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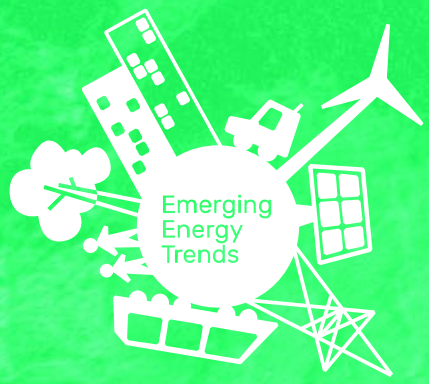
Future Drivers and Trends Affecting Energy Development in Ontario

LESSONS LEARNED FROM GERMANY, THE US AND BEYOND



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Mowat Energy's *Emerging Energy Trends* is a comprehensive study of how technological and consumer disruptions in the energy sector could affect Ontario and beyond.

This paper is part of a series of background reports informing the final report. Initial funding for this research was in part provided by the Ministry of Energy of Ontario. The final report and all other background reports are available at mowatcentre.ca/emerging-energy-trends.

The Mowat Energy research hub provides independent, evidence-based research and analysis on systemic energy policy issues facing Ontario and Canada. With its strong relationship with the energy sector, Mowat Energy has provided thought leadership to stakeholders, decision-makers and the public to help advance discussions on the challenges that energy is facing in Ontario.

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0. Introduction

Energy markets around the world are changing rapidly. With the recently signed Paris Agreement, policymakers will have to take even more fundamental action to re-build energy infrastructure in the coming decades. Governments have committed to keeping the increase in global average temperature to well below 2°C above pre-industrial levels. This translates to an almost full decarbonisation of electricity systems in developed countries by mid-century.

Renewable energy technologies and other distributed generation (DG) technologies are now established as mainstream for power generation in all parts of the world. For four years in a row, the newly installed capacity of renewable energy sources has exceeded new capacity additions from conventional power plants (IRENA 2014, Frankfurt School-UNEP Centre/BNEF 2016).

2015 was another record year for DG technologies. According to the latest REN21 Global Status Report, wind energy and solar PV accounted for 77% of all new renewable energy capacity additions. The solar PV market grew by 25% over 2014 to a record of 50 GW installed in one year. About 8% of the world's electricity generating capacity is now in combined heat and power (CHP) facilities, with a total global installed electric capacity of 325 GW. 173 countries have established targets for renewables, and 146 countries have adopted some sort of support policy (REN21 2016). 2015 was also an exceptional year in terms of renewable energy investment, with a new record for annual global investment of $285.9 billion (excluding large hydroelectric projects) (Frankfurt School-UNEP Centre/BNEF 2016).

When considering these recent develops, it is also worth noting that the future potential for DG and renewable energy growth has been consistently underestimated. In the year 2000, for example, the IEA projected that by 2020 about 2.3% of electricity demand world-wide would be met by non-hydro renewable energy technologies (resulting in 603 TWh) (IEA 2000). However, this value was reached in 2013 (IEA 2014). In 2015, non-hydro renewables provided 16.6% of electricity needs world-wide (REN21 2016). In 2010, the IEA estimated that the cumulative installed PV capacity would reach 180 GW in 2024. However, this value was reached in 2015 (Metayer, Breyer et al. 2015, Madsen, Sargent et al. 2016).

An equally impressive development can be observed in terms of costs of DG technologies. Solar PV prices have decreased sharply in recent decades.[1] Between 2009 and 2014, costs for solar PV were reduced by about 80% (Ferroukhi, Gielen et al. 2014). In many countries, solar PV has developed into a cost-competitive power-generation technology. Costs can be expected to fall further in the future, with solar PV becoming the cheapest form of electricity generation globally in the years to come (Agora 2015). Solar PV today is already the cheapest source of new electricity generation in a wide range of

[1] Since 1972, PV module prices have experienced a "learning rate" of 22%, meaning that the price has dropped by 22% each time that the market price has doubled – faster than any other technology before Channell, J., et al. (2013). Energy Darwinism: The evolution of the energy industry. . London, UK and New York, NY, Citi Group.

jurisdictions. Similarly, onshore wind power has long been the lowest cost source of new supply in many countries, such as Cape Verde, Denmark, as well as parts of Canada, and the United States (IEA-RETD 2016). Battery costs have fallen similarly rapidly between 2010 and 2014, with prices declining even more steeply in 2015. Average costs for lithium-ion batteries for electric vehicles, for example, fell by 35% in in just one year (REN21 2016).

0.1. Objective of Report and Selection of Case Studies

This report aims to provide recommendations that could help the energy sector, policymakers, and regulators in Ontario better prepare for possible energy futures. The policy solutions profiled in this report are illustrative examples of how other jurisdictions are attempting to anticipate and flexibly accommodate the scale up of new technologies, such as distributed energy resources (DERs).

The Ontario electricity system is already characterized by a large share of baseload low-carbon technologies, including hydropower and nuclear. Since 2006, the province has rapidly achieved an increasing share of DG and (variable) renewable energy generation. Carbon emissions in the electricity sector have declined by over 80% within the last decade. Achieving further carbon emissions reductions by 2035 will primarily depend on the extent that gas-fired power plants are used (IESO 2016).

It remains unclear how the electricity system will develop in both the mid- and the longer-terms (e.g., 2050 and beyond). Will the existing nuclear capacity be replaced by new nuclear power plants? What are the options for a fully decarbonized electricity system and how would gas-fired power plants be replaced? What will be the role of (variable) renewables and zero-carbon flexibility options, such as demand response and (battery) storage? What are the potential trajectories of energy transformation in Ontario, assuming higher shares of DG?

As further detailed in section 4.1, future electricity system planning will be increasingly difficult, since it will be more challenging to estimate future electricity demand. This is primarily due to sector-integration, i.e., the use of electricity for heating (and cooling) purposes and transport (e.g., electric vehicles). Moreover, centralized supply will likely compete with DG (DG). DG markets may evolve without any specific policy support or planning in a manner that is difficult to anticipate or control. A new wave of renewable energy deployment could also emerge, which is no longer (primarily) policy-driven but largely technology-driven.

Trends in new technologies and energy market regulation can already be observed today in jurisdictions with high shares of DG that have passed the first signposts on the way to fully decarbonized electricity systems. Valuable policy and strategy lessons can be drawn from markets with high shares of variable renewables and DG, such as Germany, Spain, Denmark, and California. This report primarily focuses on innovative policies and regulation in Germany and the US. However, where applicable, experiences and innovations from other jurisdictions (e.g., Denmark, France, Mexico, etc.) are included.

0.2. Content of Report

This report consists of five chapters. In line with the Request for Proposals, the research paper is organized along four broad portfolios.

Chapter 1 discusses behavioural considerations related to the emergence of "the New Energy Customer." A key variable in the expansion of DG will be the rate at which energy customers adopt new technologies and the manner in which they deploy them. The rise of energy users as producers of energy and active participants in the energy system will depend both on the adoption behaviours of residential and commercial customers, as well as the price signals that these customers are sent. Section 1.1 reviews energy technology adoption by residential customers with a focus on aggregated technology purchasing initiatives. Section 1.2 reviews emerging trends in corporate decision making related to renewable energy purchases. Section 1.3 reviews the development of time varying rates, and Section 1.4 provides an overview of how the value of renewable energy is being integrated into policy development. Each of the Sections in this Chapter features case studies from the US.

Chapter 2 deals with policies and technologies that allow for Meeting Energy Demand Behind the Meter. In Section 2.1, the core features of self-consumption policies around the world are discussed, including remuneration mechanisms for excess electricity and net metering design options. An increasing share of self-consumption usually requires a new arrangement regarding how to share infrastructure investment costs among different consumer groups. The options, including higher fixed charges, are further elaborated in Section 2.2. Section 2.3 and 2.4 discuss options for how to integrate distributed, behind-the-meter generation in the system. Both using distributed battery storage to increase system stability and policy options for blind system regulation are presented.

Chapter 3 covers two important aspects of future electricity markets, namely Grid Modernization and issued related to the Utility of the Future. It is too early to say exactly what the utility of the future will look like, but even now it seems certain that the utility of the future will require financial incentives that are far better aligned with public policy objectives such as integration of DERs and peak reduction. The first several Sections of the Chapter focus on the ways in which regulation is already beginning to shape the modernized grid and next-generation utility. Section 3.1 discusses lost revenue mechanisms meant to remove the disincentive for utilities to support energy efficiency. Sections 3.2, 3.3, and 3.4 discuss regulatory mechanisms that go even further, by providing incentives for utilities to align their behaviours with policy objectives, rather than simply removing disincentives. Section 3.5 discusses the ways in which regulation creates new roles for distribution system operators and the potential for cellular grids. The remaining sections turn to technological innovations that will inevitably affect the future grid and the next-generation utility. Section 3.6 discusses "customer-facing" and "grid-facing" technologies, both of which will shape emerging electricity systems. Sections 3.7 and 3.8 discuss microgrids and virtual renewable energy plants, and storage for flexibility and grid services, respectively.

In **Chapter 4**, the Future of Centralized Supply is discussed in more detail. The planning, design and operation of centralized supply will need to change in the future, assuming that the share of DG will increase and that electricity systems will need to become more flexible because of increasing shares of variable renewable energy sources such as wind energy and solar PV. The chapter starts by discussing system planning in light of core characteristics of future power systems (Section 4.1). In Section 4.2, strategies to avoid or eventually deal with stranded assets in power generation and transmission infrastructure are discussed. In addition, fossil fuel phase-out policies are examined. Section 4.3 elaborates on recent innovations in electricity market design to integrate higher shares of variable renewables. Another important component for cost-effective system integration of DG is the reduction of the must-run capacity of centralized, conventional power plants. This is discussed in Section 4.4. Last but not least, new electricity market products to incentivize and remunerate centralized supply flexibility are reviewed (see Section 4.5).

Chapter 5 includes a discussion of the proposed technological, economic, and social drivers of change in current and future energy systems. Short- and long-term policy solutions for Ontario will be discussed, assuming different levels of DG and variable renewable energy sources in the system.

1. THE NEW ENERGY CUSTOMER

The energy industry is undergoing a period of swift and dramatic change. Energy consumers, who have historically been the passive recipients of commodity energy, are emerging as active participants in the energy industry. An increasing number of energy consumers are producing their own energy onsite and becoming highly distributed "prosumers" of electricity. In countries such as Australia and Germany, there are now more than one million solar photovoltaic (PV) prosumers who own their own solar energy systems. The emergence of prosumers is occurring in parallel with technological advances that put new information and control capabilities (e.g., storage) in the hands of a new class of "smart" consumers. These trends could disrupt the current structure of the energy industry if they continue.

At the same time, these new distributed energy prosumers could contribute to grid stability and to national energy and environmental objectives if they are given the right signals and incentives. Policy makers around the world are grappling with the challenges and opportunities posed by prosumers, with some trying to embrace and enable prosumers and some trying to constrain prosumer development (IEA-RETD 2014, IEA-RETD 2015). This report examines many of the policy choices that decision makers are facing in this dynamic environment. Whereas many of the sections in this report focus on policy, regulatory, or technological issues, this section highlights several topics related to energy consumers themselves. The first half of this chapter focuses on energy consumer decision making at the residential and commercial levels. The second half of this chapter focuses on examples of price signals (i.e., time of use rates and value-based rates) that policy makers can utilize in order to influence consumer choices and behavior.

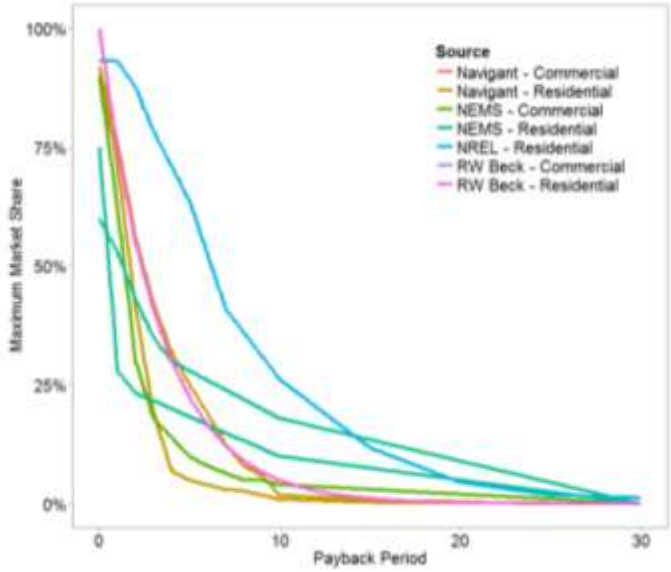
1.1. Fostering Behavioral Change

This section focuses generally on consumer adoption of new technologies in the emerging energy economy, but draws a distinction between residential and commercial behavior. There are a broad range of factors that can influence both residential and commercial adoption, including economic drivers (e.g., system costs, electricity prices and rate structures, energy resource availability, onsite demand profile, policy, etc.), technology drivers (e.g., grid constraints and new technology availability), real estate market conditions (e.g., availability of space and ownership models), and the posture of relevant stakeholders (e.g., incumbent utilities) (IEA-RETD 2016).

Behavioural factors may be a "wild card" for policy makers since they can shape energy adoption patterns that may be difficult to predict economically. Studies of technology adoption S-curves and the life-cycles of products show that new technologies generally have low rates of adoption for a long period of time, followed by more rapid adoption as market acceptance is achieved. By examining over 100 products – from cell phones to light bulbs to improved windows – researchers Fisher and Pry (Fisher and Pry 1971) found that customer payback is a valid measure of economic customer acceptance. Payback curves that apply to solar PV are shown in Figure 1.1 below. As can be seen in the Figure there is general agreement that lower paybacks will create the conditions for higher maximum market shares – although the shapes of the curves developed by organizations differs, with the US National Renewable

Energy Laboratory calculating more significant PV uptake under longer payback scenarios than Navigant Consulting.

Figure 1.1. Maximum market share as a function of payback period based on different sources



Source: (Sigrin, Gleason et al. 2016)

As shown, eventual market penetration for residential customers can be ~5%-20% for products with a long payback period such as solar PV, while commercial and industrial customers will not generally purchase products until paybacks reduce to less than 5-7 years. Note, as well, that these first-year payback calculations take into account all incentives and subsidies, such as the US Federal investment tax credit. For leased systems with no up-front costs (and hence no payback), market penetration can be higher than this figure shows.

1.1.1. Residential Adoption

There are a number of examples of markets in which emerging energy technologies have reached a "tipping point" on an unsubsidized basis and are being broadly adopted. These include buildings (insulation, insulated windows, LEDs, CFLs), automotive (regenerative braking, direct injection, low resistance tires, turbocharging, aerodynamic improvements), and residential heating and cooling (condensing furnaces, scroll compressors, larger A/C heat exchangers, heat pumps, etc.).

Since electricity has been centrally generated and then distributed to homes, there has historically been strong inertia within the industry. There are only a few examples of markets in which emerging electricity generation technologies have reached a "tipping point" on an unsubsidized basis and are being broadly adopted at the residential level. In Hawaii, where solar PV generation is a cost-competitive energy source with a 4-5 year payback time, residential adoption has reached 17%-20% (Trabish 2016), but is now limited by the need for electricity storage and grid stability technical issues

(Eber and Corbus 2013). In Australia, 16% of homes now use solar PV power nationally (with higher penetrations up to 30% in states such as Queensland) (Pearlman 2016), with 4-7 year payback times.

In some markets, distributed energy resources are on or near the frontier of cost competitiveness. Distributed resources have not crossed the threshold into mainstream adoption and there may be a range of barriers (e.g., soft costs or awareness gaps) that are constraining diffusion. At the residential level, there has also been a growing appreciation of the power of behavior to accelerate adoption in the face of non-financial barriers. Recent mapping by SolarCity of word-of-mouth PV sales in specific markets, for example, has demonstrated the power of social connections in energy technology adoption.[2] In recognition of these dynamics, there are a growing number of publicly sponsored programs and initiatives under which behavioral factors, such as peer-to-peer marketing, are being leveraged to scale-up residential adoption.

Electric vehicles and solar PV have both achieved less than 2% market penetration of the respective vehicle and electricity generation markets worldwide, and both are supported by incentives to reduce the gap between fossil fuel-based and renewable options. Because of this relatively low market penetration and market acceptance, both technologies are not well known by consumers, so educating consumers about their options makes sales of these products more complex and time consuming. In addition, incentives can vary by manufacturer, utility, and geography (country, state, and local), further complicating purchase decisions. To achieve higher scale and improve customer adoption, customers must believe that EVs and solar are economically viable compared to competing fossil fuel options.

For EVs, competing worldwide gasoline prices vary widely between .2 to 2 $/liter depending on subsidies and taxes, averaging 1 $/liter worldwide, with some advanced economies like the US paying less than .65 $/liter. Over the last two decades, oil prices increased to over 100 $/barrel, dropped to under 30 $/barrel, and are rising slightly (43 $/barrel as of May 2016). Based on their cost and reasonable rates of return, fracking of tight oil supplies may form a rough ceiling of ~ 40-70 $/barrel while these newly developed supplies last, keeping gasoline prices relatively low. But it is anyone's guess how long these supplies will last. To compete, battery costs for electric vehicles will need to be reduced. Tesla's "Giga-watt" lithium ion battery plant in Nevada just went on-line in the spring of 2016, and may bring battery costs down by 30-50% if high sales levels can be achieved; so far, sales have been robust.

For solar PV, many residential customers are unaware that solar and wind energy costs have declined by over 50% in the last five years, while coal-based electricity costs have increased the same amount in the last decade due to reduced mine productivity and quality. While there is plenty of coal left in the ground, the higher heat content coal is getting more expensive to extract. At the same time, natural gas supplies have increased tremendously due to fracking, reducing natural gas prices and the cost of natural gas based electricity to 20-year lows in some areas of the world. The cost of nuclear has gone up in the wake of Fukushima due to cleanup costs, new safety standards, and in some countries reactor

[2] See, for example, the dynamic maps of adoption in this blog post: http://blog.solarcity.com/most-contagious-solar-cities.

shutdowns. This has led to many utilities switching from coal and nuclear to natural gas, wind, and solar.

Note, as well, that fossil fuels currently enjoy higher subsidies than solar and electric vehicles, and the cost of CO_2 pollution is free in many parts of the world. With the advent of the Paris climate change agreement, this is changing, but will continue to be uneven[3]. The above evaluation of economic competitiveness does not include these "externalities."

Because of low market penetrations (Shepard and Jerram 2016), US residential consumers are relatively uneducated about their solar, wind, and electric vehicle options, especially how much these have improved recently. One policy option to improve this situation is to mount education campaigns for consumers, and to use aggregated purchasing programs to reduce initial high costs. In the US solar market, one successful aggregate purchasing plus educational campaign model is called "Solarize." Such bulk purchasing programs have seen an increase in usage, an increase in impact, and a diversification of the technologies purchased.

b. Bulk Purchasing Programs Successfully Address Customer Educational Barriers

In a Solarize campaign, a local non-profit with community connections mounts an education campaign within the community, with an agreed upon "offer." First, a request for proposal is done to solicit vendors that are willing to offer a volume discount on solar installations, and a single competitively selected vendor is chosen for each geographic territory. A limited time pre-negotiated offer to install solar at a discount is then presented to the community in conjunction with an education campaign. A well run Solarize campaigns can significantly boost solar installation sales, as costs are lowered through volume discounts and group purchasing. It is not uncommon for over 100 homes to sign up for solar installations over a 6-month period.

Recently Boulder Colorado instituted an electric vehicle group purchasing program that used the "Solarize" campaign model to promote both electric vehicles and solar at the same time(Salisbury and Toor 2016). Electric vehicle sales rose in a brief period to over 248 vehicles, over 5% of US national sales in a county with less than 0.1% of the US population. This electric vehicle sales rate is over 4 times the national average. Concurrently, solar installers installed 832 kW onto over 150 homes.

This case study was chosen to illustrate a successful method of addressing consumer education market barriers that are present in emerging low-volume markets. It is unique because it was the first time that these complementary technologies were successful promoted together. One challenge for electric vehicles is that if the source of the electricity used to charge the vehicle comes from high CO_2 emitting sources such as coal, promotion of electric vehicle use can actually increase CO_2 emissions. Similarly, a challenge for solar PV is that it cannot supply electricity when the sun is down. But together these two

[3] For instance, there are gasoline taxes in the US, but not coal taxes; and different countries apply different tax, regulatory, and/or trading schemes to carbon (i.e., the EU has a trading scheme and British Columbia has a carbon tax, while other countries do not penalize fossil fuel usage.)

technologies can complement each other --- solar sharply reduces CO_2 emissions, and parked electric vehicles can provide energy storage for solar PV.

c. Case study -- Boulder Combined Electric Vehicle and PV Group Purchasing Program

There are many market barriers for electric vehicles in addition to economics. These include range anxiety, long charging times, charging station availability, and battery lifetime concerns. These market barriers serve to reduce the "total available market," as a number of consumers that are otherwise interested in electric vehicles may not have short daily commutes that make them well suited for electric vehicles. As a result, customer acquisition costs are relatively high.

Similarly, due to shading and ownership issues, not all consumers interested in solar have residential rooftops suitable for PV. If their roof is facing North or is shaded too much, or a potential customer does not own his apartment, solar may not make sense. Again, these technical and ownership issues reduce the "total available market" for residential PV, and increase customer acquisition costs.

For the most part, non-economic market barriers have largely been addressed in the US for both electric vehicle and solar markets. Range anxiety can be addressed in two-car households by having one electric car for daily commutes and another car for longer trips (Pearre 2011, Lin 2012); long charging times can be addressed by charging overnight or using "fast charging" stations; in Boulder, CO, there are 15-20 charging stations available for public use and Denver, CO has over 100 charging stations scattered throughout the city; and battery lifetime issues can be addressed with end-of-lifetime warranties. Similarly, for PV, Boulder and Denver have 75% more sunlight available than the largest PV market in Germany; while there is more red tape in Boulder and Denver than in Germany, permitting and interconnection are becoming more streamlined.

High customer acquisition costs – due either to customer's non-suitability or lack of education – have been addressed by the "Solarize" campaign model. In Boulder, this took the form of a non-profit organization ("Vote Solar") organizing an educational campaign to improve awareness of electric vehicle options, and solar PV options, at the same time. This makes consumers both more aware, allowing them to consider EVs and solar, and allows them to "self-select" appropriately. Someone with a very long commute or a shaded rooftop should not try to get an EV or solar rooftop, respectively.

Interestingly, a key success factor for the electric vehicle part of the campaign was the presence of sales staff devoted exclusively to electric vehicles at the dealerships, <u>and</u> education of the other sales staff at the dealerships. Because EVs have a low market penetration, most US automobile dealership staff are not well educated in electric vehicle options, and EVs are perceived to be a "hassle." EVs take more time to sell, hurting overall sales and commissions, and EVs may require less maintenance---which undermines service department revenue, a key driver of automobile dealer profits. As a result, US automobile dealer enthusiasm overall for electric vehicles has been muted. The combined "Solarize" model works well to reduce this barrier, because it reduces the sales time dealers need to educate consumers (they walk in "ready to buy"). EV sales in Denver, however, were low because the featured EV dealer was located in Boulder, a 35-60 minute drive away.

The program was sponsored by Boulder County, Adams County, and the City and County of Denver and it combined active outreach by local governments, employers, and other partners, with coverage by local media outlets. Nearby towns of Lafayette, Louisville, and Nederland participated, as well as the Boulder Valley School District, the University of Colorado-Boulder, the National Center for Atmospheric Research, and the University Corporation for Atmospheric Research. RFPs went out to vendors, with Sunrun (within Xcel's service territory), Custom Solar (elsewhere), and Nissan Boulder winning the competitive RFP. Vote Solar, a local non-profit, administered the program.

Both Nissan America and the local dealer offered discount incentives; combined with federal and state tax credits, the purchase prices for a new Nissan LEAF was $12,000-$17,000, a significant discount from the MSRP of $32,000-$36,000. Solar installation prices were $3.50 per watt + $250 (Custom Solar) or $750 (Sunrun). Outreach included emails, flyers, media articles, employer networks, and workshops. News stories and word of mouth proved to be most effective.

As another example of aggregated purchasing, an "only electric vehicle" group purchase program was enacted in the Fort Collins, CO area in 2015 that offered participants the opportunity to purchase a LEAF electric vehicle for $11,600 after state and federal tax credits for 39 days. This program was more employer based, and the local dealership ran out of LEAF vehicles. 52 LEAFs were sold.

1.1.2. Commercial Adoption

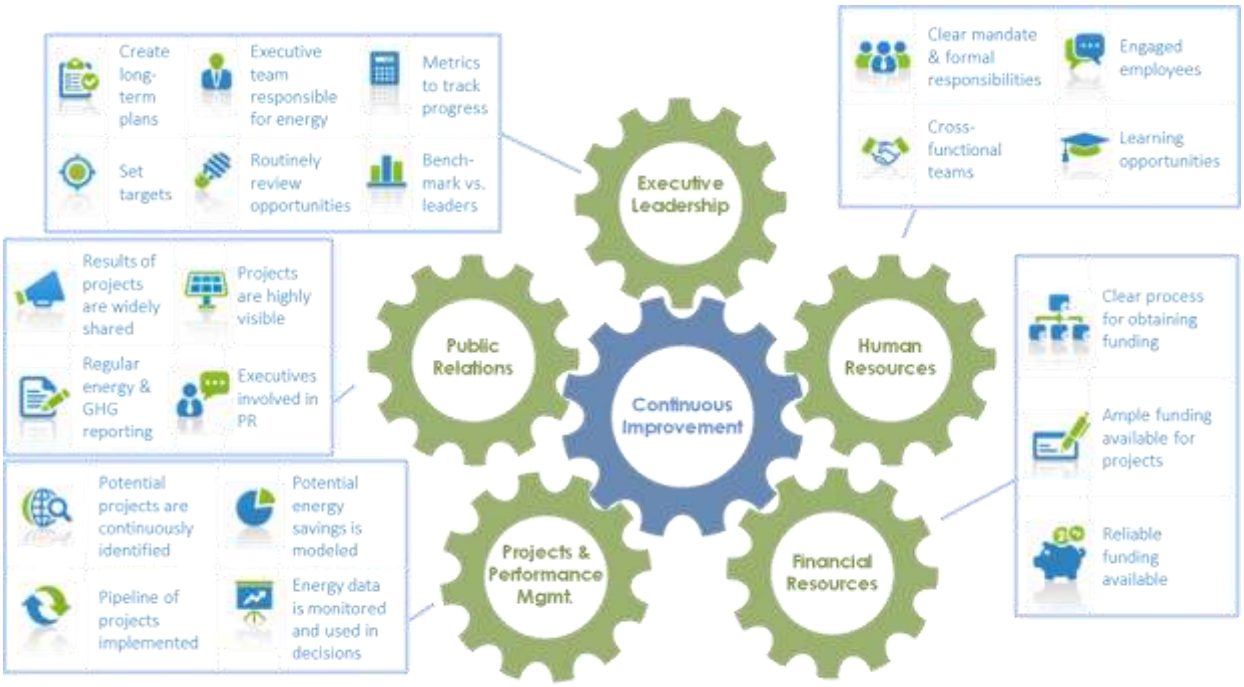
Commercial decision making related to technology adoption is highly complex, and commercial internal rate of return expectations are higher than residential. Factors such as the physical building type, ownership structure, ownership strategy, and lease type can have a significant influence on adoption. It is also difficult to draw broad conclusions about adoption within classes or types of commercial buildings, because internal decision making structures have an outsized influence on adoption.

A key challenge in addressing the barriers to energy project implementation is that they span across many departments and functions within an organization, from executive leadership, to facility managers, to finance and accounting, communications, and others. Achieving the coordination needed to address disparate and diffuse barriers rarely occurs without a deliberate and structured approach. This highlights the importance of a comprehensive approach to strategic energy management that considers the multitude of barriers and applies targeted solutions to address these specific challenges.

The drivers influencing energy management decision-making can be grouped into five organizational functions, following the "Virtuous Cycle of Strategic Energy Management" (the "Virtuous Cycle") framework, developed through collaboration between MIT Sloan School of Management and the Environmental Defense Fund (Hiller, Reyna et al. 2012). The Virtuous Cycle framework draws from over two decades of field research and system modeling by MIT Sloan partners, learnings from hundreds of Climate Corps engagements with companies and institutions, and input from peer learning network events led jointly by EDF and MIT Sloan. This ongoing research and collaboration has given EDF critical insights into the methods available to organizations that are interested in pursuing effective strategic energy management.

The Virtuous Cycle provides a framework for understanding how an entity's executive, financial, human resources, performance management, and public relations functions must be aligned to overcome systemic barriers and create a cycle of continuous improvement. Barriers in one function can prevent action even if the rest of the corporate functions are aligned. However, if each department is equipped with the right information, resources and authority, then targets set by executive leadership will be followed by successful implementation and positive public relations, thereby reinforcing the executive targets in a cyclical manner. The graphic below uses gears to represent each of the broad corporate functions that must be aligned. Each "gear" is linked with illustrative examples of corporate practice that can help the gears turn.

Figure 1.2. The Virtuous Cycle for Strategic Energy Management



Source: (IEA-RETD 2016)

The Virtuous Cycle can be used to analyze not only why corporations and other organizations adopt onsite distributed energy resources, but also to examine their motivations for power procurement more broadly. This section focuses specifically on voluntary green power procurement, which has seen a dramatic spike in recent years.

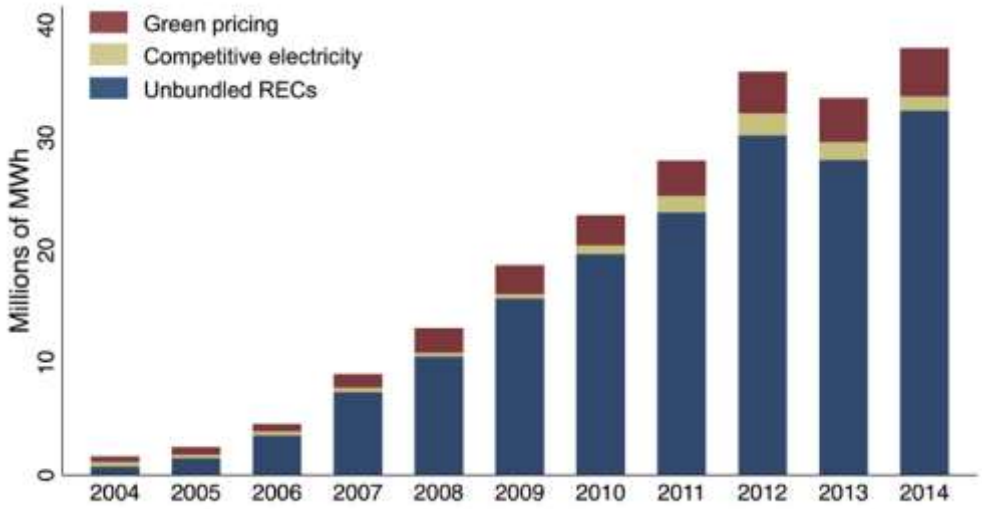
The global growth of renewable energy markets has been aided by increased demand for renewable energy on the part of consumers who purchase green power voluntarily. The popularity of such green power programs has increased globally, led on a percentage basis by Germany, where participation has grown from 0.8 million residential customers in 2006 to 5.7 million in 2013, accounting for 14.3% of the nation's residential customers (REN21 2015). In the United States, where green power purchasing programs have been in place since the 1990s (Eric O'Shaughnessy, Jenny Heeter et al. 2015), voluntary

green power sales were available to over 50% of electricity customer nationwide through electricity suppliers in 2013 and accounted for approximately 1.7% of electricity sales (REN21 2015).

As demand for green power has grown in recent years, however, so has the sophistication of the green power purchasing options offered by utilities or crafted by innovative power purchasers. Much of the recent momentum in the green power purchasing space has come from large multi-national corporations—including firms such as IKEA, Unilever, Proctor & Gamble, and General Motors—which have adopted ambitious renewable energy targets for their global operations and have increased the green power purchasing activity as a result and particularly in the US.

The market for voluntary green power sales in the United States is large and growing larger. On an energy sales basis, the market for green power sales is three times larger in the United States than in Germany (REN21 2015). On a year-over-year basis, the market for various forms of voluntary green energy programs has grown sharply in the US over the past decade, with unbundled renewable energy credit purchases accounting for the majority of the market (see Figure 1.3).

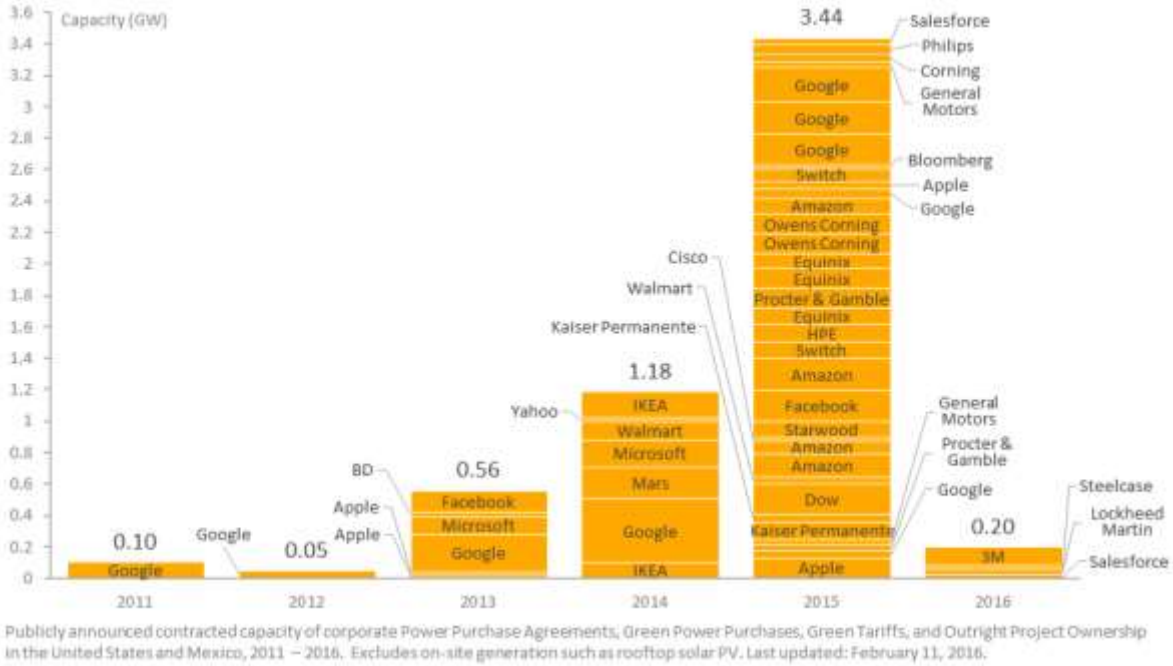
Figure 1.3. Total retail sales of Green-e Energy certified renewable energy, 2004-2014



Source: Adapted from data provided by the National Renewable Energy Laboratory, 2015

Over the last several years, however, the market for green power purchasing in the United States has been changed by the growth of large-scale renewable energy purchases by corporate entities, which have secured deals for renewable energy that go beyond REC-based purchasing options (Labrador 2016). In 2015, voluntary green power purchases on the part of large companies such as Facebook, Google, IKEA, and Walmart accounted for over 3 GW of new capacity in the US – or approximately 18% of total new renewable energy capacity.

Figure 1.4. Corporate renewable deals, 2011-2016



Source: (Rocky Mountain Institute 2016)

A number of leading corporate renewable energy purchasers have also advocated for policy changes that ensure access to renewable energy purchasing pathways. A coalition of major electricity consumers recently formulated a set of "Corporate Renewable Energy Buyers' Principles," which demand greater choice and flexibility, cost competitiveness, and long-term certainty in their renewable energy purchasing options (Tawney, Bryn Baker et al. 2014). This increased organization around procurement is beginning to be mirrored by organization around policy as well: a group of leading technology firms—Apple, Amazon, Google, and Microsoft—filed an amicus brief in support of the US Environmental Protection Agency' Clean Power Plan, arguing for the pro-business benefits of renewable energy purchasing.

This section discussed case studies for voluntary green power purchasing policies. The federated nature of electric power sector regulation in the United States has led to a diversity of regulatory and policy landscapes across the country. Depending on the specific policies in place in a given state, certain green power procurement pathways may be open or closed to corporate purchasers. In some states, specific policies have been put into place to enable corporate renewable energy purchasing. In states where purchasing options are limited, corporations have developed innovative means of securing renewable energy deals. Generally, the green power procurement options utilized by corporations can be categorized according to the table 1.1 below. Net metering and virtual net metering policies (see Section 2.1) are also important enabling frameworks for corporate energy procurement.

Table 1.1 Type of Green Power Purchases in the US

Type of Green Power Purchase	Procurement Mechanism	Description	Enabling Policies Needed
REC-Based Purchases	Unbundled REC purchases	Customer purchases and retires RECs	None
	Utility green powered programs	Customer participates in premium green-power program	Development of utility program
Contracts with Independent Power Producers	Competitive supplier purchases	Customer in deregulated market contracts for supply from non-utility competitive supplier offering renewable energy	Deregulated utility sector
	Direct Access Tariffs	Customer in regulated market participates in special program allowing limited number of competitive supply contracts	Development of Direct Access Tariff
	Green Tariffs	Customer in regulated market purchases output from dedicated renewable energy projects through special utility tariff, with utility serving either as renewable energy project owner or contractual intermediary	Development of Green Tariff
	Synthetic Power Purchase Agreements	Customer signs contract-for-differences or similar agreement with renewable energy producer and receives RECs without purchasing power	None

Source: Author

Many of the procurement pathways available to corporate renewable energy purchasers are restricted or made available by state policy actions. Purchasers that wish to move beyond RECs-based purchasing are dependent upon state policy decisions to guide their options in renewable energy development. Some of the key policy actions that have variously enabled or restricted green power purchasing options are discussed below. For each policy action, states that have already implemented policies that

encourage green power purchasing are highlighted, as are states with significant opportunities for high-impact policy action based on an index of market, regulatory, technical, and policy criteria.[4]

Green Tariffs and Direct Access Tariffs

Green Tariffs and Direct Access Tariffs are both means of allowing customers in traditionally regulated electricity markets to pursue contracts with non-utility renewable energy producers. Green Tariffs allow utilities to facilitate the green power purchases of large corporate customers, while Direct Access Tariffs allow certain classes of utility customers to contract with competitive electric suppliers, which may include renewable energy producers.

Figure 1.5. US states with green tariffs or direct access tariff policies in place

Source: (Meister Consultants Group and Advanced Energy Economy 2015)

Synthetic Power Purchase Agreements

In the absence of such policies, a number of leading corporations have constructed innovative means of still supporting and benefitting from renewable energy projects despite being located in regulatory environments that restrict green purchasing options. One innovative approach is the "synthetic PPA," in which a renewable purchaser agrees to a financial agreement (often structured as a contract-for-differences) with a renewable energy producer to assist with the financing of a green power project by providing a hedge on the price that the supply will receive for power from the wholesale market. In these contracts, the purchaser does not receive the energy output of the project directly, but does receive the environmental attributes. Such financial innovations support the development of new renewable energy resources while providing a novel pathway for corporate renewable energy

[4] Recent research by Advanced Energy Economy identified states with the greatest potential for policy actions that expand opportunities for corporate renewable energy procurement. States with significant policy opportunities were identified according to a ranked index that assessed and weighted the amount of in-state corporate energy consumption, the technical potential for in-state renewable energy generation, and the opportunity for discrete policy actions that would expand corporate green power purchasing pathways

purchasing, but add significant complexity to the green power purchasing process and are typically resorted to only when more accessible purchasing options are restricted by state policy environments.

1.2. Consumer Price Signals

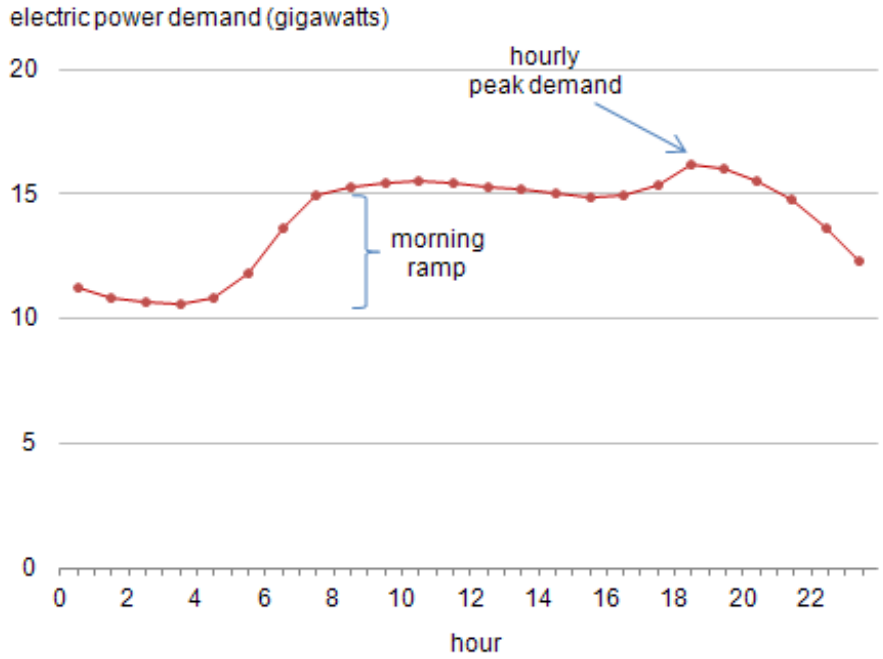
Behavior can also dictate how and when different systems of price signals are used. In some cases, policy makers may assume a large degree of sophistication on the part of energy technology users that would enable them to understand and take advantage of a large range of energy technology interactions, as well as monetize multiple potential revenue streams or react to different price signals (from, e.g., energy, capacity, and ancillary services markets). In reality, corporations may be constrained from using overly complex systems because energy management is not their core function and residences may be constrained by a lack of sophistication, time, or interest. This section focuses on specific price signals in the US.

Time Varying Rates

Electricity is more expensive during peak demand periods because the utility must turn on sources of power that are used for only a small proportion of the year. As a result, the capital equipment cost of these electricity sources, spread out over less operational time, is much more expensive than for "baseload" power.

Peaks occur daily, and vary by electricity customer class. Service businesses generally have high demand from 9am to 5pm, unless they are a 24-hour business. Residential customers have a small peak at the beginning of the day, and then a much larger one from 5:00-8:00 pm as workers get home to cook and eat dinner. Utilities' total load curve is the sum of all these individual demand curves, as shown in an example below for all of New England:

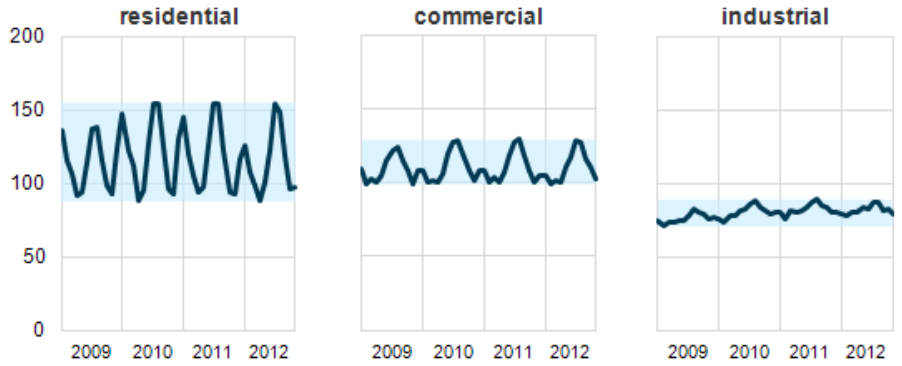
Figure 1.6. New England electric load curve, 10/22/2010



Source: (EIA 2011)

Peaks can also be seasonal. During winter, when many people are indoors and electricity is used for heating (e.g., furnace fans, water pumps, heat pumps), electricity demand tends to peak; similarly, electricity demand peaks during the summer, when air conditioning loads are high. Shoulder seasons, i.e., spring and fall, tend to be periods of lower demand, as heating and cooling loads are reduced. In the US, summer peaks are highest; Europe, with a more temperate climate overall and a higher proportion of electric heat, sees peaks in the winter (EIA 2012). The Figure below shows the seasonal variation in electricity sales by sector from 2009-2012.

Figure 1.7. US retail electricity sales by sector [billion kilowatt hours]



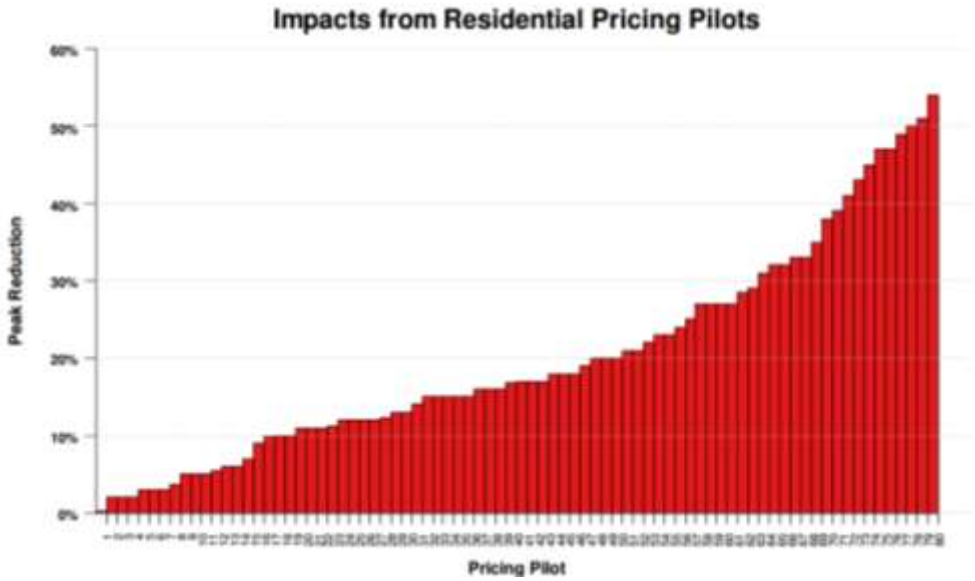
Source: EIA Monthly Energy Review

From a policy perspective, one market-driven solution to the costs of meeting high peak demand is to have customer electricity prices increase during high demand periods. This type of pricing is often referred to as "time of use" rates, and is used throughout the US, primarily for commercial and industrial customers (~20% of total US electricity customers (Hu, Kim et al. 2015).

The downside to charging customers based on their time of use is the higher complexity of the billing system. On the plus side, customers can respond to these price signals by reducing or shifting their peak load. For instance, a dishwasher or washing machine can be set to run at midnight; or a manufacturing business can choose to run its processes 24x7 rather than 9:00 am-5:00 pm. Time varying rates can also support energy storage economics, as electricity stored during non-peak times can be dispatched at peak times when it has more value.

Other dynamic pricing schemes that can influence consumer behavior include critical peak pricing (CPP), peak time rebates (PTR), and real time pricing (RTP) (Faruqui 2016). CPP uses real-time or unusually high prices at times of extreme system peak, and is restricted to a small number of hours per year with unknown timing (Walton 2015). PTR schemes pay customers for reducing demand during peak periods. Real time pricing links hourly prices to hourly changes in the day-of or day-ahead cost of power, and require smart meters, which increases cost and complexity. Overall, dynamic pricing schemes have been shown to successfully reduce electricity peaks, but with a range of outcomes. As can be seen in the Figure below, residential dynamic pricing pilots reduced peak by under 10% to over 50%.

Figure 1.8. Impacts from Residential Pricing Pilots



Source: (Sergici and Faruqui 2011)

Given this wide variance in success, there are many details to successful dynamic price rate-setting that are important to get right (Sergici and Faruqui 2011). Even as policymakers are seeking to improve basic dynamic pricing programs, they are also looking ahead to determine how such programs can accommodate technological innovation. Since dynamic pricing schemes can improve energy storage economics, for example, jurisdictions that are looking to support electric vehicles are also exploring the potential of dynamic price rate setting. The map below shows which US states are focusing on time of use (TOU) electricity pricing for plug-in electric vehicles:

Figure 1.9. PEV Electricity Pricing by Time-Of-Use (TOU)

Source: (C2ES 2016)

The section below focuses specifically on the state of Massachusetts, which recently considered and balanced many of the issues discussed above during the development of new time reflective rates.

Massachusetts Order on Time Varying Rates

On November 5, 2014, the Massachusetts Department of Public Utilities ("DPU" or "Department") promulgated an order on time varying rates (TVR). It is one of a trio of orders, the others being on grid modernization and on electric vehicle charging equipment.

The DPU's order requires electric utilities to offer basic service customers (1) a default time of use ("TOU") rate with a critical peak pricing ("CPP") component; and (2) an option to opt out of the default rate and choose a flat rate with a peak time rebate ("PTR") component. The DPU notes that TVR will provide a range of benefits, including providing appropriate incentives for electric vehicles, and incentivizing customers to reduce peak energy use in response to price signals as well as to reduce their own bills and the cost of the entire electricity system. In response to comments, the Department also observes that there is sufficient experience both in local pilots and in light of deployment elsewhere to conclude that customers will respond to TVR, resulting in customer savings (DPU 2014).

The Department considered that dynamic pricing schemes have been shown to be highly effective for critical peak load reduction, where a tiny fraction of peak loads are sharply reduced; and effective at the 5-10% level for peak load reduction overall. This is the same as can be easily achieved through conservation, and reflects the relative inelasticity of consumer demand. Automated demand response, on the other hand, has been shown to achieve higher 20%+ demand reductions, especially when used for applicable commercial and industrial customers (Vermont Transco LLC).

The DPU's order includes a discussion of its own concern and that of commenters regarding the effect of TVR on low-income customers. The Department argues that one of the reasons for adopting TVR is that the current flat rate service is relatively burdensome to customers who can least afford it. The DPU's expectation is that a large number of low-income customers will benefit from TVR. Additionally, customers who do not want to be on the TVR default rate can opt out and switch to a flat rate with a PTR component (DPU 2014).

The DPU further observes that one of the reasons for a basic service TVR program with only two offerings is to give space to competitive suppliers to develop their own innovative rate offerings. The Department reiterates the discussion in its grid modernization order regarding the importance of the electric utilities' developing procedures that will allow competitive suppliers access to customer usage data without compromising customer confidentiality. The Department indicates that it will open a separate proceeding on data access and privacy, as well as on specific implementation issues, and emphasizes the need for customer education (DPU 2014).

The DPU's order does not go into additional detail on rate design, leaving that for subsequent orders to address. However, its perspective was that low peak to off-peak price differentials is important to inducing consumers to respond to price signals. This view is confirmed by subsequent analyses (Power Advisory LLC 2014, Faruqui 2016).

Note that there is a long way to go between the D.P.U. order and implementation of TVR in Massachusetts. For one thing, Massachusetts utilities have not yet installed advanced metering infrastructure, and there is some resistance on the part of the utilities to doing so. For another, the order was issued by a prior state Administration, and it is not clear whether the current Administration will pursue implementation.

1.3. Societal Versus Market Value of Electricity

The time value of energy is only one of the values that can be taken into account when developing policy related to energy transition. Policymakers and electricity infrastructure planners must frequently weigh a broad range of costs and benefits of distributed energy resources (DER) and renewable energy when making decisions. DER costs can include, for example, the upfront investments to build the systems and the cost to upgrade and manage the electricity grid to integrate the systems. DER can also create a broad range of benefits and value when compared to centralized and fossil-fuel systems, and these benefits have been detailed in many studies (Lovins, Datta et al. 2002). These benefits include avoided environmental damages, avoided energy and capacity purchases, reduced transmission losses, and deferred transmission and distribution investments, etc. Consideration of the costs and benefits of DER is standard practice in a broad range of formal policy and regulatory proceedings internationally, including traditional environmental regulation, utility energy efficiency program design and evaluation, integrated resource planning, and renewable energy program reviews, to name a few.

Although cost and benefit assessments have been conducted for several decades, the rapid diffusion of advanced DER has ignited a new wave of analyses. The calculus around solar PV is changing rapidly, for

example, as PV costs rapidly decline and dramatic market growth raises questions about subsidies and grid integration costs. Despite a rapid proliferation of "value of solar" studies, during the past several years, there is no common or universally applied approach to benefit calculation for a range of reasons (Hansen et al., 2013):

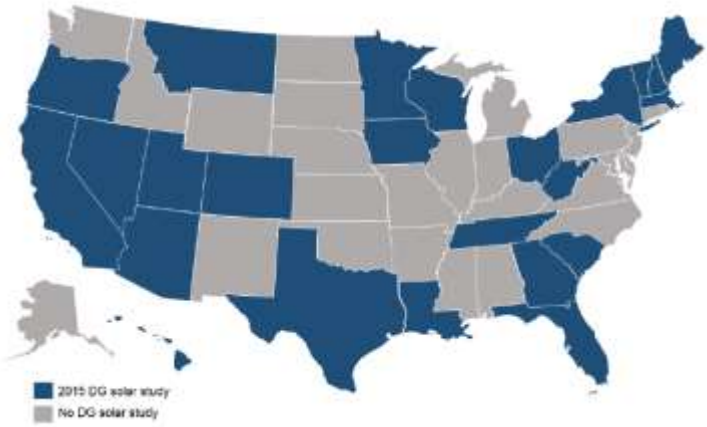
- Existing PV benefit and cost studies utilize different calculation methodologies that can produce widely different results.
- It is difficult to quantify certain types of benefits, and there remains disagreement among experts about methodologies for calculating even some of the comparatively well-established benefits.
- Benefits are geographically specific, meaning that the results from one state (or even utility) cannot be readily applied to other jurisdictions.
- Benefits and costs accrue to different stakeholders (e.g., utility, ratepayers, and system owners) (Contreras et al., 2008).
- The benefits can change over time (i.e., rising or falling) as penetrations of variable renewable energy sources increase (Bradford & Hoskins, 2013).

Figure 1.11. and table 1.2 below provide a summary of the benefits that have been analyzed in many of the different studies. Each benefit is assigned an icon and plotted against the magnitude of the benefit (y-axis - $/kWh) and the degree to which the methodology utilized to calculate the benefit is well-established or still emerging. Definitions for each of these benefits, including a legend for the icons plotted in Figure 1.11, are contained in table 1.2. As can be seen from Figure 1.11, some benefits, such as avoided energy costs, are well-established and high-value, whereas other benefits such as water savings, resiliency support, and economic development have less established quantification methodologies. It should be noted that Figure 1.11 is intended to be illustrative and the ranges for the actual value of each benefit may vary.[5]

The United States has seen a dramatic increase in value of solar studies during the past three years. Whereas there have been a number of value of solar studies prior to 2013 (Americans for Solar Power 2005, Mosey and Vimmerstedt 2009, Perez, Zweibel et al. 2011, Keyes and Wiedman 2012), there is a distinct trend towards formal consideration by state legislatures and/or regulators of the value of solar. Prior to 2013, only a handful states had developed methodologies to value DG. As of the end of 2015, 24 states had formally examined or resolved to examine the value of solar (or DG more broadly) (Figure 1.11.), and 10 states had developed formal regulatory methodologies for valuation.

[5] For the sake of simplicity, some benefit categories have been combined in Figure 1.11. Transmission and distribution benefits, for example, are represented by the same icon. However, the methodology for determining transmission benefits is arguably better established than the methodology for quantifying benefits at the distribution level. Similarly, grid support and ancillary service benefits are grouped under the same icon. However, avoided ancillary
service costs can be more clearly quantified at present than benefits related to, for example, reactive power, voltage control, or frequency response.

Figure 1.10. Value of solar studies in the US



Source: (NCSTC and Meister Consultants Group 2016)

The study outcomes have been used to serve a broad range of regulatory and policy objectives, including:

- Conducting benefit-cost analyses of net metering policies in order to inform whether such policies should be sustained, amended, or eliminated (Oregon, South Carolina, and West Virginia).
- Analyzing the benefits and costs of solar power under different deployment scenarios in order to evaluate the need for solar incentives in specific states (Utah, New York, and Texas).
- Establishing the basis for solar energy incentive payments, such as Austin Energy's Value of Solar Tariff (VOST) (Rabago, Norris et al. 2012), and the VOST established in Minnesota.

Unsurprisingly, the findings of these studies have varied widely. The value of solar study in Louisiana, for example, found that net metering customers are cross-subsidized by other ratepayers. The value of solar study in neighboring Mississippi, however, found that the value of solar exceeded the retail rate for electricity. The debate over net metering in the US is discussed in greater detail in Section 2.1.

This section discusses cases of value of solar approaches for rate setting and focuses. As discussed in Section 2.1, the majority of US states have some form of net metering policy in place, which allows onsite generators to consumer power onsite and to receive credit for excess production. The credit can then be applied against future electricity consumption.

In a handful of jurisdictions, however, states or municipalities have elected to use a value of solar calculation to set the rate at which PV generators are compensated. The theory behind a value of solar rate is that any compensation offered to onsite generators would be neutral from a cost-shifting perspective. Value of solar rates in the US typically do not permit generators to consume power onsite, and instead require that customers purchase 100% of their power from the grid and sell 100% of the power generated onsite at the value of solar rate. This arrangement is also known in the US as a "buy all,

sell all" provision and is similar to traditional European feed-in tariffs. Jurisdictions that have explored value of solar tariffs have had very different experiences, as described below:

- Austin, TX. The municipal utility in the City of Austin, Texas, was the first in the US to adopt a value of solar tariff in 2012. The initial tariff was set at US$0.128/kWh based on calculations of energy savings, generation, capacity, T&D deferral, avoided system losses, and environmental values. The rate can be adjusted annually, and the rate was changed to US$0.107/kWh in 2014 to reflect new methodological assumptions and changing market conditions. To compensate for the fact that the rate is insufficient to support new PV installations, the utility also offers a $0.80/watt rebate to residential customers.
- Minnesota. The Minnesota legislature passed legislation in 2013 requiring the state government to develop a calculation methodology for distributed PV. The legislature required that the value of solar calculation take into account the value of energy, generation capacity value, transmission capacity value, avoided line losses, and environmental value. The Minnesota Public Utilities Commission approved a methodology for setting the value of solar rate in April, 2014 (Clean Power Research 2014), but use of the methodology (and creation of a value of solar rate) by the utilities is voluntary. If utilities opt to develop a rate, it cannot be less than the retail rate used for net metering for three years after the tariff is initially approved and the rate must remain the same over the term of a 20-year contract. No eligible Minnesota utilities have opted to develop a rate to date, although the Minnesota Department of Commerce calculated a sample rate using the approved methodology and found that the payment would be above US$0.12/kWh.
- Lincoln, NE. The municipal utility in the city of Lincoln, Nebraska, conducted its own value of solar analysis during a period when local advocates and business interest were requesting a payment rate based on the generation cost of solar power. Despite the fact that the utility took into account the value of energy, capacity (transmission, distribution, and generation), avoided losses, and environmental benefit, the calculation methodology used by the utility generated a value of solar of only US$0.037/kWh (Benson 2014).

Although the use of value of solar calculations to set tariff rates had been viewed as a "next generation" DG compensation mechanism in the United States (Kennerly 2014), implementation to date has been limited and complex. As can be seen from the examples of Austin and Lincoln, the results of these calculations can be highly variable and dependent on assumptions of what is, or is not, included. In addition, there has been significant push back from elements of the US solar energy industry, which have actively lobbied against value-based buy all / sell all arrangements as an avenue for incumbent utilities to undermine net metering regimes. Among other things, these efforts have focused on the negative income tax implications of buy all / sell all arrangements; counter-analyses have called these tax disadvantages into question (Clean Coalition 2015).

Figure 1.11: Value of Solar PV Benefits and Clarity of Calculation Methodology

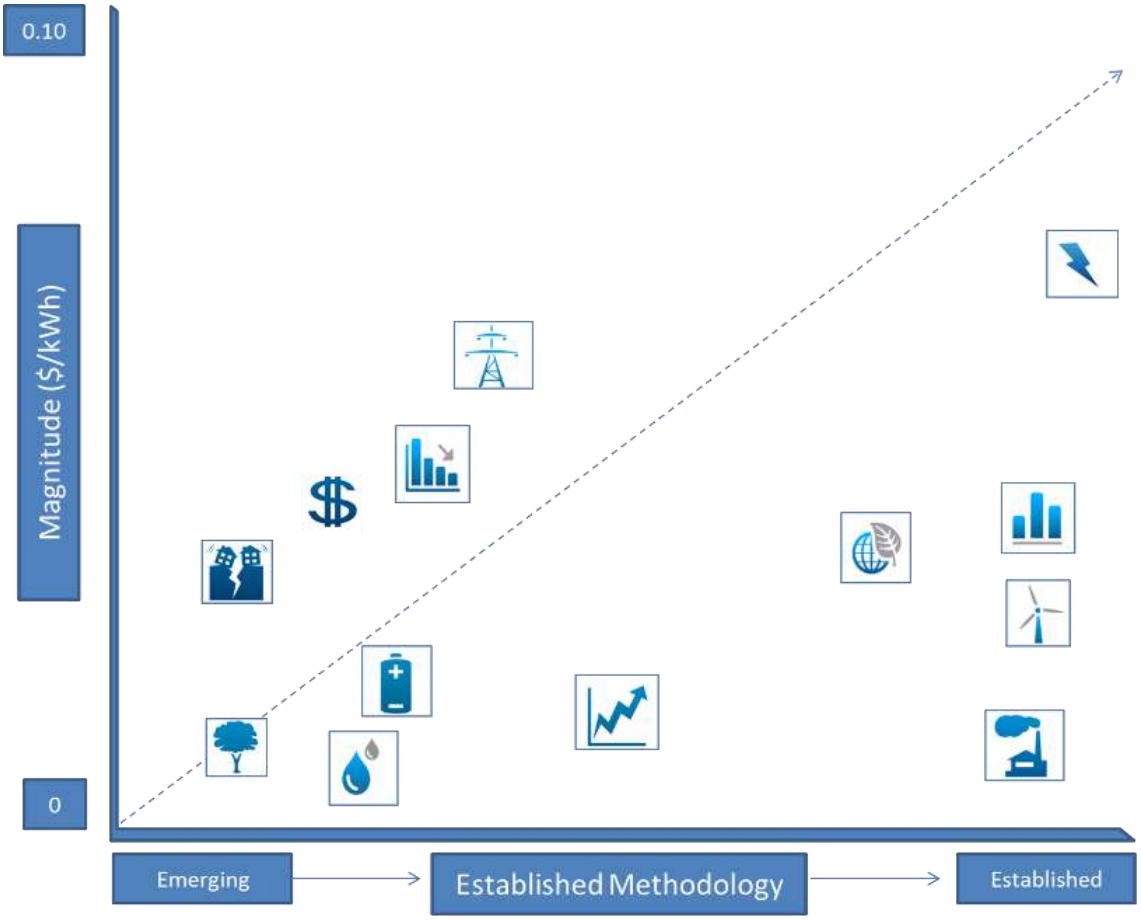


Table 1.2. Definitions and Legend for Solar PV Benefits

Legend	Benefit	Definition
	Energy	The cost and amount of energy that would have otherwise been generated to meet customer needs
	System losses	The value of the additional energy generated by central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system
	Avoided REC purchases	The cost and amount of renewable energy credits that would otherwise have been required to be purchased in order to satisfy compliance with MA RPS policy
	Generation capacity	The amount of central generation capacity that can be deferred or avoided
	Transmission capacity	The value of the net change in T&D infrastructure investment as a result relieving upstream capacity constraints or deferring / avoiding T&D upgrades
	Distribution capacity	
	Grid support and ancillary services	Provision of reactive supply, voltage control, regulation, and frequency response

Legend	Benefit	Definition
	Pricing hedging	Produces fixed-cost power compared to volatile fossil fuel prices. Can provide a hedge against fossil fuel prices and reduce utility and customer exposure to volatility.
	Market price response (DRIPE)	The impact that PV can have on electricity prices and commodity prices by lowering demand for power from conventional electricity and the fuel that it consumes
	Reliability and resilience	Increases reliability by reducing outages through reduced congestion, increasing diversity in the portfolio, and providing back-up power during outages
	Carbon emissions	The value of reducing carbon emissions from the displaced marginal generating resource
	Other air pollution (PM, VOC, CO, CH4)	The value of reducing criteria air pollutants, driven by the cost of the abatement technologies, the market value of the pollutant reductions, or the cost of human health damage
	Water	The value of reducing water used by conventional generating technologies - measured by the price paid for water in competing sectors
	Land	The comparative impact on property values, ecosystems, and land use
	Economic development	Net increase in jobs and local economic development. Drivers include the jobs created or displaced, as well as the value of each job measured by average salary and/or tax revenue

Source: Meister Consultants Group 2016

1.4. Power-to-Heat: Distributed System Integration

As discussed in the Sections above, the price signals sent through time of use rates or value-based pricing can impact the rate at which consumers adopt new energy technologies and can also impact the way in which they deploy them. In reacting to price signals and other drivers, energy consumers may not only attempt to control their onsite electricity consumption (e.g., by adding controllable loads and storage alongside onsite generation), but also to electrify their heating and transport needs.

This integration of fuels can also be supported by policy intervention. Countries targeting high shares of (variable) renewable energy sources, including Germany and Denmark, are increasingly integrating the electricity, heating/cooling and transport sectors to meet long-term decarbonisation objectives. Power systems with high shares of wind and solar PV need greater flexibility to manage variable energy production on the grid and avoid curtailment. Several recent studies have shown that using CHP, heat pumps, heat storage, and electric vehicles can provide significant power balancing capacity and contribute to a more flexible and efficient energy system (Hedegaard, 2013; Meibom et al., 2007; Mueller et al., 2014; Markel et al. 2010, Li et al. 2016. As countries continue to pursue deep decarbonisation strategies, power-to-heat (P2Heat) and power-to-vehicle (P2Vehicle) technologies will become increasingly important for intelligent homes and buildings.

A number of smart grid concepts envision (or have piloted) the use of heat pumps to electrify the heating sector, satisfy thermal demand, and replenish storage during periods of high power output from

wind and solar (IEA-RETD 2015). In such cases, geothermal or air-source heat pumps may be operated flexibly – ramping up production at times of high (renewable) electricity supply, and scaling back or turning off when there is a supply shortage. Renewable electricity is then converted by the heat pump into thermal energy and may be stored in water tanks or in the building itself (e.g., in the floor or the walls) for several hours. The Island of Bornholm in Denmark EU Ecogrid project has piloted this concept as a demand response strategy to absorb excess offshore wind power generated at night (during periods of low customer demand for electricity) and store it as heat in buildings and thermal storage units (Hedegaard 2013).

CHP systems have also been used in Denmark for a number of years to help balance intermittent production. For example, the Skagen CHP plant in Denmark – which includes natural gas CHP, a MW-scale electric boiler, and significant thermal storage – is flexible enough to provide power regulation and frequency regulation market services. The electric boiler scales up and down to serve frequency regulation and power regulation markets, as needed. Heat provided by the boiler is used for the thermal network or stored until it is needed. The natural gas CHP engines also provide heat for the thermal network as well as electricity for the spot market. By combining all these systems into an integrated system, CHP plant operators have greater flexibility to serve Denmark's energy heat, electricity, and grid services markets (Andersen and Sorknæs 2011).

In order to make P2H an economically viable option, the electricity used for heat generation has to be cost competitive with fossil-fueled heat. This does not only depend on the cost trends of fossil fuels for heating but also on the (long-term) availability of excess renewable electricity. In times of high shares of solar PV and wind, for example, wholesale market prices could decline and fall below zero as they have in some markets such as Germany. To the extent that retail electricity prices are linked to these wholesale price variations (e.g., through real time pricing) then the wholesale price suppression effect caused by renewable electricity supply could improve the competitiveness of electrical heat against, e.g., heating oil. However, the potential interactions between high penetrations of renewable energy in the electrical supply and onsite heating economics have not yet been demonstrated at scale, and additional research and modeling on this topic would be needed to develop a fuller picture. The policy levers that would enable or constrain the adoption of technologies such as P2H have also not been deeply explored.

In several jurisdictions, the barriers to integration of fuels include levies, surcharges and taxes on electricity (see case studies below). These taxes and surcharges might make sense from the logic of historic electricity market regulation. However, when it comes to sector integration they create a disadvantage for (renewable) electricity competing with fossil fuels such as oil and gas in the heating sector.

There are other systemic factors that should be taken into account as policy makers contemplate the potential convergence of electricity, heat, and transportation. Parallel investments in heating and electrical efficiencies, for example, could eventually collide. In the deeply decarbonized power systems of the future, there may only be limited opportunities for traditional CHP power-to-heat technologies

used in district heating systems. Already today in Europe, building standards for new (commercial and residential) buildings are aggressive and accordingly heating needs are low. The 2010 Energy Performance of Buildings Directive requires member states to pass legislation that requires all new buildings to be climate-neutral (i.e., zero-energy buildings) as of 2021. For public buildings, this is already required as of 2019. This poses an economic threat to conventional district heating networks, which require broad interconnection from communities and reliable heat demand from customers.

There are opportunities, however, to develop smart grids for heating and cooling. Such heating networks are more suited to a high-efficiency building stock and also could enable renewable heat to be produced on building sites (e.g., from technologies like solar thermal and heat pumps) and fed into the heating network. For widespread deployment, the smart heating grid concept would require a number of infrastructure, policy and market upgrades. Policymakers would need to develop new interconnection policies and tariffs for buildings feeding into heat, and also provide greater support for distributed renewable heating generation. It would also require the development of low-temperature heating networks, which operate more efficiently and are better suited to supply low-energy buildings.[6]

A number of jurisdictions in Germany have piloted such smart heating grid networks. For example, a community association in Wilhelmsburg, Germany integrated decentralized solar thermal into its heating network. In this case, regulations were developed to give decentralized heat exporters priority dispatch for up to 10% of the annual heat requirement. The grid operator agreed to pay decentralized generators a fixed fee for every kilowatt-hour of renewable heat that they exported (REN21, 2015).

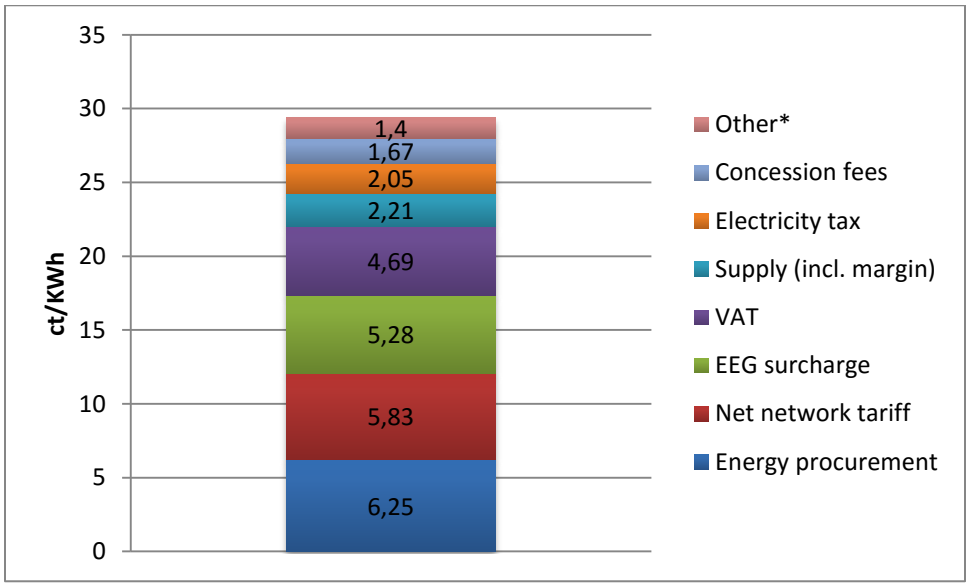
Although there are arguments for the electrification of heating, there are not yet strong examples of countries in which electric heat as a renewables integration methodology has moved out of the pilot phase. Germany, for example, faces obstacles in the electrification of heat despite its strong progress in renewables overall and in renewable heating specifically.

Germany has already made good progress with the energy transition in the electricity sector – about 30% of electricity is produced by RE technologies, compared to 6% in the year 2000 – and 13.2% of final heat energy consumption was supplied by renewable sources in 2015 (BMWi 2016). In Germany, the potential for distributed hybrid heating systems was recently analyzed by several studies (Ffe 2011, Münch, Robra et al. 2012, Bräuninger, Ehrlich et al. 2014). These studies have found that renewable electricity heating systems could be sound technical solutions to current fossil fuel-based systems. When old oil-based heating units are replaced with modern condensing boiler technology, for example, they can be combined with distributed heat storage and roof-mounted PV in conjunction with an electric heater.

[6] Low temperature heating networks are also sometimes referred to as “fourth generation” district heating systems. According to a recent IEA-RETD report, they have been piloted in a number of regions, including Denmark, and can supply low-temperature water at approximately 55 degrees C. This enables increased integration of low-temperature RES-H/C technologies such as heat pumps and solar thermal systems. It additionally is expected to support more flexible distribution and the use of assembly-oriented components and flexible materials. The final result will be a more environmentally friendly, customer-oriented solution. See IEA-RETD (2015b)

Residential electricity rate structures in Germany, however, currently serve as a constraint on the diffusion of heating systems driven by renewable electricity. The use of time-reflective retail rates (e.g., time of use rates or real time pricing) – which could provide an important incentive for innovative electric heating and storage if structured correctly – remains rare at the residential level. In addition, German electricity prices are high and include many taxes and surcharges. As shown in Figure 1.12, the German residential retail rate is close to 30 €cent/kWh (CAD$0.43/kWh). The energy and network tariffs account for about half the bill, while taxes and surcharges account for the rest (BNetzA 2014). As a result, it can be a challenging economic proposition to switch to electric heating from natural gas or oil.

Figure 1.12. Average volume-weighted retail price for household customers (ct/kWh)



*Other charges are the sum of: billing, 19 StromNEV surcharge, metering operations, offshore liability surcharge, KWKG surcharge, and metering.

Source: (BNetzA 2014), p. 146.

Given the weak economics for heat electrification, a recent study suggested exempting advanced electric heating systems from the grid usage fees (accounting for 20-25% of the retail electricity price in Germany) (Bräuninger, Ehrlich et al. 2014). German policymakers are also currently debating whether to reduce or fully suspend all surcharges and taxes during periods of negative electricity prices. During these periods, excess electricity can be effectively used for heat production in Germany – instead of paying to export the electricity to neighboring European countries.

2. MEETING ENERGY DEMAND BEHIND THE METER

As discussed in Chapter 1, DER can create substantial benefits and costs for both the onsite generator and for other stakeholders. Policymakers must take these benefits and costs into account when developing DER policy and strategy. Around the world, some policymakers have opted to attempt to limit the development of onsite generation, whereas others have enabled the emergence of DG in order to support the public interest (IEA-RETD, 2014; IEA-RETD, 2016).

This section provides a snapshot of key policy issues related behind the meter generation. The first half of the section (i.e. Sections 2.1 and 2.2) provides an overview of policy mechanisms that compensate generators for the power they feed into the grid and policies that attempt to recover the costs of grid management from the generators. These discussions have evolved into complex debates and regulatory controversies in large PV markets such as the US and Germany.

Even if the near-term issue of DER compensation is resolved, policy makers will likely still need to anticipate a future in which onsite DER markets scale up significantly. Based on existing forecasts of the future development of PV and battery costs, it is likely that the share of distributed, behind the meter generation will increase considerably in the coming decade. This could also happen without explicit policy support (see Textbox 1 below), although a favorable framework conditions will continue to be crucial for prosumers during the next several years (Rickerson, Couture et al. 2014, Rickerson, Koo et al. 2016). The rise of prosumers has the potential to transform the centralized electric utility model that has served the world for over 100 years into a more decentralized and interactive system.

Electricity system and regulatory frameworks (e.g., rate design and network tariffs) have historically been based on large-scale power generation units providing electricity to customers. Policymakers need to reconcile both worlds (the prosumer world and the existing assets in the centralized electricity system) in the coming decades through forward-looking regulation. The second half of this chapter (i.e. Sections 2.3. and 2.4) focuses on some of the technical issues related to DER market scale up, namely the governance of battery storage and DER regulation within the distribution grid. Textbox 1 below defines several of the key terms used in this section.

Textbox 1: Understanding prosumers, self-use and self-sufficiency

The term prosumer is used to refer to energy consumers who also produce their own power from a range of different onsite generators (e.g. diesel generators, combined heat-and-power systems, wind turbines, and solar PV systems) (IEA-RETD 2014).

Self-use refers to the proportion of DG output that can be directly consumed onsite. If a DG system generates 800 MWh each year, but only 600 MWh can be directly consumed (the rest being exported to the grid), then the self-use ratio is 75%.

Self-sufficiency refers to the proportion of PV output that can be directly consumed onsite as a percentage of the total amount of onsite demand. If a building has an annual demand of 1,000 MWh and uses 600 MWh of PV onsite, then the self-sufficiency ratio would be 60% (IEA-RETD 2016 : 10).

2.1. Remuneration for Excess Electricity, Virtual Net Metering, and Roll-over Provisions

DG is diffusing rapidly around the world as countries introduce (or update) policies to enable and govern onsite generation. The spread of DG policies to new jurisdictions has likewise been rapid during the past decade. As countries have adopted DG policies to their national context, they have added unique policy elements and innovations. As a result, it is now challenging to use broad policy labels such as feed-in tariffs, net metering, or net billing to accurately characterize specific policy designs, since they mean different thing in different countries (Couture, Jacobs et al. 2015). Generally, DG policies can be distinguished in two major ways:

- Can onsite generation be used to offset grid electricity? Some jurisdictions permit onsite generators to offset electricity that they would otherwise purchase from the grid, whereas some jurisdictions require that all electricity be exported to the grid (e.g., a "buy all / sell all" arrangement). Still other jurisdictions have allowed generators to choose whether to export or not.[7]
- At what compensation level is electricity exported? Historically, some jurisdictions have paid (or credited) a premium rate for electricity exported to the grid (e.g., feed-in tariffs in Germany and Ontario). In some jurisdictions, the export rate has been pegged to the retail electricity rate (e.g., net metering in the US). Finally, some jurisdictions have paid a rate that is below the retail rate to generators.

Internationally, it is possible to find examples of every potential combination of these design options and no two policies are the same. The identification of "best" or standard practices has remained elusive as policymakers have attempted to react to decreasing DG costs and rapidly scaling DG markets. In making and updating DG policies, policy makers are attempting to balance national objectives such as the decarbonisation of the energy system and support for "energy democracy" with issues related to utility cost recovery and ratepayer cross-subsidies. The result is an international landscape that remains highly dynamic.

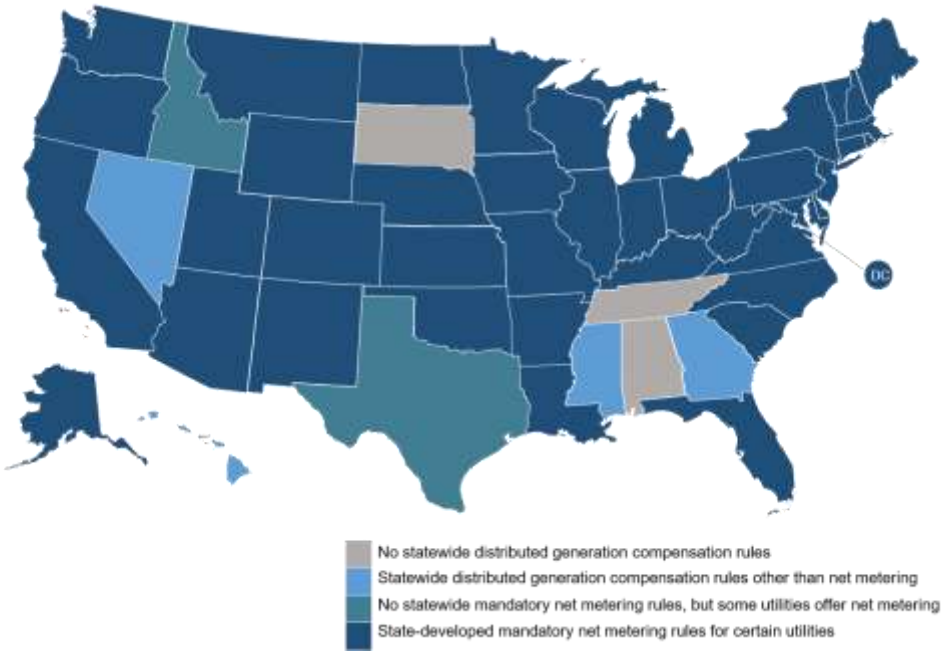
This Section focuses on DG policy development in the US. US states were among the first jurisdictions in the world to introduce DG policies, with the establishment of early net metering policies in the 1980s. Net metering policies, as initially defined, enabled onsite generators to receive credit for excess onsite generation that could be applied to future billing periods.

During the past several decades, almost all US states introduced some form of net metering or related policy to enable onsite DG. DG – and particularly solar PV – are scaling up dramatically in the US, with 7.2 GW of PV installed in 2015 for a total of 25 GW (SEIA 2015). By 2020, it is estimated that cumulative PV capacity in the US will reach 97 GW and that the US will be installing 20 GW annually (SEIA 2016). In

[7] Some jurisdictions also require that 100% of the power be consumed onsite and that no electricity be exported to the grid. These jurisdictions are not a focus of this paper.

the face of this growth, there has been a wave of policy making in the US to variously expand, amend, or remove DG policies. As can be seen in Figure 2.1. below, only three states[8] do not have some form of DG compensation policy in place, whereas 43 states have either mandatory statewide net metering or net metering adopted by specific utilities. Four states have a policy other than net metering in place.[9] Although net metering is well established in the US, it is also a policy that is very much in flux: *27* states took legislative or regulatory action related to net metering in 2015 alone. Some states, like South Carolina, added net metering for the first time, whereas other states, such as Hawaii and Nevada, moved away from "traditional" net metering to new systems that provide generators with lower compensation levels for exported electricity. In parallel with changes to net metering legislation, many states and utilities have also investigated the establishment of new charges and fees, which erode revenue for PV generators and could serve to slow market growth. These charges are discussed in greater detail in Section 2.2.

Figure 2.1. DG compensation rules in the US



Source: Meister Consultants Group 2016

The case study below focuses on the evolution of net metering policy in the state of Massachusetts. Massachusetts was one of the first states in the country to introduce net metering, in 1982, but experienced comparatively slow market growth to only 3.5 MW by 2007 (Phelps 2012). The state introduced a series of successively more ambitious targets, supported by a solar-specific renewable

[8] Alabama, Tennessee, and South Dakota

[9] These include Georgia, Hawaii, Mississippi, and Nevada. These policies generally compensate excess generation at rates well below the retail electricity rate. The practice of compensating generators for rates below retail is sometimes referred to as "net billing," although the usage of this term varies internationally.

portfolio targets and "virtual" net metering legislation. The market has grown rapidly and the state is on track to meet its 1,600 MW target ahead of schedule – but recent net metering battles have introduced uncertainty and market delay.

Traditional net metering policies have allowed onsite generation to offset consumption associated with a single meter. An increasing number of states in the US, however, have amended their net metering laws to allow generation to be applied to multiple meters (and/or multiple accounts). In the most limited way, meter aggregation only applies to a single customer who has one solar PV system and multiple meters on the same property. In the broadest form, meters that are on multiple properties and owned by third parties can be aggregated in order to offset higher amounts of distributed solar PV. The basic rationale behind meter aggregation is to incentivize investment in larger scale solar PV systems (i.e., system size is no longer limited by onsite demand). As of 2015, 14 states and the District of Columbia had introduced some form of meter aggregation or virtual net metering.

Massachusetts reformed its limited net metering law in 2008, with the much more expansive provisions contained in the "Green Communities Act." With that legislation, net metering eligibility was provided to solar and wind facilities up to two MW in size, and also to other renewable facilities on farms. Net metering was subject to a cap of one percent of each distribution company's peak load.

Under the Green Communities Act, net metering customers received payment at close to the retail rate (with some variation depending on the size of the facility), and were allowed to carry over net excess generation from month to month. The legislation also provided for so-called "virtual net metering," allowing customers with the same distribution utility and in the same load zone to aggregate their load for net metering purposes. (Additionally, the Act contained a "neighborhood net metering" provision, which has been viewed as redundant on account of the virtual net metering provisions.)

Since passage of the Green Communities Act, the net metering provisions have been amended numerous times in a number of different respects, most recently by legislation enacted in April 2016. The amendments raised the overall statewide cap for net metering, while increasing specific sub-caps for private and public facilities (i.e., to 7% and 8%, respectively). The amendments also exempted small facilities from the caps; added anaerobic digestion to the list of resources eligible to net meter; modified the compensation schedule; modified the virtual net metering provisions; and added a requirement for a "system of assurances." This focus in this section is on the virtual net metering provisions.

The most recent Massachusetts net metering legislation, passed in April 2016, addressed mainly solar PV generation, although the increases in the caps apply to other net metering eligible resources, such as wind and anaerobic digestion as well. The 2016 legislation was mostly welcomed by solar developers and many others because it raised the net metering caps, which had been hit in large areas of the state.

However, the legislation has been criticized for its impact on virtual net metering. Virtual net metering allows a solar PV installation, for example, to generate more power than the on-site load utilizes, and to share the financial benefits of the excess among multiple meters. The ability to be credited at the retail rate for net excess generation has made virtual net metering viable in Massachusetts. Under the 2008 law, virtual net metering has been responsible for an enormous expansion in solar power, much of it

municipal projects on capped landfills. One company alone reports constructing 22 MW of solar PV projects on Cape Cod and Martha's Vineyard, 19.5 MW of which were on capped landfills. (MacDonald, P., 2014).

But for many types of systems, the new legislation reduced the credit by 40 percent—close to the wholesale rate for power—for monthly net excess, with no compensation for other system benefits. This reduction applies to community solar and to large industrial projects, although not to residential and public sector solar projects or to projects that are already connected to the grid. Thus, the reduction will not affect projects like municipal installation on capped landfills, but can be expected to negatively affect community solar and large industrial virtual net metered projects.

In progressive Massachusetts, this change came as something of a surprise, since the argument nationwide has been that the retail rate over compensates solar generation, not that the wholesale rate is the appropriate level of compensation for net metered resources. In fact, there seems to be widespread recognition that the wholesale rate is too low to fairly compensate solar generation, and some states, including New York and California, are engaged in proceedings to determine the appropriate compensation level.

It is possible that omnibus legislation that is expected to emerge from the Massachusetts legislature by the end of the legislative session (July 31, 2016) will modify some provisions of the April legislation, although that appears unlikely.

2.2. Financing DG Infrastructure Investment: Fixed Charges and Other Policy Options

While DG policy creates new revenue or savings opportunities for onsite generators, it also creates costs and benefits for other stakeholders. A key challenge for policy makers is to determine how best to assess and balance these costs and benefits in service of the public interest and of policy objectives. In an increasing number of jurisdictions, the expansion of DG is beginning to impact other stakeholders.

In Germany, for example, the costs incurred through the implementation of the national feed-in tariff are recovered from electricity ratepayers in the form of a surcharge on retail kilowatt-hour sales. During the past several years, the available feed-in tariff rates (which were previously far higher than retail electricity prices) have decreased significantly below the retail electricity rates (IEA-RETD 2016). As a result, an increasing number of PV system owners were opting to consume their power onsite to capture savings at the retail rate rather than sell their power under the feed-in tariff. The decrease in electricity consumption from the grid raised the prospect that a smaller share of the population would now have to pay a higher surcharge to cover the cost of the legacy feed-in tariff payments. In response, the German government levied a portion of the feed-in tariff surcharge on every kilowatt-hour consumed onsite – even if the kilowatt-hour was generated by the customer itself.

Similar policy discussions are occurring around the world where DG is at or near the frontier of broad competitiveness. Utilities in a growing number of countries, for example, have raised concerns about the degree to which behind-the-meter DG erodes their sales revenues and therefore reduce their ability to

recover their fixed costs for, e.g., transmission and distribution system investments(Kind 2013). The main argument mounted against the policies is that net metered customers cost the electric system money, and that the cost is borne by other customers. As the arguments go, net metered customers use less power from the grid than they otherwise would, but because they still use the grid, they don't pay their fair share of its maintenance. Additionally, because under most policies net metered customers are typically compensated at a rate higher than the wholesale rate for power, and in fact close to the retail rate, the argument is that they are imposing unnecessary power purchase costs on other customers. Although the prospect of a utility "death spiral" as a result of ratepayer impacts may be exaggerated (Satchwell, Mills et al. 2014), large increases in onsite consumption from behind-the-meter DG may negatively impact utility shareholders. The counter arguments are that the renewable resources that are net metered actually benefit the grid and society more broadly in ways that aren't appropriately valued—e.g., greenhouse gas reductions, avoided distribution and transmission upgrades, peak reduction—and that as a result net metered customers paid at the retail rate, may actually be under compensated (Linvill, Shenot et al. 2013).

In response to increased DG penetration (or at least the prospect of increased penetration), an increasing number of utilities and regulators around the world are revisiting retail electricity rate designs in order to ensure that electricity system costs are covered and/or to constrain DG growth. Table 2.1 below contains a high-level summary of some of the rate redesigns that are under consideration. In the case of fixed charges, standby charges, and demand charges, policy proposals involve either increasing non-volumetric charges that are difficult (or impossible) to reduce with onsite **generation,** or introducing such charges for the first time. The increase (or introduction) of non-volumetric charges typically decreases the economic returns of DG system ownership and makes DG less competitive. It is important to note that each of these options will have different impacts on the utility, non-participating utility customers, the participating utility customer, and utility shareholders. The impact will also depend on the specific characteristics of a country's electricity market and the underlying conditions of the utility and the electric grid.

Table 2.1. Approaches to cost recovery

Approach to Cost Recovery	Description
Adjust fixed charges	Higher fixed charges on all utility customer bills or only DG customer utility bills.
Apply standby charges	A new charge on all (or only commercial) owners of DG systems that reflects the need for electricity services to be available on a back-up or standby basis when DG systems are not producing electricity. The magnitude of the standby charge is typically determined by the capacity of the DG system – the larger the system, the higher the charge.
Apply demand charges	Demand charges are extended to all customers or only customers that participate in the DG policy. Demand charges are normally measured in terms of a customer's highest electricity usage over a particular period of time (usually a 15 minute, 30 minute or 1 hour time period) and the customer is charged at a specific $/kW rate.
Set a minimum bill	Sets a minimum bill threshold that all grid-tied customers will pay unless their electricity usage exceeds the minimum threshold. Ensures a minimum customer contribution toward the costs of providing electric service and is usually targeted towards customers with relatively low energy consumption compared to users with average or high consumption.

Source: Author

Higher fixed charges for prosumers are frequently put forward as a straightforward solution to the problem (Sioshansi 2013). However, higher fixed charges also have some disadvantages, such as limiting the incentives for energy efficiency, and often placing a higher burden on low-income households with low electricity consumption levels (Jahn 2014). In addition, higher fixed charges can also improve the economics for grid defection, i.e., consumers fully cutting the cord to the central electricity grid.

Textbox 2: Self-use and Grid Defection

Self-use policies are based on the assumption that solar PV producers only generate a portion of the power demanded on their own and that they still rely on the electricity grid as a "storage unit" and as a backup solution when the sun is not shining. Since solar PV cannot generate electricity at night and power generation decreases in the winter, it is frequently assumed that prosumers will always have to rely on the electricity grid. However, with continuously falling PV prices and falling battery prices – battery storage costs in Germany have declined by 25 percent in 2014 (Enkhardt 2015) – consumers might eventually decide to "cut the cord" (Kind 2013) and disconnect themselves entirely from the electricity system. This is usually termed grid defection (IEA-RETD 2014). There is an ongoing debate on whether technological advances in solar PV (and battery) storage will eventually cause traditional utility businesses to collapse, or whether only certain market sectors (e.g., residential consumers living in private houses) will be "lost" to prosumer-type business models (Schleicher-Tappeser 2012, Sioshansi 2013, Graffy and Kihm 2014, IEA-RETD 2014).

In Australia, analysts have estimated that by 2018 households might have an incentive to fully disconnect themselves from the electricity grid (Parkinson 2014). In the United States, it is estimated that customers might opt out of using the grid between 2022 and 2050, depending on climate conditions and retail price structures (Bronski, Creyts et al. 2014). Recent studies have shown that solar PV costs will reach levels of 1.8 to 4 €cent/kWh in 2050 (Kost, Mayer et al. 2013, Agora 2015).

This change is likely to require further policy innovations in the years ahead to better accommodate the rise of these so-called "prosumers" (Rickerson et al., 2014). The appearance of grid defection on the horizon should also inform policy-makers about future designs of net metering. The more prosumers are obliged to pay fixed charges (for administrative handling, network usage or other system-related costs), the stronger is the incentive to disconnect completely from the grid in the long run.

This Section focuses on recent policymaking in the US because of the pace, breadth, and diversity of recent activity. The statistics here are drawn from the *50 States of Solar*[10] report series, unless otherwise noted.

- During 2015, 61 utilities in 30 states had submitted proposals for increasing fixed charges on all of their residential customers. Of these, fixed charge increases were approved for 21 utilities, with 16 not approved, and 24 still in process.
- Twenty-one utilities in 13 states also submitted proposals for specific additional fixed charges on solar PV customers only. Only one investor-owned utility, in Nevada, was successful in getting new solar charges approved. A utility proposal for solar fixed charge that had been approved by state regulators in Wisconsin in 2014 was struck down in 2015 by the courts. Regulators in New Mexico, meanwhile, rejected efforts to put net metered customers in a separate rate class (in order to assess solar-specific charges) on the grounds that they would not be consistent with state law.

As with net metering, the closely related policy landscape of retail electricity rate design remains highly dynamic not only across the country, but within specific states. It remains too early to determine whether certain policy mechanisms (e.g., demand charges) will emerge as the "preferred" option or whether the debate will eventually give way to broader, structural changes in the way that energy transitions are governed and regulated. In order to highlight the divergent pathways that these policy discussions are taking in the US, the case study below profiles the outcomes to date in two neighboring states: California and Nevada.

California has consistently been the largest solar PV market in the US and has continued to dominate in 2015 and the first quarter of 2016(SEIA 2016). The California Public Utilities Commission (CPUC) has attempting to define what the "next generation" of net metering will look like against the backdrop of the three large state utilities submitting proposal to introduce new demand charges and fixed fees for solar customers. The proceedings were conducted under the heading of "Net Energy Metering (NEM)

[10] http://www.dsireusa.org/resources/presentations-and-publications/

2.0." Given the size of the California market and the number of similar active cases across the country, the outcome of the case was highly anticipated.

In January 2016, the CPUC decision (16-01-044) (CPUC 2016) notably did not authorize the new charges proposed by Pacific Gas & Electric, Sand Diego Gas & Electric, or Southern California Edison. At the same time, the CPUC preserved the ability for net metering customers to receive credit at the full retail rate – although customers will be required to pay non-bypassable surcharges ranging from $0.02-$0.03 for each kWh purchased from the grid. Solar PV generators must also pay a one-time interconnection fee, which is expected to be $75-$150. The CPUC also decided that a successor tariff that takes into account the locational and time value of generation would be considered following a review in 2019.

The new policy, which will not apply to existing net metering customers, will enter into effect in July, 2017, or the point when installed solar PV capacity reaches 5% of customer peak demand for each IOU. This 5% trigger amounts to ~2400 MW in PG&E territory, 2,240 MW in SCE, and 617 MW in SDG&E. In March 2016, the three utilities submitted applications to the CPUC to rehear the decision.

The outcomes of the Nevada proceedings were markedly different from those in California. In 2015, the Public Utilities Commission of Nevada (PUCN) approved both new solar-specific charges and decreased the remuneration rates for net metering:

- NV Energy, the state's main utility, requested that a separate customer class be created for customers that own DG in order to allow the utility to levy specific fees on distributed generators. Specifically, NV Energy requested a $14.33 demand charge for each kW of PV installed per month, as well as a $5.40/month flat fee, for customers in the northern part of the state. NV Energy also requested an $8.63/kW demand charge and a $9.25 flat fee for customers in the southern part of the state. In response to these requests, the PUCN approved new fees that will grow from $5.84/month above non-solar customers in 2016 to $29.18 above non-solar customers in the north in 2028 and $25.76 in the south.
- In addition to the assessment of new charges specifically on solar generators, the PUCN also ordered that DG system owners no longer be credited at the retail rate for excess generation. Instead, the amount that generators will be compensated will decrease steadily over time from the retail rate to the average annual wholesale rate in 2028.
- These new charges and the excess generation credit rates apply to new solar generators, as well as existing solar generators. In February, 2016, the PUCN extended the ramp down period for the compensation rates by an additional three years, but denied a request to exempt existing generators from the new provisions. The courts subsequently determined that a proposal for a public referendum to restore the original net metering policies would first need to be enabled by the legislature.

2.3. Use Distributed Battery Storage to Increase System Stability

Balancing onsite generator compensation and utility cost recovery will likely continue to be hotly contested issue in North America, Europe, and beyond. This discussion, however, remains relatively focused on current technologies. Looking ahead, policymakers will likely need to consider a range of new issues as new technologies diffuse into the market and begin to scale up. A prime example of this is the diffusion of distributed storage in the residential sector.

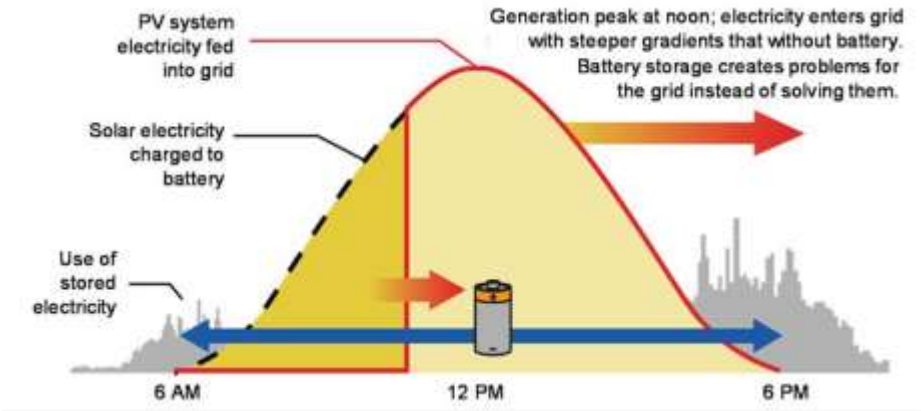
When combining PV systems with distributed battery storage, power producers generally have an incentive to maximize self-use when retail rates are higher than the rate paid for electricity export. In private households in Germany, for instance, self-use ratios are usually in the range of 30%, due to the relatively large size of roof-mounted PV systems and the option to export all excess electricity at the feed-in tariff rate (which is substantially below the retail electricity price). Adding electricity storage units to this system can increase self-use ratios to more than 60% (Weniger, Tjaden et al. 2014, Weniger, Bergner et al. 2015).

Since the combination of PV systems with battery storage is projected to become more frequent, policymakers could develop regulations to govern the use of distributed storage support grid stability. Policies such as these may become important to manage higher penetrations of electricity generation fed into the grid from distributed, behind-the-meter systems in the future. However, policy makers will need to navigate how (and whether) to require that batteries be used for grid support instead of allowing onsite generators to use their batteries to maximize their own onsite savings

In 2013, Germany established a storage program, which is managed by the state-owned KfW bank. As of 2016, about 34,000 PV-battery systems have been installed in Germany. About 19,000 systems have benefited from financial supported. The program was created to not only to support the domestic battery industry, but also to collect data and experience related to integration issues with behind-the-meter storage. Since 2015, storage units are supported under the program only if they adhere to prescribed charge and discharge patterns that support grid stability.

Without guidance, it is possible that charging patterns from distributed, behind-the-meter battery storage could be inefficient from the perspective of grid management. Batteries could be discharged in the evening or overnight (rather than at optimal times), and battery charging from distributed units could start simultaneously (nationwide) in the morning. Once batteries are fully charged by the PV systems, they could start to export excess electricity to the grid. This export could in turn result in steeper gradients and high generation peaks during midday, as depicted in Figure 2.2. below. As discussed further in section 4.5, steeper gradients and high peak generation might further increase the need for flexibility and balancing power and make the transition towards higher share of renewables more expensive from a system-wide perspective.

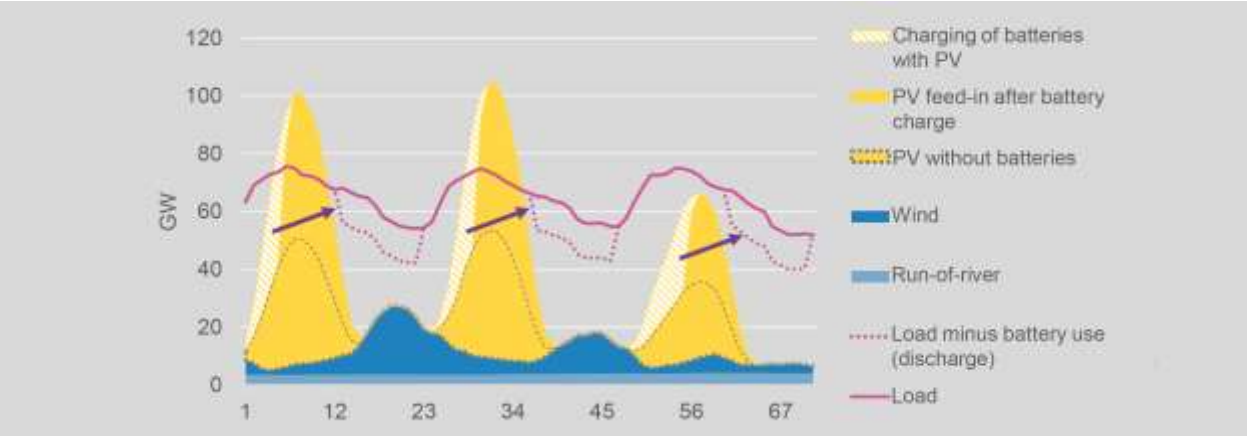
Figure 2.2. Charge and discharge of distributed battery storage to increase self-use ratios



Source: (Deutsch and Graichen 2015, Sterner, Eckert et al. 2015)

Similar challenges can also result from the charging patterns for electric vehicles. If car batteries are charged at home (once car owners return from work), this might coincide with evening hour peak demand periods and exacerbate high peaks. Figure 2.3 below shows the extent to which unfavorable charging pattern of battery storage could increase the stress on the German power systems by causing steeper ramps.

Figure 2.3. Potential effects of self-use optimized battery storage on the German power system



Source: (Deutsch and Graichen 2015)

Given the potential for unintended consequences from new storage and new EV loads, policymakers in Germany are incentivizing battery charging strategies that help to smooth the influx from distributed,

behind-the-meter units and contribute to grid stability.[11] Several charging strategies are currently applied in the German market, as detailed below.

Peak shaving

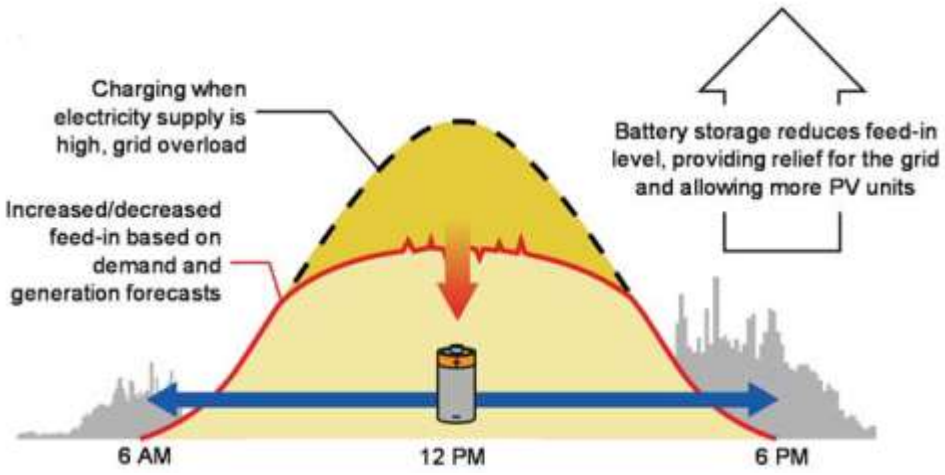
This regulation is closely linked to the "blind system regulation" discussed in section 2.4. Instead of capping small scale solar PV systems at 70% of the nameplate peak capacity, the PV-battery unit sizes are capped at 50%. Thus, injection spikes from a single system can be avoided. Excess electricity will first be fed into the grid in the morning hours and battery charging will not start until around noon – when PV electricity is available in abundance. This way, injection spikes will be lowered and the power system as a whole will be able to absorb higher shares of PV. This is required for all PV-battery units that receive financial incentives (KfW 2016).

Forecast-based charging

In this case, load and (local) weather forecasts determine the actual charging patters for behind-the-meter battery units (see Figure 2.4). This way, self-use rates can be optimized and PV curtailment can be minimized. Regional forecasts should suffice to anticipate high injection spikes of PV generation. However, for more sophisticated forecast-based charging regulation, communication infrastructure between the PV-battery system, and the system operator may need to be established (Deutsch and Graichen 2015, Sterner, Eckert et al. 2015).

[11] In addition, modern inverter technologies can support grid stability by providing voltage control and reactive power.

Figure 2.4. Forecast-based charge and discharge of distributed battery storage to increase system stability



Source: (Weniger, Bergner et al. 2015) (Deutsch and Graichen 2015, Sterner, Eckert et al. 2015)

Modified battery charging patterns (as depicted above) will be important for energy systems with high shares of behind-the-meter (plus battery) generation. The optimal use of storage by onsite generators will depend on the remuneration regulation for excess electricity (see section 2.1) and the rate structure (e.g., flat electricity rate or time-of-use pricing). Therefore, storage regulations will need to be tailored to specific national circumstances in tandem with the rules governing generator compensation.

The policy described above currently affects only storage units that are supported financially by the government. In Germany, this type of regulation will likely also be put in place for unincentivized battery storage in the long run. It remains unclear, however, whether privately owned systems can legally be regulated as described above. Policymakers may potentially need to move from a command-and-control based approach towards a more market-based policy (e.g., offering more attractive time-of-use rates for PV/battery systems that follow the prescribed charging and discharging patterns).

2.4. Blind System Regulation

Integrating increasing shares of PV and other distributed, behind-the-meter technologies can be a challenge for the management of distribution systems. This is especially problematic if the grid operator has no information about the systems located behind the meter (e.g., system size, typical onsite load patterns, typical (or actual) generation patterns, etc.).

In Ontario, for example, the system operator receives information only for systems larger than 5 MW. Smaller units are seen as negative demand. This is a feasible approach as long as the share of behind-the-meter installations is marginal. However, with increasing shares of distributed PV or other behind-

the-meter technologies, policymakers may need to implement new standards or regulations in order to improve visibility.

New PV systems can help to stabilize the distribution grid since modern inverters and other technological solutions can provide ancillary services. For instance, state-of-the-art PV inverters can provide reactive and active power as well as support for voltage dips. PV inverters can therefore be programmed in a way that supports voltage control. These regulations are usually set in national or regional grid codes by utilities or grid operators.[12]

This section focuses on policy solutions for "blind system regulation" implemented in Germany.[13] Germany is an interesting case study, since 1.5 million PV systems have been installed in residential buildings. About 85% of all PV systems in Germany are connected to the distribution system. Many of the systems were installed before modern inverter technologies existed. The roll-out of smart grids and smart meters also remains is limited in Germany (i.e., below 1% of all meters) and so policymakers have had to introduce comparatively low-tech solutions.

In Germany, blind system regulation and feed-in management started as early as 2009. According to the Renewable Energy Act (EEG), grid operators needed to be able to remotely control PV system output for systems larger than 100 kW if required for system stability. As of 2012, the capacity limit was reduced to 30 kW due to the relatively large size of the roof-mounted segment in Germany. Smaller systems have two options: a "low-tech" solution based on fixed curtailment of peak PV output, or the aforementioned "high-tech" solution based on remote-controllable communication infrastructure (i.e. ripple control receivers).

When the grid operator determines that curtailment is necessary for technical reasons, German policymakers have established a specific order in which resources must be curtailed:

1. **First**, conventional power plants are curtailed. This is consistent with the German national energy transition strategy, which requires a shift to a renewable energy-based power system.
2. **Second**, larger scale PV systems (larger 100 kW) and other RE technologies are curtailed. It is technically easier to curtail larger-scale PV and renewables than to curtail small-scale PV systems.
3. **Third**, small-scale PV systems (i.e. < 100 kW) are curtailed (SMA 2012)

Remote-controllable "feed-in management"

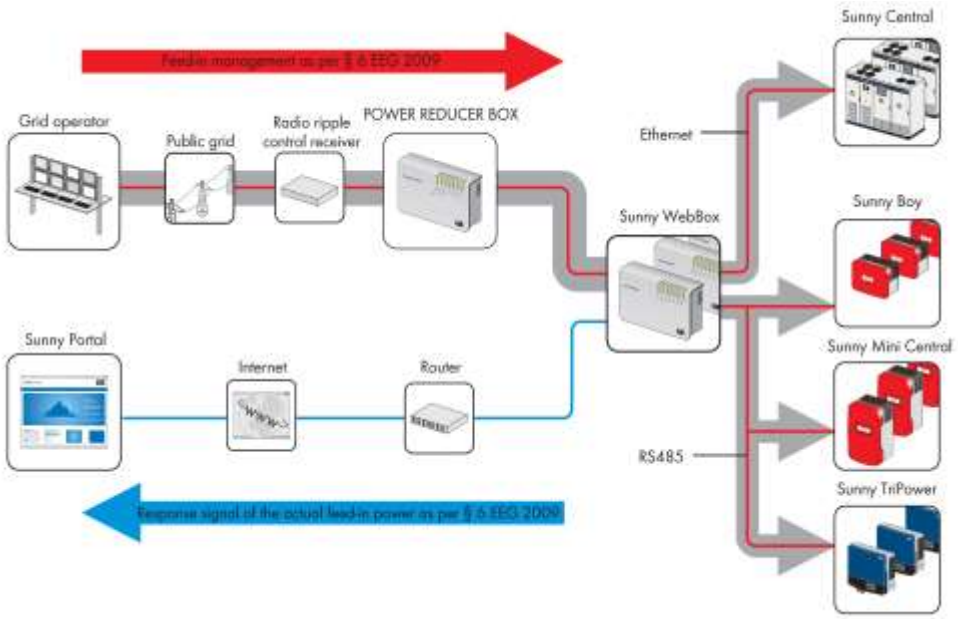
[12] A larger number of other technical solutions to better integrate distributed PV into distribution networks was analyzed as part of a larger European research project Vandenbergh, M., et al. (2013). Prioritisation of technical solutions available for the integration of PV into the distribution grid Brussels, PV Grid project (deliverable 3.1).

[13] In addition to the policies discussed in this section, German system operators use standard load profiles for small-scale consumers. These are currently updated and might reflect standard load profiles of different prosumer types in the future.

When the grid operator[14] needs to manage electricity supply by using the ripple control receivers[15], it can send signals to reduce the amount of electricity fed into the grid in 10% increments. Common practice is to reduce by 30%, 60% or 100% (SMA 2009). The inverter needs to respond to these demands within a timeframe of 60 seconds (Müller 2011). The required ripple control receiver is usually sold by the network operators.

The German inverter producer SMA was one of the first companies to provide the necessary hardware for remote-controllable PV systems. The ripple control receives the digitally coded signal from the grid operator and sends it to an additional Power Reducer Box. The Power Reducer Box then sends another signal to the inverter (see Figure 2.5 below). The amount of curtailed electricity is tracked by these devices. The grid operator then compensates generators for the amount of electricity that was curtailed.

Figure 2.5. Feed-in management with ripple control receiver and Power Reducer Box



Source: (SMA 2009)

For systems larger than 100 kW, grid operators also receive information about the amount of electricity fed into the grid at the interconnection point in real time. For this purpose, a second communications channel (e.g. Internet, telephone connection, etc.) is required (SMA 2009).

The cost of retrofitting old solar PV systems with modern communication infrastructure to allow for feed-in management created controversy. The upgrade of old systems started in 2012. It targeted PV systems installed in the years 2009-2011 (~20 GW of capacity). The German solar PV association (i.e.,

[14] In Germany, grid operators have a function akin to that of North American system operators and are responsible for voltage control

[15] The ripple control technology is used for solar systems. The signal is usually transmitted via a long-wave radio channel. The radio ripple control receiver costs about 23 € per year (2012 data).

Bundesverband Solarwirtschaft or BSW) argued that the associated costs should be borne by the grid operator since the infrastructure was required to assure grid stability. Policymakers eventually decided that the costs for retrofitting should be borne by the PV producer. Therefore, the fixed curtailment option (see below) was created for systems smaller than 30 kW.

The costs for the technical upgrade have decreased considerably over the past years. As of 2012, a remote controlled inverter cost around 900 € and was mandatory only for larger-scale systems. As of 2016, the communication infrastructure is available at around 100 €.

Fixed curtailment of peak PV output

The easiest solution, which requires almost no technical innovation, is to cap the maximum output of PV systems at a certain percentage of the nameplate peak capacity. Only PV systems smaller than 30kW are eligible for this option. In Germany, PV output of such systems is capped at 70% of nameplate capacity.[16]

This regulation reduces the annual cumulative power generation of a PV system by about 1% (Müller 2011). This is low because of the variable nature of PV generation – spikes in electricity export occur only very rarely. This regulation has had only a limited impact on the economics of solar PV systems, but has made an outsized contribution to system stability (i.e., by reducing voltage variations and grid congestion).

Monitoring the implementation of this policy solution, however, has proven to be difficult. There have been rumours that installers simply state a higher peak installed capacity when communicating the core data to the responsible authority. This way, the 70% percent curtailment cap can effectively be avoided. From the policymaker's point of view, controlling the installation of thousands (or millions) of small-scale systems is almost impossible.

With the digitalization of electricity and energy systems around the world, the issue of blind system regulation may become a thing of the past. Based on the roll-out of smart grid and smart meter technologies, real-time communication between DER and grid operators may become the common standard in the near future. This is possible since communication infrastructure for behind-the-meter PV systems with system operators is increasingly inexpensive.

[16] Technically, the meter at the customer's site measures the active power influx at the point of common coupling and controls that the feed-in power is never above the contracted maximum power or above a fixed value.

3. GRID MODERNIZATION AND THE UTILITY OF THE FUTURE

The breadth of the objectives associated with grid modernization[17] and with the creation of the utility of the future provides policymakers with enormous opportunities, as well as challenges.

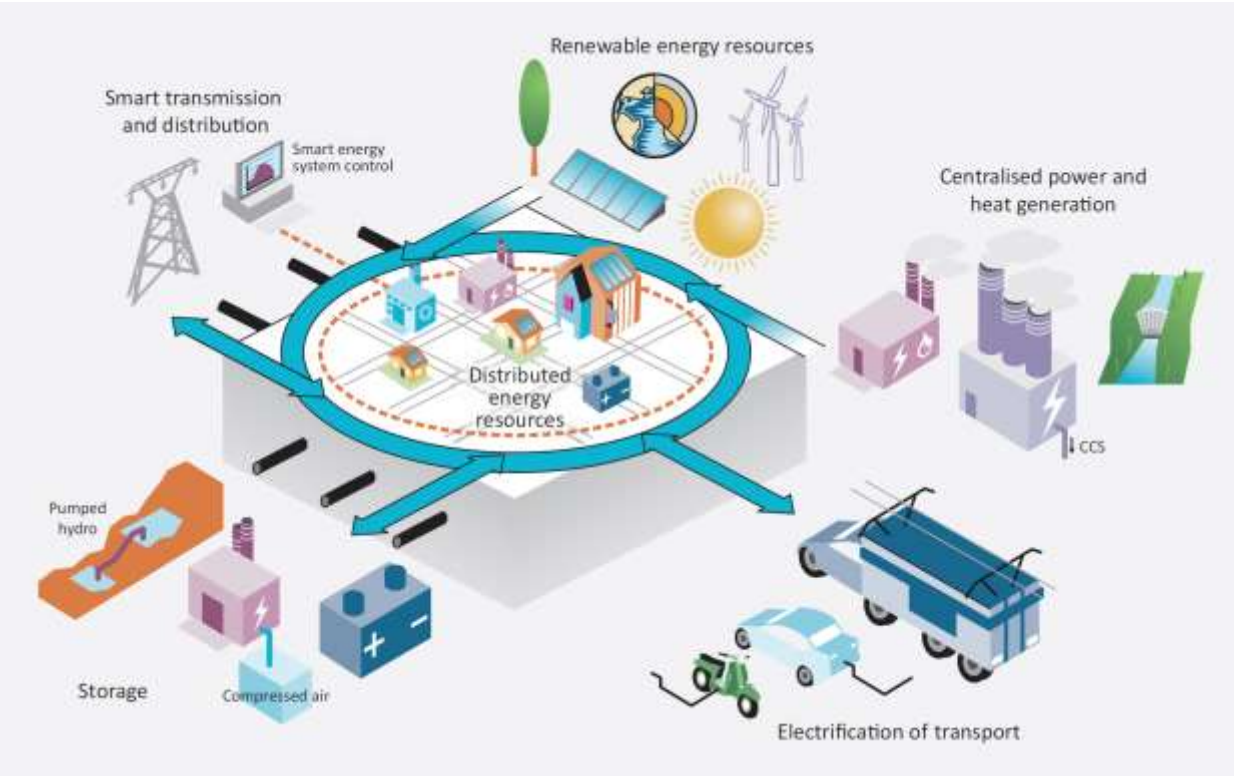
Grid modernization[18] is intended to integrate small, clean generating resources into the electric grid; enable two-way communication between the utility and customers and between Transmission System Operators (TSOs) and Distribution System Operators (DSOs); lower electricity costs through reduction of system peak usage; provide customers with more control over their electricity use; assure more reliable electric service; and handle massive amounts of data.

Inevitably, utilities will participate in the transformation of this modernized world, and will also be transformed by it. It is too early to say what, precisely, the utility of the future will look like, and the REV proceedings in New York give an indication of one set of possibilities. Even at this relatively early juncture, it seems certain that the utility of the future will require financial incentives that are far better aligned with public policy objectives, such as integration of DERs and peak reduction, than they currently are. Whether, in most jurisdictions, utilities will function chiefly as platform providers, or retain something closer to their current role, remains to be seen. Figure 3.1 shows how an integrated and intelligent electricity system will likely function in the future.

[17] Recent innovations in European smart grid technologies and regulation are summarize on the website http://www.gridinnovation-on-line.eu

[18] It is noted that the terminology associated with grid modernization is often imprecise. In this report, "grid modernization" is used to refer to the creation of an electric grid that can deliver on all of the objectives listed above. "Utility of the future" usually references a distribution utility structure that incentivizes utilities to support these objectives. The term "smart meters" is a colloquial reference to "advanced metering infrastructure," which integrates electric meters with communications and data management infrastructure, so as to enable two-way communication between utilities and customers.

Figure 3.1. The integrated and intelligent electricity system of the future



Source: (IEA 2014)

To achieve these objectives, technology development and regulation must move forward in an iterative fashion. This chapter is divided into two broad categories, "Regulation" and "Technology" to reflect the parallel developments that will be required. As technologies develop, regulation needs to direct and make space for their deployment, in a way that reflects a public policy agenda, including the objectives associated with modernizing the electric grid and, potentially, transforming the utility business model. Regulation also needs to create structures and programs that, overall, align the behaviour of utilities and other market participants with public policy objectives (The MIT Energy Initiative 2013). These interactions are a challenge because technology development generally reflects an entrepreneurial outlook, whereas regulation tends to live in a more cautious space.

Technology will realize its full value only if accompanied by appropriate regulation. At a fundamental level, two relatively recent reforms in the US are beginning to align regulation with grid modernization objectives. One is decoupling, which removes the incentive for utilities to maximize their energy sales and to resist energy efficiency programs (Shattuck and Lebel 2016). The other, still in its infancy, is the effort to incentivize utilities to facilitate the development of distributed energy resources and other alternatives, much as utilities are currently incentivized to add large infrastructure projects (The MIT Energy Initiative 2013, Advanced Energy Economy 2014, Bade 2016). In Germany, grid expansion paradigms have been changed in order to integrate high shares of wind and solar PV at the lowest possible cost (see section 4.1).

Other examples of regulations that drive grid modernization objectives do not involve changes at as fundamental a level as decoupling and departures from cost-of-service ratemaking, but are nonetheless important. For example, deployment of renewable resources is enhanced by policies like net metering, which itself has many variants that are subject to policy choices (see section 2.1). Similarly, energy storage is advanced by policies like California's energy storage procurement target. And smart meter infrastructure may realize its potential only in the context of time varying rates, which can also be instrumental in integrating electric vehicles into the grid and lowering electricity costs.

Related to the Utility of the Future, the following issues will be addressed:

- Lost Revenue Recovery through Decoupling and other Mechanisms (see section 3.1)
- Modifying the Cost-of-Service Rate-Making Paradigm (see section 3.2)
- Incentivizing Distributed Resources in Specific Locations (see section 3.3)
- The Relationship of Utilities with Other Market Participants (see section 3.4)

In this chapter, the following technological and regulatory interventions related to Grid Modernization will be discussed:

- New Roles for Distribution System Operators and the Potential for Cellular Grids (see section 3.5)
- Technological Innovations: "Customer-Facing" and "Grid-Facing" Technologies (see section 3.6)
- Microgrids and Virtual Renewable Energy Power Plants (see section 3.7)
- Storage for Flexibility and Grid Services (see section 3.8)

3.1. Utility Regulation: Lost Revenue Recovery through Decoupling and other Mechanisms

As in most industries, the profit motive for electric (and also gas) utilities incentivizes the sale of more product: sell more kilowatt hours, make more money. This incentive system was well aligned with public policy objectives for many decades when the goal was to electrify the country (and to assure that the utilities were robust enough to do it). But now, with most developed countries almost entirely electrified and the objectives having changed to increasing energy efficiency, demand response, and renewable resources, this so-called "throughput incentive" no longer makes sense.

There are a number of policy mechanisms in the US aimed at removing the throughput incentive, through "lost margin recovery" or "lost revenue recovery." These include revenue decoupling, as well as lost revenue adjustment mechanisms (LRAMs). In addition to severing the link between utility sales and revenue, decoupling has other advantages, such as shielding utility revenues from sales fluctuations and reducing the need for frequent rate cases. By contrast, LRAMs do not attempt to sever the link between revenue and sales completely but, rather, attempt to determine the portion of lost revenue attributable solely to energy efficiency programs (and not, for example, to fluctuations in the weather). LRAMs introduce serious verification difficulties, opening the door to contentious rate cases and the potential for gaming (ACEEE undated).

In establishing a program that removes the link between utility profits and the amount of power sold, regulators determine the utility's revenue requirement for a particular year, and allow the utility to collect that amount regardless of sales volume. A common approach is to connect revenue to the number of customers instead of to the quantity of sales; revenue per customer is fixed and an automatic adjustment to the revenue requirement is made with any new or departing customers. Periodic adjustments are made to ensure that the utility is not under- or over-collecting (Center for Climate and Energy Solutions undated).

Regulators have a wide range of options in designing a lost revenue recovery program. These include decisions as to how frequently adjustment should be made; whether there should be carrying charges; whether there should be an annual cap on the amount of the adjustment and, with an annual cap, whether carry-overs should be permitted; and whether rate-setting for the utility should reflect the utility's reduction in risk (Migden-Ostrander, Watson et al. 2014). Some states have lost margin recovery mechanisms for both electric and gas utilities, and others have such programs only for electric or only for gas utilities. The majority of states have some lost revenue recovery mechanism in place (IEI 2014).

For the most part, these types of mechanisms have been intended to remove the *disincentive* for utilities to support energy efficiency programs, rather than actually to *incentivize* support. However, it has become increasingly clear in recent years, given the need to decarbonize the electric system, that utilities need incentives actually to promote both efficiency and distributed resources, rather than simply incentives not to resist. Hence, the move towards creating the same types of incentives for alternative resources as exist for the construction of large capital projects, i.e., the ability to make a profit on integrating these resources, as well as direct performance incentives for accomplishing policy objectives (ACEEE undated).

3.2. Utility Regulation: Modifying the Cost-of-Service Rate-Making Paradigm

In regulated markets in the US, utilities make a profit by increasing the value of their assets, on which regulators provide them with an assured rate of return. This fundamental rate-making paradigm, known as cost-of-service regulation, incentivizes utilities to build large infrastructure projects. For this reason, utilities favour projects, transmission lines and gas pipelines over distributed resources (Climate Action Business Association undated).

However, starting with New York in the US, a small number of states and utilities are beginning to consider modifications or alternatives to this paradigm, such that utilities would receive the same sorts of rate-making incentives for facilitating the development of distributed resources, including both an opportunity to earn a guaranteed rate of return on such projects, and to recover performance incentives (Bade 2016, Shattuck and Lebel 2016).

New York is well known for its far-reaching Reforming the Energy Vision (REV) proceeding. New York is on a path to change fundamentally the way utilities are regulated, making utilities the distribution platform on which energy resources compete. The rate-making incentive structure being considered would no longer cause utilities to prefer large infrastructure projects over energy efficiency and distributed resources, and performance incentives would be provided for facilitating policy objectives like integrating renewables and reducing peak load (AGREE New York undated).

Other states are considering adopting some aspects of the REV regime. California, in particular, has proposed to provide the same rate-making treatment for distributed resources as for infrastructure projects. As New York recently has appeared to be leaning, California's proposal would add this treatment of distributed resources to the rate-making paradigm, rather than replacing cost-of-service treatment for infrastructure projects (Bade 2016).

Minnesota is also examining its rate-making paradigm, though it is earlier in these efforts than New York and California. However, it is worth taking note of Minnesota's work in that, unlike New York and California, Minnesota is a state with vertically integrated monopoly utilities (Minnesota Public Utilities Commission 2016, Trabish 2016).

3.3. Utility Regulation: Incentivizing Distributed Resources in Specific Locations

Electricity markets have long used price signals to incentivize generation and demand side resources to locate in specific locations. Although different mechanisms are used, the core principle is that the price signal varies depending on whether or not an area is transmission constrained and, therefore, a particular resource brings a different value to the system. Generally speaking, the same resource should be more valuable in an area in which transfer capabilities are limited than in areas without these constraints (M. Miller, L. Bird et al. 2013).

However, regulatory incentives such as those being developed in New York and California that drive utilities to facilitate the development of distributed resources include a focus on development in specific locations that go beyond these nodal or locational marginal pricing types of signals. They are intended to put distributed resources on an equal footing with large infrastructure projects from the point of view of utility profit-making.

For example, associated with its ambitious efforts to fundamentally overhaul the ratemaking process, New York is developing an approach to value solar and other distributed resources based on their location and other attributes. Projects in constrained regions of the grid would be credited for avoiding more expensive system upgrades, and solar panels oriented toward the west would receive greater value because of their ability to generate power when needed to meet peak demand during hot summer afternoons (Shattuck and Lebel 2016). New York has also promulgated interconnection regulations that facilitate the interconnection of new distributed energy resources and help utilities determine whether proposed projects are in appropriate geographical areas (NYPSC 2016).

Although California's redesign of ratemaking is not as ambitious as New York's, the California PUC has directed utilities to develop locational pricing for distributed resources. The state is now also attempting to go further. Using information from locational pricing initiatives and other planning, utilities would identify opportunities for cost-effective distributed resources in appropriate locations. Assuming approval of a project by regulators, utilities would propose an associated incentive payment (Bade 2016, CPUC 2016).

A frequently cited example for locational incentives is Texas, having implemented nodal pricing from more than 4000 grid connection points (M. Miller, L. Bird et al. 2013). More recently, the Mexican government has recently implemented a set of policies to increase the share of renewables and other low-carbon technologies in the power sector. In order to incentivize private sector investment, auctions for large-scale renewable energy projects will be implemented. The auctions are designed in such a way that power generation will be incentivized when and where the system needs it most.

In order to do so, the Mexican government developed a methodology that calculates an ex ante wholesale "benchmark" price that is calculated on an hourly basis for each generation zone. The wholesale electricity market operator calculates hourly price benchmarks for an average 24-hour period of each month of each year of the 15-year contract. The contract price resulting from the auction is then adjusted by the benchmark price. If the benchmark price is positive in a given location or time period this signals that the electricity provided will be of higher value to the system, resulting in additional compensation. The entirety of the location-specific 15-year benchmark trajectory is published in advance of a given long-term energy contract auction, and is intended to steer project developers toward selecting more "system-friendly" project locations. (IEA-RETD 2016).

3.4. Utility Regulation: The Relationship of Utilities with Other Market Participants

With the explosive entry of new players in the electricity marketplace—such as developers of distributed resources and owners of electric vehicle charging equipment (EVCE)—a question arises as to their roles relative to that of the traditional utilities. On the one hand, utilities have a distinct advantage over these new entrants, in that they have established customer contacts and, significantly, the ability to rate-base investments. These advantages could make them powerful players in the distributed resource space. On the other hand, these factors also create the concern that utility ownership limits the opportunity for a competitive market to develop, potentially limiting the role of players that are far more nimble and entrepreneurial than the utilities.

In unregulated markets, where DER penetration is moving particularly fast, utilities typically do not have the option of owning generating assets, including distributed resources. The question arises as to whether the alignment of distributed resource proliferation with public policy objectives should change this paradigm in any respect. The utility appetite for distributed resource ownership also arises in regulated states. The Edison Electric Institute, which is the association of investor-owned electric utilities in the US, argues for a utility ownership stake in such resources (and notes that utilities already own substantial solar assets) (EEI 2016, Lacey 2016).

At the moment, the landscape is dynamic with respect to these issues. For example, in a program that has sunset, Massachusetts law allowed utilities to own a limited amount of solar resources, despite the fact that the electricity industry is no longer vertically integrated in the state. Utilities took only limited advantage of this opportunity. Another Massachusetts example, for which the case study below is provided, is EVCE, which utilities are allowed to own for their own charging infrastructure but only in circumstances in which a market seems unlikely to develop (Elgin 2016).

By its order of August 4, 2014, the Massachusetts Department of Public Utilities ruled that owners of electric vehicle charging equipment are not "distribution companies" or "electric companies," and therefore are not subject to the Department's jurisdiction. In reaching this conclusion, the Department relied on state law that defines distribution companies as delivering electricity over "lines;" in other words, over wires, not through a connector or cord. It also determined that owners of EVCE are not electric companies under state law because they sell charging services, not electricity. "EVCE," the Department said, "allows the customer to do only one thing, charge an EV battery." Although the Department based its conclusion on a reading of Massachusetts law, it noted that the New York Public Service Commission had reached the same conclusion (N.Y.P.S.C. 2013, DPU 2014, Elgin 2016).

The Department went on to consider whether electric distribution companies may or should own and operate charging infrastructure. Its conclusion was that, in general, they should not. The Department's reasoning was that utility ownership could interfere with the development of a competitive market for the equipment and, further, that EVCE ownership was not necessary in order for electric utilities to fulfill their mandate of providing reliable distribution service.

However, the Department enunciated several exceptions to its general conclusions:

- Distribution companies are permitted to recover the cost of EVCE ownership and operation for their own vehicle fleet charging and for employee vehicle charging.
- Investment in research and development related to EVs, EVCE, and EV charging is encouraged.
- Cost recovery for distribution company ownership and operation of EVCE in response to a company proposal may be granted if the proposal (a) is in the public interest; (b) meets a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market; and (c) does not hinder the development of the competitive EV charging market (DPU 2014).

The Massachusetts case study is particularly notable for the criteria it sets forth regarding exceptions to the general rule prohibiting utility ownership of EVCE, which could provide a more generally applicable model for utility distributed resource ownership.

There are a number of other models, such as the creation of utility affiliates, incentivizing utility integration of distributed resources, and creation of a requirement that utilities purchase certain quantities of distributed resources. An example of this last is renewable portfolio standards, which exist in the majority of states and are generally viewed as successful in driving the development of

renewable resources. In many cases, they include bankable renewable energy procurement mechanisms, such as a requirement that utilities enter into long-term contracts for a certain amount of renewable generation.

3.5 Grid Regulation: New Roles for DSOs and the Potential for Cellular Grids

The paradigm that ruled the interaction between DSO, TSO (and ISO) is currently changing. The integrated and intelligent electricity system of the future (see Figure 3.1 above) requires electricity flows from the transmission network to the distribution network and vice versa. To make this happen, (real-time) data exchange between TSO and DSO has to improve. As a first step, data collection on system conditions in distribution networks needs to be strengthened, including (real-time) loads, (behind-the-meter) supply, installed capacities, and voltage. Via communication interfaces, this aggregated information need to be made accessible for TSOs.

However, some experts also argue that not all data need to be communicated to the TSO in the future, since balancing of supply and demand could already happen (partially) at the distribution level (Martinot, Kristov et al. 2015). These experts argue that balancing electricity supply and demand will be difficult at the regional or national levels once power markets move to high shares of DG, resulting from the large amount of data, data security issues, and the missing knowledge of actors about local flexibility options (Benz, Dickert et al. 2015). The distribution level, or even more granular units of the grid, might be more feasible level for balancing supply and demand. In order to accomplish this type of balancing, electricity markets would likely need to move from fixed electricity prices to time-of-use rates and eventually to real-time pricing (Hogan 2014).

This shift to time varying rates runs counter to the current design and operation of most electricity systems. Economic theory suggest that balancing power demand and supply over larger areas is more cost-effective since least-cost sources can be dispatched and fluctuations from variable renewable energy sources can be balanced more easily (IEA 2011, IEA 2016). Therefore, power markets in many regions around the world are increasingly interconnected (via transnational grids) and are integrated via market coupling (EU Commission 2015).

This contradiction poses a formidable challenge for policymakers. For the time being, market coupling and transmission grid expansion are the most cost-effective solutions for integrating high shares of DG. In the longer-term, higher shares of distributed resources, technological innovations, and advances in telecommunication infrastructure might shift the balancing obligations from the national/regional to the local level. Important lessons can already be learned today from micro-grid innovations (see section 3.7). At the same time, policymakers in Germany have started pilot projects to investigate the potential management and design of cellular grid approaches.

The German government funded six “E-Energy” pilot projects to investigate a) whether cellular systems are easier to manage than integrated regional, or national, energy systems and b) whether the technology necessary to implement them exists and is accessible (E-Energy 2012). The project in the city

of Manheim[19] designed a cellular control concept for electricity grids. The project focuses on small, grid-connected, and self-controlled structures rather than a central network monitoring and management system. The distribution grid being studied in Mannheim contains about 200 "cells", as well as smart telecommunication infrastructure to support grid- and market-driven processes (Grid Innovation Online 2013).

Similar to the Internet, all electricity cells are interconnected, but the network does not collapse if one or several units fail. This approach is supposed to increase security of supply in the long run. Physical energy transport between the transmission and distribution (T&D) networks and the cells is kept to a minimum, thus reducing losses. The cells act as autonomously as possible and are therefore more resilient and less vulnerable to failures in the larger system. Cells can be fully decoupled from the grid when needed until all elements of the overall electricity system are fully functional again. Single cells also have black start capability (E-Energy 2012, Kießling 2013).

3.6 Grid Technologies: "Customer-Facing" and "Grid-Facing" Innovations

Modernization of the electric grid is becoming increasingly important as a result of the aging of the grid, the growing dependence on appliances and other devices powered by electricity, consumer expectations regarding reliable service and power quality, and the vulnerability of the grid to storms and to cyber and physical attacks. In addition, an increasing share of DG is connected to the distribution system, which will require the modernization of the grid. At the same time, grid modernization is increasingly enabled by the advent of new information and digital communications technologies. [20]

The grid modernization technologies that are the most visible to customers are advanced metering infrastructure (so-called "smart meters") and other "customer-facing" technologies, such as remotely-controlled thermostats that allow the customer and the utility to optimize the customer's use of electricity.

However, "grid-facing" technologies are equally important in order for the grid to be fully modernized. These include the controls and automation necessary to optimize the voltage and power factor of the distribution circuits, advanced distribution automation to detect outages and minimize their impact, and

[19] The German city of Mannheim has 300,000 inhabitants and high demand for electricity due to energy intensive industry in its surroundings.

[20] A recent article emphasizes the need for industries to set long-term technology targets in order to drive innovation. The article stresses the importance of companies' pooling resources to fund research and standard-setting efforts. They add that companies "should not assume that the only improvements worth investing in are incremental to existing products." Sivaram, V. and S. Kann (2016). "To Become Truly Mainstream Solar Will Need to Cost 25 Cents per Watt by 2050, GreenTech Media, Available from http://www.greentechmedia.com/articles/read/why-solar-will-need-to-cost-25-cents-per-watt-by-2050?utm_source=Solar&utm_medium=Newsletter&utm_campaign=GTMSolar."

computer and communications infrastructure to support the exponential increase in data and to monitor and control distribution circuits remotely and in real time (The MIT Energy Initiative 2013).

Owners of electric system infrastructure also need to focus on other technologies in order to enable these "customer-facing" and "grid-facing" technologies. Modification of many utility legacy systems, including billing and accounting systems, will also be required in order to allow these new technologies to function. The Textbox 3 below describes a new approach for distribution grid planning in Germany as well as innovative technical solutions based on remote-controlled local power transformers.

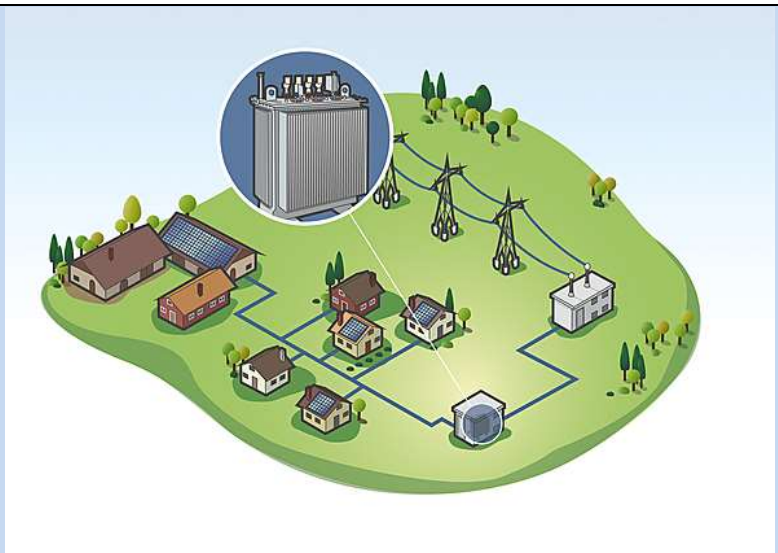
Textbox 3: Distribution grid expansion planning in Germany

DG technologies, including CHP plants and renewable energy technologies, are mostly connected to the distribution grid. In Germany, this holds true for 98% of all renewable energy plants (BMWi 2014). Therefore, expanding the distribution grid has become the next big challenge as part of the German energy transition. A simple tweak in distribution grid expansion planning will be implemented in 2016 in order to integrate DG in a more cost-effective way. In the future, distribution system operators can opt for taking a certain amount of DG curtailment into account. Instead of planning for transporting each and every kilowatt-hour produced, DSOs have the right to expand the grid in order to transport only 97% of DG. Renewable energy power producers will be fully compensated for the planned curtailment (BMWi 2015). This will considerably reduce distribution grid expansion, since wind and solar PV systems have relatively rare generation peaks. By curtailing 3% of renewable energy generation, the cost for distribution grid expansion can be reduced by up to 15% (Büchner, Katzfey et al. 2014). From a macroeconomic perspective, it is more cost-effective to curtail this peak generation and save on grid expansion costs (Bundesregierung 2016). This approach reflects the fixed curtailment and the feed-in management of DG in Germany discussed in Section 2.4.

In addition, distribution system operators are increasingly deploying innovative technical solutions to enable the integration of higher shares of DG. The major challenges for DSOs are related to voltage variations. Using remote-controlled local power transformers[21] in order to balance voltage fluctuations is frequently more cost-effective than expanding the distribution grid in traditional ways (BMWi 2014). How these technical devices can be integrated into the distribution grid infrastructure is shown in Figure 3.2 below.

Figure 3.2: Usage of remote-controllable local transformer stations in the distribution network

[21] The German term used is „regelbare Ortsnetztranformatoren (Ront)". Remote-controllable local power transformers are usually equipped with tap chargers to enable stepped voltage regulation of the output.



Source: (VDE and DKE 2013)

3.7 Grid Technologies: Micro-grids and Virtual Renewable Energy Power Plants

Microgrids involve a combination of generation, storage, thermal, and control resources, or some number of these, connected to one or multiple loads. Many microgrids include combined heat and power. Microgrids can operate entirely independently of the electric grid, or connect to and disconnect from the grid. Their benefits are that they can provide power in remote locations, ensure reliable electricity in the face of weather extremes (e.g., severe storms and rising sea levels) and, potentially, provide cleaner power than the larger electric grid (Advanced Energy Economy 2014, Institute for Local Self-Reliance 2016)

In the US, microgrids have historically been used the most in places that require a high degree of electric reliability, e.g., hospital complexes and military bases. As the owner of several microgrids, the US government itself is a leader in microgrid adoption (Advanced Energy Economy 2014). Although they are unlikely to become widespread in the near future, microgrids are becoming increasingly common in remote locations and, more widely and often with state subsidies, to provide safe havens in the event of severe weather.

At present, microgrids are being mostly deployed in areas which are not currently covered by the large grid. This is especially true for microgrids in developing countries. With costs of important system components decreasing rapidly (i.e., solar PV and batter systems), however, microgrids may eventually be cleaner and less expensive than the macrogrid would otherwise be.

Some microgrids are utility owned, and others involve private ownership. In some jurisdictions, privately owned microgrids confront objections from utilities, which claim that under certain circumstances microgrids interfere with the utilities' exclusive franchise. The viability of this claim will

depend on the particular state's law (Emmett Environmental Law and Policy Clinic 2014, Institute for Local Self-Reliance 2016).

For instance, Borrego Springs is a small (population 2,800) rural town in southern California. Because of its connection to the larger grid by means of a single, aging transmission line, frequently disrupted by weather and wildfires, San Diego Gas & Electric considered it the ideal location for a utility-owned microgrid (Hertzog 2014).

The microgrid was an existing utility circuit with a peak load of 4.6 MW, serving 615 customers. Funded by the US Department of Energy, the California Energy Commission, and the utility, the microgrid includes diesel generators, storage, electric car charging, and demand response technology. It also looked to existing resources, and included rooftop solar installations that pre-dated the microgrid itself. After its initial construction, the microgrid added connection to a 26 MW solar array in 2015 (SDG&E 2014). One of the highlights of the Borrego Springs microgrid is the ability to effectively island. In demonstrations, it transitioned seamlessly into and out of island mode. Then, during a severe summer storm in 2015, the microgrid was able to island successfully, providing cooling to residents in the microgrid and beyond during a serious heat wave (SDG&E 2014).

The project also successfully implemented a price-driven load management program that sent electricity price signals to home area networks and devices such as pool pumps and electric vehicles. This allowed the utility to demonstrate how residential customers will respond to price signals (SDG&E 2014). Perhaps the most interesting lesson of the Borrego Springs microgrid project is that it powered a portion of the surrounding distribution grid during the summer 2015 storm, and not just the community of the microgrid itself. This suggests new opportunities for engineering more resiliency into electric grids.

Another interesting case study is the NY Prize Community Grid Competition. In February of 2015, the New York Energy Research and Development Authority (NYSERDA) launched this $40 million competition. This first-of-its kind competition aims to assist in the development of community microgrids in New York State and in turn reduce energy-related costs, promote clean energy, and create a more resilient and modernized grid. The competition outlines several key objectives, which include empowering community leaders, encouraging private and public sector participation, protecting vulnerable populations, expanding the use of local distributed energy resources, engaging private sector interests, and aiding in the creation of a cleaner, more resilient energy system. These community microgrids must include at least one critical facility connected to multiple buildings acting as a group of interconnected loads and distributed energy resources. Critical facilities must provide a "critical service to the public". Eligible facilities include: wastewater treatment plants, hospitals, universities, facilities of refuge or shelters, schools, police departments, libraries, hospitals, and fire stations. An eligible microgrid must lie within a clearly defined electrical boundary and be able to operate as a single controllable entity in grid-connected or island mode. Behind-the-meter, single entity microgrids with an extensive operating history are not eligible for support from NYSERDA.

The program has three distinct stages: (1) a feasibility assessment, (2) a detailed engineering design and financial and business plan assessment, (3) the microgrid build-out and operation. The first stage offered

up to $100,000 through an RFP process for engineering studies assessing the viability of the installation and operation of microgrids (Wood 2015). Stage one proposals required participation from a local government and local electricity or fuel (if non-renewable sources are used) distribution company. The second stage, the more detailed engineering and financial study, is ongoing and will award up to $1 million dollars with a mandatory 15% cost share per accepted proposal. Approval or submittal in stage 1 is not a prerequisite to respond to the second RFP. Stage two requires participation just from the relevant local government. Payments to proposal winners in each stage thus far are dependent on the achievement of project-related milestones. The final stage of NY Prize is expected to commence in 2018 and award up to $5 million per project through an RFP process for the construction of microgrids.

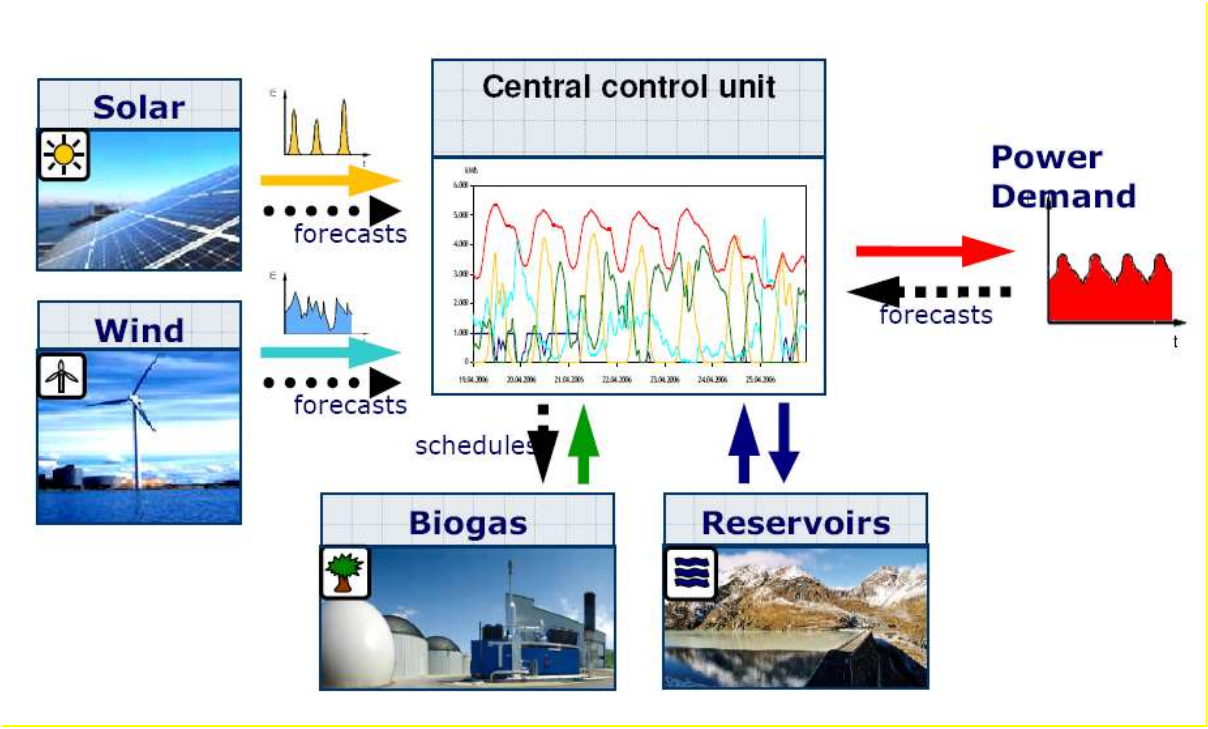
The first stage has been completed and NYSERDA awarded $8 million to 83 communities across the state. Initially the project intended to award 25 projects, but NYSERDA increased the acceptance pool when 147 applications were received (Wood 2015). A range of organizations in both the private and public sectors participated and partnered with communities in the first stage. These include multinational corporations, utilities, government organizations, and academic institutions. Many of the stage one studies are currently not feasible due to state of utility regulation in New York and also high financing costs. Stage two proposals are due in October and are expected to be awarded by the end of 2016 (Ryan 2016).

Similar to micro-grid, vitual power plant also have to balance supply and demand based on a combination of different DG technologies, including solar PV, wind energy, biomass, demand response and storage units. However, instead having to balance supply and demand in an isolated area, balancing happens “virtually” with an integrated electricity network.

Based on state-of-the-art communication technology, the system can balance fluctuations from wind and PV automatically through an increase of generation from dispatchable renewables. Currently, standards for unified telecommunication interphases are developed. This is crucial for automated trade of electricity as well as reliable system operation.

Germany started to promote the concept of virtual power plants as early as 2007 (AEE 2007). The first was the so-called “Combined Power Plant,” or *kombikraftwerk*, and was operated by leading German renewable energy companies from the biogas, PV and wind sectors. It relied on an integrated network of 36 wind, solar, biomass and hydropower installations spread across Germany. Wind and solar units generate electricity when those resources are available, and a collection of biomass and biogas plants and a pumped hydro facility make up the difference when they are not. The project size was chosen to represent the German electricity demand on a scale of one to ten thousand. Currently, Siemens and the utility RWE are working on more sophisticated communication platforms in order to bundle a larger number of distributed generators (Siemens and RWE 2015). Figure 3.3 below shows the interaction of different power generation sources within a virtual power plant based on a central control unit.

Figure 3.3: Functioning of virtual power plants in Germany



Source: (Mendonça, Jacobs et al. 2009)

3.8 Grid Technologies: Storage for Flexibility and Grid Services

Unlike all other commodities, electricity must be produced exactly to match load at all times. However, energy storage eliminates this problem and can thus increase the value of distributed resources. In addition to storing power from variable resources when those resources are unavailable, energy storage provides a host of other, ancillary grid services. Fast flexible energy storage can be used to provide ancillary grid stability services for upward reserves, downward reserves, frequency support, and voltage support functions. In general, these grid support functions can be supplied with a relatively small fraction of peak load sized energy storage capability, and therefore do not cost a lot on a $/kWh basis.

As the amount of variable renewable energy on the grid, like wind and solar, increases, storage becomes increasingly important sources for system flexibility – if other flexibility options are not available or more costly (Kondziella and Bruckner 2016). As will be discussed in a later section on the future of centralized supply and system flexibility (see section 4.1), energy storage is a relatively expensive option for balancing varying load with varying supply. Several studies have also shown that storage technologies will only be necessary from a technical point of view with high shares of (variable) renewables.

There are a wide variety of energy storage technologies, e.g., lithium-ion and other chemical batteries, molten salt and other thermal batteries, flow batteries, flywheels, pumped hydro, and compressed air. Pumped hydro has been in use for many years and is already cost-competitive (IRENA 2015). Lithium-

ion batteries are winning the race so far in the electric car and grid energy storage markets. However, they are still too expensive for widespread use.

Nevertheless, to reduce the costs of less mature storage technologies, policymakers around the world have established storage support programs. *Larger scale allows high volume production processes to be used to lower costs, similar to how semiconductor costs have been sharply reduced via Moore's law.*[22] *Currently scale is relatively low, as energy storage is used mainly for consumer applications (e.g., personal devices, automotive batteries for starting a vehicle, etc.).*

One of the largest storage programs around the world is currently rolled out in California. The state has set high renewable penetration policy goals, targeting RPS goals of 33 percent by 2020 and 50 percent by 2030.[23] California, seeing energy storage as crucial to getting to higher renewable market penetration, has mandated that larger scale energy storage be used in its market. The mandate is flexible as it allows many technologies to satisfy the energy storage function (e.g., batteries, thermal storage, etc.), increasing competition, and promotes the development of new technologies, as pumped storage is not allowed.

A further objective is to transform the market by defining operational needs, and clarifying storage regulatory frameworks, cost-effectiveness evaluation methods, price signals, and interconnection processes. Grid storage domains for the procurement are shown in Table 3.1:

Table 3.1. Storage procurement program in California

Storage Grid Domains ***(Grid Interconnection Point)***	***Regulatory Function***	***Use-Case Examples***
Transmission-Connected	*Generation / Market*	*Co-Located Energy Storage (Concentrated Solar Power, Wind+Energy Storage, Gas Fired Generation + Thermal Energy Storage)*
		Stand Alone Energy Storage (Ancillary Services, Peaker, Load Following)
	Transmission Reliability (FERC)	*Voltage Support*
Distribution-Connected	*Distribution Reliability*	*Substation Energy Storage (Deferral)*
	Generation / Market	*DG + Energy Storage*
	Dual-Use (Reliability & Market)	*Distributed Peaker*

[22] *Moore's law states that the number of transistors in a circuit doubles every two years, reducing cost per circuit as transistors shrink. Unfortunately, however, Moore's law does not apply to batteries because miniaturizing the active materials does not generally improve battery function.*
[23] *The state is on track to reach this goal, as retail sales of electricity in 2014 by renewables were nearly 25%.*

Behind-the-Meter	*Customer-Sited Storage*	*Bill Mgt / Permanent Load Shifting, Power Quality, Electric Vehicle Charging*

Source: (Commissioner Peterman 2013)

California issued an RFP in 2013 for a first large tranche of energy storage, 1.3 GW by 2020. This represents about 2-3% of California's installed capacity, so is only a first step on the way to 50% renewable by 2030. At 50% RPS under a "Diverse" source scenario, which uses a wide mix of energy resources (wind, hydro, nuclear, solar thermal w/storage, biomass, biogas, and geothermal) to meet demand when the sun is down, the consulting firm E3 estimates that 5000 MW of storage for 11 hours per day (with 80% storage efficiency) will be required by 2030 to reduce variable renewable energy integration costs (E3 2014).[24] They estimate that the 2030 mandate without storage may increase electricity rates by ~10%-15%, as high levels of curtailment are otherwise assumed (because storage costs are currently relatively high and/or pumped storage resource availability may be limited).

To increase competition, the procurement was split between the three largest investor owned utilities in the state – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). The 1.3 GW program is very large relative to the total market for storage in California and the US; California, the largest market, installed 36 MW from 2013-2015. This increase in scale alone should reduce equipment costs. A further effort to increase competition is that each utility is required to own 50% of its portion, and to obtain 50% from third parties. The above targets are further divided among transmission connected, distribution connected, and customer side of the meter categories.

The regulation also requires that the procurement be "viable and cost-effective". The CPUC proceeded to develop models to value the cost-effectiveness of the bids to satisfy this legislative requirement, but multiple stakeholders object to the models developed, noting that studies done by both EPRI[25] and DNV KEMA[26] "admit… that the final analysis depends on a number of sensitivities and inputs that cannot be accurately reflected in their model" (Commissioner Peterman 2013). This requirement of the legislation is a therefore a work in progress and allows the government to halt or delay the process if costs are too high.

The process has also spurred regulatory change and clarity. One energy storage revenue question is whether wholesale or retail rates apply when consuming electricity to charge an electric storage device, and whether other charges that traditionally apply to consumption should be levied. The CPUC has now indicated that wholesale market locational marginal prices apply for discharging and charging energy dispatches; but when the energy storage resource is located on the distribution system or behind the meter, FERC's wholesale distribution access tariff (WDAT) rates and/or the CPUC's jurisdictional retail rates may apply. The CPUC is also considering whether transmission access charges, wheeling charges,

[24] Without storage, solar PV will over-produce power during the day, costing ratepayers more. This is called "over-generation", and was the default option for the study as electricity storage costs are either prohibitive or space limited (in the case of pumped hydro).
[25] EPRI, Energy Storage Valuation Tool (ESVT) Version 4.0
[26] ES-Grid, found at www.sandia.gov/ess

and the like are appropriate to use and when, as the financing of energy storage projects depends on clarity with regards to project revenue (Denholm, Jorgenson et al. 2013, CAISO 2014, Charles 2014).[27]

[27] The CPUC is mandated to review the bidding process and progress every three years. Their website is http://www.cpuc.ca.gov; and further energy storage rulemaking updates can be obtained at http://www.cpuc.ca.gov/General.aspx?id=3462. Stay tuned.

4. THE FUTURE OF CENTRALIZED SUPPLY

This chapter discusses the future of large-scale, conventional power generation units in power systems with increasing shares of DG and variable renewable energy technologies, namely wind and solar PV. The focus is primarily on the future role of fossil-fuel based and nuclear power technologies.[28]

The chapter starts by discussing system planning and future capacity additions of centralized supply in the light of core characteristics of future power plants (section 4.1). Closely related is the issue of existing power plants becoming stranded assets and the phase-out of specific technologies (see section 4.2). In section 4.3, future electricity market designs will be discussed, focusing on gate closure periods in intraday wholesale markets and pre-qualification requirements for ancillary service markets. Finally, the technical parameters for centralized supply will be described by elaborating on strategies to reduce must-run capacity from conventional power plants (section 4.4) and remuneration for flexibility (section 4.5). The role of centralized power plants in future power markets will primarily depend on their specific characteristics (e.g., carbon intensity) and capabilities (e.g., ramping capabilities).

4.1. System Planning in the Light of Core Characteristics of Future Power Systems

Strategies for the future development of power markets differ from one jurisdiction to the next.From an international viewpoint there are common core characteristics that are likely to evolve. The future of centralized power supply will largely depend on **three trends**:

1. Decarbonization of power systems
2. Increasing shares of (variable) renewable energy sources
3. Increasing needs for system flexibility

A clear, long-term vision of where the power system is heading can help the private and public sectors adjust any new investment in energy infrastructure to the needs of future power systems (IEA-RETD 2016).

First, most **power markets (in developed countries) will be almost entirely decarbonized** if international climate agreements are taken seriously. The Paris Agreement commits nearly 200 countries to substantially reduce greenhouse gas emissions in the coming decades (IEA-RETD 2016). Many jurisdictions around the world have started to transition their power systems towards less carbon intensive technologies. This long-term objective is already reflected by Ontario's independent system operator's long-term outlook (IESO 2016). However, the gas-based power generation (which will still play an important part until 2032) would likely need to be displaced by zero-carbon technologies.

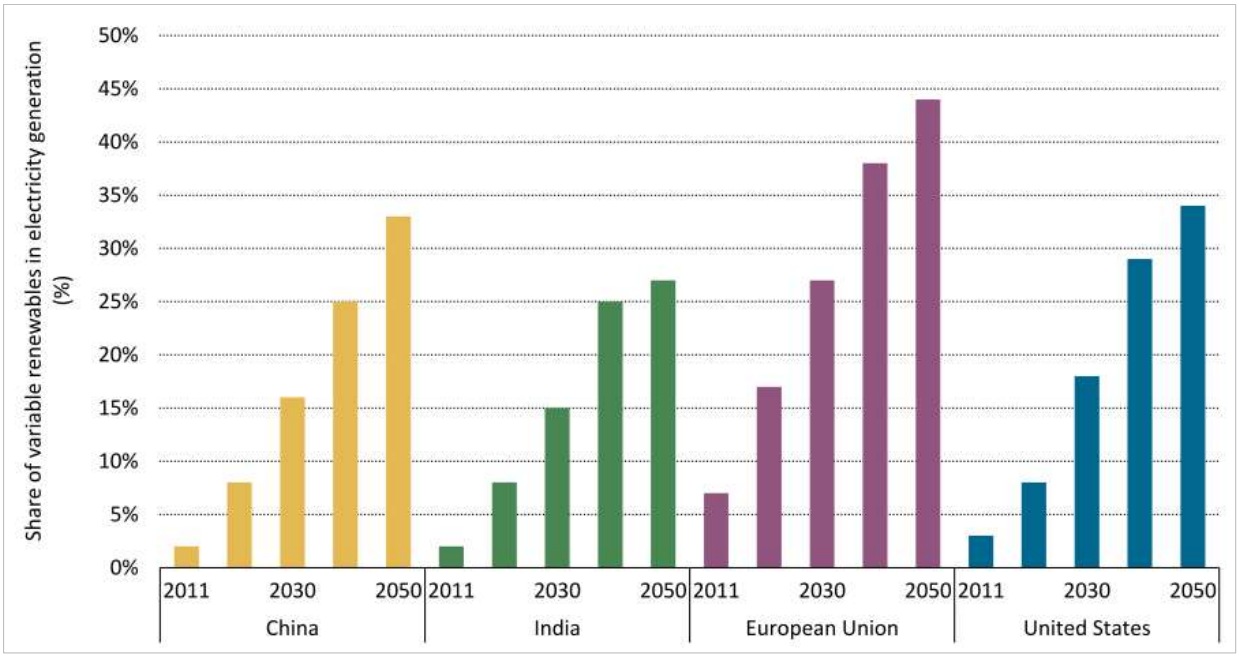
[28] Some experts also argue that large-scale renewable energy projects (e.g., 200 MW offshore wind projects) have many of the characteristics of centralized supply – in terms of grid connection and integration, distance from load centers, capital intensity, etc. However, for the sake of simplicity, these projects will not be analyzed in this chapter.

To meet the long-term decarbonisation objectives, global greenhouse gas emissions will have to be reduced by at least 50% (and up to 85%) by 2050. For developed countries, this translates to a required carbon reduction of 80-95% compared to 1990 levels (Bruckner, Bashmakov et al. 2014). The European Union has already responded to this requirement by setting the target of reducing greenhouse gas emission by 80-95% by 2050 compared to 1990 levels (EU Commission 2011, EU Commission 2011). At the G7 meeting in 2015, the largest economies of the world agreed to strive for a decarbonized global economy in the 21st century (G7 Germany 2015).

A (near) zero-carbon power sector may become a common target among countries that strive to significantly reduce carbon emissions, given the current challenges of decarbonisation across other sectors (Jones and Glachant 2010, IEA-RETD 2016). In order to reach the decarbonisation of the entire energy sector, the heating and cooling sector will have to be partially electrified with clean power.

Second, the share of variable renewable energy sources is likely to increase. More than 174 countries around the world have established targets for renewable energy deployment (Kiefer and Couture 2015, REN21 2016). Recent analyses from IEA (IEA 2014) have shown that, in key jurisdictions, variable renewable energy sources will reach shares of 30% and 45% of power generation by 2050. Certain jurisdictions (e.g., Germany and Spain) might have even higher shares as they strive fore decarbonized power systems.

Figure 4.1: The future share of variable renewable electricity generation in key markets world-wide



Source: (IEA 2014)

An increasing share of variable renewables (wind and solar PV) will require that centralized power suppliers have different operation (e.g., reduced full-load hours for previously baseload units) and configurations (e.g., higher ramping capabilities). Generators will also likely need to adapt to evolving

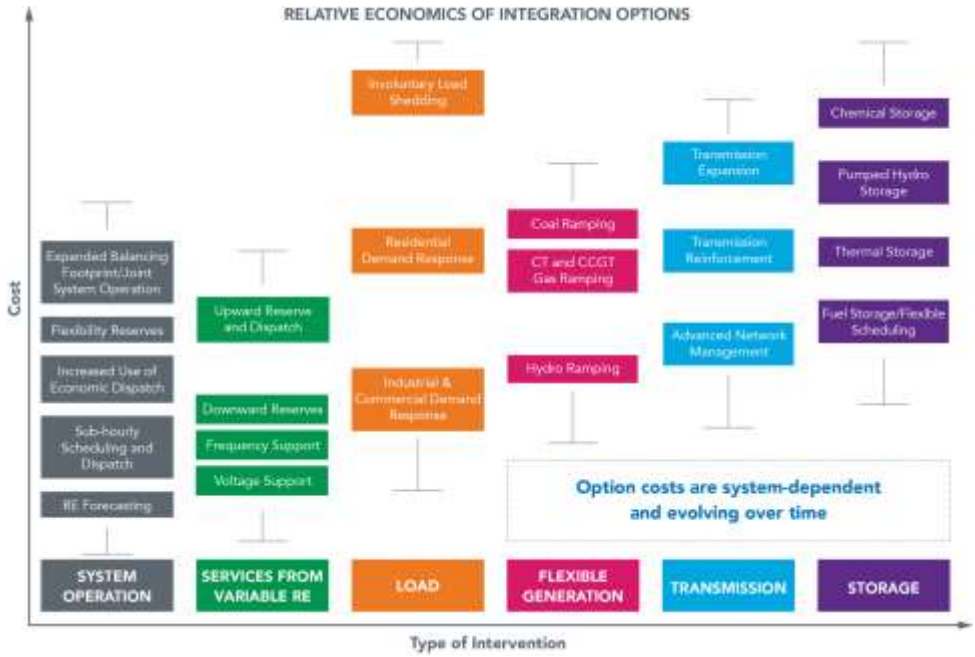
electricity market designs (see section 4.3). Wind energy and solar PV have certain **characteristics** that will also require a reconfiguration of existing electricity systems (Jacobs 2014):

- Wind and solar PV have close to zero marginal costs
- Wind and solar are capital intensive
- Wind and solar are frequently smaller-scale and distributed
- Small wind and solar PV are frequently deployed behind the meter and therefore system integration can be a challenge as penetrations increase
- **Their power generation is variable and can only be forecasted to a certain degree**

Third, power systems with increasing shares of variable renewables require a more flexible power system, one that can respond to more continual changes in demand and supply than have traditionally been the case (IEA 2016). All power systems have many options for increasing power system flexibility (Cochran, Miller et al. 2013), including (for example) alternative modes of system operation (Section 4.3). As can be seen in Figure 4.2 below, flexibility can be also achieved by transmission line expansion, storage, more flexible operation of conventional power plants, demand response (load) and system services from variable renewable energy sources.

Power systems typically include more technical potential for flexibility than is necessary – even for the integration of very high shares of wind and solar PV. The challenge for policymakers is to incentivise the needed flexibility at the lowest possible cost. The cost for flexibility depends on the flexibility options available at the national (or regional) levels. In developed countries with trans-national electricity grids, further grid expansion, market coupling and more flexible usage of existing fossil-fuel based power plants may be options for increased flexibility. At the same time, policymakers need to incentivize technical solutions, which will be crucial for fully decarbonized power systems. These may include demand response policies (see Textbox 4) and storage.

Figure 4.2. Options for electricity system flexibility



Source: (Cochran, Miller et al. 2013)

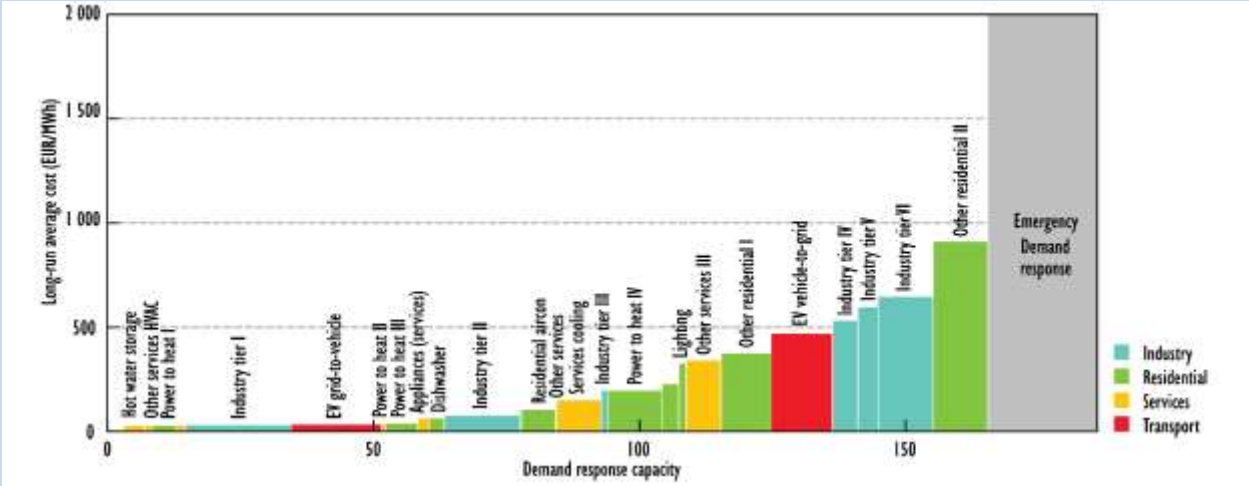
Textbox 4: Demand response – A potential game changer for power systems of the future

Demand response (DR) refers to the ability of electricity consumers to respond to wholesale market price signals. For example, consumers can reduce their electricity consumption when prices are high or when there are grid reliability concerns, through measures such as reducing lighting loads, raising temperatures to lower cooling loads, or halting interruptible industrial processes.

As shown by Figure 4.3 below, the cost for demand response varies largely. The Figure depicts the modelled demand response potential in the European Union in 2050. Demand response potential frequently amounts to around 15% of peak demand (IEA 2016). Currently, policymakers are harvesting the low-hanging fruit but they are also incentivizing demand response on a larger scale, since this will be an important flexibility option for fully decarbonized electricity systems of the future.

In some markets, utilities or system operators provide fixed payments to customers for being willing and able to decrease their load. In other market, demand response providers can participate in capacity markets and prices are determined via competitive bidding.

Figure 4.3. Modelled demand response and supply curve in the European Union in 2050



Source: (IEA 2016)

In the United States, the PJM Interconnection, for example, has over 11 GW of DR and energy efficiency capacity resources committed for the 2016/17 year.[29] Most DR capacity in PJM is emergency DR, which the utility can call on during extreme peak periods, but a growing proportion is "economic" DR, which bids DR sources into the market when pricing is favorable. This growth is due to the reduction of pricing uncertainty when the US Supreme Court upheld FERC Order 745 in January 2016 (Interconnection 2012, Walton 2016). Order 745 stipulates that DR providers be compensated for reducing load at the same electricity rates as if they met that demand with generated electricity (McAnany 2015).

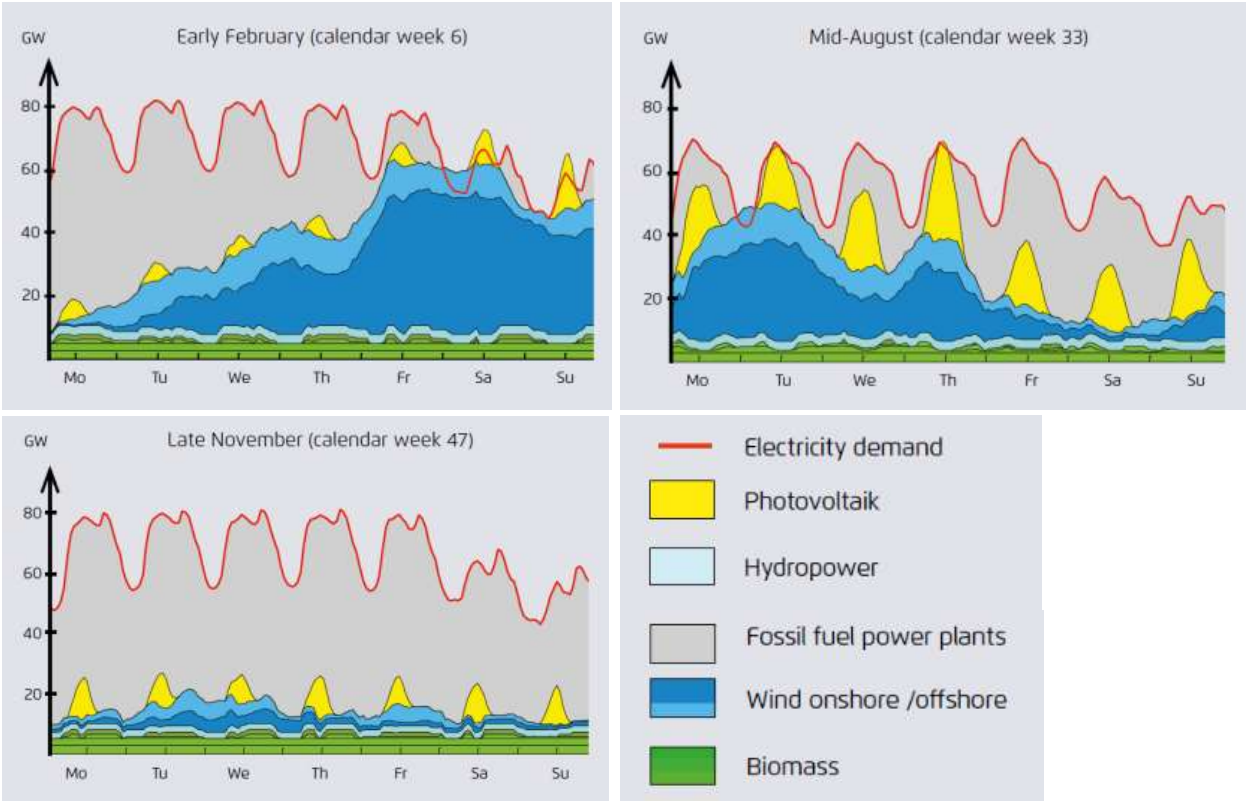
However, the operation and configuration of centralized supply will play an important role, since it can provide flexibility at relatively low costs – at least in the transitional period until power systems are fully decarbonized. The necessary configuration and operation of future centralized supply in terms of flexibility can be understood by looking at scenarios for countries with high shares of variable renewable energy sources. Germany, for instance, already has a 30% share of renewables in the power system. By 2025, the share will increase to up to 45%, with wind and solar PV providing the largest shares (RAP 2015).

Figure 4.4 depicts some of the major characteristics of the German power system in 2022. The role of centralized (fossil) power plants is shown in dark grey (Agora 2012).

- At certain times, renewables will provide more than 100% of electricity demand (about 200 hours in 2022). In the winter months, the primary source of power generation will likely be wind (onshore and offshore). In the summer months, solar PV will provide most of the power.
- During the winter months, there will be periods in which wind and PV cover only small amounts of power demand. At those times, centralized power plants will need to step in.
- The volatility of variable renewables increases with increasing shares of total power generation.

[29] http://www.pjm.com/markets-and-operations/rpm.aspx

Figure 4.4: Power generation pattern with high shares of wind and PV (Germany 2022 projection)



Source: (Agora 2012)

Accordingly, centralized supply will have to adapt with regards to power plant design and power plant operation (BMWi 2014):

- Depending on the actual share of variable renewable energy sources, baseload power plants running may no longer be able to fit into the power system of the future.
- Full-load hours of centralized power plants will decrease (e.g., coal-fired power plants in Germany today already operate for only 4,000 hours per year; gas-fired power plants for less than 1,000 hours per year).
- Centralized supply will need to become more flexible (e.g., faster ramping capabilities, reduced must-run capacity; shorter start-up times).

4.2. Stranded Asset Management and Phase-out Policies

In the long term, stranded investments can largely be avoided by taking the aforementioned core characteristics of power systems into account when planning power systems today. However, in the transitional period towards low-carbon technologies, stranded assets are likely to occur in jurisdictions with carbon intensive power sectors. The reason for this is quite simple: if governments want to reach climate targets they need to re-build the electricity sector faster than the usual economic lifetime of

some existing assets would require. New low-carbon technologies need to be deployed faster than old (carbon intensive) technologies would typically be taken out of the market.

A recent IEA report stated that the biggest challenge in the transformation phase of electricity system "may be managing the costs associated with scaling down the old system" rather than building up the new one based on low-carbon technologies (IEA 2014). Over the next 25 years, IEA estimates that worldwide a total of 610 GW of coal capacity will need to be phased out for environmental reasons (IEA 2016). In some jurisdictions of the US, Independent System Operators have identified the need for new low-carbon capacity additions due to retirements of coal-fired capacity because of stricter environmental regulation (MISO 2015). Even though a number of jurisdictions are currently preparing or planning the phase-out of coal (including the UK and Germany), there is limited empirical evidence of experience in this regard. In fact, Ontario is one of the few jurisdictions world-wide that, between 2004 and 2014, actually implemented and finalized the phase-out of all coal-fired power plants.

In addition, stranded investment may occur because system planning (in regulated markets) becomes increasingly complex. In the past, it was relatively easy for regulators to plan for system expansion based on centralized supply and on forecasts of future power demand. In the future, this will be much more difficult for two reasons:

- First, power systems will likely consist of both centralized supply and DG. The share of DG cannot be fully controlled by regulators and policymakers since certain prosumers might eventually decide to "cut the cord" and become fully independent from centralized supply.
- Second, future demand for electricity is more difficult to predict than previously. On the one hand, energy efficiency programs might lead to considerable reduction in power demand. On the other hand, the electrification of the heating and transport sector might lead to a considerable increase in electricity demand.

The ways to deal with stranded assets are largely dependent on the ownership of assets. In the case of privately owned assets, policymakers have to assure clear guidance on the future development of the electricity system in order to avoid lengthy legal confrontations with affected actors. If assets are publically owned, on the one hand, this can be an advantage since policymakers do not have to fear lengthy legal battles over financial indemnification. On the other hand, policymakers and regulators might end up being more cautious introducing any policy that would reduce the value of their "own" assets. The financial loss of publically owned stranded assets can be covered either by the general budget of a given jurisdiction or it can be passed on to all electricity consumers, as the case of Electric Industry Restructuring and Stranded Cost Recovery in Massachusetts shows below.

In the 1990s, following deregulation in other sectors of the economy, many US states required their electric utilities to sell their generating assets. The impetus was both a preference for utilizing market forces as opposed to government regulation, and an effort to bring down energy prices by harnessing competitive forces. Five states in New England—all but Vermont—restructured their electric industry.

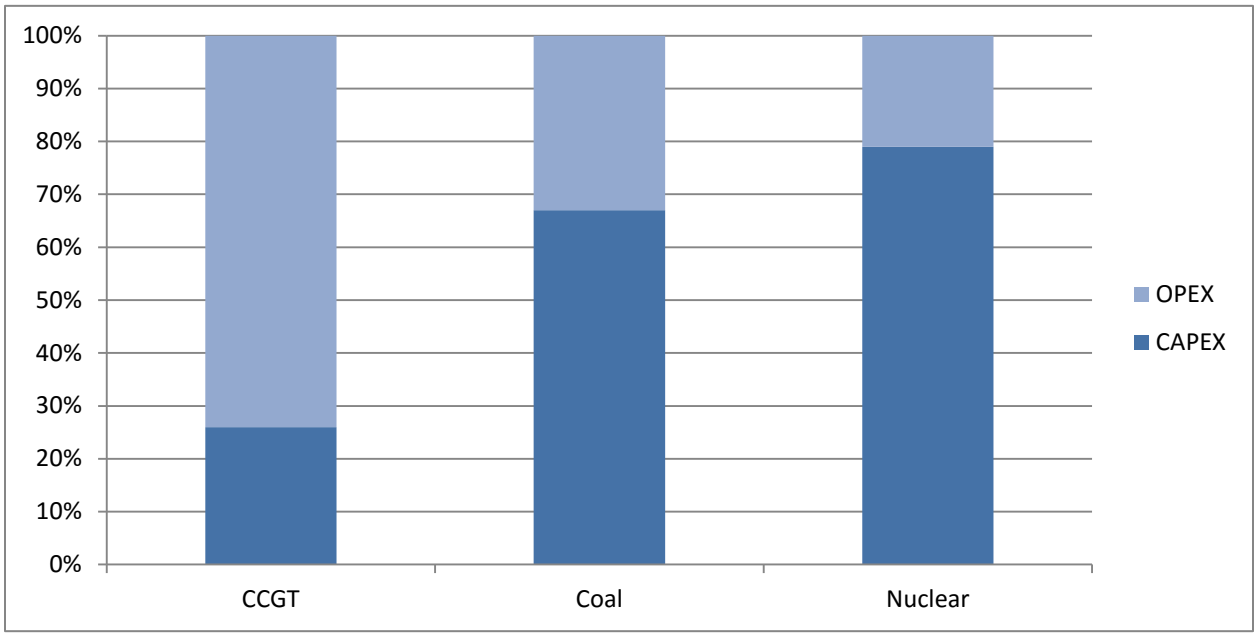
The 1997 Massachusetts Electric Restructuring Act required the state's electric utilities to sell their generating assets. This resulted in stranded costs for the utilities, associated with their investments in

these assets and the costs of divesting of them, offset by proceeds from the sale of the divested assets. The Restructuring Act required the Massachusetts Department of Public Utilities to determine these costs, to review them on a yearly basis, and to distribute them by means of a non-bypassable "transition charge" across all ratepayer classes (Attorney General of Massachusetts 2016).

Under the Massachusetts Act, stranded costs include, in addition to generating assets, above-market costs for existing power contracts, employee-related transition costs, and decommissioning costs at fossil-fuel generating plants. Stranded costs are a relatively small—and shrinking—portion of customers' electric bills (Reishus Consulting 2015). The stranded costs were more than $3.6 billion regionwide. Although the approach to stranded cost recovery across the New England states was generally similar, the amounts varied from state to state and across utilities, depending on the size and nature of the generation fleet and the magnitude of long-term contracts held when the industry was restructured. The length of time authorized by various states to recover those amounts also affected the cost amounts (Reishus Consulting 2015).

Stranded assets occur mostly due to "prematurely" decommissioned power plants. It is also noteworthy that the scope of stranded power generation assets depends on the capital structure of power generation technologies. The different share of capital expenditure (CAPEX) and operation expenditure (OPEX) leads to different levels of risks related to stranded assets. Capital intensive technologies (e.g., nuclear power and to a certain extent coal) can lead to larger amounts of stranded capital compared to gas-fired power plants (Figure 4.5).

Fig. 4.5. Share of fixed versus variable costs of selected power generation technologies



Source: Author based on (EIA 2013).

The phase-out of certain power generation technologies can be achieved via classic regulation (e.g., fixing a timetable for phasing out all relevant power plants) or via more market based mechanisms such as emission standards and carbon pricing. Mechanisms such as environmental regulation governing water consumption can also accelerate phase-out. When designing phase-out policies, the following **key principles** have been recommended (Harris, Beck et al. 2015, IEA-RETD 2016):

- Gather data and publish estimates on the various costs and benefits (including the health, environmental, and water-related benefits) of a phase-out strategy;
- Undertake detailed stakeholder consultations with power plant operators to develop realistic phase-out timelines and objectives;
- Establish a clear and transparent trajectory for phasing out power plants, including a detailed phase-out plan with timelines and a compliance schedule, potentially including penalties for non-compliance;
- Consider the funding of retraining programs, pension and healthcare assurances, and other similar measures to mitigate the negative economic and social impacts of plant retirements, as well as for elements of the fuel supply chain.

A similar approach was chosen in Germany. In order to avoid indemnification for industry and allow for a smooth structural change within the coal mining regions of Germany, policymakers and other actors are working on a consensus for a coal phase-out by 2040. The think tank Agora Energiewende has developed principles for a consensus on coal phase-out in Germany (Agora Energiewende 2016).

A coal phase-out in Germany is required because otherwise the ambitious German carbon reduction targets cannot be reached. Purely market-based mechanisms (i.e., the European Emissions Trading Scheme) have been deemed insufficient to drive the phase-out at the scale and pace desired. In Germany, it was calculated that moving lignite power plants out of the merit order via market based carbon price signals would require a European carbon price 40-60 €/tCO_2 (Götz and Huschke, 2013, Hermann and Harthan, 2014) – almost ten times higher than current prices in the European emissions trading scheme. The principles the Agora principles include:

- The establishment of a “Round Table for a National Consensus on Coal,” including all relevant national and regional actors. The consensus should stretch as far as possible since phase-out periods usually exceed the horizon of political mandates
- An incremental, legally binding pathway for phasing out all remaining coal plants by 2040 (including a decommissioning plan with flexibility for power generating companies that have more than one generating unit)
- A prohibition on building new coal-fired power plants (based on emission standards or other regulatory instruments (Schäuble, Volkert et al. 2014)) and on additional coal mining sites

- The creation of a "Structural Change Fund" for the affected regions (the financial resources would partially[30] be derived from a levy on lignite power generation)

Stranded assets might eventually also occur in grid infrastructure. Currently, transmission and distribution grid expansion is seen as one of the cheapest flexibility options to integrate higher shares of DG. However, there might be a tipping point in a few decades when distributed solutions (including battery storage, electrified heat and transport systems, and balancing of supply and demand in cellular systems,see Chapter 3) might end up being more cost-effective. In that case, policymakers might realize that the transmission grid was overbuilt and that some of the assets are stranded because of under-utilization.

Overbuilding the transmission grid has already occurred in some parts of Australia, where network fees account for about 50% of the retail electricity price, thus providing an unintended incentive for grid defection. With falling battery and PV systems, private households are now looking for distributed alternatives. Analysts have estimated that by 2018, households might have an incentive to fully disconnect from the electricity grid (Parkinson 2014, Deign 2015).[31] In order to recover their investments, the Energy Networks Association, which represents electricity transmission and distribution businesses throughout Australia, has tabled several (controversial) policy solutions to the problem, including:

- Increased grid connection fees
- Network exit fees for potential future grid defection
- Compulsory 'rates' style network access levies (even for customers who are not connected to the grid but live in a neighborhood with the potential for grid connection)
- Explicit compensation for stranding risks
- Greater regulatory flexibility in depreciation approaches (ENA 2015)

4.3. System Operation in Electricity Markets 2.0

To prepare for a future with higher shares of variable renewable energy sources, policymakers in leading jurisdictions have started to optimize the design of power markets. In Germany and other European countries, this redesign is known as "electricity markets 2.0" (BMWi 2014).[32] This process was also guided by the European Commission, which held a public consultation on future electricity market designs in 2015 (EU Commission 2015) in order to prepare related legislation. Two simple and effective changes to the market design are:

1. Shortening gate closure times in competitive wholesale markets.

[30] The rest of the financial resources required would come from the general national budget. The fund would consist of 250 million euros annually over the entire transformation period. Funding would be allocated to each region based on the number of jobs impacted in each respective lignite mining area.

[32] In 2014, Germany started a process to redesign the electricity market, the so-called electricity market 2.0. With a broad consultation process organized by the German Ministry of Economic Affairs (BMWi), a set of "no-regret" measures was adopted to increase system flexibility and reliability.

2. Opening ancillary service markets ("real-time markets") for renewables and other new actors.

In order to reduce forecasting errors for wind and solar PV generation, it is important to shorten the time between market closure and actual delivery of electricity by moving the gate closure of spot markets closer to the actual delivery time. This way, reserve requirements can be reduced and system stability can be increased (M. Miller, L. Bird et al. 2013). Balancing the system on intraday markets is also more cost-effective than real-time balancing, which is usually done with more costly conventional power plants (Weber 2010). Moving gate closure closer to the actual delivery time also rewards flexibility from the supply and the demand side (see also section 4.3).

In Germany and other European countries, gate closure of spot markets was reduced considerably. Until 2009, market operation stopped 75 minutes before actual delivery (Weber 2010). This gate closure time was reduced to one hour in 2009. As of 2011, 15-minute intraday markets were introduced in Germany (BMWi 2014). This not only facilitates the integration of high shares of wind and solar PV in the German power system but also enables new actors, namely storage providers, to participate in this market segment. In 2014, the trading platform EPEX SPOT[33] has introduced another quarter-hour product. In order to simplify administration, traders can offer the 96 quarter hours of the following day simultaneously in an opening auction before the start of intraday trading.

Wholesale electric markets also include ancillary service markets for spinning reserves, non-spinning reserves, and regulation service for minute-to-minute balancing (Shah, Valenzuela et al. 2016). These balancing markets have the function of balancing out unforeseeable gaps between the commercial market results (see Gate Closure above) and actual production and consumption. The need for balancing capacity is expected to increase with an increasing share of variable renewable energy sources (BMWi 2014, IEA-RETD 2016). From a technical perspective, many providers can supply balancing capacity, including large-scale batteries, flexible consumers, and remote-controlled wind and PV installations (M. Miller, L. Bird et al. 2013).

In Germany, new market actors, including renewable energy producers and storage technologies, were previously de facto excluded from balancing markets due to long auction periods and the high minimum bid size. As of 2011, the pre-qualifications for participating in balancing markets auctions have been changed. Due to shorter auction periods and reduced minimum bid sizes, competition on balancing markets increased considerably, thus lowering prices (BMWi 2014). As of 2016, primary balancing capacity will no longer be auctioned weekly but daily instead. These shorter periods and lead times will further help renewable energy and storage providers to compete with conventional power plants on a level playing field (BMWi 2014, Bundesregierung 2016).

4.4. Reduction of Must-run Capacity from Conventional Power Plants

Conventional, centralized supply is frequently inflexible. This can be due to technical limitations of plant technologies or operation decisions by power plant owners. Many power plants cannot be ramped from

[33] https://www.epexspot.com/en/

0% to 100% of the nameplate capacity. Old hard coal and lignite power plants frequently have to run at 50% of the maximum output if long shutdown periods are to be avoided. The same applies for old nuclear power plants. Even older gas steam units must be run at about 20 percent of their maximum capacity overnight to be available to meet higher loads during the daytime, whereas modern "flex" natural gas combined-cycle plants can operate on an as-needed basis (Lazar 2016). For an overview of start-up times and ramping capabilities of conventional power plants in Germany, see table 4.1.

Table 4.1. Start-up times and ramping capabilities of centralized supply options

	Start-up time	Maximal change in 30 sec	Maximum ramp rate (%/min)
Open cycle gas trubine (OCGT)	10-20 min	20-30%	20%/min
Combined cycle gas turbine (CCGT)	30-60 min	10-20%	5-10%/min
Coal plant	1-10 hours	5-10%	1-5%/min
Nuclear power plant	2 hours - 2 days	up to 5%	1-5%/min

Source: (Fraunhofer IWES 2015 based on NEA 2011)

In order to make electricity systems more flexible, the must-run capacity of centralized power plant needs to be reduced. This can be achieved via policy interventions summarized in table 4.2.

Lowering the must-run capacity of centralized, conventional power plants does not only allow for the integration of higher shares of variable renewable energy source -it also makes the integration more cost-effective, since the market value of renewables in competitive wholesale markets will increase and negative prices can be reduced (Winkler, Sensfuß et al. 2015).

Table 4.2. Measures to reduce must-run capacity of conventional power plants

Factors influencing high must-run from conventional power plants	Measures to reduce must-run capacity from conventional power plants
Technical factors (which vary from one power generation technology to the next)	Upgrade existing power plants; change electricity market design, incentivizing flexibility (ramping capabilities; maximum must-run) and/or penalizing inflexibility (see section 4.5 on policies in California)
Operation of CHP plants according to heat demand (and not electricity demand)	Require (new) CHP plants to operate according to electricity demand patterns (and not primarily according to heat demand). CHP support might have to be adjusted to finance additional capital costs for heat generation via boiler systems and storage.
Provision of balancing power	Change market design: open balancing power market for new actors by shortening delivery periods and reducing the size of tranches (see section 4.3)
Voltage support	Require renewable energy producers to provide reactive power. This reduces reactive power needs from conventional power plants.
Re-dispatch	In Germany, the need to re-dispatch power plants increased in recent years due to transmission constraints between

	Northern German (with most of the RE capacity) and Southern Germany (with most loads). Solution: Transmission system grid expansion.

Source: Author based on (Consentec 2016)

In Germany, the must-run capacity of conventional power plants amounts to 20-30 GW (FGH, CONSENTEC et al. 2012, Consentec 2016).[34] This inflexibility of conventional power plants can lead to negative electricity prices even though renewable energy sources have not (yet) reached 100% of supply at any time of the year. In order to allow for a cost-effective integration of increasing shares of variable renewables into the electricity system, technical must-run capacity needs to be reduced to 4 GW (Winkler, Sensfuß et al. 2015). Therefore, the reduction of must-run capacity from conventional power plants has been part of the Ministry's strategies formulated in the Green Paper and the White Paper of the electricity market 2.0 design (BMWi 2014, BMWi 2015).

Many of the technical features previously provided by centralized, conventional power plants can now also be provided by new technology options, including renewables. This includes reactive power and short-circuit capacity (Milligan, Frew et al. 2015). Whether the technical upgrade of existing power plants is economically viable or not cannot be decided without knowing the technical setup of each individual power plant (Krzikalla, Achner et al. 2013). The following Textbox 5 describes the technical potential for the flexibility of nuclear power plants in France.

Textbox 5: Flexibility of nuclear power generation in France

The power mix in the French electricity system is dominated by nuclear power (about 75%).[35] France also has considerable hydropower capacity as an important factor for system flexibility, covering about 15% of electricity demand and 50% of the necessary balancing power (Fraunhofer IWES 2015).[36]

In 2014, the French government passed the Energy Transition Law, which aims to reduce the share of nuclear power in the French electricity mix to 50%. At the same time, the share of (variable) renewable energy sources in the system increases, from about 15% in 2012 to more to 40% in 2030 (MEDDE DGEC 2015). Thus, more system flexibility will be required.

The French nuclear fleet has a certain degree of flexibility. Nuclear power plants in France are able to adjust to the cyclical variations in power demand on a daily and weekly (e.g., lower demand on Sundays) and seasonal basis (e.g., lower demand in summer). Figure 4.6 shows the operation of the nuclear power plant Golfech 2, which has been in operation since 1994, in comparison with an old nuclear power plant (Fessenheim, in operation 1977). It reveals that new nuclear power plants have a certain load-following capability.

Figure 4.6. Ramping of nuclear power plant Golfech 2 in France (2013)

[34] Must-run capacity includes up to 5.5 GW for balancing power, up to 8 GW of internal reserve capacity to assure balancing power commitments, up to 5 GW for re-dispatch and additional capacity from CHP plants and industrial load requirements. Maximum demand is around 80 GW.

[35] Similar to Ontario, France also has opted for lifetime expansion of nuclear power plants and refurbishments of existing nuclear plants.

[36] 25 GW of installed capacity in 2014, including 13 GW run-of-river power stations and 12 GW of pumped storage.

Source: (Fraunhofer IWES 2015)

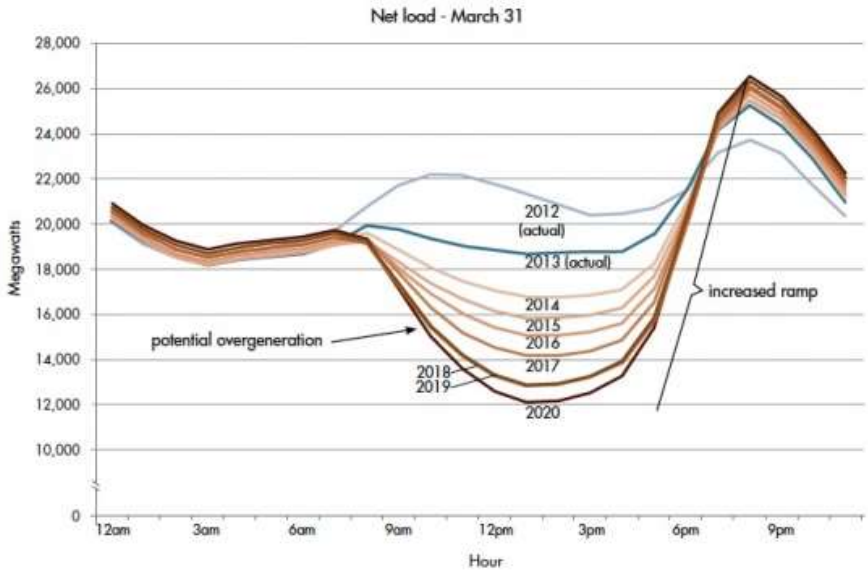
In 2030, nuclear generation will have to be more flexible in order to optimally integrate even higher shares of wind and solar PV in the electricity system. Must-run levels of existing nuclear power plants will need to be reduced. At that time, start-up times and ramping rates will also need to be reduced (see table 4.1). However, more flexible operation of nuclear power plants could undermine their profitability. Increasing shares of wind and PV would reduce full-load hours of nuclear power plants and thus the revenues for nuclear producers. Under the current rate regime in France, nuclear power plants rely on at least 6000 full-load hours of operation in order to be profitable.

4.5. Remuneration of Flexibility in Wholesale Markets

Another option to incentivize flexibility is to develop new market products that adequately remunerate the required flexibility. Efficient market incentives need to be designed to translate the flexibility needs into market prices and leverage this technical potential in the most cost-efficient way. This path was taken in California with the new Flex products. The state has been developing significant volumes of variable renewables like wind and solar PV to meet its 33% Renewable Portfolio Standard (RPS) target by 2020, with 13 TWh of wind power and 10.5 TWh of solar PV as of 2014 (California Energy Commission 2014). The power system will have to become more flexible and centralized power plants will have to increase their ramping capabilities (Denholm, O'Connel et al. 2015). Figure 4.7 shows the so-called "duck

curve" caused by the increasing integration of solar PV into the California electricity system. The residual load will have to be primarily covered by flexible, centralized supply and partially by demand response providers.

Figure 4.7. California Duck Curve (2012-2020)



Source: (CAISO 2013)

The California Independent System Operator (CaISO) has outlined a set of key operating capabilities that flexible resources must be able to provide. All actors that can provide the following features will compete with each other in a competitive bidding process. In order to qualify for the auction rounds, the resource or technology must be able to respond to changes in net load within a 5-minute timeframe (IEA-RETD 2016). The features required by the system operator include:

- Sustained upward or downward ramp;
- Change ramp directions quickly;
- Respond rapidly within a defined period of time to sudden changes in operation requirements;
- Store electricity or rapidly modify onsite demand;
- Ability to start and stop several times over the course of a day;
- Ability to accurately forecast available operating capabilities.

Being able to provide these technical requirements will be increasingly important for the general economic viability of large-scale, centralized supply units. As indicated above, full-load hours of conventional power plants will be reduced by an increasing share of zero-marginal cost technologies such as wind and solar PV, since more costly power plants are pushed out of the merit order. In addition, wholesale market prices in liberalized markets have been going down in past years, partially related to the so-called merit order effect.

In recent years, it has frequently been argued that the deployment of (variable) renewable energy technologies reduces wholesale market prices and therefore undermines any investment in new conventional power plants that are necessary for backup power – especially in systems with high shares of renewables. Analysts have pointed at decreasing prices in European wholesale markets, arguing that these price declines have been caused by renewable energy deployment (Auverlot, Beeker et al. 2014). However, the story is slightly more complex, as the text box below clarifies.

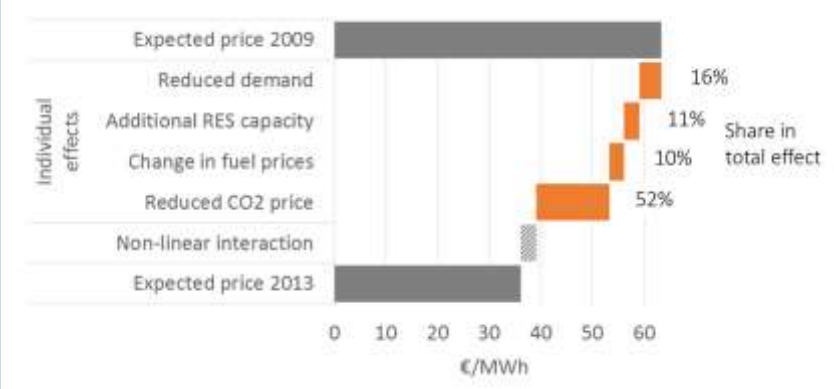
Text box: Understanding decreasing wholesale electricity market prices in Germany and Europe

It is clear that the deployment of zero marginal cost technologies, such as wind and solar PV, reduces wholesale market prices, This so-called merit order effect has been shown in several European countries, including Italy (Clò, Cataldi et al. 2015), Spain (Sáenz de Miera, Del Río González et al. 2008), Germany (Sensfuß, Ragwitz et al. 2008), and Denmark (Ray, Munksgaard et al. 2010).

However, other factors have influenced German and central European wholesale market decline much more strongly, and these are usually not taken into account in public debate, as shown by a recent study of Kallabis et al. regarding the development of future electricity prices (see Figure 4.8). First and foremost, decreasing CO_2 prices within the European Emissions Trading Scheme (EU-ETS) reduced wholesale future prices by 52%. Reduced electricity demand accounted for 16% of the decreasing market price. The merit order effect related to additional RE capacity was responsible for only 11% of the price decline, and reduced fuel costs for gas and coal accounted for 10% (Kallabis, Pape et al. 2016).

However, the effect that renewables have on wholesale market prices can be more pronounced in jurisdictions with high shares of hydropower, as an analysis for Sweden shows (Hirth 2016). It should also be noted that overcapacities in the European electricity market are a result of adding new renewable energy capacity without phasing out carbon intensive technologies, such as lignite. Therefore, RE targets might also have to be combined with phase-out policies for fossil-fuel based power generation as discussion in section 4.2 (IEA-RETD 2016).

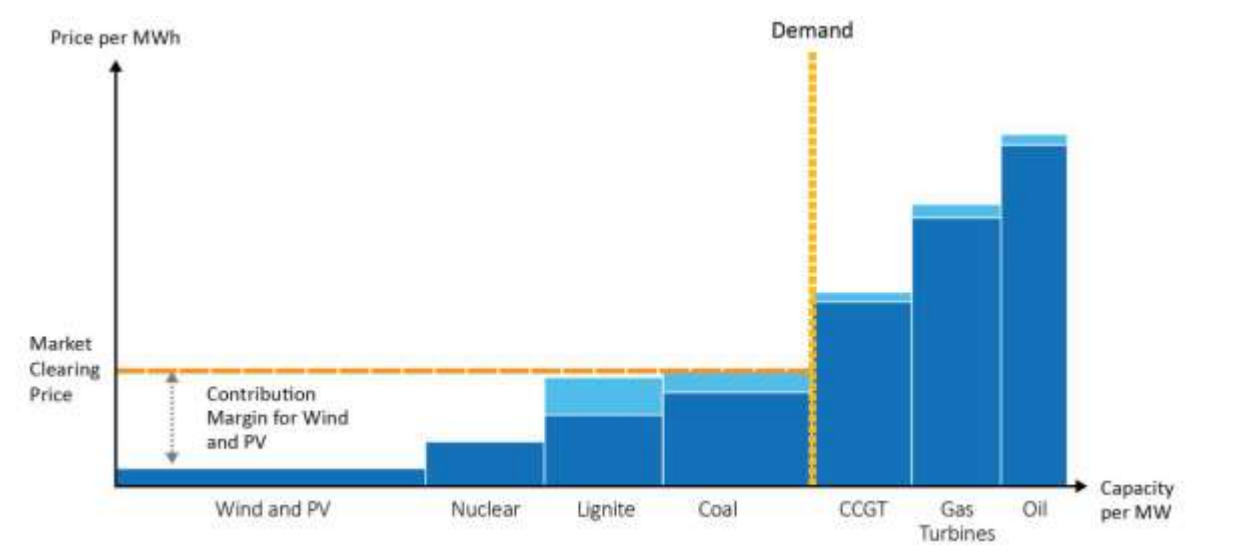
Figure 4.8. Factors influencing wholesale market price decrease in Germany

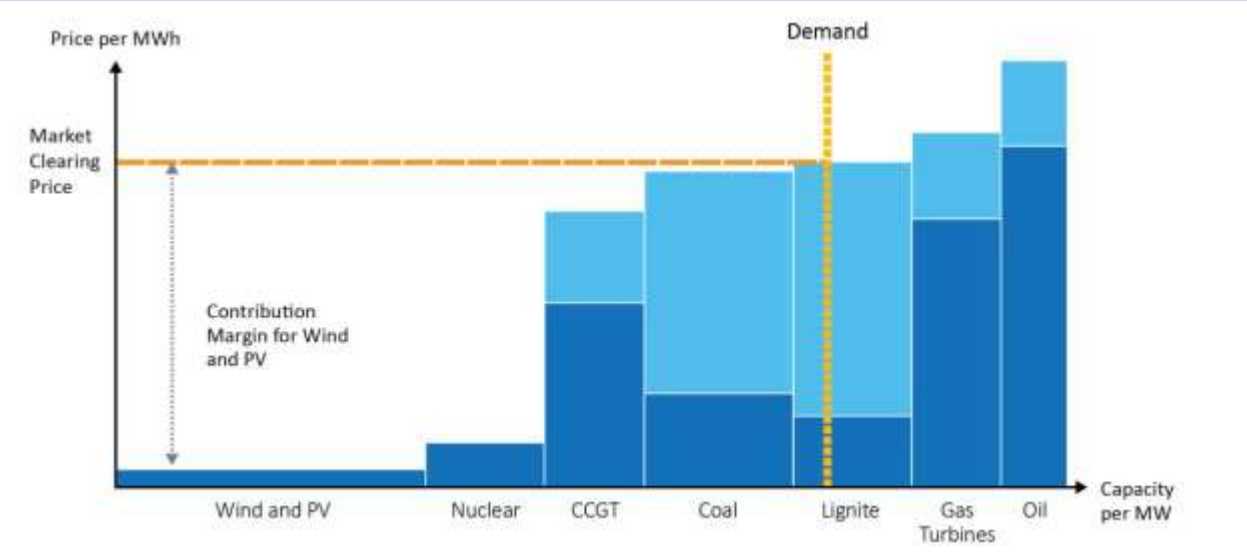


Source: (Kallabis, Pape et al. 2016) as cited in Hirth 2016

Knowing about the dampening effect of wind and PV deployment on wholesale electricity market prices, several experts have prematurely concluded that wholesale market prices will end up being low forever. However, the revenues that can be earned via wholesale markets in the future largely depend on the system's flexibility and carbon pricing levels (Winkler, Sensfuß et al. 2015). Figure 4.9 shows a typical merit order in competitive wholesale markets with and without carbon pricing. As long as the marginal power plant is a fossil-fuel based power plant, a significant contribution margin can be achieved for zero- or low-carbon technologies. At the same time, electricity wholesale market prices are expected to increase again once overcapacity is gone (see the discussion on scarcity pricing (IEA 2016)).

Figure 4.9. Effects of carbon pricing on the merit order and contribution margins in competitive wholesale markets





Source: (IEA-RETD 2016)

5. SYNTHESIS AND CONCLUSION

This report aims to provide an overview of policy solutions that might help Ontario to better prepare for possible energy futures. This report primarily focuses on innovative policies and regulation in Germany and the US and other leading jurisdictions with respect to the integration of increasing shares of DG and variable renewable energy sources into power systems. As discussed in depth in Chapter 4, electricity markets of the future will be characterized by three trends: decarbonization of power systems, increasing shares of (variable) renewable energy sources, and increasing needs for system flexibility

This is also a likely scenario for the Ontario electricity sector. Currently, the share of distributed generation and variable renewable energy in Ontario is still relatively small (about 10%). However, based on business as usual policies, the share of renewable energy sources will have increased by 20 percentage points between 2005 and 2035. At the same time, the share of nuclear will have declined by 20 percentage points compared to 2015 (IESO 2016).

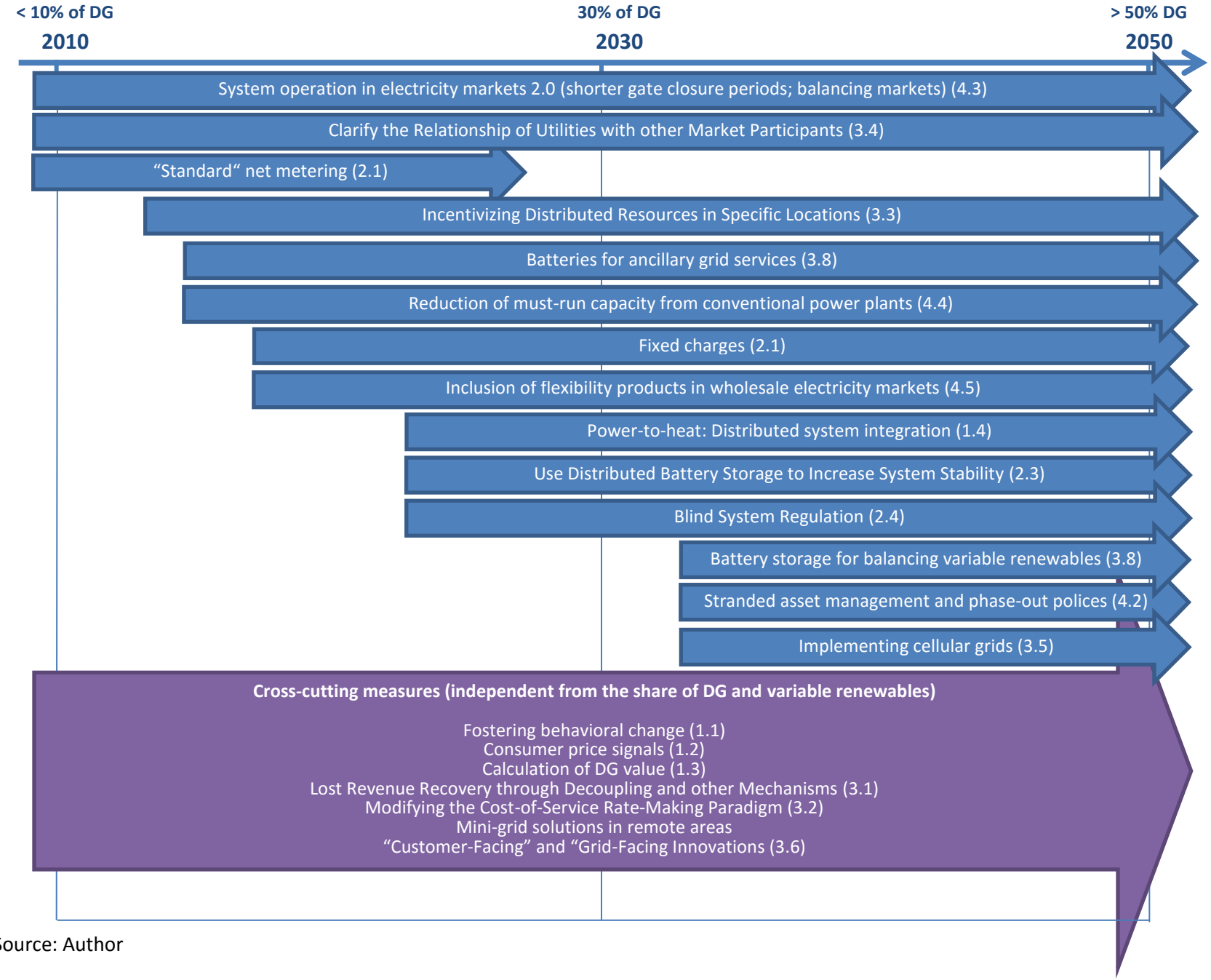
Even though the Ontario Independent Electricity System Operator expects that variable renewables and distributed generation will still be a niche market and that the energy system will remain dominated by centralized supply, it is reasonable to contemplate (and prepare for) a different type of energy future. As laid out in the introduction, the growth rates and cost declines of renewable energy (and other DG) technologies have frequently been underestimated. At the same time, future electricity system planning will become increasingly difficult for two reasons (see Section 4.1). First, the share of DG cannot be fully controlled by regulators and policymakers. In the long run, large-scale deployment of distributed generation might happen even without specific subsidies. Certain prosumers might eventually decide to "cut the cord" and become fully independent from centralized supply. Second, future demand for electricity is more difficult to predict than it previously has been. On the one hand, energy efficiency programs might lead to considerable reduction in power demand. On the other hand, the electrification of the heating and transport sector might lead to a considerable increase in electricity demand.

5.1. Timing for the implementation of policy solutions

The timing for designing and implementing the policies discussed in this report can be understood as a function of the shares of distributed generation and variable renewable energy sources. Assuming that the share of distributed generation and variable renewable energy sources will increase within the Ontario electricity system over time, the policies discussed can be implemented at different moments.

At the same time, there are certain cross-cutting policies that can be deployed to govern and integrate distributed generation development. These can be implemented immediately, irrespective of the share of DG and renewables. In the short summary of policy solutions below, the timing of the implementation of them will be discussed alongside potential pitfalls. The potential timing for implementation is summarized in Figure 5.1 below, starting with policies for low shares of DG and variable renewable on the left.

Figure 5.1: Policy solutions as a function of increasing shares of distributed generation and variable renewable energy sources over time



Source: Author

1.1. Fostering Behavioral Change

Consumer behavior is a complex variable that can at times accelerate or delay DG market growth and development unexpectedly. However, policies to increase consumer behavior are cross-cutting and can be implemented irrespective of the actual or targets share of DG and variable renewables. Voluntary green power purchasing has long been a component of the renewable energy landscape. However, its share of the market has consistently remained low in countries where it is available (e.g. typically below 1%). A key factor in the low uptake of voluntary green power purchasing has been that green power has historically come at a premium. As the energy landscape has continued to evolve, however, a widening range of cost competitive clean energy options has emerged.

For policy makers seeking to grow clean energy adoption, the new challenge may not be to create a convincing economic argument for clean energy, but to raise awareness of the opportunities that exist. At the residential level, policy makers have supported aggregated buying models that harness peer-to-peer marketing to scale up onsite clean energy. Initiatives such as Solarize campaigns have successfully proven that geographically and community-driven marketing can accelerate adoption. As markets reach the tipping point of mainstream adoption, however, the incremental benefit of community-specific adoption drives may decrease. As a result, publicly-sponsored campaigns may be thought of as a comparatively early-stage intervention.

At the commercial scale, green power purchases are emerging in many jurisdictions as a competitive alternative to conventional electricity offerings. In markets with full electricity competition, the primary barriers to adoption will likely be internal to institutional structure and culture – for example, does the corporation have the decision making processes in place to take advantage of available energy opportunity or not? Market structure aside, there may be significant opportunities for public-private partnerships under which large-scale corporate purchases can help create green power demand to help reach and exceed national (or state) renewable energy targets.

1.2. **Consumer Price Signals**

Consumer price signals, such as time differentiated pricing, have long been a mainstream electricity ratemaking strategy in many jurisdictions for large-scale consumers. As onsite distributed generation markets scale up, and as policy makers strive to make grids more intelligent, time of use price signals at the residential level has emerged as a policy of interest. Concurrently, the use of real time price signals that are directly coupled to wholesale market pricing has been increasingly integrated in some in markets. The actual impact of time of use pricing on distributed generation in a given market will vary based on factors such as the structure of the rates, the correlation between DG output and peak usage periods, and the structure of policies to support onsite DG. In jurisdictions where onsite consumption of DG output is not allowed, retail electricity price signals will be less relevant to DG adoption.

Time of use pricing at the residential level can therefore be considered cross-cutting policy in markets that encourage DG through onsite consumption policies. In the longer-term, it is also important to keep the potential interaction between the DG and wholesale electricity markets in view. If DG and centralized variable renewable markets scale up in parallel, then large penetrations of renewables may

place downward pressure on wholesale electricity prices (see Section 4.5). If DG generation compensation is directly linked to wholesale prices through real time pricing, then the wholesale price suppression driven by centralized renewable energy may disadvantage DG.

1.3. Societal Versus Market Value of Electricity

The calculation of DG value can be a useful exercise at a number of different points during market development. When creating policies to drive initial market growth, value of DG calculations can support (or counter) arguments for premium incentive payments. During periods of transition, value calculations can be included in cost-benefit analyses to determine whether existing policies should be sustained, amended, or removed.

As discussed in Section 1.3, there have also been arguments that value calculations should be use directly as the basis for DG compensation – either as the payment rate utilized under buy all / sell all arrangements or as the credit amount awarded to excess electricity generation under net metering or net billing arrangements. In North America, value calculations related to each of these different objectives are either ongoing or have recently been completed. For subnational governments such as Ontario, a key question will be how best to utilize the outcomes such analyses and then how often to repeat them. On the one hand, DG value changes over time and frequent updates may be necessary if value calculations are central to policymaking. On the other hand, value calculations can be complex, time consuming, and expensive if integrated into formal regulation and rulemaking.

1.4. Power-to-heat: Distributed system integration

Integrating the electricity and the heating system is nothing new. Larger-scale combined heat and power plants (as well as electrical heating systems) have been around for many decades. However, large scale electrical heating deployment at the distribution level to support system integration will only become necessary once renewable electricity is available in abundance, i.e., solar PV and wind will produce more electricity than usually required (medium to high shares of DG and VRE). In these situations, using the excess electricity for heating or e-mobility purposes is an effective solution and economically more reasonable than simply curtailing excess renewable energy power. This policy solution might also be feasible in congested electricity grids at an earlier stage. Germany, for instance, is incentivizing power-to-heat technologies in certain areas in the northern part of the country, where curtailment and re-dispatch costs have increased considerably over the past years due to limited interconnections with the national grid.

Using power-to-heat or power-to-transport should not be incentivized too early if substantial shares of electricity are still generated with fossil fuels. Otherwise, the carbon emissions of the entire energy sector might actually increase, instead of leading to the decarbonisation of all three sectors.

2.1. Remuneration for Excess Electricity, Virtual Net Metering, and Roll-over Provisions

Net metering, feed-in tariffs, and related policies have been utilized by different countries to accomplish different goals at different times. In the US, net metering has been the foundation for DG market development across the country. In Europe, some countries have instead considered net metering as a potential "next generation" successor policy beyond their original feed-in tariffs. While future policy trends on both sides of the Atlantic remain unclear, there is a significant amount of flux and transition related to the traditional policy types. Both feed-in tariffs and net metering have successfully been used to jumpstart DG markets and sustain development over time. Therefore, this policy solution is usually applied for low shares of DG and variable renewables.

As DG markets approach higher levels of penetration and maturity, however, there will likely continue to be calls to remove or amend such policies. To date, however, no standard "next generation" policies for DG support has emerged internationally – although there has been a trend toward steadily lower feed-in tariff rates and the beginnings of a trend toward compensation that is below the retail rate under net metering/net billing policies. For jurisdictions such as Ontario, there is now an increasingly rich body of regulatory decisions related to DG support policies that can be drawn from – this includes decisions where existing policies in large markets have been largely preserved (e.g. California) and decisions in smaller markets where DG policy structures have been fundamentally altered (e.g. Arizona and Nevada).

2.2. Financing DG Infrastructure Investment: Fixed Charges and Other Policy Options

The use of fixed charges (and related rate structures) is complicated and controversial. Non-volumetric retail electricity charges have been used in most countries for decades. As onsite consumption increases, a greater reliance on fixed charges can theoretically help insulate incumbent utilities from revenue erosion and protect other ratepayers from increased rates. On the other hand, fixed charges can also be deployed to reduce the economic returns of DG systems and constrain DG market development. The conflict over what constitutes reasonable method for utility cost recovery will likely continue to play out internationally in the coming years. Over time, it will be important for policymakers to calibrate and balance mechanisms that allow for some degree of cost recovery without bringing DG market growth to a halt.

2.3. Use Distributed Battery Storage to Increase System Stability

The use of distributed battery storage to stabilize the electricity system starts to be important once distributed PV systems have reached a considerable share (medium share of DG and variable renewable energy sources). The most cost-effective flexibility options (e.g. more flexible centralized power generation) may no longer suffice to effectively balance supply and demand as variable resource penetration levels increase. These issues might also occur first of all in distribution circuits with high shares of variable renewables. This policy should be implemented in conjunction with blind system regulation (see below).

2.4. Blind System Regulation

Blind system regulation also starts to become crucial with medium shares of DG and variable renewables. Once a certain share of solar PV is reached, it is no longer feasible to simply consider PV systems as negative load. Operators of distribution systems need to know better when PV systems are producing power and what type of self-consumption profiles exists.

As indicated in Section 2.3, the low-tech solution of simply capping the maximum output of PV systems at a certain percentage of the nameplate peak capacity is the most cost-effective approach to small scale PV systems. However, enforcing the implementation of this policy options is difficult. In the coming years, the cost for communications infrastructure for remote-controlled curtailment will likely decrease further. In this case, remote-controllable feed-in management can also be implemented for very small PV systems (smaller 30 kW).

3.1. Utility Regulation: Lost Revenue Recovery through Decoupling and other Mechanisms

Lost revenue adjustment mechanisms (LRAMs) like decoupling remove the disincentive for utilities to support energy efficiency programs, thus incentivizing these DG technologies. Mechanisms that sever the link between utility revenue and sales completely are preferable to mechanisms that attempt to determine the portion of lost revenue attributable solely to energy efficiency programs. The latter types of mechanisms introduce serious verification difficulties.

LRAMs are an important first step towards achieving decarbonization and cost-reduction goals. However, they are only a first step, in that they remove a disincentive rather than actually creating an incentive for utilities to implement programs that are aligned with public policy objectives. LRAMs are a cross-cutting measure, applicable regardless of the shares of DG and variable renewables. They can be implemented immediately in Ontario.

3.2. Utility Regulation: Modifying the Cost-of-Service Rate-Making Paradigm

Modification of the cost-of-service rate-making paradigm is the new world that is being explored in the U.S., so far mainly in New York and California but, inevitably, elsewhere in the future. In the U.S., utilities make a profit by increasing the value of their assets, on which regulators provide them with an assured rate of return. This fundamental rate-making paradigm, known as cost-of-service regulation, incentivizes utilities to build large infrastructure projects.

In New York and California, regulators are looking to provide utilities, by means of rate recovery and performance incentives, to be equally enthusiastic about energy efficiency, integrating distributed resources, and reducing peak load. Moving away from the current cost-of-service rate-making paradigm towards policies that align utility incentives with public policy objectives is a cross-cutting measure, applicable regardless of the shares of DG and variable renewables. It is still early days with respect to these reforms, but it seems inevitable that policy makers will move in this direction in order to align utility incentives with public policy objectives. It may make sense to let the first-movers move forward

with these policy initiatives, in order to learn from their successes and mistakes.

3.3. Utility Regulation: Incentivizing Distributed Resources in Specific Locations

Electricity markets have long used price signals to incentivize generation and demand side resources to locate in specific locations. Although different mechanisms are used, the core principle is that the price signal varies depending on whether or not an area is transmission constrained and, therefore, a particular resource brings a different value to the system.

In the first years of deploying renewables and other distributed resources, this policy solution is not a priority. However, when approach medium levels of distributed generation, this policy start to become crucial in order to avoid grid congestion and to make the best use of the existing transmission and distribution grid. Solar PV and wind energy are often deployed where the natural resources are best and frequently not where deployment makes most sense from a grid perspective.

Recent initiatives in New York and California go beyond the nodal or locational marginal pricing types of signals. In these initiatives, incentives are associated with identifying and implementing opportunities for distributed resources in appropriate locations. New York, for example, is creating incentives for solar panels oriented towards the west—maximizing value for the system rather than for the individual homeowner or business, and is revising interconnection rules to reflect locational priorities. Both Texas and Mexico are also making progress with respect to these objectives.

3.4. Utility Regulation: the Relationship of Utilities with other Market Participants

There are competing concerns about the relative roles of utilities and the multitudes of new entrants in the electricity marketplace. On the one hand, utilities are effective players in that they have established customer contacts and the ability to rate-base investments. But on the other hand, these factors could limit the opportunity for the development of competitive markets, and limit the role of more entrepreneurial and nimble players.

This is a highly dynamic landscape, with models including utility ownership of resources, the creation of utility affiliates for ownership purposes, incentives for utilities to integrate distributed resources, and purchase requirements for renewables through mechanisms like renewable portfolio standards and long-term contracts. The example of Massachusetts in addressing ownership of electric vehicle charging equipment and, specifically, in light of the state's efforts to allow utility ownership only where to do so will not stifle competition, could provide a more generally applicable model for utility distributed resource ownership.

Even with low levels of DG and variable renewable penetration, regulators should begin to clarify the relationship of utilities to new market entrants. This will be important as the market continues to transition to increasing amounts of DG. As the amount of variable renewable energy penetration in the market increases, rules respecting the relationship of utilities and DG providers should be implemented,

so as to provide clear signals to the market.

3.5. New Roles for DSOs and the Potential for Cellular Grids

This area of regulation reflects the tension between the current and a potential new paradigm for grid planning, management and balancing. On the one hand, today the most cost effective way for integrating large shares of variable renewables is based on balancing supply and demand over large balancing areas by expanding transmission grids and interconnecting markets. On the other hand, some experts argue that power systems with (close to) 100% renewable electricity and large shares of distributed demand response technologies can be securely operated only within small units, so-called cellular grids, which are more resilient.

The operator of these cells will also depend on future technological developments (e.g., cheaper storage) and the integration of the electricity system with the heating and transport sector. Therefore, it is clear that this policy solution is primarily recommended for markets with very high shares of variable renewables and DG. In order to prepare for this (potential) future, policymakers can test this regulatory paradigm shift with pilots in areas with very high shares of renewables.

3.6. Grid Technologies: "Customer-Facing" and "Grid-Facing Innovations

Modernization of the electric grid becomes increasingly important as the grid ages, as consumers' expectations change, as increasing amounts of DG are connected, and as concerns grow about the vulnerability of the grid. But at the same time, grid modernization is enabled by the advent of new technologies. The grid modernization technologies that are most visible to customers are smart meters and other "customer-facing technologies like remotely-controlled thermostats.

"Grid-facing" technologies, such as the controls and automation necessary to optimize the voltage and power factor of the distribution circuits and infrastructure to monitor and control distribution circuits remotely and in real time are also crucial. The major challenges for DSOs are related to voltage variations. Using remote-controlled local power transformers to balance voltage fluctuations is frequently more cost-effective than expansion of the distribution grid. Adoption of cost-effective grid modernization technologies are cross-cutting measures, applicable regardless of the shares of DG and VRE.

3.7: Microgrids and Virtual Renewable Energy Power Plants

Microgrids involve a combination of generation, storage, thermal, and control resources, or some number of these, connected to one or multiple loads. Many microgrids include combined heat and power. Microgrids can operate independently of the electric grid, or connect to and disconnect from the grid. Some microgrids are utility owned, and others involve private ownership (which can run into utility claims of interference with the utility's franchise). Cost-effective microgrids are a cross-cutting measure in vulnerable areas of the grid, in areas that require a high degree of reliability, and in areas that are not

connected to the larger grid.

Microgrids can provide power in remote locations, ensure reliable electricity in the face of weather extremes and, potentially, provide cleaner power than the larger electric grid. The Borrego Springs microgrid is a good example of the success of a microgrid, both in terms of ensuring reliability and delivering clean power. Historically, microgrids have been used most in places that require a high degree of electric reliability, like hospitals and military installations. Microgrids are currently being deployed most in areas that are not covered by the macrogrid, particularly in developing countries.

3.8. Grid Technologies: Storage for Flexibility and Grid Services

Energy storage eliminates the problem that electricity must be produced exactly to match load at all times, and can thus increase the value of distributed resources. Energy storage for this purpose is relatively expensive. Significant amounts of storage to balance variable resources are necessary only in markets with a high share of variable renewables.

There are a variety of energy storage technologies, with lithium-ion batteries winning the race so far in the electric car and grid energy storage markets, but they are still too expensive for widespread use. In addition to storing power from variable resources when those resources are unavailable, energy storage provides a host of other, ancillary grid services. California has one of the largest storage programs in the world, because of the importance of storage for getting to its high targeted penetration of renewables.

4.2: Stranded assets and phase-out policies

The need to phase-out certain (carbon-intensive) technologies primarily depends on the carbon-intensity of the power generation mix. Due to the past coal phase out in Ontario, the issue of further stranded assets is not likely to return in the near-term. However, stranded assets could occur again once policymakers decide to fully decarbonize the electricity system. Strategies of how to phase-out gas-fired power plants (and replace with solutions based on storage and demand response) might be a challenge in the longer-term future, within a power system with high shares of DG and renewables.

Section 4.3: System operation in electricity markets 2.0

Improving the operation of wholesale power markets is a simple and effective policy solution, already applicable for low shares of DG and variable renewables. Shortening gate close periods is crucial for cost-effective market integration of variable renewables, since this policy can significantly reduce forecast errors. By allowing DG technologies to also participate in ancillary services markets (balancing markets), competition in these markets will be increased, thus lowering prices (keeping in mind that the requirements for balancing power increase with increasing shares of variable renewables). At the same time, policymakers can prepare for markets with very high shares of DG by allowing renewables to take over ancillary system services.

Section 4.4: Reduction of must-run capacity from conventional power plants

The need to reduce must run capacity for conventional power plants emerges once renewable energy sources start to provide close to 100% of electricity at certain hours of the year. This frequently happens as soon as variable renewables account for about 10 to 20 percent of total power demand. Therefore, this policy solution is most applicable for systems with medium shares of DG and variable renewables.

As discussed in section 4.4, there are many technical and regulatory parameters which can help to reduce must-run capacity for centralized, conventional power plants. Some of them can already be implemented at an earlier stage, e.g. require (new) CHP plants to operate according to electricity demand patterns.

Section 4.5: Inclusion of flexibility products in wholesale markets

New products for flexibility have recently been implemented in markets with considerable shares of distributed generation and variable renewables (medium shares). Both California and Germany have started to promote DG technologies at a relatively early stage. For instance, as the share of solar PV (and wind) increases, centralized power plants need to become able to ramp up and down faster. The actual need and timing for this policy solution also depends on the availability of alternative flexibility options. Jurisdictions with a large share of (flexible) hydro power, like Ontario, might need to makes use of more flexible fossil-fuel based power systems only at a later stage.

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