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Identifying and Evaluating New Market Opportunities with Capacity Expansion Models

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EXECUTIVE SUMMARY

The shift of the electricity system from fossil fuels to renewable energy will require major investments in power generation, transmission lines, energy storage, and demand response technologies. This shift presents large investment opportunities. In this paper, we investigate engineering-based capacity expansion models for high renewable futures, examining the implied capital investment requirements of these scenarios. In particular, we examine the United States, as an example of the value of this approach for anticipating investment opportunities and identifying those with the highest potential for being economically viable. For the United States, key transformations in the electricity sector with respect to capital requirement include:

- Additional capacity in generation, storage, transmission, and demand response technologies ranging from 11% to 609% of the currently installed capacity;
- The average utilization factor (capacity factor) of installed power generation and consumption capacity drops; and
- Renewable-intensive power systems undergo a shift in cost structure away from ongoing operational costs for fuels towards higher upfront costs as the share of renewable generation and energy storage increase.

We conclude that increased used of planning models such as those applied here provide great value to the finance community as it looks to increase the pace of clean energy finance.

1. INTRODUCTION

Energy systems with high fractions of renewable energy supply will require greatly increased flexibility. We currently extract fossil fuels, at rates we control, from large deposits containing decades of resources. A renewable-based system will instead extract energy from variable flows as available on natural time schedules. This shift will have implications for capital requirements for the energy industry because investment to mitigate variability will be required. Because of the large scale and fundamental importance of the energy sector, these decadal-scale shifts in capital requirements of the energy sector will produce large opportunities for investment. In this paper, we explore the capital investment implications of high-renewables futures by examining the results of engineering-based grid modeling studies.

The recent growth of renewable investment has been spectacular. Investments in clean energy have been growing over the past decade (2004-2015) at an average compound annual growth rate of 15.5%, with total global investment of $349 billion in 2015 [1]. Almost 80% of these 2015 investments were spent on new wind and solar photovoltaics installations, with an added capacity of 118 GW [2]. Such large investments are expected to continue to grow over coming decades, and the share of renewables in the power supply will increase.

Such increases will call for additional flexibility from the electricity system. Numerous strategies have been proposed to improve energy system flexibility. First, we could build large amounts of renewable power capacity in diverse locations with a more robust connecting grid so that more hours of demand are met [3]. Second, energy can be stored for use in times when demand exceeds available flows [4] (e.g., in batteries or pumped-hydroelectric storage). Lastly, energy-consuming equipment can be turned on and off in response to available power (so-called demand response).

In this paper, we discuss these diverse strategies using a common question: what are the investment implications and opportunities of these different flexible energy strategies? In particular, we explore three key changes to the investment requirements of the electricity system: (1) a change in the overall amount of capital investment in the energy system; (2) changes in the capacity factor of generating and consuming capital; and (3) changes in the proportion of ongoing vs. upfront costs for the energy industry.

2. CHANGES IN THE SCALE OF ENERGY CAPITAL: BUILDING FOR FLEXIBILITY IN THE FACE OF VARIABILITY

Numerous studies have evaluated future systems with high shares of renewable energy [5], [6]. These studies look at overall energy supply in varying levels of detail. Generally, fully resolved models including all possible factors would be computationally intractable, so there are modeling trade-offs between the detail of physical and market modeling, and between the resolution of the model in time and space.

For our question, the most relevant models are long-term planning models for power sector investment over the scale of decades. These models evaluate which and how much of each technology choice will be built in the future, mostly using hourly time-series of electricity demand, wind speed, and solar irradiance. They tend to find that systems with high penetration of renewables are feasible, but that significant investments are required in order to achieve these systems [5]. Such investments are required in all aspects of the electricity system, including generation, transmission, and demand.

These studies often focus on a large geographic region such as the United States or Europe. Some studies focus on single countries (e.g., single European countries [7], or New Zealand [8]). The time scales vary, but they often focus on marker years 2030 (medium-term) and 2050 (long-term).

For simplicity, we focus below on results from four models of the United States with a variety of renewable penetration scenarios (see Box 1).

BOX 1. MODELS INCLUDED IN STUDY

ReEDS: The Regional Energy Deployment System (ReEDS) model was developed at the National Renewable Energy Laboratory (NREL). It was used for the Renewable Electricity Futures Study and determines an electricity system that can supply 80% of 2050 demand through renewable electricity generation [12], [13]. ReEEDS operates at hourly resolution and contains over 300 wind/solar resource regions.

SWITCH: The SWITCH model was developed at UC Berkeley. Nelson et al. [16] used a variant, SWITCH-WECC, to simulate the western United States' power system and its transition until 2030. Scenarios of different carbon prices and renewable portfolio standards (RPS) were explored. Resources are modeled in 3 hour blocks with resolution in 10s of km.

NEWS: The National Electricity with Weather System (NEWS) model was used by MacDonald and Clack et al. [17] to explore impacts from varying cost projections of energy technologies. NEWS models US renewable resources with ~10 km spatial resolution and hourly temporal resolution.

LOADMATCH: This model was developed by Jacobson and co-authors to simulate systems with 100% renewable energy for the electricity, transportation, heating/cooling, and industrial sectors [14], [15]. They consider wind, water, and solar power generation. For flexibility purposes, the studies consider hot and cold storage, pumped hydro storage, phase-change materials, and hydrogen. LOADMATCH models high temporal resolution (upscaled to hourly) with 4o x 5o grid cells (~400 km).

2.1 EXPANSION OF GENERATION CAPACITY

The amount of installed generation capacity is model specific, strongly depending on modeling constraints and assumptions [5]. Assumptions include future capital cost of each technology, discount rates, and carbon prices. Results range from hydropower-dominated systems to bioenergy-dominated systems to solar- and wind-dominated systems.

We compile results from the above models for high penetration of renewables scenarios in Figure 1. In all studies, generation capacity increases more than demand, consequently the average capacity factor drops as the share of renewables increases. This is because conventional dispatchable technologies like coal have high utilization factors, whereas renewable technologies generally produce on average 20%-40% of their nameplate capacity. The increase in the installed generation capacity differs widely in these models, for example, by 41% in the ReEDS study, by 15% in the NEWS study, by 609% in the LOADMATCH study, and by 11% in the SWITCH-WECC study. The large difference in

FIGURE 1. Capacity factor as a function of renewable generation share. Renewable generation share is on delivered MWh basis. Capacity factor is average MW delivered over total MW capacity installed

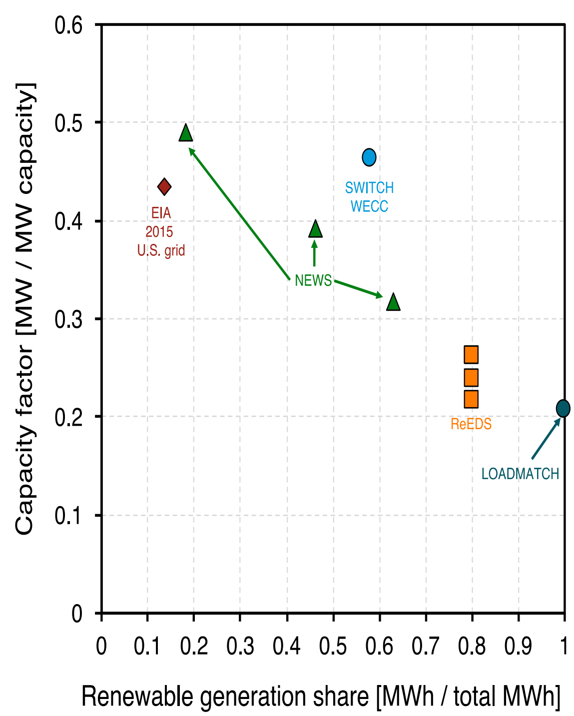
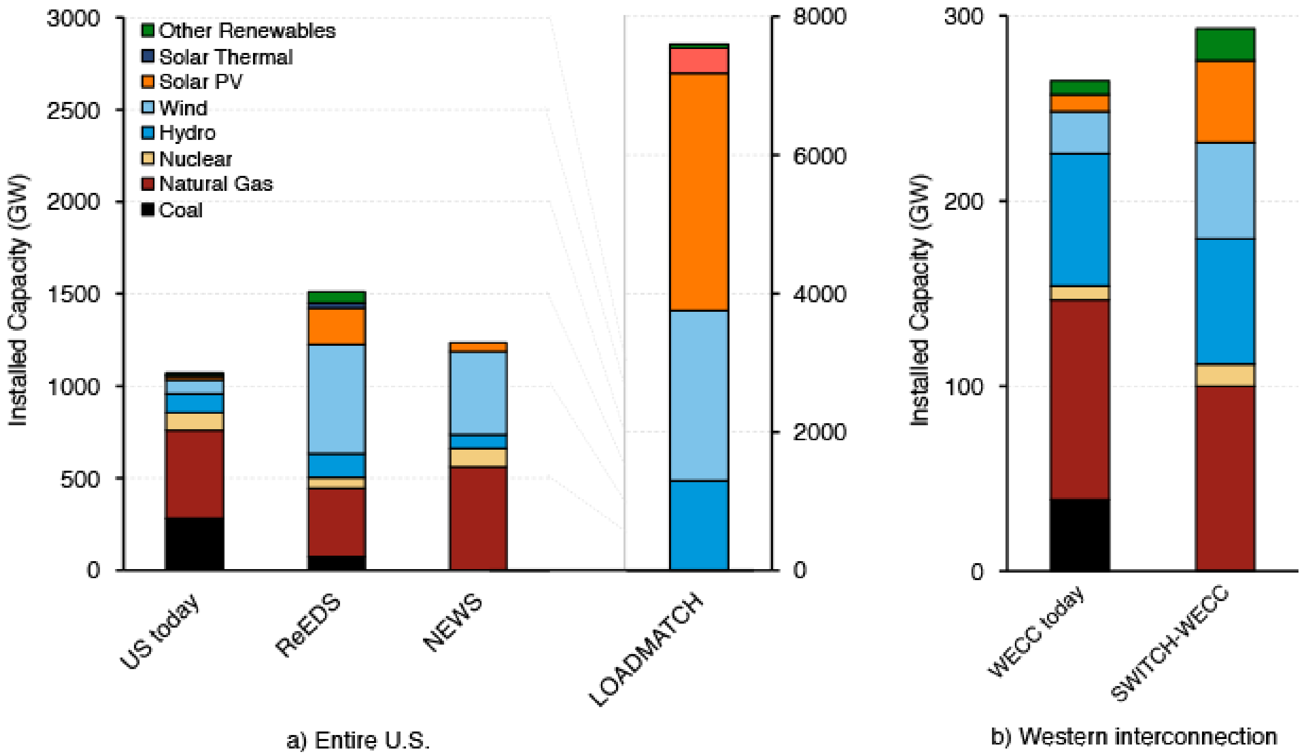


FIGURE 2. Studies of the generation capacity mix compared to the installed generation capacity mix as of today for the United States (a) and for the western interconnection (b). Note that the LOADMATCH study's capacity installations are on a different scale.



these values is at least partly due to different modeling assumptions and modeling horizons (e.g., LOADMATCH meets all energy demand with renewables).

The capacity mix of power generation technologies is shown in Figure 2. The NEWS and SWITCH-WECC studies show a moderate increase in total capacity because their renewable energy generation provides 46% and 58% of total generation, respectively. They phase out coal generation, rely on natural gas and have significant capacity extension in wind and solar power. The ReEDS study models an 80% renewable energy generation system, which relies on significant capacity installations in wind and solar. The LOADMATCH study models a system with 100% renewable energy for all sectors, which leads to an enormous capacity buildup. Overall, we observe that shares of renewable energy of ~50% require replacement of coal capacity and a slight additional increase in capacity provided by wind and solar, and that shares of 80% to 100% require a significant increase in total capacity.

2.2 EXPANSION OF TRANSMISSION CAPACITY

Variability in wind and solar power can be partly mitigated by interconnecting power generation over large areas. This aggregation of renewable resources reduces variability by smoothing the overall renewable power output. Large-scale correlation studies tend to find that wind resources become de-correlated over distances of around 1000 km, with partial de-correlation available at shorter distances [9], [10].

The US electric grid will require major upgrades in the coming decades, as 70% of the transmission lines and power transformers are more than 25 years old [11]. The

US grid today has capacity of 241-321 million MW-km [12]. Increasing need to interconnect renewable resources will increase the need for these upgrades. Several of the above studies investigate future investments in transmission capacity expansion.

The ReEDS studies [12], [13] evaluate the need for additional long-distance transmission lines. They find that transmission expansion depends on the scenario. Especially in the case of significant electricity demand growth over the coming years, they find that investments in long-distance transmission lines are needed to connect load centers on the coasts to wind resources in the center of the United States. While a total of 23-27 million MW-km are installed in the low demand base case, up to 182-254 million MW-km are installed in the case of greater demand growth, approximately doubling the size of the US grid. These numbers include both long-distance transmission and transmission to connect wind and concentrated solar power facilities to the grid.

In the LOADMATCH studies, Jacobsen et al. [14],[15] assume that 30% of all wind and solar electric power generation require long-distance transmission lines and add a cost to the price of that energy. However, they assume that the infrastructure, i.e. a national grid, already exists at no expansion cost. The SWITCH-WECC study [16] finds that high-voltage long-distance transmission is needed to connect load centers to wind power sites in the Rocky Mountains. In their 70$/t$CO_2$ carbon price scenario, they find 9.8 million MW-km installation by 2030 in the Western United States. The NEWS study [17] explicitly computes long-distance transmission capacity as part of the optimization problem as high-voltage direct current (HVDC) transmission lines. A total of 111 million MW-km of HVDC lines are added.

These results are summarized in Table 1. Across studies, modelers find expansion of order 7% to 79% compared to the existing capacity of the US grid (assuming 321 million MW-km today). Combined with the current condition and age of the grid, these results suggest that the rebuilt and expanded grid will be at least as large, and potentially twice as large in total, as the current grid.

TABLE 1. Transmission capacity extensions to the electricity grid

Model	Time period	Renew. target	Current or Added capacity [million MW-km]
Today's grid	2015	-	241-321
ReEDS	2010-2050	80%	23-254
LOADMATCH	2050-2055	100% all sectors	-
SWITCH-WECC	2014-2030	58%a	9.8
NEWS	2013-2030	46%b	111c

a - The base scenario uses a carbon price of 70$/t$CO_2$. The share of renewable energy is a result, not a modeling constraint.

b - This is the "midrange" scenario with medium cost projections for the natural gas price and capital costs of wind and solar power. Cost-minimization without constraints on minimum share of renewables or a carbon price adder led to the resulting share of renewable energy as a result, not a modeling constraint. Additionally to renewables, the scenario results in 16% nuclear power, which also is a zero-emissions technology

c - This is the "midrange" scenario with medium cost projections for the natural gas price and capital costs of wind and solar power. A scenario of high cost of renewables and low natural gas prices leads to 32 million MW-km of additional transmission, and a scenario of low cost of renewables and high natural gas prices leads to 142 million MW-km of transmission expansion.

Other studies specifically investigate transmission grid extensions in other regions. Schaber et al. [18] model the European grid and its grid capacity extension from 2010 to 2020 as its share of renewable energy increases to 34%. The study shows that grid extension helps reduce the effects introduced by wind and solar power. They find that overhead transmission capacity extension of an amount of 60% of the currently installed transmission capacity would yield the lowest overall system costs. They also find that revenues of conventional power plants increase at this level of transmission extension because the average utilization is increased and the ramping is decreased compared to a scenario without transmission capacity extension. In addition, they find that transmission expansion also increases the revenue of wind and solar power.

Transmission capacity extension tends to be challenging due to long lead times, numerous stakeholders, and large capital requirements. Cochran et al. [5] mention that reduced transmission capacity extension is possible, but increases overall system costs and would lead to the need for additional storage, reserve capacity, and curtailments.

2.3 EXPANSION OF STORAGE CAPACITY

Electricity storage is often described as one of the main additions to the electricity system in order to cope with the variability and intermittency introduced by renewable energy [19]. However, high capital costs are considered a barrier to wide-spread storage deployment [1].

The ReEDS study considers three storage technologies: pumped hydropower, battery storage, and compressed air energy storage. The study finds that significant storage expansion is needed in high renewable energy scenarios. The study finds a buildup from 20 GW of storage in 2010 to 181-195 GW of storage in 2050 in the 80% renewable energy scenario. The LOADMATCH study considers hot and cold storage, pumped hydro storage, phase-change materials storage, and hydrogen storage. It does not consider battery storage. In order to keep the grid balanced, the study finds that 2.6 TW of storage would need to be deployed, 113 times current deployment (currently largely in pumped hydro storage) [20]. The SWITCH-WECC study considers battery storage, compressed air energy storage, and thermal energy storage as part of solar thermal systems. Due to round-trip efficiency losses and high capital costs, none of these technologies is used at significant scale. The NEWS study initially included storage as a capacity extension option, but removed it from the model because it was not cost competitive and thus not deployed in initial evaluations.

In a study specifically aimed at investigating how much multi-hour storage is needed for a low-carbon future of the electricity sector, Safaei and Keith [19] model the Texas grid (ERCOT) and find that even when renewable energy takes up a large share of power generation, there is no technical or economic need for large deployment of multi-hour electricity storage. Only when the grid is allowed to emit very little $kgCO_2$ per MWh – in this case 150 $kgCO_2$ per MWh – does the capacity of multi-hour electricity storage increase from 3% today to 10% of the peak load. While this would still be a small fraction of the overall capacity of the grid, it would be a significant increase from current storage capacity. However, storage capacity growth would be smaller than renewable energy growth.

Sisternes et al. [21] provide another study that investigates the role of storage in a capacity extension model. They also base their model in Texas and find that storage is needed when very high shares of renewables are deployed. However, they stress that a flexible generation mix can result in a feasible low carbon emission future without significant need for storage.

While capacity extension models have a resolution on the order of hours, storage technologies are valuable to provide grid services on smaller time-scales as well. With higher shares of renewable power generation, ancillary services and short-term shifting of energy become more important and will likely lead to additional storage deployment due to the economic incentives on these shorter time-scales [22].

2.4 DEMAND SIDE MANAGEMENT

In recent years, demand side management has received increased attention. The studied models include demand side management in various ways. However, in a meta-analysis of long-term capacity extension studies, Cochran et al. [5] point out that these studies do not generally model demand side management adequately in order to understand its value for the future of the electricity system.

Demand side management can be divided into energy efficiency and demand response. Energy efficiency results in lower consumption of energy, and thus in a reduction in required generation and transmission investments. Demand response shifts the timing of electricity demand. An example of demand response is the installation of smart metering equipment with devices that can respond to price signals. Thus, electricity consumption can then be scheduled such that it falls in times of low electricity prices, and equipment is turned off in times of high electricity prices. Investments in demand response capabilities lead to a more flexible use of equipment, but turning off equipment at times of high prices may result in costs due to under-utilization of capital. We focus on demand response in the remainder of this paper.

One can distinguish between demand response for residential, commercial, and industrial systems. Residential demand response can involve scheduling HVAC, dish washers or washing machines based on electricity prices[23]. Commercial facilities such as supermarkets can take advantage of variability in electricity prices, for example by modulating energy use for refrigeration, to provide services to the electricity system [24]. Many sources of residential and commercial demand response can likely be installed and used with minimal to moderate capital investments.

Industrial demand response is likely to entail the largest impacts on capital investment. Industrial demand response is challenging: complex integrated chemical and manufacturing processes can be sensitive to fluctuations in output or scheduling. Furthermore, industrial customers often have onsite electricity generation, enter bilateral contracts, or bid in multiple electricity markets on different timescales [25].

The six largest electricity consuming industrial sectors account for around 15% of United States electricity consumption [26]. Industrial facilities have identified demand response as a measure to reduce operating costs [25] by shifting electricity intensive process steps to times of low electricity prices. Demand response has been studied for industrial separations [27], [28], chemical facilities [25], [29], [30], manufacturing [25], [29], [30], and primary metals industries like steel and aluminum [31], [32].

Demand response is often not included or modeled in a simplified way in long-term capacity extension studies. The ReEDS study models demand response as interruptible load, with up to 16-24% of the peak load of each region being interruptible by 2050 [33]. This leads to 55-107 GW of total interruptible load, compared to 16 GW in 2009. The NEWS study focuses only on generation capacity extension and transmission capacity extension and does not consider demand response as a means to reduce the impacts of variability of renewables. The LOADMATCH studies assume that 70% of all electric load is shiftable by 8 hours at no additional cost. However, the LOADMATCH studies do not consider the investments in increased capacity required to provide such flexibility. The SWITCH-WECC study assumes that a certain percentage of residential and commercial demand is shiftable to any hour of the same day.

One study by Paulus et al. [7] focuses specifically on industrial demand response in a long-term planning model for the German electricity system. In this study, the authors find that by including the current industrial demand response potential, demand response mitigates variability, and investments in two average-sized gas turbines can be avoided. Demand response programs that have been implemented in industrial facilities are promising. For example, Merkert et al. [34] find cost savings of up to 12% (2-5 million USD) for eight steel plants. The Alcoa Aluminum smelter [35] recovered an investment cost of $700,000 in flexibility enhancing equipment within four months [36].

Zhang et al. [25] mention that several factors enhance the potential of industrial customers, compared to residential and commercial ones, to participate in DR: industrial facilities are large consumers, metering equipment is already installed, and unlike residential and commercial customers, they are not primarily concerned with human comfort. Furthermore, while electricity storage itself is generally expensive, "virtual" storage of electricity in the form of product inventory may be cheaper.

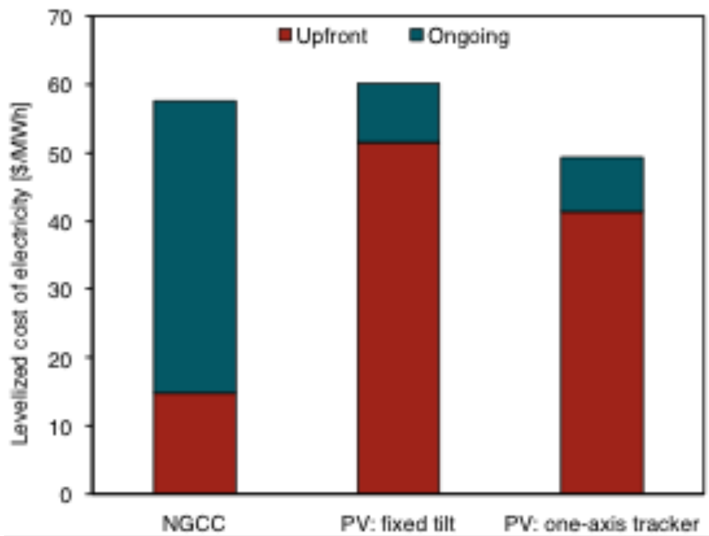
The more industrial demand response is used, the larger the effect on utilization of capital. The utilization factor – the ratio of the time that the facility is in use to the total time that it could be in use – is a useful indicator. In order to shift electricity from times of high prices to times of low prices, the facility has to reduce or shut down production in times of high prices. If total output from a suite of facilities is to remain constant, additional capacity will be needed to make up this shifted production in times of low prices. Facilities today have downtime due to several reasons: overcapacity on the market (e.g. the steel industry today [37]), seasonal demand fluctuation, holidays, and scheduled maintenance. Demand response would increase this downtime on net.

The first tranche of demand response is very low cost: predictive models can help schedule existing downtimes to align with times of high electricity prices, without affecting the overall capital utilization factor or requiring excess capacity. Beyond that scale, more demand response would require higher production capacity for the same product output. This leads to lower utilization factors. In the case of the LOADMATCH model results, overall industrial demand utilization factors were ~30% [14], whereas recently observed industrial utilization factors are ~75-80% [38].

3. CHANGES IN COST STRUCTURES: A SHIFTING MIX OF UP-FRONT AND ONGOING COSTS

A second factor in addition to increased capacity investment is the changing mix of upfront vs. ongoing costs for various forms of power generation. That is, two power sources with the same nominal levelized cost of electricity (LCOE), i.e., 50 $/MWh, may have different fractions of LCOE attributable to upfront capital investment as compared to ongoing or marginal operating costs. Figure 3 shows examples of this using most recent Department of Energy cost reports for

FIGURE 3. Shift in cost structure between NGCC and PV. NGCC Data from Fout et al., Table ES-4, cost summary for NGCC plant. Solar data from Fu et al. for Bakersfield CA (high insolation area).



natural-gas-based and solar-PV power generation, with similar overall LCOE, but dramatically different capital costs vs. ongoing costs [39], [40].

This shift in cost structure has implications given the share of renewable energy in future electricity systems. Hirth and Steckel [41] investigate the effect of different costs of capital on the share of renewable energy in future electricity systems. They find that different values for weighted average cost of capital (WACC) lead to fundamentally different structures of future electricity systems. They find that a WACC of 3% leads to 40% renewable energy generation and a reduction of carbon emissions by ~50%, whereas at a WACC of 15%, almost no renewable energy is cost-optimal. Both of these scenarios assume a carbon price of $50/MWh. The fundamentally different structures of future electricity systems depending on the WACC are a result of the different cost structures of conventional and renewable energy technologies. Technologies with a high share of upfront costs such as wind and solar become significantly more expensive with an increase in cost of capital. In future scenarios where the WACC is high, renewable energy deployment is slowed.

A study by Ondraczek et al. [42] signifies the importance of this shift in cost structure in a different context. They examine LCOEs of solar PV systems in 143 countries all over the world. They find that LCOE of solar PV systems may be lower in northern countries than in equatorial countries, due to lower cost of capital. This cost advantage exists despite the less valuable solar resources available in those countries. They stress that low-cost financing (i.e., low WACC) is essential to the growth of renewable energy and that policies that de-risk investment in low carbon emission technologies are thus a key driver of the sustainable energy transition.

4. CONCLUDING REMARKS

Energy systems are shifting from being fossil-fuel-dominated toward being renewable-energy-dominated. This shift presents major opportunities for investments in power generation, transmission lines, energy storage, and demand response technologies. In this paper, we compare studies with targets ranging from 40% renewable energy generation to 100% renewable energy generation.

At moderate shares of renewables, studies find that existing coal capacities are phased out early and replaced with wind and solar energy. At high shares of future renewable power generation, conventional power generation is replaced by extensive amounts of renewable energy, with additional ranging from 41%-609%. Transmission capacity extension varies widely based on demand estimates, and ranges from 7% to 79% of additional transmission capacity. In future electricity systems with high penetration of renewables, energy storage is an option for mitigating variability effects that are introduced by wind and solar.

Studies find that with a diverse portfolio, storage is not necessary, but that in some scenarios it can be cost effective to deploy, especially where very low CO_2 emissions targets prevail. Demand response can help mitigate the effects of wind and solar power. However, this may come with under-utilization of capital, which means that for example more production capacity in industrial facilities needs to be installed to generate the same product output.

Furthermore, the technologies that are installed include a shift in cost structure from ongoing to upfront costs. While 25% of the levelized cost of natural gas power is upfront capital cost, solar PV systems incur ~85% of their levelized costs in the form of upfront capital investment. From a finance point of view, this suggests increased opportunities for lenders to participate in electricity generation capacity extension. If a larger fraction of costs of power system operation require financing, the role of capital investment increases as does the importance of the cost of capital.

Overall, capacity expansion models can be a valuable tool for the finance community in identifying opportunities and long-term shifts in the electricity generation sector. We see from the above studies that significant capital investment will be required and that the nature of future power systems will increase the importance of access to low-cost capital.

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