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AT THE UNIVERSITY OF HAWAII

Working Paper No. 2024-2

February 21, 2024

UNIVERSITY OF HAWAII AT MANOA  
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# Optimal transmission expansion minimally reduces decarbonization costs of U.S. electricity \*

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February 21, 2024

## Abstract

Solar and wind power are cost-competitive with fossil fuels, yet their intermittent nature presents challenges. Significant temporal and geographic differences in land, wind, and solar resources suggest that long-distance transmission could be particularly beneficial. Using a detailed, open-source model, we analyze optimal transmission expansion jointly with storage, generation, and hourly operations across the three primary interconnects in the United States. Transmission expansion offers far more benefits in a high-renewable system than in a system with mostly conventional generation. Yet while an optimal nationwide plan would have more than triple current interregional transmission, transmission decreases the cost of a 100% clean system by only 4% compared to a plan that relies solely on current transmission. Expanding capacity only within existing interconnects can achieve most of these savings. Adjustments to energy storage and generation mix can leverage the current interregional transmission infrastructure to build a clean power system at a reasonable cost.

**Keywords:** Decarbonization, renewable energy, intermittency, transmission, trade, optimization

**JEL Classification:** Q42, Q52

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\*First version: February 21. This version: February 21, 2024. The authors would like to acknowledge all contributors to Switch 2.0, the open-source capacity expansion model we use in this work, as well as Catalyst Cooperative's Public Utility Data Liberation (PUDL) Project (<https://catalyst.coop/pudl/>), which is a key input into PowerGenome. Partial funding for this project was provided by the Sloan Foundation via the Environmental Defense Fund's Model Intercomparison Project. Comments welcome.

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# 1 Introduction

Although solar and wind power are affordable and likely central to efforts to decarbonize the world economy, their variability presents a considerable challenge to existing systems dominated by easily controllable thermal power plants. Interregional transmission can help smooth imbalances in supply and demand over space while transferring power from places relatively rich in solar and wind resources to places with poorer options. For example, compared to other regions, the desert Southwest receives more solar radiation, while the Great Plains have abundant wind resources. These aspects of solar and wind contrast sharply with existing generation. Thermal power plants perform nearly the same wherever they are placed. It is unclear how suitable existing transmission lines are for the emerging energy system with different interregional and intertemporal gains from trade. At the same time, extreme weather events and reliability impacts (e.g., heat waves and wildfires in California and winter storms in Texas) have increased discussion of the need for strong connections between U.S. grids.

Existing interregional transmission capacity was not built with a high-renewable future in mind, and building new transmission lines is costly economically, logistically, environmentally, and politically. Historically, building new transmission lines has often been fraught with controversies about where to site transmission lines, how to finance them, and how costs should be allocated to buyers, sellers, and electricity customers. While enhanced trade between regions generally benefits all sides, individual stakeholders, such as existing transmission line owners and locally advantaged existing generators, can lose rents amid enhanced competition (Hausman, 2024). New transmission lines might also pass through regions that do not benefit from them, and these communities may understandably resist their siting, especially when transmission line construction has considerable environmental and biodiversity impacts (Biasotto and Kindel, 2018; Marshall and Baxter, 2002; Söderman, 2006; Hyde, Bohlman and Valle, 2018). In addition, ERCOT, the Texas-only interconnect, is especially isolated and likely to resist connections with other regions given its unique market structure and aversion to oversight from the Federal Energy Regulatory Commission (FERC). These challenges cast doubt on the likelihood that interregional transmission will expand in line with conventional measures of benefits and costs.

When these challenges are paired with a perception that transmission expansion is an essential part of the decarbonization puzzle (Brown and Botterud, 2021; Pacala et al., 2021; Moch and Lee, 2022; Joskow, 2020; Davis, Hausman and Rose, 2023), it highlights the importance of evaluating the benefits and costs of interregional transmission upgrades, taking into account the full portfolio of alternatives, both within and between the existing interconnects. If future transmission expansion is uncertain, some may wonder whether near-term investments in solar, wind, and other infrastructure will be compromised if transmission expansion does not proceed as expected. While there is a significant body of literature addressing the optimal design of electricity systems for the U.S. (Brown et al., 2018; Mai et al., 2018; Jayadev, Leibowicz and Kutanoğlu, 2020), few studies consider 100% decarbonization. Even fewer studies have evaluated the value of transmission in a 100% decarbonization future. Given the scale and useful lifetimes of these investments, it is important to consider the rapidly falling costs of storage and other technologies that could serve as substitutes.

Findings from existing work about transmission are divergent. Using a modified version of OS-

eMOSYS (Howells et al., 2011), (Jayadev, Leibowicz and Kutanoglu, 2020) illustrate the limited value of long-distance transmission in the least cost scenario with no carbon policy applied. In contrast, the recent study by (Brown and Botterud, 2021) finds that interregional transmission upgrades in a zero-carbon electricity system can reduce the average cost of decarbonized power from over \$100 per MWh to about \$70 per MWh. However, this measure compares ideal “greenfield” transmission systems and pays no attention to existing transmission capacities. Moreover, it does not consider seasonal balancing options, such as green hydrogen, nuclear power or carbon capture and storage (CCS) paired with natural gas generation. Moderate deployment of these technologies can both lower the cost of decarbonization and greatly diminish the value of added transmission, even if these emerging technologies are costly.

Our work contributes to the literature by evaluating transmission value in least-cost, zero-emissions, and socially-optimal scenarios, while building from existing infrastructure, including transmission. It accounts for how a broad range of technologies, including renewables, batteries, hydrogen, nuclear, and CCS, can substitute for transmission using a model with high temporal and spatial resolution of weather and associated supply and demand.

Our main finding is that an optimal nationwide zero-emissions plan would more than triple current interregional transmission, which validates the conventional wisdom that much more is needed. However, we find that such a system would cost only 4% less than a well-designed zero-emissions system with no new interregional transmission, as a complex array of substitutes from storage to generation mix adjustments can limit excess costs.

## 2 Current and idealized future systems

The value of expanding transmission depends on what already exists, including generation and transmission infrastructure. It also depends on the resource availability to build and connect new generation and on expected future demand. The existing grid evolved from primarily local power provision to increasingly interconnected regions. At first, transmission was used mainly to transport power from remote generating plants to urban customers (Decker, 2021). Over time, it became clear that efficiency would be enhanced by connecting population centers to exploit economies of scale with large “base load” power plants that could operate continuously at full capacity (e.g., coal and nuclear), paired with smaller local ramping and peaking power plants that could accommodate time-varying demand (Masters, 2013). A larger, more connected grid also has more inertia and stability in the face of demand shocks, severe weather events, plant outages, and, increasingly, renewable energy intermittency. As a result of these economic forces, regions are more interconnected today than a century ago. Still, the U.S. grid remains highly fragmented, with three nearly disjoint sections, the Eastern, Western, and ERCOT interconnections (panel **b** of Figure 1), and varying degrees of connectivity between regions within each of these interconnects.

The existing transmission system was not designed for the future, which will likely employ much more solar, wind, batteries, and other forms of storage, given their low and declining costs and lack of CO<sub>2</sub> and other pollution emissions. However, long-duration storage remains expensive, so there is an ongoing debate about what the future generation mix should look like (Jacobson et al., 2018; Purisiheimo, Holttinen and Koljonen, 2019; Qazi, 2022), and how the degree of interregional transmission



expansion could factor into the generation mix (Stadecker et al., 2023), its geographic disposition, and overall cost. The future energy system is also policy-dependent. It will hinge on subsidies for clean energy, taxes or other restrictions on carbon dioxide and other pollutant emissions, local market rules and structures, and decisions by state and federal regulators.

To obtain a sense of what an idealized future system could look like, we used Switch (Fripp, 2012; Johnston et al., 2019; Stadecker et al., 2023; Hidalgo-Gonzalez, Johnston and Kammen, 2021; Sánchez-Pérez et al., 2022), a state-of-the-art, open-source power-system planning model, paired with PowerGenome (<https://github.com/PowerGenome/PowerGenome>), an open-source platform that compiles comprehensive weather and utility system data, to develop a least-cost plan for a zero-carbon power system for the continental United States in 2050. The model co-optimizes potential new generation capacities, storage, interregional transmission, and hourly chronological operation of the system for all 8,760 hours, which is essential for finding true least-cost high-renewable systems given their weather-driven variability and critical dependence on storage and transmission. Technology and fuel cost assumptions are derived mainly from the National Renewable Energy Laboratory’s Annual Technology Baseline (National Renewable Energy Laboratory, 2022). This idealized system of the future, portrayed in panel c of Figure 1, is dominated by solar and wind generation, possesses ample storage in the form of batteries and green hydrogen, and increases interregional transmission capacity by over 200%.

This idealized, zero-emissions system is 68% more costly per MWh than the least-direct-cost system that excludes any account of external CO<sub>2</sub> emissions costs. At a markedly lower cost (45% above least-cost, excluding emissions’ costs), we could achieve roughly 95% decarbonization, a level of decarbonization consistent with the Environmental Protection Agency’s estimated social cost of carbon dioxide of \$190 per ton. The difference in cost and emissions between the socially optimal and zero-emissions scenarios is mainly derived from natural gas with carbon capture and storage (CCS) replacing hydrogen. Note that these costs pertain only to generation and transmission and do not account for local distribution costs, which can comprise almost half of the retail electricity costs for residential customers today (Borenstein, Fowlie and Sallee, 2021). Hence, these decarbonization costs are a considerably smaller share of retail prices. However, these idealized systems optimize interregional transmission, roughly tripling it, including building new connections between the three interconnects.

### 3 Scenarios considered

Each scenario jointly optimizes generation and storage capacities, transmission, and hourly chronological operation of the system over 52 weeks, subject to emissions and transmission constraints of the given scenario. We use 942 clusters of candidate renewable energy projects, corresponding to approximately 21 TW of potential capacity, with each cluster’s variable capacity factors derived from weather data synchronized with demand. Both weather and demand are based on 2012; details are provided in methods.

To show how interregional transmission influences the cost of decarbonization, we built a series of scenarios with different restrictions on emissions and transmission expansion. These include three emissions scenarios: (i) a *least-direct-cost* system that ignores external costs of CO<sub>2</sub> and other pollution emissions; (ii) a *socially-optimal system* that assumes a CO<sub>2</sub> price of \$190 per ton; and (iii)

a *zero-emissions system* with no CO<sub>2</sub> emissions. All three of these scenarios use the same projected demand for 2050, which is 74% greater than today’s demand, roughly accounting for the growth of electric vehicles, partial electrification of heat, and electrification of some industrial activities. For each of these three emissions scenarios, we consider three transmission scenarios: (a) *existing* transmission in 2022; (b) optimized expansion *within interconnects*, but no expansion between interconnects; and (c) *fully-optimized* expansion of transmission between regions both within and between interconnects. Crossing the emissions scenarios and transmission scenarios gives a total of nine scenarios labeled below.

- LE Least-direct-cost, existing trans.
- LI Least-direct-cost, within-interconnect trans.
- LO Least-direct-cost, fully-optimal trans.
- SE Socially-optimal, existing trans.
- SI Socially-optimal, within-interconnect trans.
- SO Socially-optimal, fully-optimal trans.
- ZE Zero-emissions, existing trans.
- ZI Zero-emissions, within-interconnect trans.
- ZO Zero-emissions, fully-optimal trans.

The main figures in this manuscript focus on **LE**, **LO**, **ZE**, and **ZO** and we report results for the other scenarios in the supplement since they are similar to the cases shown here. In each case, all other aspects of the system are co-optimized, subject to transmission constraints. Existing and candidate generation technologies include solar, wind, batteries, hydrogen, natural gas with and without carbon capture, battery storage, nuclear, pumped-storage hydroelectric power, pre-existing hydroelectricity, and distributed solar. Hydrogen production can be produced endogenously via electrolysis and later used for generation via fuel cell, and thus serves as a form of long-term storage. The model accounts for all systems’ operations and maintenance costs, including existing transmission lines. By optimizing all options in conjunction with different transmission constraints, we see how portfolio adjustments compensate for less-than-ideal expansion of long-distance transmission.

## 4 Results

This paper uses average load-weighted, long-run marginal cost as the “wholesale cost” metric (the dual of the load-serving constraint in the optimization model). This roughly corresponds to demand-weighted locational marginal prices in wholesale power markets, assuming markets are perfectly competitive and in long-run equilibrium. This metric includes rents to scarce resources and can thus differ slightly from engineering-based measures of levelized cost. Note, however, that we do not account for reserves, excess capacity payments for obsolete or partially obsolete assets, within-region congestion costs, or any sub-optimal investment or operation of the system. The costs also correspond to a single weather year.

**Optimizing transmission for the least-direct-cost system minimally reduces the average wholesale cost of power from 37.4 \$/MWh under existing transmission to 37.0 \$/MWh, a savings of just 0.3% (Overall LE - Overall LO in Figure 2, panel a).** This difference is barely visible in the graph due

to its small size. Optimally expanding transmission within interconnects reduces overall cost by 0.2 \$/MWh, or about half the savings from fully-optimal transmission. Although the least-direct-cost scenarios do not take into account emissions and assume inexpensive future natural gas following NREL-ATB projections, they still include a nearly five-fold expansion of solar and wind capacity relative to 2022 levels and reduce electricity sector CO<sub>2</sub> emissions by 6.9 to 7.8% relative to 2022. These emission reductions occur despite 74% growth in overall demand and thus result in over 50% reduction in emissions intensity (CO<sub>2</sub> per MWh delivered) compared to 2022. Furthermore, the projected growth in demand embodies substantial growth of electric vehicles and electrification of heat, such that economy-wide emissions reductions would likely be much greater; a precise calculation is beyond the scope of this study.

**Optimizing transmission for the zero-emissions system reduces the average wholesale cost of power from 64.8 \$/MWh under existing transmission to 62.2 \$/MWh, a savings of 4%** (Overall ZE - Overall ZO in Figure 2). Optimally expanding transmission within interconnects, but not between them, reduces cost by 3.2% (not shown). The relative savings of expanded transmission are greater in the high-renewable zero-emissions system than in the least-direct-cost system with about one-third the amount of wind and solar. And because the direct costs are far higher, net transmission savings are fairly substantial. As shown in Figure 5, optimal transmission scenarios reduce prices slightly throughout the distribution.

**The overall cost of decarbonization, defined as the difference between the average marginal cost of a zero-emissions system and a least-direct-cost system, is 25.2–27.4 \$/MWh, or 68–73% of the least-direct-cost system, depending on the transmission scenario.** If emissions are valued at \$190/tCO<sub>2</sub>, the avoided harm in the zero-carbon case is much greater than the extra direct costs in the power system. We find that full decarbonization has total societal costs—including both direct costs and emission impacts—that are 57%–59% below the least-direct-cost case. If, instead of full decarbonization, societal costs are minimized, direct costs increase by 34–36% relative to the least-direct-cost scenario, electricity sector emissions fall by 95.5 to 95.7% relative to 2022, and societal savings rise to 66%. These estimates do not include economic and emissions savings in transportation, heating, and industrial sectors of the economy that would be substantially electrified (supplement Table A1).

**The costs of decarbonization and benefits of optimal transmission vary across regions.** In Figure 2 panel a, regions are ordered from least to greatest cost in the scenario with zero emissions and existing transmission (ZE). These costs vary from about \$47/MWh in TRE\_WEST, which encompasses southwestern Texas, to about \$91/MWh in NYCM, which contains New York City and Long Island. It is clear from the map (panel b) that the transmission benefit for decarbonization varies across regions; in a few cases, expanding transmission increases the decarbonization cost (shades of red). The precise calculation for each point is the demand-weighted average hourly marginal cost for each region under each scenario. Because the model optimizes the system's capital and chronological operation, and capital decisions are nearly continuous at the regional scale, the average marginal cost equals the average cost, including positive or negative economic rents to infra-marginal or stranded generation and transmission. We report on rents below and show how transmission changes their allocation,

which may be relevant to the political economy of transmission expansion and of generation plants siting.

**To fully decarbonize using only existing transmission, investments in storage must increase by 21%, generation by 9%, and hydrogen electrolysis by 0.6% relative to the fully-optimized transmission scenario** (Figure 3, panel a). If transmission can expand optimally only within interconnects, generation and storage capacities change minimally relative to the fully optimized transmission scenario, while hydrogen is minimally used regardless of transmission. In the socially optimized system, limiting to existing transmission causes storage and generation expenditure to increase by 23% and 5%, while hydrogen is minimally used regardless of transmission (shown in the supplement in Table A1 and Figure A4). In general, the mix of generation is similar regardless of transmission but uses slightly more nuclear and solar and less wind when transmission is constrained (panels c and d of Figure 3). These compensating adjustments in generation and storage expansions are somewhat more expensive than the optimized transmission expansions that they replace (Figure 3, panel a). The adjustments are modest, however, relative to the 15-fold increase in renewables and other capacity increases needed for decarbonization.

Generation capacities and their geographic locations, including those for solar, wind, batteries, hydrogen, nuclear, and other sources, are generally similar regardless of transmission expansion and vary mainly with the degree of decarbonization. We illustrate these differences in Figure 4, which plots capacities in each region and type when only existing transmission is used against capacities when interregional transmission is fully optimized. The similarity of these generation mixes has a practical implication for planning: it suggests that generation expansion should proceed similarly regardless of inter-regional transmission expansion, especially during the early to intermediate stages of decarbonization. In the supplement Figure A5, we show similar comparisons for the socially optimum scenarios that assume a carbon price of \$190/ton.

In addition to the technologies shown, the model includes options for carbon capture and storage (CCS) paired with natural gas and coal generation facilities. These technologies are only selected in the socially optimal scenarios, with details provided in the supplement (Figure A4).

**Transmission expansion will have little influence on price variability, while the extent of decarbonization will significantly increase price variability** (Figure 5). In competitive markets, wholesale prices equal marginal cost, the distributions of which we can infer from model's dual variables associated with each hour's balancing constraint. We show these distributions as cumulative densities because they tend to have significant mass points at zero, and especially large ones in high-renewable scenarios. In the supplement we use multiple bar plots to show the density functions, which may be more intuitive. We discuss likely real-world departures from competitive markets below.

The marginal-cost distributions for the least-direct-cost scenarios have about 90 percent of MWh between 20 and 40 dollars per MWh. About 2 percent of MWh have a marginal cost of zero or nearly so ( $< \$1/\text{MWh}$ ), and about five percent have marginal costs above 40 dollars per MWh. The zero marginal-cost times occur during curtailment events (wind and/or solar energy are discarded). The influence of transmission on the marginal cost distribution is so small that it is difficult to discern in the graph.

In contrast, the high-renewable scenarios, including both zero-emissions and socially-optimal scenarios with a \$190/tCO<sub>2</sub>, have starkly greater variability, with 28 to 48 percent of delivered MWh having a zero or near-zero marginal cost (< \$1/MWh). The large share of “free” energy occurs because solar and wind capacities are optimally built out to help serve demand on days with low to medium wind and sunlight and high demand. These times are seasonal, tending to occur in late fall and winter. As a result, there are often surpluses during other seasons, especially spring and summer, when wind and sunlight are more abundant, leading to many stretches of time with zero marginal cost. During these times, renewables are curtailed because there is more energy in batteries than could be depleted before being fully charged again with excess wind and solar, and electrolysis capacity is fully utilized.

In zero-emissions scenarios, the spread of marginal cost above near-zero is smooth and broad, with about 25 percent of marginal costs spread evenly between \$10 and \$100 per MWh, and the marginal cost of most other energy spread evenly between \$100 and \$200 per MWh. Extreme marginal costs above \$1000/MWh are rare. The main effect of transmission is to slightly increase the frequency of hours in the \$30 to \$80 and \$100 and \$200 range. Again, the influence of transmission is modest. In the socially optimal scenarios, marginal costs above near-zero are more concentrated in the \$75 to \$200 range. Like the other cases, the influence of transmission on the distribution of marginal costs is minimal.

The extreme variability of marginal cost in high-renewable scenarios, especially the high frequency of zero-marginal-cost energy, suggests that flexible demand could be especially valuable in these systems, as indicated by (Imelda, Fripp and Roberts, 2022).

**Transmission expansion increases economic rents for some resource owners while reducing them for others** (Figure 6). If resource owners are paid a price equal to the the incremental cost of power in each region and hour, then all variable and fixed costs are recovered in long-run equilibrium, which is what our model assumes. In addition, some owners of scarce resources glean rent above their total costs. The potential rents we can identify in this study pertain to heterogeneous solar and wind resources and potentially constrained transmission resources. Areas with unusually large or well-timed amounts of solar radiation or winds earn rent (above competitive profit) because they provide more value than marginal resources. Our model indicates that these rents tend to be highest in the zero-emissions scenarios.

Transmission expansion increases rents for some resources and regions and decreases them for others. For example, a region that has high-quality wind or solar resources gains from expanded transmission and trade with regions that have worse wind and solar resources, while a region that has lower-quality wind and solar resources may lose out when enhanced transmission instills greater competition from neighboring areas.

Combining rent and cost changes, which mostly benefit consumers, all regions gain from transmission expansion. However, since some resource owners lose rents relative to the no-expansion case, diverging stakeholder interests could hamper efforts to expand transmission. Figure 6 illustrates these divergent interests for solar and wind resources, which are most prevalent and have greater rent than in the zero-emissions scenarios. The graph shows gains and losses in solar, wind, nuclear, and transmission rent. The coastal regions and South tend to lose solar and wind rent with transmission expansion, while Arizona, Ohio, and Michigan gain solar rent, and the Rocky Mountains, Oklahoma,



and upper Great Plains gain wind rent. Nuclear plants mostly lose rent, as sunk costs from existing plants earn less revenue when transmission is optimized, enhancing competition from renewables.

**Hourly operational detail in ERCOT shows how transmission expansion can aid resiliency during the most constrained times** (Figure 7). The model optimizes hourly operations and interregional flows in each region, revealing how the system achieves balance. Here we consider a costly day in the most isolated region, TRE, the Eastern part of ERCOT, which has most of the interconnect’s generation and demand. In two of the four scenarios (LO, ZE), the day depicted (December 13th, 2050, based on actual weather data in 2012), is the most expensive in the region. This is a cold day in early winter near the solstice, when solar resources would generally be more limited, with unusually little wind.

Compared with the least-cost scenarios, decarbonization is achieved via substantially greater capacities of solar and wind paired with significant use of batteries and hydrogen, which replaces natural gas and some old-vintage coal. The deficit from renewable energy is mostly counterbalanced with natural gas in the least-cost scenarios and with imports, battery storage, and hydrogen in the zero-emissions scenarios. Notably, even the least-direct-cost scenarios use batteries to help serve the net peak at 7pm, when wind and solar power fall to near-zero.

The effects of optimizing transmission are subtle and difficult to discern in the least-direct-cost scenarios. In these scenarios, some power is imported from the Western part of ERCOT (TRE\_WEST) at 1pm and 3pm of December 13th, 2050 when transmission is fixed (panel **a**), but less is imported under optimal transmission, because, in this case, more natural gas capacity is built so the region can export more on other days. The generation mix is largely the same when transmission is fully optimized (panel **b**), except there is slightly more gas generation and less battery use during the evening peak. The peak hour marginal cost falls from about \$20,000 to about \$16,000 when optimizing transmission.

The zero-emissions scenarios (**c** and **d**) show a somewhat greater influence from optimizing transmission. Generation mixes are similar regardless of transmission, but there is noticeably more battery use and slightly less wind in the scenario with existing transmission. And while imports help, especially in the optimal transmission scenario, it is interesting that imports occur midday to help replenish batteries, and much less during the expensive evening peak. The peak marginal cost of about \$22,000 per MWh falls to about \$7,000 with expanded transmission. And where the nighttime hours after the peak stay elevated at \$5,000 per MWh with existing transmission, marginal cost falls back to very low levels when transmission is optimally expanded.

Although we do not consider demand response or demand-side flexibility in this study, this difficult day in ERCOT suggests it could be valuable. In all scenarios, hours up to 5pm are very low cost or free. Adjustments in EV charging, thermal storage or pre-heating in buildings, or even modest thermostat adjustments during the critical peak, would reduce required hydrogen or battery capacity, saving substantial costs. Even existing demand responses by some industrial customers could make a difference. Such demand responses would likely reduce transmission value, too.

## 5 Discussion

More than 2 TW of solar, wind, and storage capacity was waiting for interconnection to the U.S. grid at the end of 2022, a staggering quantity equal to multiple times existing capacity. The U.S.

electricity sector would take a healthy step toward decarbonization if all of it were built, connected to the grid, and managed efficiently. Still, the wait times are substantial, and many proposed projects are never completed (Rand et al., 2023). Full decarbonization will require even more growth of renewable energy capacity by 2050, especially with higher demand from electric vehicles and electrification of heat and industry. Many kinds of local transmission upgrades are critical to connect these resources, including spur lines to the locations of new generation facilities, and grid-enhancing technologies that can help to maximize the use of existing transmission lines within and between regions. The Federal Energy Regulatory Commission is considering the nature and extent of transmission upgrades needed, and how best to manage a considerable queue of clean energy resources.

This study does not focus on these immediate transmission challenges of grid interconnection and optimal power flow (which considers exact existing lines, their impedances, currents, voltage limits, and real and reactive power flows). However, it does account at least approximately for the cost of spur lines and transmission upgrades to connect new solar and wind installations to the grid. Rather, it considers the costs and benefits of transmission expansion and large-scale energy flows between large regions, which could allow more power to be traded over greater distances but could face considerable social, political, and environmental challenges. This research question and scope can be adequately addressed using capacity expansion models as we do in this work.

While the optimal expansion of interregional transmission would require more than a three-fold increase relative to what presently exists, we find that the net benefits of this expansion are small relative to the overall cost of a decarbonized system. Alternatives to expanded transmission are multifaceted and include greater renewable generation capacity, battery storage, and hydrogen electrolysis paired with fuel cell power generation. While expanded transmission might improve resiliency in some locations, the overall distribution of marginal costs (i.e., competitive wholesale prices) is similar regardless of interregional transmission expansion.

One caveat is that some kinds of transmission might be expanded at lower cost using various grid enhancing strategies<sup>1</sup> to improve power flow, or by employing new high-capacity conductors in existing right-of-ways (Chojkiewicz et al., 2024), which could halve the cost of expanding existing lines. It is also conceivable that storage costs could fall more than projected. Such technologies could only serve to expand the portfolio of options available to integrate clean energy affordably.

Another caveat to these findings is that they generally assume economic efficiency or perfectly competitive outcomes. During congested times, transmission and generation capacity owners may possess considerable market power, and be tempted to withhold generation or transmission to raise wholesale prices and profits (Borenstein, Bushnell and Wolak, 2002). Greater transmission capacity could, therefore, have the added benefit of increasing competition. At the same time, those earning substantial scarcity and/or market-power rents may resist expansion efforts that would reduce such rents. Transmission expansion may need to be expanded much more than otherwise optimal if the goal is to attenuate market power.

Perhaps a greater limitation of this study is that it does not account for demand-side adjustments that could substitute for transmission, storage, and generation. Such responses could be achieved through strategic timing of electric vehicle charging, vehicle-to-grid technologies, improved building

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<sup>1</sup><https://www.energy.gov/oe/grid-enhancing-technologies-improve-existing-power-lines>



insulation, thermal storage, smart control of building HVAC and water heating systems, thermostat adjustments during extreme weather events, and industrial demand shifting, some of which already exist. Given the extraordinary growth in marginal cost variability in the decarbonization scenarios, it seems likely that utilities, industry, communities, and opportunistic intermediaries will find ways to exploit growing wholesale price differentials. If they do, interregional transmission growth could be worth less than we estimate. Future research could consider how optimal transmission upgrades and expansion interact with demand response and distributed resources from local to interregional scales. A robust demand-side market that is responsive to real-time marginal costs would have the added benefit of reducing potential market power during congested times.

## 6 Methods

The paper reports results from Switch, a structured power system planning model with input data compiled by PowerGenome. Both Switch and PowerGenome are open-source platforms with online documentation. We provide a brief characterization of the model here.

### Limitations

Three main aspects are important to discuss in the context of transmission line expansion. First, in this study, we model transmission capacity in an aggregated manner to represent important energy flows between load zones. Our approach models the transfer capability of the electrical network but does not directly represent the physics of AC optimal power flow. Hence, our findings should not be taken as a claim that there is no need to worry about transmission expansion within individual regions in 2050. Our work sheds light on what are the most important electricity transfers between regions and interconnects to achieve zero emissions in 2050. Our findings speak to the lack of need and minimal economic impact of deploying “energy corridors” between interconnects as opposed to speaking about the value of specific transmission lines, for which power flow modeling would be required with an accurate model of the transmission network (e.g., California should be modeled with its approximately 9,000 buses). Second, our study, while high-resolution, considers only a single weather year and coincident demand. We do not account for reserves or for extreme weather events that do not occur in a typical year. Appropriate account of reserves and extreme events in reliable high-renewable environments requires the compilation of many years of high-resolution weather. It would also be important to include a careful account of demand response in such a study.

### Switch Characterization of the Planning Problem

Our analysis uses Switch (Fripp, 2012; Johnston et al., 2019), which is an open source capacity expansion model that minimizes the net present value (NPV) of costs for an electricity grid across all investment periods and timepoints. It optimizes both the investment and operational costs subject to constraints such as emissions limits or prices, or other policies, such as Renewable Energy Portfolio Standards (RPS).

Switch has a modular structure. Core modules define the time and spatial scale for the power system as well as an hourly load-balancing constraint and cost-minimizing objective function, both of which is initially empty. Additional modules define physical components and add their costs to the objective function and their power contribution to the load balance. Other modules define constraints

or costs to reflect policy choices, such as renewable portfolio standards or carbon caps. The modules we used in this study are described briefly below.

### **Timescales**

Timescales defines the time horizon for the investment planning and energy balancing. Under the Switch modeling toolkit, the time resolution has a three-level hierarchy that accounts for the temporal dimension at various scales: periods, time series, and time points. Periods are a set of multi-year timescales that describe the times when the investment decisions are made. In this model, to focus squarely on the question of transmission, we assume just one investment period that stretches 10 years from 2041 to 2050 and refer it as period 2050. The next level of granularity is the time series. This denotes blocks of consecutive time points within a period. An individual time series could represent a single day, a week, a month, or an entire year, or even a mix of blocks of different lengths. The length of time that energy may be stored is typically limited to the time series, which means that the amount of energy storage at the beginning of the time series is constrained to equal the ending amount at the end of the time series. (Hydrogen is an exception, as explained below.) There are 52 time series in this study, each one week long, with hourly time points from each week, comprising all 8760 hours in a year. Having 52 one-week time series instead of one time series of length 8760 saves considerably on computational cost while losing little practical precision, since battery storage and most hydroelectric resources cannot be economically used for long-duration storage that exceeds a week.

### **Financial**

The financial module defines the base year for the NPV calculation, the discount rate applied, and interest rate used for financing capital investments. The base year in this study is year 2022 with the interest and discount rates set to 5% (real). The cost-minimizing objective function is defined in this module.

### **Generation**

The generation modules define generation build-out options (both new and existing) and electricity dispatch, including fuel costs, variable O&M, and overnight build costs. Solar and wind installations have no fuel costs, but have variable capacity factors associated with each candidate project that account for hourly resource availability at that site. Switch has separate modules for storage, hydro and endogenous hydrogen production and storage because of their unique operation and function. The storage module defines energy storage assets, optimizes new power and energy capacity, and optimizes their operation (charging and discharging). The hydro module enforces minimum and average flows for hydro resources for each time series. Newly built hydrogen generators can be implemented as generators that require the supply of hydrogen as an external fuel. In addition, Switch includes a module that produces hydrogen endogeneously. In this module, Switch optimizes the amount of electrolyzer, fuel cell, liquifier and hydrogen storage tank needed to be built and used for every model region. Storage tanks are sized to accommodate a whole year of hydrogen production and thereby facilitate seasonal storage, which is the predominant use.

## **Transmission**

The Transmission module represents the expansion and operation of the transmission assets using a transport model. In addition to optimized transmission expansion which allows additional capacity along any potential corridors, this module offers the option for users to disable expansion of any corridor using a binary parameter – `trans_new_build_allowed`. This flexibility allows us to consider scenarios without expansion or with partial expansion (e.g., within interconnects but not between).

## **Policies**

The policies subpackage has modules that enforce energy policy constraints such as RPS and carbon targets or carbon prices. The three decarbonization scenarios in our study are defined via the carbon policies module. (i) a least-direct-cost system that ignores external costs of CO<sub>2</sub> and other pollution emissions; (ii) a socially-optimal system that assigns a cost of \$190 per tonne of CO<sub>2</sub> emitted; and (iii) a zero-emissions system with an emission cap of zero at 2050.

## **PowerGenome and Principal Data Sources**

One of the most difficult parts of running electricity capacity expansion models is assembling all the data. PowerGenome ([Schivley, 2020](#)) serves as a platform to generate inputs files for power system optimization models—including Switch, GenX, Temoa and USENSYS. The source data comes from a number of different resources, including EIA, NREL, and EPA.

## **Model Regions**

The extent of geographic coverage and number of regions is one of the first decisions to make when running an electricity planning model. Model regions in PowerGenome are derived from IPM regions. To align with the new-build resource cost multipliers for Electricity Market Module (EMM) regions in EIA's NEMS model, we group the IPM regions into 26 model regions in this study. These regions conjoin existing sub-regional balancing authorities. Region names are determined by matching the actual names listed in EIA's Open Data query search against each map and then looking at example API urls. Data on existing generating units, cost estimates for new generating units, transmission constraints between regions, hourly load profiles and hourly generation profiles for wind & solar to construct the optimization problem, are all parsed by these regions. The sources of these data are presented below.

## **Existing and Candidate Generators**

Existing generating units are from the latest version of form EIA-860 ([U.S. Energy Information Administration, 2021](#)), 2021 supplemented with 860m from June 2023. The cost and heat rates of new-build resources are provided by NREL's Annual Technology Baseline (ATB) 2022 ([National Renewable Energy Laboratory, 2022](#)). Renewable resources are generally location-specific, with unique generation profiles and interconnection costs. Rather than representing all potential new-build renewable resources as individual sites, PowerGenome lets the user specify how much capacity of each resource type should be available for consideration in a model region and how many clusters the resource

should be represented by. We use 942 clusters of candidate renewable energy projects, corresponding to approximately 21 TW of potential capacity. High-resolution weather data provided by Vibrant Clean Energy for 2012 (the year upon which our demand data is based) is used to construct hourly variable capacity factors for each cluster.

### **Transmission lines**

Existing transmission capacities between IPM regions are from EPA. Model regions in our study can consist of one or more individual IPM regions. When two or more IPM regions are combined to make a Switch model region, the transmission capacity between individual IPM regions is also combined. Transmission lines in this study are defined as connections between major metros in each region, with additional backbone networks connecting major metros within a region (if there is more than one). Costs and line loss use transmission line segments created with a least cost path method described in Appendix F of ([Patankar et al., 2023](#)).

### **Demand**

Hourly demand starts with NREL EFS profiles ([National Renewable Energy Laboratory, 2019](#)). Stock values (historical) and hourly demand profiles of electrified end-use technologies like transportation, water heating, and space heating/cooling (derived from NREL EFS data) are subtracted from the 2019 EFS profiles. The remaining demand is inflated using sector-specific growth rates from EIA AEO 2022 ([Nalley and LaRose, 2022](#)). The future hourly demand from electrified end-use technologies are added back in using future stock values (from the REPEAT ([Rapid Energy Policy Evaluation and Analysis Toolkit, 2022](#)) scenario IRA\_MID) and hourly demand profiles derived from EFS.

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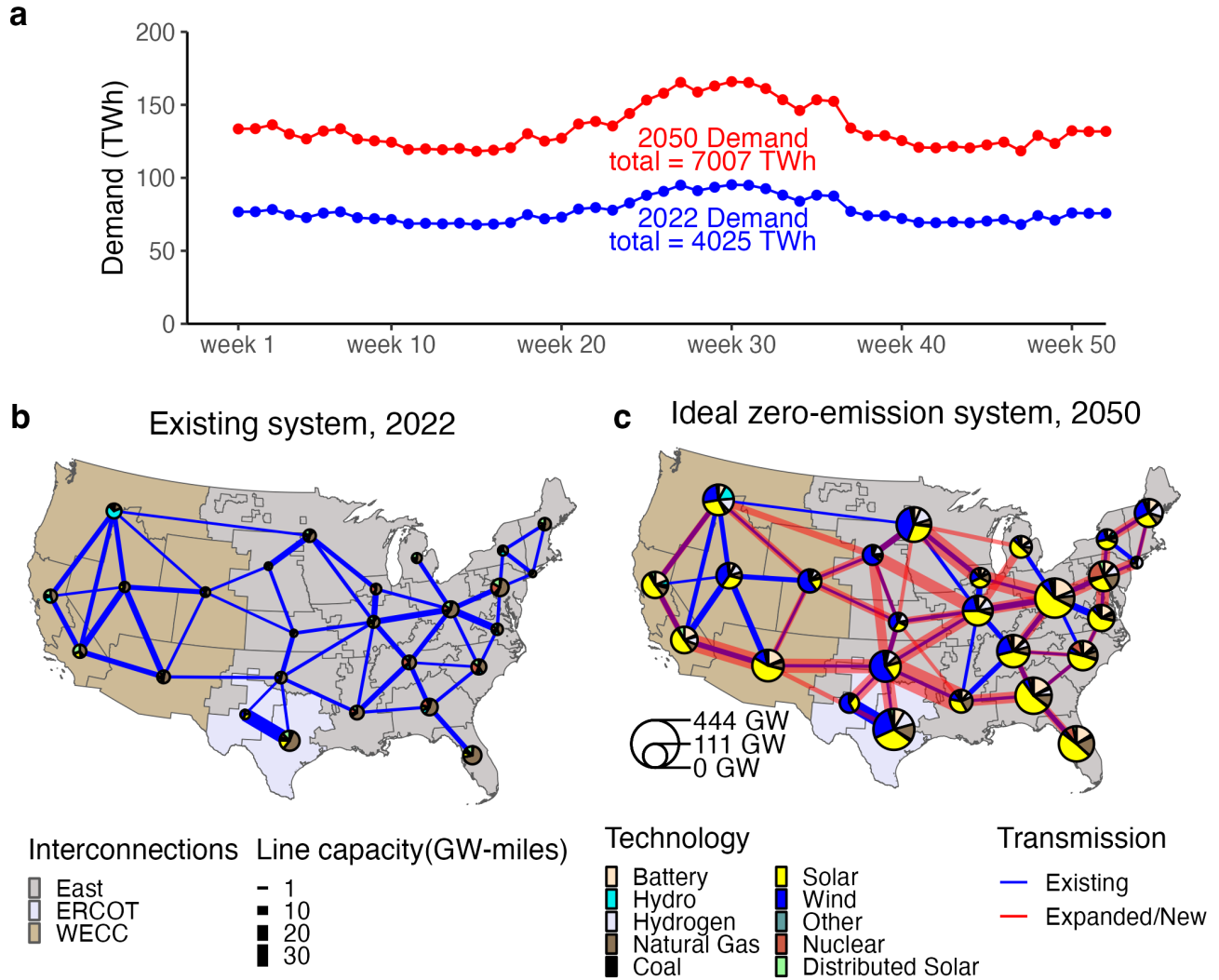
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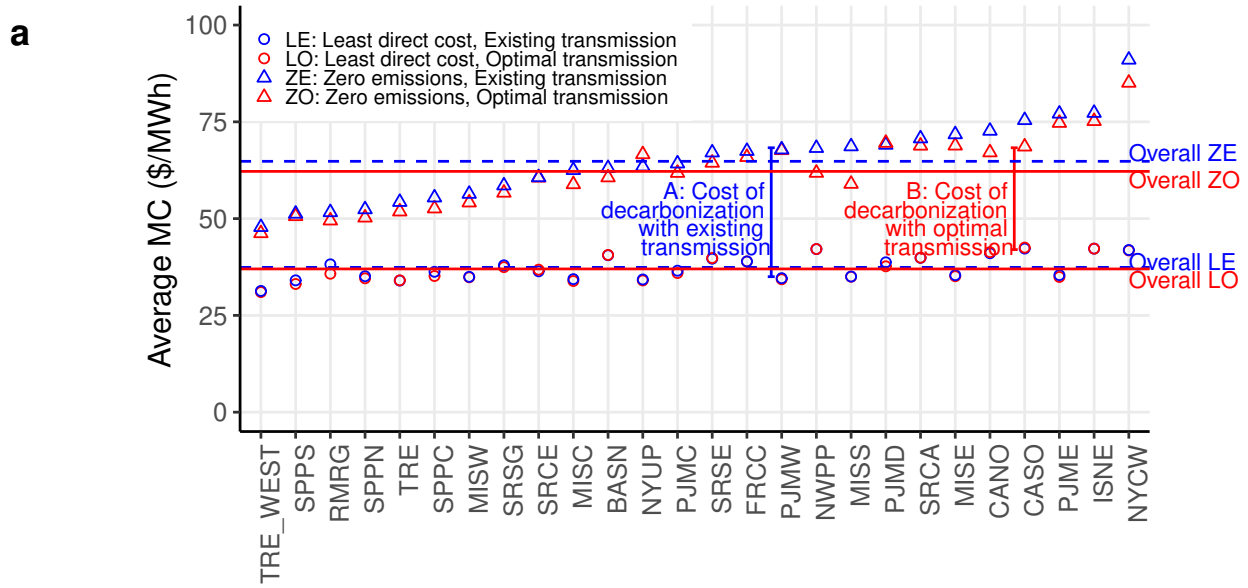
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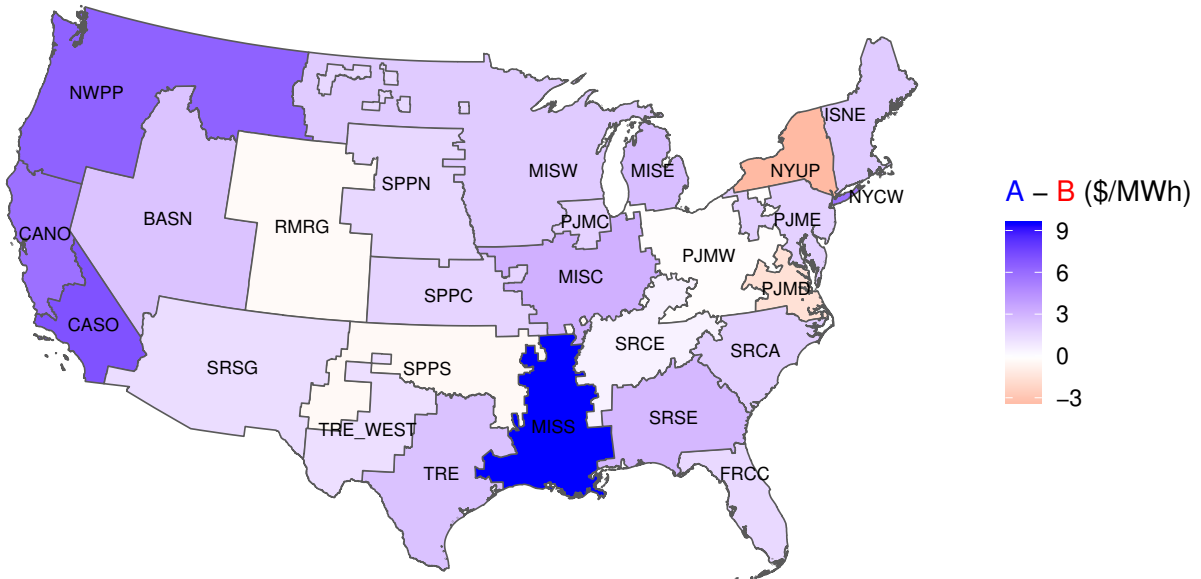
# Figures



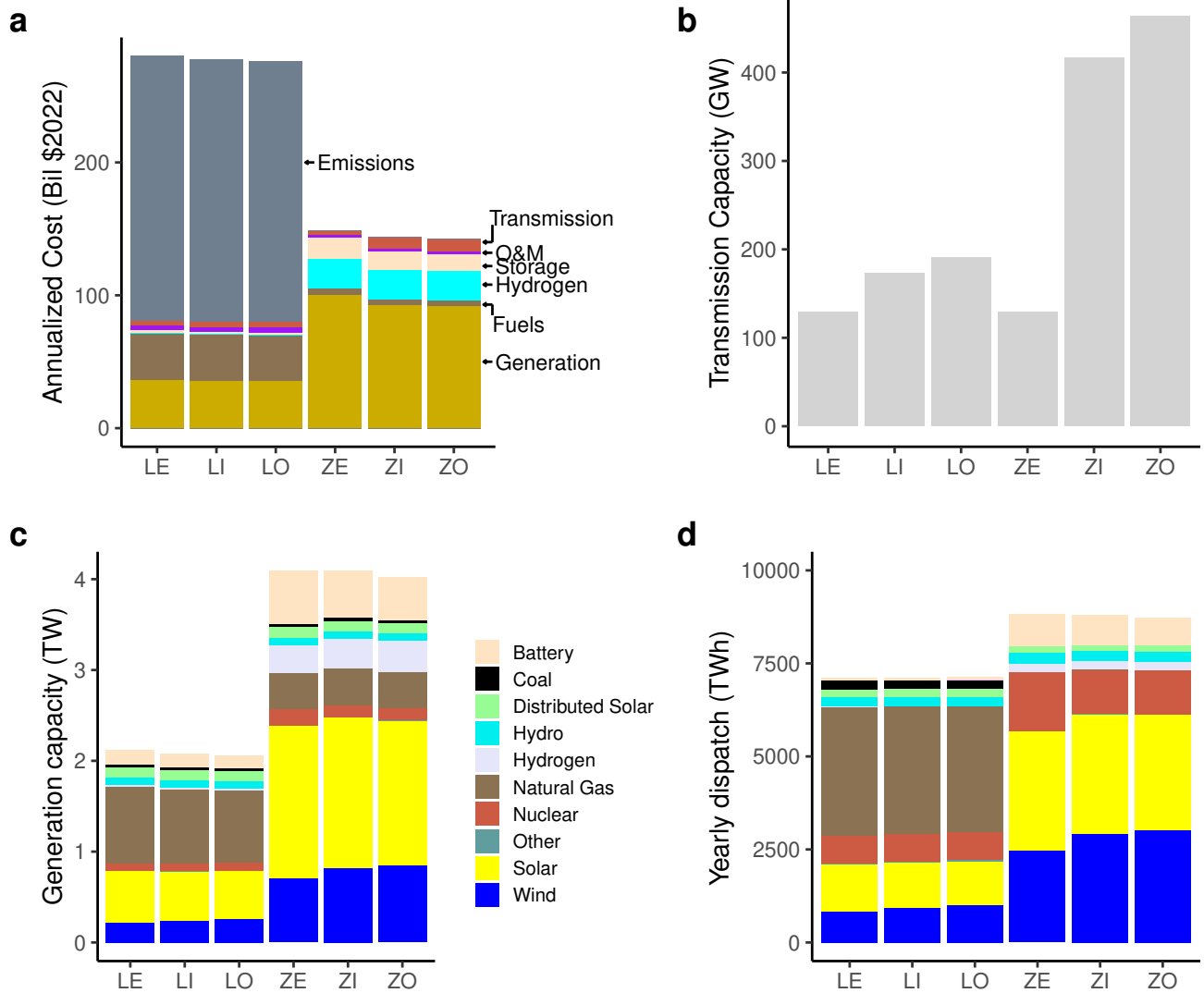
**Figure 1: Demand, generation, and transmission capacities in existing and idealized future zero-emission electricity systems.** Panel a shows weekly demand as modeled for 2022 and 2050. These demand data are derived from 2012 to synchronize with the weather data but are re-scaled to 2022 and projected to 2050 levels. Panel b shows 2022 generation capacities and inter-regional transmission. Note that total transmission capacity is less than 1 GW between the East and WECC. Panel c shows a least-cost, zero-emissions system for 2050 without superfluous constraints on the generation mix or transmission expansion.



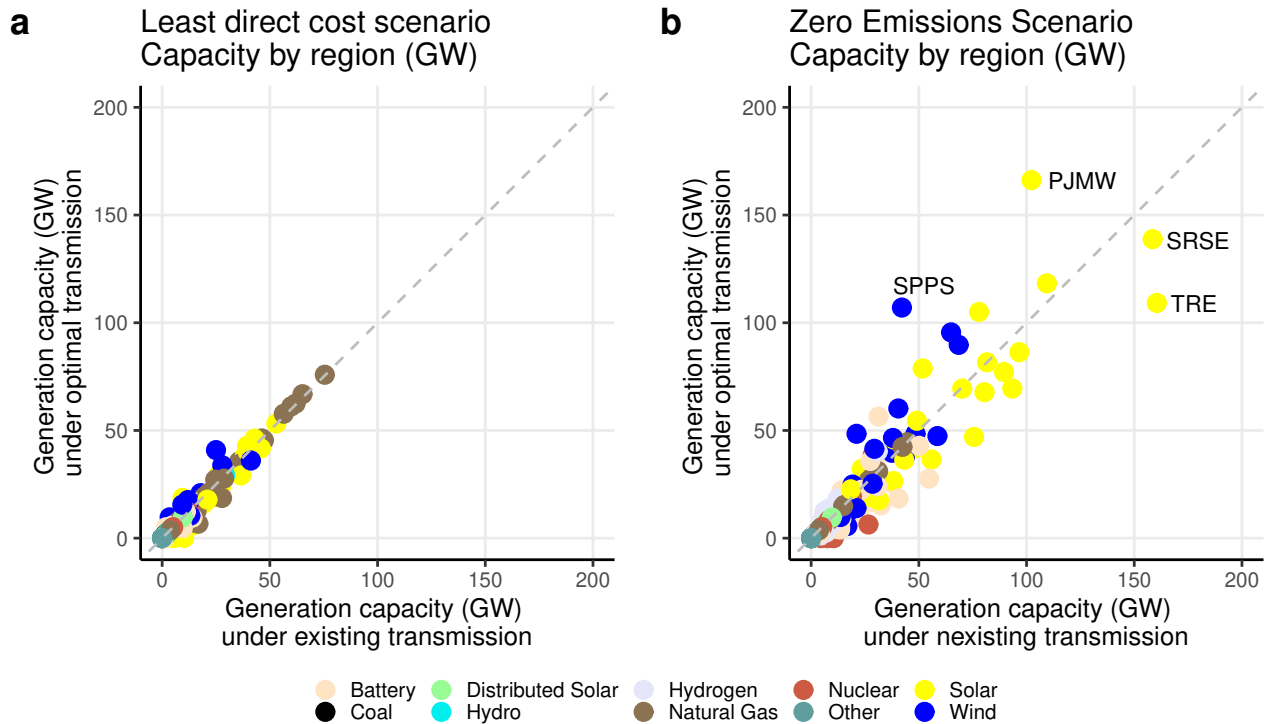
**b** Effect of transmission expansion on cost of decarbonization



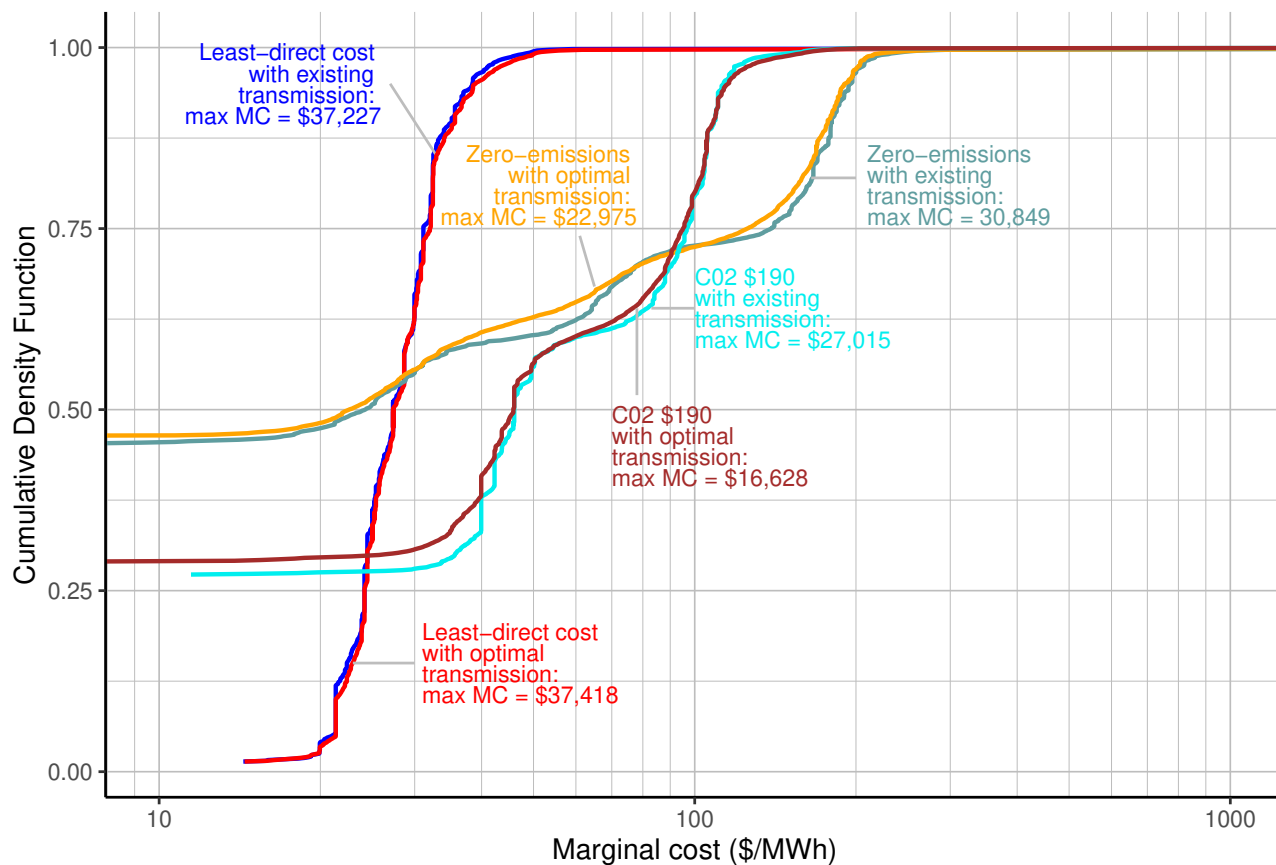
**Figure 2: Cost per MWh for the different emissions and transmission scenarios.** Panel a shows the demand-weighted average marginal cost for each region in 2050 in four scenarios, least-direct-cost (triangles) and zero-emissions scenarios (circles), each with existing (blue) and optimized (red) transmission. Comparing circles to triangles of the same color gives the region’s cost of decarbonization, with blue indicating the cost without transmission expansion (difference A) and red indicating the cost with optimized transmission expansion (difference B). Comparing the same shapes of different colors gives the net savings from expanded transmission. Panel b shows a map of the difference in differences (A-B): the cost savings (\$/MWh) from fully decarbonizing using optimal transmission instead of using only existing transmission.



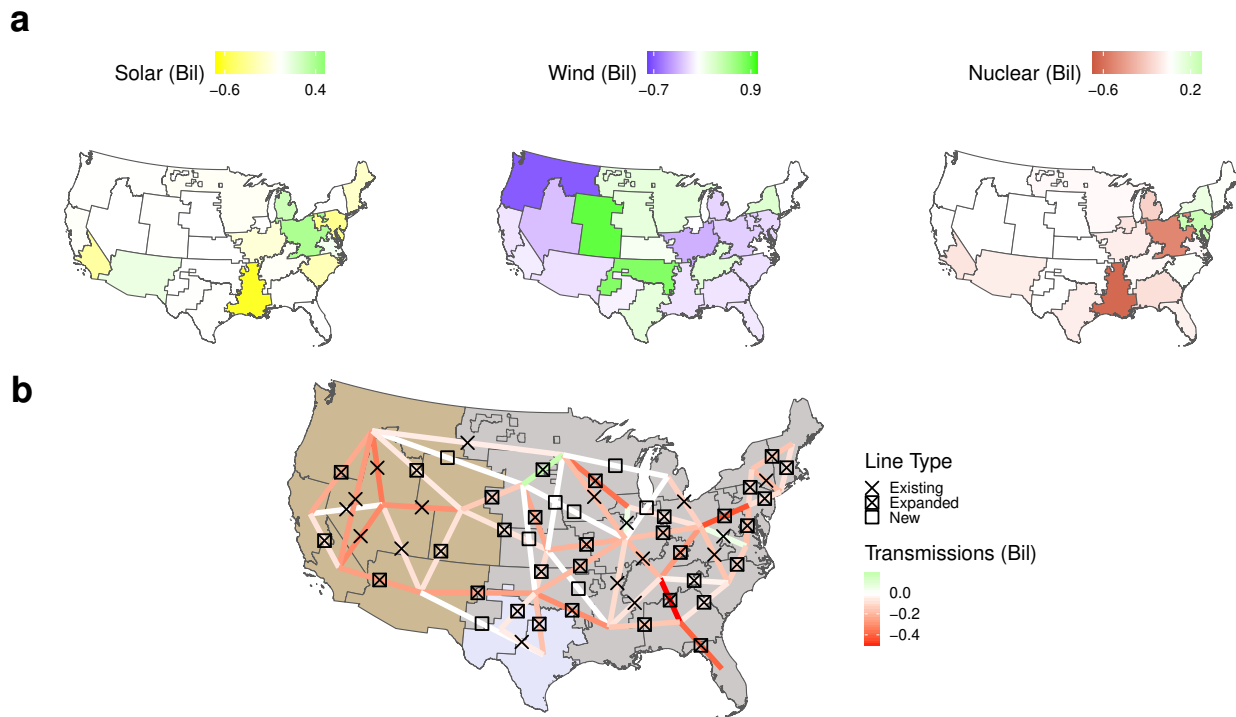
**Figure 3: Comparing component costs and capacities.** The graphs compare costs, generation mixes, and transmission capacities across six scenarios, LE (least-direct-cost with existing transmission), LI (least-direct-cost with optimal within-interconnect transmission), LO (least-direct-cost with optimal fully-optimized transmission), ZE (zero-emissions with existing transmission), ZI (zero-emissions with optimal within-interconnect transmission), and ZO (zero-emissions with optimal fully-optimized transmission). Panel **a** shows broadly categorized cost components; panel **b** shows total transmission capacity in each scenario (GW-miles); panel **c** shows total generation capacities (TW) in each scenario; and panel **d** shows the share of dispatch (source of energy consumed) in each scenario.



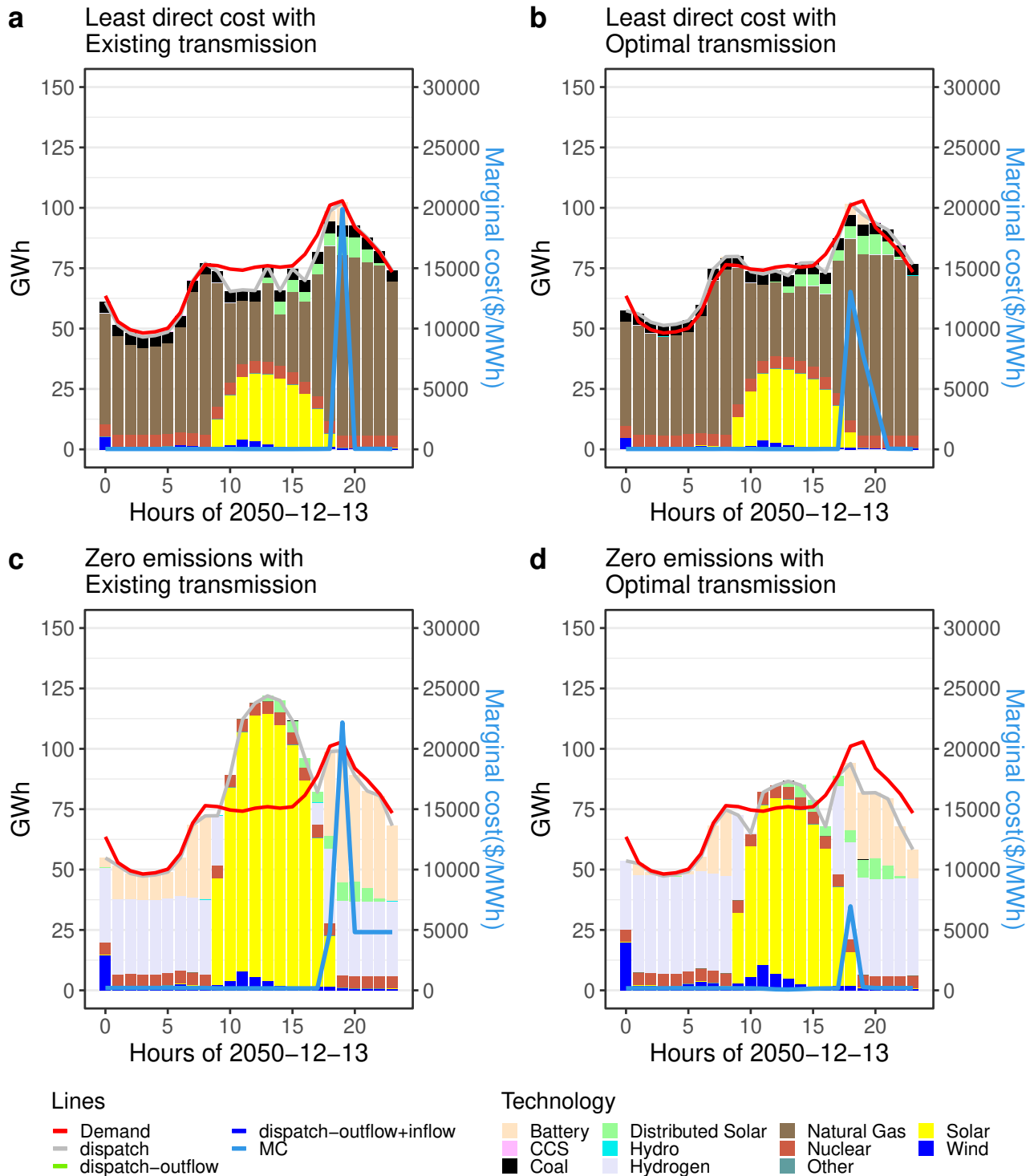
**Figure 4: Comparison of regional capacities across transmission scenarios.** These scatter plots show how transmission expansion influences the mix of generation capacities across regions. It plots generation capacities in each region and type when only existing transmission is used against capacities when interregional transmission is fully optimized. Panel **a** shows the relationship under least-direct-cost scenarios, and panel **b** shows the relationship under zero-emissions scenarios. Different types of generation are plotted in different colors.



**Figure 5: Distribution function of marginal cost.** This graph shows the distribution functions or (cumulative density functions) for hourly marginal cost across all MWh in all continental U.S. regions in 2050. To construct these, we account for the MWh of demand in each region/hour. Six scenarios are depicted: least-direct-cost, with existing and optimal transmission (LE & LO), zero-emissions with existing and optimal transmission (ZE & ZO), and socially optimal, with an assumed price of CO<sub>2</sub> emissions of \$190 per ton, which achieves roughly 89% reduction of emissions from the electricity sector relative to 2022. All scenarios assume 74% demand growth relative to 2022 and conservative projections from NREL-ATB.



**Figure 6: Rent changes when going from existing to optimal transmission in zero-carbon scenarios.** Each graph shows the rent change to a resource when going from the ZE scenario to the ZO scenario. The rents accrue to infra-marginal wind and solar resources that are more valuable than marginal sources, existing nuclear facilities (costs are assumed sunk), and constrained transmission resources that receive surplus congestion rents. Panel **a** shows transmission expansion benefits solar and wind producers in regions unusually rich in these resources relative to their neighbors, while reducing rents in neighboring areas; it also shows that existing nuclear typically loses with transmission expansion since it becomes less competitive. Panel **b** shows the change in rents to transmission lines. Expanded transmission links typically lose rent as congestion charges decline. New transmission links have zero rent because expansion is optimized. Existing but non-expanded lines also tend to lose rent as congestion charges decline. The rare exceptions where transmission rents rise are cases where existing transmission is marginally overbuilt and losses are reduced.



**Figure 7: Hourly generation, dispatch, transmission, and marginal cost in TRE during the most costly sample day.** The graphs show hourly dispatch, inflows, outflows, and marginal cost in four scenarios for the TRE region, the Eastern part of ERCOT in Texas, on the sample day with the highest demand-weighted average marginal cost. Panels a and b show the least-direct-cost systems under existing and optimized transmission (LE and LO), and panels c and d show the zero-emissions systems under existing and optimized transmission (ZE and ZO).



# Optimal transmission expansion minimally reduces decarbonization costs of U.S. electricity

## Appendix

Rangrang Zheng, Greg Schivley, Patricia Hidalgo-Gonzalez,  
Matthias Fripp, Michael J. Roberts

### Supplemental Analysis

Here we describe mathematical structure of Switch in more detail and present additional results, with an emphasis on comparing the least-direct-cost (LX) scenarios with the *socially optimal* (SX) scenarios that minimize costs subject to a carbon emissions price of \$190 per ton rather than forcing zero emissions. This price leads to 90 to 95% emissions reductions relative to 2022 levels in most cases, even with a 75% growth in electricity production. We refer to these scenarios as socially optimal because they equate the marginal cost of abatement to the Environmental Protection Agency’s marginal social cost of emissions (i.e., the estimated marginal benefit of abatement).

### Switch Formulations

Here we provide a brief overview of the mathematical formulation of Switch 2.0, the model used for our research. More complete documentation of the software can be found in (Johnston et al., 2019). Switch 2.0 has a modular architecture that reflects the modularity of actual power systems. Most power system operators follow rules that maintain an adequate supply of power, and most individual devices are not concerned with the operation of other devices. Similarly, core modules in Switch define spatially and temporally resolved balancing constraints for energy and reserves, and an overall social cost. Separate modules represent components such as generators, batteries or transmission links. These modules interact with the overall optimization model by adding terms to the shared energy and reserve balances and the overall cost expression. Switch 2.0 supports co-optimization of multiple investment periods, but we have omitted those definitions here, since we use a single stage for this study (2041-2050). We have likewise omitted details on spinning reserves and unit commitment, which were not used for this study.

### Objective function

The objective function is defined by the **financials** module. It minimizes the net present value of all investment and operation costs:

$$\text{Min} \left\{ \sum_{c^f \in \mathcal{C}^{\text{fixed}}} c^f + \sum_{t \in \mathcal{T}_p} w_t^{\text{year}} \sum_{c^v \in \mathcal{C}^{\text{var}}} c_t^v \right\} \quad (1)$$

Function 1 sums over sets of fixed costs  $\mathcal{C}^{\text{fixed}}$  and variable costs  $\mathcal{C}^{\text{var}}$ . Each fixed cost component  $c^f \in \mathcal{C}^{\text{fixed}}$  is a Pyomo object, indexed by investment period and specified in units of \$/year. This object may be a variable, parameter or expression (calculation based on other components). The term  $c^f$  is the fixed cost that occurs during our study period. Each variable cost component  $c^v$  is indexed

by timepoint ( $t$ ) and specified in units of \$/hour. Modules add components to the fixed and variable cost sets to represent each cost that they introduce. Hence, the exact equation will depend on which modules are selected by the user. In most runs, fixed costs in  $\mathcal{C}^{\text{fixed}}$  include capital repayment for investments at a fixed financing rate over the lifetime of each asset, sunk costs from existing infrastructure, as well as fixed operating and maintenance (O&M) costs. Variable costs in  $\mathcal{C}^{\text{var}}$  typically include fuel costs and variable O&M. The weight factor  $w_t^{\text{year}}$  scales costs from a sampled timepoint to an annualized value.

## Operational Constraints

*Power Balance:* Specifies that power injections and withdrawals must balance during each time point  $t$  in each zone  $z$ . As with the objective function, plug-in modules add model objects to  $\mathcal{P}^{\text{inject}}$  and  $\mathcal{P}^{\text{withdraw}}$  to show the amount of power injected or withdrawn by each system component during each timepoint. For this study, production components include renewable and conventional generators, batteries, hydrogen fuel cells, and inbound transmission flows. Withdrawals include customer loads, battery charging, hydrogen electrolysis and refrigeration, and outbound transmission flows.

$$\sum_{p^i \in \mathcal{P}^{\text{inject}}} p_{z,t}^i = \sum_{p^w \in \mathcal{P}^{\text{withdraw}}} p_{z,t}^w, \quad \forall z \in \mathcal{Z}, \forall t \in \mathcal{T} \quad (2)$$

*Dispatch:* Power generation from a source  $g$  (e.g., a power plant) must fall below its installed capacity  $K_g^G$  during time point  $t$  multiplied by a capacity factor  $\eta_{g,t}$ , that may vary with exogenous factors like solar radiation or wind speed.

$$0 \leq P_{g,t} \leq \eta_{g,t} K_g^G, \quad \forall g \in \mathcal{G}, \forall t \in \mathcal{T} \quad (3)$$

*Transmission Flows:* Transmission flows  $F_{\ell,t}$  along a corridor  $\ell$  are constrained by the installed capacity  $K_\ell^L$  on that corridor. Additional constraints (not shown) define the flow out of a corridor to take a smaller value than flow into the corridor, reflecting transmission losses.

$$0 \leq F_{\ell,t} \leq K_\ell^L, \quad \forall \ell \in \mathcal{L}, \forall t \in \mathcal{T}_p \quad (4)$$

*Power System Construction:* Eqs. (5) and (6) define installed capacity for generation projects  $K_g^G$  and transmission lines  $K_\ell^L$  as the sum of capacity additions during the study ( $B_g^G$  or  $B_\ell^L$ ) and preexisting capacity of the same type in the same location ( $k_g^G$  or  $k_\ell^L$ ).

$$K_g^G = B_g^G + k_g^G, \quad \forall g \in \mathcal{G} \quad (5)$$

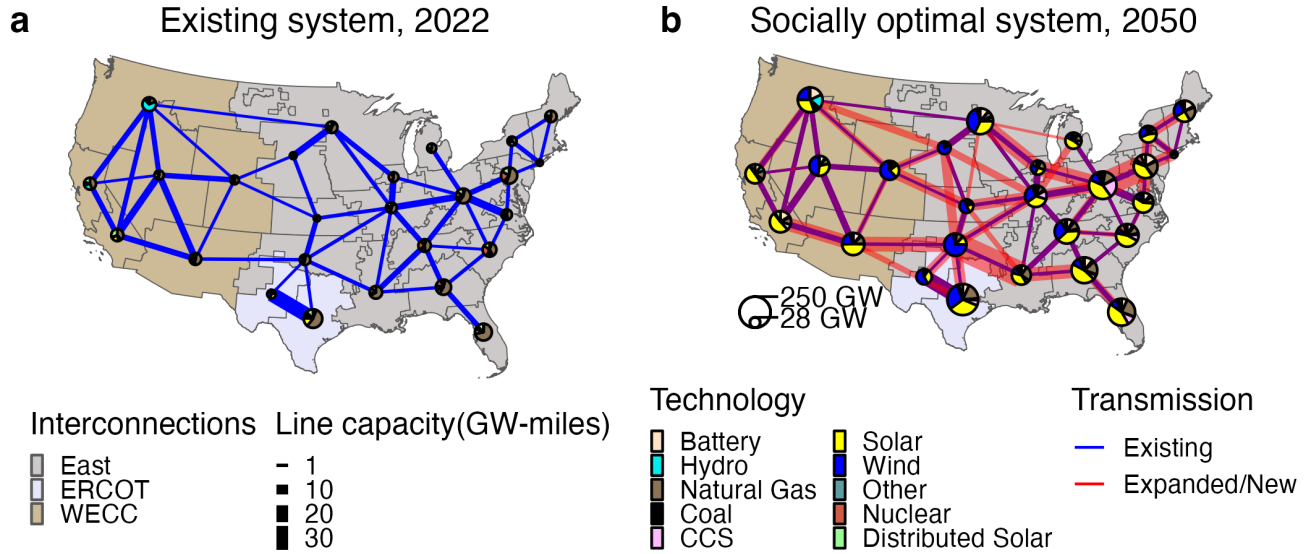
$$K_{\ell,p}^L = B_\ell^L + k_{\ell,y}^L, \quad \forall \ell \in \mathcal{L} \quad (6)$$

Some generation projects (the set  $\mathcal{G}^{\text{rc}}$ ) also have caps on installed capacity  $\overline{k_g^G}$ . These may be plants of a type that cannot be built in the future or renewable projects with limits on available land.

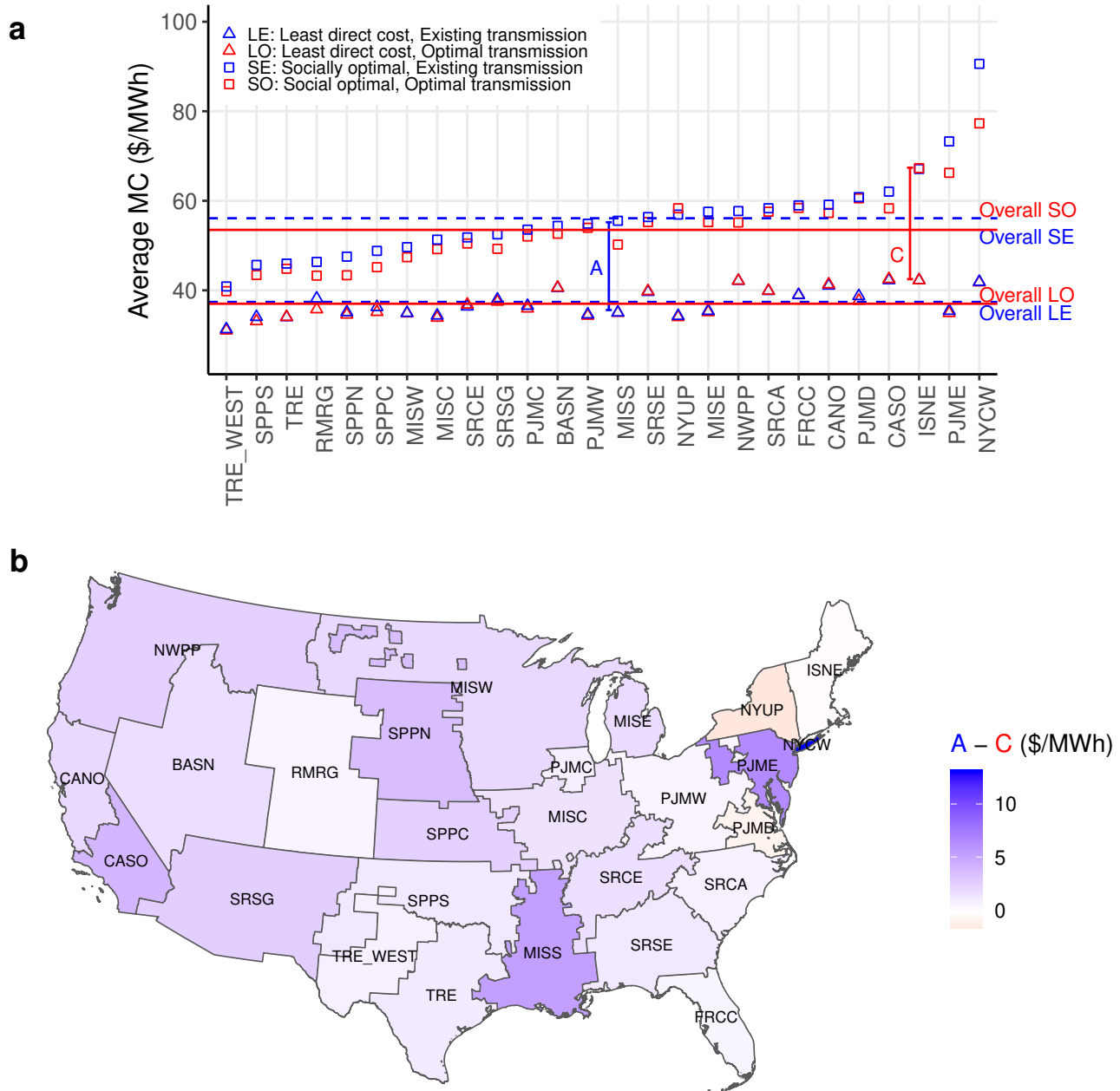
$$K_g^G \leq \overline{k_g^G}, \quad \forall g \in \mathcal{G}^{\text{rc}} \quad (7)$$

Additional terms define behavior of storage facilities (charging, state of charge, round-trip losses), fuel consumption (full load heat rate times power production) and hydrogen facilities (production and storage of hydrogen and conversion back to electricity). For complete details on Switch's mathematical formulation, see the Supplementary Material of (Johnston et al., 2019) at <https://ars.els-cdn.com/content/image/1-s2.0-S2352711018301547-mm1.pdf>.

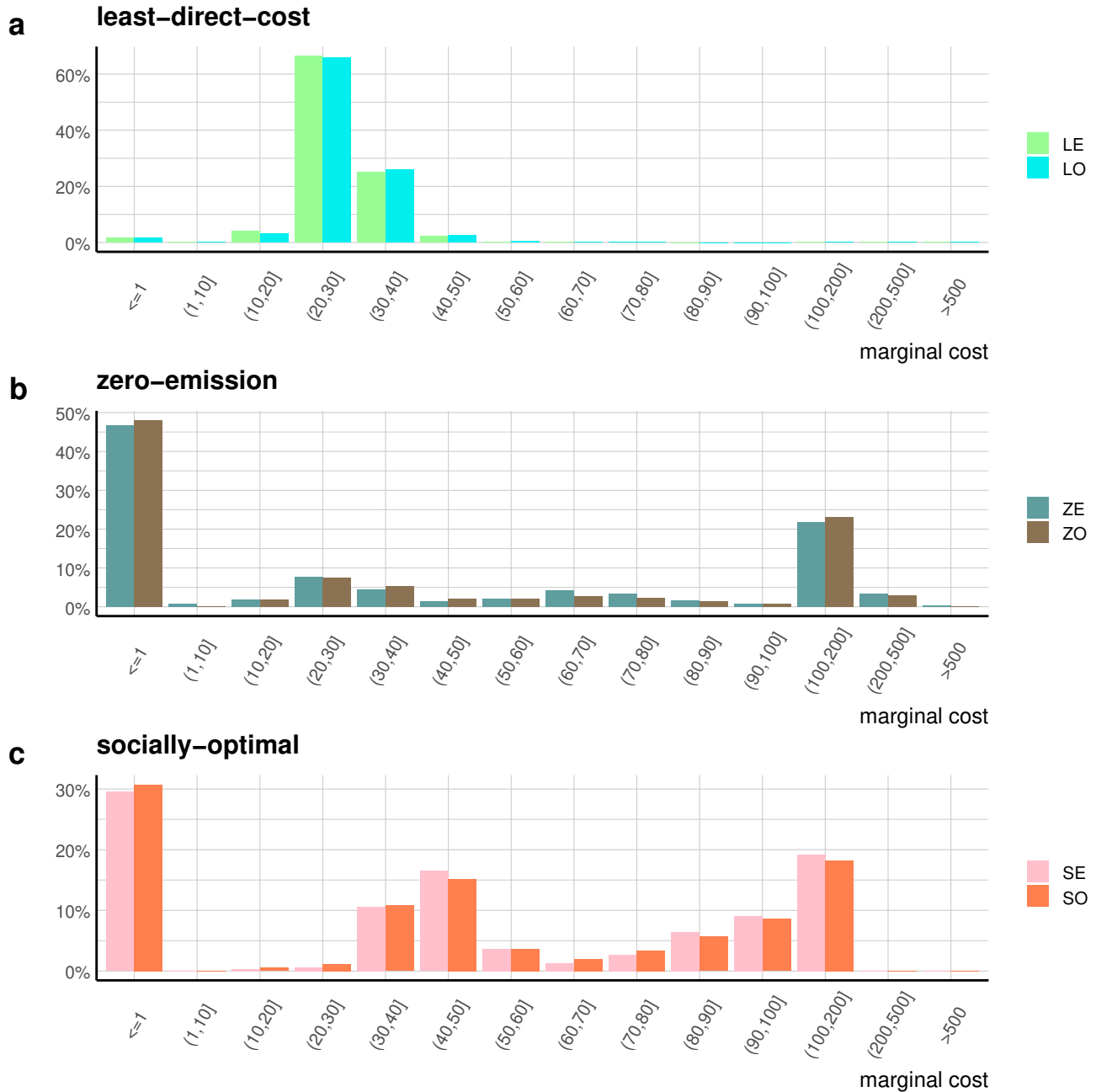
# Supplemental Figures



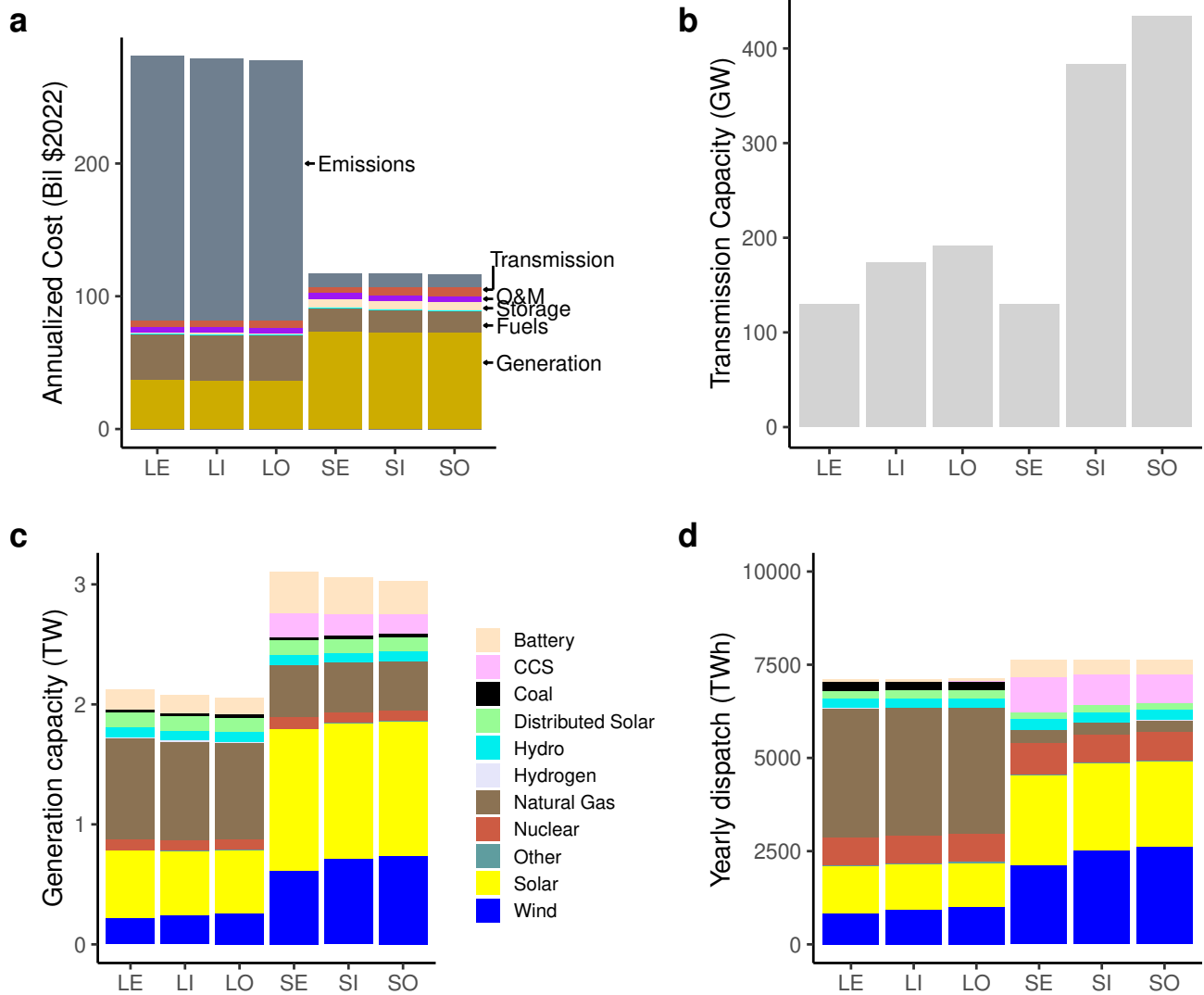
**Figure A1: Demand, generation, and transmission capacities in existing and idealized socially optimum electricity systems.** Panel **a** shows 2022 generation capacities and inter-regional transmission. Panel **b** shows an optimized, socially-optimal system for 2050 without constraints on the generation mix or transmission expansion. It is important to note the substantial difference in scale of generation capacities for 2022 and 2050.



**Figure A2: Cost per MWh for different emissions and transmission scenarios.** Panel a shows the demand-weighted average marginal cost for each region in 2050 in four scenarios, least-direct-cost (triangles) and socially-optimal scenarios (circles), each with existing (blue) and optimized (red) transmission. Comparing square to triangles of the same color gives the region’s cost of decarbonization, with blue indicating the cost without transmission expansion (difference A) and red indicating the cost with optimized transmission expansion (difference C). Comparing the same shapes of different colors gives the net savings from expanded transmission. Panel b shows a map of the difference in differences (A-C): the cost savings (\$/MWh) from optimizing transmission under full decarbonization relative to using only existing transmission.

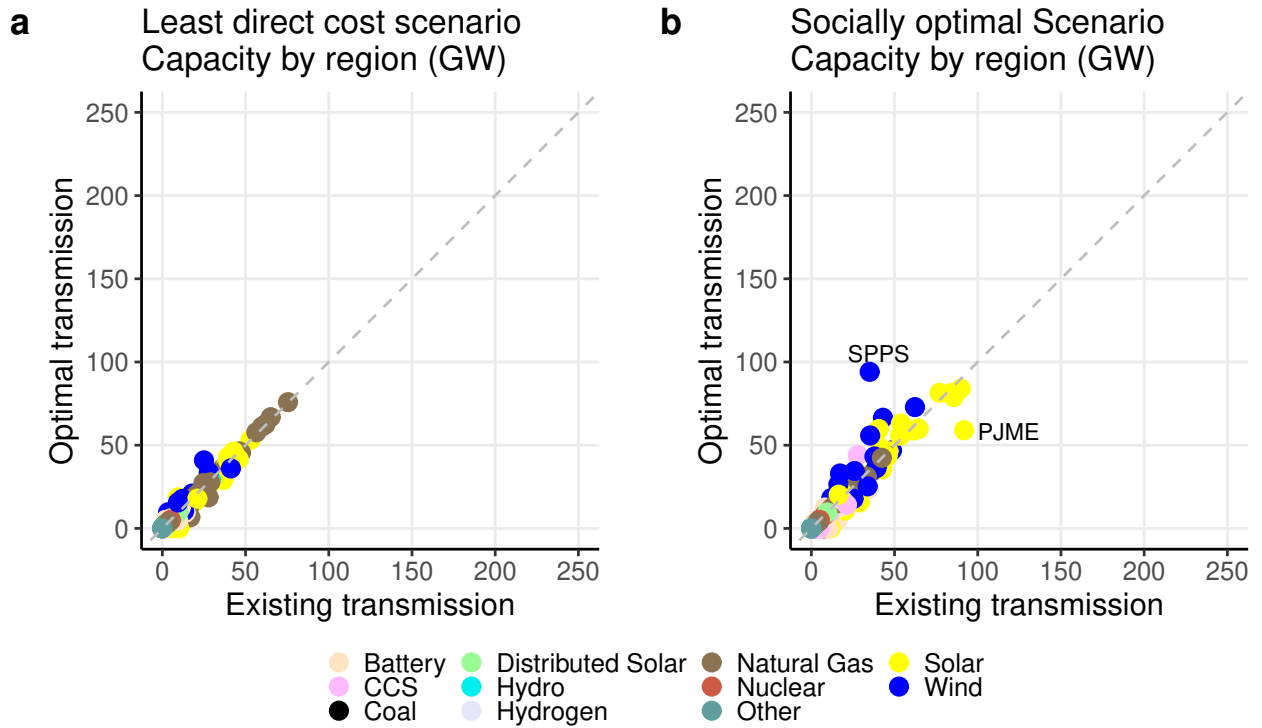


**Figure A3: Count percentage of marginal cost.** This graph shows the count percentage for hourly marginal cost across all MWh in all continental U.S. regions in 2050. Six scenarios are depicted: Panel a shows the system of least-direct-cost, with existing and optimal transmission (LE & LO); Panel b shows the system of zero-emissions with existing and optimal transmission (ZE & ZO); Panel c shows the system of socially optimal, with an assumed price of CO<sub>2</sub> emissions of \$190 per ton, which achieves roughly 89% reduction of emissions from the electricity sector relative to 2022.

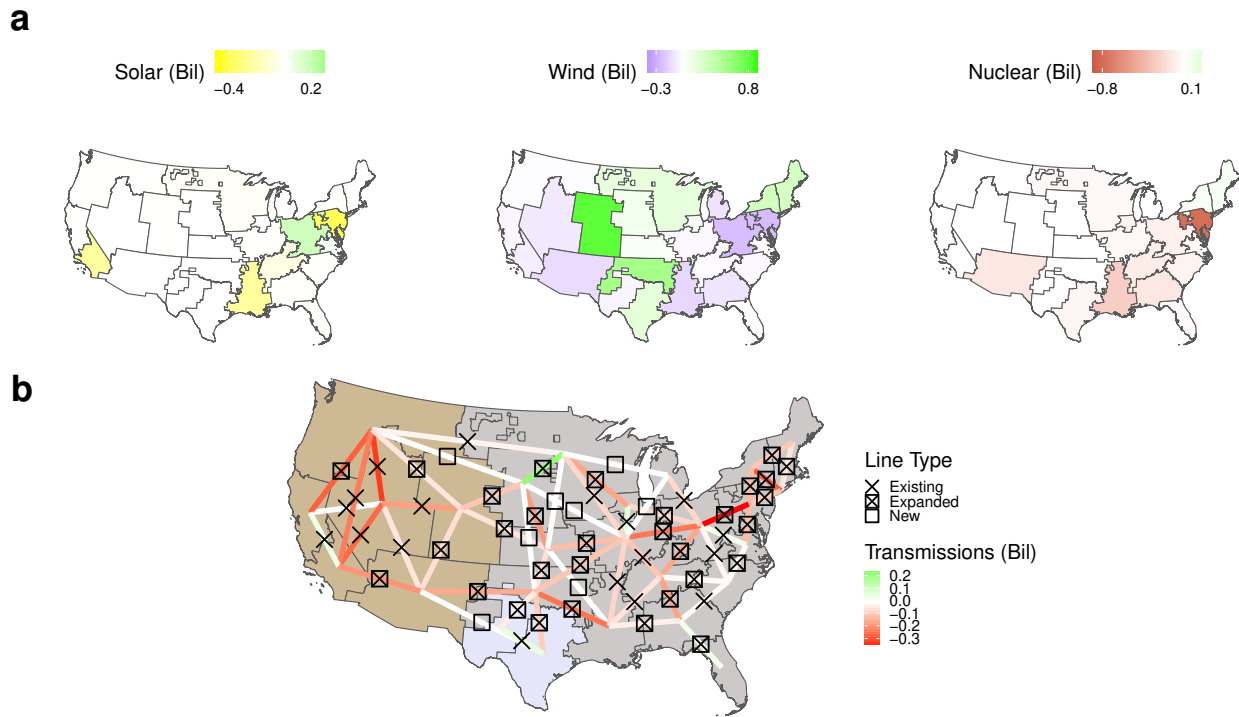


**Figure A4: Comparing component costs and capacities.** The graphs compare costs, generation mixes, and transmission capacities across six scenarios, LE (least-direct-cost with existing transmission), LI (least-direct-cost with optimal within-interconnect transmission), LO (least-direct-cost with optimal fully-optimized transmission), SE (socially-optimal with existing transmission), SI (socially-optimal with optimal within-interconnect transmission), and SO (socially-optimal with optimal fully-optimized transmission). Panel **a** shows broadly categorized cost components; panel **b** shows transmission capacity in each scenario (GW-miles); panel **c** shows generation capacities (TW) in each scenario; and panel **d** shows the share of dispatch (source of energy consumed) in each scenario.

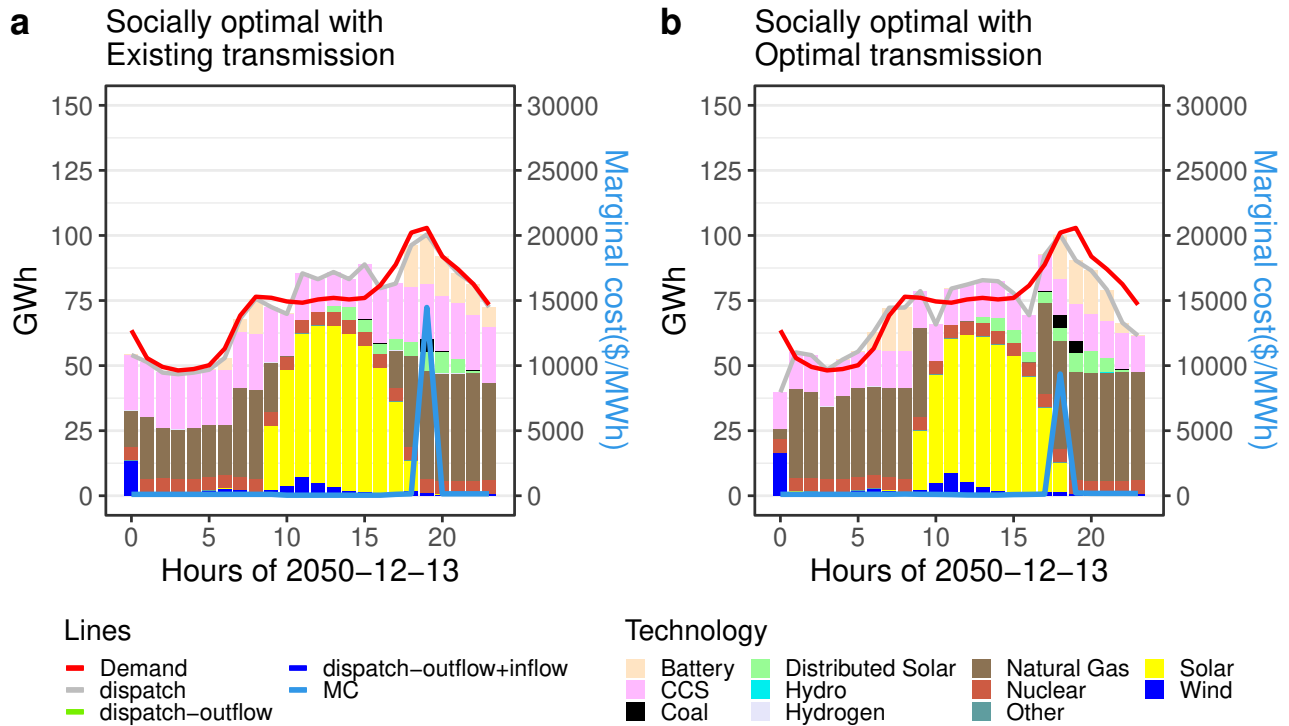




**Figure A5: Comparison of regional capacities across transmission scenarios.** These scatter plots show how transmission influences the mix of generation capacities across regions. Each panel shows optimized region-level generation capacities under existing transmission plotted against generation capacities under fully optimized transmission. Panel **a** shows the relationship under least-direct-cost scenarios, and panel **b** shows the relationship under socially-optimal scenarios. Different types of generation are plotted in different colors.



**Figure A6: Rent changes when going from existing to optimal transmission in socially optimal scenarios.** Each graph shows the change in rents to a resource when going from the SE scenario to the SO scenario. The rents accrue to infra-marginal wind and solar resources that are more valuable than marginal sources, to existing nuclear facilities (costs are assumed sunk), and to constrained transmission resources that receive surplus congestion rents. Panel a shows transmission expansion benefits solar and wind producers in regions unusually rich in these resources while hurting producers in other regions; it also shows that existing nuclear generally gains with transmission expansion since it can enjoy higher capacity factors. Panel b shows the change in rents to transmission lines when going from the SE scenario to the SO scenario.



**Figure A7: Hourly generation, dispatch, transmission, and marginal cost in TRE during the most costly sample day.** The graphs show hourly dispatch, inflows, outflows, and marginal cost in four scenarios for the TRE region, which is the Eastern part of ERCOT in Texas, on the sample day with the highest demand-weighted average marginal cost – Dec 13th, 2050. Panels c and d show the socially-optimal systems under existing and optimized transmission (SE and SO).

## Supplemental Table

	Least-direct-cost			Zero-emissions			Socially-optimal		
	LE	LI	LO	ZE	ZI	ZO	SE	SI	SO
O&M	4.2	4.2	4.2	1.8	1.4	1.4	5.5	4.9	4.6
Fuel	35.3	34.9	34.5	4.8	3.6	3.7	15.9	13.8	13.3
Storage	1.4	1.3	1.3	15.8	14.2	13.0	7.4	6.37	6.0
Generation	36.3	35.6	35.4	100.1	92.9	91.9	77.6	74.6	73.9
Transmission	3.1	4.0	4.3	3.1	9.1	9.8	3.1	8.4	9.3
Hydrogen	0.4	0.3	0.3	22.7	22.5	22.5	0.2	0	0
Subtotal	80.6	80.2	79.9	148.3	143.8	142.4	109.6	108.1	107.0
Emissions Cost	272.3	272.0	269.8	0	0	0	13.3	11.6	11.6
Total	352.8	352.2	349.7	148.3	143.8	142.4	123.0	119.7	118.6

**Table A1: Cost components for all nine scenarios.** The table reports the annualized costs in billions of 2022 dollars for each scenario, discounted at 5% (real) from the 2041-2050 investment period, to the present. Graphical displays of these numbers are in Figures 3 and A3. The *Least-direct-cost* scenarios minimize the net present value of all costs excluding emissions; the *Zero-emissions* scenarios force zero emissions; and the *Socially-optimal* scenarios optimize CO2 emissions assuming a social cost of \$190 per ton. Scenarios **LE**, **SE**, **ZE** restrict transmission capacities to their current level, but do account for maintenance of those lines; scenarios **LI**, **SI**, **ZI** optimize transmission capacities *within* existing interconnects, but do not disallow new transmission between interconnects; scenarios **LO**, **SO**, **ZO** fully optimize transmission within and between interconnects. Emissions costs multiply metric tons of emissions by \$190/tCO<sub>2</sub>.