M-0101, Proceeding on Motion of the Commission in Regards to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order)
[5] CASE 14-M-010, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016) (Guidance Order)

investors. This increases the uncertainty faced by operators, planners and traditional investors. As a result, there is an urgent need to design regulatory solutions that better coordinate investment decisions within the distribution network. NWAs may present a way to achieve this, as many existing NWA projects have been developed by third parties that source, or develop, DERs from consumers to be operated in such a way to address a particular need in the network.

Many aspects of DER deployment– including type favored by investors, deployment and operation – depend critically on the prices and charges DER face, which is often influenced by policy and set by regulators. This raises the question, what is actually influencing decisions and setting the course for the sector? Is technology driving regulation or vice versa? The answer is both, however better coordination is needed to ensure harmony in the system, which will provide greater certainty for investors and lower costs. Furthermore, new technologies and systems will enable more options in the future (innovation is not expected to stop), regulators need to continually evaluate regulations to enable this and ensure lowest cost service is occurring.

It is important to highlight that potential value of NWA depends on the characteristics of the grid. For example, a grid with a high proportion of DER faces different challenges to one without, and is very dependent on network needs in a particular area. That is, NWAs may be economic in some situations and not others, and requiring utilities to consider NWA in every situation may unnecessarily increase regulatory burden. This raises the question, under what circumstances is it beneficial to consider NWAs in network planning? This is addressed further in Section 8.

Significant uptake of DER is expected to remain, and continued deployment of ICT-enabled smart grid technologies and systems will likely reduce the costs associated with supplying electricity. To minimize costs over the long term, regulators need to incentivize distribution companies to develop innovative network management approaches and to migrate to active network management approaches in which locational network services can be provided by DERs (MIT Energy Initiative, 2016). The following section describes current approaches to network planning, before a flexible design approach is discussed in Section 7.

6 Review of Current Approaches to Network Planning and Decision Making

Current planning practices of the distribution industry will not be adequate in the future. The mission of the distribution utility remains to provide long-term affordable and reliable service, but the way to achieving this is changing drastically. To deliver on these objectives requires utilities to facilitate the uptake of new technologies and practices to facilitate greater amounts of DERs, in particular low-carbon sources such as rooftop PV, as well as to provide greater opportunities for end-consumers to actively participate in the electricity system. Jurisdictions around the world are in different stages of this transformation, and some jurisdictions are more equipped to respond to this transformation than others. The urgency of these changes is driven in part by the uptake of DER and changes in consumer behavior and expectations.

While distribution utilities are primarily concerned with serving the immediate needs of their customers, they also need to consider future requirements of their customers and operation, to avoid unnecessarily costly decisions. This is particularly important when forecasting out several decades.

The transmission and distribution system is designed to meet peak demand, even if it lasts only a few hours per year, and not to meet average loading conditions. As the cost of building the network to meet peak demand is responsible for about 25–40 per cent of the cost of the transmission and distribution system (Willis, 2004), inaccurate forecasts or high uncertainty, can result in a significant cost to users.

The planning of the distribution system can be roughly separated into three periods: 1–4 years for short-term, 5–20 years for long-term, and 20+ years for horizon planning. System planners aim to minimize future costs by determining the optimal design given assumptions about the future (Fletcher and Strunz, 2007). However, with the rapid state of change, current approaches to long-term planning can lock in less optimal investments.

This chapter reviews current and emerging approaches to distribution network planning and decision making to confirm if it remains fit for purpose in light of rapid changes occurring in the sector. Next, current attempts in some jurisdictions to ensure distribution network planning develops in line with the system are discussed, before further work, that will be the focus of this thesis, is described.

This chapter is structured as follows:

- **Section 6.1** provides an overview of how distribution system planning occurs.
- **Section 6.2** outlines solution assessment and option determination.
- **Section 6.3** reviews whether the distribution system is delivering on its objectives.
- **Section 6.4** explores whether the incentives remain fit for purpose.
- **Section 6.5** discusses whether the distribution system is flexible to changing circumstances, before introducing changes currently being undertaken in some jurisdictions.

6.1 Overview of how distribution network planning occurs

In order to determine what investments may be needed to ensure the distribution system can deliver safe, reliable electricity in the future, it is necessary to first have an understanding of the current performance of the distribution system.

6.1.1 Assessment of equipment condition

The first step in the planning process requires a thorough assessment of the current condition of equipment. This is achieved through an engineering study using power flow analysis, which identifies operational characteristics of the existing and planned distribution grid. It identifies technical parameters, which are used to identify capacity constraints and identify options to resolve these. This also includes an assessment of substation and feeder reliability, condition of assets, and loading on individual assets and operations. An assessment of current operation against prior forecasts, incorporating load and DER adoption, is needed to determine whether the network performs how it was expected to, given particular forecasts and how the system actually evolved (ICF International, 2016; Mid-Atlantic Distributed Resources Initiative, 2019).

Additionally, utilities need to determine how existing assets are likely to perform going forward, given some assumptions about the future. Condition Based Risk Management is a technique used by some utilities to support the condition, age and failure rate assessment of network asset, as well as assessing how an existing grid asset will perform in the future.

Increasingly, equipment condition is dependent on the amount and type of DERs on a distribution network, and will be further discussed in section 6.1.5.

Once the condition of existing assets are known, the utility has a greater understanding of how much load or DER can be supported on the existing grid, as well as what, if any, investments are required. An assessment of the current condition of equipment goes in hand with the assessment of how demand actually materialized, to determine if network assets have performed in line with expectations.

6.1.2 Accuracy of previous forecasts and assumptions

As stated previously, the distribution system is designed to meet peak demand, even if it only lasts a few hours per year. If forecasts were incorrect, the utility may have reinforced the system at significant cost to end-consumers. Therefore, it is prudent for utilities to assess the accuracy of their forecasts retroactively. This is necessary for several reasons, first to determine if any major deviations occurred, second, whether changes can be made to improve forecast accuracy, and third, if they should continue their intended investment strategy.

For example, if the realized demand in a network only reaches the forecast level of five years previous, it may be prudent for the network to defer any major capacity addition for another five years, all else equal. Demand forecasting is further discussed in Section 6.1.4.

6.1.3 Assessment of future needs

Next, the utility determines the future needs of the system through load and DER forecasts, which when compared against the capabilities of the existing system identifies locations of the distribution network where the forecast needs will exceed existing capabilities. As previously outlined, this is performed through power flow analysis (Mid-Atlantic Distributed Resources Initiative, 2019).

NERC conducts the Long-Term Reliability Assessment (LTRA) annually for a 10 year period to identify reliability, as well as trends, emerging issues and potential risks for the bulk power system (NERC, 2019).

The LTRA is informed by supply and demand forecasts provided by industry, including from distribution utilities. The peak demand and planning reserve margins are based on average weather conditions and forecasts of economic activities (NERC, 2019). As populations grow and the energy intensity of economies change as a result of technology developments and pressures to decarbonize, there are going to be greater uncertainties around demand forecasts. Furthermore, as described previously, DERs have a significant impact on a utilities ability to forecast demand due to their lack of visibility of DER technologies.

6.1.4 Demand and DER Forecasting

Utilities conduct a load forecast each year of their planning horizon, to identify the level of demand, as well as the time and location for which it will be needed. They use peak demand and annual energy use as primary inputs for network planning. These forecasts need to consider DERs in order to determine net load, as DERs act as a demand reduction, and also impact the operation of the distribution system (Fletcher and Strunz, 2007).

Net load forecasting is increasingly complicated, as new technologies emerge that can significantly add to demand, including EVs, whereas more efficient appliances and greater control of load through demand management programs can reduce load. This challenge is compounded by the fact these changes are largely being driven by consumers, not utilities. Consumers ultimately control the type of DERs, the rate they are deployed and how they are used. This drastically increases the complexity and uncertainty of load and operation forecasts. Furthermore, as peak demand and annual use are reflections of consumer demand (NERC, 2019), it can be expected to change as consumer preferences change.

This has resulted in planners developing scenarios to have a better understanding of possible realizations of the future, such as high, medium or low EV uptake, further discussed in Section 6.1.8. These scenarios can assist utilities in developing their predictions of the locational (where) and temporal (when) aspects of demand, the importance of which is discussed in the following section.

6.1.4.1 Considerations for demand forecasting

Forecasts report probabilities of a range of possible outcomes, rather than a set prediction of the future. Often regional demand projections represent the expected midpoint of possible demand outcomes, meaning that actual demand may deviate, due to the inherent uncertainty of key inputs. NERC regional projections have a 50 per cent chance of a demand that is higher than forecast, and a 50 per cent chance that the demand will be below that forecast (NERC, 2019).

However, planning networks cannot just be based off peak demand levels, and planners also need to consider operational, timing and locational aspects. Purely looking at variations in forecast does not give an accurate picture of what is occurring in the distribution network.

Figure 12 identifies the variation in load profile across short (hourly), medium (weekly) and long-term (yearly) operation of the network. Accumulation of demand over larger time-scales disguises the daily and even seasonal variations that occur.

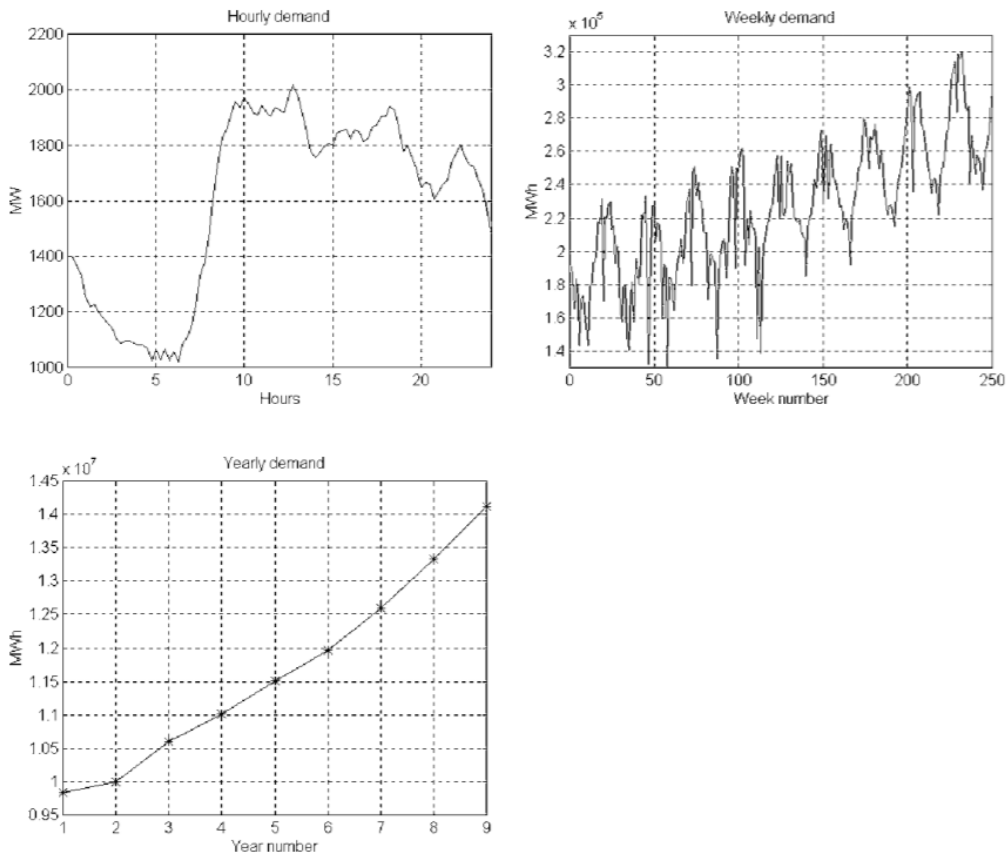


Figure 12: Electricity demand profiles in the short, medium and long-term (Ringwood, Bofelli and Murray, 2001)

Consideration of the locational nature of demand is essential to avoid unnecessarily costly investments. For example, Jemena Electricity Network (Australia) indicates that it is not unusual for one part of the network to grow at three or four times the average rate of the network, while other parts may experience no growth (Jemena Electricity Network, 2019). If the network was built to meet the average demand, one part of the network will be significantly over built, while another part of the network will be significantly constrained.

The rapid deployment of DER on the distribution network has had a significant impact on the accuracy of load forecasts, as they can have a material and unpredictable impact on the power system given their cumulative size and changing characteristics (Australian Energy Market Operator, 2017). The following section discusses the impact DER can have on the distribution network, and how much can be 'hosted' before operational challenges are faced.

6.1.5 Quantity and type of DER impacts a network's "hosting capacity"

Hosting capacity studies are an emerging planning methodology, promoted to address the shortcomings of current techniques that do not give the oversight needed to identify the potential impacts of DER across the distribution network (Electric Power Research Institute, 2016).

Hosting capacity refers to the amount of DER that can be accommodated on the distribution system, without adversely impacting power quality or reliability (Smith, Rylander and Rogers, 2016). The hosting capacity varies between distribution systems, and is driven by DER location, feeder (wire) design and operation, and DER technology. Significant levels of small DER can have a considerable impact of the performance of the distribution system (Electric Power Research Institute, 2016). Large centralized DER can also have a significant impact, but this impact varies widely, based on where the DER is located within the system. The impact of DER technology is determined by whether the DER can be controlled or not, and when the DER is available. Technologies that provide utilities with better control and predictability can contribute more value than those which do not provide this.

Hosting capacity studies can help utilities identify where DER can be best accommodated, and where DER participation can provide the greatest benefit on the local distribution system. Hosting capacity studies are now being required in several jurisdictions, including New York, and are used to inform interconnection processes of DERs.

Once a network's existing hosting capacity and performance is identified, it is possible to predict the future needs of the network, and what investments may be required to ensure the utility continues to deliver quality service to meet future needs of their electricity consumers.

The hosting capacity combined with long-term DER forecasts provides utilities with information to better evaluate where infrastructure upgrades will be needed, so they can incorporate this information into the overall strategic decision making process.

6.1.6 Inputs to demand forecasting

Utilities and organizations that produce national forecasts use many inputs to determine demand forecasts over the short, medium and long term. These forecasts indicate total energy demand, and peak demand over time and by location.

These inputs change based on the country, state or region, but typically include the following: economic-demographic projections (informed by market research or consultation with end-users); historic sales data; and, weather projections. This is informed by spatial land-use forecasts prepared by regional planning agencies (Snohomish County, 2015). These forecasts can help identify the possible impacts of land-use changes on the distribution system in the horizon planning model.

The complexity of load forecasts varies widely by region. For example, a well built up area may have less uncertainty in demand projections, than one that is facing rapid expansion. Furthermore, the type of consumer served also has a significant impact. A distribution feeder that serves predominately industrial consumers, is likely to have stable demand and significant warning for increases, whereas a feeder that serves residential consumers may face greater uncertainty, reflecting changing consumer preferences and rapid uptake of emerging technologies, such as electric vehicles. Finally, unforeseen circumstances are always a potential risk to utilities. It is necessary to consider these risks and subsequent uncertainty in determining possible solutions.

For instance, covid-19 has had a significant impact on electricity demand, with New York seeing a reduction in demand of 6–9 per cent relative to typical load patterns, and a morning peak shifted to later. Figure 13 shows this change, and highlights the rapid reduction by week from early March to the beginning of April (U.S. Energy Information Administration, 2020b).

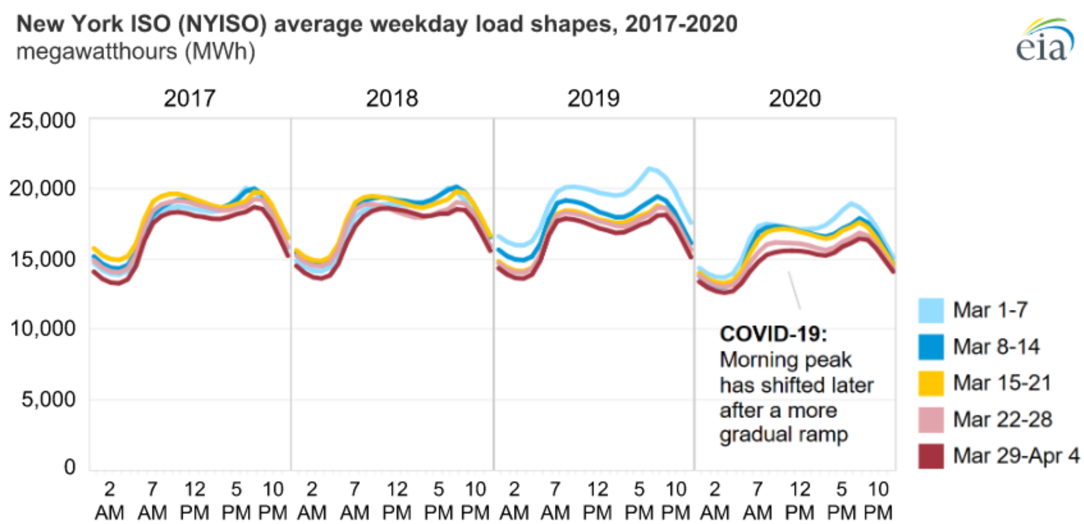


Figure 13: Impact of COVID-19 on New York ISO average weekday load shape and demand level (U.S. Energy Information Administration, 2020b)

These uncertainties are compounded by the timeframe over which planning occurs, as discussed in the following section, and can have a significant impact on the optimal investment schedule and costs.

6.1.7 Horizon Planning

The horizon planning model is used to test design assumptions and provide guidance for the strategic short-term planning of the distribution network, in a way that is consistent with the long-term view of the future over several decades.

The horizon model provides a framework to determine the optimal level of reliability for a chosen protection scheme, and assumptions about reliability impacts. It includes the net present value of interruption costs per consumer. These models are informed by assumptions on consumer density, energy costs, reliability impacts and costs, and consumer load characteristics. Both distributed generation and demand side management (collectively DER) are incorporated into the load forecast. The model determines the optimal design given these future assumptions and the impact on design parameters (system constraints). In addition, the recommended design, including location of, and distance between substations, capacity, and number and size of transformers are provided. The model optimizes to minimize the total cost per consumer (Fletcher and Strunz, 2007).

Given the uncertainty about the future, particularly the 20 plus year horizon, it is prudent to evaluate a number of possible future scenarios, discussed further in the following section (Fletcher and Strunz, 2007).

6.1.8 Probabilistic future scenarios

A probabilistic or stochastic forecast serves to quantify the uncertainty in a prediction. It incorporates a distribution of possible outcomes, rather than a point forecast (Gneiting and Katzfuss, 2014). Giavarra et al. propose a methodology to incorporate probabilistic future supply scenarios into a planning tool. They start with a base supply assumption for the target year and then define probabilistic future scenarios. These scenarios represent uncertainties in future developments, and typically have a lower probability of occurring than the base scenario. The scenario's are dependent on the network under consideration, and can include different realizations of load (low, medium or high), uptake of DER or new technologies (Giavarra, Engels and Maier, 2019).

In New York, the current regulatory CBA relies upon deterministic net present value (NPV) methodologies. Unlike probabilistic methodologies, these deterministic forecasts do not account for uncertainty in load growth. However, this is inconsistent across utilities, with CHG&E using a probabilistic methodology, and Con Edison, National Grid and NYSEG/RG&E using deterministic methodologies (State of New York Public Service Commission, 2018). The Commission also highlight that probabilistic modeling is more suited to horizon-planning, as it recognizes increasing uncertainty further in the future, and can lead to more optimal investment decisions. The Public Utility Commission recommended that utilities should move to probabilistic forecasting methodologies that identifies the primary hours that drive system investments, noting that uncertainty can affect the size and timing of peak demand.

This is particularly important as the state transitions to incorporating NWAs into the CBA, as the length and timing of peak demand events impact the optimal NWA solution. For example, distribution system with multiple short peaks that are driving an investment need may be best addressed with a NWA, while a system with a high baseline demand which is driving the investment decision, may be best met by a wire solution. This identifies that utilities must have a thorough understanding of system needs, before an evaluation of possible solutions can occur.

6.1.9 Needs Assessment

The above steps form part of the in-depth needs assessment, which alongside rigorous power flow analysis, is used to formulate the optimal expansion. This includes identification of the best location, size and installation time for the asset. The planning problem is co-optimized to minimize the NPV of the total cost including costs related to investment, maintenance, production, losses and unserved energy. Incorporating DERs drastically increases the complexity of the co-optimized planning problem.

Following this, the utility prioritizes the needs of the network, for example capacity or voltage control, and evaluates the options for meeting these needs, outlined in the following section.

6.2 Solutions Assessment and Option Determination

Utilities next identify the least-cost way to meet identified needs through an optimization process that generates a set of valid solutions (outlined above).

Historically, there have been few alternatives to ‘traditional’ networks investments, which include substations, poles and wires. However, this has changed with the emergence of new technologies, in particular battery storage systems.

While utilities are more familiar with some solutions, such as the traditional network assets of transformer or additional feeders, there has been a push recently for utilities to consider NWAs in this process. In many jurisdictions, this has been a direct intervention from regulators or the legislature to require utilities to consider NWAs to further other policy objectives (as discussed in Section 4 and 5.3.2).

In considering each of the valid solutions, the utility performs a risk analysis to ensure the system can deliver quality and reliable service. Following this, the utility compares different solutions, which is typically done through a benefit-cost analysis.

6.2.1 Benefit-Cost Analysis

The planning of electricity networks is done to maximize social welfare, that is, maximize sum of consumer surplus, minus costs of actions required to supply electricity. The physical constraints as well as other imposed constraints, such as policy measures, result in a trade-off between system costs for planning and operation, with the costs associated with losing energy supply (MIT Energy Initiative, 2016).

In many cases, regulators require utilities to conduct benefit-cost analysis (BCA) in order to determine the optimal balance between cost and quality of service provided. The California Standard Practice Manual outlines five cost-effectiveness tests to evaluate the distribution of costs/benefits across a range of classes (California Public Utility Commission, 2018), including:

- *Utility Cost test* includes the cost and benefits experienced by the utility system.
- *Total Resource Cost test* assesses the utility system costs plus the costs and benefits to program participants.
- *Societal Cost test* includes benefits experienced by society as a whole.
- *Rate Impact Measure (RIM) test* which assesses the rates paid by all customers.
- *Participant test* includes the costs and benefits for those who participate in the program.

The BCA helps identify and compare multiple different costs and benefits, including the distribution of the costs/benefits amongst different parties. They are included in utility proposals to regulators and/or stakeholders for approval before expenditures.

BCAs commonly use Discounted Cash Flow (DCF) analysis to discount future cash flows to achieve a NPV. This allows costs and benefits that occur in different years to be compared on a common basis. However, there are considerable limitations in DCF analysis. In particular, the assumption that companies hold assets passively, and do not actively use these to maximize gains or minimize losses (Brealey, Myers and Allen, 2010). That is, the DCF does not value the flexibility a utility may have to respond to changing circumstances.

Over the extended planning timeframes of 20 plus years, this evaluation technique may lock-in less optimal investments. This is particularly important to address, considering the rapid changes in the sector. Changes to planning practices are needed to assess, under what conditions flexibility to respond to changing situations may result in a greater NPV, and a lower cost for customers, than current techniques. In response to this, some jurisdictions are requiring utilities to consider NWAs in BCAs.

6.2.2 Non-wire alternatives

Non-Wire Alternatives (NWAs) are DERs that alleviate the need for a permanent traditional network investment, or defers a larger network investment for a period of time. They can be specific technologies, such as battery storage systems, or programs to encourage changes in consumer behavior, such as demand management programs.

DERs are less influenced by economies-of-scale than network investments and so can be implemented at smaller scales and typically more quickly. NWAs can include a portfolio of DER solutions, and due to the nature of the technologies, can be installed in a staged or modular fashion. Investing in a scalable NWA provides the opportunity to make a further investment if demand materializes, or abandon any further investment if it does not. That is, it enables the utility to make a further investment decision to respond to changing circumstances.

Many jurisdictions are starting to look at NWAs for multiple reasons. Regulators are recognizing that new technologies provide new options, and have identified that increased uncertainty may result in sunk assets. NWAs can provide flexibility to network planners to invest in modular NWAs when and where they are needed, mitigating the risk that large investments will become stranded if demand does not materialize.

A recent case study of 10 NWA projects in the United States highlight the various uses of NWAs, with each project addressing different challenges, including distribution and transmission constraints, thermal constraints on feeders, reliability and grid resiliency, as well as substation upgrade deferral.

Despite the vast uses of, and approaches to, NWAs, these projects have reported similar benefits. Utilities have pointed to the uncertainty of forecasting load growth and the benefits NWAs provide in substantially reducing potential stranded costs from investing in unnecessary infrastructure upgrades. They noted the successful delays and deferrals of infrastructure upgrades, flexibility in implementing solutions incrementally as load grows, and significant cost savings (E4TheFuture, 2018).

As can be seen through these case studies, NWAs have been successfully used by utilities to build flexibility into network planning. However, the chosen case studies are likely to suffer from selection bias. A standardized approach to identify when NWAs should be considered is needed, as well as how the unique characteristics of these portfolios of solutions should be compared against traditional investments. For instance, some jurisdictions have encouraged utilities to consider the 'option value' of NWAs in the cost-benefit analysis assessment of their network options.

It is important to reflect on both historic performance, as well as how the existing grid may cope with the changes forecast in the future. An assessment of how the grid has performed, and is expected to perform, is given by service quality metrics, including reliability of supply and the technical characteristics of supply, such as system voltage. The following sections outline how these quality metrics are defined and implemented through distribution system planning protocols, and whether the current system is currently delivering on these objectives.

6.3 Objectives of the distribution system

Public Utility Commissions aim to provide affordable and reliable electricity to consumers, while ensuring that utilities are given the opportunity to recover their costs with a reasonable rate of return (U.S. Department of Energy, 2017).

This section outlines three key objectives of the distribution system, to deliver reliable, quality and affordable service, and discusses the necessary trade-offs between these goals.

6.3.1 Reliability performance

Evaluation of the reliability of the distribution system is two part, measuring past performance and forecasting future performance. Utilities achieve this by collecting data on past system performance and producing indices to provide an assessment of system reliability (Billinton, 1988). An understanding of performance by customer class and their willingness to pay for greater quality informs the physical operating parameters of the networks, and therefore the required investments.

Reliability constraints simplify complex economic and technical calculations to develop measures of failure and interruption indices, based off the duration and frequency of service interruptions. The North American Electric Reliability Council (NERC) is responsible for developing and enforcing mandatory reliability standards to ensure reliable operation of the bulk power system, including both the generation and interconnected transmission system. NERC petitions the Federal Energy Regulatory Commission (FERC) for approval of these standards, which are enforced by regional reliability organizations.

The key reliability indices used for system planning include the System Average Interruption Duration Index and System Average Interruption Frequency Index:

- *System Average Interruption Duration Index* (SAIDI) indicates the total duration of an interruption for the average customer during a period (IEEE, 2012).
- *System Average Interruption Frequency Index* (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period (IEEE, 2012).

For example, if there is a failure in a power line to a group of consumers, the length of the outage (time the consumer is without electricity supply) contributes to SAIDI, whereas the number of different times the interruption occurs counts towards SAIFI. A network could have a large number of very short outages, resulting in a high SAIFI but low SAIDI. Similarly, a network could have a single very long outage, which would result in a low SAIFI but high SAIDI. Therefore, both metrics are needed to assess the reliability of a network.

It is also important to note that the SAIDI and SAIFI figures are often calculated across a service area for a utility, and as such could be calculated at a state level or larger. This does not represent the reliability of a distribution network, and so some regulators track reliability at a more granular level by observing the distribution of reliability, or for the “worst-served” customers (The Brattle Group, 2012).

Loss of service impacts the reputation of a utility, however, with minimal or non-existent competition for the distribution of electricity, consumers are not able to select an alternative provider. For this reason, regulation is required to ensure a minimum standard of reliability is met. There are multiple types of reliability regulation, including standards for the quality of service, such as frequency and voltage standards, as well as standards for service interruptions (continuity), discussed in the following section.

The combination of stringent reliability metrics and a tendency to overbuild networks (due to asymmetric risks) can result in unnecessary costs or stranded assets as we face greater uncertainty, unless changes are made to ensure electricity networks are more flexible to changing circumstance.

6.3.2 Quality of service

Service quality incorporates technical and non-technical traits. The technical aspect of 'power quality', refers to the characteristics of the supply that consumers receive. This includes continuity of supply, and voltage quality (low supply voltage, voltage spikes, dips, or swell) as well as frequency and harmonics (Meyrick & Associates, 2002; Fumagalli, Delestre and Lo Schiavo, 2006). The non-technical aspects, also referred to as 'commercial quality', include timeliness of connection, billing, customer relations etc.

Poor service quality can impact end-consumer operations and equipment, and can be very costly. However, the value of service quality and reliability changes between consumers (discussed further in Section 6.4.2), which can create challenges for distribution utilities serving different customers on a single network. There are different ways for regulators to determine the minimum quality required of distribution utilities, which is further discussed in the following section.

Due to the possible impact of poor service, and the lack of competition in distribution systems, regulation is required to ensure a minimum quality of service is provided. There are many approaches to incentivizing reliability of service, which are outlined in Section 6.4.1.

Quality of service will become more complex and costly to ensure as increased penetration of DERs create challenges for quality in the distribution network, such as from two-way power affecting the management of network voltage.

6.3.3 Affordability

Affordable electricity is a basic necessity of everyday life, and is an enabling factor across other critical industries forming the cornerstone of modern economies (MIT Energy Initiative, 2016).

Retail electricity bills consist of costs associated with generating and delivering (transmission and distribution) the electricity, as well as other costs, such as policy costs associated with environmental measures.

Electricity delivery costs are an increasing proportion of household bills. Average retail electricity prices rose approximately 1.5 per cent from 2006 to 2016, while the price of natural gas, a key generation technology, fell by an average of 8.4 per cent per year over the same period. This indicates that network costs have been increasing, and offsetting the savings from lower energy costs. Consequently, the proportion of electricity costs attributed to delivery has risen from 22 per cent to 36 per cent, as identified in Figure 14 (U.S. Energy Information Administration, 2017).

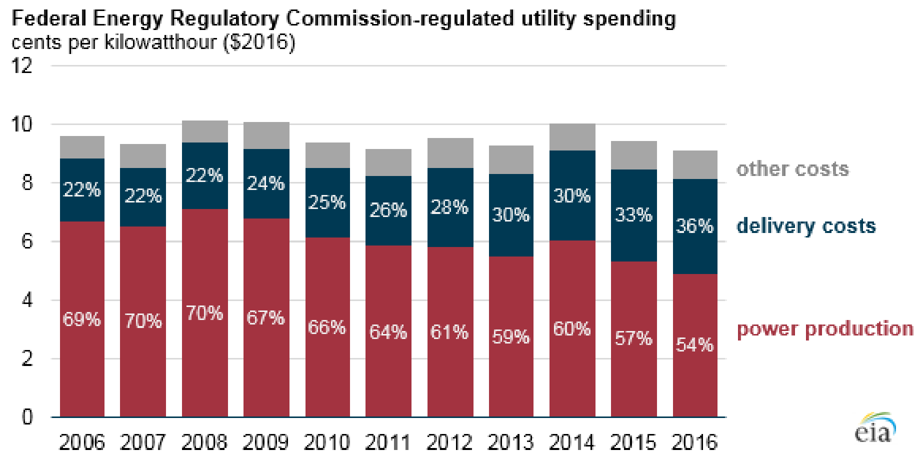


Figure 14: Federal Energy Regulatory Commission regulated utility spending cents per kilowatt-hour (U.S. Energy Information Administration, 2017)

This increase in delivery costs is drawing scrutiny from consumers and regulators, and is resulting in greater oversight of network investments. Furthermore, consumers have higher expectations of networks to invest in new technologies where they can further environmental considerations, especially if they reduce network costs.

For example, in 2008 Central Maine Power proposed a $1.5 billion transmission upgrade for the state. Grid Solar challenged this proposal contending the load forecast were too high and did not warrant the proposed solution. As a result, Maine Public Utilities Commission allowed Grid Solar to develop NWAs in two locations in place of a traditional network investment (Maine Public Utilities Commission, 2010).

Previously, the focus has been on providing reliable and quality service. Recently, there has been greater scrutiny over affordability. With changes occurring in the system, the management of the distribution system is becoming more challenging and costs are increasing. Therefore, it is prudent to reassess our approach to distribution network investments to ensure least cost investments are occurring. This may require regulators to reevaluate the incentives they provide to utilities.

6.4 Does the current system provide the right incentives?

6.4.1 Incentives for minimum service reliability

Requirements for minimum service reliability depend on the regulation of the distribution network. For instance, Weisman 2005, identified that under price regulation, the incentive to invest in service quality increases with the price-cap. Under a restrictive price-cap, the incentive to invest in service quality reduces. Finally, revenue-share penalties may actually provide incentive to reduce quality, whereas profit-share penalties provide a strong incentive to invest in quality (Weisman, 2005).

Reliability performance regulation can be one-sided, where networks face a penalty if minimum standards are not met, or two-sided, where they could also receive a benefit if they exceed their standards. These penalties may be paid to the regulator, or paid directly to affected customers, depending on the type of interruption or impact, such as significant economic losses due to lost load.

Reliability standards are set off ‘normal’ conditions, and are typically determined as what networks can plan for or have some control over. For example, often large storms or hurricanes which cause outages are not considered as ‘under’ the utilities control, and therefore typically do not impact their reliability performance.

There are four basic instruments a regulator may use to ensure service quality, including “naming and shaming”, minimum quality standards, financial rewards and penalties, and premium quality contracts (Williamson, 2001; Fumagalli, Delestre and Lo Schiavo, 2006). These instruments can be employed individually or in combination. Each are dependent on what we might consider a reasonable level for minimum or target reliability.

6.4.2 Setting an appropriate level of quality: cost-reliability tradeoff

The higher the desired reliability, the greater the cost required for network investments. Consumers are unlikely to want to pay for 100 per cent service quality, if costs increase exponentially, or if they can have a much smaller bill for a very high quality.

Some jurisdictions use value based or customer willingness to pay, to determine network investments and maintenance routines, while others use internal data concerning costs or system characteristics to guide decision-making.

Customer Willingness to Pay- the value of reliability to consumers can be important in setting reliability standards, while minimizing costs. For example, a feeder supplying high-value industrial businesses, is going to have a greater willingness to pay for higher reliability, than a feeder supplying households who are typically resilient to some interruptions, particularly if they receive a lower electricity bill.

In this example, the industrial customer’s willingness to pay for higher reliability is impacted by the value of lost load.

Value of Lost Load (VOLL)- indicates the economic consequences of power interruptions and blackouts, such as resulting damage and other macroeconomic costs (lost utility). VOLL relates the financial losses to the amount of energy lost (kWh) (Schröder and Kuckshinrichs, 2015). It is a measure of the customer’s value of the opportunity cost of outages, or benefits foregone, through interruptions to electricity supply. VOLL is used in network planning to determine optimal level of supply reliability, which informs the level of investment or reserve capacity needed. In theory, the VOLL is equivalent to what customers would be willing to pay to avoid an outage, or the minimum they would be willing to accept in compensation, for lost value resulting from supply interferences (Willis and Garrod, 1997).

The network should be reinforced until the cost of the investment equals the marginal damage associated with lost load (Röpke, 2013).

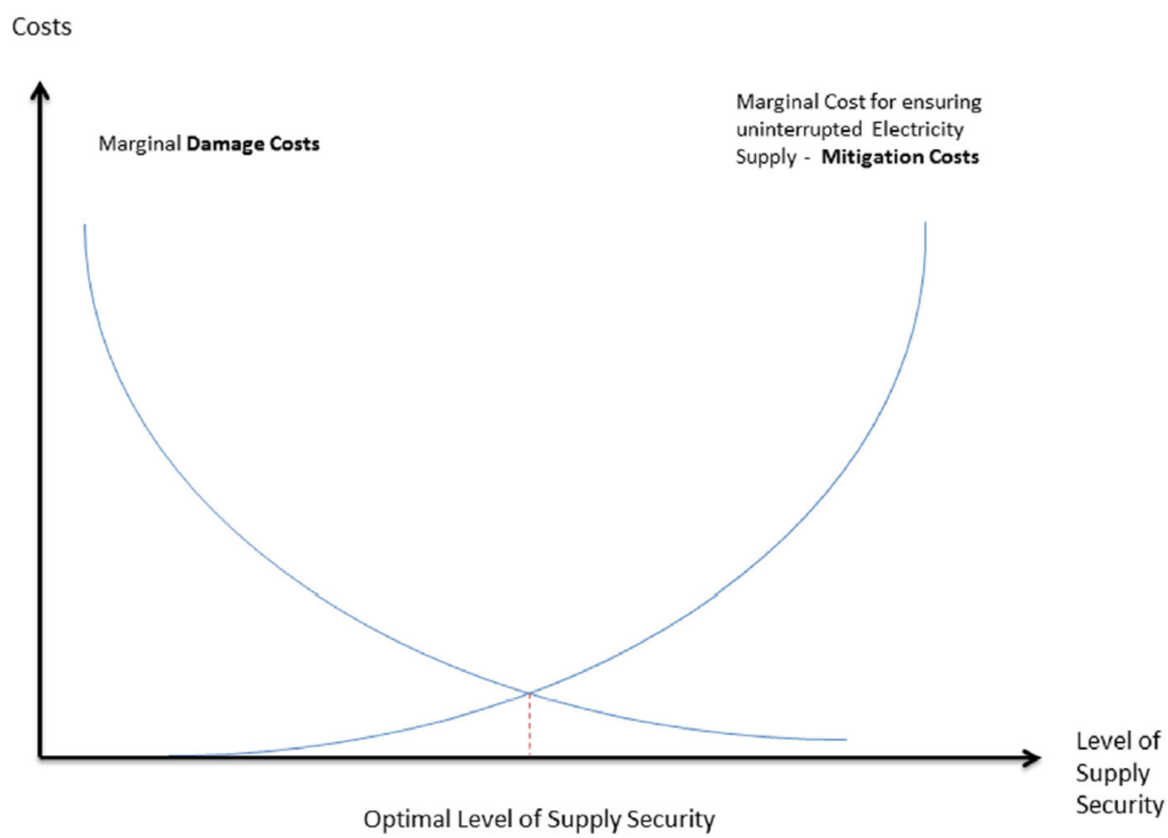


Figure 15: Optimal level of supply security determined by marginal damage costs and mitigation costs (Bliem 2005, as presented in (Schröder and Kuckshinrichs, 2015)*)*

With recent developments in the electricity system, there are now greater levels of uncertainty, which is impacting utilities abilities to build networks to meet future demand, at least cost. This has resulted in a shift in some jurisdictions, to build greater flexibility into electricity network investments to allow utilities to responding to changing circumstance. Furthermore, as these changes are occurring, regulators need to reassess how they determine cost effectiveness

6.5 Is it possible to build a distribution system flexible to changing circumstances?

Traditional distribution networks are not able to easily respond to changing circumstances, and this can result in unnecessary costs. Dixit and Pindyck, identified that there is a value for waiting for better opportunities when analyzing the investment case where there is a sequence of opportunities (Dixit and Pindyck, 1994). Additionally, Baldwin (1982) showed a simple NPV rule leads to overinvestment. This indicates that current methods to value distribution projects need to change to limit overinvestment and value the option that flexible investments provide in allowing distribution utilities to take advantage of subsequent opportunities.

More recently, the New York Department of Public Service and NYSERDA in their Energy Storage Roadmap (2018) indicated that "Projects that appear to be higher cost on a deterministic basis may be the lower-cost option when risk and uncertainty of future conditions are accounted for."

The current approach to project valuation used in distribution networks does not value flexibility. Some jurisdictions have noted the limitations of traditional DCF and BCA methodologies, and are working to value flexibility, in particular that offered by NWAs. It is necessary to value emerging technologies according to the benefit they can provide to the grid, in order to facilitate the use of emerging technologies to meet grid needs. For example, New York State Department of Public Service have recommended that utilities develop a methodology detailing how optionality valuation should be performed and to provide examples (Department of Public Service and New York Energy Research and Development Authority, 2018). This has been the motivation for this work, and a case study is presented in Section 8 to address both recommendations, identifying an approach to how option valuation can be performed using an example of a distribution network assessing investment options.

Furthermore, New York State Public Utility Commission recognizes the value optionality can provide to investor owned utilities, due to the uncertainties in energy price and demand forecasts, and changing need of the electric system. However, because additional work is needed regarding optionality, they declined to implement these changes at the time.[6]

It is possible to build a distribution system that is flexible to changing circumstance, but regulators and industry need to further assess possible options that build in flexibility to respond, as well as how existing processes and regulations need to change to facilitate this functionality. A standardized methodology to value flexibility is required to determine under what circumstances a NWA may be more beneficial, as well as an approach to value this flexibility.

In the following chapter, a flexible design approach to network investments is outlined, incorporating real option analysis to value this flexibility for consideration in a BCA.

[6] Case 18-E-0130, In the matter of energy storage deployment

7 Applying a Flexible Design Approach to Electricity Networks

Flexibility provides a strategic benefit when firms compete in a world of substantial price and demand uncertainty, product variety, short product life cycles and rapid product development (Nembhard and Aktan, 2009). For electricity networks, a flexible design approach may allow utilities to optimize investment decisions, particularly during periods of high demand uncertainty.

This chapter introduces the theory of flexible design and how it can be applied to electricity networks, as well as what drives the value of flexibility, and how this value can be quantified. This in turn informs the case studies developed in later chapters of this thesis.

This chapter is structured as follows:

- **Section 7.1** introduces approaches to flexible design and their use in infrastructure planning.
- **Section 7.2** discusses the potential impact from applying these approaches to the electricity sector.
- **Section 7.3** outlines how a 'real options' approach can be used to value flexibility in networks.
- **Section 7.4** discusses the core components of options valuation and how they can impact overall estimates of value.

7.1 What is a flexible design approach?

Flexibility in engineering design is an interdisciplinary field that adapts the concept of financial options to real engineering systems (de Neufville and Scholtes, 2011; Cardin, 2014). Flexibility exists 'on' engineering systems, associated with managerial flexibility, and 'in' engineering systems, by technical engineering and design components that enable real options (Trigeorgis, 1996).

The purpose of flexible design is to identify options that provide greater expected net present value of the investment over the life of the project, compared to the outputs from the standard ('robust') design and project evaluation approach (Cardin, Ranjbar-Bourani and de Neufville, 2015). For electricity networks, this approach may help identify options that have a higher expected net present value than those determined as the optimal solution through the standard DCF and CBA outlined in the previous chapter.

By building in flexibility, utilities are better able to adapt to the future environment and shift the distribution of the possible NPVs, improving the upside potential while minimizing the downside risk, relative to the static optimum (dashed line), as shown in Figure 16. The increase in the expected net present value is the value of the option (option premium).

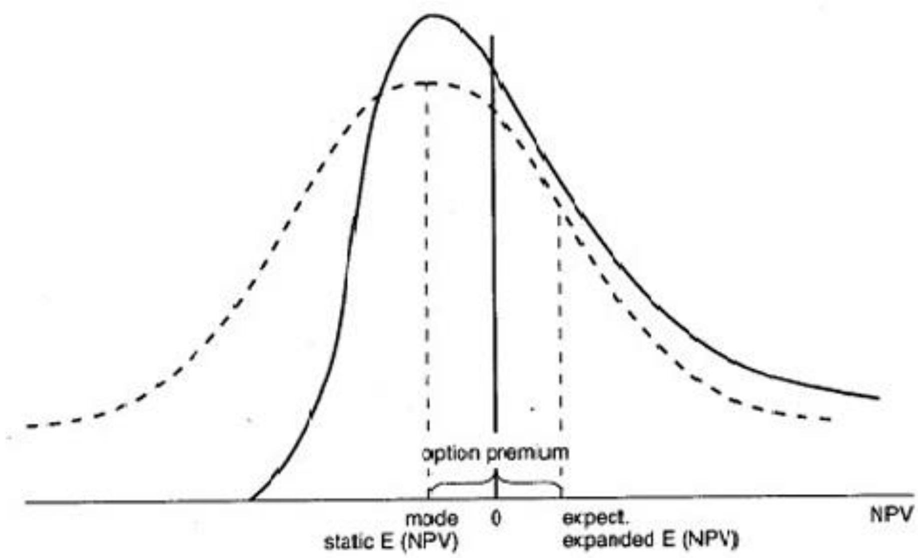


Figure 16: Managerial flexibility or options introduce an asymmetry in the probability distribution of NPV, allowing planners to reduce their downside risk. Dashed line shows symmetric distribution of NPV in absence of managerial flexibility (Trigeorgis, 1996)

For example, Cardin et al. (2015) applied a modular deployment strategy for LNG terminals, and found that this flexible design improved the economic performance compared to the optimum fixed design approach. Cardin considered the trade-off between the time value of money, learning rates and economies of scale, discussed further in section 7.4, to show the advantages of flexible design under uncertainty. A key aspect of flexible design is the use of modularity to allow the system to perform better as requirements and opportunities evolve over the life of the plant (Cardin, Ranjbar-Bourani and de Neufville, 2015).

Electricity networks are characterized by large capital investments with significant economies of scale, that once made are sunk, that is, the cost is unable to be recovered by selling on or salvaging the unutilized asset. Further, these investments are made to satisfy demand decades into the future, which in some cases can be highly uncertain. Dixit and Pindyck, showed that small-scale investments that increase future flexibility can offset, to some degree, the advantage that comes from large economies of scale (Dixit and Pindyck, 1994). The case study presented in Section 8 provides an example of how NWAs can be used to provide flexibility 'on' the network, by allowing planners the option to abandon, defer, expand or mix production. The potential benefit for flexible design in electricity networks is discussed in the following section.

7.2 What does this mean for electricity networks?

Electricity networks are characterized by large, 'lumpy' investments. A 'lumpy' investment refers to an investment that is characterized by large infrequent outlays, rather than continuous or recurrent investments of a smaller scale. If there is a need to make investment decisions far in advance, the potential for stranded assets is greater, particularly if the investment is not reversible and forecast demand does not eventuate. This may result in network assets that are 'sunk', that is, the asset is not fully utilized. Although the costs may be recovered by the distribution utility, if the original investment was prudent, continued ‘over-investment’ (or ‘gold plating’) will face greater scrutiny from regulators and the public, possibly resulting in direct or indirect costs, such as penalties or reputational damage.

A flexible design approach may be particularly valuable in periods of high uncertainty, as it provides utilities the flexibility to make a small initial investment and wait for more information to become available, such as actual demand levels and operational needs, before making further investments.

If projected demand is not realized, the DER enables the utility to avoid a more significant stranded asset cost. In some circumstances, the DER can be utilized for other purposes, or alternatively can be removed and relocated to another part of the grid. If this is not the case, investing in a lower capacity and lower cost DER means there is a comparably smaller unused capacity and stranded asset.

However, if the expected level of demand is realized, a further investment may be required. It may be the case that undertaking the network investment initially would have been a lower cost course of action. Real options can be used to determine the value of this flexibility, taking account of the relative likelihood of different demand projections, as discussed in the following section.

7.3 Real Options to value flexibility in network investments

Growth opportunities can be viewed as ‘call options’. A call option is a financial instrument, which allows its owner the right, but not the obligation, to buy a stock at a specified *exercise* or *strike* price, on or before the maturity date (Brealey, Myers and Allen, 2010).

Part of the value of a firm is the value of options to make further investments on favorable terms. The firm is valued in part on the expectation of continued future investment if a favorable state occurs, or to not invest if an unfavorable state occurs (Myers, 1977). They are valued given the assumption that they will pursue whatever results in the greatest expected net present value, be it to pursue an investment if the climate is positive, or to hold off and wait for other opportunities if this is expected to deliver the best outcome.

Real option analysis recognizes a firm’s ability to actively hold an asset, and make decisions including the option to:

- wait (and learn) before investing;
- reduce scope or abandon a project;
- expand a project; or
- vary output or the firm’s production method.

This provides the firm the opportunity to make decisions to maximize value or minimize losses in a flexible manner.

An example of this ‘optionality’ could be to purchase an adjacent piece of land to a factory, for the option to build there in future if the climate is positive. In the case where the climate is positive, such as if the factory experiences high demand for their products, the factory can expand their operations by building on the adjacent land. If the demand doesn’t eventuate, they can hold the land until a later period if they still think demand could eventuate (option to defer), they could sell the land on (option to abandon) or they could diversify their operations and build a different facility (production option). The ultimate value of this option to the factory depends on further, discretionary investments.

The real-option value considers the possible changes to the project economics given the distribution of uncertain outcomes (Skinner 2009). In addition, it values the flexibility that an option provides to decision makers. There are several major parameters that impact option value, which are discussed in the following section.

7.4 What impacts option value

7.4.1 Discount rate

In real options analysis, the discount rate is the opportunity cost of capital, defined as the expected return on other securities with the same risks as an equivalent share (Brealey, Myers and Allen, 2010). This means that the discount rate for a given firm or project, should align with the discount rate expected for a firm/project with the equivalent level of risk. Projects that are high risk, for instance, pharmaceutical products and high-tech ventures have a high discount rate, while low risk projects have a low discount rate.

The discount rate is a key input in the valuation of a project. It represents the time value of money, and provides an incentive to delay expenditures to a later period. The discount rate is the opportunity cost of investing in the project rather than in the capital market. When the discount rate is high, there is a larger incentive to defer expenditure. In this case, a high discount rate increases the value of flexibility and favors a modular approach to design, where capacity can be deployed over time or delayed (Cardin, Ranjbar-Bourani and de Neufville, 2015).

The choice of discount rate can be a controversial topic, due to its ability to impact the optimal solution. In the analysis presented in this thesis, the appropriate discount rate does not need to be identified; rather, we assess the outcome for a given discount rate.

7.4.2 Economies of scale

Economies of scale exist when larger capacity investments are cheaper per unit of capacity, than a smaller investment. This is a crucial consideration in determining the optimal investment, as it incentivizes designers to create the largest economically reasonable facility, counter to a flexible approach (de Neufville and Scholtes, 2011).

This trait has important design implications. For example, if there are no economies of scale, there would be no need for a planner to anticipate future needs and build to that level, as small-scale expansion would occur as needed.

However, other traits can counteract economies of scale, such as learning rates, which means that the relative cost of future investments is lower than the cost of an equivalent investment made today. This creates a tradeoff between taking advantage of economies of scale while considering the future demand for the good, and benefits that may come from taking advantage of learning rates through modular or delayed investments.

7.4.3 Learning Rates

The learning rate is the phenomena whereby the cost of capacity reduces as the number of units produced increases, resulting from design innovation and manufacturing improvements (de Neufville et al., 2019).

The value of flexibility increases when there is a significant learning rate, as deferring an investment enables the producer to take advantage of this learning to reduce production costs or improve product quality. The impact of economies of scale and learning rates on the value of flexibility is shown in Figure 17.

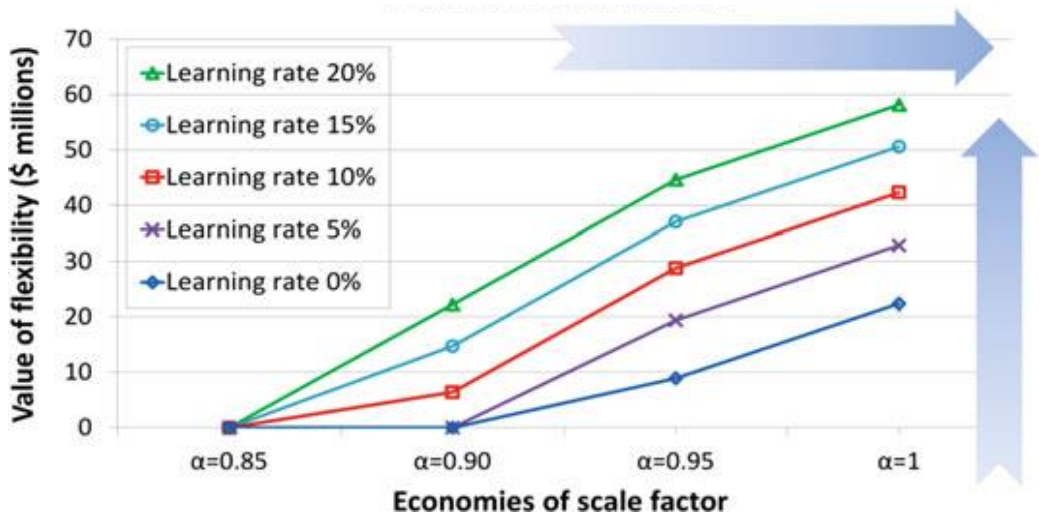


Figure 17: Value of flexibility with different economies of scale and learning rates (Cardin, Ranjbar-Bourani and de Neufville, 2015)

The above figure shows that as learning rate increases, the value of flexibility increases. The economies of scale decrease as we move to the right (as the factor approaches one), indicating that learning counteracts the effects of economies of scale, and incentivizes more flexible investments.

Due to the developed nature of many traditional network investments, they are less likely to have a significant learning rate. Conversely, many DERs that are utilized as NWAs are nascent technologies, which have a larger learning rate. This is highlighted by the significant cost declines of solar and wind technologies, in both Figure 6 and Figure 7.

This suggests that the benefit of economies of scale for traditional investments are unlikely to be counteracted significantly by the learning rate. However, if considering a NWA versus a traditional investment, the potentially higher learning rate of the NWA should be considered by the utility. This may mean that in defering the traditional investment, the cost of the NWA reduces significantly providing a greater reason for flexibility. Investing in a NWA is not just an option to expand to a wire investment, but also to abandon the existing NWA for a superior one in future.

This highlights some of the contingent decisions that can be made to protect against negative future conditions, thereby building flexibility into design (Saleh, Mark and Jordan, 2009). Real options analysis seeks to value these sources of flexibility.

7.4.4 What is real options analysis?

'Real options' refer to the choice available to system planners regarding their investment opportunities, whereas 'real options *analysis'* is the technique to calculate the financial value of flexibility (Dixit and Pindyck, 1994).

Real options analysis moves away from a traditional discounted cash flow approach, which assumes companies hold assets passively and ignores the opportunities to expand if successful, or exit if unsuccessful (Brealey, Myers and Allen, 2010). For this reason, discounted cash flow techniques bias against projects that have operating and strategic adaptability (Trigeorgis, 1996). Real options analysis is an approach to value a project, recognizing that planners will actively manage the investment, and take advantage of strategic opportunities as the future unfolds. Several methods to calculate the real option value are outlined in the following section.

7.4.5 Approaches to real options analysis

7.4.5.1 Black-Scholes Model

The Black-Scholes model values an option by establishing an option equivalent that can be priced. In this model, the value of the option will depend on the price of the stock and time, as well as some variables that are assumed to be known constants. This enables a hedge position, where the holder can take a long position in the stock and a short position in the option. This implies there is only one correct price for the option (Black and Scholes, 1973). By continuous application of their dynamic portfolio replication strategy, they produced a partial differential equation that must be satisfied by the value of the call option (Trigeorgis, 1996). The Black-Scholes model requires an understanding of the risk profile of the underlying assets, which can be hard to quantify for many engineering projects.

7.4.5.2 Dynamic Programming

Dynamic programming seeks to optimize decisions based on the view of the future. It involves breaking a sequence of decisions into two components, the initial decision and a payoff function that represents the expected value of subsequent decisions (continuation value) given the initial investment decision. The net present values of an investment in the initial period can be compared with deferring an investment to the next period. By working backwards to the initial condition this approach enables the estimation of the expected continuation value and allows the investment decision to be optimized (Dixit and Pindyck, 1994).

7.4.5.3 Simulation approach

Simulations can be run to determine how different design schedules behave under different assumptions of the future. Monte Carlo simulation is a tool used to consider all possible combinations of future scenarios, allowing the planner to observe the entire distribution of outcomes (Brealey, Myers and Allen, 2010).

A large number of simulation runs are needed for reasonable accuracy. When a simulation run has reached a given decision point, there is no way to know if early exercise would be optimal, this makes valuation of problems involving options for further investments challenging, as it is not possible to undertake a dynamic-programming valuation (Trigeorgis, 1996). The aim of Monte Carlo simulation is to find the stochastically optimum design, however, it does not recognize the opportunity to modify projects (Brealey, Myers and Allen, 2010).

For electricity networks, a flexible design approach can allow utilities to optimize investment decisions, minimize the risk of stranded assets and reduce network costs. This is particularly important during periods of high demand uncertainty.

In the following chapter, a real options approach using dynamic programming has been applied to the example of an electricity distribution investment.

8 Case Study

This case study applies a simple real options framework to an investment decision being made by a distribution utility. We explore the traditional decision utilities currently assess, before introducing the emerging option of NWAs representing a flexible investment. Finally, we observe the impact of flexibility under a case of increased uncertainty.

This chapter is structured as follows:

- **Section 8.1** outlines the problem the distribution utility is facing in this study.
- **Section 8.2** describes the model, key inputs and assumptions.
- **Section 8.3** outlines how a decision is made using a traditional wires approach.
- **Section 8.4** explores how the decision is made using an emerging flexibility approach.
- **Section 8.5** explores how the flexibility approach performs under increased uncertainty.
- **Section 8.6** concludes the chapter with a discussion of other sources of flexibility and challenges in implementing a flexible design approach using NWAs.

8.1 Introduction

In this study, we consider the case of a distribution network that is assessing options to meet the requirements of a section of the grid where demand is projected to increase. The network utility has produced forecasts of future demand, which may or may not materialize. Network planners need to decide when they will make their investment, and what type of investment they will make.

This case study is partly informed by a NWA project that occurred at Boothbay Maine, cited previously. This includes the identification of challenges highlighted and some cost estimates. Other inputs are indicative, and have been used to illustrate the example.

8.2 Model description

In this case, the utility has identified three possible realizations of demand in the future as well as their relative probability of occurring. In order to determine what investment should be made, the expected net present value for our investment options are calculated.

The decision tree presented in Figure 18 (following page), represents the major milestones the distribution utility faces in their planning process. Starting at the present (T0), the utility must make an investment decision in period 1 (potentially one or more years later), in order for the investment to be operational by period 2. The investment that is made in period 1, will be operational by period 2 regardless of how demand materializes.

The investment decision will be made in period 1 (T1), based off the projected payoff in period 2 (T2) given our decision in T1. The decision tree presented in Figure 18 identifies the nine possible pathways to three demand outcomes in T2– high, medium and low demand.

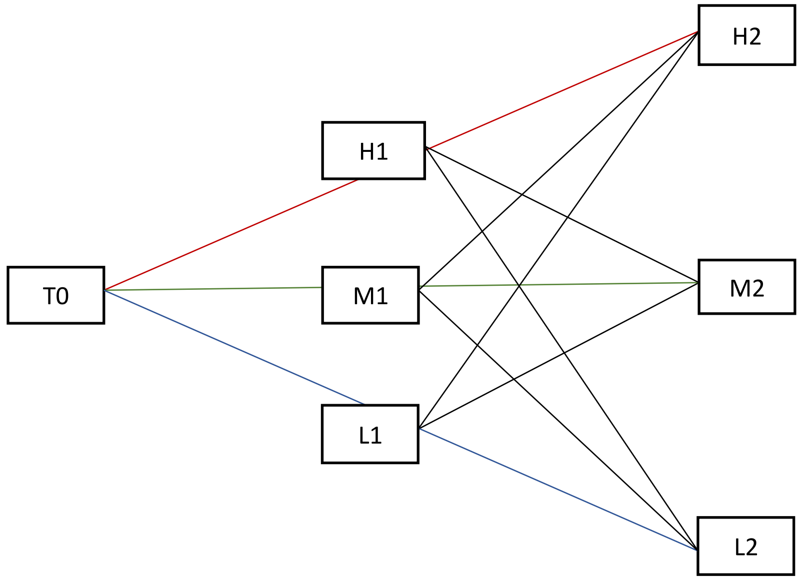


Figure 18: Tree identifying the nine possible paths as demand realizes, resulting in three possible outcomes

This tree highlights the uncertainty that comes from making decisions far in advance. At T0 we have nine possible paths to three demand outcomes. On reaching period 1, there are still three possible outcomes from this stage (H, M or L), but we have more information available to us as we know the demand in period 1. Due to conditional probabilities, we know that if we have high demand in period 1, we are more likely to have high demand in period 2. But there is still some probability that demand will decrease to a medium or low level. This introduces some uncertainty into the decision that we make. Ideally, we would wait to make our decision until just before the capacity is required. However, due to the time for approvals, permitting and construction, we need to make our decision in T1 to ensure it is operational by the following period (T2).

There are a range of probabilities around the possible demand outcomes in T2, which varies conditional on the demand reached in T1, as presented in Table 1.

Table 1: Probabilities of high, medium or low demand in T2 given demand in T1

	Probability of T2 demand | T1 demand		
	H2	M2	L2
H1	0.75	0.15	0.10
M1	0.15	0.75	0.15
L1	0.10	0.10	0.75

For example, this table identifies that if a high demand is reached in period 1, there is a greater chance of high demand occurring in period 2 (75 per cent). However, there is still a possibility that demand will decrease to medium demand (15 per cent) or even low demand (10 per cent) in period 2. There are different outcomes (payoffs) for each level of demand, and so it is necessary to ensure this uncertainty is captured in our valuation of each option.

The investment decision is determined by the expected net present value (ENPV) of the options available. The ENPV is the difference between a project's expected value and its cost based off some assumptions of the future. It is determined by multiplying the likelihood (probability) of a given demand occurring (H, M or L) by the expected payoff for that demand outcome, minus the cost of the investment, as shown in (1):

$$ENPV = P_{H2} \times Payoff_H + P_{M2} \times Payoff_M + P_{L2} \times Payoff_L - Cost_{investment} \quad (1)$$

The option in period 1 that gives the greatest ENPV in period 2, is selected. The ENPV incorporates uncertainty into our decision, by weighting the different payoffs by their probability of occurring. However, it is important to note that ENPV is a valuation technique, it does not indicate the actual payoff a utility will receive in period 2. When the utility reaches T2 and we know what demand occurs, the utility will receive the payoff for the option pursued given that demand outcome, not the ENPV.

8.2.1 A note on payoff structures

Subsequent sections outline payoff structures for each option and demand outcome (Table 2 and Table 5). The differing payoffs result from the projected revenue for each investment option, which is impacted by the additional network capacity each option provides. In this scenario, a wire investment doubles the capacity of the network, which means that the utility can deliver twice as much electricity at a point in time. The NWA option increases the capacity, although by a much smaller amount than the wire, but occurs at a much lower investment cost (see Table 6). The nil option indicates no further investment in network capacity is made. For this reason, the payoff, determined over the long-term, is the largest under the wire scenario, followed by the NWA, and then the nil investment.

While the wire investment doubles capacity, electricity demand will not double over night. In most cases, demand will gradually increase over time, with the peak capacity planned to match peak demand over the investment period (out to 5 or 10 plus years). This means any investment designed to meet peak demand in some future year is likely to have a period of underutilization before this peak is reached. Generally, the more electricity a utility can deliver, the more revenue it can receive, however this is dependent on the regulatory environment.

The payoff differs across the high, medium and low demand scenarios. This reflects the impact realized demand has on the payoff of a certain investment. Although networks typically receive a set return based off a regulator approved investment schedule, these differing payoffs reflect:

- less energy sold, or fewer customers served, which means fewer costs can be recovered (NB: there is a regulated or political limitation to how much can be recovered per customer).
- indirect penalties, whereby utilities receive a lower approved rate of return or lower regulated asset base in a future rate review, reflecting poor forecasting or inflexible investment schedule.
- direct penalties enforced by regulators, such as (in an extreme case) if negligence or price gouging has occurred (for example by purposefully over-estimating demand to justify greater network investments).

Two planning approaches will be explored in this chapter, the first is the traditional investment choice using wire investments, and the second incorporates the emerging opportunity of NWAs.

8.3 The Traditional Wires Approach

Historically, the two options available to network planners were to invest in a traditional network asset ('wire'), such as a transformer or wire, or not invest at all. For instance, if there was a reasonable chance of high demand occurring, the network would invest in a wire, whereas if demand was projected to be low, they would choose to not invest at that time. Networks have the option to wait until a later period to make an investment, however this is different to the option to defer, which will be discussed further in the following section.

The payoff for these two options are given in Table 2, and the cost of these options and the relative capacity addition are shown in Table 3.

Table 2: Payoffs for the traditional investment options in a high, medium and low demand outcome

	T2 Payoff | T1 action ($M)	
T2 Demand	Wire	Nil
High	40	26
Medium	24	21
Low	15	15

Table 3: Investment options, costs and additional capacity

	Cost ($M)	**Capacity**
Wire	18	Most
Nil	0	None

Table 2 represents the payoff the utility obtains in period 2, based off their investment decision in period 1. If utilities have perfect foresight, they will choose to invest in a wire if demand will be high to receive a payoff of 40, at a cost of 18, resulting in a net benefit of 22. However, this also incorporates any subsequent decision a utility may make. If they arrive at period 2 and the outcome has deviated from what was forecast in period 1, the utility would make a subsequent investment if it allowed them to maximize gains or minimize losses, given this new information.

For example, in the case where the utility does not make an investment in period 1 ('Nil'), but the demand in period 2 is high, they will choose to make a subsequent investment in a wire. This subsequent decision is captured within the payoff table.

In making a subsequent decision in a wire, we would expect the payoff in the high case to be the same as if we had initially invested in the wire (40). However, there is a penalty associated with having made the 'wrong' initial investment. This is associated with unserved load during the period it takes for the subsequent investment to be operational. For this reason, the payoff in T2 under a high demand outcome, given an initial 'Nil' investment, is 26, not 40.

The expected outcomes for these two options, wire and nil, are shown in Table 4. The highest ENPV for each T1 demand is bolded, to highlight the decision that will be made in that scenario.

Table 4: Expected net present value of traditional investment options under high, medium and low demand in period 1

	ET1(T2) | T1 action ($M)	
T1 Demand	Wire	Nil
High	**17.1**	10.2
Medium	**8.3**	7.9
Low	-0.4	**16.0**

For example, if a high demand is reached in period 1, the ENPV for a wire investment is given by the following calculation:

$$ENPV = 0.75 \times 40 + 0.15 \times 24 + 0.1 \times 15 - 18 = 17.1$$

At period 1, the decision with the highest ENPV is a wire in the high and medium demand scenario, and no investment in the low demand scenario. Note the negative value in the low demand case with a wire investment, indicates the cost of the investment is greater than the expected value from undertaking that investment.

In this situation, if the network experiences medium demand in period 1, planners would commit to building a wire as it has a higher ENPV than if they chose no action. If demand in period 2 is high, they will receive a payoff of 40 (ENPV 17.1), or if it is medium, they will receive a payoff of 24 (ENPV 8.3).

However, if demand in period 2 turns out to be low, the network was unnecessarily reinforced and there is excess capacity. This results in a payoff of 15, which, including the investment cost of 18, results in a -3 payoff (ENPV -0.4), causing a loss for the network and therefore higher costs for consumers. If the planner had decided to make no investment, the payoff would be the same (15), however they would have avoided an unnecessary capital investment of 18. This highlights the impact uncertainty can have on the value of a project and the investment decision made.

As uncertainty in demand projections are anticipated to increase due to changing consumer preferences, uptake of DERs and technology developments, decision making is becoming increasingly challenging for utilities. However, recent technology development has also resulted in new options for utilities to meet consumer needs.

8.4 The Emerging Option of Non-Wire Alternatives

Technological developments and regulatory changes have presented new opportunities for meeting network needs through alternate means, referred to as ‘Non-Wire Alternatives’. This means that a utility now has the decision to invest in a traditional asset, such as a transformer or additional wire (‘Wire’), to invest in a smaller NWA (‘NWA’), or to make no investment (‘Nil’). We will calculate the ENPV for each of these three investment options.

The payoff structures for the three different investment options are shown in Table 5.

Table 5: Payoffs for the three investment options in a high, medium and low demand outcome

	T2 Payoff | T1 action ($M)		
T2 Demand	Wire	NWA	Nil
High	40	26	26
Medium	24	24	21
Low	15	15	15

The investment options, associated investment costs and indicative additional capacity are presented in Table 6.

Table 6: Investment options, costs and additional capacity

	Cost ($M)	**Capacity**
Wire	18	Most
NWA	3	Some
Nil	0	None

The expected payoffs incorporating this new option are shown in Table 7.

Table 7: Expected net present value of a wire, NWA, and no investment under high, medium and low demand in period 1

	ET1(T2) | T1 action ($M)		
T1 Demand	Wire	NWA	Nil
High	**17.1**	15.6	10.3
Medium	8.3	**21.2**	7.9
Low	-0.4	13.3	**16.0**

This table shows that the addition of the NWA option increases the ENPV under the medium demand scenario from 8.3 to 21.2. In this scenario, the NWA has a larger expected NPV of 21.2, over a traditional wire at 8.3 and no investment at 7.9. In the situation where demand is medium in period 1, network planners will now choose a NWA over a wire investment, as it increases the ENPV by 12.8. This is the value of flexibility or 'optionality' that the NWA provides.

In determining these ENPVs we are incorporating the probability weighted payoff for each of the three possible decisions (wire, NWA and nil) under each of the three possible demand outcomes (high, medium and low) from period 2 onwards.

For example, if in period 1 our electricity demand is tracking against our medium demand forecast, we look forward and value the payoff of the NWA based on the probability the medium demand continues to period 2. However, there is also the possibility that demand will increase or decrease in period 2. Hence, we must also include the probability and payoff if demand increases to a high level in 2, requiring a further investment in a wire, or if demand decreases, and we have no need for the NWA.

In the case where we progress to the second period and demand has increased to a high level, the NWA is not sufficient and we have to undertake a subsequent investment in the wire. This now shifts the NPV of our investment to 26. However, we see in the top left of Table 5, that if we initially invested in the wire, in the high demand outcome we would have a payoff of 40. The payoff is lower because we have had to expend additional cost for the wire, after already paying for the NWA (although this cost is discounted in comparison to period 1 as it occurs in a later period). We have also incorporated a penalty associated with the cost of unserved energy, which occurs during the delay between the demand materializing the subsequent investment being made.

In contrast to this, if we reached period 2 and the demand was low, we would have avoided making an investment that lost 3 (payoff of 15 minus 18 for wire), instead gaining 12 (payoff of 15 minus 3 for NWA). The value of this flexibility is captured in the ENPV, where investing in the NWA has an ENPV of 13.3 in the low demand scenario, a significant increase on the -0.4 if a wire investment was made.

In this example, the additional option of investing in a NWA improves the ENPV in the medium demand scenario. We will next explore the impact of greater levels of uncertainty in our demand projections.

8.5 Increased Uncertainty

In order to explore the impact of uncertainty on the distribution utilities investment decision, the probability of demand outcomes have been amended, to increase the likelihood of a different demand occurring subsequently. This means, if high demand is reached in period 1, there is now a greater probability that either a medium or low demand will occur in period 2, compared to the previous cases. This is presented in Table 8.

Table 8: Probabilities of high, medium or low demand in T2 given demand in T1 in the uncertainty case

	Probability of T2 demand | T1 demand		
	H2	M2	L2
H1	0.60	0.30	0.10
M1	0.30	0.60	0.30
L1	0.10	0.10	0.60

The ENPV's adjusted with the new probabilities are provided in Table 9.

Table 9: Expected net present value of a wire, NWA, and no investment under high, medium and low demand in the uncertainty case

	ET1(T2) | T1 action		
T1 Demand	Wire	NWA	Nil
High	14.7	**15.3**	9.4
Medium	12.9	**23.7**	10.9
Low	-2.6	11.0	**13.7**

We can see that the greater uncertainty has shifted the preferred decision for the high demand case in T1 to be a NWA (15.3), not a Wire (14.7). This indicates that when there is a higher chance of a medium demand outcome from a high demand in T1 (relative to the initial case), we prefer to invest in a NWA.

In this scenario, the value of flexibility is 0.6 in the high demand outcome, and 11.1 in the medium demand outcome.

8.6 Summary and Further Discussion

We have provided an example of how flexibility in design can be applied to electricity networks, and have shown how real options analysis can be used to value the flexibility or 'optionality' that a NWA provides.

By performing a case study with greater uncertainty, we have shown that the flexibility provided by NWA is particularly valuable during periods of uncertainty

However, there are other forms of flexibility provided by NWA, which a utility should consider in determining the optimal investment schedule. The following sections discusses other sources of flexibility and challenges implementing a flexible design approach, which are key areas where further work is required.

8.6.1 Other sources of flexibility

There are three other sources of flexibility that a utility may wish to consider, including, flexibility:

- in function
- to expand with an additional NWA
- to repurpose or resell (not just abandon)

NWA's can provide flexibility in function, they can be utilized as additional capacity, to shift peak load to another period to defer capacity addition (load shifting), as well as other applications dependent on the resources utilized in the NWA. In the example of a battery storage system as a NWA, there are several other benefits that may be achieved. These include electricity loss minimization, mitigation of intermittency from increased variable renewables (hosting capacity improvements), ancillary services, such as voltage control which impacts power quality and black start services following outages (Karadimos *et al.*, 2017). These services will become more valuable as the amount of DERs in both the bulk power and distribution system increase.

There is a further option to expand representing the additional flexibility that comes with investing in modular NWAs. This option is not just whether to invest in a wire following a NWA, or to abandon/repurpose the NWA if demand is low. There is also the option to invest in an additional NWA, such as if demand increases but not by enough to justify a wire investment.

Additionally, the option to abandon can include the option to repurpose the NWA for use in another part of the network (such as outlined by Karadimos et al.), to resell or to salvage value.

These additional features have not been valued within this thesis. However, the salvage value would be relatively easy to determine, although the value associated with additional functionality and repurposing are highly dependent on the distribution network and require significant research to quantify accurately.

8.6.2 Challenges in implementing a flexible design approach for network investments

Above we outline a technique to value flexibility in electricity network investments through NWAs, however, it is prudent to discuss the potential impacts of utilizing nascent technologies in place of mature traditional solutions. The challenges discussed in the following subsections are not insurmountable but do require further research or policy changes.

The following subsections have been informed through discussions with utility network providers in the United States and Australia.

8.6.2.1 Program execution

A major challenge in many jurisdictions is regulation limiting utility ownership of generation assets, including NWAs. This means in some cases utilities have to outsource development and control of NWA sources. This can increase the costs and time required to identify and implement the NWA option.

Additionally, there are major challenges associated with identifying and compiling a range of DERs to form a NWA capable of replicating or replacing a traditional network investment. This challenge is compounded by utilities lack of familiarity with NWA solutions. This leads to uncertainty are the possible NWA solutions and costs, which in some cases, requires a utility to undergo a tender process. This is a costly process, due to administration overheads and time required, with no guarantee of feasible NWA solutions being tendered.

Furthermore, if the NWA solution is controlled by a third party, or utilizes customer-sited DERs, there are significant reliability concerns, which can result in strict contracting requirements or increased redundancy, and hence increased costs, as discussed in the following section.

8.6.2.2 Reliability considerations

There can be challenges in comparing the reliability performance of a NWA with a traditional measure. This can be a result of the limited runtime of batteries during extended outages, or due to the challenge of comparing reliability profiles of traditional versus NWA upgrades. To meet the reliability goals, utilities may need to consider redundancy, back-up plans, battery oversizing and operational limits. This has a significant impact on the cost and therefore the ENPV, impacting the BCA. In cases where a utility is highly risk averse, they may justify the need for several layers of redundancy for a NWA, potentially changing the most ‘optimal’ investment strategy.

Further work is required to determine how the reliability performance of NWA solutions compare with traditional investments. This may require a review of the current regulatory incentives for service quality and reliability, to determine if these stringent controls are unnecessarily hampering the novel use of emerging technologies for grid security.

9 Conclusions and Recommendations

Rapid developments underway in the electricity sector are having significant impacts on utilities and regulators, and require a change to the traditional approach to network planning. However, these changes are also providing new options for utilities to meet consumer needs, as well as a way to build an electricity network more flexible to changing circumstances.

This thesis has provided an example of how real options analysis can be applied to electricity networks, and has shown how real options analysis can be applied to value the flexibility or 'optionality' that a NWA provides to decision makers. Furthermore, we have shown that this approach is particularly valuable during periods of uncertainty.

NWAs and other emerging technologies need to be considered in the benefit-cost analysis of options in order to ensure least cost investments are occurring. Furthermore, the current approach to benefit-cost analysis needs to be changed to ensure that the 'option value' of investments that enable flexibility, are considered on an equal footing to traditional robust investments. This can be achieved by incorporating real options analysis to ensure that investments, which allow for subsequent decisions (options) are valued, according to the benefit they provide to the grid and network planners.

The current approach to network planning is resulting in over investment and suboptimal investment schedules. This thesis has shown that considering flexibility in electricity network investments, achieved through NWAs, can improve the net present value for utilities and reduce the costs of serving customers. There is potentially significant lost value if a utility does not consider NWAs. A standardized methodology to value flexibility is required to determine under what circumstances a NWA may be more beneficial, as well as an approach to value this flexibility. It is particularly important to provide clear guidance to utilities as to when, and how NWAs should be considered, in order to minimize regulatory burden.

As new services are required in the distribution system, driven by the uptake of DER, NWA will have different functionalities valued, and are likely to become more economically favorable. Furthermore, learning rates for DERs, will influence the feasibility of NWA solutions. If there is not a feasible NWA now, it does not mean there will not be a feasible NWA later. Therefore, NWAs should be part of periodic reviews for capital projects.

Finally, a standardized approach to valuing flexibility is needed, to ensure utilities are valuing flexibility appropriately. It is also important to note that different distribution networks can have very different needs, and the value of flexibility, or case for an NWA, will depend on the needs and attributes of a particular distribution network. This is further reason for a standardized methodology to determine under what circumstances NWAs should be required to be considered in a utilities solution assessment and benefit-cost analysis.

10 Appendix

A copy of the spreadsheets developed through this thesis are included on the following page. The emerging NWA option assessment is included in Figure 19 and the uncertainty case is included in Figure 20.

The discounted cost for the subsequent investment in either the wire or NWA was determined using a period of five years and a discount rate of five per cent.

Period 1	Wire Gross	Wire Cost	Wire Net	NWA Gross	NWA Cost	NWA Net	Nil Gross	Nil Cost	Nil Net	Penalty (USE)	Period 2		Payoffs Given T1 Action: Wire	NWA	Nil
H	35.1	-18.0	**17.1**	24.6	-3.0	**15.6**	24.2	0.0	**10.2**		H2|H1	**0.75**	**40**	**26**	**26**
										-6	H2|M1	**0.15**	Wire	NWA	Nil then
										-14	H2|L1	**0.10**		then	Wire
M	26.3	-18.0	**8.3**	24.2	-3.0	**21.2**	21.9	0.0	**7.9**		M2|H1	**0.15**	**24**	**24**	**21**
											M2|M1	**0.75**	Wire,	NWA	Nil then
										-14	M2|L1	**0.10**	unused		NWA
L	17.7	-18.0	**-0.4**	16.3	-3.0	**13.3**	16.0	0.0	**16.0**		L2|H1	**0.10**	**15**	**15**	**15**
											L2|M1	**0.15**	Wire,	NWA,	Nil, no
											L2|L1	**0.75**	large	not	further

Costs of T1 Actions

Wire	NWA	Nil
18	3	0

Build Wire later

Discount cost	Payoff if wire in 1	Payoff if wire in 2
-14	40	25.9

Build NWA later

Discount cost	Payoff if NWA in 1	Payoff NWA in 2
-2	24	21.6

Figure 19: Copy of spreadsheet for emerging option case

Period 1	Wire Gross	Wire Cost	Wire Net	NWA Gross	NWA Cost	NWA Net	Nil Gross	Nil Cost	Nil Net	Penalty (USE)	Period 2		Payoffs Given T1 Action: Wire	NWA	Nil
H	32.7	-18.0	**14.7**	24.3	-3.0	**15.3**	23.4	0.0	**9.4**		H2|H1	**0.60**	**40**	**26**	**26**
										-6	H2|M1	**0.30**	Wire	NWA	Nil then
										-14	H2|L1	**0.10**		then	Wire
M	30.9	-18.0	**12.9**	26.7	-3.0	**23.7**	24.9	0.0	**10.9**		M2|H1	**0.30**	**24**	**24**	**21**
											M2|M1	**0.60**	Wire,	NWA	Nil then
										-14	M2|L1	**0.10**	unused		NWA
L	15.4	-18.0	**-2.6**	14.0	-3.0	**11.0**	13.7	0.0	**13.7**		L2|H1	**0.10**	**15**	**15**	**15**
											L2|M1	**0.30**	Wire,	NWA,	Nil, no
											L2|L1	**0.60**	large	not	further

Costs of T1 Actions

Wire	NWA	Nil
18	3	0

Build Wire later

Discount cost	Payoff if wire in 1	Payoff if wire in 2
-14	40	25.9

Build NWA later

Discount cost	Payoff if NWA in 1	Payoff NWA in 2
-2	24	21.6

Figure 20: Copy of spreadsheet for the case of higher uncertainty

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