McKinsey & Company

Energy transition in the US power sector and its implications for MISO

December 08, 2022

MISO

Executive summary

Recent events underscore, the energy transition must balance **decarbonization, reliability, and affordability**

There are **significant tailwinds**: passage of federal legislation (e.g., BIL, IRA), and state, local and corporate commitments

Considerable hurdles remain, including:

- Early stage technologies must come down **cost curves** and scale-up with reliable, **secure supply chains** and **skilled workforces**
- **Siting and permitting** must accelerate for large-scale deployments (e.g., renewables, hydrogen production, carbon sequestration)
- Investments must be made in a **highly inflationary economy**

On the US's current trajectory, accelerated by the IRA, we forecast:

A **40% growth in electric demand** by 2035 as buildings electrify heating and new vehicle sales shift to EVs

B **135 GW in baseload retirement** of coal and **almost 1000 GW in renewable deployments** (550 GW solar and 450 GW wind) by 2035

C **A broad portfolio of flexibility solutions** is needed**,** including 180 GW of storage, demand response, maintenance and expansion of gas generation, transmission expansion, and long-duration storage

D 2021 levels of natural gas plant capacity required in 2035; **100 GW of new gas plants by 2040**, but utilization drops to ~25%

E Gas to the power sector declines by 25% (2040 vs. 2021), shifting to capacity-based value and potential new load for hydrogen production

F Power grid serves 30% higher peak electricity demand by 2035 with new centralized generation and DERs interconnected

G **Investment in transmission and interregional coordination required** to integrate renewables and expand capacity on congested routes

More would be needed to achieve the US's emissions targets and align with a global pathway of warming below 1.5 deg

The last two years have seen dynamics shift in the power sector – highlighting the need to balance across decarbonization, affordability, and system reliability

Inauguration Day January 20, 2021	Winter Storm Uri February 2021	IIJA Passage November 15, 2021	Russian Invasion of Ukraine February 2022	IRA Passage August 16, 2022	California extends nuclear plant Sept 2022	Renewables overtake coal and nuclear YE 2022
Biden sworn in as President, with goal of **net-zero emissions from the power sector by 2035** and a net-zero economy by 2050	Winter Storm Uri in Texas drives up wholesale natural gas prices 100x-300x across parts of the central US, highlighting risks of **grid reliability and resiliency**	Bipartisan Infrastructure Law passed with $73B for **energy and power** and $46B for **resiliency**	War in Ukraine continues to have deep human, as well as social and economic impact. 1650% increase in EU power prices and 1220% increase in gas prices in August ’22 compared to same time last year	Inflation Reduction Act passed with $415B in climate spending, including incentives for **clean energy technologies**	Governor Newsom signs legislation to extend nuclear plant’s operating license to providee **zero-carbon firm power**	US **renewable generation** expected to exceed coal and nuclear generation at 20+% of power supply

Source: White House Office of Management Budget; Kansas Corporation Commission, US Energy Information Agency

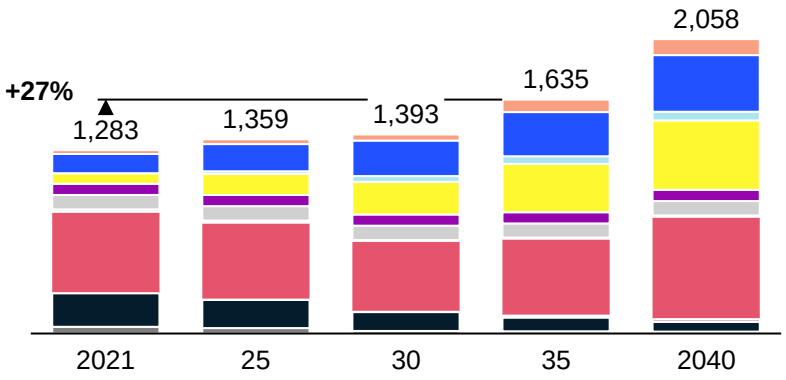
The IRA has accelerated many elements of the energy transition and revised the US's trajectory

The IRA's impacts are still insufficient to achieve the Biden Administration's goal of zero-by-2035

Storage | Offshore Wind | Hydro | Biofuels | Gas CCS[2] | Other[3]
Onshore Wind | Solar | Nuclear | Gas[1] | Coal

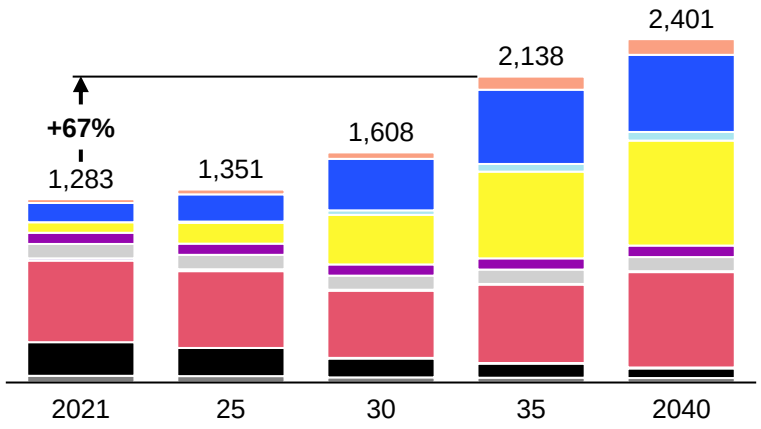
US Installed Capacity (GW)

Current Trajectory, without IRA



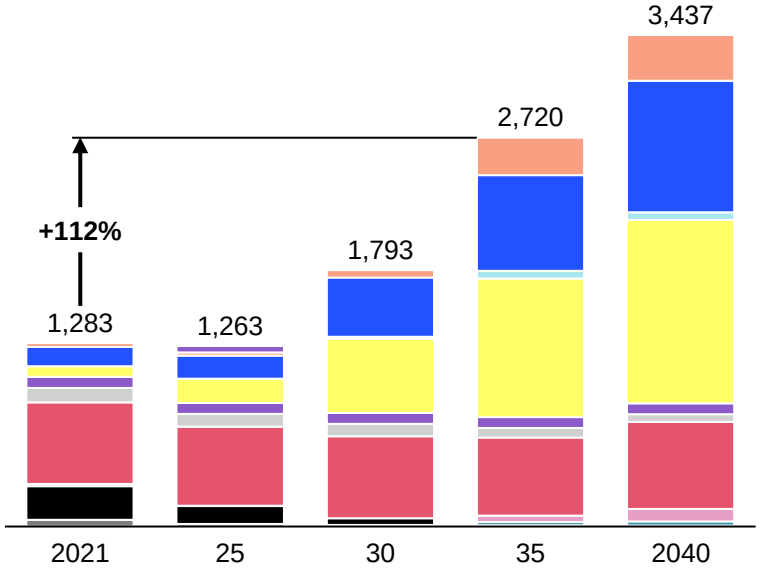
Modeled the US power sector based on current technology cost curves and performance trajectories, with any pre-IRA policy incentives

Current Trajectory, with IRA



Modeled the US power sector based on current technology cost curves and performance trajectories, with IRA policy incentives (based on interpretation as of September 2022)

Zero-by-2035 scenario



Modeled the implications of the Biden Administration's goal for net-zero emissions from the power sector by 2035 and a net-zero economy by 2050. This is one scenario that illustrates both the technology and investment needs that underlie this aspiration.

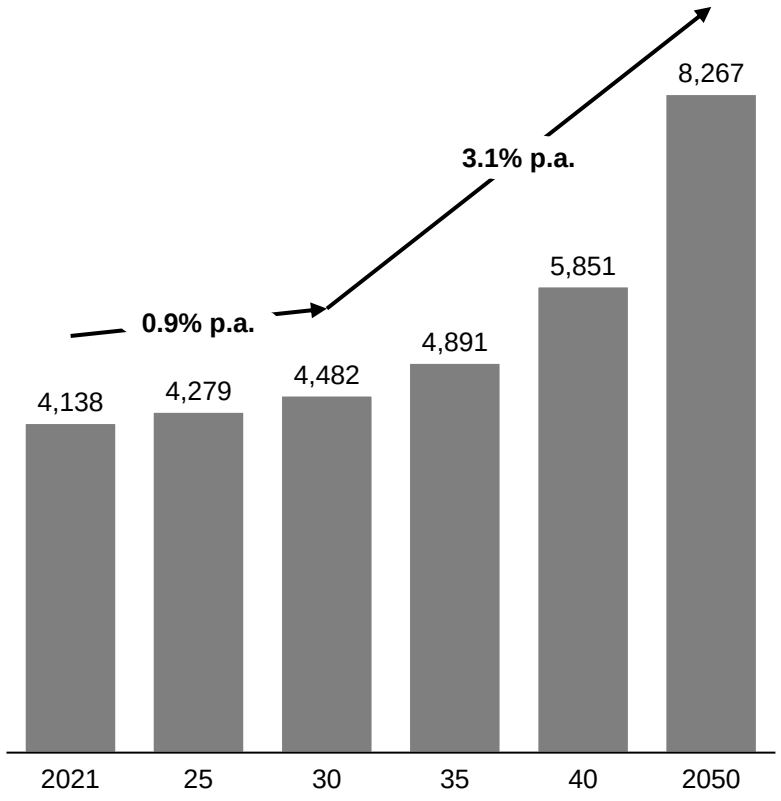
1. Includes gas that blends hydrogen in its fuel mix. It does not include gas plants that have been retrofitted for carbon capture and storage (CCS), which are listed separately
2. Carbon capture and storage (CCS) involves capturing the carbon dioxide produced by power generation, transporting it; and then storing it such that it is not re-emitted
3. "Other" includes geothermal, oil, and biomass and biogas plants

A. Decarbonization of transport, buildings and industry would drive electric load growth

With the IRA, US demand grows ~30% by 2035, at a CAGR of ~2%

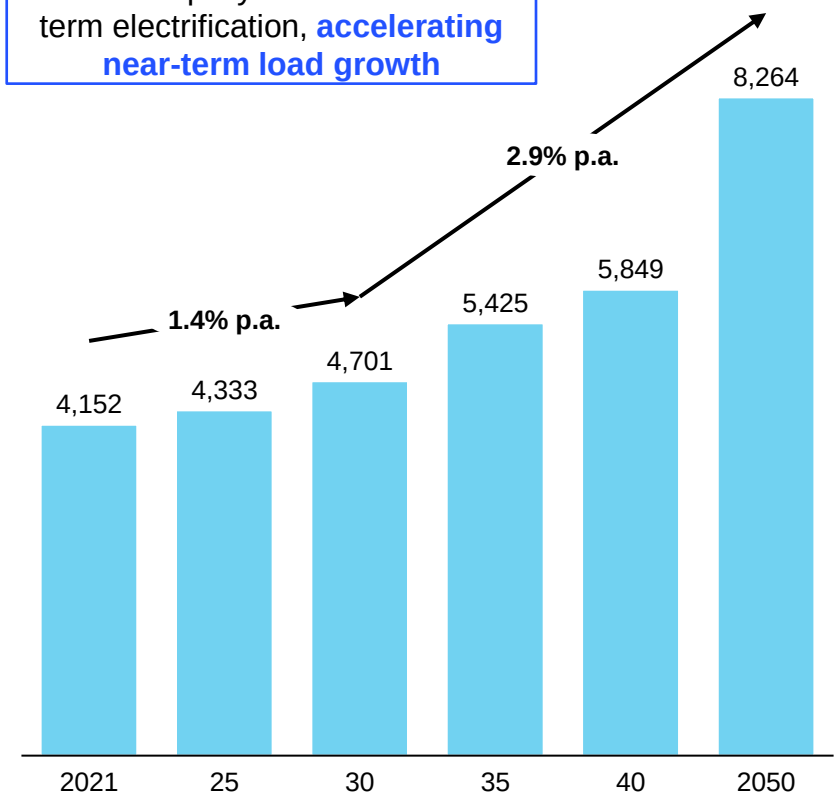
Electric demand growth (TWh)

Current Trajectory, without IRA[1]



Current Trajectory, with IRA

The IRA rapidly accelerates near-term electrification, **accelerating near-term load growth**



1. 2019 used as a pre-COVID pandemic base year (electric load in 2020 is reduced due to the effects of stay-at-home orders and other pandemic response measures)

Source: McKInsey analysis, using PowerIQ (a McKinsey solution)

Takeaways

A key lever for achieving the decarbonization ambitions of the US economy will be **transitioning from burning fossil fuels for transportation and heating to using clean electricity**

IRA subsidies – particularly for low- and middle-income households, **pulls forward load growth** in vehicles and transportation resulting in higher near-term demand

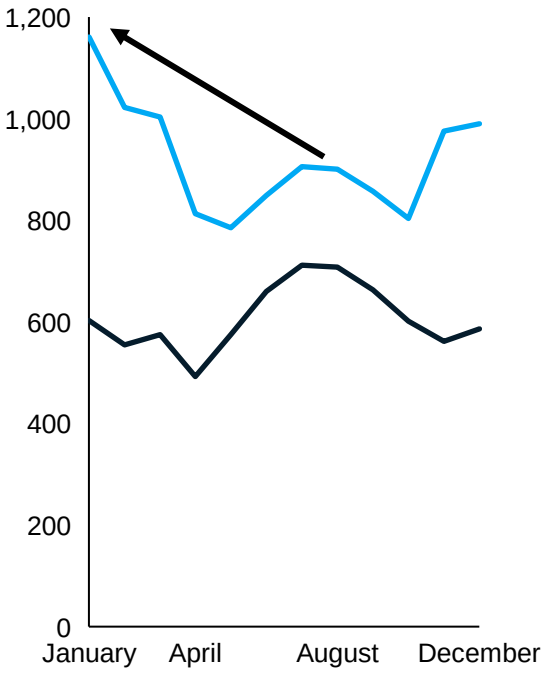
The shape of this load will shift significantly, with a greater movement to **winter peaking** given the accelerated adoption of **electric space heaters, water heaters, and stoves**

A. To electrify heating in a zero-by-2035 scenario, peaks would shift from summer to winter in several regions making dispatchable winter capacity critical

2019 — Zero-by-2035 (data in 2040)

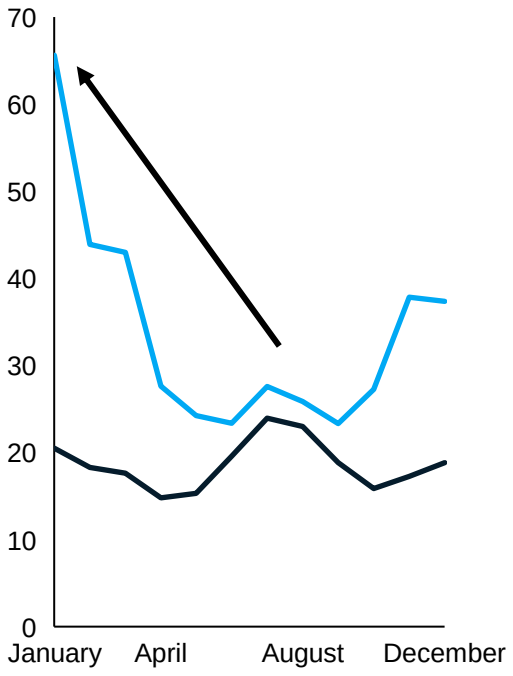
Monthly peak coincident load in 2019 and under a zero-by-2035 scenario, GW

National (winter peaking)



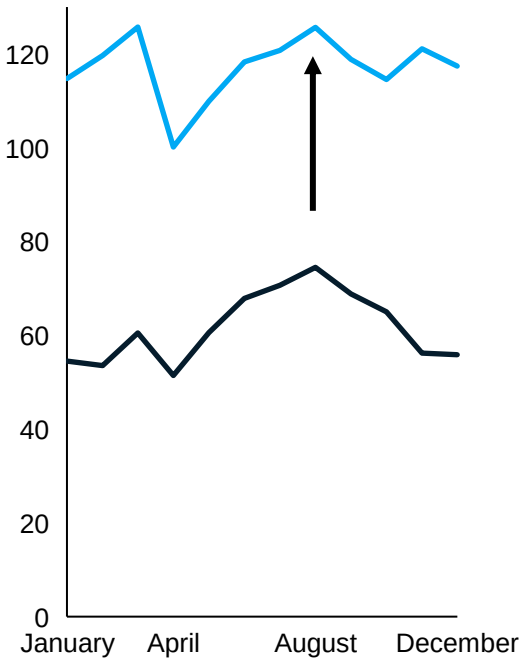
Nationwide peak power demand would move from July to January

ISO-NE (winter peaking)



New England's peak power demand would move from July to January

ERCOT (summer peaking)



ERCOT's power demand would continue to peak in August

Source: McKinsey EPNG practice

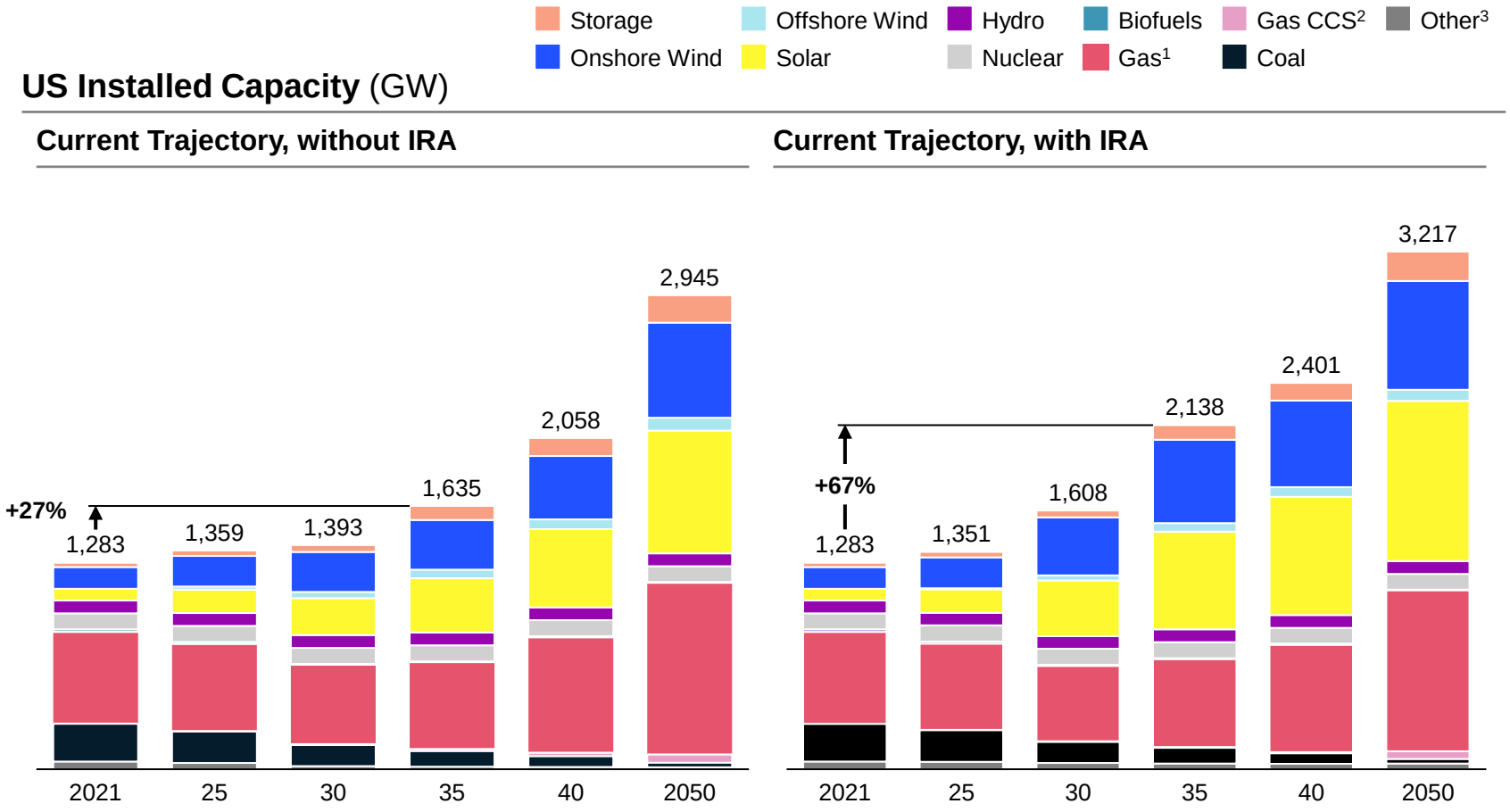
Takeaways

In a fully decarbonized system, as building electrification plays a bigger role, the **load would shift from summer peaking to winter peaking in 2040** in several regions

In those regions, the growing winter peaks **bring into focus the adequacy of supply resources** during long winter peaks, when renewables might be less available, making dispatchable power critical

Solar plants are less available in the winter and solar+storage, while important, is unlikely to be the only dispatchable resource to solve the problem

B. The IRA drives 40% higher total installed capacity in 2035 with a significant shift in the asset mix



1. Includes gas that blends hydrogen in its fuel mix. It does not include gas plants that have been retrofitted for carbon capture and storage (CCS), which are listed separately
2. Carbon capture and storage (CCS) involves capturing the carbon dioxide produced by power generation, transporting it; and then storing it such that it is not re-emitted
3. "Other" includes geothermal, oil, and biomass and biogas plants

Source: McKinsey EPNG practice

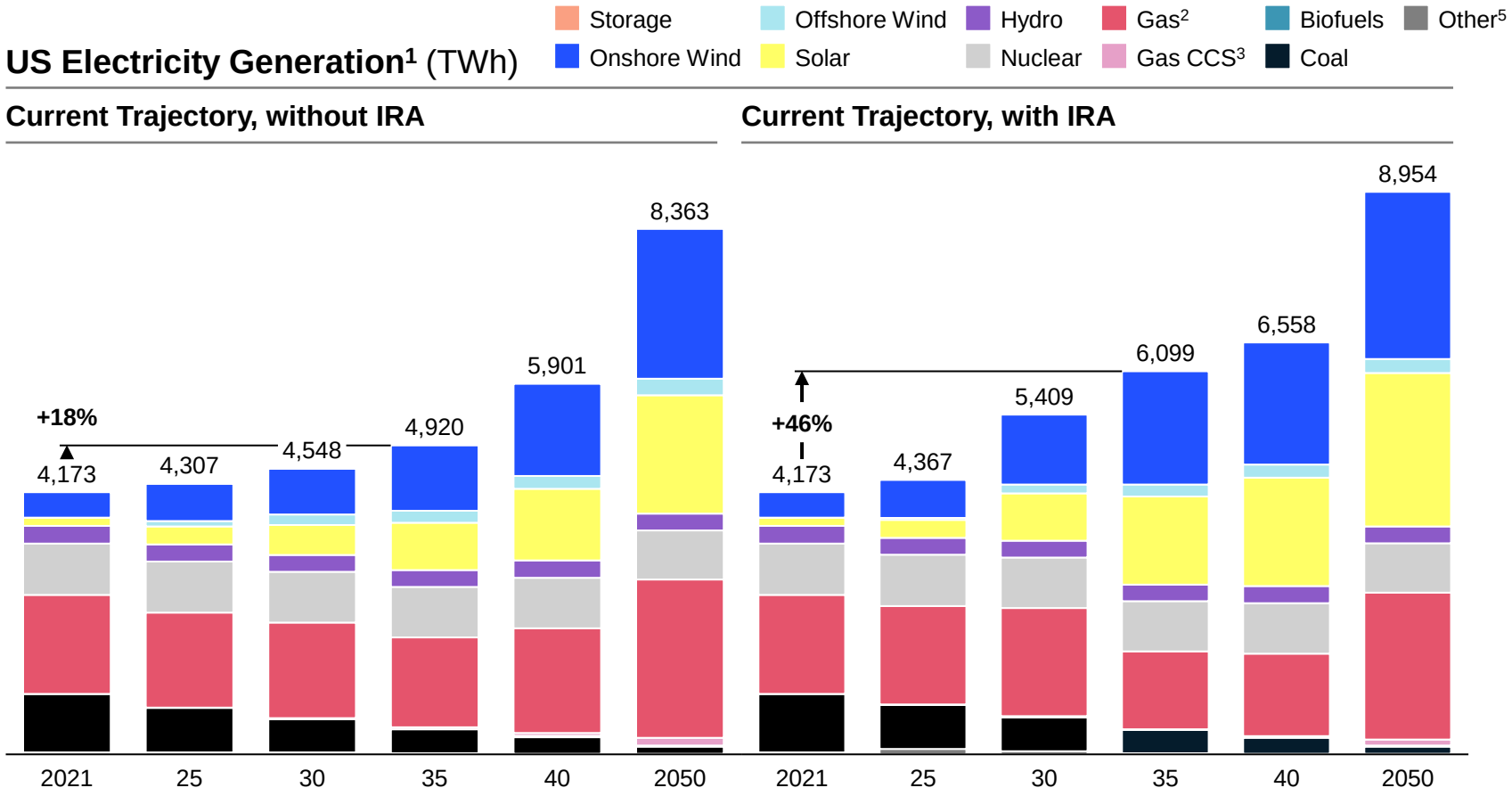
Takeaways

By 2035, the IRA could result in a significant increase in capacity compared to a pre-IRA case in order to meet increased electric load and produce hydrogen

Coal plants are likely to provide <5% of power capacity in 2035, and continue to decline

Gas remains a critical source of reliable, dispatchable power – making up almost 25% of total capacity - but is utilized more rarely

B. Total generation would increase ~50% by 2035 to meet electric demand, as coal would retire rapidly



1. Gap between electric power demand shown previously and increased generation is due to load and transmission losses and additional transmission flows from Canada (not shown)
2. Includes hydrogen blending, as detailed later in the document
3. Carbon capture and storage (CCS) involves capturing the carbon dioxide produced by power generation, transporting it; and then storing it deep underground
4. "Other" includes geothermal, oil, and biomass and biogas plants

Source: McKinsey EPNG practice

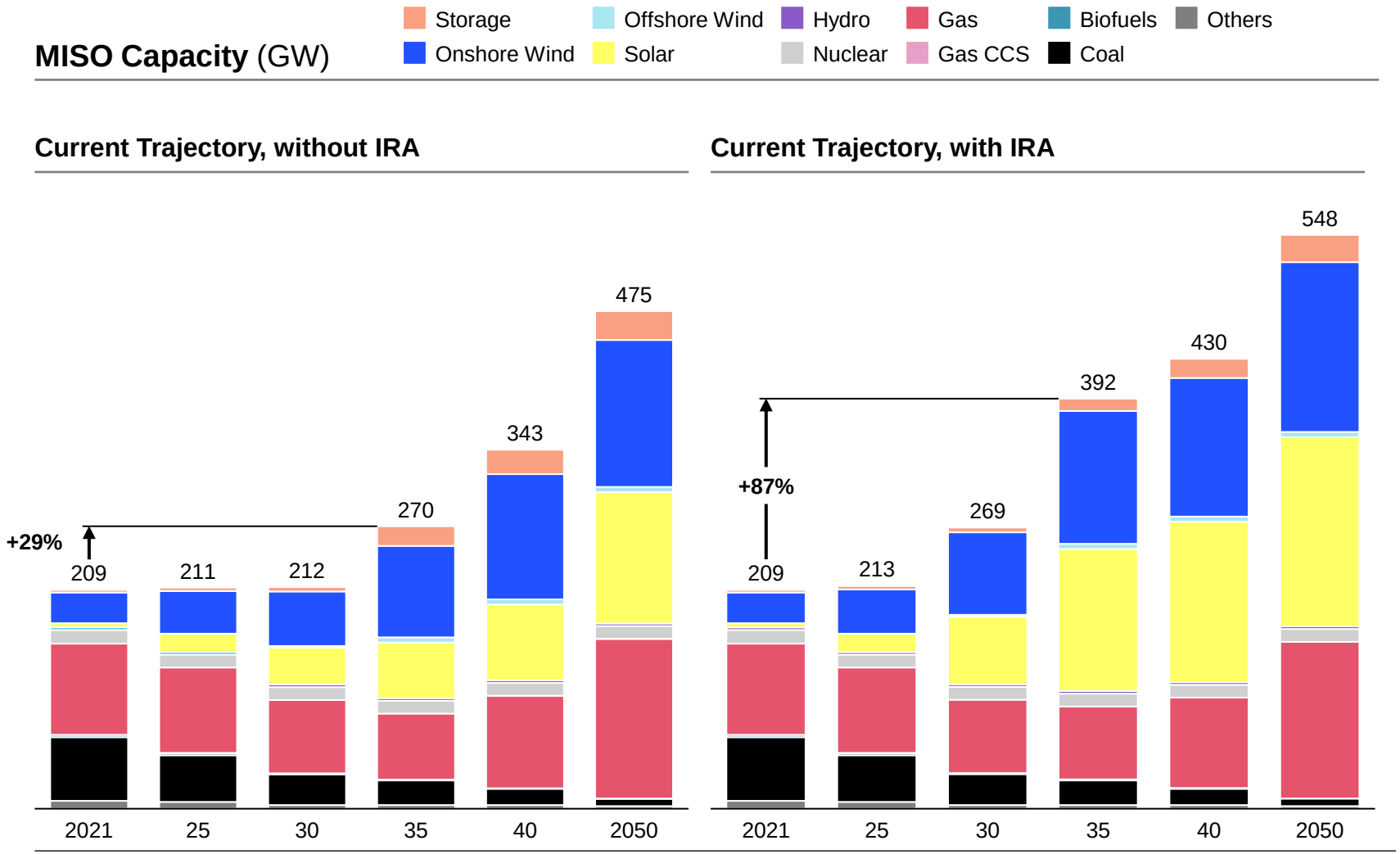
Takeaways

By 2035, ~55% of total generation would come from wind and solar. And an additional ~17% would come from hydro and nuclear

Gas volumes grow through 2030 as demand increases and coal comes offline, before declining in the 2030s as renewable deployment continues to accelerate

B. MISO would see almost 50% increase in capacity by 2030, and doubling by 2035 with the IRA driving accelerated solar and wind

MISO Capacity (GW)



Source: McKinsey Power Model

Takeaways

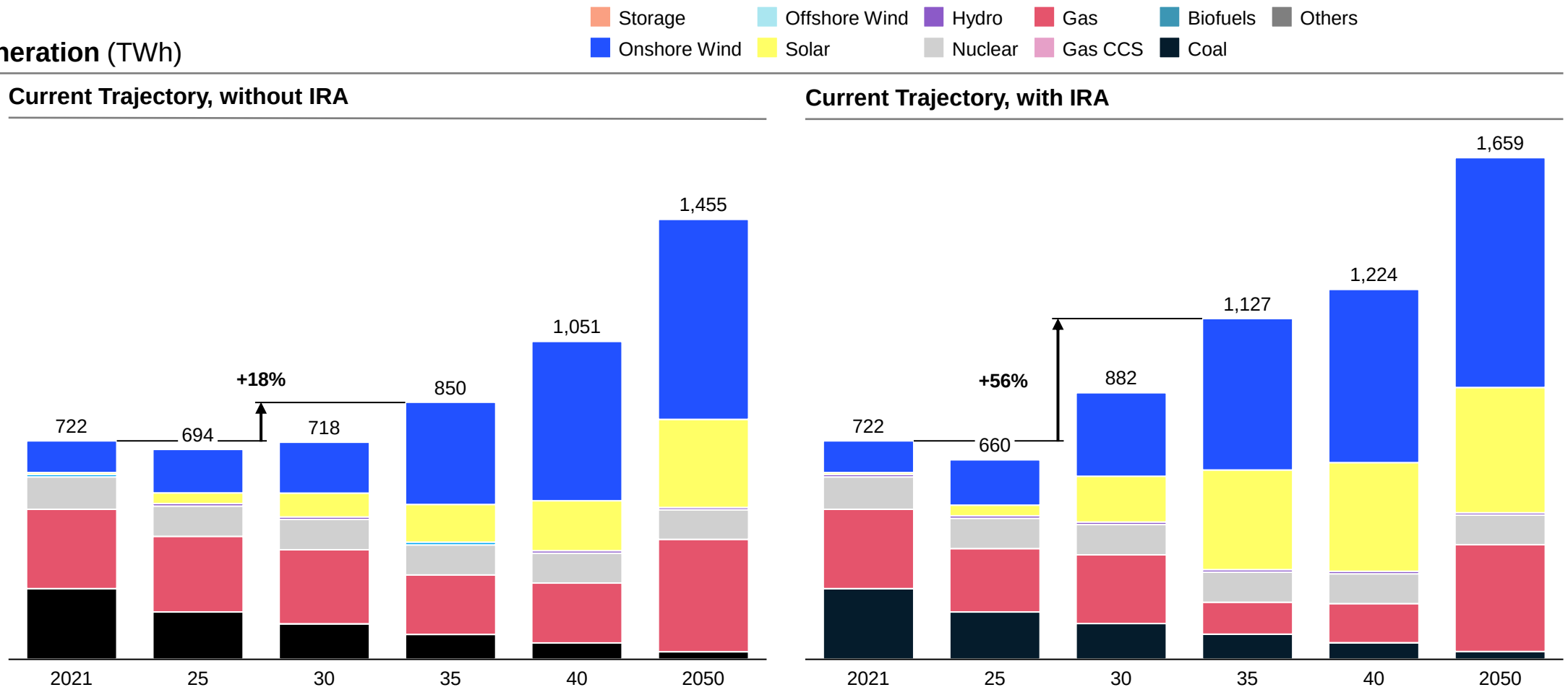
Over 135 GW of new solar and 130 GW of new onshore wind capacity is forecasted to be built by 2035, though challenges related to supply chain, labor, permitting and siting, and transmission remain

Coal is likely to be mostly phased out across MISO by 2050

While gas capacity declines in the 2030s, additional capacity is needed in the 2040s and 50s

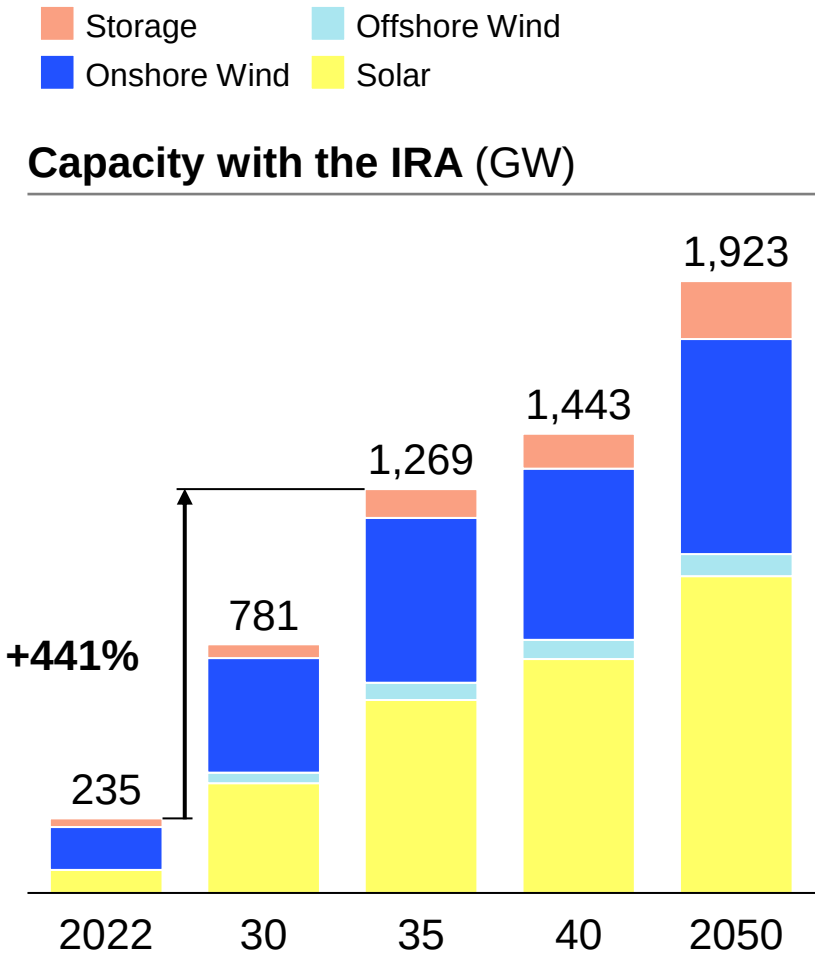
B. MISO would see a sharp rise in generation, with majority coming from solar and wind while coal phases out and gas declines

MISO Generation (TWh)



Source: McKinsey Power Model

B. Renewable capacity would increase significantly, but developers will face more complex decisions to differentiate themselves



Opportunities to differentiate renewable offerings:

Secure advantaged interconnect: Interconnection to power grid is the main driver of cost and time overruns. Concerns around the availability of suitable land will grow, further complicating the sourcing of suitable land close to available grid interconnection capacity

Secure stable offtake at low risk: Projects will increasingly require complex and higher risk offtake relationships such as direct contracts with C&I customers or taking merchant risk for renewable projects

Bring local scale, expertise & insights: Local scale is critical to reduce procurement, development, and execution costs and develop insight to local permitting and land use debates. As the supply chain expands substantially to accommodate this volume of annual installs, a mix of global procurement scale and local pool for labor and services will be key

Source: McKinsey EPNG practice

C. The need for flexible resources will increase as the power sector decarbonizes

2020 - 2025: Current state renewable uptake

Dispatchable gas and coal resources balance current fluctuation in customer demand and renewable supply except in extreme circumstances

2025-2030: Significant growth in variable capacity

Hourly load flexibility becomes increasingly valuable to grid operations

ISOs can continue to reduce baseload / fossil fuel power and utilize storage, demand management, and renewable curtailment to manage the grid

Beyond the 2030s:

Baseload coal is largely retired during the 2030s. Without low cost, flexible resources, the system faces new challenges for seasonal flexibility that are most acute in northern regions where winter peaks are most pronounced. Gas remains online, though utilization declines. Alternate solutions, like long duration energy storage, could be deployed

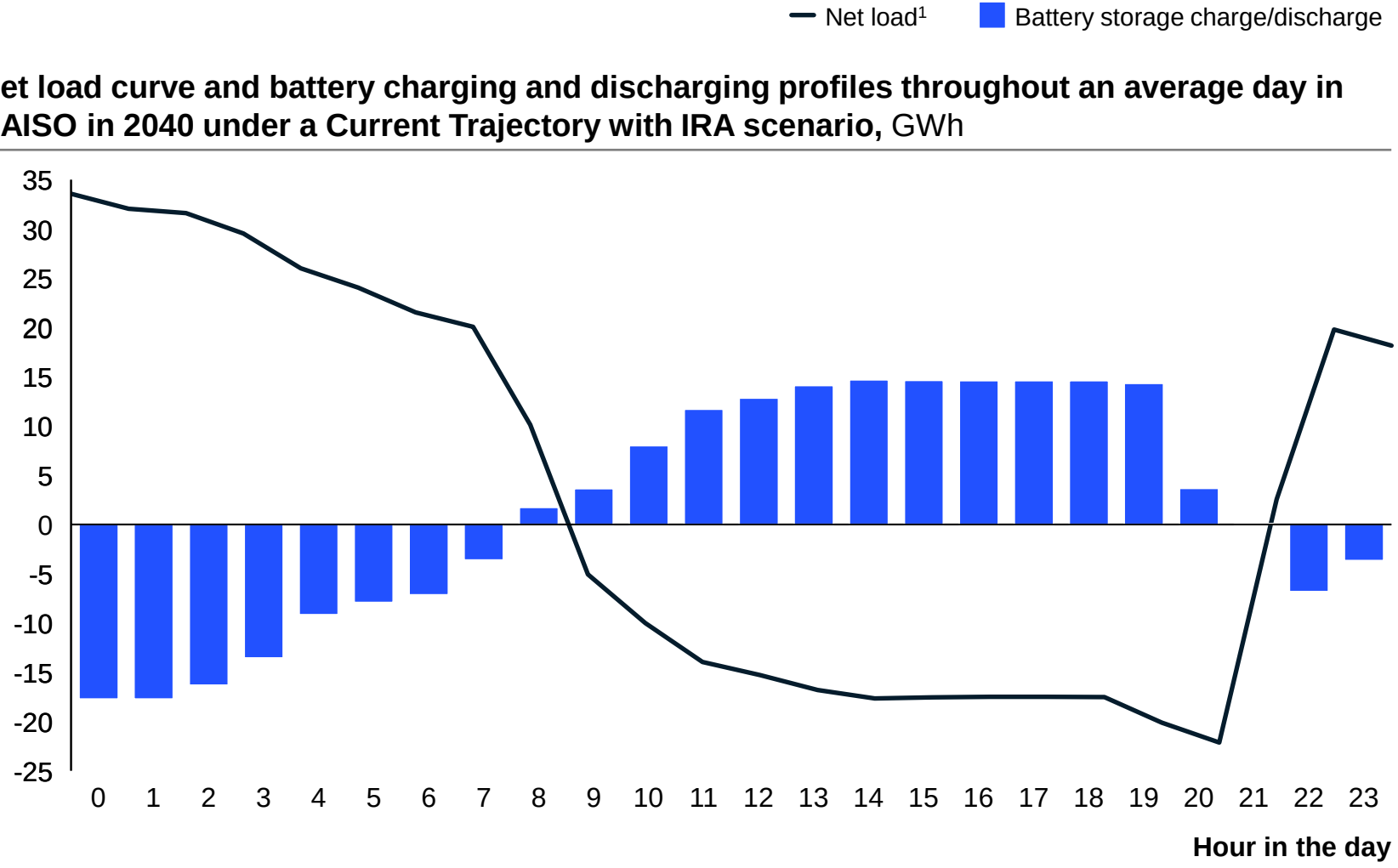
Where flexibility challenges will likely be greatest

CAISO ercot ISO new england New York ISO Independent System Operator pjm SPP Southwest Power Pool MISO

Source: McKinsey EPNG practice

C. In markets like CAISO, storage capacity would be needed to manage intraday fluctuations in solar generation

Net load curve and battery charging and discharging profiles throughout an average day in CAISO in 2040 under a Current Trajectory with IRA scenario, GWh



1. Net load: solar and wind generation profiles subtracted from the bulk load profile

Source: McKinsey EPNG practice

Takeaways

As load increases and load profiles shift by 2040, there is a **greater need for storage capacity to balance the intraday fluctuations** in solar generation

Battery storage also plays an important role at night when solar generation is not present and wind generation might not be enough to serve demand

The size of batteries would expand: Battery duration expands expand from 2-4h today to 6-8h by 2040, to support much longer durations of solar unavailability

C. Sources of flexibility will play a role in integrating low carbon variable energy into the power sector

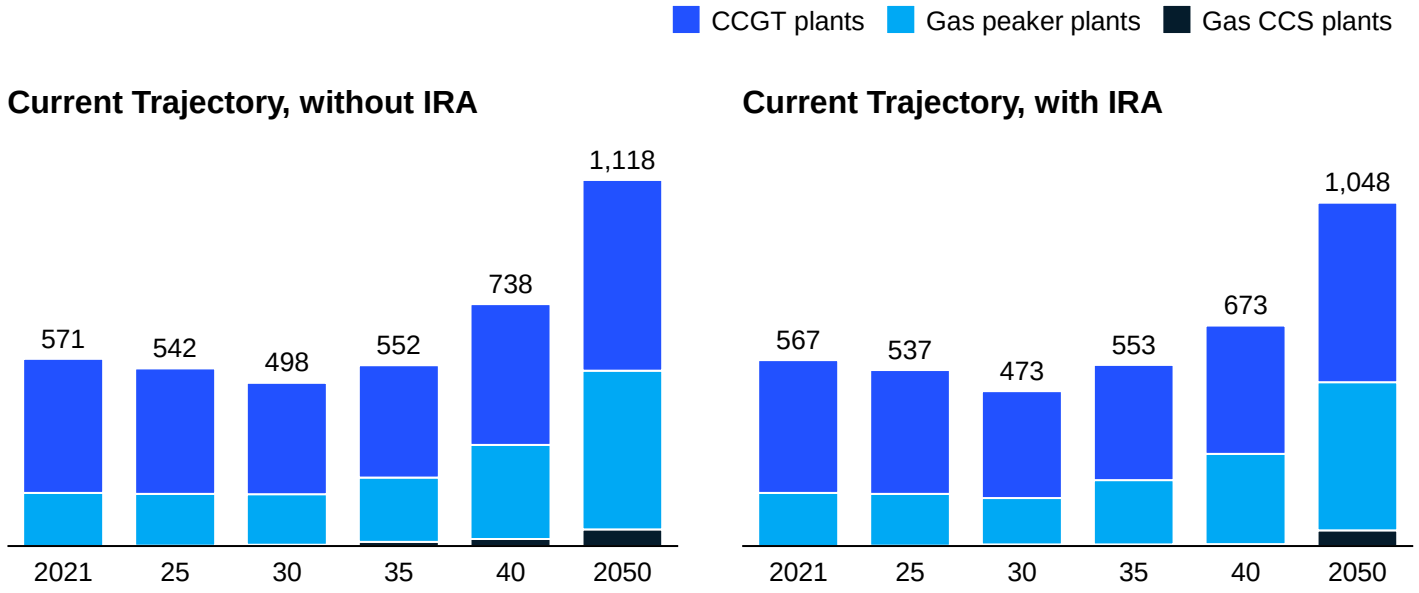
Scale-up of wind/solar comes with challenges as production is variable and not dispatchable

Generation source | Negative emissions | Low/zero carbon

Sources of flexibility	Tailwinds	Headwinds
New fission/fusion	• Nuclear is clean and provides baseload power without intermittent generation	• Newest techs not commercialized, long history of cost overruns on recent projects
Fossil CCS plants[1]	• Allows grid operators to continue 'without much change'	• Not-yet scaled – technology or CCS infrastructure • High capex limits economic opportunity as peakers
Biofuels with carbon capture	• One of very few sources of negative emissions, thermal and dispatchable	• High cost, low availability of at-scale fuels • High capex limits economic opportunity as peakers
Drop-in biofuels for thermal plants (biomethane)	• Allows plant and grid operations to continue "without much change"	• High cost, low availability of at-scale fuels
Hydro reservoir	• Large reservoirs allow plants to mimic dispatchability of gas/coal w/zero emissions	• Remaining potential is low, and public opposition to new build is high
RE Curtailment	• Overbuild+curtailment is a simple method to achieve more consumption of VRE	• Increases the cost of power, limited ultimate potential; Contracting is difficult
Transmission expansion	• Increasing the flow of low-cost electricity from VRE-rich regions should reduce costs	• Siting is particularly difficult in many cases • Project timelines are long, and costs are often prohibitive
Battery storage	• Capable of participating in many flexibility value streams; rapidly growing market	• Practically limited duration to intra-day balancing
Mechanical storage	• Pumped hydro is the largest storage technology globally; well-established	• New-build cost are high for PHS/ siting remains a challenge; emerging technologies are costly/pre-commercial
Mid/long duration chemical storage	• Multi-day storage to displace gas peakers has gained momentum in planning discussions	• No cost-effective technologies deployed at scale • Round-trip efficiencies often very low
Bi-directional loads (e.g., V2G)	• Growing fleet of electrified vehicles offers significant temporal and spatial opportunity	• Charging demand quite often inflexible, and the case to car owners to 'use up' cycles on EVs not yet established
Aggregated demand response (e.g., home loads)	• Massive capital asset base (e.g., water/space heaters) can be unlocked with sensors and controls	• Customer acquisition remains a challenge • Loads typically only shiftable by a few hours at most
Large-scale opportunistic loads	• Demand-side peakers/dispatchable demand create value potential for products and electricity system	• Capex for assets and scale-up model not yet demonstrated; market mechanisms not universally in place
Direct air capture	• Potential to be the breakthrough technology which could eliminate net global emissions	• Not yet demonstrated at scale, extremely costly and energy intense; effective price of carbon captured very high

1. 100% capture is difficult in post-combustion systems, but emissions rates are much lower than unabated fossil plants

D. Gas generation increasingly provides firm capacity-value; gas capacity increases while utilization declines



	Current Trajectory, without IRA						Current Trajectory, with IRA					
CCGT capacity factor, %	35	33	29	29	26	24	35	33	37	25	24	24
Peaker capacity factor, %	4	4	3	2	2	2	5	4	4	2	2	2
Gas with CCS capacity factor %	N/A	44	40	27	27	25	N/A	47	29	29	27	29

Source: McKinsey EPNG practice

Takeaways

Gas capacity would continue to grow in the 2030s with the IRA to provide **seasonal flexibility** and support a **significantly higher electric load**

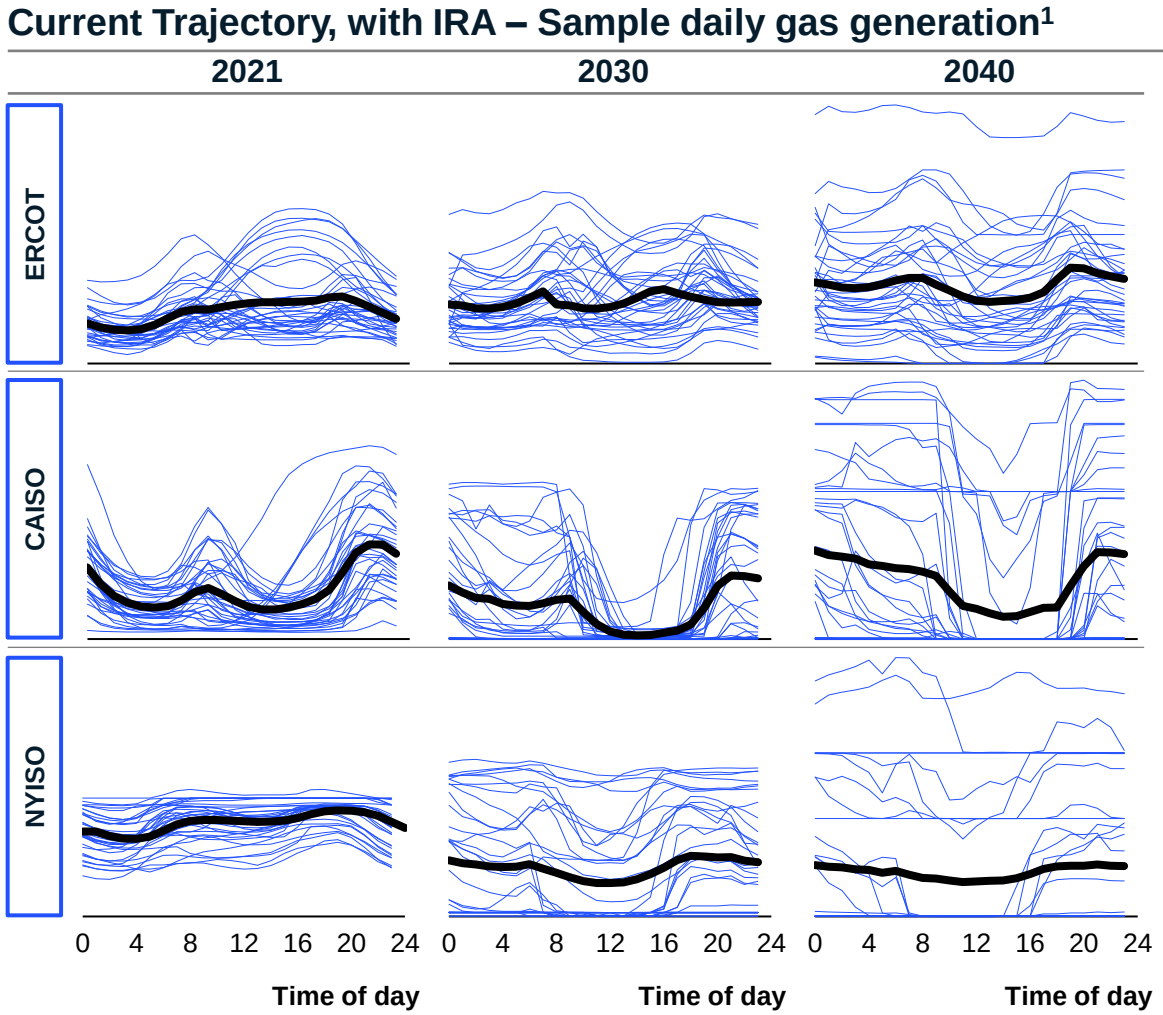
CCGT plants would continue to get built, but their capacity factor would eventually decline below 25%

Gas plant operators likely to choose between retrofitting their plants for **carbon capture and storage (higher CapEx decision) and blending hydrogen (higher OpEx decision)** to reduce the carbon footprint of gas, particularly after 2035

To fully decarbonize the system, more gas capacity would be needed in the 2020s and almost all new gas capacity built after 2040 would include CCS capacity

D. In all regions, gas cycles more throughout the system; average gas generation also declines each decade

Current Trajectory, with IRA – Sample daily gas generation[1]



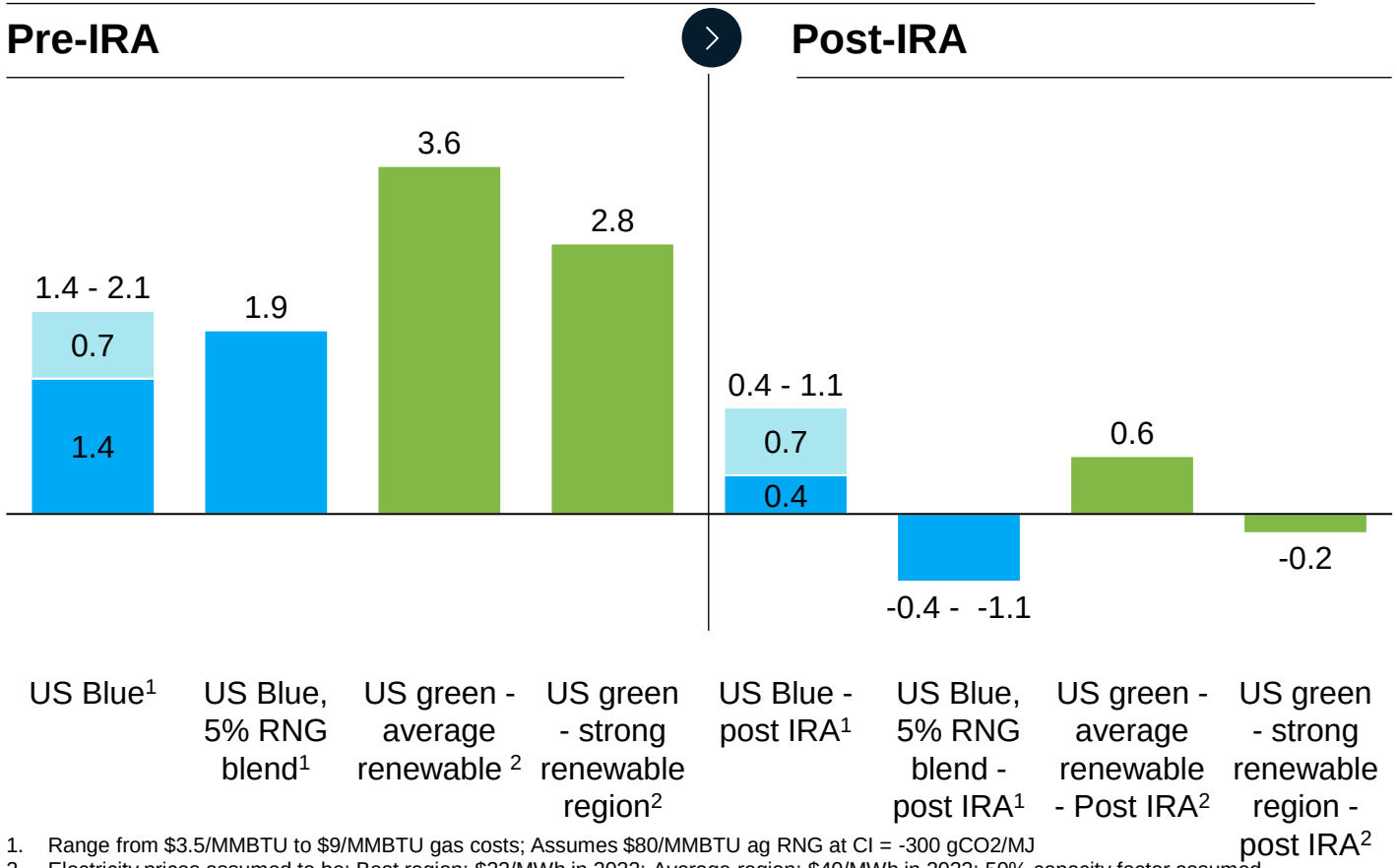
- All ISOs would see **increased gas cycling** as variable renewables (especially solar) become a larger portion of the generation stack
- At times of day when renewables are abundant, gas plants could be offline or at minimum generation level. But evening peaks frequently require gas generation – meaning that **flexible gas plants become increasingly important**
- The effect becomes **more prominent in solar-heavy regions,** such as ERCOT and CAISO
- In a system that decarbonizes fully by 2035, these dynamics become more pronounced earlier, with more variable and increased gas cycling in the 2030s

1. Not drawn to scale across ISOs

Source: McKinsey EPNG practice

E. With the IRA, green hydrogen is more attractive in the US, though economics are significantly improved for both

Levelized cost of H_2 production in the US after applying H_2 PTC, 2022 ($/kg)[3] a



1. Range from $3.5/MMBTU to $9/MMBTU gas costs; Assumes $80/MMBTU ag RNG at CI = -300 gCO2/MJ
2. Electricity prices assumed to be: Best region: $22/MWh in 2022; Average region: $40/MWh in 2022; 50% capacity factor assumed
3. Assumes green H2 and 5% RNG blend blue H2 gets $3/kg credit and blue gets $1/kg credit

Source: McKinsey Hydrogen Model

As electrolyzers and renewables continue to come down the cost curve, **green hydrogen could become cost competitive with blue without IRA incentives**

Electrolyzer deployment also accelerates as renewable penetration increases and the value of electrolysis as a flexible demand resources improves

With carbon intensity-based incentives in the IRA, green hydrogen is very cost competitive. Investment in green hydrogen likely to increase – though **challenges around scale-up (labor, supply chain, manufacturing), permitting/siting, and renewables deployment could slow deployment**

E. As volume of natural gas delivered declines, gas networks will need to consider new roles

	Transformative options for the gas utility to consider	Timeline for at scale deployment (2020 – 2050)
Natural gas/renewable natural gas	RNG production and supply	
	Core NG network safety	
	NG network digitization and automation	
	Transmission network leak reductions	
Downstream, customer, end-use	Non-pipe alternative programs	
	Gas energy efficiency	
	Gas low income and other support programs	
	Fuel cells	
Hydrogen	H2 transmission system upgrades	
	H2 production[2]	
	New H2 network (transportation)	
	Fueling stations	
CCS	Carbon capture and storage pipelines	
	CO2 storage capabilities	

1 Range of reduction highly driven by state policies on electrification

2 Either blue or green hydrogen

Source: McKinsey EPNG practice

Key insights

As heating electrifies the **role of methane in gas networks subsides**, leading to a gradual ~15+ year deceleration of NG volumes

Gas networks could trend towards a long-term **blended, cleaner gas grid** (NG plus hydrogen and RNG)

Business model of gas networks would transition to **a capacity-based, instead of volume-based** model

Gas network owners could now contemplate a “combined, full system” view of decarbonization across gas and electric that manages resiliency, affordability and decarbonization tradeoffs

F. The Energy Transition will create challenges for our power grids

Congestion – at the T and D levels

Buildout of cheap, centralized renewables will pressure transmission corridors and increase the value of DER sited near urban load

Renewable interconnection

Uptake of RES & DG are raising new issues on the T&D grid (e.g., power quality) straining the utility's resources to process thousands of interconnection requests

Variable intra-day loads

Increasing adoption of intermittent DERs – EVs, solar, heat pumps – along with more renewables to drive less predictability in circuit load patterns at a nodal level

Common gas and electric network planning

In a highly electrified, high resilience world, gas infrastructure will be relied on to backstop electric services as well

Land use and permitting

NIMBY issues and interstate co-ordination and permitting challenges are delaying the buildout of much-needed cross-regional transmission

Higher resiliency standards

A more electrified economy (transportation, buildings) will come with higher demands for reliability and resiliency, even as climate change stresses grid resiliency and design standards

Data and communications

The growth in digital grid devices and data (3rd party and utility-owned) is straining the capability of existing utility communication networks

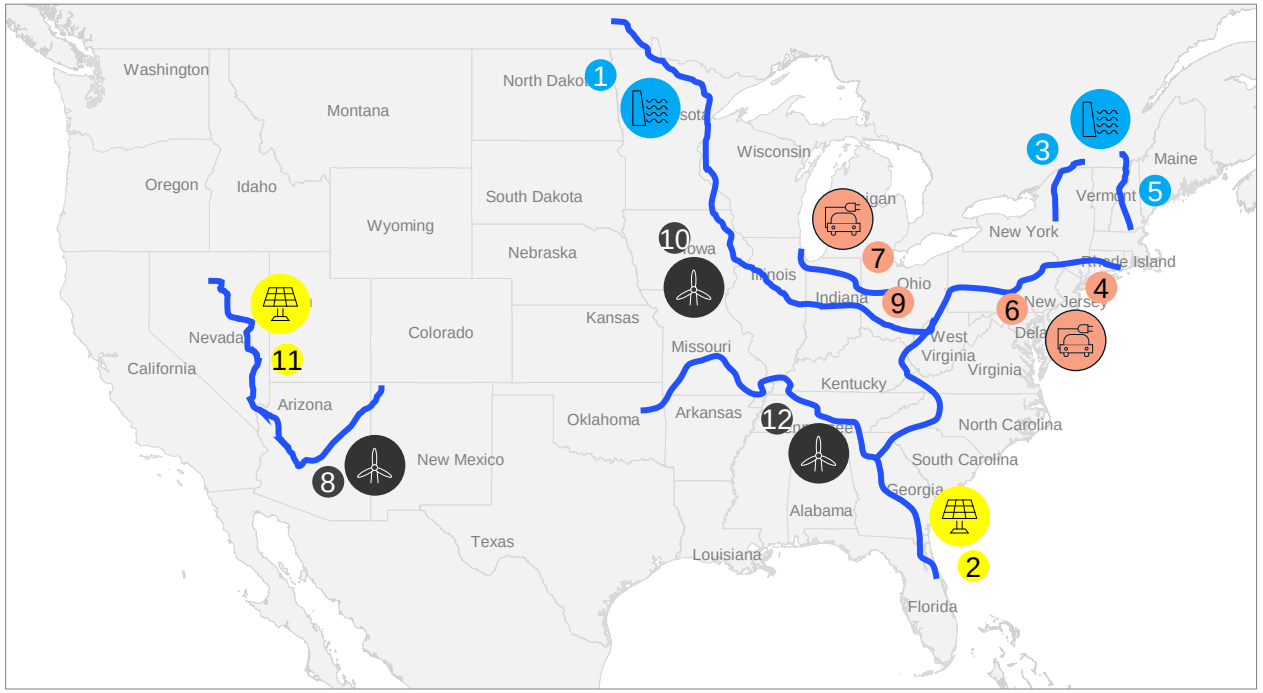
DER aggregation

More and more digital devices that need to be interconnected, monitored, and controlled on the grid, and aggregate to provide grid services

As the power system evolves to address these challenges, affordability will be critical. Capital efficiency, rate design, customer education, and other levers will be needed to enable affordable power

G. Transmission congestion and constraints would grow, driven by changing power flows and inadequate capacity of local grids

Most frequently congested US interregional transmission corridors in a decarbonized power system scenario



Congested corridor

Transmission corridor rank

Abundant solar

Abundant wind

Abundant hydro

Urban congestion

1 Alberta ↔ Northern MISO
2 FL ↔ Southeast
3 Quebec ↔ Northern ISO-NE
4 Downstate NY ↔ PJM-NJ/MD
5 Quebec ↔ Upstate NY
6 PJM-NJ/MD ↔ Southeast
7 PJM-Chicago ↔ PJM-OH
8 WECC-CO ↔ WECC-Southwest
9 MISO-IL ↔ PJM-OH
10 Northern MISO ↔ Southern MISO
11 Northern CA ↔ WECC-Southwest
12 Southeast ↔ SPP

Transmission congestion would become more acute as renewable capacity continues to be added away from load centers

Interregional **transmission planning and coordination** can help alleviate these grid constraints

Local and intra-regional transmission congestion would also need to be addressed. Today it causes interconnection process delays, long interconnection queues and sometimes even withdrawals of projects from the queue

Source: McKinsey EPNG practice