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Opportunities for flexible electricity loads such as hydrogen production from curtailed generation

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ABSTRACT

Variable, low-cost, low-carbon electricity that would otherwise be curtailed may provide a substantial economic opportunity for entities that can flexibly adapt their electricity consumption. We used historical hourly weather data over the contiguous U.S. to model the characteristics of least-cost electricity systems dominated by variable renewable generation that powered firm and flexible electricity demands (loads). Scenarios evaluated included variable wind and solar power, battery storage, and dispatchable natural gas with carbon capture and storage, with electrolytic hydrogen representing a prototypical flexible load. When flexible loads were small, excess generation capacity was available during most hours, allowing flexible loads to operate at high capacity factors. Expanding the flexible loads allowed the least-cost systems to more fully utilize the generation capacity built to supply firm loads, and thus reduced the average cost of delivered electricity. The macro-scale energy model indicated that variable renewable electricity systems optimized to supply firm loads at current costs could supply ~25% or more additional flexible load with minimal capacity expansion, while resulting in reduced average electricity costs (~10% or less capacity expansion and ~10% to 20% reduction in costs in our modeled scenarios). These results indicate that adding flexible loads to electricity systems will likely allow more full utilization of generation assets across a wide range of system architectures, thus providing new energy services with infrastructure that is already needed to supply firm electricity loads.

1. Introduction

Effective integration of variable renewable power generation remains one of the biggest challenges for a low-carbon electricity sector [1]. Regions with substantial installed quantities of wind and solar power, such as California, Texas, Germany, and Great Britain are experiencing increasing amounts of curtailment, which stimulates interest in flexible, productive uses for this intermittent, low-cost, low-carbon electricity [2–4].

A combination of load-following generators, energy storage, expansion of grid transmission, and load flexibility could effectively fill gaps between non-dispatchable generation and inflexible demand [5]. Load-following generation can increase and decrease output to meet system needs regardless of season [6,7]. The role of low-carbon, load-following generation in achieving deep decarbonization in electricity systems (80% to 100% reduction of CO_2 emissions from current levels) has been extensively evaluated [8–10].

Expanding battery energy storage and/or transmission networks increases system flexibility and smooths out the variability in electricity supplied by wind and solar generation [11–13]. Long-duration energy storage technologies, such as power-to-gas-to-power (PGP), pumped hydropower, and compressed air energy storage, are also being explored to provide flexibility by storing excess produced energy for use during later weeks, months, or years [14–16].

Flexible electricity loads, such as smart home appliances, can alter their operations within constraints to respond to signals from electricity systems [17]. Demand response programs, which can coordinate flexible loads within an electricity system, have been studied and deployed in industrial [18], commercial [19], and residential [17,20] applications. Flexible loads can also be added to electricity systems by electrifying other energy end uses, such as transportation or space heating [21–23].

Cross-sector couplings through power-to-gas (PtG) technologies can produce fuel (usually hydrogen or methane) for non-grid uses [24–26]. The economics of wind-powered electrolysis has been assessed for facilities connected to the electric grid [27,28]. These studies have analyzed system configurations and operations that produced least-cost electrolytic hydrogen, with a decision made at every time step regarding whether the generated wind power should be used for electrolysis or sold to the electric grid.

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Previous studies have shown the magnitude of generation overbuild that may be required to reliably supply electricity in future low-carbon electricity systems [9]. This overbuild may lead to generation curtailment, which can result in periods of nearly free or even negatively priced electricity [2,3]. Our work focuses on the cost of using the unused or curtailed electricity for a new electricity user, how much electricity is available economically, and how quickly the most economical electricity is exhausted as new electricity uses expand. The trade-off between 1) utilization of intermittent "free" electricity with intermittent use of the flexible assets, and 2) systems that operate nearly continuously using more costly, predictable electricity, determines the economic value proposition for the energy services provided by the flexible load.

Accordingly, we have evaluated least-cost, low- and zero-carbon electricity systems that supply both historical electricity system loads (firm loads) and a prototypical flexible electricity load that embodied the production of electrolytic hydrogen for use in other sectors. We incrementally varied the fraction of energy delivered to the flexible load from 0% to 100% of total delivered energy (total load). We define an electricity system that serves a 100% flexible load as a system that supplies zero firm load and is a dedicated, stand-alone hydrogen producing system. The stepwise approach and focus on the evolving economic opportunity for a generic flexible load distinguishes this work from previous studies, and allows us to address three main issues:

1. How do electricity costs for the firm load and flexible load scale with the fraction of electricity that supplies the flexible load?
2. How much flexible load can be added to the system before generation curtailment becomes insubstantial and new generation capacity is needed to supply the flexible load?
3. How do costs for hydrogen production scale with the fraction of electricity that supplies the flexible load?

Multiple low- and zero-carbon electricity system technologies were modeled: wind, solar photovoltaic, dispatchable natural gas generation that used carbon capture and storage (CCS), and short-term battery energy storage. The abstract flexible load embodied herein by electrolytic hydrogen production is broadly applicable to different flexible load options as well as to a combination of flexible load technologies.

We are interested in dynamical relationships and system characteristics, and do not attempt to predict future absolute costs or detailed future electricity system architectures. Therefore, we have used current asset costs for all generation, energy storage, and hydrogen production assets. The variable renewable energy resource profiles were obtained by selecting high-output regions across the contiguous U.S. (CONUS) for wind- and solar-power generation. Hourly resource variability was obtained from a historical weather data set that allows reconstruction of the wind and solar resources [29]. Electric load profiles with hourly resolution were obtained for the CONUS from the U.S. Energy Information Administration [30]. Lossless transmission was assumed between generation and load. We parameterized around a wide range of future asset costs to establish the robustness of our conclusions regarding the system behavior.

2. Material and methods

2.1. Macro-scale energy model

A relatively simple, transparent, macro energy model (MEM) was used to represent an electricity system coupled with an electrolysis facility (Fig. 1) [8,16,31–33]. The system was determined by a least-cost linear optimizer that solved for the installed capacities and hourly dispatch for all technologies included in the system. The firm load was supplied at each hour by dispatched power plus dispatched stored energy. The quantity of electricity that supplied the flexible load (i.e., for hydrogen production) was constrained on an annual basis.

The mathematical formulation of the model is presented in Section 2.2. At each hourly time step, energy was balanced in the model. A demand response mechanism allowed the model to supply less than the demanded firm load, at a high cost, as economically warranted. Scenarios without a demand response mechanism are presented and discussed in Section S.13. Generation resources that dispatched less than their maximum possible hourly output provided "unused" generation, and unused wind or solar generation is specifically denoted as "curtailed" generation. The annual sum of used and unused generation is the "total available generation," where "available generation" at a given time is the amount of generation that would be produced if all generation assets were operating at full capacity.

Low- and zero-carbon emission scenarios included the "Dispatch," "Dispatch + Renew + Storage," and "Renew + Storage" scenarios (Table 1). A combined-cycle natural gas facility with 90% efficient CCS was used to represent dispatchable, low-carbon generation technologies. Fig. 1 represents the Dispatch + Renew + Storage scenario. Long-duration energy storage was also modeled via PGP (power-to-gas-to-power) as a possible asset (Section S.18).

The "flexible load fraction" was defined as the fraction of electric power supplied for electrolysis (flexible load) divided by the total load (electricity supplied for the firm load plus electricity supplied for the flexible load), calculated annually (Eq. (1)):

$$\text{flexible load fraction} = \frac{\text{flexible load}}{(\text{firm load} + \text{flexible load})}. \tag{1}$$

For each modeled scenario, the flexible load fractions considered ranged from 0 (only firm load present) to 1 (only flexible load present) in steps of 0.01, resulting in 101 cases. The firm load profile was held constant across all cases except when the flexible load fraction equaled 1 and no firm load was present. A cost of hydrogen production could not be defined when the flexible load fraction was 0, whereas a cost for supplying the firm load could not be defined for a flexible load fraction of 1. In these cases, the system behavior was simulated with additional cases having flexible load fractions of 0.000001 and 0.999999.

The model was based on existing technologies and current cost estimates (Table 2). The fixed capital investment for each system component represented the purchase cost for each component and installation, including all ancillary components and needs during installation such as instrumentation, piping, electrical, buildings, and service facilities [34]. A fixed hourly cost was calculated that included the fixed capital investment plus fixed annual O&M costs. Variable O&M and variable fuel costs were included as appropriate. Additional battery storage details included a 1% per month self-discharge rate [35] and a 1:4 power capacity to energy capacity ratio. This ratio was based on market trends for Li-ion systems paired with solar PV to reduce solar curtailment and better align power output with electricity system demand [36].

The baseline characteristics and costs for a polymer electrolyte membrane (PEM) water electrolyzer that produced hydrogen were taken from the default values in the National Renewable Energy Laboratory's (NREL) H2A model (Section S.10) [37–40]. The electrolyzer stack was 67.7% efficient based on the LHV (lower heating value) of hydrogen. No ramp rate constraint was placed on the electrolyzer operations. A compressor was modeled to compress the hydrogen gas in preparation for storage or transportation (storage and transportation were not included in the model). The baseline compressor characteristics and costs were also taken from the default values in the NREL H2A model (Section S.10). The electrolyzer stack, balance of plant components, and compressor had a combined efficiency of 61% based on the LHV of hydrogen and are collectively referred to as the electrolysis facility.

The firm load was based on historical hourly electricity load data for the CONUS. The data were cleaned to remove irregularities and what are thought to be spurious outlier values [30,41]. Wind and solar resources were represented by time series of hourly capacity factors derived from the MERRA-2 weather re-analysis data [29]. MERRA-2 comprises ~2,500 0.5° latitude by 0.625° longitude cells spread across CONUS. Solar capacity factors were calculated using a horizontal single-axis tracking system with a tilt ranging from 0° to 45°. Wind capac-

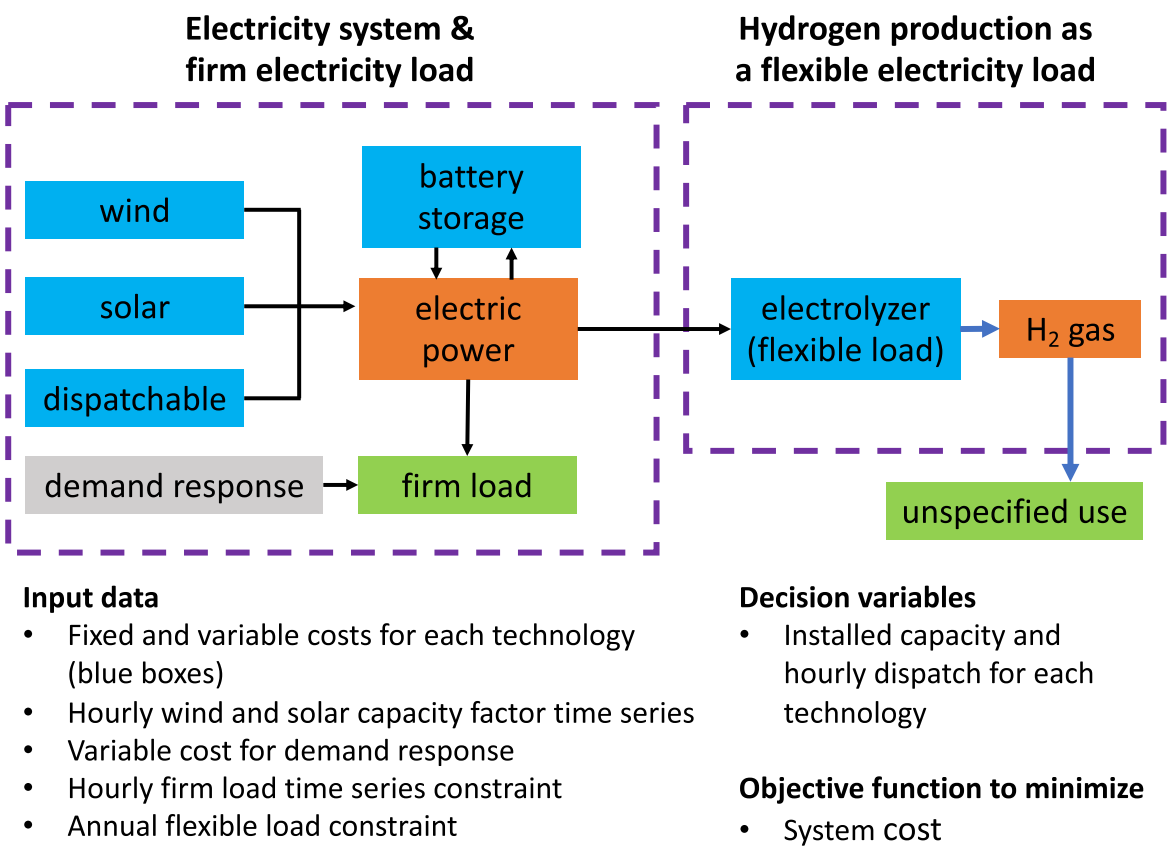

Fig. 1. Electricity system and a flexible load: the schematic system model is split into three sections. The electricity system, including the firm electricity load, and the flexible electricity load (electrolysis facility) were all modeled directly. No specific hydrogen end use was modeled. The technologies with both capacity and dispatch decisions are blue, demand response is modeled with only a dispatch decision, energy carriers are orange, and the energy demands or uses are green. Arrows show the flow of energy. Black arrows indicate electric power, and blue indicate hydrogen. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 1
Scenario definitions: the technologies included in the electricity system are shown for each scenario. Included technologies are marked by a "•," while excluded technologies are marked with a "–" mark.

scenario	natural gas+CCS	wind	solar photovoltaic	energy storage
"Dispatch"	•	–	–	–
"Dispatch+Renew + Storage"	•	•	•	•
"Renew+Storage"	–	•	•	•

Table 2
Asset costs and characteristics: the costs for all electricity system components and the electrolysis facility are included. All dollar values are in US$$_{2019}$. The "–" mark indicates the value is not applicable. The variable fuel cost for the combined-cycle plant was based on 3 $/MMBtu natural gas. CF is capacity factor and BoP is balance of plant. Electrolysis facility details combine the electrolyzer stack, BoP, and compressor. Electrolysis facility costs are based on the input power capacity in kW_e per kg of resulting compressed hydrogen; the efficiency value includes energy losses to BoP and the compressor. Additional cost and technical details are available in Section S.10.

technology type	wind	solar	combined-cycle with 90% CCS	electrolysis facility	battery storage
fixed cap. investment $\left(\frac{\$}{kW_e}\right)$	1,300 [45]	1,300 [45]	2,600 [45]	1,100 [40]	370 $\left(\frac{\$}{kWh_e}\right)$ [36]
fixed O&M $\left(\frac{\$}{yr \cdot kW_e}\right)$	26 [45]	15 [45]	27 [45]	36 [40]	12 $\left(\frac{\$}{kWh_e}\right)$ [36]
lifetime (yr)	30 [46]	30 [46]	20 [46]	7 stack, 40 BoP, 15 compressor [40]	10 [36]
fixed hourly cost $\left(\frac{\$}{h \cdot kW_e}\right)$	0.015	0.014	0.031	0.021	0.0074 $\left(\frac{\$}{h \cdot kWh_e}\right)$
relevant efficiency	43% CF	28% CF	48% [45]	61% [40] (LHV)	90% round trip [36]
variable cost O&M $\left(\frac{\$}{kWh_e}\right)$	0 [45]	0 [45]	0.0058 [45]	0 [40]	0 (applied in fixed O&M)
variable fuel cost $\left(\frac{\$}{kWh_e}\right)$	–	–	0.021	–	–
total variable cost $\left(\frac{\$}{kWh_e}\right)$	0	0	0.027	0	0

Table 3
Model nomenclature.

Symbol	Unit	Description
g	label only	Generation technology (wind, solar, natural gas with CCS)
v	label only	Energy conversion (electrolysis facility)
s	label only	Energy storage (battery storage)
from s	label only	Discharge from energy storage
to s	label only	Charge to energy storage
t	h	Time step, starting from 1 and ending at T
c_{capital}	$\$/\text{kW}_e$ for generation or conversion $\$/\text{kWh}_e$ for storage	(Overnight) capital cost
$c_{\text{fixed O\&M}}$	$(\$/\text{yr})/\text{kW}_e$ for generation or conversion $(\$/\text{yr})/\text{kWh}_e$ for storage	Fixed operating and maintenance (O&M) cost
c_{fixed}	$(\$/\text{h})/\text{kW}_e$ for generation or conversion $(\$/\text{h})/\text{kWh}_e$ for storage	Fixed cost
c_{var}	$\$/\text{kWh}_e$	Variable cost (natural gas with CCS)
f	unitless	Capacity factor (generation technology, $f = 1$ for all t for natural gas with CCS)
h	h/yr	Number of hours per year (8,760 in 2017)
i	unitless	Discount rate
n	yrs	Asset lifetime.
Δt	h	Time step size, i.e., 1 h in the model
C	kW_e for generation or conversion kWh_e for storage	Capacity
D_t	kW_e	Dispatch at time step t
M_t	kWh_e	Firm electricity load at time step t
A	kWh_e	Annual flexible electricity load
H	kWh_{LHV} (kWh based on lower heating value of H_2)	Annual hydrogen production
r_t	kWh_e	Demand response at time step t
S_t	kWh_e	Energy remaining in storage at time step t
γ	1/yr	Capital recovery factor
δ	1/h	Storage decay rate, or energy loss per hour expressed as fraction of energy in storage
η	unitless	Efficiency (storage round-trip, electrolysis)
τ	h	Storage charging duration
MC_{firm}	$\$/\text{kWh}_e$	marginal cost of electricity for the firm load
MC_{flex}	$\$/\text{kWh}_e$	marginal cost of electricity for the flexible load

ity factors were calculated based on a GE 1.6–100 wind turbine with a 100 m hub height and 1.6 MW nameplate capacity [42], and used the methods described in Refs. [42–44]. Annual mean capacity factors were calculated for each grid cell. Aggregate time series were then produced using an area-weighted average of the 25% of these MERRA-2 cells (~625 cells) with the highest annual capacity factors. This aggregation smoothed the resource profiles by averaging over a quarter of the CONUS cells, thus producing a less variable profile while using the most productive regions (Sections S.14 and 4.1 discuss the impact of this modeling choice). Firm load, wind, and solar resource data were all from year 2017 to ensure that correlations between weather variability and firm load were preserved.

2.2. Model formulation

The complete model formulation and nomenclature is presented below.

Fixed cost calculations:

Fixed hourly cost of generation, conversion, and storage technologies (wind, solar, natural gas with CCS, electrolysis facility, battery storage):

$$c_{fixed}^{g,v,s} = \frac{\gamma c_{capital}^{g,v,s} + c_{\text{fixed O\&M}}^{g,v,s}}{h} \tag{2}$$

Capital recovery factor:

$$\gamma = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{3}$$

Constraints:

Capacity:

$$0 \le C^{g,v,s} \qquad \forall g, v, s \tag{4}$$

Dispatch:

$$0 \le D_t^g \le C^g f^g \qquad \forall g, t \tag{5}$$

$$0 \le D_t^v \le C^v \qquad \forall v, t \tag{6}$$

$$0 \le D_t^{\text{to s}} \le \frac{C^s}{\tau^s} \qquad \forall s, t \tag{7}$$

$$0 \le D_t^{\text{from s}} \le \frac{C^s}{\tau^s} \qquad \forall s, t \tag{8}$$

$$0 \le S_t \le C^s \qquad \forall s, t \tag{9}$$

$$0 \le D_t^{\text{from s}} \le S_t(1-\delta^s) \qquad \forall s, t \tag{10}$$

Storage energy balance:

$$S_1 = (1-\delta^s)S_T\Delta t + \eta^s D_T^{\text{to s}}\Delta t - D_T^{\text{from s}}\Delta t \qquad \forall s \tag{11}$$

$$S_{t+1} = (1-\delta^s)S_t\Delta t + \eta^s D_t^{\text{to s}}\Delta t - D_t^{\text{from s}}\Delta t \qquad \forall s, t \in 1, \ldots, (T-1) \tag{12}$$

System energy balance:

$$\sum_g D_t^g \Delta t + D_t^{\text{from s}}\Delta t + r_t = M_t + D_t^{\text{to s}}\Delta t + D_t^v \Delta t \qquad \forall t \tag{13}$$

Annual flexible load:

$$A = \sum_t D_t^v \Delta t \tag{14}$$

Annual hydrogen production:

$$H = \eta^v A \tag{15}$$

Objective function: minimize(system cost)

system cost =

$$\sum_g c_{\text{fixed}}^g C^g + \sum_s c_{\text{fixed}}^s C^s + \sum_g \left(\frac{\sum_t c_{\text{var}}^g D_t^g}{T}\right) + \frac{\sum_t r_t}{T} + \sum_v c_{\text{fixed}}^v C^v \tag{16}$$

Electricity system costs:

$$\text{electricity system cost} = \text{system cost} - \sum_{v} c^{v}_{\text{fixed}} C^{v} \tag{17}$$

$$\text{average cost} = \frac{\text{electricity system cost}}{A + \sum_t M_t} \tag{18}$$

$$MC_{firm} = \frac{1}{\sum_t M_t} \sum_t M_t \frac{\Delta\text{average cost}}{\Delta M_t} \tag{19}$$

$$MC_{flex} = \frac{\Delta\text{average cost}}{\Delta A} \tag{20}$$

$$MC_{firm} \sum_t M_t + MC_{flex} A = \text{electricity system cost} \tag{21}$$

2.3. Electricity costs

For every optimization, the model minimized the "system cost" (Eq. (16)). The "average cost" of supplied electricity was calculated as the electricity system cost (system cost less electrolysis facility capacity cost) divided by the total load (firm load plus flexible load), (Eq. (18)). "Marginal cost" was used as a second cost metric that attributed electricity costs to each load individually [47,48]. The marginal cost to a specific load is the change in the average cost divided by an incremental increase in that load in kWh_e. These values can be provided by linear optimization software as dual variables [49].

The marginal cost for the firm load was the average energy-weighted marginal cost of the firm load across all hours, MC_{firm} (Eq. (19)). Because the quantity of electricity used by the flexible load was constrained on an annual basis (as opposed to hourly), the marginal cost for the flexible load (MC_{flex}) was calculated based on a change in the annual quantity of flexible load (Eq. (20)). The energy-weighted sum of MC_{firm} and MC_{flex} is equal to the electricity system cost (Eq. (21)), implicitly assuming that the capacity-related costs of generation and storage are paid for by the load that most required such capacity, usually the firm load.

3. Results

3.1. Electricity cost and generation end use

Fig. 2 shows, for least-cost systems, the marginal electricity costs (MC_{firm} and MC_{flex}) and the average cost of delivered electricity. Increases in the load flexibility resulted in substantial reductions in the average cost per delivered kWh_e.

MC_{firm} was always greater than MC_{flex} (i.e., the option of getting electricity when desired always increased electricity costs), and the difference between MC_{firm} and MC_{flex} was greatest when negligible flexible load was present in the system (Fig. 2(a,b,c)). The variability in both the firm load profile and in the wind and solar resource availability resulted in reliable electricity systems overbuilding generation capacity for most hours each year, which resulted in extensive unused and curtailed generation (Figs. 2(d,e,f) and 4).

The least-cost system with no flexible load had the greatest quantity of excess generation capacity on a total available generation per total load basis. The fraction of total available generation that was unused (i.e., both curtailed and unutilized generation capacity) ranged from 33% in the natural-gas focused Dispatch scenario up to 54% in the wind-and-solar focused Renew + Storage scenario (Fig. 2(d,e,f)). In the Dispatch + Renew + Storage scenario, when no flexible load was present, only 2% of the unused generation was curtailed wind and solar power with zero variable cost.

In all scenarios, at low flexible load penetration, the flexible load was powered by the otherwise unused or curtailed generation (Fig. 2(d,e,f) and Fig. 4). In these cases, the marginal cost of electricity for the flexible load (MC_{flex}) approximately equaled the variable cost of generation (Table 2). In the Dispatch scenario, MC_{flex} was equal to the cost of natural gas fuel (0.027 $/kWh_e$). In contrast, MC_{flex} was free in the Renew + Storage scenario because the electricity was from zero variable cost wind and solar generation that would have otherwise been curtailed.

In the Dispatch + Renew + Storage scenario, the variable cost of electric power was free for hours with otherwise curtailed wind and solar generation, and the cost attributed to all power was 0.027 $/kWh$_e$ for hours in which the dispatchable generator was used. This behavior resulted in MC_{flex} = 0.025 $/kWh$_e$ because greater than 90% of hours used natural gas generation and, therefore, had an hourly marginal cost equal that of natural gas fuel. For all scenarios, the MC_{firm} and MC_{flex} values remained approximately constant for flexible load fractions less than 0.2.

With further increases in the flexible load fraction beyond ~0.2, each system transitioned from having substantial unused and curtailed power, with capacity decisions driven by demand for firm load, toward having diminishing quantities of unused and curtailed power, with capacity decisions driven by demand for both the firm and flexible loads (Fig. 2(d,e,f)). In this transition region, systems were characterized by lower electrolyzer capacity factors because increasing quantities of otherwise unused or curtailed generation were used (Figs. 4 and 5(d,e,f)). At large flexible load fractions, the least-cost Dispatch systems asymptoted toward utilizing 100% of the total available generation, whereas the Dispatch + Renew + Storage and Renew + Storage systems both asymptoted toward curtailing approximately 10% of total available generation. As the flexible load fraction increased through the transition region, new generation capacity was added to the system to power the flexible load (Figs. 3 and 4). As the flexible load increased, the fixed costs of electricity system assets were increasingly shared between the firm load and the flexible load, as evidenced by the converging marginal electricity costs in the transition regions in Fig. 2(a,b,c).

3.2. Generation capacities and system expansion

The slopes of the capacity lines in Fig. 3 indicate how the generation capacities varied as a function of the quantity of power supplied to the flexible load. The Dispatch and Renew + Storage systems contained sufficient excess generation capacity that substantial flexible load could be added to the system with minimal expansion of generation (Fig. 4). An expansion of total available generation capacity by 1% allowed least-cost systems to power flexible loads that were 41% and 43% of the size of the firm load for the Dispatch and Renew + Storage scenarios, respectively (Table S.9).

The Dispatch + Renew + Storage system behaved differently from the Dispatch and Renew + Storage scenarios. The Dispatch + Renew + Storage systems expanded wind and solar generation while contracting natural gas generation with CCS as the flexible load increased, despite having excess available generation at low flexible load fractions. As the flexible load increased the system flexibility, the least-cost systems reduced their reliance on costly dispatchable natural gas generation with CCS as a source of system flexibility. Power from dispatchable natural gas generation with CCS was the most expensive (Table 2) with a fixed cost = 0.031 $(\$/h)/kW_e$ and variable cost = 0.027 $/kWh$_e$. Non-flexible, variable wind power was the lowest cost generation with a fixed cost = 0.015 $(\$/h)/kW_e$ installed and a 43% capacity factor resulting in 0.035 $/kWh$_e$ generated. Non-flexible, variable solar power has a fixed cost = 0.014 $(\$/h)/kW_e$ installed and a 28% capacity factor resulting in 0.050 $/kWh$_e$ generated.

Fig. 3 shows the transition for the Dispatch + Renew + Storage scenario from flexible generation toward lower cost, non-flexible, variable generation. At a flexible load fraction of 0.27 the total available generation capacity is 10% greater than the system with zero flexible load. The dispatchable natural gas generation with CCS capacity decreased by 7%, whereas the wind capacity increased by 45% and the solar capacity increased by 10%. Despite the immediate expansion of total available generation capacity with increasing flexible load fraction, the transition from higher-cost dispatchable natural gas generation with CCS toward

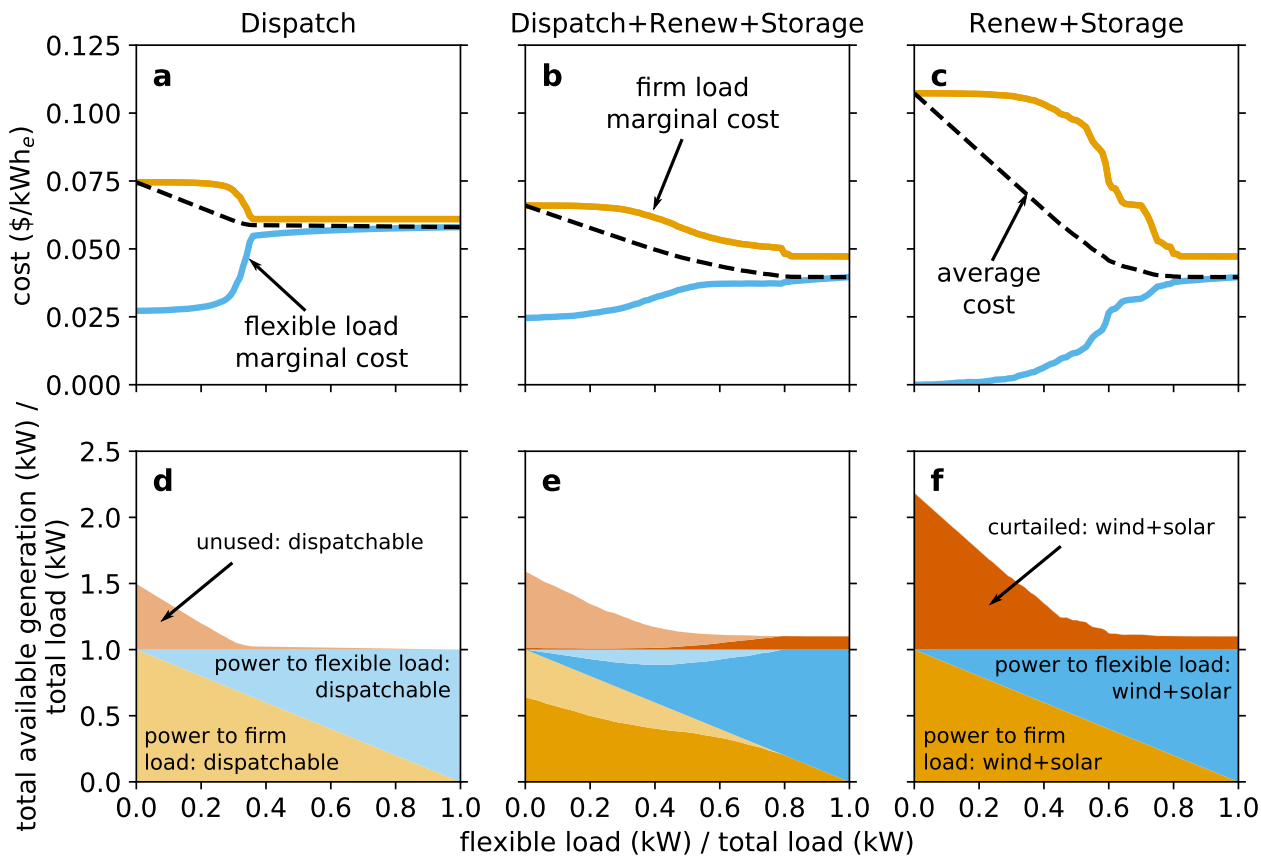

Fig. 2. Electricity costs and generation end use: the marginal cost of electricity for the firm electricity load (MC_{firm}) and flexible electricity load (MC_{flex}) and the average cost of delivered electricity are shown across the full range of flexible load fractions in (a), (b), and (c). Total available generation is split into power used by the firm and flexible loads and unused/curtailed generation in (d), (e), and (f). In all scenarios, when unused and curtailed generation is abundant MC_{flex} approximately equaled the variable cost of generation. As generation was added to supply the flexible load, capacity-related costs were increasingly incurred by the flexible load. The energy losses due to battery storage are not shown because they are negligible in the three scenarios.

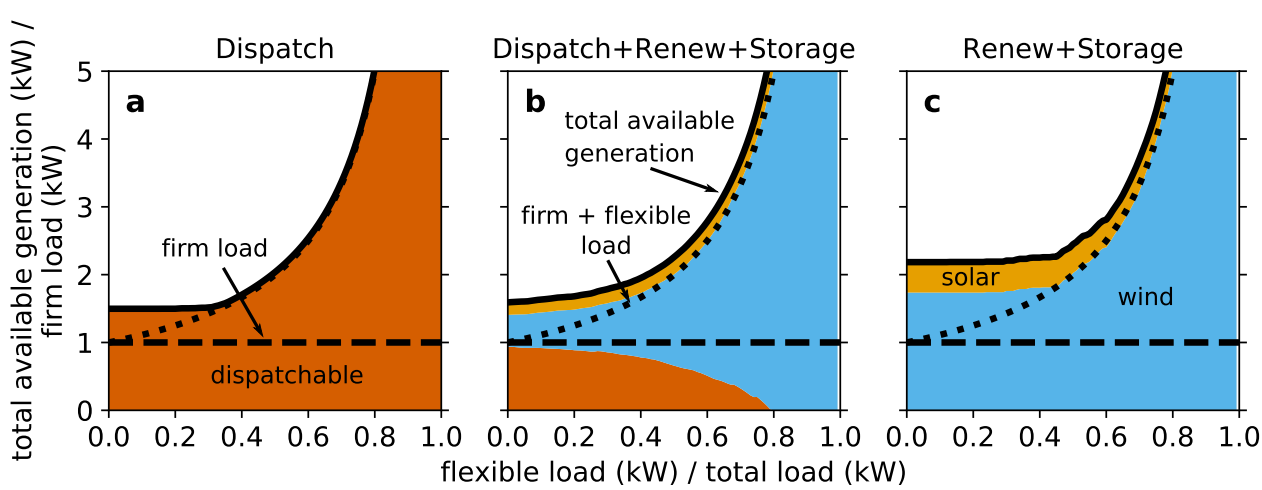

Fig. 3. Electricity system generation capacities: the total available generation capacity divided by the firm electricity load is shown across the range of flexible load fractions for each generation type, which shows the rate of generation expansion as a flexible electricity load was added to the systems. The least-cost systems initially added flexible loads with minimal capacity expansion. The rate of capacity expansion increased as more flexible load was added to each system.

lower-cost variable wind generation kept the MC_{firm} and MC_{flex} values relatively constant for flexible load fractions <0.2 (Fig. 2).

3.3. General coupled system characteristics

Fig. 4 provides system capacities and hourly dispatch during the hours of peak firm load for four different flexible load fractions, 0.05, 0.15, 0.30, and 0.40, in the Dispatch scenario. At low flexible load fractions, unused generation capacity exists during almost all hours, as shown by the difference between the "natural gas capacity" line and the "firm load" line. As the flexible load fraction increases from zero (not shown) to 0.05, to 0.15, the unused generation decreases without the system requiring any new generation capacity.

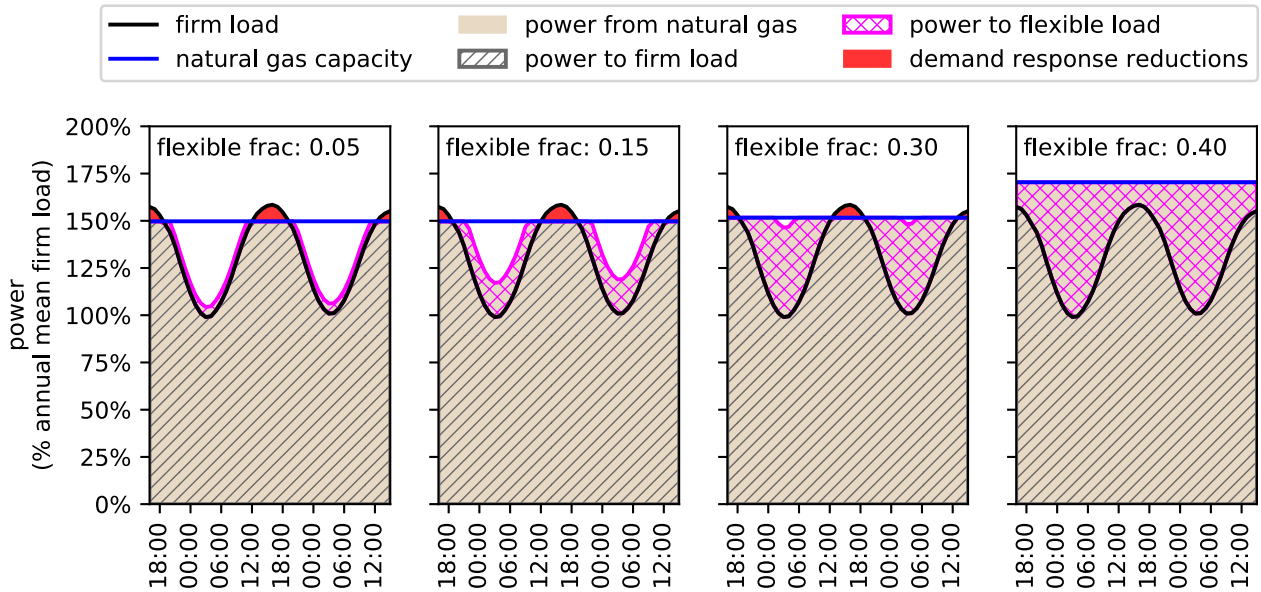

Fig. 4. Dispatch curve for the Dispatch scenario: the natural gas generation capacity and operations are shown over 48 h, and are centered on the maximum firm electricity load value experienced on 20 July 2017. The flexible load divided by the total load (flexible load fraction) is denoted on each panel as "flexible frac" and includes the values 0.05, 0.15, 0.30, and 0.40. When the flexible load was relatively small, capacity decisions were made exclusively to supply the firm load, while simultaneously the flexible load operated at >99% capacity factor.

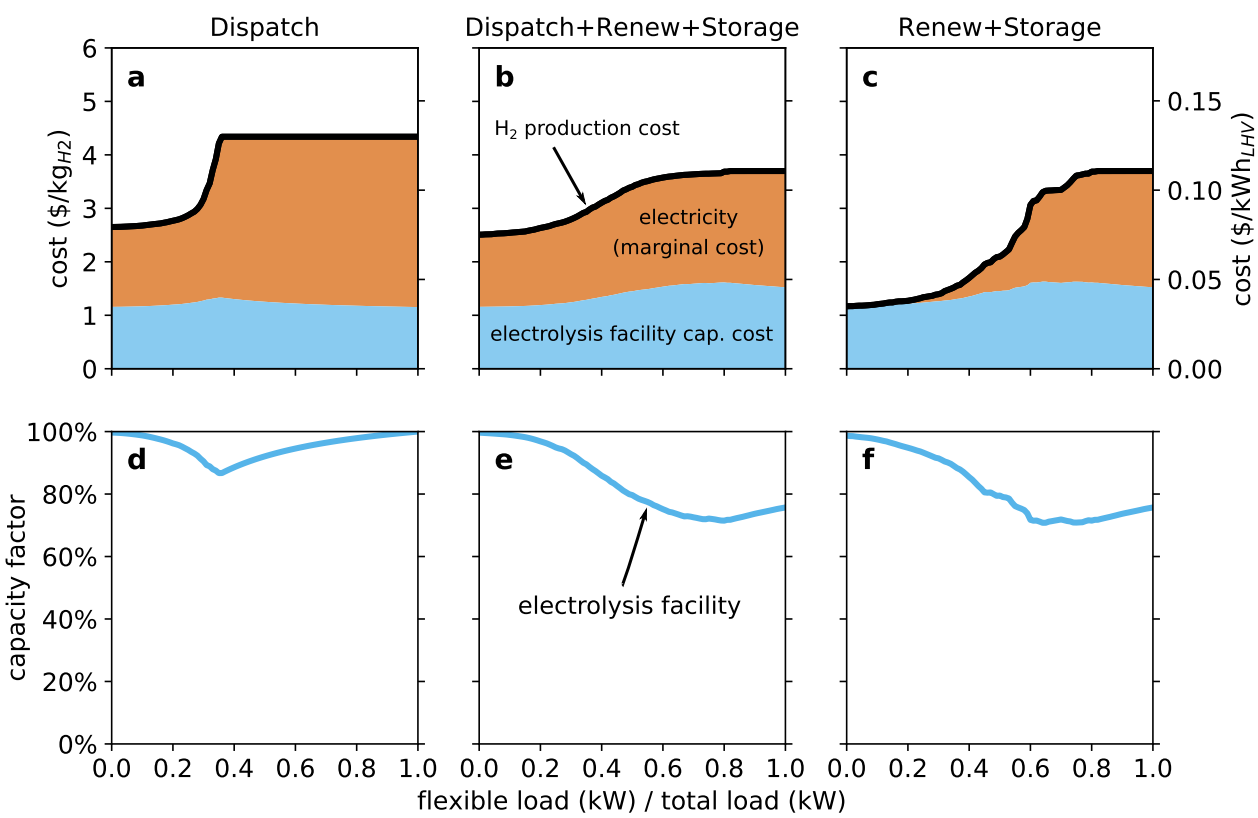

Fig. 5. Hydrogen production costs and electrolysis facility capacity factor: the cost of producing hydrogen per kg_{H_2} and per kWh_{LHV} is shown across the full range of flexible load fractions in (a), (b), and (c). The costs are split into the fixed cost of electrolysis facility capacity and electricity costs. Electricity costs are the marginal costs of electricity for a flexible load. The electrolysis facility capacity factors are shown in (d), (e), and (f). In all scenarios, capacity factors were near 100% and marginal electricity costs were lowest when minimal flexible load was present in the system.

The electrolyzer operated at almost 100% capacity factor when the flexible load was relatively small, and electrolysis operations were halted only during hours when demand response was used (Fig. 4 and Section S.13). Demand response allowed the model to supply less than the demanded firm load, at a high cost. In the Dispatch case with zero flexible load, 0.3% of hours used demand response to load balance (Table S.7), and unused generation was available during 99.7% of hours.

Demand response was used during the hours of peak firm load, and reduced the total supplied firm load by 0.012% of the annual load demanded (i.e., greater than 99.98% of the firm load was met). Because of the demand response mechanism, the system built natural gas generation capacity 5.5% lower than the peak firm load value in this zero flexible load case. When demand response was excluded from the system, electricity was available for the electrolyzer during all hours except the single peak firm load hour for year 2017. Results that exclude demand response are presented in Section S.13.2.

The electrolysis facility capacity factor decreased as the flexible load initially increased (Fig. 5(d,e,f)). While the flexible load expands, the least-cost system balances: 1) the costs of building additional generation capacity and operating the electrolyzer at a higher capacity factor against 2) the cost of building additional electrolyzer capacity and operating it at a reduced capacity factor without expanding generation capacity. This balance is shown in Fig. 4 at a flexible load fraction of 0.30 where the natural gas generation with CCS capacity has increased by 1.3% despite the visible presence of unused generation capacity.

3.4. Hydrogen production as the flexible load

The cost of producing hydrogen was split into the fixed cost of the electrolysis facility (Table 2) and the variable cost of electricity for electrolysis (Fig. 5(a,b,c)). The variable cost of electricity is shown using the marginal cost method (MC_{flex}) (Fig. 2(a,b,c)). In the least-cost systems, the fixed cost of the electrolysis facility depended inversely on the electrolyzer capacity factor (Fig. 5(d,e,f)). Section S.16 extends the model to include conversion of hydrogen into a synthetic, drop-in replacement for gasoline (an "electrofuel").

For flexible load fractions less than 0.2, the average hourly capacity factors were almost all greater than 0.9, whereas the monthly capacity factors were almost all greater than 0.8 (Fig. 6). In the Dispatch scenario, the electrolysis facility operations were limited by the peak firm load hours in the afternoons during summer months, likely when air conditioning is in use across much of CONUS (Fig. 4). The capacity factors reached a minimum between a flexible load fraction of 0.3 to 0.4 in the Dispatch scenario. Beyond a flexible load fraction of 0.4, the capacity factor asymptoted toward 100% as more dispatchable generation was added to supply the flexible load.

The Dispatch + Renew + Storage and Renew + Storage scenarios contained an abundance of unused and curtailed generation at flexible load fractions less than 0.2 during all hours of day and months of the year. At a flexible load fraction of 0.2, all hours and months had generation available greater than 90% of the time on average, except during the months of July and August, when the availability of generation is greater than 80%. The unused and curtailed generation was strongly dependent on hour of day and month of the year at flexible load fractions greater than 0.3, leading to a substantial reduction in electrolysis facility operations in July and August at flexible load fractions greater than 0.5 in these least-cost systems. The reduced capacity factor in July and August resulted from the summer doldrums in wind generation in the CONUS, coincident with an increase in firm load for air conditioning.

4. Discussion

In stand-alone wind- and solar-powered electrolysis systems, without battery storage, which are used to produce hydrogen, the electrolyzer is operated at a capacity factor determined by the capacity factor of the generation assets. Hence, an electrolyzer connected to a single-axis tracking solar panel array might be utilized with ~28% capacity factor, resulting in expensive ($\sim 7\,\$/\mathrm{kg}_{\mathrm{H}_2}$) hydrogen at current solar array and electrolyzer costs. An electrolyzer powered exclusively by an array of wind turbines might be utilized with ~43% capacity factor. As a result, the hydrogen generated in this type of wind-powered system produces relatively high cost hydrogen ($\sim 5\,\$/\mathrm{kg}_{\mathrm{H}_2}$) due to the high current fixed costs associated with the electrolyzer and the associated low capacity factor of the (generation) assets in the system. Alternatively, electrolyzers fully powered by the current carbon-emitting grid operate as firm loads with 100% capacity factors, and produce hydrogen at $\sim 5\$/\mathrm{kg}_{\mathrm{H}_2}$ based on access to electricity at average current industrial costs of $0.068\,\$/\mathrm{kWh}_e$ and current electrolyzer fixed costs of $0.020(\$/h)/\mathrm{kW}_e$ [50].

In this study, we have evaluated the magnitude and duration of excess generation available for coupling to flexible loads, with particular focus on systems in which the predominant fraction of generation is from wind and solar energy. At one extreme, utilization of intermittent "free" electricity entails only partial utilization, and hence low capacity factors, of the flexible assets that utilize the excess generation. The other extreme involves systems that operate at nearly 100% capacity factor using more costly, predictable electricity.

We find substantial unused and curtailed generation capacity can be exploited when flexible loads are just beginning to enter the energy system (and represent a low fraction of total load). Under those circumstances, flexible loads can operate at high capacity factors while avoiding exerting pressure on electricity systems to expand generation capacity. Moreover, if flexible loads have access to marginally priced electricity, they would be able to produce energy services with low-cost electricity *and* at high capacity factors.

4.1. Unused and curtailed generation and electricity costs

Excess generation capacity existed in substantial quantities in all three hypothetical scenarios studied. Even when the flexible load was in excess of 20% of total load, supplying the flexible load—exemplified in our study specifically by electrolytic hydrogen production—did not require substantial capacity expansion. Thus, the flexible load did not incur additional costs associated with capacity expansion while the electrolyzer was nevertheless used at nearly 100% capacity. Consequently, more complete utilization of the total available generation led to substantial reductions in the average cost of delivered electricity for all scenarios (Fig. 2), and the capacity-related costs of generation and storage were incurred by the firm loads (Table S.9).

The magnitude of unused and curtailed generation is a direct result of the variability in the firm load profile (Fig. 4) and the variability in the wind and solar resource availability profiles. The extensive unused and/or curtailed generation that can be exploited in such electricity systems fundamentally derives from two geophysical phenomena: the large short-term and monthly variability of the wind resource, even if aggregated over areas as large as the CONUS, and the diurnal and seasonal variability of the solar resource. The variability of the firm load is the result of human choices and could potentially be altered with demand-side management or other techniques (Section S.13.1).

The Renew + Storage scenario relies exclusively on variable wind and solar generation, and at low flexible load fractions has the largest quantity of unused (curtailed) generation of the three studied scenarios, consequently providing the largest opportunity for a flexible load to exploit the resource variability and generate relatively inexpensive hydrogen.

The variability of wind and solar resources can be reduced, but not eliminated, by aggregating resources over a wide geographical area [51,52]. Congested transmission lines act to geographically constrain the load balancing and therefore will increase the variability of renewable generation and thus increase the opportunity for exploiting the flexible load relative to the opportunity represented in our idealized base case. When smaller geographic regions with zero or limited transmission between regions are modeled, more generation and energy

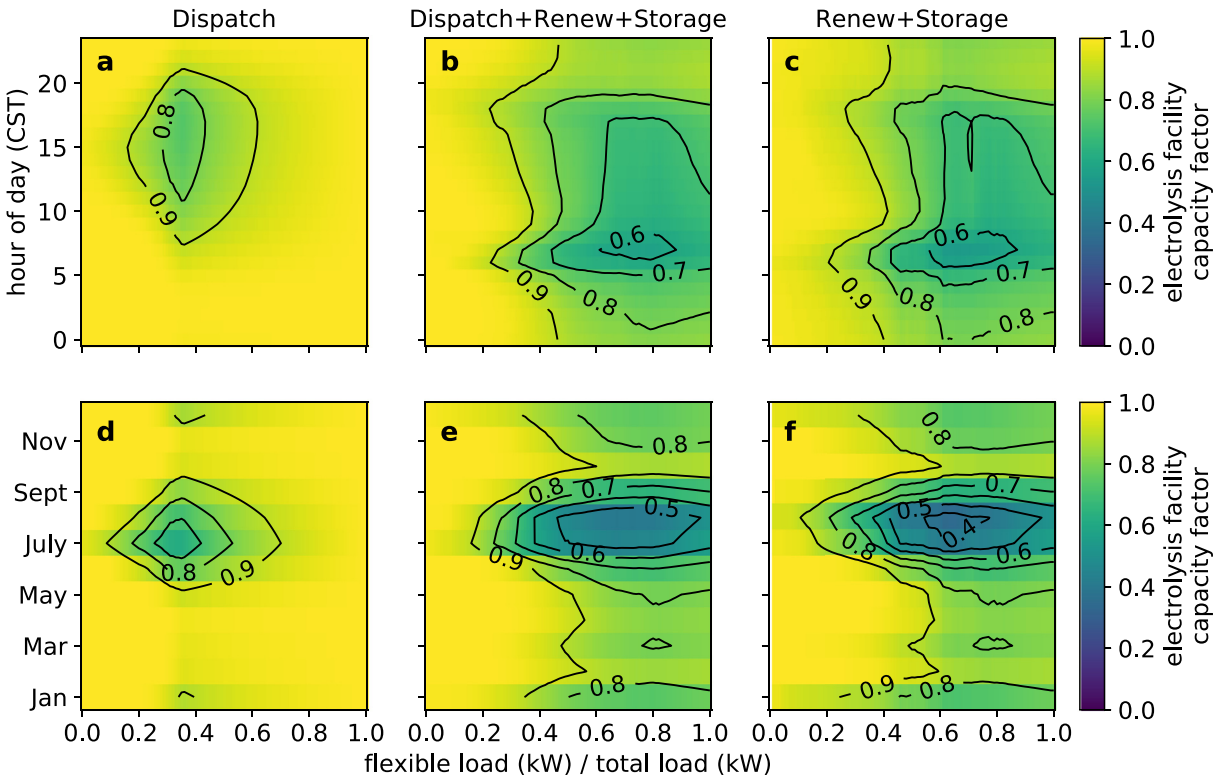

Fig. 6. Electrolysis facility operations by hour and month: the electrolysis facility operational capacity factors by hour of day (a, b, c) and month of the year (d, e, f) are shown, averaged across the year (2017), across the full range of flexible load fractions. The hour of day is shown in Central Standard Time (CST). The electrolysis facility operated at a high capacity factor during most hours and months when there was minimal flexible load in the system.

storage capacity are required to maintain high reliability, thus increasing system costs [6,16,25,51,53]. This increase in generation capacity increases curtailed generation and the average cost of electricity, but is also the origin of the low-cost MC_{flex} that can be exploited by the flexible load.

4.2. Production cost goals for hydrogen

The U.S. Department of Energy has set a goal of producing hydrogen for less than 2 $\$/kg_{H_2}$ [54]. When minimal flexible load was present in the systems, hydrogen could be produced for less than 2.7 $\$/kg_{H_2}$ using the marginal cost of electricity (MC_{flex}) in all scenarios (Fig. 5(a,b,c)). However, real-world electricity consumers do not in general have access to electricity prices based on real-time marginal costs (Section S.19.1).

Current electricity systems rely heavily on dispatchable generation. Consequently, a direct transition to a 100% wind- and solar-powered electricity system, such as the Renew + Storage scenario, is unlikely without first transitioning through a mixed architecture that has dispatchable and variable renewable generation, such as the Dispatch + Renew + Storage scenario. If a 100% wind- and solar-powered system were to exist in the future, a host of system flexibility technologies would likely be used to balance reliability and cost (Section 4.3). Despite this uncertain future, our analysis shows that the U.S. Department of Energy goal of 2 $\$/kg_{H_2}$ can be achieved with existing technologies, at current technology costs, in wind- and solar-powered electricity systems, when electrolysis facilities have access to marginally priced electricity. Moreover, the cost of producing hydrogen was less than 2 $\$/kg_{H_2}$, based on MC_{flex}, when the flexible load was less than approximately half of the total load in the Renew + Storage scenario. This broad range of low-cost hydrogen production indicates that many flexible load technologies could likely be added to these systems before marginal electricity costs increase substantially.

The cost of distributing hydrogen from a centralized production facility to end users was not included in this study; these costs are less affected by the availability of otherwise unused and curtailed power (Section S.11) [55].

4.3. Other flexible loads

The inherent daily and seasonal mismatch between generation profiles, in systems with substantial variable wind and solar generation, and firm electricity loads creates an opportunity for flexible loads to use generation capacity at a low cost that would otherwise be unused or curtailed. This mismatch is present even in systems with energy storage and natural gas generation. The economic opportunity presented by this mismatch will depend on the characteristics of the energy services provided by the flexible load, and their marketplace values. Furthermore, different flexible loads will compete for a share of the unused or curtailed, low-cost generation depending on their costs, margins, and size of their markets. Factors such as the scale of the energy services potentially filled by each flexible load and profit margins will partially determine the mix of flexible loads in future energy systems. Beyond economic considerations, the operational constraints of each flexible load will help determine the share of unused or curtailed, low-cost electricity that could be available to them.

Different types of flexible loads have different operational constraints (Table S.5). The times when electric vehicles are charged, and home appliances are run, can be shifted by a few hours within a day. Battery electric vehicles, for example, require access to power on a daily cycle or will fail to meet expectations. The availability of unused and curtailed generation by hour of the day and month of the year is shown in Fig. 6 by equating the time of operations of the flexible load with otherwise unused or curtailed generation.

In all studied scenarios, an abundance of unused and curtailed generation was present for almost any hour of day or month of year at

flexible load fractions less than 0.2 (electrolysis facility capacity factors of greater than 90%). Systems optimized to supply only a firm load could supply ~25% additional load with minimal capacity expansion (less than 0.1% in the Dispatch and Renew + Storage scenarios and an expansion of 6% in the Dispatch + Renew + Storage scenario), when that additional load is flexible (flexible load fraction 0.2). Despite adding load, system costs per kWh_e are reduced 13% in the Dispatch and Dispatch + Renew + Storage scenarios and 20% Renew + Storage scenario. Additionally, MC_{flex} (Fig. 2) could be reasonably applied to other flexible loads or combinations thereof when the flexible load fraction is less than 0.2.

As flexible loads expanded in the model, the availability of unused and curtailed generation was more limited in time, and the results herein, based on hydrogen production, are applicable to fewer flexible load technologies. This reduction in applicability is because more hours per day or months per year are constrained. Therefore, fewer types of flexible loads can operate well under the availability constraints of the excess, low-cost generation.

The availability of unused and curtailed generation decreases noticeably around flexible load fractions of ~0.3 for the Dispatch scenario and for values greater than 0.3 for the Dispatch + Renew + Storage and Renew + Storage scenarios (Fig. 6). The electrolysis facility capacity factor was less than 0.5 in July and August in the Dispatch + Renew + Storage and Renew + Storage scenarios for flexible load fractions >0.5. These two months have multiple consecutive days when the flexible loads operate substantially below capacity. Therefore, without expansion of other system flexibility options (Table S.5), flexible loads that can shift operations by hours within a day, but not days within a week (battery electric vehicles), would have severely limited operations at these times. In contrast, flexible loads that can suspend operations for months would not be greatly impacted by the lack of generation available in July and August in this example.

4.4. Adding electricity system flexibility

The Dispatch + Renew + Storage scenario included three flexibility mechanisms mentioned in Table S.5, load-following natural gas generation with CCS, load flexibility through a demand response mechanism, and Li-ion energy storage. Dispatched power from natural gas generation or from batteries can supply the electricity loads in times of low wind and low solar availability and/or high demand. In this case only 2% of the unused generation is zero marginal cost variable generation at low flexible load fractions. Thus, even the first increment of hydrogen production must pay the variable cost of natural gas generation (Fig. 2(b,e)). This behavior suggests that the availability of "free" power depends on having an electricity system with very little flexibility (either on the generation side or the demand side) as seen in the Renew + Storage scenario.

Demand response provided a minimal amount of flexibility to the firm load. The system was allowed to supply less than the demanded firm load for a high price (Section S.13). The demand response mechanism simulated a demand response program in which customers would be paid to reduce their load during critical hours (no load shifting). For the Dispatch case with zero flexible load, demand response reduced the peak in the supplied firm load by 5.5%, a reduction approximately two times larger than those seen in the U.S. from voluntary demand response programs (approximately 1% to 3% reductions in peak firm load [50]). Reducing the peak firm load by 5.5% resulted in a 5.5% reduction in the required natural gas generation capacity and lowered system costs. Scenarios that excluded demand response showed greater generation capacity, more unused and curtailed generation, and higher system costs (Section S.13.2).

Energy storage, modeled using Li-ion battery costs and technical parameters, was the only source of flexibility that stored excess power during one hour and transferred it to a later hour. As modeled, the flexible load was purely an energy taker that provided a use for excess generation and could not contribute electricity back into the system. Power-to-gas-to-power (PGP) energy storage [16,24,56,57] could use the electrolysis facility in our model. The hydrogen produced via electrolysis can be stored for a season or longer and then used on demand by either fuel cells, or in combustion turbines to power the grid. Unlike hydrogen used to meet various flexible loads beyond traditional electricity loads (Table S.5), with PGP, the hydrogen is used to meet load in the electricity sector.

When the full PGP process was added as a technology option in each of the three studied scenarios, PGP was only used in the Renew + Storage scenario, which did not allow dispatchable natural gas generation with CCS in the system. In the Renew + Storage scenario, incorporating PGP in the electricity systems reduced average electricity costs by ~10% and reduced the quantity of curtailed generation by ~60% (Section S.18). The addition of PGP better aligned available generation with the firm load and increased the flexibility of the electricity system as a stand-alone entity. By making the stand-alone electricity system more flexible, less curtailed power was available for the flexible load (compare Fig. 2(c) against Fig. S.14(c)). Less available curtailed generation resulted in a faster rise in the marginal cost of electricity for the flexible load (MC_{flex}) (compare Fig. 2(f) against Fig. S.14(f)).

4.5. Limitations and assumptions

Our idealized macro-scale energy model can be considered a limiting case example that minimizes the variability of wind and solar generation by assuming lossless, zero-cost transmission from generation to load over the contiguous U.S. Splitting the contiguous U.S. into dozens of subregions connected via transmission would increase the variability in wind and solar resource availability for each subregion [51,52], thus requiring greater generation capacity to ensure the firm load can be supplied at all hours in all regions. These simplifications in the present model provide a reasonable lower bound on the quantity of generation capacity required to supply the U.S. electricity load, and, therefore, a reasonable lower bound on the quantities of unused and curtailed generation that can be expected in similar systems. Wind power off the east cost of the U.S. has higher capacity factors than onshore wind power in the U.S., in general, and has lower variability [56]. The exclusion of offshore wind power from the model is one exception to this lower bound. However, we note that offshore wind generation profiles also exhibit considerable resource variability [56,58].

The least-cost systems relied on perfect model foresight of future wind and solar availability and firm load. Deviations from perfect foresight would reduce performance and necessitate greater generation and/or storage capacities to cover these inefficiencies. Electricity systems are engineered to supply firm load ~100% of the time [59]. To ensure reliability over many years, generation and energy storage capacities would likely need to be increased with respect to the modeled results obtained from optimization over a single year. Thus, optimizing over multiple years would increase the quantities of unused and curtailed generation.

Exploring many transition pathways from current energy systems toward low-carbon futures is important because of uncertainties in the development of current and future technologies. In general, models of future low-carbon energy systems include a combination of renewable wind- and solar-power, low-carbon dispatchable generation, and energy storage [9]. We evaluated a variety of possible end-states incorporating different combinations of these low-carbon technologies. Because each model run represents a single end-state, no learning rates were used in cost assumptions. Current cost estimates were used for all technologies, likely providing an upper bound on all reported costs. We explored the degree to which our results are sensitive to cost reductions, and obtained no substantial change in the main conclusions (Section S.12).

Additionally, the cost of electricity in the U.S. is affected by subsidies that include the production tax credit (PTC) for wind generation and the investment tax credit (ITC), which benefits solar power installa-

tions. These and other policies lead to policy-driven market distortions in electricity pricing [2]. These distortions are complicated, do not pertain to all markets, and will likely change in the future. We do not directly model the effects of the PTC, ITC, or other subsidies in this study.

Severe weather events, such as hurricanes, can strain electricity systems and temporarily leave millions of people without access to power [60]. Extreme weather events were not explicitly modeled in this study except insofar as these events were present in the observational data used to drive the model. Various types of flexible loads would likely respond differently to such events. Flexible loads that can shift demand by hours, such as electric vehicle charging, may be able to coordinate their charging to relieve pressure on strained electricity systems. Battery electric vehicles could also support a strained electricity system for a limited period of time, by using vehicle-to-grid discharging. Moreover, flexible loads, such as the hydrogen production modeled herein, could suspend operations for days at a time if needed to lessen the burden on the electricity system.

5. Conclusions

We studied least-cost electricity systems that relied on combinations of wind, solar, dispatchable natural gas, and energy storage technologies to supply firm and flexible electricity loads. We varied the fraction of firm to flexible load in the systems to evaluate the evolving economic opportunity associated with the addition of new flexible loads to these modeled electricity systems. In all of the studied scenarios when flexible loads were minimal, excess generation capacity was available during most hours. This availability allowed the introduction of flexible loads into the systems that operated at high capacity factors while using generation capacity built to supply the firm loads. Thus, electricity costs for the flexible loads were based solely on the variable cost of electricity generation. As more flexible loads were added to the electricity systems, generation capacities expanded and the flexible loads increasingly incurred the capacity-related costs of electricity generation.

The different studied scenarios all had differing amounts of unused and curtailed generation. When the flexibility of the wind- and solar-powered electricity system was increased by allowing dispatchable natural gas generation, long-duration energy storage, and/or demand response into the system, the excess generation capacity available for newly added flexible loads decreased, yet remained substantial. In general, adding flexible technologies to these least-cost systems reduced the excess generation readily available for low-cost use by flexible loads, while simultaneously reducing the cost of the electricity system.

Our results indicate that electricity systems with limited system flexibility likely have abundant unused or curtailed generation capacity. This unused and curtailed generation could be available for use by entities that can flexibly adapt their electricity consumption up or down based on the availability of low-cost electricity. Flexible electricity loads, such as hydrogen production, could potentially avoid incurring the capacity-related costs of generation by ramping down electricity use during the most critical, highest cost hours or weeks each year. Our results indicate that in electricity systems relying on wind and solar generation, substantial amounts of free or low-cost electricity may be available to power a nascent hydrogen economy or other flexible loads, but expansion of a hydrogen economy would at some point require additional generation capacity, leading to higher costs of hydrogen production.

Data and code availability

In the interest of transparency and reproducibility, all model code, input data, and analysis results are publicly available and documented at https://github.com/carnegie/SEM_public/tree/Ruggles_et_al_2021.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Tyler H. Ruggles: Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Jacqueline A. Dowling:** Formal analysis, Resources, Writing - review & editing. **Nathan S. Lewis:** Conceptualization, Methodology, Writing - review & editing. **Ken Caldeira:** Conceptualization, Methodology, Writing - review & editing, Funding acquisition.

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Supplementary material

Supplementary material associated with this article can be found, in the online version, at 10.1016/j.adapen.2021.100051

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