SEU 2021

STATE OF THE ELECTRIC UTILITY

SURVEY REPORT

UTILITY DIVE

CONTENTS

INTRODUCTION AND SUMMARY

The COVID-19 pandemic had a significant impact on the electric utility industry in the U.S. in 2020, as it did for the economy overall.

But as the year went on, one thing became increasingly clear — the broad trends that have emerged in the sector in recent years persisted, and the forces propelling those trends are getting stronger.

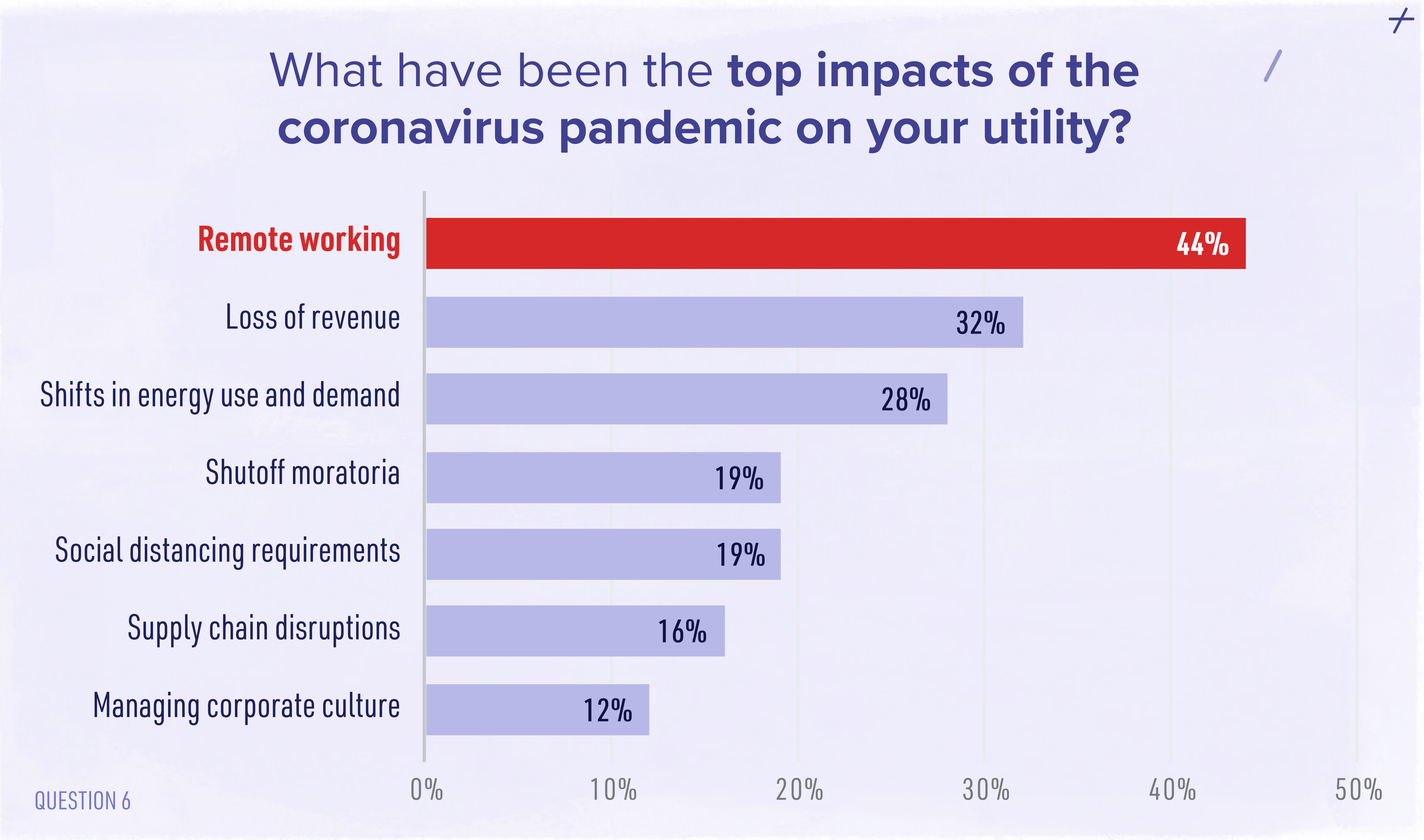
After dips earlier in the year, U.S. wind, solar and storage saw significant capacity additions in 2020, propelled by economic, policy and other drivers. The new year could bring even greater deployments as more and more power providers and purchasers choose cleaner generating options.

At the same time, utilities and regulators are grappling with the best ways to handle increasing amounts of distributed energy resources on the power system — from rooftop solar to behind-the-meter storage — while exploring new business and regulatory models to ensure desired outcomes.

Utility Dive conducted its latest survey of electric utility professionals last fall as the presidential election results were becoming increasingly clear, but while the outcome in the Senate was far from certain. With the victories of Sens. Raphael Warnock and Jon Ossoff in Georgia, the Democrats now have the slimmest of majorities in Congress. While that bodes well for the clean energy transition overall, the concerns of Republicans and some Democrats over the impacts of the sector's transformation on the workforce, power system reliability, and other issues will need to be addressed to keep the momentum going.

As seen by the passage of the Energy Act of 2020 in December, bipartisan progress is possible. The question now is how much can Democrats push through additional measures to realize President Joe Biden's target of achieving net-zero carbon emissions in the U.S. electricity sector by 2035.

Utility Dive heard from hundreds of utility professionals from across the country for this year's survey, many of them at the vice president level and above. Full results of the survey can be found in the appendix to this report and the sections ahead will dive into more detail on many of the key findings discussed in this introduction, but here are some of the most notable items, starting with the current pandemic.



COVID-19 Impacts

Survey respondents said the biggest impacts of the COVID-19 pandemic on the electric utility industry have been remote working (44%) and loss of revenue (32%), when asked to select the top two among nine impacts. However, despite the multiple impacts, U.S. electric utilities have been able to weather the pandemic relatively well overall, said Jim Thomson, U.S. power, utilities and renewables leader at Deloitte. Many utilities have pandemic plans and put them into effect quickly — for example, dispersing call center operations to workers' homes and using digital solutions (such as drones and other technologies) to reduce the number of employees in the field. "It was impressive to see how companies responded," Thomson said.

"Utilities have done a good job of adapting," though financial impacts, including bad debt, are rising, said Sharon Allan, chief strategy officer at the Smart Electric Power Alliance.

But while the moratoria on shutoffs have slowed cash flow, "for the most part, there will be a true up mechanism for most utilities, whether it's in a future rate case or rider," said PA Consulting energy and utilities expert Jeremy Klingel.

Another impact of COVID-19, Allan said, is regulatory. Some projects that involve green tech have been delayed. The new administration under Biden brings an urgency for utilities to move fast and get in front of their carbon goals. But if rate cases are delayed, leading capital projects to become delayed, that will start to add pressure for utilities as 2021 continues.

As for what variables have been most important in how well utilities have handled the pandemic, many factors are at play, Allan said, including their mix of commercial and industrial customers and their proximity to fuel sources.

It's not that some utilities are responding better than others, she added. They are responding based on their particular situations and the challenges they face.

Beyond loss of revenue and remote working, other significant impacts on electric utilities from COVID-19 include shifts in energy use and demand, shutoff moratoria, disruption in capital projects and social distancing requirements.

However, none of these additional impacts was selected as a top two by more than 28% of respondents.

“We’ve seen a shift from the early days of the pandemic, when it was almost as if the industry thought that maybe it could hold its breath and make it through, to the realization later in the year that this is going to truly change the way that we do business. And so things that perhaps before were a bit more buzzwords, such as ‘predictive maintenance,’ are now a necessity,” Klingel said.

How long will COVID-19 impacts last?

As for how long the business impacts from COVID-19 will continue, slightly more than half of respondents said six to 12 months, while a sizable number said one to three years. Few respondents expect the impacts to last beyond three years.

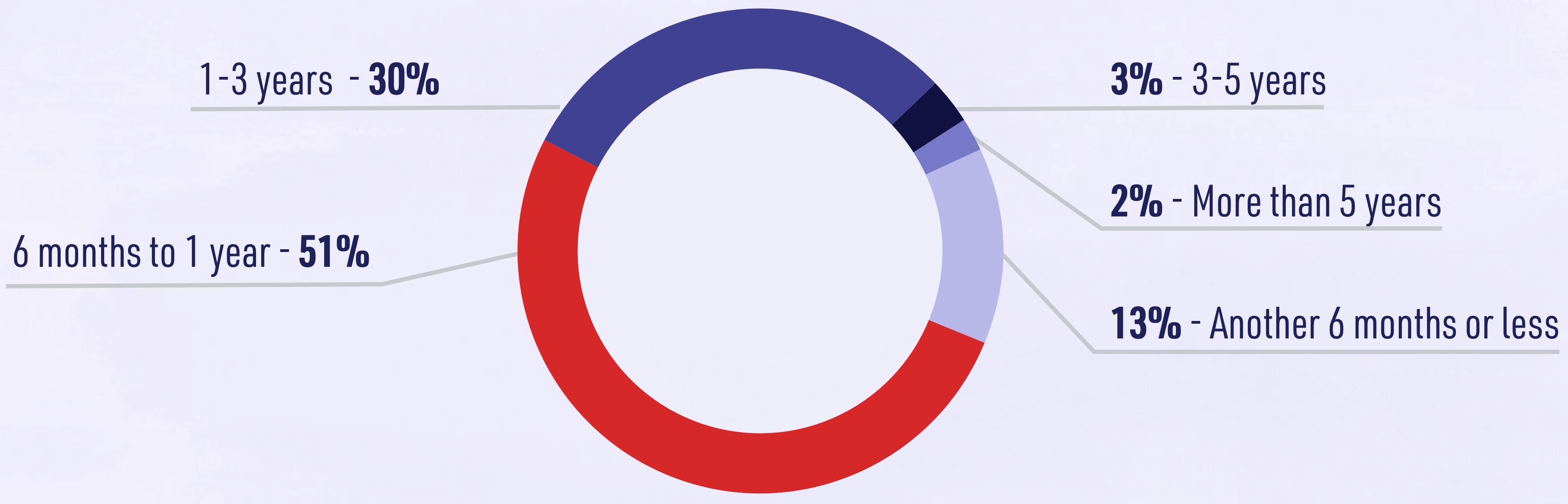
The ability of companies to return to normal depends on how quickly the U.S. can reach a tipping point on vaccination, Allan said.

The survey took place as the first COVID-19 vaccines in the U.S. were heading to regulatory approval and eventual deployment. While vaccination programs are underway, they’ve proven to be challenging and the impacts of COVID-19 on the electric utility sector will probably last at least another six to 12 months, with some changes made in response to the pandemic likely becoming permanent, Thomson said.

For example, utilities may not necessarily reconstitute their call centers at the same in-person level as they had prior to the pandemic, he noted. One thing that’s fascinating to watch, he said, is how utilities have embraced digital tools and new ways to connect with customers during the pandemic. It has changed the way companies think and what customers expect, and Thomson predicts that will continue.

But while some changes due to the pandemic might become permanent, other impacts, such as the rise in residential load and decline in commercial and industrial loads for many utilities, will likely subside over time. Still, some expect residential load may settle somewhat above pre-pandemic levels as the working-from-home trend carries forward.

How long do you expect the business impacts of the COVID-19 pandemic on your company to continue?



QUESTION 7

Load trends and drivers

COVID-19 was by far the biggest driver of load change for utilities in 2020, with 58% of respondents selecting it among a list of seven options.

But utilities have seen differing degrees of load impacts from COVID-19 depending on where they operate and the types of customers they serve, Thomson noted. Utilities that depend on large commercial or industrial operations, such as auto manufacturing, for example, never made up for large facilities shutting down, while utilities with more residential customers to begin with saw a less dramatic load shift and a lower impact overall, he said.

While COVID-19 has clearly been the top driver of load change for utilities over the past year, energy efficiency and demand side management are also leading factors and have kept demand growth flat for more than a decade, Thomson said.

It's too early to know what the biggest drivers will be going forward, Thomson added. That will depend partly on what changes in policy occur under the Biden administration, including the potential tighter fuel economy standards or other policies that promote transportation and building electrification.

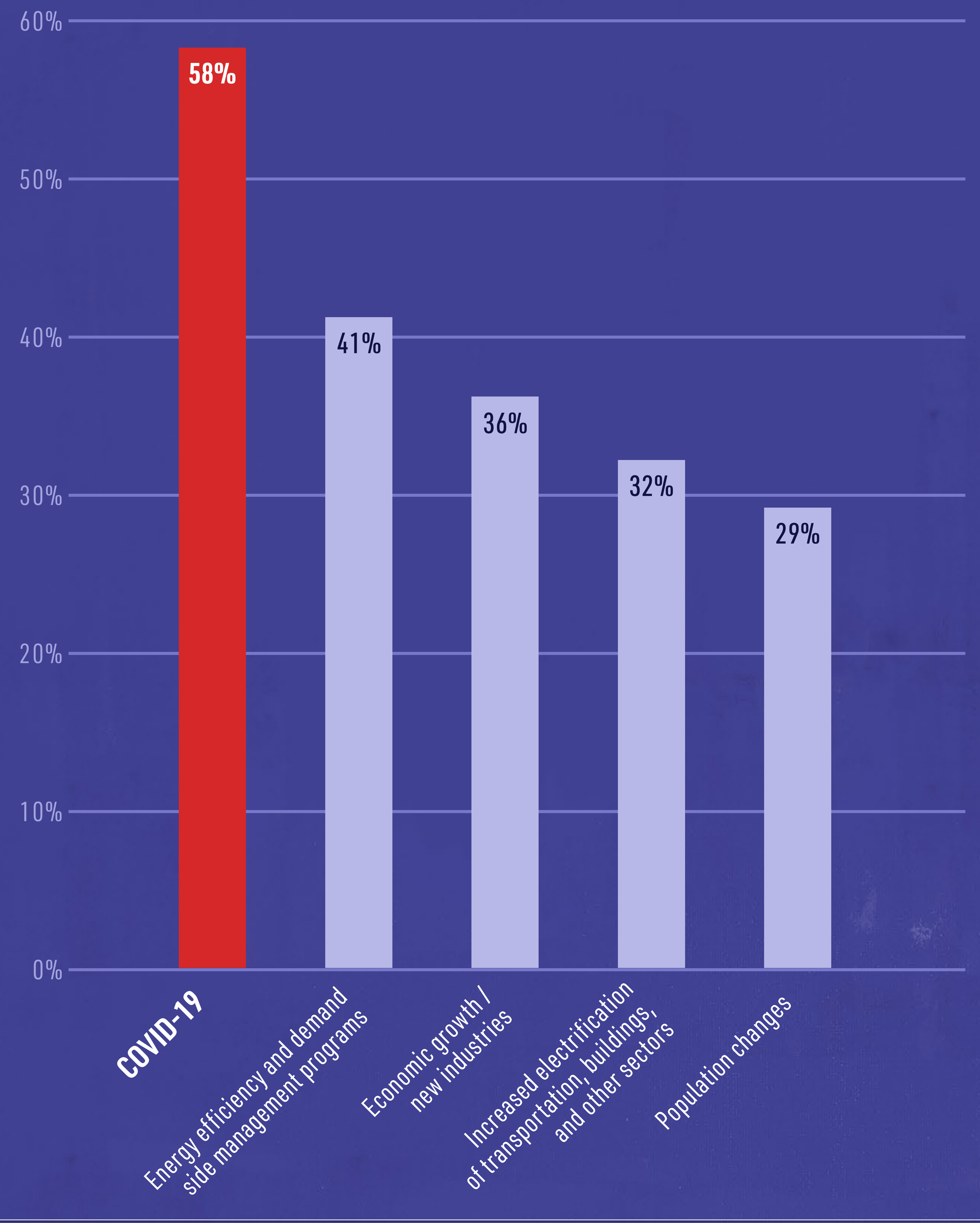
SEPA's Allan was more confident about projected top drivers. By far, the biggest source of load change will be the electrification of transportation and buildings, she said. But electrification won't be a driver of load change so much as the outcome of utility moves to decarbonize and change how they interact with customers to meet their needs, she added.

Survey respondents offered a number of other load drivers, beyond the seven options provided, including weather, the downturn in the oil and gas industry, and distributed energy resources.

The impacts of COVID-19 can also be seen in the near-term expectations for load shifts among different customer segments in the power sector.

Reflecting the shift to remote work spurred by the pandemic, a significant percentage of survey respondents, some 71%, expect net load growth to increase in the residential sector, while 46% expect it will decrease in the commercial sector.

What have been the **top drivers of load change** for your utility?



QUESTION 9

A smaller percentage (31%) see net load growth decreasing in the industrial sector. Overall, however, half of the respondents expect stagnant loads, while 29% expect an increase and 21% a decrease.

While COVID-19 has been top of mind for many companies over the past year, utilities have been consistent in what they consider to be the top issues they face.

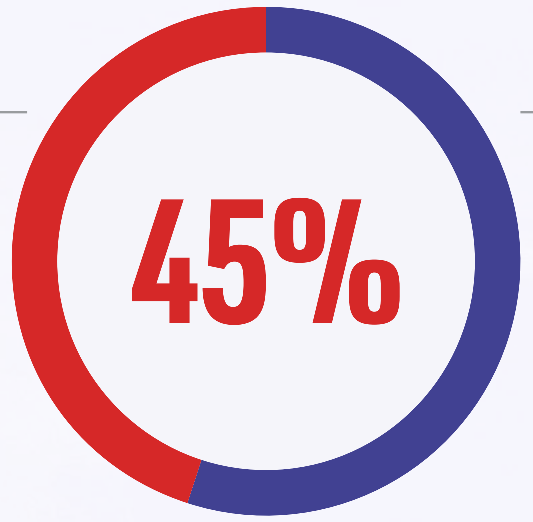
Top issues for utilities

As with Utility Dive's prior State of the Electric Utility Industry survey, the top issue for utilities among a list of about a dozen is renewables, sustainability or the environment, with nearly half of respondents saying it's among the three most important issues facing their organization.

That puts it significantly ahead of the other options offered in the survey. And with utilities' growing focus on climate and other sustainability issues, driven by the need to meet the demands of legislators, regulators and customers, it is likely to remain a top issue.

The next tier of issues — chosen by anywhere from 21% to 29% of respondents — revolve mostly around reliability, security and resilience.

Which issues are currently **most important** to your organization?



Close to half of participants select
renewables, sustainability or the environment
as the most important issue facing their organizations.

There are six issues that are in the second tier of importance.

- 29% Reliability of retail distribution grid
- 28% Climate change impacts and resilience
- 27% Bulk power system reliability
- 26% Aging grid infrastructure
- 24% Cybersecurity and physical security
- 21% State regulatory model reform

Third tier issues are:

- 18% Electric vehicles
- 18% Distributed energy resources
- 17% Generation retirements and/or stranded assets
- 15% Federal energy policy uncertainty

QUESTION 10

The six issues selected by the highest percentage of respondents remained roughly the same from the 2020 report. Two exceptions: Distributed energy resources dropped out of the top six in 2021 — going from 29% of respondents selecting it to 18% in 2021. And climate change impacts and resilience jumped from 18% in 2020 to 28% in 2021 to enter the top six.

Deloitte's Thomson agreed that renewables, sustainability or the environment should be the top issue for utilities.

"How to deliver clean and reliable power in the face of an aging grid and natural disasters while keeping everything affordable and secure … is definitely top of mind," he said.

PA Consulting's Klingel concurred on the primacy of renewables, sustainability and the environment for utilities.

"The buzzwords that you mentioned … are being pushed across the board. Whether a utility or not, it's impacting companies' valuations," he said. "It's something that's, quite frankly, important to all of us in one way or another, as long as it's economically viable," he continued.

"Utilities have been putting [these pieces] in place, whether that's renewable integration plans, whether that's their own development, whether that's incentivizing others to develop out renewable energy assets. That will continue — all those plans will be in place. But I think it's important to realize, though, the time for that to scale is going to be 10 years, 15 years — not three to five years. And so … it's going to be a long-term priority," he continued.

But you can't add too many renewables without upgrading the grid, SEPA's Allan said. "You can't have clean without modern. To bring on new technology, you need to make sure it's done in a safe and economical way." That's why issues like reliability appear in the second tier of top priorities for utilities.

Even fewer respondents pointed to electric vehicles, federal energy policy uncertainty, or generation retirements as a top three issue among the list of options in the survey. Some offered other responses, including wildfire risk; workforce retirement, needs and training for future grids; keeping rates affordable; serving low-income communities; and building adequate transmission to serve increasing load.

> "**You can't have clean without modern.** To bring on new technology, you need to make sure it's done in a safe and economical way."
>
> **Sharon Allan**, chief strategy officer, Smart Electric Power Alliance

A C-suite executive at a small Midwest public power utility also cited "significant ongoing litigation."

But renewables, the environment and related grid impacts are clearly top priorities for utilities and are reflected in respondents' views about how their resources are likely to change in the coming years.

A changing power mix

Solar and wind have seen significant growth in the U.S. and are poised for even more in the years to come. If Biden can implement his 2035 net-zero carbon target for the U.S. power sector, that would be a game changer, Thomson said.

Some 90% of survey respondents expect an increase in grid-scale solar over the next 10 years, followed closely by distributed energy resources at 87%, grid-scale battery storage at 86%, and wind at 74%.

While solar outpaces wind in terms of overall growth expectations, there's an even greater discrepancy between those who expect solar to increase significantly in the next 10 years (52%) and those who expect wind to increase significantly (29%). Klingel chalked up the discrepancy to the generally easier process of adding solar — from a procurement and construction standpoint — including permitting and connecting it to the grid. Wind projects are much larger, and the skill to build them is greater. "They're not always as easy to interconnect, there are permitting issues. ... I think there are just more obstacles to wind than there are solar," he said.

"All things equal, I think you would say they both have tremendous opportunity, but the path of least resistance is to put in grid-scale solar first versus a brand new greenfield wind project, which is going to be a very heavy lift," Klingel added.

Not surprisingly, the three resources with the highest share of respondents expecting a decrease in the next 10 years are coal, oil and nuclear. In the 2020 report, 13% of respondents expected a significant decrease in nuclear in the next 10 years; in 2021, that number increased to 18%.

That actually brings nuclear close to where it was in the 2017 SEU report, when 20% of respondents said it would decrease significantly over the next 10 years. But the biggest change in terms of a negative forecast from five years ago is with natural gas. In the 2017 report, 13% of respondents said natural gas would decrease

> "All things equal, I think you would say they both have tremendous opportunity, but **the path of least resistance is to put in grid-scale solar first** versus a brand new greenfield wind project, which is going to be a very heavy lift."
>
> **Jeremy Klingel**, PA Consulting energy and utilities expert

in the next 10 years. In the current report, that number has jumped to 30%, reflecting increasingly ambitious clean energy targets.

At the same time, however, nearly 38% of respondents expect natural gas capacity to increase in the next 10 years, indicating its continued importance to many utilities. And, while coal and oil will likely continue their declines, nuclear remains more of a question mark, given its potential role in meeting the growing number of clean energy targets and Biden's support for the technology.

These projected resource trends are borne out by the Federal Energy Regulatory Commission's forecasts, as shown in its Energy Infrastructure Update for December 2020.

The commission sees 36,691 MW of "high probability" net solar capacity additions over the next three years, 21,938 MW of net wind additions and 17,279 MW of net gas additions. On the flip side, it projects a 24,024 MW decrease in coal capacity, a 4,369 MW decrease in oil and a net 4,330 MW decrease in nuclear capacity over the next three years.

How do you expect your organization's **mix of power resources to change** over the next 10 years?

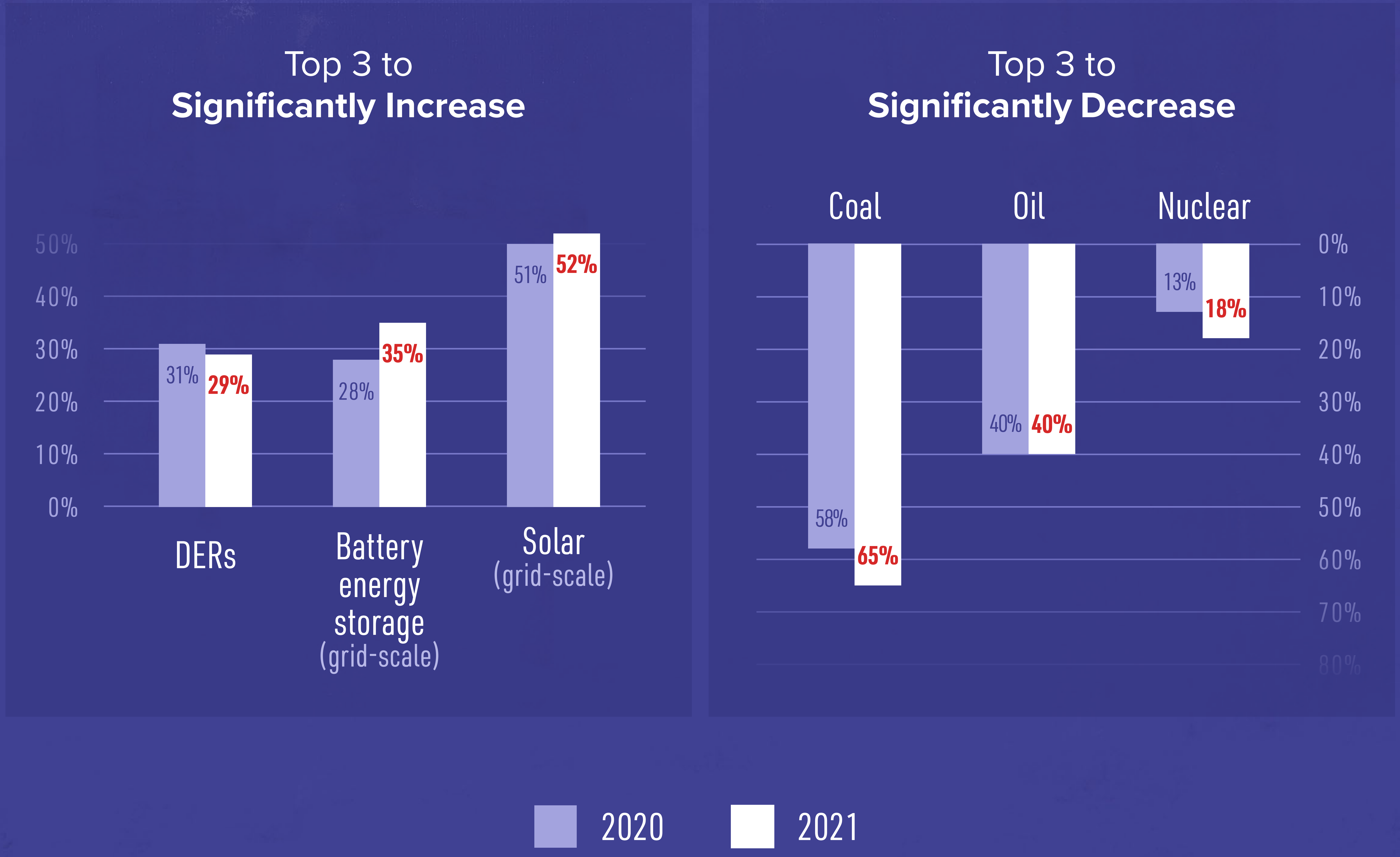


FIGURE 12

Which approaches are **most effective in decarbonizing the power system?**

50% ^ 7% FROM 2020
Financial incentives for renewable energy development

45% ^ 2% FROM 2020
Strong federal decarbonization policy, backed up with clear targets, regulation and enforcement

43% ^ 12% FROM 2020
Updated transmission infrastructure

37% v 1% FROM 2020
Performance-based rates or other strategies to shift the utility business model

36% v 4% FROM 2020
State policies and mandates

35% ^ 2% FROM 2020
Nuclear power support/expansion

23% ^ 5% FROM 2020
Carbon capture technology

20% ^ 2% FROM 2020
Voluntary energy industry measures

10% v 1% FROM 2020
Decarbonization is not an appropriate goal for the power system or for energy policy

QUESTION 14

Path to decarbonization

Renewables, sustainability or the environment was clearly the top issue for utilities in the current and prior survey, but what do utility professionals see as the best way to bring more renewables to the grid? More broadly, what do they consider the most effective way to drive the decarbonization of the power system?

While states and localities have been significant drivers in the shift to a less carbon-emitting power system, particularly in recent years, federal action remains the higher priority.

Half of the survey respondents pointed to financial incentives for renewable energy development as the most effective way to decarbonize the power system, followed by strong federal decarbonization policy at 45%, updated transmission infrastructure at 43%, performance-based rates or other strategies to shift the utility business model at 37%, state policies and mandates at 36%, and nuclear power support/expansion at 35%.

As with last year's report, about one-tenth of respondents said decarbonization is not an appropriate goal for the power system or for energy policy.

Financial incentives for renewables retained the top spot as the most effective decarbonization strategy, although the percentage picking it increased from 43% in the 2020 report to 50% in the 2021 report. But the biggest change came with transmission, which jumped from 28% in the 2020 report to 43% in the current report. This reflects growing recognition of the critical role new and upgraded transmission has to play in delivering renewable energy from where it's plentiful to where it's needed.

To decarbonize the power system, policy needs to come first, Klingel said. "Utilities react positively if they know that there is a path forward to where … there will be a regulatory construct that will support them being able to earn some rate of return. … Sustainability is wonderful, but it will not stand alone unless it's economically viable." Anything that can serve as a catalyst for utilities to move past start will be well received, he added.

While the highest number of respondents said financial incentives for renewable energy are the best way to decarbonize the power system, they picked no clear winner when it comes to the most effective way to get more renewables on the grid: Eight options were selected by anywhere from 7% to 17% of respondents.

Klingel expects to see infrastructure incentives in the next few years that will bolster renewables in the same way energy efficiency and the smart grid got a boost from the federal government during the 2008 recession and its aftermath.

> Sustainability is wonderful, but it will not stand alone **unless it's economically viable."**
>
> **Jeremy Klingel**, PA Consulting energy and utilities expert

"I think we're probably going to see a very similar focus here that's going to help advance not just new technologies, whether that's battery storage or hydrogen, but also, quite frankly, the extended growth of core technologies of solar and solar-plus-storage." Incentives are going to have to come into the market, he added, whether in the form of taxes or as an extension of current programs.

Distributed trends

Another major trend in the U.S. power sector is the increase in distributed energy resources, spurred by customer demand, resilience needs and other factors. Such a trend could pose a threat to traditional utilities, but it also offers opportunities.

The top two choices for respondents in terms of building a business model around DER were partnering with third-party providers to deploy DERs on the grid (46%) and owning and operating DERs as a regulated utility through rate-based investments (42%).

The next tier of preferred approaches was procuring or aggregating power from DERs owned by third-party providers (29%) and owning and operating DERs through an unregulated subsidiary (21%). An even smaller number of respondents (16%) said their organizations should not have a business model around DERs.

But while many utilities are working to capitalize on the proliferation of DERs, they also pose significant challenges. The first and third most frequently mentioned challenges related to the utility regulatory models in the states where respondents' organizations operate relate to DER:

- Justifying emerging utility investments, such as energy storage, EV chargers and microgrids (42%)
- Managing distributed resource growth and net metering (36%)

Many utilities are trying to figure out how best to work in a world with an increasing amount of distributed resources.

When it comes to DER, "the unsuccessful ones have kind of taken the — and there's not that many, I will say — put your head in the sand a little bit and hope it goes away'" approach, Klingel said.

In general, however, "I think we're seeing utilities become more proactive … in taking a developer mindset. They realize that this is going to be a marathon … and they're starting to build a solid foundation, whether it's their own investment, or it's incentivizing those in their jurisdiction. 'You're Fortune 500, and you want to transition to a full decarbonized power supply. How do we best help you to do that?'" some utilities ask.

"It's taking a retail mentality of being a service provider, not just being 'Doctor No' and saying, 'There's absolutely no way; this doesn't fit my current rate case. I don't have a mechanism to recover. I don't know how I'm going to interconnect all this new load. It doesn't look like what I've done for the past 50 years.'

Taking that flexible approach and trying to think like a developer has helped utilities in three ways, Klingel said: Keep customers happy; be better suited, as DERs proliferate and renewables of all shapes and sizes come online; and help customers with their system planning.

As for broader utility challenges, both new and old assets are at the top of the list.

Utility challenges

Survey participants cited a number of challenges their organizations face in evolving their business models. At the top are aging assets or technology, reliably integrating renewables, cost of transition to ratepayers, and changing customer expectations/needs.

Some 10% of participants said nothing is standing in the way of their business model evolving.

One of the biggest roadblocks for utilities, Deloitte's Thomson said, is the regulatory environment and the lack of consistency from state to state.

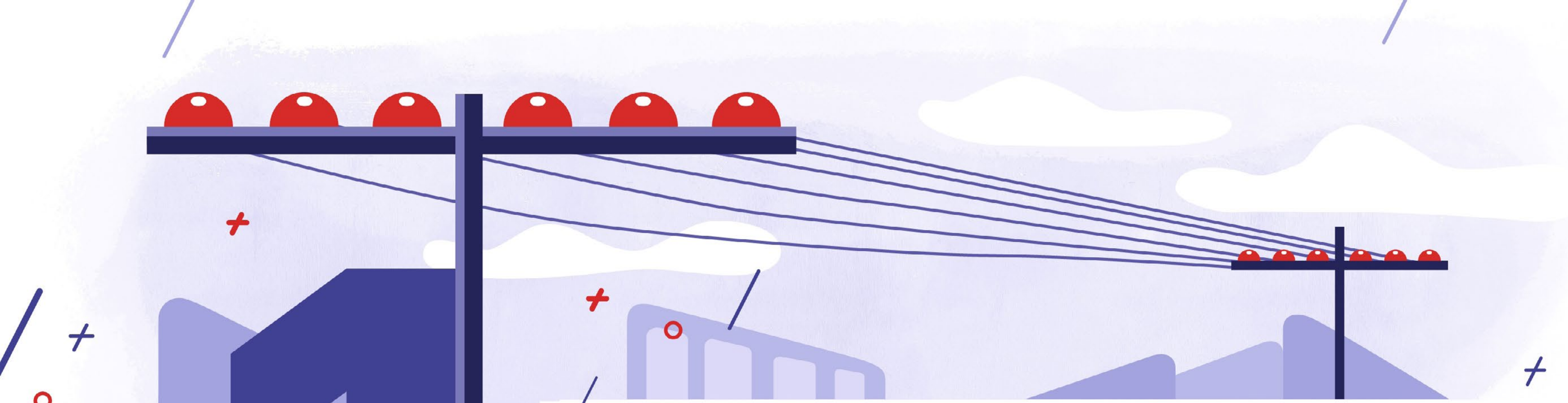
Utilities need to evolve new business models in ways that make sense for the regulatory framework that they operate in, he said. For many, that regulatory structure still offers incentives to keep building large centralized infrastructure, when sometimes other types of investments, such as grid modernization to support DER integration, may be more appropriate to help them evolve new solutions to meet customer needs.

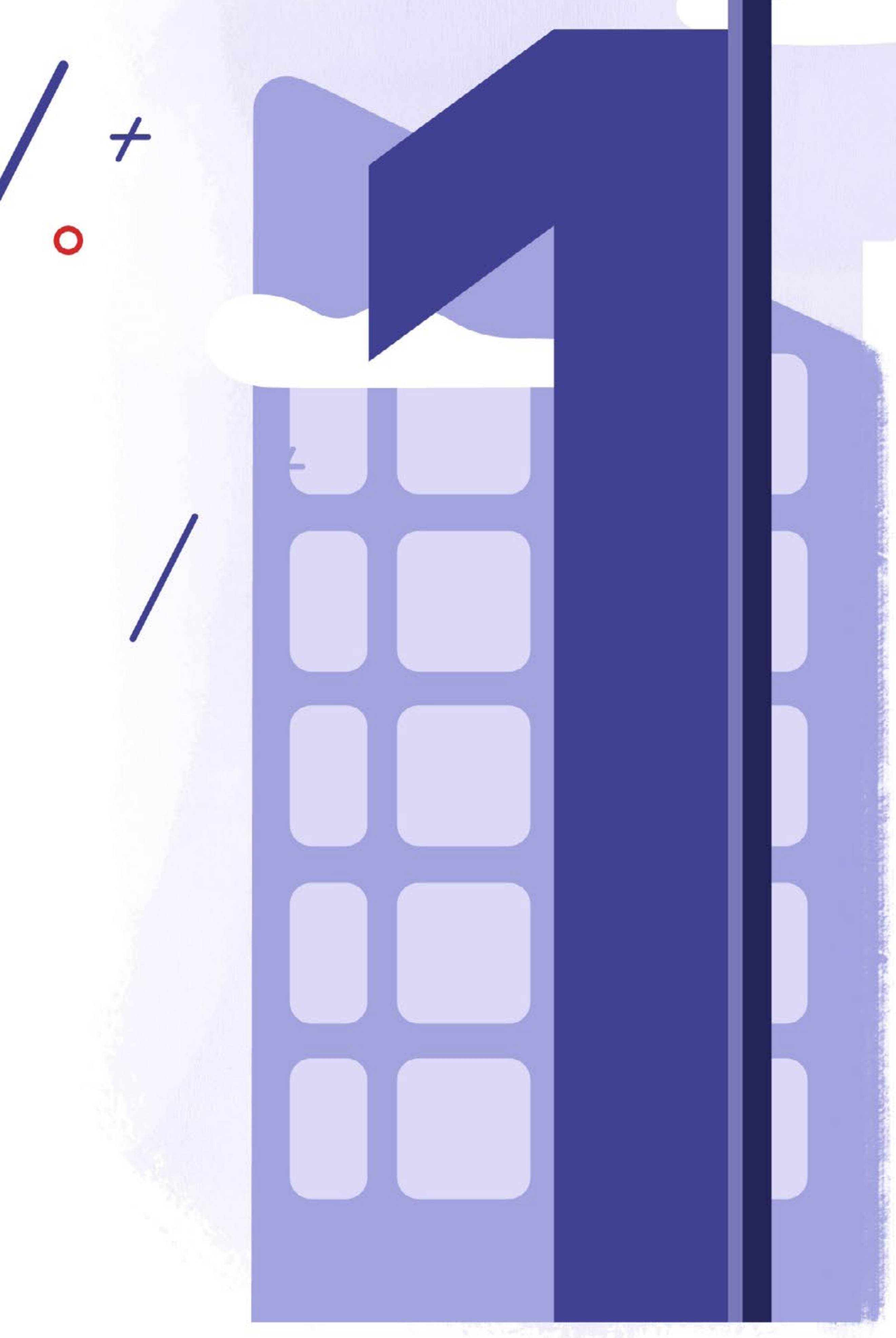
SEPA's Allan said that in terms of the energy transition, the regulatory arena is still moving slowly. "We need to see what are the ways to do this with different models; there's a lot of discussion. Whether trying multiyear rates or performance-based incentives, everyone is looking to see how this will work and looking at examples like Hawaii," she noted.

Investor-owned utilities won't evolve without a regulatory foundation. "To facilitate the transition, regulatory decision-making needs to accelerate," Allan said.

"The pace of technology change is greater than the ability of regulators to handle it."

> "The pace of technology change is **greater than the ability of regulators to handle it.**"
>
> **Sharon Allan**, chief strategy officer, Smart Electric Power Alliance





LOAD TRENDS

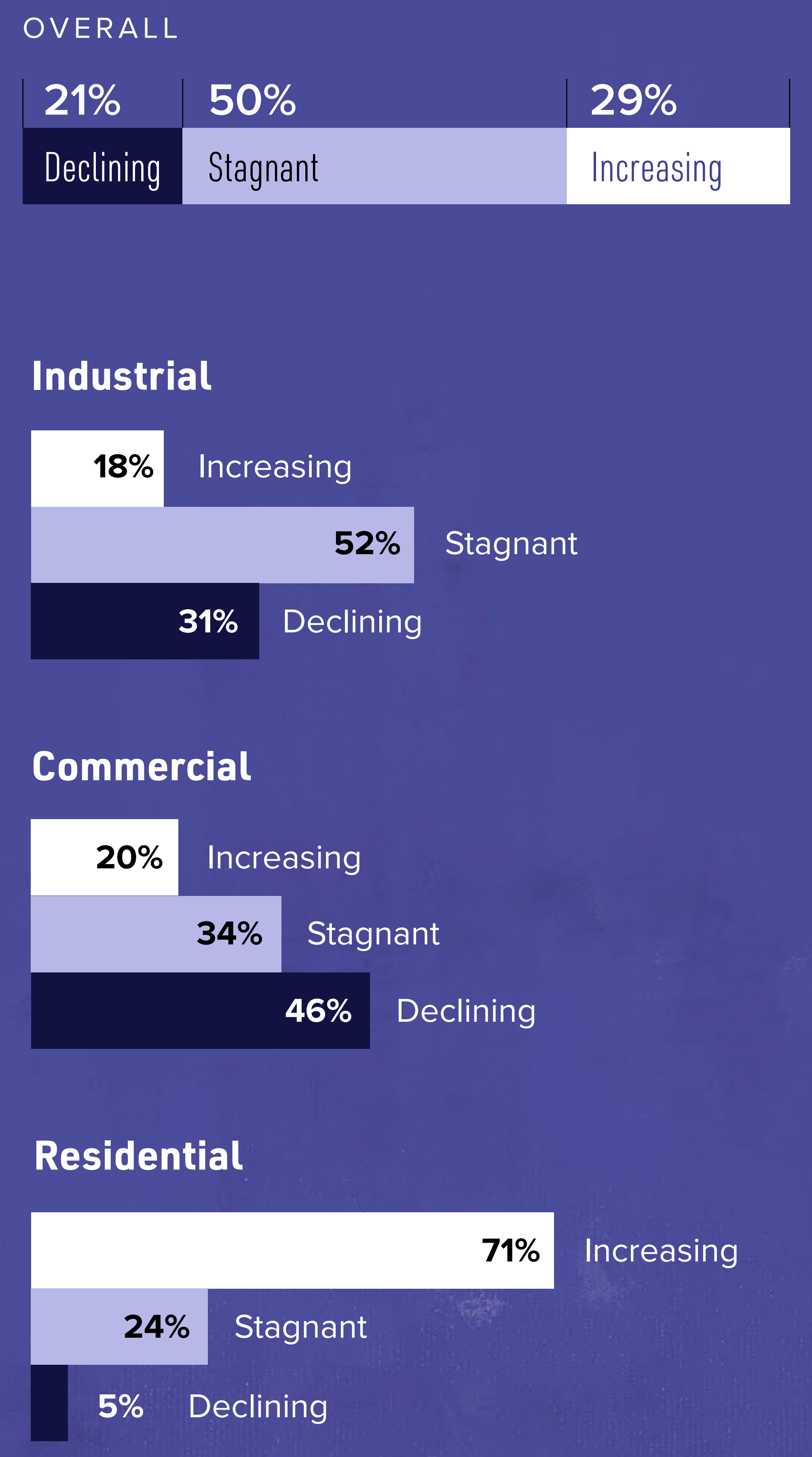
Utilities have seen electricity loads remain relatively stagnant for years, but the global pandemic changed everything in 2020.

Economic shutdowns, quarantines and a rise in remote working caused residential energy use to climb while commercial and industrial loads dropped. More than seven out of 10 participants (71%) in Utility Dive's survey see increasing loads in the residential sector, while close to half (46%) see declining loads in the commercial sector and 31% see decreasing loads in the industrial sector.

Looking ahead, experts said widespread electrification will roughly double grid loads in the next three decades. But right now, 58% of survey respondents indicated COVID-19 has been the top driver of load change for their utility.

Stagnant load has been a concern for utility earnings growth since 2008, when there was a flattening of growth curves, according to Peter

Which net load growth trend do you see in your service area?



QUESTION 8

Shaw, director of energy, sustainability and infrastructure at Guidehouse. But there is "an increasing acknowledgment and enthusiasm for electrification as a saving grace for boosting throughput sales," said Shaw. "It's a big issue and it's all tied into the energy transition."

In 2020, U.S. electricity sales decreased 4% overall from 2019, led by a 7% drop on the commercial side and 8% decrease in industrial demand, according to Guidehouse estimates. Residential electricity sales rose more than 1% last year, on a weather-adjusted basis, but there are service territories where the shifts are more extreme. Electric utilities in New England, for example, saw June residential sales over 15% higher than the year before.

Overall annualized load from February to November 2020 was down 3% in the U.S., said Eric Gimon, consultant and policy adviser for clean energy policy shop Energy Innovation. That load change includes a commercial drop of 6%, an industrial decline of 7% and a 2% increase in residential usage. "The long-term load trajectory over the last 14 years has just been flat," though there have been fluctuations in demand between segments, Gimon said. "There's been a pretty strong decoupling of economic growth and load growth," partly driven by a switch to more efficient lighting, he added.

There's no reason to think commercial and industrial demand will not rebound, Gimon added, though he does expect some permanent shifts in workplace loads due to more people working remotely.

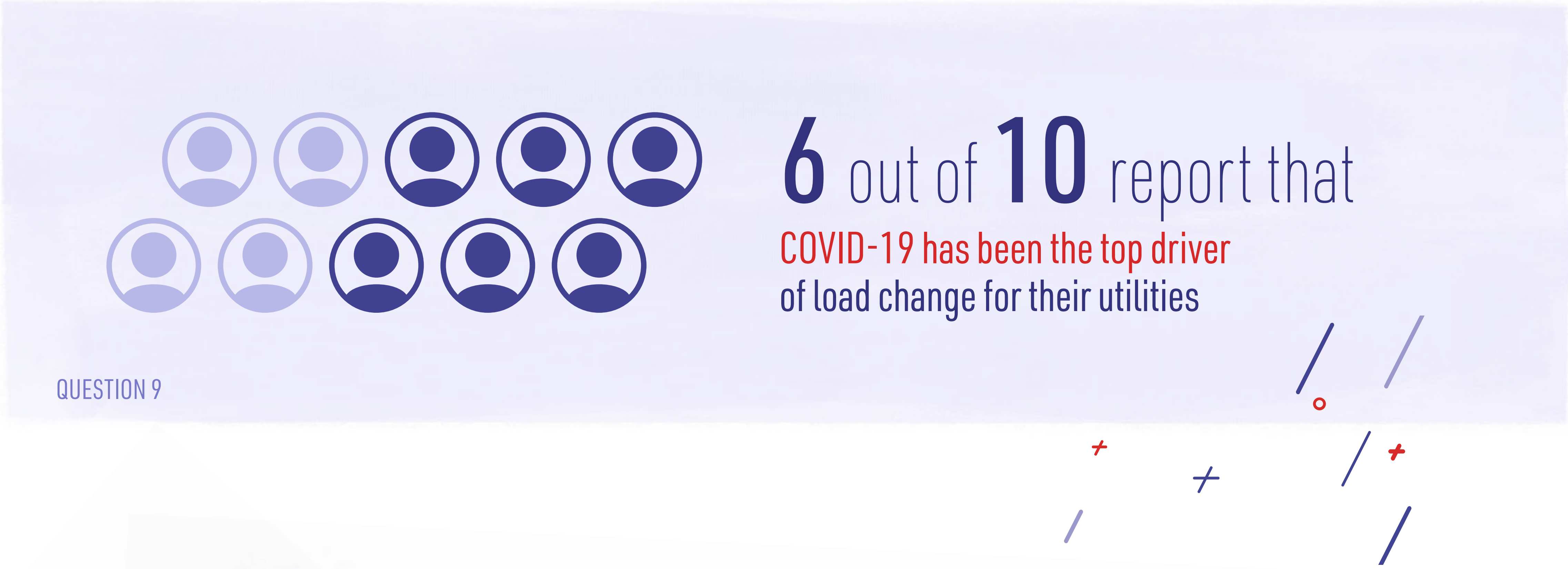
COVID-19

Electric loads have shifted significantly since March 2020, when local governments began issuing stay-at-home orders, said Scott Hinson, chief technology officer at Pecan Street, a non-profit electricity test bed, in Austin, Texas, and Ithaca, N.Y. When Austin first issued a stay-at-home order, Pecan Street saw EV charging loads drop 85 to 90%.

Pecan Street data also showed demand ramps that typically occur at 5 a.m. shift to later in the morning, said Hinson. A 3 p.m. ramp, when people begin returning home from school or work, did not occur as populations quarantined. As a result, residential loads began to rise. "You started to see usage levels be higher during the day because people were home," he said.

By August, EV loads on the Pecan Street system had rebounded to 80% of pre-pandemic levels. "At first we thought it was them going back to old behaviors, but the energy usage in the house has stayed high," Hinson said. "We think it has more to do with short curbside pickup trips and more frequent errands."

Refrigerator use and air conditioner loads were higher on the system last summer, said Hinson. So far, utilities have handled the demand shifts caused by the pandemic with relative ease, but he said the bigger question is to what extent the consumption shifts remain or revert to historical baselines after the pandemic.



Is COVID-19 accelerating the clean energy transition?

COVID-19 is helping to accelerate the shift to clean energy and more efficient utility operations, according to some experts. "Everyone is talking about the demand destruction spurred by shutdown, with shifts from commercial to residential loads," Shaw said. "That is all true, but it's not as terrible a story as it first appeared."

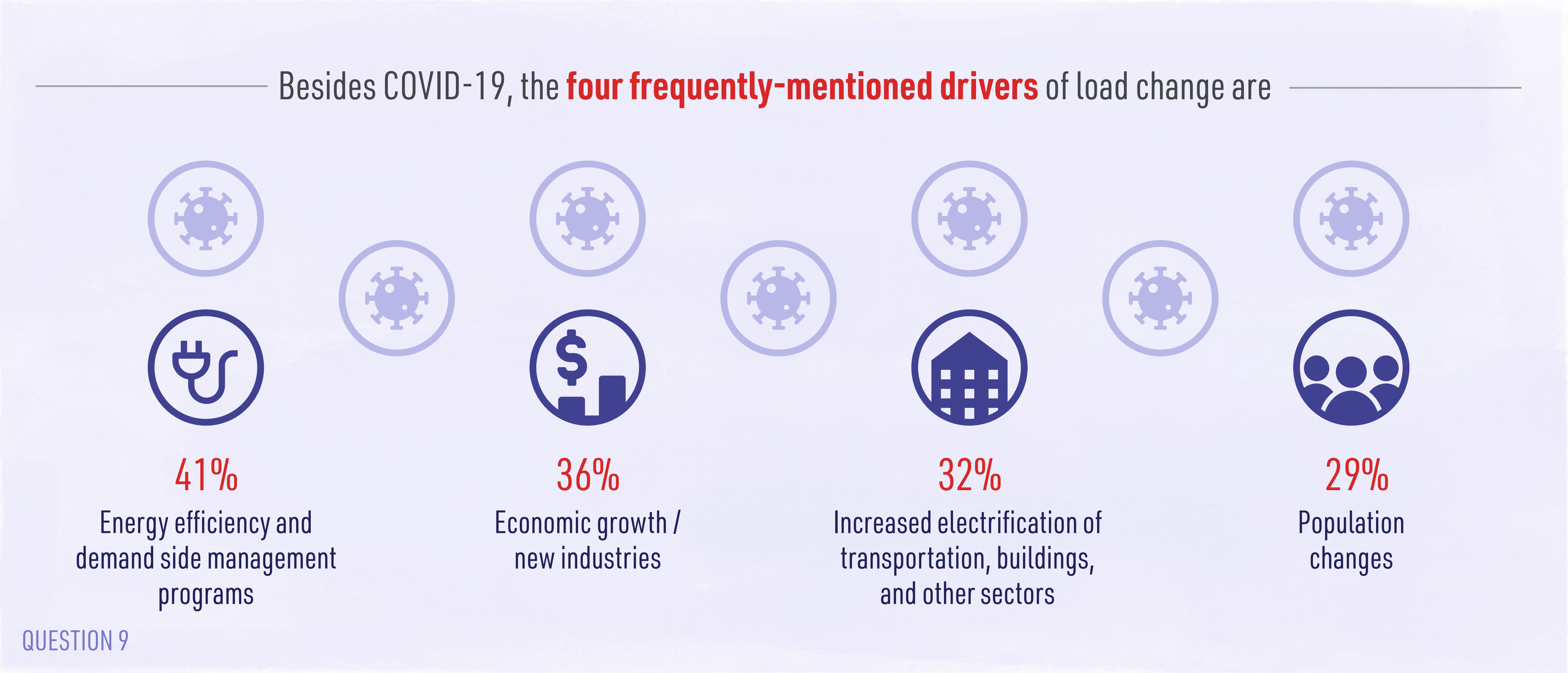
Rather, COVID-19 is acting "as an accelerant of what we think of as the energy transition" by rapidly advancing some customer solutions and giving a boost to renewables, he said.

> Everyone is talking about the demand destruction spurred by shutdown, with shifts from commercial to residential loads. **That is all true, but it's not as terrible a story as it first appeared."**
>
> **Peter Shaw**, director of energy, sustainability and infrastructure, Guidehouse

Softening demand has triggered lower wholesale costs, he added, making renewables fleets more competitive in those markets while also hurting the prospects of some coal plants.

The lower throughput has also accelerated operational efficiencies for utilities, particularly around digitization and power company efforts to develop contactless operations. Utility walk-in offices may be a thing of the past, said Shaw, and companies are considering how to make supply chains less dependent on human interaction.

"We got done in five months what would probably have happened in five years" without the pandemic, he said. "You don't have the need for people to interact physically. Systems are being deployed to minimize that level of contact."



Energy efficiency and demand side management

Second only to pandemic-driven shifts, 41% of survey respondents said energy efficiency and demand-side management (DSM) are top drivers of load changes — a trend that is likely to accelerate as the resources are more widely understood and used.

Increasingly, efficiency and DSM are being treated by states and utilities as investment options and being integrated more fully into supply-side resource planning. Some utilities also are including these resources as part of plans to reach state decarbonization goals. "We're seeing utilities start to look at the demand side as part of the package of resources they can look at to meet decarbonization targets," said Mark Dyson, principal at RMI's Carbon-Free Electricity Practice.

Energy efficiency is becoming more strategic than just a set of mandates, Shaw said. "It becomes more of a flexibility service offering" and creates a scenario in which demand becomes a resource. "All those DSM and energy efficiency programs over the next 10 years will become part of utilities' arsenal for reaching decarbonization targets and for integrating the customer side of the meter with intermittent central generation to balance the power grid," he said. "Our clients are exploring their 2030 DSM strategies now."

RMI recently completed a survey of utility resource procurement process outcomes and found a "small but material" number were explicitly taking advantage of efficiency and DSM. For example, Portland General Electric issued an integrated resource plan in 2019 that used "cost-effective energy efficiency and an expansion of flexible load programs" to meet load. In Glendale, Calif., the city's utility developed an IRP that called for 28 MW of demand response and efficiency.

RMI has looked at 12 GW of recent procurements from vertically integrated utilities over the last couple of years and found 5% of those gigawatts are coming from efficiency and demand response. "And that's in addition to the energy efficiency and demand response realized through typical DSM programs utilities and state agencies run anyway," said Dyson. That represents a change from historical practice, he added. "We think this will grow and more utilities will do this."

Electrification

The parallel to demand management is electrification — the shift to use electricity for heating and transportation.

A smaller portion of Utility Dive survey participants, 32%, identified increased electrification of transportation, buildings and other sectors as a major driver of load. But there is near-universal consensus that higher loads are in the future. “If I was a really forward-thinking utility CEO, I would be going all in on vehicle electrification,” Gimon said.

> “If I was a really forward-thinking utility CEO, I would be going all in on **vehicle electrification.”**
>
> **Eric Gimon,** consultant and policy adviser, Energy Innovation

Utilities are just beginning to view electrification as a potential source of revenue growth, including the potential for “dispatchable demand” to use more renewable energy during high production times, he said.

State and sometimes city planning efforts are moving quickly to electrify large parts of building and vehicle fleets, RMI reports. “Electric utilities are beginning to see this as a clear opportunity,” Dyson said. They are “increasingly getting behind vehicle electrification efforts because they can use this to grow sales.” If sales grow, fixed costs can be spread over more kilowatt-hour sales.

After years of stagnant system loads, electrification will lead to new demand, particularly if it is used to meet decarbonization goals. Electricity load will need to double, approximately, in the next 30 years to reach a net-zero energy system, Dyson predicts. The next 10 years will show modest load growth, but the following 20 will be the most important for electrification. “Electrification itself is an energy efficiency investment,” with heat pumps, electric motors and vehicles operating three to four times as efficiently as burning fossil fuels, he said.

RMI has estimated that electrifying all of the roughly 251 million light duty vehicles now on U.S roads would increase annual electricity demand by about 25% — and that doesn’t include medium and heavy-duty sectors like freight and public transit along with a host of other applications.

The trend is global. According to Wood Mackenzie, EV sales in China, Europe and the United States together will reach more than 7 million a year by 2025 and will double to 15 million by 2030.

But while transportation electrification is a “significant chunk” of the new load coming, Dyson said, buildings actually represent the “lion’s share.”

Buildings account for 75% of U.S. electricity consumption and up to 80% of peak demand, according to Lawrence Berkeley National Laboratory. And in 2019, The Brattle Group estimated the U.S. could have 198 GW of cost-effective load flexibility by 2030, with much of that coming from buildings and capable of delivering more than $15 billion in annual avoided system costs.

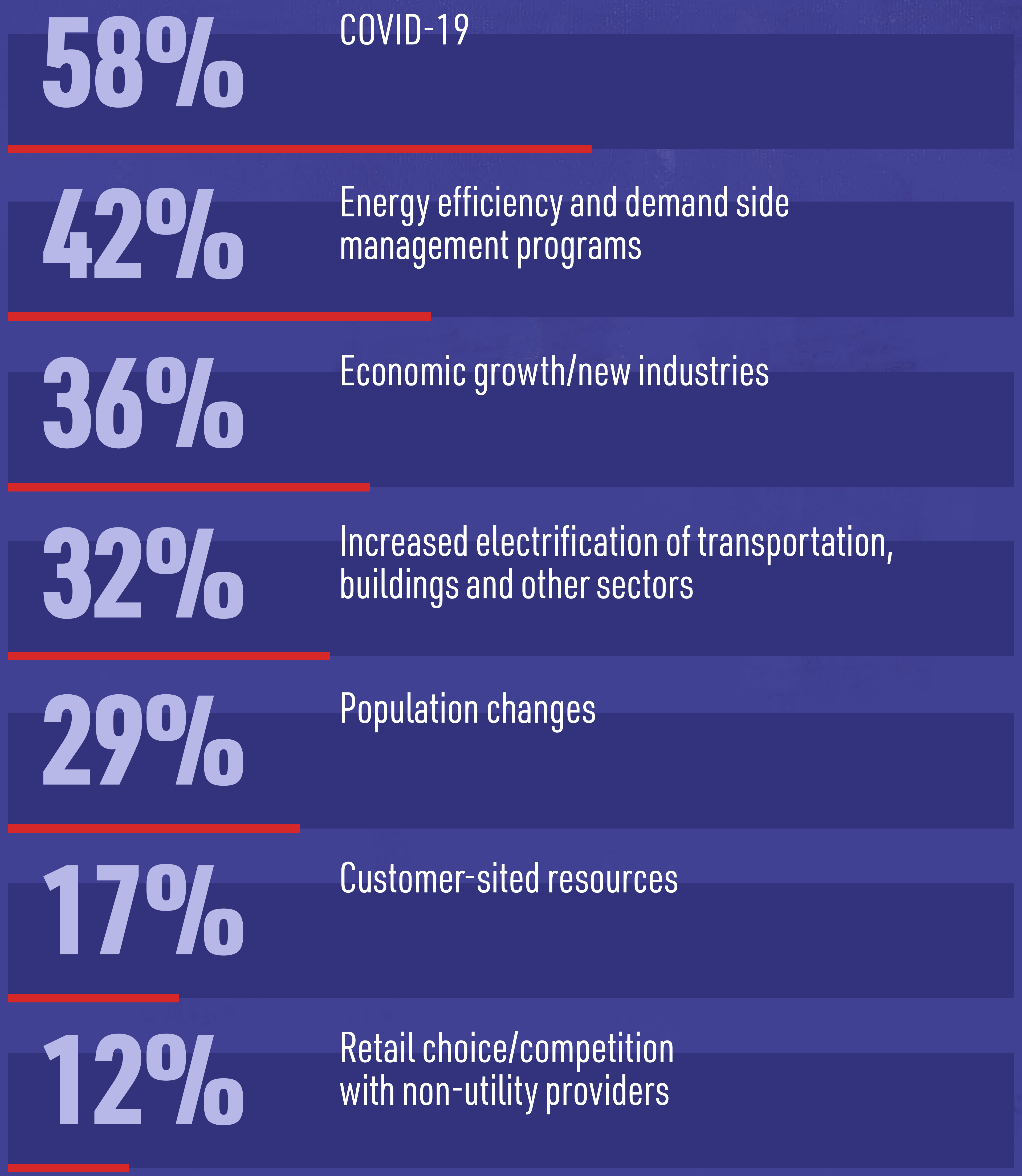
Transportation, buildings and large manufacturing processes will require “a tremendous amount of electricity to be generated,” said Shaw. “If climate policy compels the electrification of everything, with a combination of central renewables and steady growth in distributed resources, you can get to 70%, maybe 80% clean energy on the system.”

But while system load may double by 2050, experts said the capacity of the electric grid does not need to be immediately increased that much. In nearly all parts of the country, electricity demand peaks in summer. With electrification, heating in particular will add winter load, Dyson said.

“Adding a bunch of winter peaking loads to that system means you don’t actually increase peak demand for a decade, maybe 15 to 20 years,” he said. “There’s a lot of slack in the current system in terms of peak capacity. That can help to electrify at low cost for the first decade or more.”

“Peak load will double, but not for a while. We have a lot of time to plan for it,” he added. “There’s an amazing ‘once in a grid’ opportunity to effectively plan for massive electrification and target energy efficiency and demand response programs, such that you minimize and defer capital investments.”

What are the **top drivers of load change** for your utility?



QUESTION 9

> There's an amazing 'once in a grid' opportunity to effectively plan for **massive electrification** and target energy efficiency and demand response programs, such that you minimize and defer capital investments."
>
> **Mike Dyson**, principal at RMI's Carbon-Free Electricity Practice

Potential for new industry, including green hydrogen

Survey participants identified a range of smaller factors impacting load. Population changes were cited by 29% of respondents, and 36% noted economic expansion. Less frequently mentioned were customer-sited resources (17%) and retail choice and competition with non-utility providers (12%).

Utilities should start planning for growth from new industries that can take advantage of low-cost electricity, experts said. The transition to a renewables-focused grid will lead to gluts of low-cost energy, creating an opportunity for new businesses. That could include production of green hydrogen, said Dyson, though he sees those opportunities growing more in about a decade.

"Hydrogen is the hot topic now, like solar was 15 years ago," Shaw said.

Forward-looking utilities will be looking for new industrial customers to take excess electricity, said Gimon. Green hydrogen is not economic at current electricity rates, but he said projects in the works are connecting electrolyzers directly to renewable energy parks so that industrial customers don't have to pay for transmission.

The prospects for new technologies in the next few years are likely "slower than you might want," Gimon said. But looking out seven to eight years, those prospects are "probably faster than you expect."

GENERATION TRENDS

Although pandemic conditions deeply affected the energy sector, longer-term outlooks for generation aren't showing a marked difference from the trends established in recent State of the Electric Utility Industry surveys.

Decision makers in the utility sector continue to view renewable resources, energy storage and distributed energy as a point of significant growth in the next decade.

"The expectation within the utility industry has been growing … in the fact that there will be a much greater role of renewables generally, in the future," Val Jensen, senior fellow of energy utility services at ICF, said.

About 90% of survey participants expect grid-scale solar to increase in some amount over the next 10 years, with 52% expecting a significant increase — top numbers for both among 10 resources in the survey. Grid-scale solar emerged at the top of projections in 2019 and 2018 as well.

During 2020, participants also signaled their confidence in the longer-term increase of distributed resources (87%), grid-scale energy storage (86%) and wind power (74%), following the general trend of support in past State of the Electric Utility Industry surveys.

Grid-scale solar may have received more votes from utility respondents because "it tends to be a little less geographically focused," Jensen suggested, noting the potential to site solar locally, whereas wind capacity has faced bottlenecks as various transmission corridors have been delayed due to permitting issues.

"Solar is exceeding policy targets in a lot of different places because the costs have come down so much," said Chris Namovicz, team leader for the Energy Information Administration's renewable electricity analysis.

The high confidence in the resource from utility respondents is particularly impressive when, 15 years ago, solar power was "really an afterthought in the consideration of future power markets," he said. When considering high-renewables scenarios in 2005, the focus was on wind, hydropower and biomass, according to Namovicz. Subsidies and incentives for the resource in Europe and Asia at that time created a manufacturing opportunity, allowing more experience to be developed around photovoltaic solar in a way that worked with the economies of mass production. The advances abroad ultimately allowed the U.S. to take advantage of cost trends, he said.

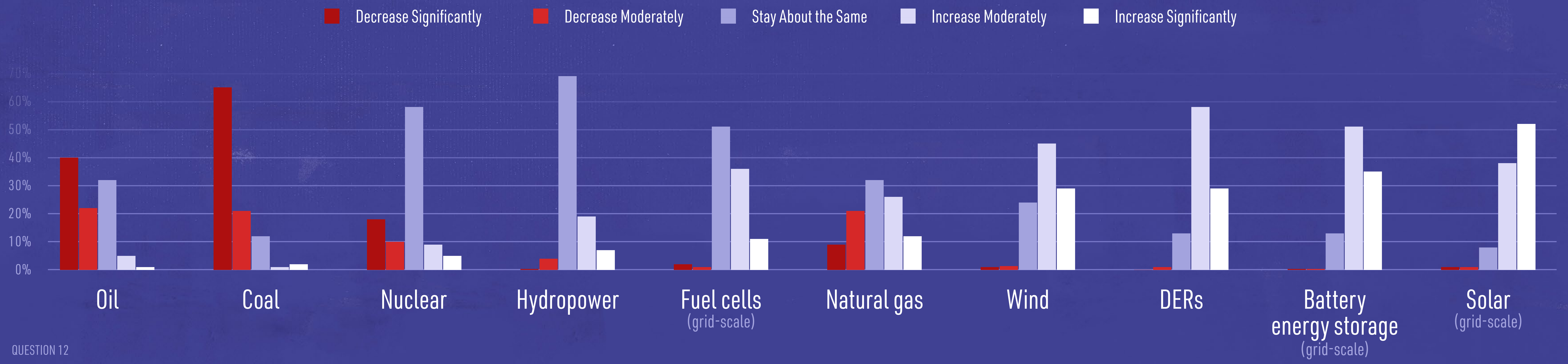
Having recently experienced a lot of growth in solar, the utility sector is likely to have that top of mind, particularly when seeking options on the generation side to continue decarbonization, Jensen said.

Wind power continues to be very promising, as ongoing research and development seeks to make more wind turbines fully recyclable and to increase the size and efficiency of wind energy systems. Offshore wind, a nascent industry in the U.S. that is not currently separated in the survey, faces permitting headwinds, but many states on the East Coast are expecting to meet their clean energy goals in part through offshore wind plants in federal waters.

The survey responses are not necessarily a show of faith in any specific technology because they could be influenced by prevailing trends and policies to decarbonize the energy sector, Jensen said.

"It's always hard for people to imagine a future that has heavy reliance on something that they haven't seen already," he said, noting that technologies like fuel cells have been "on the edge of feasibility but have never really cracked in a big way either due to the technology or the economics."

How do you expect your organization's mix of power resources to change over the next 10 years?



QUESTION 12

Meanwhile, a growing portion of survey participants show less confidence in the growth of natural gas. Fifty-one percent of participants in 2018 thought natural gas would increase a moderate or high amount in the next decade; that confidence dropped to 44% in 2019 and 38% in our most recent survey.

> “It's always **hard for people to imagine** a future that has heavy reliance on something that they haven't seen already.”
>
> **Val Jensen,** senior fellow of energy utility services at ICF

The resources that survey participants expect to decrease the most in the next decade continue to be coal and oil. But while natural gas continues to be viewed by some as a transition fuel for adding more clean energy to the grid, 30% of survey participants in 2020 saw the resource decreasing in some capacity over the next decade.

In a separate question regarding the retirement of coal and nuclear generation, one participant indicated that policymakers should manage baseload resources by allowing for “fast-tracking new nuclear technologies,” echoing anticipation in the utility sector over the potential of advanced, modular nuclear reactors.

Utilities split on effective approaches for decarbonization

With grid-scale solar and other clean energy forecast as an increasing resource in the generation mix, participants considered the best pathways to getting more renewable energy on the grid.

The desire to add solar and wind to the grid often is met with concerns about the intermittency of those resources. “Getting more renewables isn't the problem. Getting the right dispatch of resources at the right time is what is needed,” one survey participant wrote.

“A newer, more helpful perspective to view that same phenomenon is that the power system is not [as] flexible as it needs to be if it cannot accommodate renewables that are intermittent,” said David Farnsworth, principal at the Regulatory Assistance Project.

Solar energy had a big moment in 2020 as renewable energy continued to be developed at record-breaking rates, but potential remains for more additions. “Outside of California, there's not that much solar” compared to utilities' natural gas resources, said Wesley Cole, researcher at the National Renewable Energy Lab's Strategic Energy Analysis Center. Those areas face opportunities to diversify their generation, whereas California is planning for grid reliability in a future with mostly renewables on the grid, he noted.

When considering how to best integrate more renewables, survey participants were prompted to select among options that lowered costs for the resources and opportunities to increase grid flexibility, such as aligning state priorities with wholesale market structures and offering incentives for the addition of storage and the buildout of transmission infrastructure.

Participant responses were relatively tied among the extension of federal tax credits (17%), building new transmission infrastructure (15%) and creating more opportunities to add energy storage resources (14%).

What is the best way to get **more renewables** on the grid?

17%	Extending federal tax credits
15%	Facilitating the build of new transmission infrastructure
14%	Incentivizing and simplifying the addition of energy storage resources to the grid
12%	State mandates
11%	Federal mandates
11%	Letting the market take its course
8%	Simplifying interconnection requirements
7%	Ensuring wholesale market structures accommodate state clean energy policies

QUESTION 15

Congress recently extended tax credits for solar power, creating a lot of opportunity to move things forward, Cole said. "Every time we model a tax credit extension, we see more deployment of whatever is getting the tax credit."

> Every time we model a tax credit extension, we see **more deployment of whatever is getting the tax credit.**"
>
> **Wesley Cole,** researcher at the National Renewable Energy Lab's Strategic Energy Analysis Center

Participants working for investor-owned utilities and electric cooperatives prioritized transmission infrastructure and the extension of federal tax credits to increase the amount of renewables on the grid, while responses from municipal utilities favored opportunities to add more energy storage to manage the intermittency.

Utility perspectives on increasing clean energy resources also depend on the regulatory structure in the states where they operate.

A utility in a restructured state, typically not allowed to own generation, would seek to boost renewable resource adoption through the wholesale market, whereas utilities that can own generators need approval from regulators to include those costs in the rate base, Jensen said.

Utility respondents were similarly divided on the best options for decarbonization, although surveys from recent years show an increasing appetite for federal action.

Throughout the tenure of the Trump administration, states, cities and municipalities took the lead on setting targets and standards to decarbonize the energy sector.

When prompted for the best ways to decarbonize the power sector, 45% of respondents focused on "strong federal decarbonization policy, backed up with clear targets, regulation and enforcement."

When asked the same question with similar choices in 2019, survey respondents were similarly split, chiefly preferring financial incentives for renewable energy (43%), federal decarbonization policy (43%), and state policies and mandates (40%).

50%

of utility respondents said the most effective approach to sector decarbonization is creating financial incentives for renewable energy development.

In the 2020 survey, fewer participants believe that carbon capture technology (23%) and voluntary energy industry measures (20%) would be effective in decarbonizing the power system.

While the U.S. power sector has seen modest reductions in carbon emissions since 2005, 2020 marked a large decline in emissions based on a greater amount of renewable energy generation coupled with a drop in energy use spurred by the global pandemic, according to the latest Sustainable Energy in America Factbook, published in February by BloombergNEF (BNEF) and the Business Council for Sustainable Energy.

But full decarbonization will require more technology to enable greater grid flexibility, according to NREL's Cole.

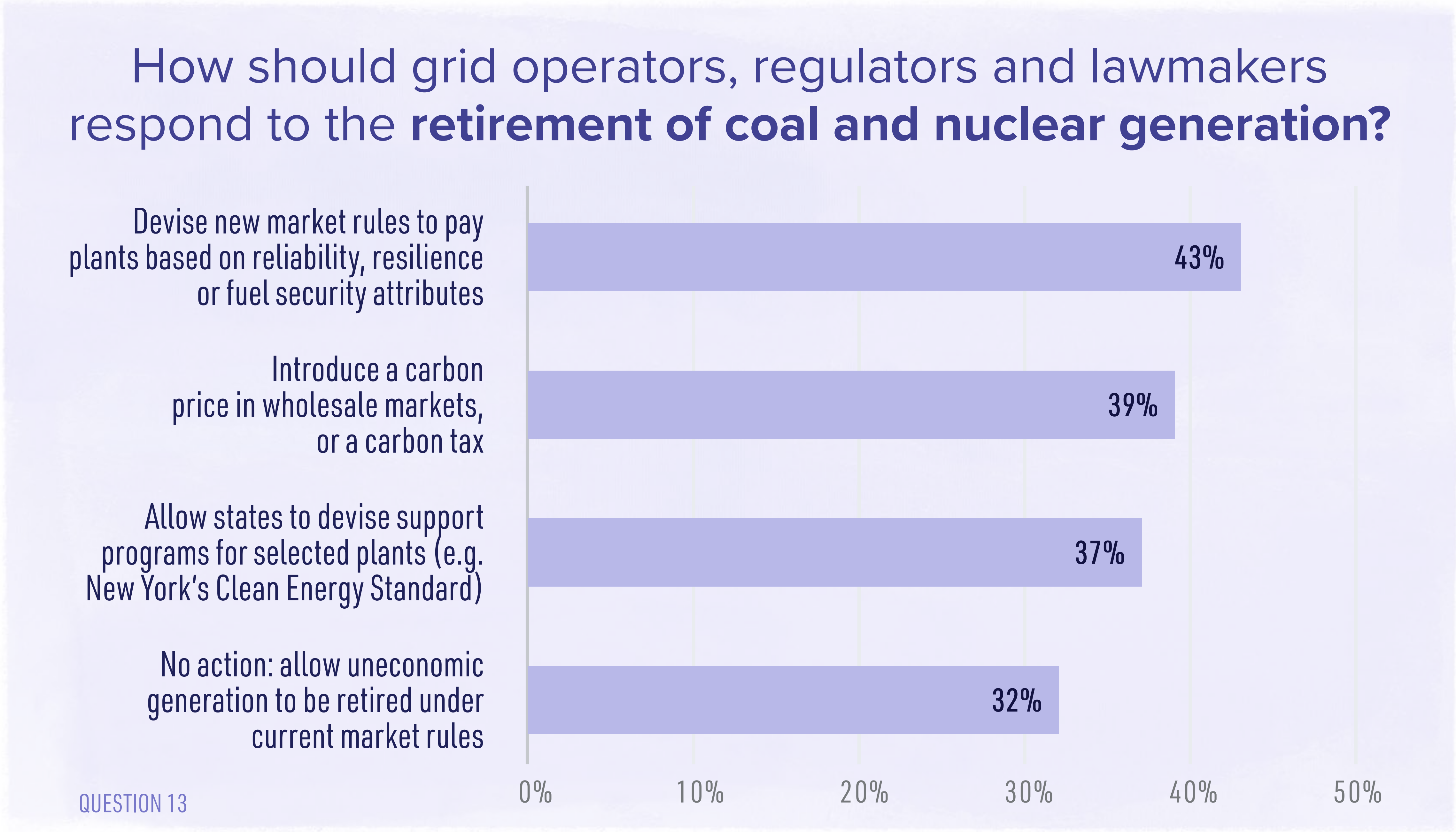
"You can get a long ways with just batteries, wind and solar, in terms of decarbonizing the grid, but if you want to go really far, then you need something else that's got more capability to move power around on your timescales," Cole said. Something like hydrogen power, he said, would help shift power seasonally, as opposed to shorter durations, as with lithium-ion battery storage.

> You can get a long ways with just batteries, wind and solar, in terms of decarbonizing the grid, but **if you want to go really far, then you need something else that's got more capability** to move power around on your timescales."
>
> **Wesley Cole,** researcher at the National Renewable Energy Lab's Strategic Energy Analysis Center

Retiring baseload generation

The survey also asked participants for their preferred policymaker response to the retirement of coal and nuclear generation, but decision makers in the sector do not have a consensus opinion.

Respondents to the survey are moving further away from favoring “no action” when it comes to dealing with retiring baseload generation, which was a leading choice in previous surveys.



In 2018, nearly 34% of participants preferred avoiding intervention from grid operators, regulators and lawmakers, to allow generation retirements under the existing market rules. The second highest preference that year, at 23%, was to ask policymakers to devise market rules that pay resources based on fuel security, resilience and reliability attributes.

As survey respondents this year were split among various ways to adapt market rules, the sector remains conflicted on how to best value the reliability attributes of baseload generation. Some critics maintain that reliability is not a correct framework for valuing baseload power.

“Reliability standards in the wholesale markets seem to create the impression that there needs to be a lot more generation out there than we need,” Farnsworth said, noting the must-run plants that are kept around. “If your policy goal is to make the fleet cleaner, then it would be worth looking at these must-run reliability requirements.”

While some clean energy groups continue to advocate for nuclear, both types of resources tend to be more expensive and less flexible compared to natural gas and renewable resources.

“People who aren’t in that business aren’t really seeing the dynamics of (nuclear plant economics) play out to the extent that (utilities) like Exelon are,” said Jensen, a former senior vice president at Exelon Utilities. “But if you lose a substantial fraction of nuclear power plants, the decarbonization challenge becomes really much more difficult.”

A separate survey question indicated 85% of respondents expected to reduce their coal generation in the next decade, while 28% expected to reduce nuclear power. The continuing move to replace coal power, a trend featured in past State of the Electric Utility Industry reports, is mirrored in additional forecasts from BNEF, the U.S. EIA and others.

And the numbers for upcoming coal retirements may be even greater than what utilities have announced.

EIA’s reference case for resource retirements in its latest Annual Energy Outlook predicted the retirement of “quite a bit of coal plants” that weren’t reported by utilities, based on the specific amount of capacity in particular regions and price projections for natural gas, as “the economics of running a coal plant (are) … dependent especially on the price of natural gas,” EIA’s Namovicz said.

On the nuclear front, Jensen described the divide over how to support the plants as a rift between proponents of market-based solutions, such as a carbon tax, and regulatory administrative solutions, such as “action being taken” by grid operators or at the state level.

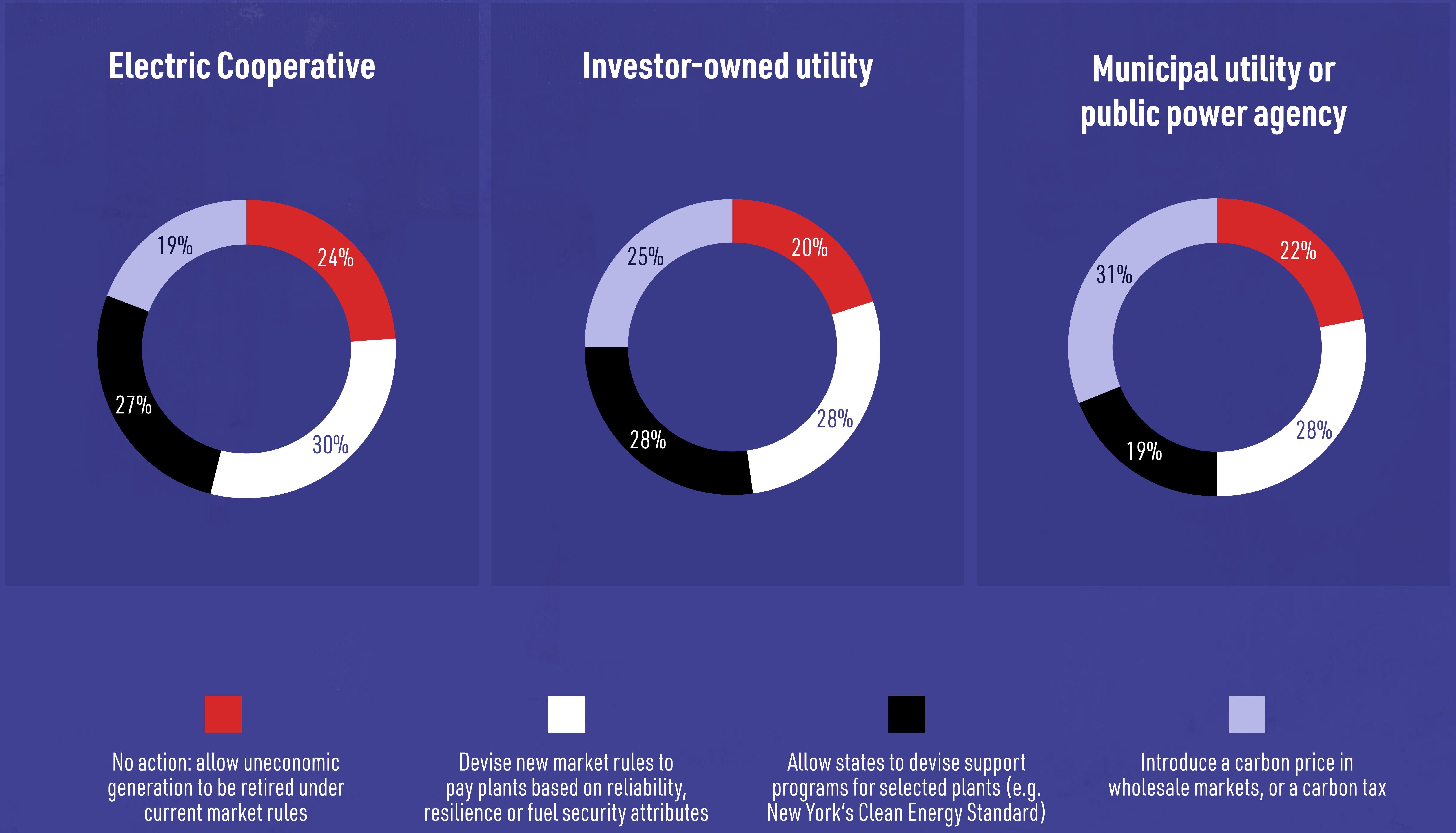
Participants tied in 2019 in their preference of "no policymaker action" and "devising new market rules," and in 2020, respondents preferred reliability-based market rules (43%), the introduction of a carbon tax or price (39%) and support for state-devised programs (37%) over asking policymakers to take no action (32%).

Participants from municipal utilities and public power agencies preferred the introduction of a carbon tax or price to other alternatives for addressing retiring baseload generation, at nearly 40%. Only 25% of participants from investor-owned utilities and 24% from electric cooperatives preferred that measure.

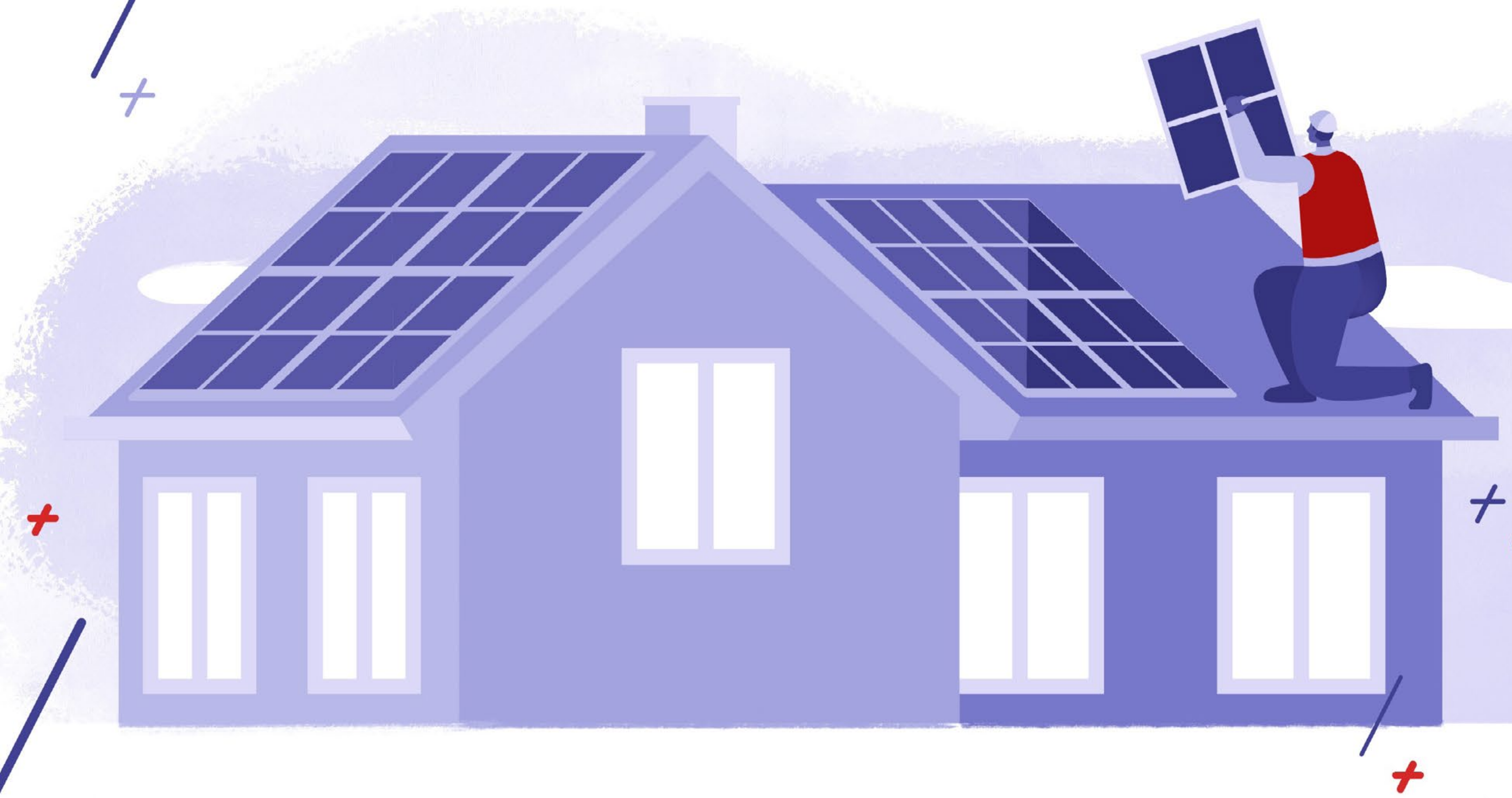
"In (the] residential sector, bill for energy as a service. In the commercial and industrial sector, bill for energy based on demand," one respondent wrote regarding potential policymaker action on retiring coal and nuclear generation.

Other respondents similarly took the opportunity to suggest separate resource adequacy incentives to ensure utilities could recover their investment in baseload assets retired early and to value different attributes of baseload generation.

How should grid operators, regulators and lawmakers respond to the **retirement of coal and nuclear generation**?



QUESTION 13



NON-BASELOAD POWER TECHNOLOGY TRENDS

In 2020, the utility sector continued to grapple with how best to approach the rising amount of DERs, including rooftop solar and electric vehicles, as well as the challenges of adding storage to the system.

In September, the Federal Energy Regulatory Commission passed Order 2222, a rule that requires grid operators to revise their tariffs to ensure DER aggregations can participate in wholesale power markets – a move that analysts call a “game changer.” This order follows Order 841, issued in 2018, which required regional transmission organizations and independent system operators to craft market rules for storage resources to participate in wholesale energy, capacity and ancillary services markets.

As the sector continues to form strategies around the integration of more DERs, a key area to watch will be the integrated customer transformation — a transition to integrating the customer, whoever that may be and whatever market segment they may occupy, and their load profile into operations, according to Dan Bradley, partner at Guidehouse in the energy, sustainability and infrastructure segment. Utilities, markets and third parties will need to understand how these resources will change their load profile, and what price signals and controls can be laid out to enable the customer to integrate those devices and applications to be managed alongside grid operations.

“If we’re having this conversation in 10 years, we’d look back and be able to see a great deal of (virtual power plants) out there, a great deal of managed charging and grid-edge flexibility taking over traditional demand response as one of the main ways to address some of the daily challenges with a high renewable grid,” Bradley said.

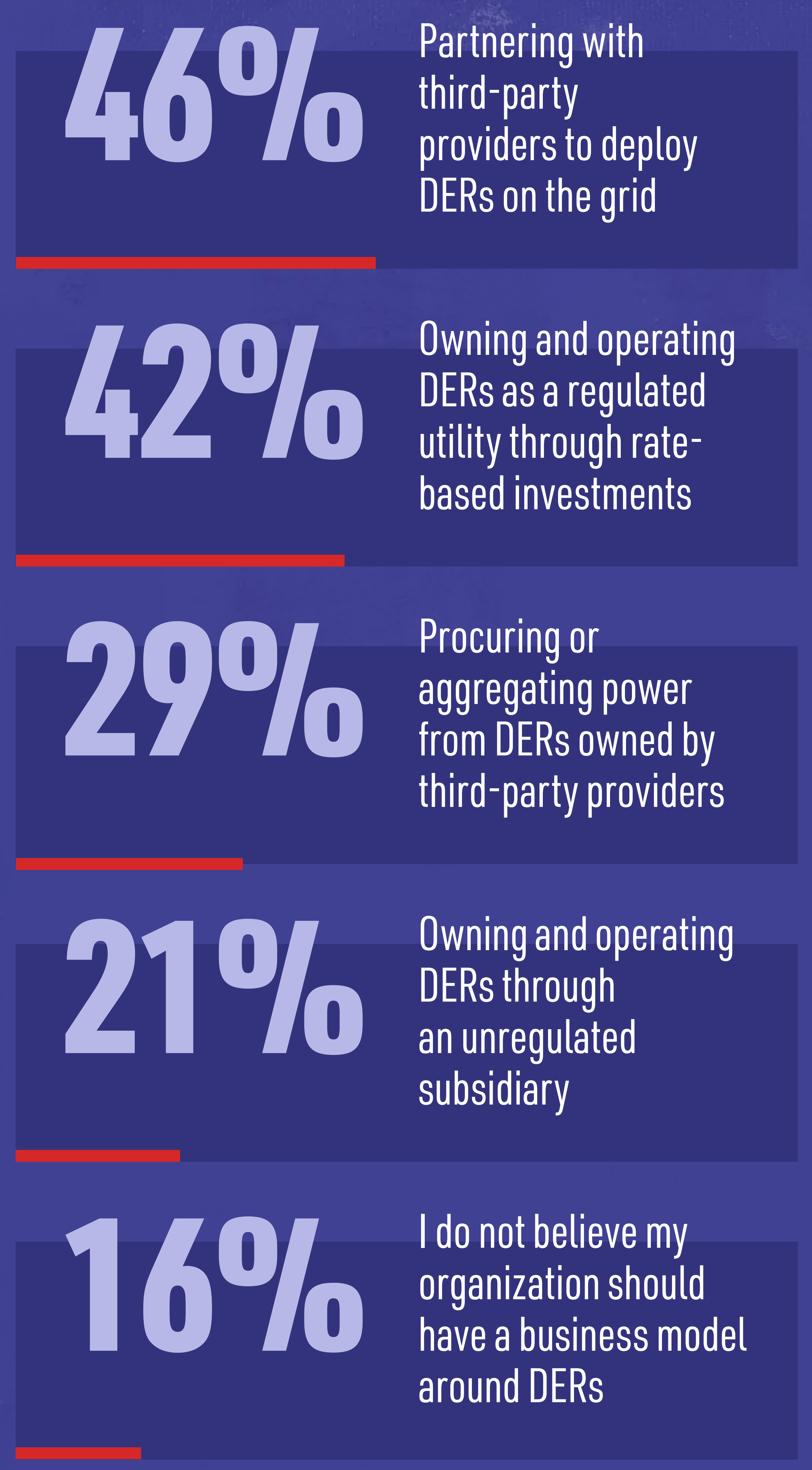
> “If we’re having this conversation in 10 years, we’d look back and be able to see a great deal of (virtual power plants) out there, a **great deal of managed charging and grid-edge flexibility taking over traditional demand response** as one of the main ways to address some of the daily challenges with a high renewable grid.”
>
> **Dan Bradley,** partner at Guidehouse

DER business models and ownership structures

A majority of survey participants tended toward two options for building a business model around DERs — 46% selected partnering with third-party providers to deploy distributed resources on the grid, while 42% chose owning and operating these resources as a regulated utility through rate-based investments. A smaller number favored procuring or aggregating power from DERs owned by third-party providers and owning and operating DERs through an unregulated subsidiary — 29% and 21%, respectively. And 16% of respondents did not think their organizations should have a business model concerning DERs.

But while many utilities prefer owning DERs and including them in their rate base, their ability to get regulatory approval to do so has been varied, according to Ryan Hledik, principal with the Brattle Group. In the case of rooftop solar — which has a robust, competitive industry of private developers and installers — regulators have been hesitant to allow utilities to go in and compete in the area by owning rooftop solar installations themselves. But in the case of demand response (DR), it’s more common to see the utility as the DR provider.

How do you believe your organization should build a **business model around distributed energy resources**?



QUESTION 18

"There I think you tend to see more willingness among regulators to allow the utility to go out, install whatever equipment is needed to manage a given customer's appliance or end use, and then through some mechanism recover those costs," Hledik said.

That mechanism could involve including the costs in the rate base, or providing the utility with a financial incentive to encourage such programs.

Distribution system planning has traditionally been tackled as a holistic singular cost rather than by service item, so figuring out ways to value and compensate distributed storage remains a challenge, said Jason Burwen, interim CEO of the Energy Storage Association (ESA). As a result, some states are beginning to move toward integrated distribution planning approaches to answer those questions.

"Now, with (Order) 841 and 2222 from FERC, there's a lot of interest to see these distribution-connected resources also participate in wholesale markets and unlock the holy grail of true value stacking across domains," Burwen said.

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>
> **Jason Burwen,** interim CEO of the Energy Storage Association (ESA)

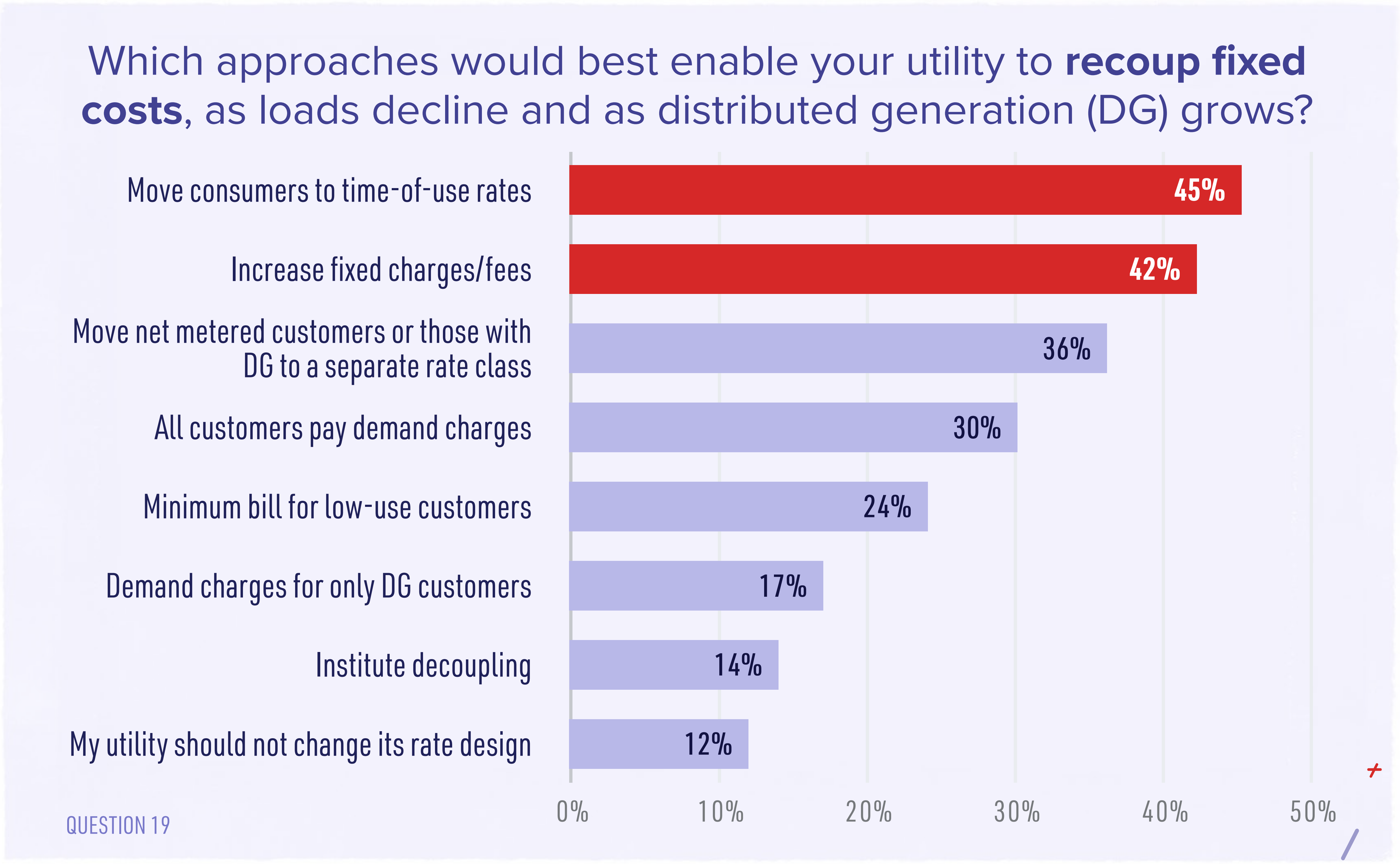
Recouping fixed costs amid DER growth

On allowing utilities to recoup fixed costs as distributed generation grows and loads decline, 45% of participants opted for moving customers to time-of-use rate structures, while 42% selected increasing fixed charges and fees.

There is definite movement in the direction of making rates more time-varying, particularly for residential customers, rather than the flat volumetric charges that most customers are on today, Hledik said. The initial barriers to deploying time-varying rates tended to be technical — earlier, utilities had conventional electromechanical measurers that didn't gauge electricity consumption by time of day, so offering time-of-use rates was cost prohibitive on a large scale. But now that the majority of the country has smart meters, that barrier no longer exists.

In the last five years or so, time-of-use pricing has also been viewed as a way to address, at least partly, the unintended cross subsidy that rooftop solar customers receive when they have net metering under flat rates, said Hledik, adding that the increase in DERs, and rooftop solar in particular, has been another motivating factor for utilities to introduce time-varying rates. California utilities, for instance, are rolling out time-of-use rates on a default basis, and in Maryland, Baltimore Gas and Electric has had customers on a different type of time-varying rate called the peak time rebate for a while now, he said.

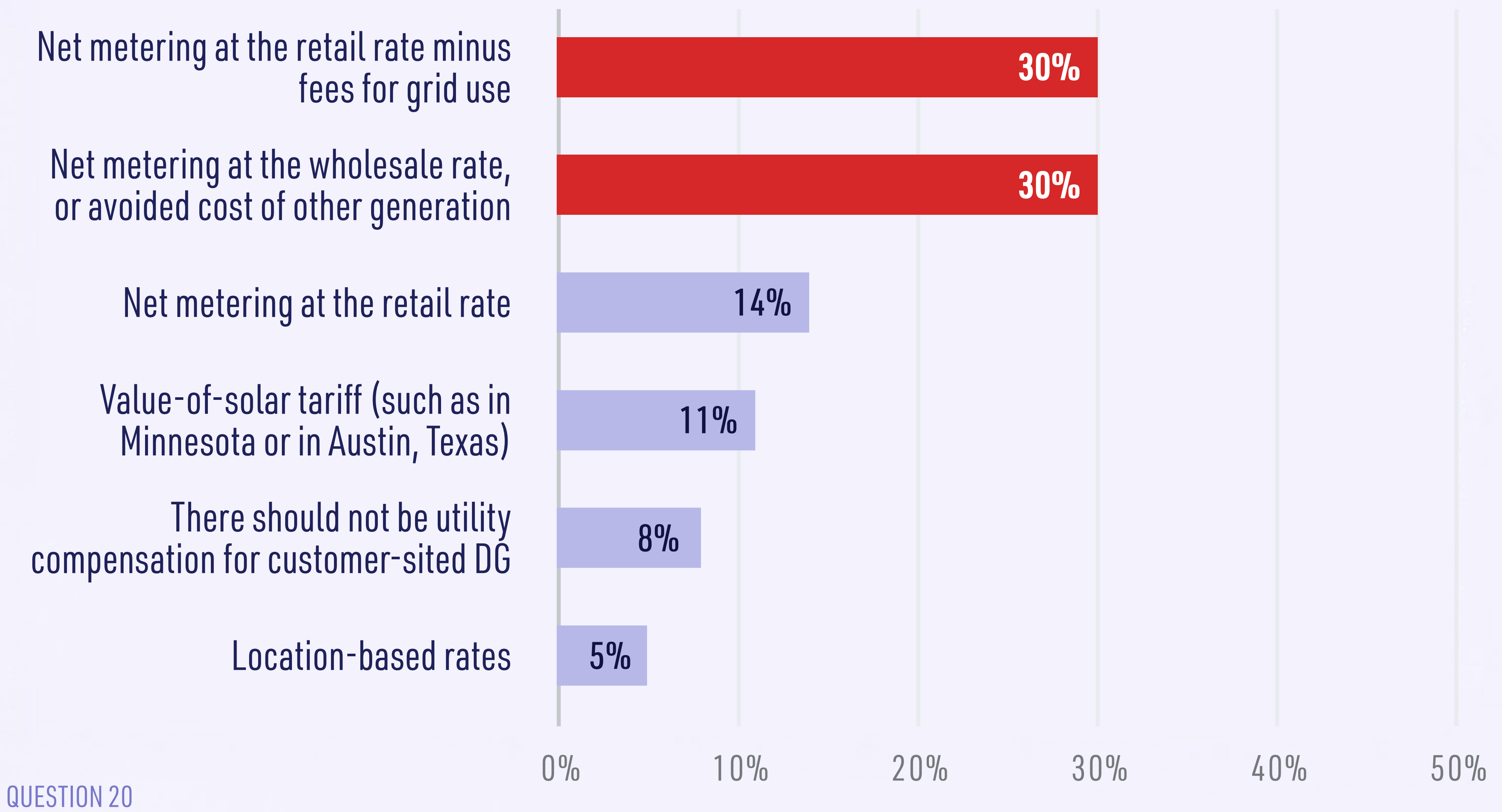
But concerns remain — particularly among consumer advocates — that while some customers' bills will go down on a time-varying rate,



others will increase. This worry about “winners and losers” under a new rate design is unlikely to go away, in Hledik’s opinion, and could be a reason that the industry hasn’t seen faster movement in the direction of time-varying rates.

Other options for recouping fixed costs as distributed generation grows included moving net metered customers or those with distributed generation to a separate rate class, picked by 36% of respondents; 30% opted to have all customers pay demand charges; 24% selected minimum bills for low-use customers; and 17% and 14% selected demand charges for distributed generation customers only and instituting decoupling, respectively.

What is the best **compensation mechanism for distributed generation** (particularly rooftop solar) in your service territory?



QUESTION 20

Compensation models for DERs

Regarding the best compensation mechanism for distributed generation — particularly rooftop solar — in utility service territories, 30% of respondents picked net metering at the retail rate minus fees for grid use, and 30% chose net metering at the wholesale rate, or the avoided cost of other generation.

Net metering mechanisms compensate customers who have distributed solar resources for the energy they generate but don’t consume. Wholesale electricity rates are generally lower than retail rates, since they don’t include costs related to transmission and distribution. Multiple states, like New York and Utah, have looked into successor tariffs to net metering in the last few years.

Compensation mechanisms that were less popular included net metering at the retail rate (14%), a value-of-solar tariff, such as in Minnesota and Austin, Texas (11%), and location-based rates (5%). Only 8% of participants said that utilities should not be compensated for customer-sited distributed generation.

Impacts of transportation electrification

When asked about increased transportation electrification, slightly more than half of survey participants — 52% — thought that utilities should approach the trend by offering special pricing for electric vehicle (EV) charging. Three other approaches that were chosen almost as frequently include creating pricing or rates for EV battery services; owning and operating charging stations as regulated utilities; and providing utility-owned chargers where private companies can’t or won’t deploy their own.

Less popular was the option to construct make-readies for chargers and let private companies own them (27% of respondents) and allow unregulated utility subsidiaries to supply chargers (21%). Five percent of respondents said utilities should not pursue transportation electrification.

The main issue the power sector is now trying to address related to transportation electrification is the speed of the scale up of EVs, Guidehouse's Bradley said. At low levels, EV charging is unlikely to have a significant impact on the grid. But as penetration increases, the sector will have to deal with possible requirements for upgrades, timing issues related to load curves and timing issues related to wholesale markets.

"As more EVs come on to the system, the compensation and the rate around charging is going to have to change. And I think what we're seeing now is just that tension between where we are today and where many see the growth of electric vehicles happening, how steep that ramp up is and the impact of it," Bradley said.

Pricing structures for EVs could also play a critical role in vehicle-to-grid integration efforts, since they play an important role in a customer's decision to participate in such applications, Bradley noted. The clearer the price signal, the higher the participation he expects to see as vehicle-to-grid integration scales up.

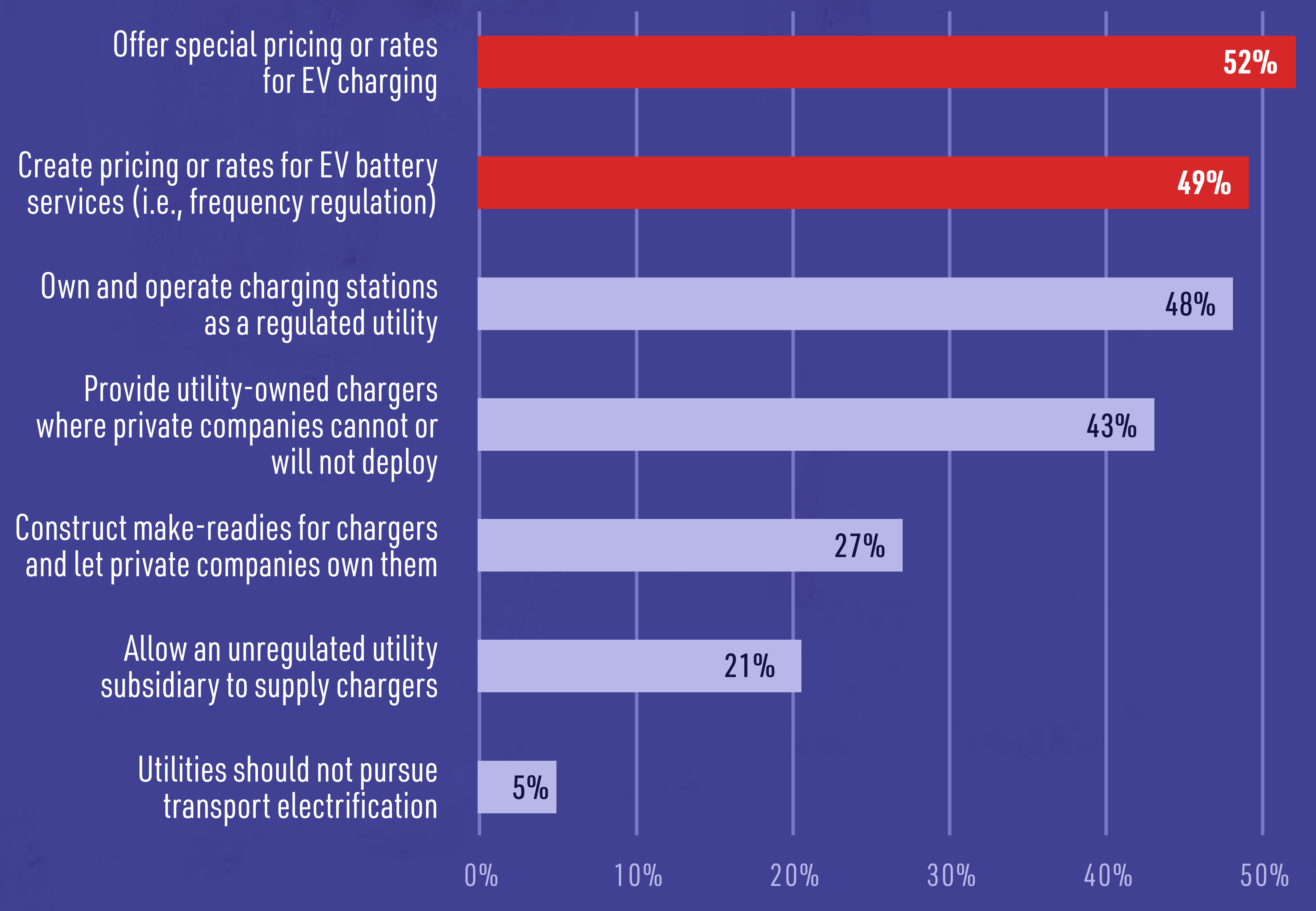
"[F]rom the current rates of electric vehicle deployments, it would seem to me like there's a lot of potentially aligned interests among utilities, EV chargers and storage providers to get the pricing structures and incentives right, so that all these new loads can show up on the system without causing significant additional cost," Burwen said.

> **"As more EVs come on to the system, the compensation and the rate around charging is going to have to change.** And I think what we're seeing now is just that tension between where we are today and where many see the growth of electric vehicles happening, how steep that ramp up is and the impact of it."
>
> **Dan Bradley,** partner at Guidehouse

Fifty-five percent of respondents said they have initiated pilot or test projects around EV charging, and 50% have conducted feasibility studies on providing EV charging infrastructure. Thirty-seven percent have deployed public charging stations in partnership with third-party networks; 32% have had sales, rebates or subsidies for charging stations on customer premises; and 28% have deployed utility-owned public charging stations.

52% said offering special pricing for EV charging is the way utilities should approach the electrification of the transportation sector.

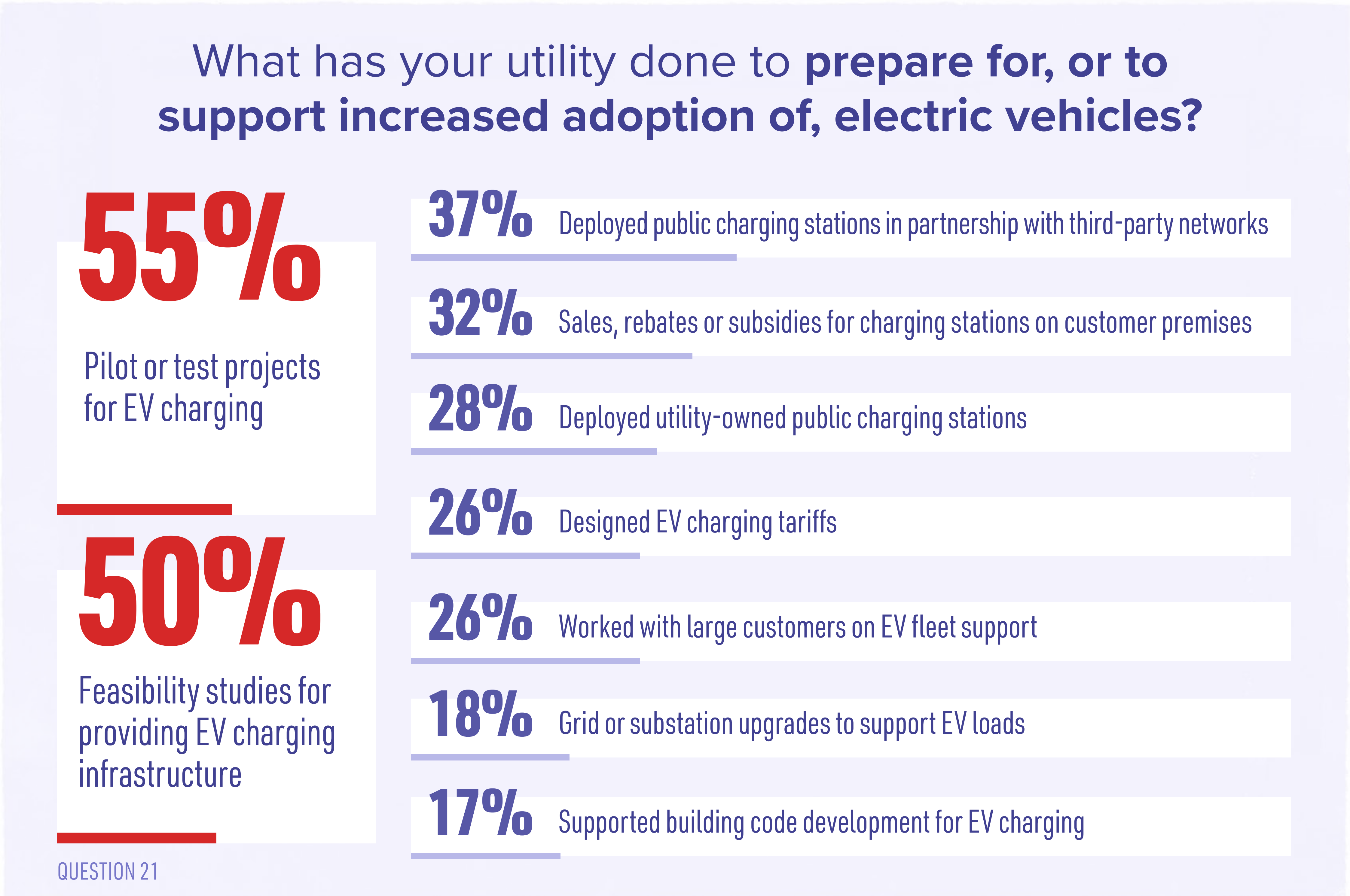
How should utilities approach the **electrification of the transportation sector**?



QUESTION 22

Other steps taken by participants' organizations include designing EV charging tariffs, working with large customers on EV fleet support, upgrading grids and substations to support loads from EV growth and supporting building code development for EV charging. Sixteen percent of respondents said their organizations have not taken any significant actions related to EV growth, while 7% are not sure.

Even residential EVs can cause a pretty steep spike in demand at full charge application, Bradley said, raising questions about whether utility systems are flexible enough to accommodate that impact. An example of a particularly challenging scenario: Imagine 50% of the population of Houston owns EVs, and a hurricane in the Atlantic Ocean is projected to hit the city in a week.



Challenges to storage deployments

Storage deployments continued to grow in 2020. In the third quarter, an unprecedented 476 MW of storage resources were deployed across the country — 240% higher than the previous record, from the previous quarter. A report from Wood Mackenzie and the Energy Storage Association estimated that the domestic battery energy storage market would grow sixfold, to nearly 7.5 GW, by 2025, driven largely by large-scale utility procurements.

But high costs still appear to be a challenge. Sixty-six percent of participants identified high costs as the biggest challenge their organizations are facing when it comes to adding storage to their systems.

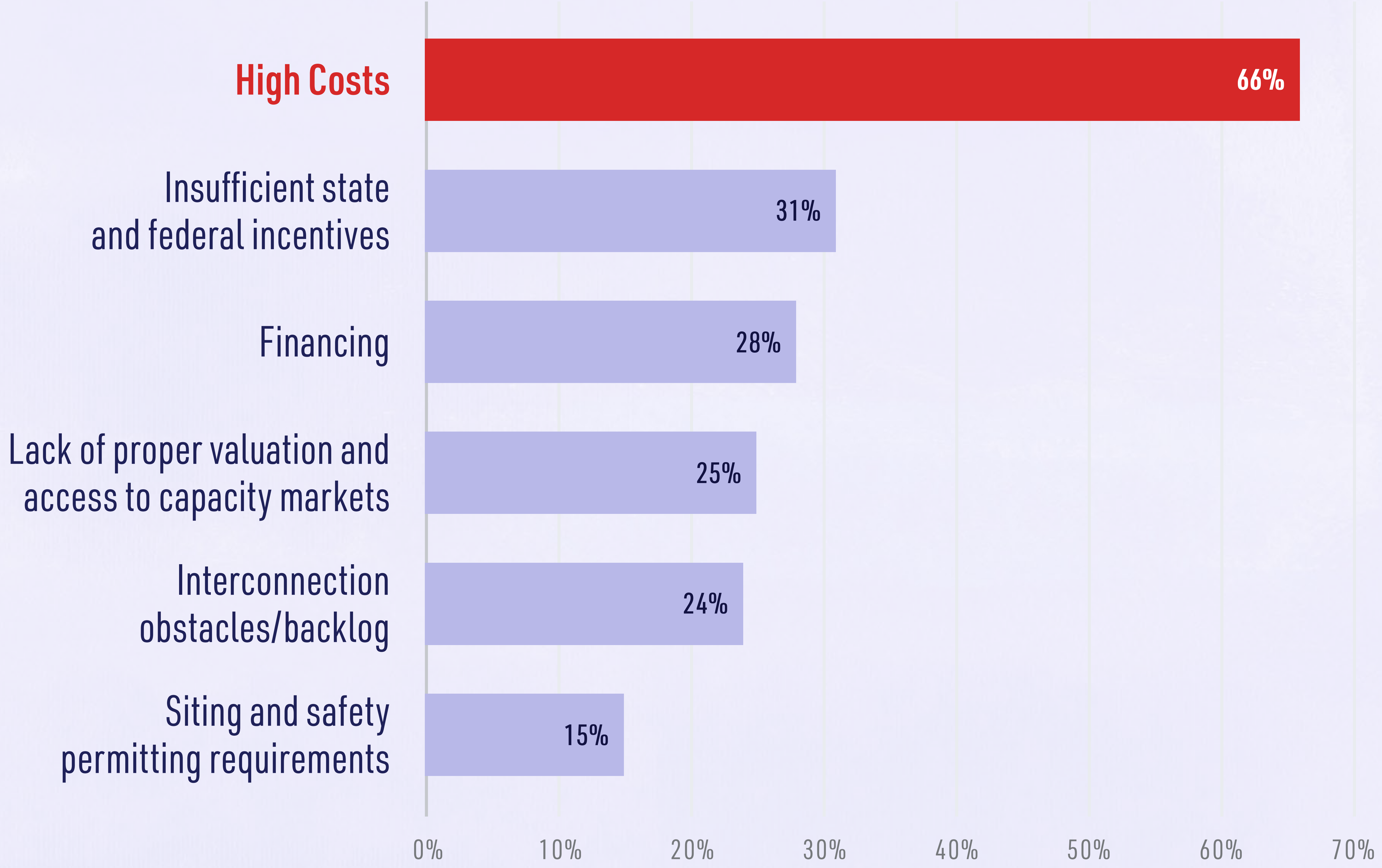
In comparison, 31% pointed to insufficient state and federal incentives, like tax credits; 28% cited financing; 25% selected a lack of proper valuation and access to capacity markets; 24% selected interconnection obstacles and backlogs; and 15% identified siting and safety permitting requirements as the biggest challenge. In total, 12% identified "other challenges" — such as the lack of need, regulatory hurdles and unproven technologies.

Storage costs have been falling precipitously, but they started off very high and only recently has storage become cheap enough to compete with other resources, Hledik noted. At the same time, Brattle analysis has found cost-effective opportunities to deploy storage in the fairly near term — not only in California but in several markets where deployment of utility-scale storage projects has increased significantly.

"There's a huge amount of capacity in the pipeline that suggests that that will continue," Hledik said, adding that cost declines are expected to continue, if not at the rate observed historically.

When it comes to getting more storage onto the grid, the question of cost comes down to the expected application of the resource, ESA's Burwen said. "[W]hen you hear costs are too high, it just means that whatever that person is looking at in terms of a specific geography and a specific application, maybe they are not going to get it to pencil there," he said.

What are the two biggest challenges you face to **adding more storage** onto your system?



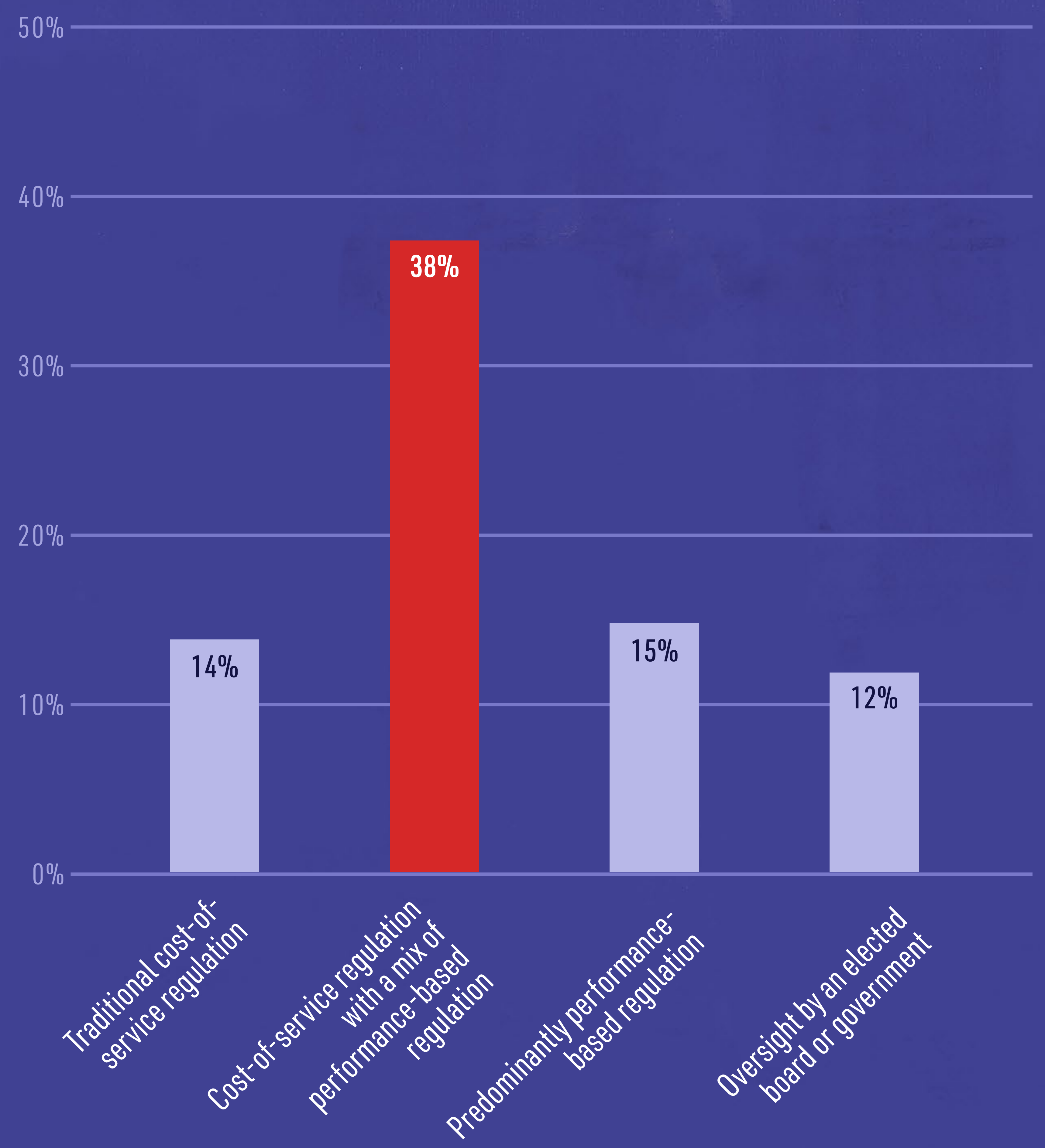
QUESTION 23

TRENDS IN UTILITY REGULATORY/ BUSINESS MODELS

Utilities prefer cost-of-service regulation, mixed with performance-based regulation

The majority of survey participants — 38%, or almost four out of 10 — said that cost-of-service regulation (COSR) with a mix of performance-based regulation (PBR) is the regulatory model that would best support their organizations' business growth over the next 10 years. A hybrid model has been the consistent preference for several years running, but this year respondents' desire for some performance-based mechanisms rose slightly over the 2020 results.

Which utility regulatory model would **best support your organization's business growth** over the next decade?



QUESTION 16

"There is not a bright line separating traditional cost of service ratemaking from PBR, as even traditional cost of service ratemaking provides a financial incentive to control costs via regulatory lags," a 2017 Brattle report found. "However, PBR is generally differentiated by the methodical incorporation of incentives into the regulatory framework."

Under cost-of-service regulation, states determine how much a rate-regulated utility can charge customers for the services they provide. Performance-based incentives have gained traction in the last several years as a way to align utility incentives with state and local renewable energy goals and broader decarbonization targets.

"Performance-based regulation is really, I think, in practice, a combination of trying to ensure some level of performance in terms of reliability and traditional utility areas of operations," said Bill Zarakas, a principal at Brattle. "And it also incentivizes some things that utilities are not necessarily financially motivated to do."

States leading on PBR hybrid models

Several states have enabled some sort of hybrid regulatory model, which can include anything from incentives for connecting more distributed energy generation and reducing carbon emissions to penalties for reliability issues or other safety concerns. Policy observers believe enabling such performance mechanisms can encourage utilities to deploy higher levels of distributed energy resources, something regulators believe can provide load flexibility and other electric system benefits.

Hawaii is furthest along in implementing a regulatory framework that leans more heavily on performance incentive mechanisms. In December, regulators issued an order that aims to move Hawaiian Electric off cost-of-service regulation and toward a more performance-based model.

Because the model remains largely unexplored, the financial community is uncertain whether its risks will benefit or hurt the utility's bottom line, Utility Dive reported in January. Other states, including Colorado, Connecticut and Minnesota, explored some form of performance-based ratemaking or performance-based regulation in 2020, according to the North Carolina Clean Energy Technology Center (NCCETC), with Connecticut enacting legislation to adopt a performance-based regulation framework.

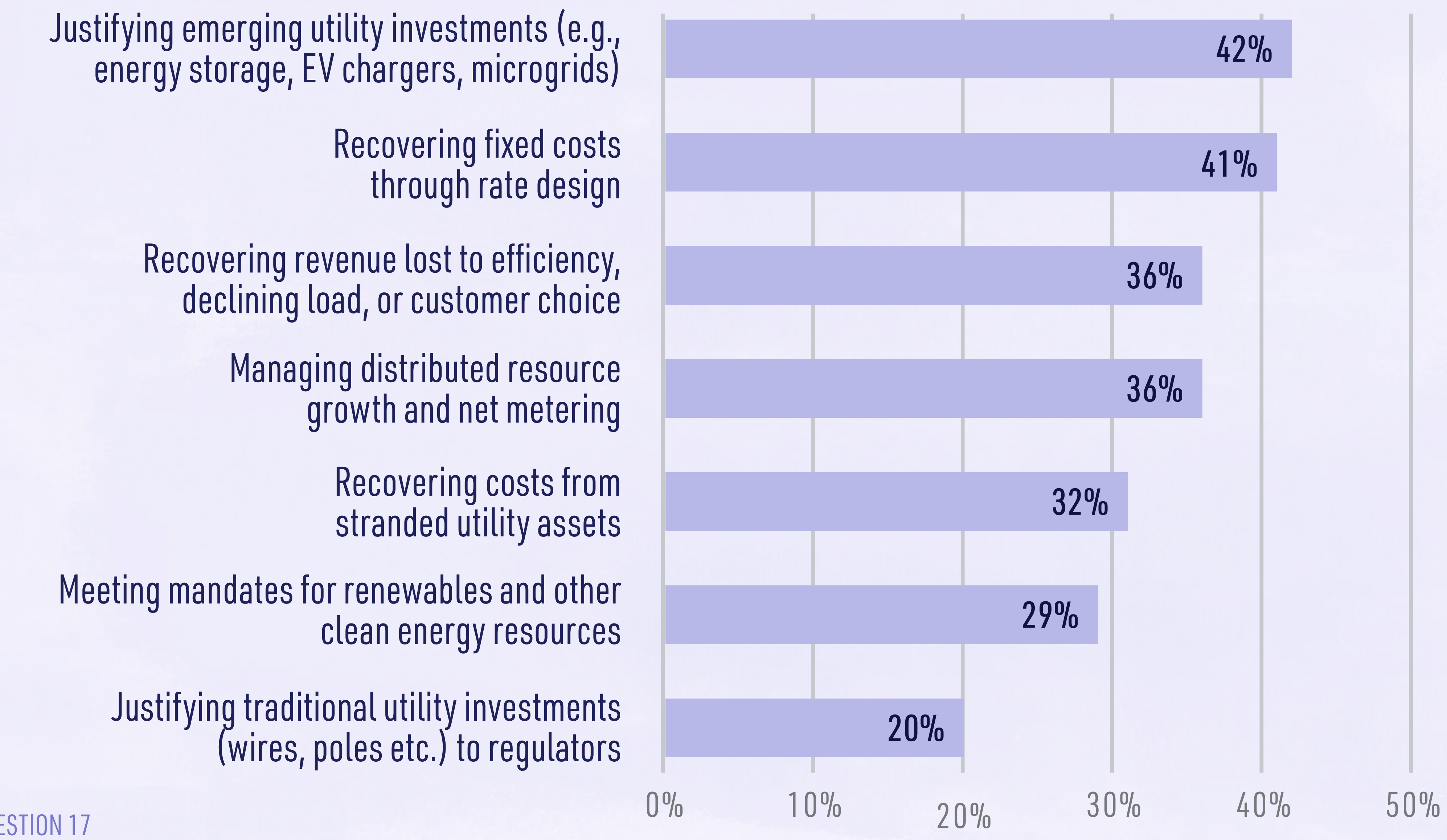
One in five respondents were unsure which model would best serve their future needs, perhaps signaling greater uncertainty over how performance-based measures might impact their business model.

Despite uncertainties, preference for a predominantly performance-based regulation model slightly outweighed preference for the traditional cost-of-service framework in best supporting a power generator's growth — a shift from years past. Fifteen percent of respondents said they would favor predominantly performance-based regulation, with 14% preferring to maintain the traditional cost-of-service route. Just 12% of respondents said they would prefer oversight by an elected board or government, a significant drop from the last two surveys: 35% of respondents preferred such a model in 2019, and 20% in 2020.

15%

of utility respondents said they would favor predominantly performance-based regulation

What are the most difficult challenges associated with the utility regulatory models in the states where your organization operates?



QUESTION 17

Justifying investments and recovering fixed costs through rate design: Two greatest challenges

Justifying investments in new technologies — such as energy storage, electric vehicle chargers and microgrids — is the top challenge utilities see with the current regulatory structure, consistent with years past.

Aging infrastructure and rapidly emerging and changing technologies require a tremendous shift on the part of utilities to retire old assets and make new investments. But there's a risk of passing along too many costs to customers, experts said. Grid modernization, in particular, can be a difficult investment to justify to regulators, especially technologies like advanced metering infrastructure (AMI).

"There seem to be challenges with justifying those investments to regulators," said Autumn Proudlove, senior policy program director at

NCCETC. “And also regulators, on the other hand, we’ve heard that they’re not sure how to evaluate them. Do they evaluate them just as they would traditional grid investments, or how should that cost benefit analysis be done?”

Overall, AMI deployments began to slow down at the beginning of last year as regulators questioned whether the billions of dollars invested in the technology are paying off, Utility Dive reported last year. A 2020 report from the American Council for an Energy-Efficient Economy also found that utilities were not maximizing the value of smart meters, potentially risking regulatory approval and harming future investments.

But 48 states plus the District of Columbia took some form of action on grid modernization in 2020, according to NCCETC. Most of that activity involved deploying energy storage, utility business model reforms, smart grid deployment, customer data access policies, AMI rules, distribution system planning and AMI deployment, NCCETC found in its February 2021 50 States of Grid Modernization report. Already in early 2021, New Jersey regulators approved an almost $800 million Public Service Electric & Gas plan that will install 2.3 million smart meters across the utility’s service territory, Utility Dive reported.

Distributed energy continues to upend the traditional model

Recovering fixed costs is respondents’ second most cited challenge under current utility regulatory models, with 41% of respondents naming it, also similar to years past. The growth of distributed energy resources has perpetuated that concern, previous Utility Dive surveys have shown. Moving customers to time-of-use rates or increasing fixed charges are popular solutions to this concern, as is explored later in the report. Managing distributed resource growth and net metering, as well as recovering revenue lost to efficiency, declining load or customer choice followed those concerns, with each chosen by 36% of respondents. Stagnating load and increased customer interest in energy efficiency and other distributed energy resources were some of the top climate change factors cited by utilities as a potential risk to their business model, Utility Dive found in an analysis of 16 utility CDP filings.

Recovering costs from stranded assets and meeting mandates for renewables and other clean energy resources follow at 31% and 29%, respectively. Stranded assets were considered a top risk by just 18% of respondents last year, which Utility Dive reported was likely a sign that vertically integrated utilities felt confident that regulatory structures and new financing mechanisms would allow them to recover those costs. However, stakeholders noted stranded assets present a high risk to ratepayers, perhaps explaining the jump.

Justifying traditional utility investments was listed as a challenge by 20% of respondents.

Time-of-use rates and fixed fees best ways to recoup fixed costs

Similar to years past, and as discussed in section four above, utilities indicated that they are moving toward time-of-use (TOU) rates as a way to allow them to recoup fixed costs given load declines and increased use of DERs. TOU rates shift prices so that customers pay more during high-demand periods, and are intended to shift customers’ consumption to lower-priced, off-peak periods. Such rates allow utility companies to recover costs while also making it easier to integrate large solar and send price signals to rooftop solar owners.

Maryland regulators last year approved a series of time-of-use pilots to address peak demand issues and to lower overall customer bills. And a September settlement between Duke Energy and DER advocates in North and South Carolina could bring a new TOU model to that region as well. The settlement would, if approved by state regulators, pair rooftop solar owners with smart DER devices and time-varying rate designs, giving customers an incentive to help reduce peak demand on the utility.

41%

said recovering fixed costs is a challenge under current utility regulatory models

40%

consider aging assets or technology to be a major challenge facing their organization

More sophisticated, time-varying rates are necessary to manage load-varying resources and ensure higher levels of DERs can be integrated and maximally benefit the system, stakeholders said. AMI is a necessary component as well — allowing home energy management, usage alerts and time-varying rates, according to a 2019 Edison Foundation report.

Preliminary September results from Brattle on TOU pilots run by three of Maryland's investor-owned utilities found that summer peak demand fell 10.2% to 14.8%, non-summer peak demand fell 5.1% to 6.1%, and electricity bills, including across low-to-middle income segments, were reduced 5% to 10%.

Raising fixed charges was the second most popular option for utilities to recoup fixed costs, as loads decline and as distributed generation grows, selected by 42% of participants. That option shields utilities from revenue losses caused by shifts in demand, but is less favored by ratepayers because it doesn't allow customers to exercise much control over their rates.

Moving net-metered customers or those with distributed generation to a separate rate class is the third most popular option, with 36% of respondents indicating that as their preference, also consistent with years past. Net-metered customers have often been a complaint of utilities, citing cost-shifting from rooftop solar customers to other customers as a reason they dislike the rates.

Some 30% of respondents believe that all customers should pay demand charges, slightly lower than last year, but higher than two years ago. Demand charges are additional fees that utilities charge non-residential or commercial customers for maintaining a constant supply of electricity. Minimizing bills for low-demand customers, demand charges for only distributed generation customers and decoupling were preferred by 24%, 17% and 14% of respondents, respectively.

Utilities see four major challenges in evolving the utility business model

More than a third of respondents mentioned four major challenges their organizations are facing in evolving their business models. The most frequently cited challenge, at 40%, was aging assets or technology, an increased concern from previous years. Many utilities are retiring older coal plants sooner than the end of their depreciated life, leading to an increased concern over how those facilities will be replaced and how utilities will pay off their remaining costs.

Aging assets don't have to be a challenge, though, and can actually be seen as an opportunity, Proudlove said. "When you're trying to evolve your business model, if you have aging assets, then that's kind of an opportunity to maybe invest in some newer technologies, like AMI, that can enable more demand response and time-of-use rates, and actually save you some money and lead to these things that are beneficial to customers and the utility," she said, "kind of aligning those interests."

Reliably integrating renewables closely follows at 39%, consistent with last year. Reliability has been on particular display in California this year, where rolling blackouts were triggered following excessive demand, coupled with inadequate resource planning targets under the state's changing power mix and broader market issues.

The cost of transition to ratepayers was chosen by 37% of respondents, a decrease from previous years where cost has been the No. 1 concern. Changing customer needs and expectations was the fourth most listed concern at 36%, also a slight decline from previous years. Customer expectations are driven by both a desire to combat climate change and a desire to have more control over generation and save money through rooftop solar, home batteries or other forms of DER.

Nearly a third of respondents also listed workforce transformation as a major challenge, and 27% listed regulatory inflexibility as a top issue. It's "interesting" that workforce transformation "has really dropped," said Carl Pechman, director of the National Regulatory Research Institute, under the National Association of Regulatory Utility Commissioners. Other surveys have found that "the aging utility workforce was a big problem," he said. "And I don't really know that they've hired a lot of younger employees."

> "When you're trying to evolve your business model, if you have aging assets, then that's kind of an opportunity to maybe invest in some newer technologies, like AMI, that can enable more demand response and time-of-use rates, and actually **save you some money and lead to these things that are beneficial to customers and the utility.**"
>
> **Autumn Proudlove,** senior policy program director at NCCETC

Climate change and climate activism rose slightly as a concern this year, with 23% of respondents listing it as a top challenge, tied with internal corporate resistance to change. Climate change is really a "surrogate" for many of these problems, including changing customer expectations, noted Pechman, and is also the main driver of the industry's entire transformation and its successive challenges. Environmental regulations and technology disruption were listed as the lowest concerns, selected by 20% and 19% of respondents, respectively.

"What you have here, largely, is a description of how complex the issues facing the industry are and that it needs to juggle all of these kinds of factors," Pechman said. "There are a lot of opportunities, but there are many, many challenges in the industry."

The four issues seen as the **greatest challenges** facing organizations' in evolving their business models

40% Aging assets or technology

39% Reliably integrating renewables, and other new generation/grid technologies

37% Cost of transition to ratepayers (stranded assets, grid modernization, etc.)

36% Changing customer expectations or needs

QUESTION 27

5

LOOKING FORWARD

The COVID-19 pandemic likely will not have the same impact in 2021 as it did in 2020 — clearly a challenging year for the power sector — but cybersecurity, reliability and other risks continue to rise.

While a variety of factors contributed to the widespread power outages in Texas in February, the event was a stark reminder of the vulnerability of the grid, particularly as extreme weather events increase.

A February cyberattack on a water utility in Florida, the widespread hack of U.S. government agencies and companies that use SolarWinds software, and other cybersecurity incidents further demonstrate the need to address risks to the power system.

And there is a desire among utilities for regulators to act.

“Strengthening cybersecurity requirements for utilities” ranked second among seven priorities for FERC in this year’s SEU survey.

The top-ranked priority for FERC was to “work with grid operators to better ensure state renewable energy policies are accommodated.”

With new FERC Chair Richard Glick’s promise of “significant progress” on the energy transition, efforts to lower barriers to clean energy resources will be a key focus of the commission, along with transmission reform and capacity markets.

And with Glick’s commitment to enhanced stakeholder engagement, the public is poised to play a greater role in all of this.

Regulators, utilities, grid operators and other players have a tremendous challenge in building a clean, affordable, reliable and secure power system.

At the state level, utility commissions are taking an increasingly skeptical look at integrated resource plans and ordering utilities to revise plans that lack a sufficient consideration of clean energy.

States are also looking at new regulatory models to offer better incentives to utilities to achieve broader policy and customer-focused goals.

And while today’s utilities face many risks and challenges, there is also tremendous upside for companies willing to adapt their business models and pursue opportunities that go outside their traditional way of doing things, such as taking advantage of the growing interest in DER.

Solar, wind, energy storage and distributed resources are on the rise, while the future of natural gas is increasingly in question, although it retains strong support among some in the power industry. While many utilities continue to see gas as a critical bridge to a zero-carbon future and an important part of their portfolios, there has been a significant jump in the last five years in the number of survey respondents who expect their company’s gas-fired generating capacity to decline in the next 10 years.

A key question to watch in 2021 is how much state regulators will push back on utility plans to bring new gas-fired power plants on to their systems.

Another big question mark for 2021 is whether momentum will continue to build around hydrogen, which could use existing gas assets.

Electrification of transportation and buildings is also poised to be a significant opportunity and load growth driver for utilities. The Biden administration is committed to advancing EVs, and carmakers are investing billions in their development and production. But it remains to be seen if current forecasts of widespread adoption will bear out.

Driven by state requirements, growing public demand and other factors, utilities are also investing billions to create cleaner generation portfolios and to secure their assets from physical and cyber threats.

More and more utilities are pledging increasingly ambitious timelines to achieve net-zero carbon emissions. While there has been some concern on whether actions match rhetoric around such commitments, the next few years should provide increasing clarity about whether utilities can achieve or even accelerate their current goals.

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QUESTION 1

Which type of energy provider employs you?	
I am not currently employed by a utility*	56%
Investor-owned utility	21%
Municipal utility or public power agency	11%
Electric cooperative	6%
Retail energy provider*	6%

* These respondents were disqualified from the survey

QUESTION 2

Which electricity services does your organization provide?	
Distribution	77%
Generation	72%
Transmission	65%
Retail sales	48%

QUESTION 3

What is your job level/role at your organization?	
Non-management employee	43%
Department manager	30%
VP or other high-level executive	12%
C-suite	7%
Board member	7%

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QUESTION 4

In which regions does your organization provide electricity service?	
Midwest	24%
Other countries or regions	22%
West Coast	21%
South & Southeast	16%
Southwest & Texas	16%
Northeast	15%
Great Plains & Rocky Mountains	12%
Mid-Atlantic	8%
Non-contiguous U.S. states & territories	4%

QUESTION 5

How many electricity customers does your organization serve?	
More than 4 million	28%
1-4 million	27%
Fewer than 100,000	21%
100,000-500,000	13%
500,000-1 million	11%

QUESTION 6

What have been the top impacts of the coronavirus pandemic on your utility?	
Remote working	44%
Loss of revenue	32%
Shifts in energy use and demand	28%
Shutoff moratoria	19%
Disruptions in capital projects	19%
Social distancing requirements	19%
Supply chain disruptions	16%
Maintaining corporate culture	12%
Employees getting sick	7%
Other	5%

QUESTION 7

How long do you expect the business impacts of the COVID-19 pandemic on your company to continue?	
6 months to 1 year	51%
1-3 years	30%
Another 6 months or less	13%
3-5 years	3%
More than 5 years	2%

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QUESTION 8

Which net load growth trend do you see in your service area?	Declining Load	Stagnant Load	Increasing Load
Industrial	31%	52%	18%
Commercial	46%	34%	20%
Residential	5%	24%	71%
Overall	21%	50%	29%

QUESTION 9

What have been the top drivers of load change for your utility?	
COVID-19	58%
Energy efficiency and demand side management programs	41%
Economic growth/new industries	36%
Increased electrification of transportation, buildings and other sectors	32%
Population changes	29%
Customer-sited resources	17%
Retail choice/competition with non-utility providers	12%
Other	6%

QUESTION 10

Which issues are currently most important to your organization?	
Renewables, sustainability, or the environment	45%
Reliability of retail distribution grid	29%
Climate change impacts and resilience	28%
Bulk power system reliability	27%
Aging grid infrastructure	26%
Cybersecurity and physical security	24%
State regulatory model reform	21%
Electric vehicles	18%
Distributed energy resources	18%
Generation retirements and/or stranded assets	17%
Federal energy policy uncertainty	15%
Other	5%
None of the above	0.3%

QUESTION 11

What should be FERC's top two priorities over the next year?	
Work with grid operators to better ensure state renewable energy policies are accommodated	35%
Strengthen cybersecurity requirements for utilities	32%
Take action to support baseload generation	31%
Establish a carbon price mechanism for the power sector	30%
Address state clean energy subsidy impacts on the overall competitiveness of wholesale capacity markets	23%
Update its transmission incentive policy	23%
Establish and apply a clear and consistent method for assessing climate impacts of any projects it reviews	18%
Other	8%

QUESTION 12

How do you expect your organization's mix of power resources to change over the next 10 years?

	Decrease Significantly	Decrease Moderately	Stay About the Same	Increase Moderately	Increase Significantly
Oil	40%	22%	32%	5%	1%
Coal	65%	21%	12%	1%	2%
Nuclear	18%	10%	58%	9%	5%
Hydropower	0%	4%	69%	19%	7%
Fuel cells (grid scale)	2%	1%	51%	36%	11%
Natural gas	9%	21%	32%	26%	12%
Wind	1%	1%	24%	45%	29%
Distributed energy resources	0%	1%	13%	58%	29%
Battery energy storage (grid scale)	0%	0%	13%	51%	35%
Solar (grid-scale)	1%	1%	8%	38%	52%

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QUESTION 13

How should grid operators, regulators and lawmakers respond to the retirement of coal and nuclear generation?	
Devise new market rules to pay plants based on reliability, resilience or fuel security attributes	43%
Introduce a carbon price in wholesale markets, or a carbon tax	39%
Allow states to devise support programs for selected plants (e.g. New York's Clean Energy Standard)	37%
No action: allow uneconomic generation to be retired under current market rules	32%
Other	7%

QUESTION 14

Which approaches are most effective in decarbonizing the power system?	
Financial incentives for renewable energy development	50%
Strong federal decarbonization policy, backed up with clear targets, regulation and enforcement	45%
Updated transmission infrastructure	43%
Performance-based rates or other strategies to shift the utility business model	37%
State policies and mandates	36%
Nuclear power support/expansion	35%
Carbon capture technology	23%
Voluntary energy industry measures	20%
Decarbonization is not an appropriate goal for the power system or for energy policy	10%
Other	8%

QUESTION 15

What is the best way to get more renewables on the grid?	
Extending federal tax credits	17%
Facilitating the build of new transmission infrastructure	15%
Incentivizing and simplifying the addition of energy storage resources to the grid	14%
State mandates	12%
Federal mandate	11%
Letting the market take its course	11%
Simplifying interconnection requirements	8%
Ensuring wholesale market structures accommodate state clean energy policies	7%
Other	4%

QUESTION 16

Which utility regulatory model would best support your organization's business growth over the next decade?	
Cost-of-service regulation with a mix of performance-based regulation	38%
Not sure	20%
Predominantly performance-based regulation	15%
Traditional cost-of-service regulation	14%
Oversight by an elected board or government	12%
Other	1%

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QUESTION 17

What are the most difficult challenges associated with the utility regulatory models in the states where your organization operates?	
Justifying emerging utility investments (e.g. energy storage, EV chargers, microgrids)	42%
Recovering fixed costs through rate design	41%
Recovering revenue lost to efficiency, declining load, or customer choice	36%
Managing distributed resource growth and net metering	36%
Recovering costs from stranded utility assets	31%
Meeting mandates for renewables and other clean energy resources	29%
Justifying traditional utility investments (wires, poles etc.) to regulators	20%
Other	6%
There are no difficult challenges	4%

QUESTION 18

How do you believe your organization should build a business model around distributed energy resources?	
Partnering with third-party providers to deploy DERs on the grid	46%
Owning and operating DERs as a regulated utility through rate-based investments	42%
Procuring or aggregating power from DERs owned by third-party providers	29%
Owning and operating DERs through an unregulated subsidiary	21%
I do not believe my organization should have a business model around DERs	16%
Other	4%

QUESTION 19

Which approaches would best enable your utility to recoup fixed costs, as loads decline and as distributed generation (DG) grows?	
Move consumers to time-of-use rates	45%
Increase fixed charges/fees	42%
Move net metered customers or those with DG to a separate rate class	36%
All customers pay demand charges	30%
Minimum bill for low-use customers	24%
Demand charges for only DG customers	17%
Institute decoupling	14%
My utility should not change its rate design	12%
Other	5%

QUESTION 20

What is the best compensation mechanism for distributed generation (particularly rooftop solar) in your service territory?	
Net metering at the retail rate minus fees for grid use	30%
Net metering at the wholesale rate, or avoided cost of other generation	30%
Net metering at the retail rate	14%
Value-of-solar tariff (such as in Minnesota or in Austin, Texas)	11%
There should not be utility compensation for customer-sited DG	8%
Location-based rates	5%
Other	3%

QUESTION 21

What has your utility done to prepare for, or to support increased adoption of, electric vehicles?	
Pilot or test projects for EV charging	55%
Feasibility studies for providing EV charging infrastructure	50%
Deployed public charging stations in partnership with third-party networks	37%
Sales, rebates or subsidies for charging stations on customer premises	32%
Deployed utility-owned public charging stations	28%
Worked with large customers on EV fleet support	26%
Designed EV charging tariffs	26%
Grid or substation upgrades to support EV loads	18%
Supported building code development for EV charging	17%
No significant action taken yet	16%
Not sure	7%
Other	5%

QUESTION 22

How should utilities approach the electrification of the transportation sector?	
Offer special pricing or rates for EV charging	52%
Create pricing or rates for EV battery services (i.e., frequency regulation)	49%
Own and operate charging stations as a regulated utility	48%
Provide utility-owned chargers where private companies cannot or will not deploy	43%
Construct make-readies for chargers and let private companies own them	27%
Allow an unregulated utility subsidiary to supply chargers	21%
Utilities should not pursue transport electrification	5%
Other	5%

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QUESTION 23

What are the two biggest challenges you face to adding more storage onto your system?	
Financing	28%
Interconnection obstacles/backlog	24%
High Costs	66%
Lack of proper valuation and access to capacity markets	25%
Insufficient state and federal incentives (such as tax credits)	31%
Siting and safety permitting requirements	15%
Other	12%

QUESTION 24

What is your organization doing to enhance cybersecurity for its systems and data?	
Training all employees in safe email use, how to spot phishing attempts, and similar skills	79%
Complying with government mandates and/or industry guidelines (NERC CIP, etc.)	58%
Increased spending for digital operations and security	57%
Systematic and prompt patching/upgrades for existing systems	55%
Briefings for executives, boards and managers on cybersecurity risks to the power system	54%
Partnering with outside cybersecurity firms	42%
Setting requirements for, and/or testing, the security of integrated third-party systems	39%
Accelerating cloud adoption to leverage cloud providers' advanced cybersecurity capabilities	38%
Establishing procurement and supply chain cybersecurity protocols	38%
Not sure	13%
Other cybersecurity measures	11%
None of these	2%

QUESTION 25

Did your organization experience any of the following in the past year due to a physical or cyber attack?	
Other	61%
System downtime	15%
Decrease in system reliability	11%
Loss of data	8%
Loss of revenue	8%
Reputational impacts	7%
Insurance claims	6%
Customer impacts (such as billing disruptions)	5%

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QUESTION 26

How is your organization approaching climate resilience?	
Coordination with officials: public safety, state/local government, emergency response, etc.	47%
Top executives fully support climate resilience as a high organizational priority	41%
Substation and grid assets are being hardened	37%
Emerging technologies (microgrids, energy storage, etc.) are adopted with climate resilience in mind	32%
Customer education on preparedness for natural disasters and extended power outages	32%
A well-defined, actionable climate resilience plan is in place	21%
We are evaluating climate resilience options, but no decision yet whether/how to act	21%
We can proactively de-energize grid sections during times of peak fire risk	17%
Little/no attention or action on climate resilience at our organization	12%
Internal disagreement about how we should respond to climate change	10%
Leadership is opposed to, or apathetic about, climate resilience measures	5%
Other	6%

QUESTION 27

What are the greatest challenges to evolving your organization's business model?	
Aging assets or technology	40%
Reliably integrating renewables, and other new generation/grid technologies	39%
Cost of transition to ratepayers (stranded assets, grid modernization, etc.)	37%
Changing customer expectations or needs	36%
Workforce transformation	31%
Resistance from state regulators, or regulatory model inflexibility	27%
Internal resistance to change	23%
Climate change and/or climate activism	23%
Environmental regulations	20%
Technology disruption	19%
Nothing: Our business model is evolving well, or does not need to change	10%
Other	4%

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SEU 2021

STATE OF THE ELECTRIC UTILITY

SURVEY REPORT

UTILITY DIVE