

**HARVARD ELECTRICITY POLICY GROUP**

**VIRTUAL SESSION**  
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**Rapporteur's Summary\*****Electrification of the Economy: Is it Economic? Is it Green?**

It is widely argued that de-carbonization calls for electrification of the economy. Cities from Brookline and Cambridge, in Massachusetts, to Bellingham, Washington, have either banned or are considering banning the use of natural gas for residential heating in new construction. New York State, has effectively foreclosed new natural gas pipelines, prohibited fracking, and sent mixed messages about use of natural gas heating in the state. The decline in the use of coal has made that fuel source less of a target in the debate and made this issue more about discouraging (or banning) the use of natural gas, and the use of fracking to obtain it, for environmental benefit. What are the costs of discarding or severely limiting the use of natural gas for heating, generation, transportation, etc., particularly at a time when the commodity is plentiful, inexpensive, and is helping to drive down carbon emissions by making coal uneconomic? Are there real environmental gains to be derived from further electrification and diminution in the use of natural gas? How will we generate sufficient electric energy to meet the increased demand? Are we far enough along in the evolution of renewable energy and storage to be highly dependent on those technologies?

**Moderator.**

In any event, what happens is being recorded. We will use the comments that are made, but we're not going to attribute any anybody individually and we never do that. And so I will recognize people as I see them. On this session, Bill will actually be monitoring the chat and so if things come up that need to be raised below, raise it. You're obviously welcome to raise it yourself during the Q&A comment and discussion period. So those are the ground rules.

Today, of course, the topic is electrification of the economy, which a number of people are discussing, both for environmental reasons and perhaps for economic reasons. And the whole purpose of today's session is to take a look at exactly what does this mean. All the speakers have been very involved with this issue.

The first two speakers have done this on a very fairly broad level, look at the economy

in general. Then we'll hear from somebody from the GA talking about from a perspective of natural gas, how they view this issue. Then we'll finish off with a micro study of specific application of conversion from gas to electric and what that means. So we'll go from the macro to the micro. Speaker 1, if you'd start off with, I'd appreciate it.

**Speaker 1.**

Thanks very much for the invitation to be here. I'm excited to share our work. I'm with the Electric Power Research Institute, and we've done a lot of work on electrification. I've been leading the modeling of this from an energy economy perspective. There's a lot of work in other parts of EPRI on the technology and program level, and I'll refer to that where I can. But then I want to talk about some of our system-level impacts and what we found with our economic modeling.

Our first study on this came out, actually, roughly two years ago, almost this month, of

\* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants. Participant comments have been edited for clarity and readability.

US national electrification assessment. We used our platform to conduct an economy-wide assessment across all the sectors, where we're really looking at endogenous technology adoption. So there's sort of technology-neutral perspective here, and we're looking to see where electrification plays.

Those customer decisions were integrated with an electricity supply model to understand the system implications, in a small number of scenarios as a reference case, as well as two scenarios where we're carbon pricing to start to understand the interaction between decarbonization and electrification. Now this was just the beginning. There are a number of studies that followed on from this, particularly at the state level, we worked in about 12-15 states, where we've done specific assessments for those regions and we're starting a new initiative around resources to look at the low-carbon fuels that could complement electrification.

Our modeling platform here—and I'm going to be brisk here, I don't want to spend a lot of time on that methodology—but this is a detailed modeling platform. We have a fairly sophisticated representation of the electric system that's on the left. What's new in this study is we developed a detailed representation of energy end use, trying to capture all the dimensions of heterogeneity that drive the many ways in which energy is used, to be able to evaluate at the technology level, some fuel level, the trade-offs between these technologies and end-use fuels.

That gets rolled up into sort of system aggregate load shapes, which are then evaluated and synchronized with the electric system. So we're able to look at both where electrification make sense at this granular level and then show the system implications, as well. So I'm going to talk about both of

those types of results, again, fairly high level here because we only have a few minutes.

The next slide shows a breakout of the final energy debate here. We started in 2015, this shows end use fuels by end use sector and application. This is still aggregated from the level of resolution in the model. But you start to get a sense of where the fuels are used, where the big categories are. The yellow boxes show what the electrification technologies that map on to these different end uses and where they're applied.

Light-duty vehicle stands out for a couple reasons. One, it's the largest use of energy and also the technology. For electrification, the electric vehicle and the plug-in hybrid that's emerging as battery costs come down, as technology starts to come to market. This is one of the most promising areas and also one of the largest. So that's an area where we focused a lot.

We've also focused on space heating. It's another large category of energy. Heat pump technologies change quickly. It's a little bit more mixed, the results. But I want to talk about those two in particular. We have studied all of these applications, and if there are questions we can get into some of those.

The next slide, it's almost a cartoon, a little bit of the two key elements of the trade off, which is energy expenditure and emissions. So the left hand side shows for an average household and the current configuration of the system, what an average household's spending on energy and what the carbon footprint is, if you map these out to the activities.

And on the right-hand side shows what happens if you replace their conventional vehicles with EVs. And the idea is that you're saving on energy bills, the increased

expenditure on electricity is significantly less than what you're spending on gasoline. This is against average and depends on how much you drive and so forth. But this is true for many drivers, many potential customers. Then the emission savings are also significant, in this case we've assumed a marginal CO<sub>2</sub> intensity based on a new natural gas combined cycle.

Of course, that's a complicated calculation that depends on the system and depends on everything else that's happening. So that's a modeled outcome. So this is kind of a cartoon in that sense. But it's a pretty good estimate of what the marginal CO<sub>2</sub> intensity coming out of the model is. The bottom shows if you look in a future year with improved efficiency and also carbon incentives to lower the carbon intensity of marginal generation, then the emission savings are even greater.

So this is only part of the equation. There's also the fact that the EVs are a little bit more expensive, there's charging infrastructure. But at the same time maintenance costs for EVs are presumed to be lower.

This slide summarizes the inputs and what the model is doing with adoption. Again, this is on that granular side. These are our assumptions on the lefthand side, prices continue fall rapidly, a wider range of models becomes available. I think both of those are happening. It's still uncertain as to how that develops. Home or work charging were assumed to be available in the study, although not without a cost. So we do assume that there's some costs associated with the charging infrastructure, but it's part of the balance and still the net costs are lower for the EV going forward. EV maintenance costs are a big part of the equation.

We also assume that fuel prices remain relatively low and the incumbent ICEV that the EV is competing against continues to improve in efficiency. But even with all those, even with those forces, these assumptions lead to, from the economics—across a wide range of customer types we look at, different settlement types, urban, rural, suburban, look at different amounts of mileage—for about 75% of drivers by 2030, EVs or plug-in EVs are the most economical choice.

And that goes up to serve 90% by 2050. Now we have an adoption model that sort of has lots of legs built in, so we're not assuming that adoption follows the economics immediately. Eventually, we assume that it does. So we have 40% adoption of new vehicle market share by 2030 of EVs. Now that's a lot higher than, I guess if you were to forecast from current market trends, if you were to kind of project that forward.

So I think that reflects the fact there still remain a lot of barriers to realizing those economic benefits. But just from a technical, economic perspective, the EV potential is very compelling and large. This is for light duty vehicles. The same is becoming true for medium- and heavy-duty as well.

I want to move on to a couple stories around space heating. A key factor with space heating, and we're basically talking about heat pump technology here. Heat pump technology, of course, depends on the climate. We're looking at air source heat pumps, primarily, so the efficiency depends on the outdoor temperature, some cold climates you have less efficiency. Heat pump technology's improving over time and that relationship is improving, over time, but it's a physical constant that you're going to have decreased efficiency as the temperature drops with an air source heat pump.

What you see here is the regions of the country, states plotted in terms of the ratio of the gas price of electricity price and then the ratio of the efficiency of the heat pump to the efficiency of a gas furnace, which of course is fixed relative to temperature. If you're above the line, the heat pumps are a little bit more expensive terms of operating costs. If you're below the line, the heat pump is less expensive. That means that the relative price of electricity is not as high, compared to gas, as the efficiency advantage of the heat pump. That tends to happen to milder climates.

So something like Florida would be the bottom of the chart and then something like New York might be at the top of the chart. Over time, both those things are changing. So gas prices and electricity prices are changing over time, but primarily what's happened is the technology is improving. So as the technology improves, a relative efficiency between electricity and gas improves and those dots move to the right, and you have more regions where the heat pump is more economical. Not everywhere, but certainly more.

Then if you move to a transformation case where we apply a pretty high carbon price, by 2050, almost everywhere is under the line. Now there's still capital costs, this is just looking at operating costs. But the point is that over time as technology improves and as you add a carbon incentive, heat pumps become more economic in more places.

The next slide shows the current market share, existing stock in residential buildings, and I've separated out into colder requirements and milder climates. The bottom chart shows the market share of existing stock in that sort of lighter blue and the upper chart in the darker blue. So electric heat pumps and electric resistance have a

pretty solid market share in the south and not as much in the north.

That's reflected in our results. The new market share that we project going forward, this is in 2030, certainly it has a higher share of electric heat pump adoption in moderate climates, but still some in the northern climates as well. Another thing that's happening is the model prefers heat pumps through electric resistance. So you see a lot of efficiency in that regard, that's really a case of, if you're willing to pay up front for the more efficient technology, it pays off very rapidly. Of course, there are adoption barriers with that, that we're all familiar with around efficiency.

So that's another trend that happens in the model, that the heat pumps are replacing resistance, as well as other fuels. But it's not 100%. There's also a role for heat pumps, combined with non-electric fuels as a backup source, particularly in northern climates, where the efficiency in the heat pump falls in the colder temperatures. And so it's more efficient to have a non-electric fuel at the peak in the house.

So that's just a snapshot of what we're doing with space heating. This is giving you an overview of our economy-wide energy use. On the lefthand side, this is total energy, it's final energy. And so the electricity part is growing, the darker blue is what is additional electricity demand due to electrification. So you see the final energy is actually falling over time. This isn't a reference case.

A lot of that is due to what we know to be the case about energy intensity declining over time, structural change in the economy, their efficiency improvements throughout. But electrification contributes to that trend, because electricity essentially [UNINTELLIGIBLE] fuel and that's where

the benefits derive. You have increased electricity, decreased particularly other non-electric energy, which is mainly petroleum because the main scale effect here is in the transportation sector. So the righthand side shows the new electricity demand, broken out by sector and the main category for increased load is vehicles, both light duty and medium/heavy duty, but majority is light duty. There is some electrification going on in the building sector, but because they're looking at heat pumps replacing electric resistance, there's a netting out effect so that there's not a lot of additional load in industry.

I haven't talked a lot about industry. There are some opportunities, certainly not as much in a reference case where there's no the carbon price. But there are definitely opportunities within industry. The next slide shows what happens when we acquired carbon price. So there's increased electrification, more displacement of non-electric fuels. Buildings, in the industry sector in particular, are more responsive to the carbon price because a lot of the electrification of vehicles has already made sense in the baseline and is driven by economics, independent of the carbon price.

Last two points I want to make are around emissions and load shapes. The next slide shows our results for emissions in CO<sub>2</sub> and we've also looked at criteria pollutants and air quality. I won't be able to get into that, but you have similar impacts here of electrification on air quality, but what we see here is increasing electrification leads to lower overall CO<sub>2</sub> emissions, even in a reference case where you have electric generation emissions rising. So the whole sector's emissions are rising. Over time, due to the base load and there's no carbon incentive, it's mainly gas, some coal.

You have an increase in CO<sub>2</sub> emissions from the electric sector, but a net decrease overall

because admissions benefits of electrification. If you apply a carbon price, it very rapidly reduces the carbon density generated in the sector, as well as increasing the incentives for electrification.

So you get more electrification, lower carbon electricity, much lower carbon, and so that drives significant economy-wide productions. It doesn't drive it to zero. There are still some applications where the electrification doesn't reach, it doesn't make sense, even with a high carbon price. Part of that is our built-in lags with respect to how our end users respond to a carbon price. But part of it is we know that some technologies and applications just don't lend themselves to electrification. So further reductions would be facilitated by a range of other technologies, which we're continuing to study and we have a new initiative around those things, like hydrogen and bioenergy, CCS outside of the electric sector.

Some last few points on load shapes. The next slide shows the current load shape broken out by category. This is a model load shape. One of the things the model can do is look at individual categories' hourly load shapes and then we can compare that to the observed aggregate. Actually these line up really well within observed years. This is a model shape. So it's not perfect, but it's very close. You can pull out the non-seasonal things and look at what's driving the seasonal peaks, and that's space heating, cooling. Vehicle charging is essentially zero on the base here. But this is in the southeast model region, where spacing is already driving winter peak in the system.

The next slide shows a reference case for 2050. Space heating increases, vehicle charging is a significant new load. You actually have a decline in total energy for cooling, because efficiency improvements

are going faster than new service demand. But the vehicle charging shape is, primarily, it's a diurnal shape and we made some assumptions about how a diurnal shape looks. But we've also factored in the temperature impact on battery charging, battery efficiency, which actually makes the charging shape a winter peaking shape as well.

So if you look at the aggregate shape, this is the current aggregate and then moving to the next slide, you see the 2050 winter peak is significantly higher, because of both a combination of space heating and the vehicle charging, which also peaks on the coldest day. Now where it peaks diurnally, relative to the space heating shape, is important. We've done some work around flexible charging shapes.

This shows the potential impacts on the diurnal peak around the heating peak, this is for a study we did in North Carolina showing that you can actually reduce allow charging. This is maybe overly optimistic, you can allow charging to happen anytime within the day to optimize against the system if you get enough, in this case about five gigawatts off of a 40 gig on peak. And the upper right there shows you can actually get a lot of benefits by going in about half the households.

I think this is well known that there's a lot of potential benefit to flexible charging and I want to emphasize that the key thing is being able to avoid charging on the heating peak. That's the real value in terms of reducing the system peak, with respect to new electrified loads and that peak, of course, first thing in the morning. So you're looking at a combination of workplace charging and long-duration home charging, sort of managing those to avoid.

The last slide I want to show around load shapes is an example of an extreme scenario that we modeled in the state of New York. This is a case where in what we're calling the transformation case in this scenario, we're actually requiring all new heating after I think 2025 to be electric heating and all buildings, new vintage.

So you get this very big increase in the winter peak because of the technology assumptions there. This also depends a lot on the configuration of the heat pump that you're putting in and how much you're relying on the resistance backup, how large the heat pump component is. So those are technology-specific design assumptions that actually translate directly to a winter peak in a case like this, and there are things you can do to mitigate this very strong increase in the peak that you see here. One of them is coordinating EV charging. One of them is better utilizing the heat pump versus the electric resistance, but there's also strategies around non-electric backup to reduce the peak demand from electricity, even if you're getting a lot of load from electricity, a lot of space heating demands inspired by electricity. The key is, what's happening at the peak. So this is an example where you can get a sort of extreme outcome in the northern climate with an aggressive electrification.

My last slide summarizes the key takeaways. Technological improvements, especially batteries and heat pumps and whatever illustrated here, but there are other areas that are making electrification an economical choice in many key sectors and applications. Light-duty vehicles are a really strong example where I think you could see a big change in electricity demand and corresponding reduction of non-electric demand through electrification.

This question of, is it green? is it economic? I think they're strongly correlated. Efficient electrification equals economic electrification. Where the technology is efficient is where it engenders fuel savings and economic savings and makes it a good choice in terms of a total cost of ownership. That almost always leads to economy-wide emissions reductions, as well, when you think about what's happening in the electric sector. So, you know, I think where it makes sense. It makes sense, sort of across the board.

That's not a blanket statement, but that's generally true. Carbon price or carbon pricing and carbon policy incentives for decarbonization tend to strengthen the incentive for electrification, because it has the emissions advantage. But barriers to adoption remain. I mean, we know that people are having trouble getting their heads around EVs. I think a lot of people who already own them can't understand why not everyone's buying them.

And there are, of course, a lot of factors to that. It's partly information, it's also partly some real things like infrastructure and other barriers. Electrification doesn't make sense in all applications, even with the carbon price. And so we're going to be looking at, I think, a combination of technologies ultimately in the decarbonization scenario.

I'll just highlight one key challenge that I haven't really talked about but I'm sure will come up later in the panel. We've assumed average cost pricing and we've made evaluations based on that. But this can lead to pretty peaky use of certain resources, particularly if you're driving a lot of the gas out, but not all, in certain building locations you're looking at trying to recover that infrastructure.

If you're looking at recovering infrastructure over a smaller number of molecules, that's going to affect the price. Aligning rate structures with those impacts, I think it's going to be important. It could change some of the results here. Things going to be important for getting efficient market outcomes with respect to the trade-offs that that we're modeling. So it's been a little bit fast, and I'm trying to keep to my 15 minutes. I'll stop there and I look forward to your questions. Thanks very much.

*Moderator:* Thanks. You have given us a lot to think about that will hopefully generate a bunch of questions. Let's turn to Speaker 2.

**Speaker 2.**

Very good morning or good afternoon. Thank you very much for the opportunity to present today. What I will be covering is NREL Electrification Futures Study, which in many ways, I would say, is similar to the efforts just presented.

The overarching purpose of our work was to establish some bounds around what electrification could mean going forward. Our group, which is leading the study, has a background primarily from the volt power system perspective. So our interest in electrification was originally motivated by all these things happening in the demand side which we normally take for granted. We just assume some static load profiles and we let them grow steadily over time. We don't think too much about how they might evolve and what that would mean for the power sector planning process.

So that was the motivation for this effort, to try to establish some bounds around different levels of electrification and to understand, at what point this becomes, disruptive might not be the right term, but at what point it starts to become a lot more meaningful for the

planning process. And when utilities and system operators really ought to start making some stronger bridges between the demand side of their institutions and their bulk power system planning side of things.

I'll just note upfront, first, there is some unpublished material in this presentation. So I would appreciate if we can abide by the guidelines laid out at the beginning of the meeting. I'll also point out what is previously published and can be accessed directly from our website and what is still forthcoming.

I'll also mentioned that our study does not involve any explicit policy incentives. So we are looking at a range of electrification levels. None of them are driven by specific policy direction, but rather what we're looking at is different evolutions of the cost and performance of key electro-technologies. And also some of those barriers that Speaker 1 was just alluding to, in terms of the barriers to electrification, so things like EV charging infrastructure, upgrading of residential building panels, upgrading the distribution system. We consider opportunities for mitigating some of those barriers, but without any explicit drivers or policies trying to get us at those goals.

The study that I'll be presenting on is an NREL-led collaboration. It's about a three-year study which is winding down at the end of this fiscal year. Our approach to this question of electrification was meant to be very pragmatic and it was also meant to bring in the different experts from across the National Laboratory, who have historically been focused on one of these sectors, but not the interactions between them. So we began by looking at the technology cost and performance of key electro-technologies. So a lot of the ones just mentioned in the presentation. Electric vehicles were a main technology that we were focused on as well

as air source heat pumps for residential and commercial space heating and cooling. Water heaters were also part of the mix.

We had a somewhat more limited treatment of industrial technology, mostly due to data challenges and also the broader electrification challenges associated with the industrial sector.

Our first study was published in December 2017. What we tried to look at was a range of technology costs and performance trajectories going forward. What we tried to look at was, what could different levels of research and development mean for cost reductions of key technologies over time, as well as efficiency improvements?

This involved a very detailed treatment of things like lithium ion batteries and their role in electric vehicles. We spent a lot of time looking at both conventional air source heat pumps, as well as cold-climate heat pump technologies, and looking at this trade-off between cost and performance, if you want to try to expand into colder climate regions. Now that's going to take a more expensive technology.

But at the end of the day, what does that mean for our potential to increase the deployment in different regions based on the cost effectiveness of that technology, considering both the upfront capital costs and the operational costs which was just described for electric vehicles? We looked at that on a regional basis. This was all studied in our December 2017 study.

It also fed into our next research effort, which was looking at demand-side adoption scenarios. Based on the cost and performance of some of the key electric technologies, we use this stock turnover model to look at what that could mean in terms of that tipping point



when electro-technology became cost competitive against its conventional counterpart, taking into account equipment lifetime. Things like that, as well as some of the consumer barriers and resistance to new technologies.

Then we looked at sales and stock trends over time to look at what that would mean in terms of their aggregate electricity demand, which again was our original motivation, that linkage between the deployment of these electrode technologies and what it would mean for the bulk power system planning process?

I'll show just a couple of those results on the next slide. That goes into our detailed power system model, which is the work that I'll be focusing on today. I think that's the work that most directly addresses the questions that the organizers laid out for this panel.

And at the very end of my presentation, I'll just touch briefly on the work that we have that's still ongoing, and it's wrapping up relatively soon, which involves detailed modeling of the operations of the power system under various electrification levels.

So this is my methodology slide for all of the results that I'll be presenting, to try to address the questions that are posed to this panel. The bottom right corner, we can start there. This summarizes all of the efforts that I just described on the previous slide, so, taking into account different trajectories for the cost and performance of key electro-technologies and what that could mean for adoption rates in the various end-use sectors.

So residential and commercial buildings; transportation here is aggregated across light-duty, medium- and heavy-duty vehicles as well as transit buses; and then the industrial sector. Taking into account the evolution of

key elector technologies in each of those sectors, and then in turn their adoption rates over time, what does that mean for electricity consumption patterns which are the inputs into our bulk power system modeling efforts?

This is a summary slide in the bottom right. Hopefully my picture isn't blocking too much of it for you. But at the bottom there, it just goes out to 2050. And the red wedge there is the industrial sector, which you see is actually relatively flat, regardless of the scenarios that we look at.

So the sort of textured pattern, which is a little bit less shaded in the bottom part. That's our reference scenario going forward. This is most equivalent to kind of an annual energy outlook. In this case, we're not assuming very dramatic shifts in the adoption of different electro-technologies. That bottom black line there that's labeled as reference, that mostly just refers to population and economic growth over time, resulting in steady electricity demand growth on the order of about 0.6% per year in terms of a compound annual growth rate.

Then the wedges that are stacked on top of it show the results of our different electrification scenarios. And specifically, what it means for the different sectors. So this echoes a lot of what Speaker 1 just presented. The blue wedge there under both medium and high refers to additional electricity demand associated with transportation services.

Most of this does arise from the light-duty vehicle fleet. So that includes light-duty cars and trucks, but we do have some assumptions, especially in the high-electrification scenario that involve covering some of the vehicle miles traveled under the medium-duty fleet and a little bit under the heavy-duty fleet as well. Some of those are met by electricity demand rather than through

gasoline or diesel fuel. So you see a fairly dramatic growth in the transportation service demand being met by electricity. In these cases, our compound annual growth rate for annual electricity demand is on the order of doubling or tripling from the present to 2050.

Under our high electrification scenario, where you see quite a bit of blue stacked wedges on top, our compound annual growth rate is about 1.6% per year between 2016 and 2050. This is similar to some of the growth rates that we saw in the early evolution of the power system. But, of course, this is a dramatic shift from the last decade or so, when electricity demand has been flat or declining in certain sectors.

This is one of the key findings from our end-user adoption scenarios. This really could mean a dramatic shift in terms of how the power sector looks at its planning of assets going forward in time. The other thing I'll note on this figure is, you notice much smaller, or maybe you can't even notice some of the wedges that are green and orange. This refers to the building sector. In this case, the smaller size or maybe lack of evidence there, has to do with sort of a couple of factors. First, those sectors are already heavily electrified, so there's less opportunity to see dramatic growth in those sectors. Also, as Speaker 1 mentioned, the efficiency gains associated with air source heat pumps really kind of outweigh the additional growth in them.

And so, in our case, we have some situations where heat pumps are actually replacing resistance heating in households. So in that case it would be reducing overall electricity demand while meeting an increased share of total air space heating, for example, from electricity. So the latter part points to the replacement of gas furnaces and oil heating, especially in the midwest and northeast with

electricity. But also when you have the trade-off with resistance heating that negates any demand growth that we might see in the residential and commercial sectors.

As I mentioned before, we had sort of a workflow that goes through, first, we looked at the electric technology evolution over time. And we looked at what that would mean for customer adoption. And ultimately that fed into the part of the study that I led, which has to do with the power sector modeling. For this effort, the model that we relied on is the regional energy deployment system model. This is NREL's capacity expansion model that looks at the long-term evolution of the bulk power system. So, transmission level assets across the contiguous United States.

For those who aren't familiar with the model, the key points of it that we emphasize are its high spatial resolution. We have a very detailed treatment of renewable energy resources across the continental United States, as well as how those integrate into different balancing areas across the country. The base model that we use for this effort was the 2018 version of the model, which is now available for download and use by anybody for non-commercial uses. The base version of the model is used historically to look at sort of different power sector evolution scenarios. We built off of this version of the model to try to capture some of the unique effects of electrification. That's what's listed in the bottom lefthand corner of this slide.

The first dynamic that we want it to look at is how reduced end-use consumption of natural gas might influence the cost competitiveness of natural gas-fired generation on the bulk power system. If end users are using less and less natural gas, that would drive down the cost, which would, in turn, make it more cost competitive to build gas-fired generation.

That's the dynamic that we built into the model. Historically, we just treat load as an input and we don't really consider end-use energy demand as part of our model dynamics. But that's something we wanted to capture in looking at these electrification scenarios.

The second aspect of electrification that we wanted to be able to capture in more detail is demand-side flexibility. So for this version of the model we built in the capability to look at different amounts and also extents of flexibility of their end users, and what that would mean for the power system process. So, as Speaker 1 was mentioning, if you have EV charging coincident with your space heating demand, for example, that would make it very challenging. Your peak will be very high, your ramp rates will be very high and that would translate in our model into a lot of additional capacity needs to meet that peak demand.

What we built in was an ability to look at how different amounts of flexibility could mitigate the need for additional bulk power system infrastructure and similar to our treatment of different parts of the study, we look at a range of values to see whether there are reducing returns on investment. If you were to look for additional sources of flexibility, do you start to get lower returns in terms of the benefits associated with the power system investment needs?

Finally, the last model improvement that we engaged in to try to represent electrification in more detail, was related to resource sharing. So we wanted to understand how, as you potentially see the adoption of these technologies that have different demand profiles over the course of the year, to what extent can you leverage sharing across regions to try to meet your peak demand? If one region is a winter-peaking region, trying

to meet a lot of new load associated with space heating, for example, would they be able to share some of their peak demand resource needs across regions where maybe there's still a summer peaking regions?

Rather than having every region need to build its own peak capacity, to what extent can we start to look at more cooperation across regions, particularly those that have non-coincident peak demand periods?

This is all the foundation for the results that I'll be showing on the next couple of slides. I do just want to mention again that the next couple slides involve preliminary results. These are still under review and we would certainly welcome your feedback on additional features that would be good to capture or additional scenarios that would help define the boundaries for the scenario results that we're showing.

OK, so trying to address some of the questions about, what would meet the new electrified loads with on the bulk power system? This slide compares our current electricity generation mix. This is only utility-scale assets mixed with rooftop solar. The 2018 bar on the left shows our current mix across the continental United States. Matching with the legend on the right, the bottom part of the stack is all conventional generation. The top part ends up being variable renewables are the ones that are primarily visible, there may be a tiny sliver of battery storage at the very top of that. Then all the bars in the main part of the figure there referred to our 2050 scenario results across a wide range of scenario definitions.

The base case, the first one, this would be your traditional annual energy outlook type approach, where you use your default costs and performance assumptions for all technologies, as well as the reference natural

gas prices from the EIA going out to 2050. The first thing you notice is that the bar in the base case under 2050 with high electrification is around 2500 gigawatts, compared to just over 1000 gigawatts today. So that's a dramatic growth in the capacity mix on the bulk power system by 2050 under base case assumptions.

The other obvious thing is that the brown wedges extend expands dramatically. This is reflecting the increased cost effectiveness of natural gas-fired generation going forward, both due to declining gas prices over time as well as the dynamic I mentioned, about electrification further driving down the cost of natural gas, and making it more competitive on the bulk power system.

And then at the top of the stack you see dramatic growth in the yellow, which is our solar generation, again, both rooftop and utility-scale, but mostly utility-scale in this case. And the blue wedge right below it would be wind capacity. So the growth in those bars has to do both with the lower capacity factors of those technologies, as well as their improving cost and performance over time, resulting in them being the most cost effective source of new generation or capacity generation going forward under base case assumptions.

The other bars, looking across there, look at different natural gas price assumptions going forward, costs and performance trajectories for renewable technologies, in particular. And on the far right, we have what we refer to as our system constraints scenarios. So retirement constraint, third from the right. This looks at extended lifetimes for all conventional generators. You see a very similar dark gray wedge at the bottom that refers to a lack of retirement of coal-fired power plants over time, which are otherwise

driven by economic factors across all other scenarios.

There's a similar feature for nuclear capacity at the very bottom of the stack, although, in this case the treatment of the nuclear retirement is entirely exogenous in our modeling. So if it's not there, it's because we've assigned a retirement date and, if it is there, it's because we've extended the lifetime of that plant.

The next one is an emissions constraints scenario. It's not a CO<sub>2</sub> price. Actually, it's a cap on power sector emissions over time. You notice in this case a lot more battery storage at the top as well as pumped hydro storage and compressed air energy storage in the gray. A lot more renewable energy technologies. And those things are making up for a reduced natural gas-fired capacity in 2050 under emissions constraints scenario.

Finally, we looked at a transmission constraint scenario, where we assumed that you really can't build much new long distance transmission. You really have to rely on the existing network. So what does that mean in terms of shifting the resource mix? What we find, actually, is that there's not much of a change in the results from the base case results into the transmission constraints scenario, which reflects the fact that the transmission network is not utilized to its maximum extent possible now. And so if we're able to improve the efficiency with which the system is used, you can end up with a very similar generation mix without having to build new transmission.

In responding to the question posed to the panel about how will we need this new electrified demand, what we see across our scenario is that variable renewables make up the majority of the increased demand, they absorb that, both due to the interactions

between the demand side and the supply side in that case, as well as the improved cost and performance of those technologies over time.

But in all scenarios, also, natural gas-fired generation plays a very large role, even in our emissions constraints scenario, due to the fact that it does have a lower carbon intensity than the coal-fired generation, which there is still an opportunity to replace, even under our base case and different sort of economic sensitivity scenarios.

I'll just walk through this slide one at a time. On the left-hand side is the result that I included to try to respond to the question about whether there are additional environmental benefits to be gained from electrification. What this chart shows is the change in energy-sector CO<sub>2</sub> emissions between a reference electrification version of a given scenario and a high electrification version.

So all of those different stacked bars that I just showed on the previous slide, comparing reference electrification demand assumptions with high electrification demand assumptions—what we see is that all scenarios involved in emissions that are below zero on this axis. What that translates into is that, regardless of what we assume about the power sector mix going forward, high electrification always results in CO<sub>2</sub> emissions reductions across the energy sector. This is including both end-use emissions as well as power sector emissions.

This includes the scenario where we extend the lifetimes of coal-fired generation going forward, as well as nuclear generation at the same time. It includes transmission constraints. It includes the low gas price scenario, which involves a very large fraction of generation on the bulk power system being met by natural gas.

In all of these cases, energy use's CO<sub>2</sub> emissions go down. This is because of the displaced emissions in the end-use sectors, and especially in the transportation sector. But it also reflects the higher efficiencies of natural gas-fired generation even considering the conversion of the transmission of that electricity generation debt to the end users. The efficiency is higher, and therefore you need less natural gas to meet the same level of service demand.

On the right-hand side is my results that are responding to the question about whether this is a cost-effective strategy. In contrast, maybe, to the EPRI effort, we were not focused as much on efficient electrification as much as we were looking at the potential for electrification. In that case, we haven't pre-selected cost-effective application of the end uses. We also have not assigned any requirements for different electricity generation mixes going forward.

In the absence of those constraints, just looking across the space, what we find is that the cost effectiveness of electrification depends, which is probably not a very satisfactory result. But ultimately, the main thing that we find that drive the cost effectiveness of electrification has to do with the evolution of end-use electric technologies going forward. If those evolve very slowly, if their efficiency does not improve very rapidly from where it is today, if the cost does not decline very much from where they are today, in those instances electrification is not a cost-effective strategy. But if we assume a default technology learning curve for the key electro-technologies going forward, in that case, we see that the system cost effect.

Not looking at the residential bills, more looking at the investment needed on the end use and bulk power system—in that case, what we see is sort of a wash between the

reference and high-electrification scenario. Here you see electricity prices as one example of that. What this mainly demonstrates is that we really have an abundance of natural gas and renewable generation sources in this country.

In that case, regardless of the electricity demand levels, regardless of the shape associated with that electricity demand—so some of the results Speaker 1 was showing at the end—we can meet that increased electricity demand with resources of very similar costs, which leads to equivalent electricity prices, regardless of the electrification levels that we explored.

This is not the full range of possibilities. You could end up getting into a regime where it suddenly becomes more and more expensive to try to meet incremental electricity demand. But across the range of areas that we looked at, we see that electricity prices remain roughly the same across the electrification levels, which means we just have an abundance of resources to meet that increasing demand.

At a system class level, we see very similar trends. But, again, the main factor that influences whether electrification is cost effective, even at these very aggressive electrification levels, has to do with the advancement of electro-technologies over time. I'm thinking about things like lithium ion batteries, air source heat pumps, things like that.

That's the last slide that I have to show. The last thing I wanted to mention is just where the study is going as it wraps up. What we are currently in the process of doing is some detailed power system operation modeling. So using a production cost model to look at how electrification and the renewable energy integration and demand-side flexibility all

interact with one another. As we vary those different levels for all three parameters, we start to look at where there are synergies and where there might be competition among different sources of flexibility, where there might be the reliability challenges associated with some of these highlighted application load profiles.

Those are the things that we're in the process of exploring now and hopefully we'll be publishing all the results that I just showed, as well as some of that detailed operational modeling later this year or early next year. So thanks, that's my presentation.

*Moderator:* Thanks very much. That's a lot of information. Now we can turn to Speaker 3.

**Speaker 3.**

Great, thank you all for the opportunity to talk on this subject, and it's really nice to break away from a lot of the other news and discussions that have been happening lately and focus on some business as usual, and these higher level questions that AGA and our group at AGA have been diving into over the last few years. They're of paramount importance to public policy, to consumers and to the gas utility industry.

Just briefly, I run our energy markets analysis and standards group, and I'm going to take you through some of the studies that we have done on this topic of electrification and, more broadly, the role of the potential for natural gas utilities and the underlying infrastructure to contribute to our collective goals of reducing greenhouse gas emissions reductions.

Real briefly, those of you who aren't familiar with American Gas Association. We represent the more than 200 investor-owned natural gas utilities that deliver natural gas

every day to primarily the residential, commercial and industrial sectors, as well as power generation and the transportation sector.

A quick level setting here. Where is the market at today? What we've seen, over the past decade, is that abundant natural gas supplies and expanding infrastructure has led to low and stable prices. Natural gas production has increased up 86% from 2005 to the end of 2019. Current levels of production are in excess of 90 billion cubic feet per day and that remains true even in the early days of this larger-scale disruption that we see related to COVID. The market remains right now fairly stable.

The tremendous growth in gas production, attributable to the shale revolution and innovations in exploration production technologies has led to a natural gas pricing regime that is very low and relatively stable compared to history. Low and stable prices helped bring the US out of recession 10 years ago. How will the natural gas industry contribute to a recovery next time?

The use of natural gas in combination with renewable energy and energy efficiency has contributed to US energy-related CO<sub>2</sub> emissions dropping to their lowest level in 27 years. The current emission levels are at 1992 levels and they are projected to continue to decline, at least for the next couple years. And on the natural gas utility space at the end of the line, those pipelines, those systems that delivered gas to US consumers, gas utilities and its customers have made significant progress in reducing emissions. On the left side, this is a view of what the average residential natural gas customer's CO<sub>2</sub> footprint has looked like over the past 50 years. That carbon footprint has been cut in half since 1970 as a result of energy efficiency improvements, including tighter

building envelopes, more efficient appliances, consumer conservation and, importantly, the effects of natural gas utility efficiency programs.

The distribution system itself, the pipelines, the compressor stations and so forth, those systems have a small emissions footprint shaped by declining trends. So looking at the methane emissions footprint from gas utilities systems, those methane emissions have declined 73% since 1990, even as the gas utility companies have added 760,000 miles of pipeline to serve 20 million more customers. The whole system is expanding to serve more customers and the environmental footprint of that system in terms of methane has shrunk significantly, 73%. And that end-use customer efficiency has dropped the per customer CO<sub>2</sub> emissions by half since 1970.

Earlier this year AGA released its climate change position statement. I'm not going to go into any detail, other than to say, I would encourage you to access the link at [aga.org/climate](http://aga.org/climate), where we state unequivocally that natural gas and natural gas utilities are committed to doing their part to achieve a significantly lower carbon energy economy, and through that we outline a set of commitments that the industry collectively is stepping up to commit to, as well as the set of policy principles that AGA believes best reflects the role and the value of gas and gas infrastructure in reducing greenhouse gas emissions in terms of federal policy.

Moving now to the topic at hand, electrification. We started looking at this topic back in 2017, where we saw several proposals looking at ways to reduce greenhouse gas emissions. The concept of deep decarbonization as a means for mitigating the impacts of climate change and noting that several organizations, NREL, EPRI, for example, as well as even the White

House, putting forward studies that examine the different pathways to drive down significant productions in greenhouse gas emissions.

The common theme in most of these papers is the call to magically reduce electricity and really overall energy consumption through aggressive efficiency programs, advanced policies that require electricity to be generated from renewable energy sources and, importantly, to replace fossil fuel end-use appliances and equipment with advanced electrical equipment across all sectors in the economy.

We've heard some analysis already today to that. Really, building electrification was the key strategy among many of these deep decarbonization studies coming out. We sat and thought that there was not a sufficient amount of analysis at the time that were examining the potential impacts of these policies.

Before I get into the actual study itself a little bit more level setting about what it is we're really talking about out there. Let's take a closer look at the residential market. Natural gas is used for primary space heat in approximately 60 million homes. Residential natural gas, that gas consumption in home. Not just for space heating but for water, cooking, clothes drying and so forth. Residential natural gas accounts for only about 4% of total greenhouse gas emissions reductions.

Now I'm looking at the right-hand side here. Left hand side was the number of US heating systems by fuel, right hand side the pie is total US greenhouse gas emissions from the EPA inventory. Residential natural gas use, including a share of methane, is about 4% of total greenhouse gas emissions.

The commercial sector—natural gas use in commercial buildings—accounts for about three percentage points. And just for reference, this is as of 2017 data. The rest—residential, electricity-related CO<sub>2</sub> emissions plus also a share of methane emissions—accounts for about 10%. So when we're talking about electrifying residential space and water heat, for example, this is the number of homes and this is the share of greenhouse gas emissions that we're talking about. I want to be very clear; I'm not saying these are unimportant emissions. They are important and we can and should reduce it, and again utilities are committed to reducing that portion of the total greenhouse gas emissions pie.

But the size that we're talking about, that 4% really represents about 250 million metric tons per year. That's roughly equivalent to two weeks of Chinese coal emissions. That's the size of the pie and we're tackling.

One of the key *a-ha* moments as we started on this work, examining the potential impacts of electrification on the residential sector, was recognizing how much more energy we use during the winter compared to summer, and that natural gas is a critical residential energy source for heating homes in the winter. Residential natural gas demand over the course of a peak month, at the time January 2014, is more than twice the electricity demand in July. In other words, significantly more energy is required to meet our heating demand in peak winter than our peak demand in the middle of summer.

So the impacts of electrification must evaluate the peak energy requirements in order to fully recognize that cost implications. So in 2018 AGA engaged a team of experts at ICF to assist in the evaluation of what we call “policy-driven electrification” of the US residential sector.



When I say “policy-driven residential electrification,” what I mean by that is policies, in terms of legislation or regulation that would compel or otherwise incentivize a switch away from direct use of natural gas and fuel oil and propane in uses for residential space and water heating, and replace that with an electric alternative.

That's a policy-driven approach now that you can contrast that with a market-driven approach or some other definition. Our policy-driven residential electrification scenario effectively assumed that starting in 2023, no new natural gas, fuel oil or propane appliances would be installed in the residential sector. That's including new construction, and when equipment was reaching the end of its life in the existing market, it would be replaced with an efficient electric heat pump and electric heat pump water heater.

I will say that this created a very aggressive electrification scenario. It's widespread. It was only applied in places where electrification actually reduced emissions by 2035. So we ran a couple different cases. In one case, where we were assuming only generic renewables on the electric grid, we applied it everywhere. In another case, it was only applied in part of the country.

A lot of the details there. But suffice to say this was a widespread electrification policy scenario. But it was consistent with several studies that we were examining at the time that were assuming electrification of the building sector and residential buildings, in particular, in order to drive greenhouse gas emissions reduction. So they weren't, while aggressive, not inconsistent with some of the literature out there at the time.

Our study set a set out to answer several key questions regarding the potential costs and

benefits of this widespread residential electrification approach. So we're coming at this from a different direction than the EPRI study and the NREL study, but, as you'll see, I think we arrived at similar conclusions, despite the different pathway and different set of questions to get there.

I'm going to go through these questions and real briefly, but I would say, no matter where you are, and you're evaluating electrification policies in terms of its potential to reduce greenhouse gas emissions, whether at the state or local level, or certainly regionally or nationally, these are among the set of questions we believe are important to try to ask and answer to understand the implications of electrification policies as a way to reduce emissions.

So the key questions we asked: One, will policy-driven residential electrification actually reduce greenhouse gas emissions? the answer is, “It depends.” It depends where you are. In some states in 2035, this residential policy for electrification would not reduce emissions. This is mostly in areas where coal and natural gas remains a substantial part of the electric generation mix. In other parts of the country, it does reduce greenhouse gas emissions.

And then the question is, of course, how a policy-driven residential electrification impacts natural gas utility customers. We found it had significant impacts, potentially burdensome to customers, and would increase average residential household energy-related costs.

Three, what would be the impacts of the on the power sector and electric transmission infrastructure requirements? At the time, that question really hadn't been asked and answered in terms of evaluating electrification policies. Since then, a lot of

work has been done. In our view, and when we went out to answer this question, what we found that widespread residential electrification would lead to increases in peak electric demand in every region of the country, resulting in the need for significant new investments in the electric grid, including generation, transmission and distribution capacity.

The fourth would be the overall cost. We found the overall cost to be significant, upwards of \$600 billion to \$1.2 trillion. These are fairly conservative estimates, which I'll get into in a second. How do the costs compare to other approaches to reduce emissions? We found it to be a fairly costly approach relative to other pathways to reduce greenhouse gas emissions reductions.

Just real quick, in terms of the kind of key findings and the specific numbers, those costs in terms of electric generation capacity and transmission system upgrade costs. It depends on the scenario where if you include natural gas or you're only including renewables and batteries, ranges from 155 to a little over \$400 billion.

Overall greenhouse gas emissions reduced by 1-1.5%. And again, remember that slice where I showed you the 4% of the total pie. So you're reducing some amount of that and it ends up based on our scenario 1-1.5 percentage points of the total pie. The cost per customer on average is about \$1000-1400 per year in increased energy costs. So that's the cost of energy as well as the amortized equipment costs. That's an average for the US, it really depends on where you are in the country. Certain parts in the South will look a lot different than, say, New England, that has significant heating demand. So there's a regional aspect to this. That's very important. Finally, the cost of emissions reductions based on this policy scenario and the

implications of the policy, around \$600-800 per ton of CO<sub>2</sub> emissions reduction. So a pretty expensive path to reduce CO<sub>2</sub> emissions.

I'm going to go through these pretty quickly, but just to illustrate the level of analysis that we try to conduct here. What we tried to do is recognize that electrification policies will depend on the replacement of gas, propane and fuel oil space heating with electric heat pumps. That's the idea. That's how you're going to get the expected environmental benefits. Heat pumps can be very effective and very efficient, particularly on an annual basis, but we tried to be careful to model heat-pump performance as it degrades as the lower outdoor temperature declines, so that you know your heat pump performance must be assessed based on a low climatic conditions.

We evaluated heat pump performance to 220 different places, temperature conditioned zones across the country. In very low temperatures, heat pumps typically cannot provide adequate heat and require some sort of backup energy, typically electric resistance heat. And so the actual climate-adjusted, heat pump performance must be calculated for each region to estimate the consumption of peak demand.

And peak electricity demand is the key variable to understanding the impact of electrification policies on electric system capacity requirements. Because the electric system must be designed to meet peak demand at any given time. So to do this we determine the impacts of our residential electrification policy on peak generation requirements. We created a peak send up for natural gas under a reference case and we looked at that—2025, 2030, 2035—which was the extent of our time period for our analysis. And using this peak day demand and hourly profile of natural gas usage by

type. So that includes space heating, water heating and other demand. Using that hourly profile, we estimated an equivalent electric generation requirement based on the heat pump efficiency at local design day temperatures. The details of the impact of peak generation on the overall power system capacity requirements in two cases.

All that is to say, when you look at the incremental peak demand growth if you electrified the entire residential sector, just to map that extreme case, you would effectively double the US electric grid's peak hourly demand requirements. Very significant amounts of peak demand required to meet current winter and uses currently served by natural gas, as well as propane and fuel oil.

The overall magnitude of the costs we found to be significant, both in terms of the customers and to the overall economy. The overall costs increases are a result in the change of consumer energy costs—so what's the delta between what you were spending on natural gas and what you're spending for electricity?—consumer equipment costs—so what's the delta between your gas and efficient gas furnace and that very efficient electric heat pump? What are the power generation requirements in order to meet that peak electric demand? What are the costs associated with the electric requirements that I described on the prior slide?

We did an analysis for two regions of the country in terms of what are the electric transmission requirements. This is where we get the \$1000-1420 per year per converted household in our renewables-only case, which was the higher of the two. That accounts for about a 71% increase above what customers currently pay for their energy.

Keep in mind that we didn't evaluate all the costs. We didn't look at local electricity distribution upgrades that would be required. That would have been much more in-depth analysis and that would require looking under the hood in every single electric utility system across the country. We didn't evaluate the impacts to electric or gas rates. We kept those fixed. And, of course, these types of investments or changes in that investment in our electric and gas system would lead to impacts on both electric and gas rates. And then finally, we didn't look at the fixed costs associated with shifting the fixed costs associated with gas distribution and how those would be shifted to gas customers that remain on the system. In other words, those fixed costs gets spread over a smaller and smaller user base, and therefore gas rates would go up for those customers.

I've already stated our residential electrification policy would be an expensive approach to greenhouse gas production and this just puts that into perspective—the cost per ton of CO<sub>2</sub> reduced relative to other potential pathways to reduce emissions or other metrics for reducing emissions, whether it's a social cost of carbon, fuel efficiency improvements and other sectors and so forth.

Let me just pause and say, that's our electrification study and there's a ton of work that went into it. I'd be happy to answer any questions on the technical aspects, but I don't actually want to get stuck on that. I think the costs and the questions are significant.

What we did in parallel to the electrification study was that we had conducted a separate evaluation of emerging gas technologies and whether they could contribute to meaningful reductions in greenhouse gas emissions. In other words, it wasn't just enough to say, "All right, electrification, it's got its challenges,

but there are ways to reduce emissions and reduce that burden or reduce those costs on customers. How can natural gas systems play a role?”

So we engaged with a group to conduct a global search on emerging gas technologies in the residential small-commercial sector, and found significant emission reduction potential on a per customer basis from 25-40%, through the integration of these advanced gas technologies. Then, pushing those assumptions even farther, assuming even more advanced gas technologies and the integration of renewable gaseous fuels, bio gas, power-to-gas, for example, we saw in the greenhouse gas emissions reductions potential of 80+% that were achievable through 2050.

The feedback from that work was that we needed a deeper dive into several of these questions. And that's what the American Gas Foundation took up last year. I'm going to just briefly reference these two studies, but they are available at [gasfoundation.org](http://gasfoundation.org). They were published in December 2019, and these studies focused on specific components of the natural gas pathway to emissions reductions.

First, we had the opportunities for reducing greenhouse gas emissions through emerging natural gas direct-use technologies. Really, what we did is we examined the potential of natural gas heat pumps for space and water heat and some other technologies as well. And then the second study, “Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. We engaged, the foundation engaged with ICF to do a deep dive in updating our understanding of the resource potential for renewable natural gas in the United States.

Briefly, the first study, two of the highest-level key findings. One on the first study that highly efficient, emerging direct-use technologies could reduce natural gas CO<sub>2</sub> emissions in the residential sector by 40%. That's off the baseline. And that's including the millions of new customers that will be added to the system between now and 2050 and reducing it, from that 2050 baseline, up to 40%. That's just through the integration of these specific advanced gas technologies, gas heat pumps in particular.

We did not include other potential efficiency measures to improve building shell efficiency, Internet of Things controls of how you use your energy to optimize that energy, all sorts of things could be added on to that 40% to bend that curve even farther

So that's the first study. The second study's key findings I've identified an RNG, resource potential equivalent to roughly 95% of current residential natural gas use and the majority of that resident renewable natural gas cost is \$7-20 per ton, excuse me, per MMBtu of gas.

When you characterize these findings in terms of the emissions abatement potential, on the right-hand side of this chart, we find that on the first study, a potential net savings of \$51 per metric ton of CO<sub>2</sub> reduced, up to \$66. In other words, you're making money reducing emissions in the first case, all the way up to a relatively modest cost of \$60-66 per ton.

In terms of RNG resource potential and how it may be used to mitigate greenhouse gas emissions, ICF developed a carbon-based abatement cost which ranges between \$55-300 per ton. Well, it's slightly higher than the costs identified in our direct-use study. It is still significantly less than the carbon abatement costs associated with our policy-

driven residential electrification report that I referenced earlier.

If you have any questions on these studies, there's a ton of work that went into it. I'd like to give kudos to Rick Murphy. He's the executive director from the American Gas Foundation, also on my team at AGA. He and his team did a terrific job in pulling these together, and he and I are both resources to you, if you have any questions on these foundation studies, as well as the electrification study that we referenced earlier.

Just in terms of actions to pursue, what we call our thoughtful pathway to emissions reductions—I know this panel today is about electrification, but really what it is we're talking about is emissions reductions and how do we cost effectively achieve those emissions reductions, how do we utilize all resources available to us to meet our common objectives. We believe that as companies continue to modernize our gas infrastructure and connect homes and businesses to the system, that new opportunities arise to achieve low-cost greenhouse gas emissions reductions by leveraging new and existing gas infrastructure, advanced technologies and our nation's abundant natural gas resources.

Additionally, gas infrastructure can and will be used for renewable energy storage and delivery of renewable gases derived from either biogenic sources or zero-carbon electricity. And, ultimately, the gas system's ability to integrate high value sources of energy like renewable natural gas and hydrogen or methanated hydrogen. All of those are going to be critical components of our nation's ability to reach ambitious greenhouse gas reduction goals. I appreciate your time and attention. I look forward to the discussion a little later on. So, appreciate it. Thanks.

*Moderator:* Thank you. It's a lot of interesting information, and interesting discussion when we get into the discussion period. Let's turn from the large-scale, macro view to a more specific application point of view.

**Speaker 4.**

As our Moderator mentioned, we're going to get into a specific case of electrification here, and presumably one that's familiar to all of you as we keep being instructed to wash our hands a lot. We're going to talk about that hot water that is involved in that clean hands production function.

This is drawing on some joint work that I've been doing with my colleagues, Dallas Burtraw, Jhih-Shyang Shih on the hot water paper and also broader electrification work with Kathryne Cleary.

Again, we're taking as the premise for this work two things. One is that deep decarbonization, when applied to the electricity sector, is going to involve a growing role for renewable energy. And, two, that electrification is going to be, in many end uses, including ones that we've discussed earlier in this session, is going to be an important part of realizing that deep decarbonization.

So when we think about the first part of that, which is decarbonizing the electricity sector, we all recognize, everyone on this call I'm sure does, that expanding the renewables contribution to the grid is going to challenge our conventional electricity market.

Renewables are growing for a variety of reasons, costs are indeed coming down, we're trying to achieve our environmental objectives and, in some places, consumers are expressing their preferences for relying more on renewable energy. But the issue here

is that you've got a lot of variability over the course of the day of electricity supply.

Here we have the very familiar duck curve picture that shows how net demand of the grid is declining during the sunny hours of the day and creating an increased ramp up of demand as the sun goes down. Coinciding with this solar abundance, that basically zero marginal cost, means that when the sun is shining wholesale prices are also falling at that time. And that means that the incremental value of new solar is going down and Bushnell and Novan have a paper about that.

We've talked here about the various visions of how electrification plays a role in deep decarbonization. There's just a couple of other studies referenced here that really envision a big role for combination of a electrification and hydrogen. There's a recent study that Brattle did that looked at decarbonization pathways in New England. It suggests that electrified hot water heating, which is what we're exploring here today, will play an important role. I should say that their studies focused on heat pump hot water heaters, and that's not what we're talking about here. What are we talking about is on the next slide.

You'll see a picture of a hot water heater I took when I was a jogging one day. But here's basic facts about hot water heaters, which is that roughly half of residential water heating according to the 2015 RECs by EIA was fueled by natural gas, and a similar share by electricity. The natural gas water heaters contribute about 1% of US CO<sub>2</sub> emissions. They account for, amazingly, the third biggest currently consumption category in the residential sector for electricity after cooling and lighting.

The way that water heaters typically operate is a fairly predictable fashion, it depends on the fuel type, but essentially the water heats up and then it starts to cool down until it hits a particular temperature in the tank and then it heats up again. So it's sort of this heat-addressed kind of model of operation. A gas hot water heater, we've got constant heat coming from the pilot light. An electric water heater maybe has to cycle more frequently during the course of the day. On the next slide we're going to talk about what if you did a different way of operating this and look at the interrelationship between these newly electrified hot water heaters and renewable supply.

What if the water heaters could respond to this variation in renewable energy supply and essentially store clean energy? So we're talking about a modeling exercise, that I'll discuss in a moment, where we take the demand for the energy services so that hot water that you use for various things within your home is given, and how can we exploit this thermal storage to do a number of things.

One is support the market for renewable energy by essentially shifting demand for electricity use to periods where it's cheap and to an evolving grid that corresponds with periods when renewable energy is abundant. The extent to which this mode of operations shifting from gas, electricity can reduce the emissions associated with water heating from gas and optimal operation could reduce the greenhouse gas emissions associated with conventional water heating that involves an electric water heater. There's been some research on this, and one study that we cite here finds that these water heaters could be a more cost-effective way to store electricity than batteries, if you want to use them to integrate home solar. The water heater can equal a battery.

In the analysis that I'm going to talk about, we sought to answer a number of different questions. These overlap quite a bit with the questions before this panel. One is whether or not grid-connected water heaters could save consumers money, both relative to heating with natural gas and relative to the way they might operate their conventional electric water heater.

Again, we didn't really look here at the efficiency gains associated with electric heat pumps, because their ability to serve this storage function is a bit limited. So we're just addressing conventional ones for this presentation today. Also looking at how electricity prices are going to affect the economics. What are the greenhouse gas benefit? But also, what are the barriers out there, be they technical, regulatory or economic, preventing the introduction or stalling the introduction of grid-connected water heaters?

I'm not going to spend a ton of time on this, but basically what we did was develop a model that's both a simulation tool and can be an optimization tool that looks at five different types of water use, in five different types of households, where they're basically different-sized households, where the size of the household is based on the number of bedrooms.

With respect to the water uses, again, you'll see there at the top of the list is sinks and that's everything you do in your sinks, including wash your hands. And we have output or actually a simulation tool from DOE that really looks at second-by-second water consumption for all these various end uses in a distributional framework.

In this study, we're focusing on three different cities: Houston, Sacramento and Chicago. We're assuming that everyone has

the same size hot water heater with a 50-gallon tank. The efficiency of the various models is going to come from information that we got from the web about new hot water heater options that are out there for people to purchase.

What we used this model to do first was to look at the cost over the course of a year of various modes of energizing, fueling and operating your water heaters in these different household sizes. So instead of going through this whole big graph, let me just go to the next slide, which focuses on the three-bedroom houses' results. So what you're looking at here are the annual cost of operating your water heater, heating water for all those end uses in three bedroom homes across these three different cities.

The two bars to the left are basically the simulated water heater. So the heat and direct approach to water heating with gas and with electric where you're paying the retail price. Essentially, you've got on this slide, both the blue bar, which is the annualized cost of the new appliance, and the red bars, which are the energy costs associated with that priced at the retail price. Then over to the right we have comparing gas at its commodity price. So basically, setting aside the delivery charges for the moment, and electricity at the day-ahead prices charged in the market in these two different cities.

We have two versions of this, because one of the things we wanted to be sure to achieve here is satisfying people's demand for hot water. Hot water would be there when you wanted it. And there's two ways that we did this. One was using a deficit constraint. The next to the farthest right bar basically says that the hot water in your tank, you're not going to be disappointed any more than you would be with a conventional electric hot water heater. So you basically get hot water

when you need it, as often as you would under traditional operation. Then the bar at the right is actually having a temperature constraint imposed, which says you can optimize the hot water heater, but you can't let the temperature drift below what it would have been if you just had a regular operation with the heat [UNINTELLIGIBLE].

Essentially what we're seeing here is, under retail prices, that these electric hot water heaters are more expensive in these three cities to operate when you're not taking advantage of time-varying prices and when you don't have an entity that's able to take advantage of those the wholesale prices. But when you do, you can actually see savings.

But what that slide didn't show is what the benefits are of optimizing your hot water heater, holding the price of electricity constant. That's what this slide is providing, essentially. Here you've got, in the red bars, the simulation where you're just letting the hot water heaters operate and not trying to optimize them. The green bar is optimization meeting that deficit constraint, no more hot water deficits than under the simulation. And the purple bar is the temperature constraints.

What we find here is that the savings associated with optimization are biggest where the electricity prices vary most over the course of the day. And that's in Sacramento, California. But you can see some fairly substantial savings summed up over the whole year in those areas where there's substantial variation within the day.

What we're basically finding is the biggest opportunity to incentivize this electrification is when you're paying for the electricity essentially at wholesale prices. Customers don't pay wholesale prices, they pay retail prices. And retail prices include a number of

costs, including some sunk costs associated with transmission and distribution.

If it's the case that new sources of electricity demand, such as electrified hot water heaters, introduce modest costs on the grid then maybe they don't need to bear all those particularly sunk costs, and the actual cost to the grid of adding these newly electrified loads could be [UNINTELLIGIBLE]. In addition to the extent that this new source of electricity demand is able to raise the value of renewables at particular times of day, there's that offsetting benefit there. So you have to take all of this into account.

With respect to the fixed costs part, there's not really an efficiency principle to guide how to share those fixed costs. And if you're doing electrification to achieve decarbonization then maybe you want to meter this newly electrified load separately. That might be a path towards getting at all our goals.

On the next slide, we take on this question about, well, what is the efficient price of electricity? Some colleagues at Berkeley and Davis, Severin Borenstein and Jim Bushnell, now have a paper where they look at the question of, is electricity priced efficiently, and if not, how far off is it across different regions of the country? What their findings show, summarized here in this map, is that the differences between retail electricity prices and the marginal social cost of electricity are quite large. The places where electricity prices are too high relative to the marginal social costs, which is something that could discourage electrification that would be beneficial, are indicated here in blue. The other, of course, important aspect of this is that the prices of electricity that people pay very, very little over time, but the marginal social costs of producing that electricity can vary quite significantly.



Backing up a little bit and thinking about what are the admissions applications of electrifying these hot water heaters. What we're displaying here is a slide that includes both the private costs of a gas hot water heater and also just the energy and capital costs, and also the emissions costs associated with the gas that's emitted at the residents where the water heaters operate. Now for electricity, our modeling hasn't taken us so far as to represent the marginal emissions associated with, we can't have the aggregate marginal emissions.

But what we've done in this graph is essentially show at what point would the social costs associated with the electricity that's being used to power these optimized hot water heaters have to be to make you kind of indifferent. And so you get a sense about what the so-called headroom is here. We're hoping to take our analysis to the next stage where we look at this, but we can look a little bit about where things have been headed and are headed in terms of emissions from the grid. And that's what the next few slides are about.

The next slide, essentially, shows that, for California in particular, the low emission rates actually coincide with the low-cost hours. So an optimized hot water heater that was incentivized to operate in these low-cost hours would be experiencing a lower emissions factor. While this graph is for California, you get this kind of variation in many parts of the country, these estimates are based on current data.

But what about the future? The next slide shows that in all of the regions that we've explored the emissions rates are declining over time and have been falling over time in all of these regions. The next slide shows the results of an analysis that EIA did that looks

at the sources of emission reductions in the electricity sector relative to 2005.

Basically, they're looking at comparing each of the years in this graph to the year 2005, and attributing emission reductions to both the shift towards more reliance on natural gas during that time period and the growing role of non-carbon generation, which includes renewables. Not limited to them, but what you see in this graph is that the extent to which emissions rates are declining is increasingly due to the incorporation of these non-emitting sources, including renewables, into the sector.

So it could be the case that you could have this sort of combination of phenomena going on, where the electrification of hot water heaters and perhaps other sources of energy consumption, where arguably you can shift the demand in time through appropriate use of incentives, can help to ameliorate and move along the integration of renewable sources and provide value to them.

What needs to happen in the policy world to make this happen? Well, we need to do something with rate designed probably and think harder about that, both time bearing rates and perhaps rates that are really getting at the marginal cost of these resources, particularly if this is a key part of transitioning the electricity sector. Another way to do this is allowing folks to aggregate water heaters, which, as a distributed energy resource, this is happening some places. But there are complications associated with issues of federal and state jurisdiction.

This is particularly true where retail markets aren't deregulated. There are policy challenges here that have to be confronted and dealt with, but maybe as we think about encouraging this type of demand-side scheduling as a renewables integration, it will

be able to break some logjams that we're facing currently.

That's kind of wraps up on the main takeaway points from the talk here, which is integration of renewables poses challenges for going to achieve our long-term goals. You have to decarbonize electricity production and electrify some additional energy and uses, maybe a number of them. Electrification offers opportunities. I talked here about water heaters, but a lot of this scheduling and providing incentives to do things when renewables are abundant could apply to other, larger electrified end uses that have been talked about today. So I think it's not just water heaters that are at play here. Innovations in rate design and other regulatory forums are going to be important steps in realizing these renewable integration opportunities.

The last bullet that I left off the slide is: During the break, everybody remember to wash your hands.

*Moderator:* Okay, thank you very much. Just a couple points before we take a break. One is I just want to let you know that Bill and Jo-Ann and I are working on where we're going to go from here in terms of the new programs there will be held.

The other point is that there's a lot of folks in the chat, which is great. I would like to remind those folks that your questions will be appreciated, just raise your hands. A number of people have made really interesting comments that will be worth raising.

### **Discussion.**

*Question #1:* I think all three of you in your scenarios concluded, more or less, that the economic electrification is most obvious on the transportation side. And less obvious on

the building side. And you mentioned the interaction with gas to some extent.

A question and comment is, the question is mostly for the NREL and EPRI studies, to what extent have you thought about what happens to the infrastructure costs on a per-customer basis, if even some combination of higher energy efficiency and adoption of, say, heat pumps, reduces the volume of gas that flows through the system? And then, to what extent that might create feedback loops? Then the second and somewhat related question is, in thinking about the building sector, what does the but-for world look like, given that a lot of the places where heating-related costs are significant, in the north or the northeast, the states actually have very deep decarbonization targets? So, the long-run question is not necessarily whether it's electrified and decarbonized, electricity-fired heat pumps versus continuing to burn natural gas.

But there has to be something else. For example, gas gets over time blended in a way that decarbonizes the gas. That's why I switched over to the most recent American Gas Foundation study. Its basic conclusion is that you have about 2000 trillion BTUs a year of renewable gas supply that's under \$20 a million BTU. The two trillion, that's roughly half of the residential gas demand. It's a small single digit percentage of total gas demand in the United States.

Is there an issue that, if we compare decarbonization paths, that actually the price of gas delivery system using decarbonized gas doesn't look at all like the natural gas at high volume system looks today?

I'm just getting trying to get a little perspective from all of you about how the building-related electrification story might change if you consider both volume changes

on the gas grid, which is a high-fixed cost. And if you think about the cost of fossil-free substitutes or blends that have to be added to the natural gas. Thanks.

*Moderator:* Panelists, go ahead.

*Respondent 1:* I think it's a really important question. It is challenging from a modeling perspective because there's resolution issues that you have to serve the model in the household level to know what are all the appliances doing. We sort of model the appliances separately, heating and cooling we model together. But then water heating and the other uses are separate. [UNINTELLIGIBLE] explodes if you try and look at all the different combinations, which is what you really need to do to understand what's happening to the distribution of the ratio of energy to peak for gas consumption.

But, in general, I think it's definitely true that, if you will get electrification of some, but not all uses, you're obviously driving down the volumes of gas. And if you're relying on pipeline gas for heating in the peak moment, then you know you haven't really reduced the infrastructure needs. So it has to have the effect of driving up the average costs and we didn't factor that in.

I think that's definitely an open question. How you handle that. One, there are strategies to think about. It could be to the point where in model climates where the electrification heat pumped combination with a little bit of resistance on the backup. It's adequate for space heating, then this kind of drives out gas infrastructure. That that is one possibility. I'm not saying that's necessarily the right answer, but that is a possibility that you basically have these redundant infrastructures, and maybe you only need the one. In places where you definitely need

both, cold climate. I think you're going to start looking at, in a decarbonization setting, as you said, a different type of molecule.

I think it gets a little bit difficult on the economic side to think about a hydrogen blending because the percentages that you can reach with hydrogen, maybe 10% or something with existing infrastructure, unless you're already in the PVC plastic piping, which most of the northern US is not.

You're only looking at a small share that's hydrogen, in which case, the hydrogen is much more expensive than the gas and all of a sudden, the economics don't work too well for that and you haven't really haven't displaced a lot of emissions.

So I think it's going to have to be some combination of that, renewable natural gas or rebuilding the pipeline infrastructure. I think there's really difficult questions that come into play when you're talking about getting to quite low CO<sub>2</sub> levels. Just to reinforce what we focused on in our study is, looking at where there's low-hanging fruit with respect to electrification.

You can do a lot, without getting into some of those negative feedback loops. If you don't force in electrification in places where it doesn't necessarily make sense in the building side. But it's definitely a question we're looking at more and trying to do, to be able to answer the question better.

*Respondent 2:* I only have indirect responses to the questions. For our studies, the scope of what we've looked at so far is purely in the system cost regime, so it doesn't get down to the customer level.

We had originally planned to extend the study to look at those sorts of questions but the funding for the project won't allow for us

to go that next step. From the system cost perspective, what I mentioned before about electrification being somewhere between kind of a wash to flight system cost savings, that does account for the sunk costs in the existing natural gas pipeline. We look at the fact that if a gas pipe has a low enough utilization factor that it will eventually be taken offline, but those costs don't go away. That does factor into our system costs calculation.

But in terms of going that next step and looking at what is a highly localized problem in terms of the utility rates and utilization in a more localized region, that's something that we haven't looked at and won't be able to look at it in this study.

*Respondent 3:* At the end of the day, the system costs matter but cost to consumers really matter. If you're going to achieve anything you have to be cognizant of those direct costs to those direct impacts to customers. In terms of the renewable natural gas potential in the foundation study, and the amount there and how it might be directed and what role it plays in the building sector versus other end use sectors that are deemed harder to decarbonize, first, from all the work we've done and from what we've seen, it's not a slam dunk that the building sector is going to be easy to decarbonize, so that's one.

I'm not saying you suggested that, but I would say that that's sometimes an implicit assumption that many are making when they're looking at the renewable gas resource base and trying to figure out, well, if it's a limited resource, where should be directed to? We believe that there is a significant amount of resource based on our current evaluation and that it can play a significant role in reducing emissions, hopefully cost effectively in several sectors, and you have to be fairly strategic about how it will be used.

That will depend on where you are in the country and your end-user mix and so forth. But it's just one more tool in the toolbox. We're going to need significant improvements in energy efficiency, we're going to have to think how we utilize the electric and gas system in tandem to achieve meaningful emissions reductions in efficiencies, at lower cost for that matter.

We have to think through, also, the value of how these systems interact and support each other, beyond just the dollar amounts or the carbon reduction potential. Right now, amid everything going on, I would say the concept of resiliency in our systems, both energy and economic and social systems, is going to be pretty important when we come out of this crisis. And making sure that any of these potential decarbonization pathways don't sacrifice reliability or resilience in the pursuit of a single source solution to reducing emissions. Quite simply, if you just try to electrify everything, what happens to the gas system and other potential values in terms of reliability and resilience? I think there's a lot of work to still be done there to map that out qualitatively and maybe quantify some of those value streams, but suffice to say we are thinking through that right now.

There's a lot of open questions that we'd like to dive into, especially what are all the different components, just setting aside the vulnerability resilience for a second, what are those different components of how gas utilities and gas infrastructure can contribute to these significant emission reductions? We talked a little bit already about advanced gas technologies and renewable gas, but how do you start to piece this all together in a broader portfolio to meet our common objectives cost effectively?

And thinking through those impacts to customers and system reliability and all those

things that we actually need to care about as we plan for the energy system in the future.

*Respondent 4:* We really didn't look at the infrastructure costs, but I know we recognize that that's an issue, which is part of why our gas/electric comparisons try to focus on just the energy part. But it's going to be important to completing the picture, that and also understanding incremental cost to the distribution grid as you get more electrified stuff out there, when you kind of hit those moments.

*Question #2:* A clarifying question about the projects. What assumption did you make for the purpose of the analysis of the tariff design? Was there some kind of dynamic pricing, or just sort of the flat pricing we use in most places now?

*Respondent 1:* I'll start. We assumed a flat retail price to evaluate the trade-offs between technologies. That was by necessity. Because, again, we don't have the [UNINTELLIGIBLE] household level—how many different appliances are using the fuel? So you don't actually have a sense of what a more complicated tariff might look like. So I think that would change a lot, potentially, in some cases, the results. I think that's an important caveat.

*Respondent 2:* The answer for our study depends on which phase of the analysis we're looking at. In the end-use adoption side of things, what we prescribe are the sales shares for different technologies over time. And those are based on a combination of cost effectiveness based on a flat-rate structure as well—but also some expert judgment feeding into that, how barriers to electrification might change over time from the consumer's perspective.

In our capacity expansion modeling, that is more based on retail markets and structures and things like that. So it's not as constant across the board for that part, in terms of which resources are most cost effective in terms of when they can provide services to the grid.

*Question #3:* This has been a great panel. First of all, I want to thank everybody for taking the time to do this for us. I think Speaker 4's work kind of brings out the issue of retail rate design and how to cure some of the issues that ail us in California. You had two slides, one with the duck curve and then one with the work that that Jim and Severin had done on retail rates, showing the huge disparity between the optimal rates and the retail rates.

I guess the question I have is, how do we combine the kind of work that you're doing with the work that both EPRI and NREL are doing so that we can actually arrive at something that's a much more holistic result here? To integrating renewables and deep decarbonization without having to expand capacity, whether it's on the transmission or distribution systems or as much generating capacity as, I think, Speaker 3 showed in that presentation? How do we get those things combined? That's the big overarching question for the entire panel, I guess.

But I think that the second one is the issue about just batteries in general. Storage is not a resource. Storage is actually a net load. And I think Speaker 4's work really shows that very clearly. Why is storage being modeled as a resource, number one? And then, number two, with respect to both the EPRI and the NREL studies, why haven't we looked at ground-source heat pumps as another option here, especially in cold weather climates that might actually do better than having gas as backup? Thanks.

*Respondent 1:* So, again, on the rate structure, I agree. I'm interested to get more details on how those tariffs were modeled. I would like to try and factor that in. I will say, on the supply side it's possible, to distract away a little bit from what's happening in the individual end users at the household level, to build in the implications of flexible demand at the system level. If the system had control of a certain amount of gigawatts, what is that worth in terms of avoiding other types of resources?

We certainly can model that, and we have modeled that. I think gave an example of the flexible charging. The gigawatts of charging load is probably going to be much larger, at least in these scenarios that we're running, then the gigawatts of water heating. So this is definitely going to be one where the ability to control is going to have a lot of value in terms of scale. We can build that into the system side. It's essentially kind of virtual storage, in terms of how storage is modeled. I mean, you're right. Obviously, there's no energy coming from storage, it's a net load in terms of the net losses, round trip losses. That's exactly how we model it in our system.

So it's being used to provide capacity in peak moments and then has to be charged in other moments. It's all about shifting energy to a time when it's less costly to provide and avoiding other types of capacity resources, like gas turbines and facilitating renewable integration, to a certain extent.

But the economics of storage, in a way it's a separate question. But it's also related to this value flexible modes. Those are represented, I think, technologically accurately in the models. Not as a free resource. There's a cost and a value to it.

You also asked about ground-source heat pumps. So we do include ground-source heat

pumps in the model. The trouble with ground-source heat pumps in a model where you have economic adoption is that they're really expensive. I think there are ways to make it more cost effective, particularly in new construction, if you can share the reservoir among a number of buildings or you can think about a commercial building setting where it sort of fits into the construction better. Retrofitting these things in residential homes, it's really only for people with a lot of money to burn, as far as I can tell. I know that the technology can improve, but the ground loop is a big cost. So you really have to want it.

We find that there are other ways to achieve the services that that provides that lower costs. In certain settings of my work. It would be interesting to look at what it would take to get a pool or district geothermal heating situation into a levelized cost, where it's kind of similar to an air-source heat pump. But ultimately, it's a difficult trade-off to justify, when you see how much that costs relative to the efficiency that it gets you. You have to really value capacity of the margin. There's other ways to provide that. So that's how the model is treating it right now.

*Respondent 2:* I'm going to jump around a little bit. I can lump the answers together based on our tools, a little bit out of order. For both the rate structure and the ground-source heat pump question, part of our capacity expansion model is integrated with a demand-side adoption of distributed generation sources. And that's really the place where both of those questions would be most relevant.

That's our separate model that's really focused. It's an agent-based model, looking at how people make decisions and how the rate structures and the economics of different options would play out based on different

consumer behaviors. That would be a natural place to build in some of the rate type information from the work from others.

We do have an active research portfolio, looking at how tariff structures and retail rates might evolve over time. That wasn't really incorporated into this work, but it certainly would be an interesting future direction for especially electrification-related questions of how retail rates evolve and how that interplay between the demand side and the supply side leads to kind of different consumer decisions.

That model also does have a representation of ground-source heat pumps. They do tend to be more regionally relevant. They wouldn't probably make much of a dent in our national scale results.

Although one thing I have failed to mention in this study is that everything that we've done is available at a state-level resolution, at least, and sometimes at a finer resolution, as well. So, certainly, if you were to look at a region like New York, you might be able to find a much bigger impact on something like ground-source heat pumps, then you would find in a place like Colorado, for example. Not necessarily something that we touched on, but something that we do have some tools to look at. And I do think it's an area that's ripe for development in the regions where it especially makes sense.

For the storage question, that's mostly relevant for our ReEDs work. I did just want to clarify that storage, similar to what was just said, it is treated as a net load in our model, we have a round trip efficiency that [UNINTELLIGIBLE] how much it can supply versus how much it is charged.

The other thing I want to point out is that our storage is not purely batteries in that work.

Compressed air energy storage and pump hydro actually make up a large share of the capacity in our results, especially in depending on our cost and performance assumptions. The reason that they're included in our capacity stack is because they feed into our system cost results, so that's the main reason why they're there.

That's an investment that the power system has to make. And if we want to look at the broader economics of electrification by sector, that's really why they're included in that place. But, yes, you certainly don't want to just say, we go from 1000 gigawatts up to 2000 gigawatts, or 2500 gigawatts, and then emphasize the storage component of it. Because I think the more important consideration is really on the system cost side of things.

*Moderator:* Anyone want to add anything?

*Respondent 2:* I just want to say a couple of things. One is, these models are big and there's a lot of dimensions to them. So I think narrowing the geographic dimension to have a more regional focus on the electricity production side might enable you to expand detail on the demand side and get at these inter-temporal-demands-shifting choices. A lot of models that are out there don't even have price-sensitive demand in an annual sense or monthly sense or anything. So there's a lot of parameters that one needs to come up with. In an optimization we did, it was just a US cost minimization thing, which there's some entity that's managing your hot water heater and they're doing the smart thing, making sure you still have supply when you need it.

But to the extent that consumers are part of the game here, I also think it's important for to understand how consumers are going to respond to various optimization algorithms

that are out there. Some colleagues and I are doing some work related to using smart thermostats to again shift load around in time, seeing how well customers play ball with that. Because I think we need to understand that to, too, make our models relevant.

*Respondent 3:* I have a comment by way of a question for the other panelists. It's something we contemplated in our own work. I'm wondering how you all in your modeling efforts have addressed this, and it's specific to the building sector and heat pumps in particular, to the point that regionalization matters and where you are in the country matters, especially for the size of the heat pump. Typically, if you're in the South, you're going to size your heat pump based on the cooling load. And your heating load on a peak winter day might not be met by that size. I'm sorry. No, it would be met in south, but the farther north you go if you're sizing it to your cooling load your heating load is not going to be met.

So then you might have to be sizing it for your heating load, and you're giving up something on the cooling side. I'm just wondering if you guys have addressed this issue, because obviously oversized in the heat pump to meet people winter requirements could result in different priced, maybe more expensive equipment different efficiencies. Wear and tear on the equipment. Have you guys thought through these challenges or these questions?

It's actually something our groups been mulling over. How you really get your arms around the size of the heat pump relative, because the cooling and heating loads can be quite different, depending on where you are in the country.

*Respondent 1:* Yes, if I may. We have looked at exactly that question. We have different

rules for sizing. You can also look at sort of an optimal size where you try and look at the marginal cost of the heat-pump capacity versus the impacts on efficiency through its operation.

But you're absolutely right that if you size the cooling level, which is a conventional rule, you end up with a pretty big shortfall in the heating peak in a colder climate which leaves a lot of resistance if you're trying to do all electric. What we found is, particularly over time, if you assume that variable-speed heat pump technology becomes more the standard and improves in costs over time, and that an air cooling sizing rule is based on a single-speed heat pump, which becomes very inefficient if it tries to cycle too much at the peak. Or if the variable speed can operate at partial capacity with much better efficiency. So you don't have as much of the impact on cooling performance and you are able to meet more of the heating load with the heat pump. That's the main efficiency advantage in cold weather, with a variable-speed heat pump. It does cost more, and you need a larger heat pump. So that does impact the cost of the installation.

However, it also reduces peak demand. So there's a sort of capacity value. If you've got a winter heating system, anything you can do to reduce the contribution of resistance on the peak, that's straight capacity value. So it's usually justified to oversize the heat pump to meet the heating load, at least most of it, in the northern climate. And we have looked at that explosive technology question.

*Respondent 3:* Well, thanks for that. I would just make a meta comment, which is, the more you peel back the onion on some of these questions it gets very, very complicated, and the modeling for this gets increasingly complex. I'm glad to hear you



guys are thinking through this. It's something we've been pondering over. Thanks.

*Moderator:* Next question.

**Question #4:** Thank you. I'm deliberating whether to ask my more rate-geeky question or my more blue sky question. Oh, well, let's take one at a time, and if I have time to come around, I'll ask the other one.

Obviously, we're going through an extraordinary time right now, with so many sectors of society more or less shut down and huge changes in people's commuting patterns and so forth. I've seen really two macro forms of instant analysis in the media and in the energy Twitter, what that means for things we're doing to respond to climate change.

The first being, well, we're entering a period of economic downturn, possibly even a depression, so obviously things we might have done to electrify things or work on climate mitigation, they have to take a backseat, because we have bigger problems as a society. That's one thread of debate. And then the other is along the lines of, wow, look what we can accomplish if everyone does the same thing. And if we took climate change this seriously, imagine what we could do. Why don't we treat climate change like we treated COVID-19 and imagine what we'll accomplish. That's been the other macro theme that gets echoed in the Twitterverse.

I guess I'm wondering for you people who've done so much work and study, if we presume a medium-term to long-term societal change with maybe different work patterns and different commuting patterns and maybe some changes in mass gatherings, which are very peaky—I mean nobody really knows, we're in the middle of it right now—whether there's anything we should model or study for how we can take advantage of this period to

learn about customer usage patterns in a way that will make the money we spend more effective if we try to electrify or change customers' patterns.

I know it's really in the middle of it. So it's not really fair, but it just seems something very unusual is going on right now that might be an opportunity

*Moderator:* Panelists?

*Respondent 1:* I think disruptive events have a tendency to bring out efficiencies and we're going to see that. We're also going to, as I alluded to earlier, find different things that we value in terms of the interconnectedness of our systems and the resiliency of those systems to disruptions, or unexpected events and so forth.

So I think there's going to be a lot to think through and you're asking the right questions. How is this really going to change and how can we make the best of this? But certain things aren't going to change. Even if we're not getting together in groups and certain electricity-demand profiles change, we're all turning on our heaters on the coldest winter day and there's going to be a peak.

So you might be able to get some efficiencies in different parts of the system. I think we'll learn about that but the fundamental still exists. And I think all of the discussion we're having today around how we move people and goods in the transportation sector, how we heat and cool our homes and our businesses, all that's going to have just as much relevance.

I'm glad we're having this conversation, even amid this crisis, because these are all going to be very relevant issues, even as we come out of this crisis with a new perspective on things.

**Question #5:** Thanks. First of all, a comment. I think it'll be really interesting to see where this analysis goes as you begin to see rate designs move towards something in which we take more of those common fixed costs and we put them in potentially differentiated but fixed charges to customers to get to a more efficient rate design.

My question is really more on the greenhouse gas emission impacts. One of the things that we're looking at and seeing has to do with the fact that the relevant metric is, what's the marginal emissions impact? Looking at average emissions, particularly in electricity doesn't really tell you a great deal. And what's on the margin depends a great deal on what's driving policy.

Is it technology? Is it a state-driven or regional or national policy? It also depends very much on time and location, and things like transmission constraints can have noticeable impact on what marginal emissions are. I'm wondering to what extent the analysis that's being done is really taking a careful look at marginal emission rates and at what level of granularity you're doing that, as opposed to a more higher-level marginal or average commission rate analysis?

*Respondent 1:* I think that's exactly the issue. And that's what we're hoping to get at, in thinking about the opportunities to shift demand in time for the storage of electricity sources. It is true that transmission constraints and things like that matter. So it's important in thinking about any efforts to encourage folks to shift their demand in time to take those things into account.

I mean, one way you can get a better sense of that, of course, is to be really pricing carbon. Presumably the prices will go down to the nodes that reflect that, until it will all be reflected in the prices that get passed on when

you're separating energy from fixed costs in the appropriate way, to what gets translated to customers. Shy of that, I just think it's important to do a careful job of trying to align. And it's difficult because, of course, these things are evolving over time. Understanding the impact now is not necessarily helpful in terms of what they're going to be in the future.

But we do have some sense about particular areas where renewables are getting curtailed. And that's areas where there are opportunities in the space to shift demand to those hours and locations with presumably admission-reducing consequences.

*Moderator:* Do the other panelists want to respond?

*Respondent 2:* I agree with you. Obviously, it's the marginal generation intensity that you want to be evaluating. But in some ways when you're doing a systems integrated model, the model it takes care of that. I mean, the constraints of the resolution of the model. It's almost harder to report than it is to model. You add in these new shapes or shape for changing over time, the model is choosing dispatch and investment against those new shapes. So whatever changes you observe in emissions in the total emissions are reflecting as marginal decisions that the model is making differently with the new load shape. When you report aggregate results, you can't always see the marginal, you'd have to have more detailed reporting calculation to tease out the marginal.

And we've done that in some cases. You will miss some effects, to the extent that renewables are being curtailed—maybe solar is being curtailed in a place where you've got a lot of solar and not enough to get out some bottleneck in the transmission at work that's

below the level of resolution in the model. You'd miss something like that.

But I think, in general, you're hitting the key impacts, which is, what are they doing to existing asset utilization? And what is it doing to demand for new capacity? How is it driving new capacity additions? That's absolutely dependent on the policy that's constraining the generation sector, whether it's state policies or whether there's a federal policy that you put in, or whatever it is.

I would just say that there's almost no case where the marginal emissions intensity is so high, for an electrified load like vehicle charging, that it's higher than the petroleum emissions that you're offsetting. You would have to be something like old coal on the margin, all the time, which is not the case anywhere. And so the model results reflect that. Adding these load shapes does not necessarily increase asset utilization of coal doesn't necessarily increase asset utilization on average overall.

It depends on the shape and how it interacts with the peak. It drives new capacity additions. The model's giving you a sense of what those margin generation sources are likely to be under different assumptions. Almost always they're less carbon intensive than petroleum in the trial setting and, as well, in space heating, in some cases.

*Moderator:* Any panelists want to add to this?

*Respondent 3:* I would mostly echo what was just said. That certainly applies to our treatment in our capacity expansion model. The only thing I'll add is that the study that we're wrapping up now is the production cost modeling that looks at hourly unit commitment and dispatch. So I think that's the study where we would start to get at some of these things in more detail, including the

transmission congestion question, also the utilization of storage and the highest benefits of it there. Then, of course, the marginal generator will be captured in that case. By comparing across electrification levels, we're not reporting the specific marginal unit, but it will be reflected in the emissions outcomes of those scenarios. That is about to be sent out for external review. So if anyone is interested in reviewing it, please feel free to reach out to me and I can see if we still have room on our reviewer list for it.

*Respondent 4:* I think you have to look at the marginal emissions to accurately reflect the impacts of these types of consumer decisions or even system-wide decisions. It gets trickier when you go system-wide, of course. And of course these margins change over time. So you have to be careful in how you treat it. We're doing a lot more work to try to evaluate, in particular, the marginal impacts over the lifetime of equipment and so forth.

We're thinking through some of those challenges and the mechanics of how you model these types of decisions. For example, a heat pump water heater versus gas water heater under a range of electric grid assumptions, over the lifetime of that equipment. Then what happens if you integrate some level of renewable natural gas into that. What are the marginal emissions impacts from that, relative to other scenarios? So, again, you peel back the onion, that gets complicated quickly. But that's the only way to do it and do it correctly when you're evaluating the actual grid and overall energy and emissions impacts of these decisions.

*Commenter:* Can I make one comment here? Which is, it came up in the chat room, as well, and particular comments were some compliments to Speaker 2 for presenting the marginal cost of CO<sub>2</sub> reduction, those various graphs and tables, which is similar to the idea

of the old McKinsey curve for reducing carbon emissions. The McKinsey curve was very controversial because of the numbers, but not because of the idea. And the idea of being able to just lay that out and tell us how it's increasing at the margin, which is reflecting to the last question, I think is important.

If that information is available from the other speakers in addition to what Speaker 2 did, it would be great if we could see that, because it's a nice, handy way of understanding how far you're going and where you want to stop.

**Question #6:** Thank you everyone. This has been very interesting. I'm particularly focused on the transportation piece of this, which I think has not been the primary focus in the discussion. I noted when Speaker 3's graphs were up, she had what does the generation mix look like under these various assumptions. Natural gas was orange and red in the graph.

I can't find it in the deck. But the bottom line is, right now the electricity system is using 40% of the natural gas delivered in the United States. Her graph showed a significant increase in that in many of the cases. We know that this 40% isn't evenly distributed across the country. And we know that it's highly seasonal and in some cases it's also sensitive to what time of day it is.

I'm very surprised to see this much natural gas as part of an electrification strategy. But what are the thoughts in the modeling into where the infrastructure for that gas is going to come from? Five years ago, we used to think building a pipeline was easy and a transmission line was hard. We don't think that way anymore. They're both hard. And, unfortunately, gas is like wind and solar. It's only in certain places in this country. So what does this mean for the modeling? And what

does this mean for the potential for transportation?

*Respondent 1:* So in the capacity expansion modeling results, which were included in the slides, the orange and red wedges that you were referring to, we don't have an explicit representation of the natural gas pipeline network in our model. The way that we represent that is through regional cost multipliers that represent how hard it is in certain regions, especially the New England region, for example, would have a very high cost multiplier.

Whereas, if you're close to the Permian Basin or some of the other natural gas resources that would have a, maybe even a less than one cost multiplier in those cases, because natural gas is abundant and easy to access. So that's how we deal with it in the model. It certainly is not the perfect way to look at pipeline congestion and pipeline challenges.

The only other thing I'll say is that, as you consume more and more natural gas, we do have a supply curve that represents the fact that it gets harder and harder. You do need to make more investments to flow more natural gas into that region. Therefore, your natural gas-fired generation on the power system would become more expensive. So it's all about purely in an economic sense in the model. Of course it's not the best way to do it, but it's the way that the ReEDS model structure works.

Though the only other thing I'll add is that natural gas was prevalent in all of the scenarios, that was a capacity chart instead of a generation chart. So all of the darker wedges are combustion turbine systems, which are usually not run. In that case, I think the chart overemphasizes the role of natural gas in the power system. In some of our scenarios, as well, there are instances where

natural gas doesn't see a pronounced growth relative to current values, especially on the consumption or generation side of things on the power system, because there are so many different ways that we can meet this electrified load, depending on what your assumptions are, just based on the wide range of resources we have in the country. So I certainly agree with your point. It shouldn't be taken for granted that rapid or dramatic expansion of natural gas-fired generation would be easy.

I just want to point out that it isn't required in the scenarios that we have. And we've done what we can to try to represent the fact that it does get harder, especially back to this marginal question. The next increment of gas is harder to add than the one before it, so I totally agree with your points. It is acknowledged as something that the ReEDS model in particular is not really designed to deal with in detail, but we do our best to approximate some of those issues.

*Questioner:* One point about that. I see gas coming in more and more as a peaking fuel in these scenarios, whether it be gas backup for a heat pump. But in the transportation gas doesn't work very well as a peaking fuel, because of all this infrastructure.

So when you're saying, the gas turbines only use it four hours a day, you've got to pay for it 24 hours a day. So this is very important. I think the solutions are going to be regional. I think everybody who says regional is on the right track. But I also think that we have to realize that this is not a free good, and we're going to burn through the infrastructure we have in some of these scenarios, which means new infrastructure as you've acknowledged.

*Moderator:* Any of the other panelists want to speak to this point?

*Respondent 2:* I don't fundamentally disagree with that. This is a regional issue. And the ability to build new pipelines, the challenges associated with that are still quite regional, especially if you're building a pipeline over longer and longer distances. That can create challenges as well.

This is not free, but we do have an extensive infrastructure base, as well. There's 2.6 million miles of pipeline in this country and, thinking carefully about how we leverage that infrastructure, whether with existing gas resources or with renewable gases and hydrogen, using that infrastructure. There's some real potential there, but there will be a need for new infrastructure, expansion to new customers, new transmission projects.

Those expansion projects can be entirely consistent with these decarbonization pathways that we're exploring and modeling and talking through today. So just as a philosophical point, I kind of reject the idea that there's no justification for new gas infrastructure in this country. I don't think that's true at all.

But I think we're going to be thinking differently about that infrastructure, in part because of the politics and the difficulties in getting some of that infrastructure built, but also thinking through how we're going to leverage the existing and new infrastructure based to meet our objectives. And that's not just in carbon reductions, although that's a key objective, it will be reliability and resilience of our overall energy system.

How the gas system supports maybe these other pathways of thinking through changes in the transportation sector, for example. I don't know if that quite gets to your question. Maybe it does, but that's how we've been thinking about it. It's complicated, and you have to think through this carefully. It's

definitely not a free resource and sometimes some models do assume that, and we have to be careful with that.

*Moderator:* Next question.

**Question #7:** I'm from Alberta, Canada, so most of the discussion applies very directly to Canada and abroad as well. So Alberta is unique in the sense that it is not as dense as most of the states and some provinces.

We have very high distribution and transmission costs, both on the natural gas side and the electricity side, and it is recovered mostly on a fixed basis. On a per-customer basis or a per-unit basis, those are significant numbers, which makes savings on, let's say, in commodity or the energy or the carbon, not as attractive as other places.

I was wondering whether you folks have seen something that can work for such a system? The additional complication is, of course, Alberta's economy is based on oil and natural gas, so it seems to be very difficult times ahead. I was just wondering whether you folks have some suggestions for us to look into.

*Moderator:* Who wants to take that on first?

*Respondent 1:* I will say, we're actually working on a similar study in Canada, where we're trying to build the model and assumptions and see how Canada is different than the US. Specifically you're referring to the density of population in Alberta as a factor? I'm not sure how this plays out. I guess you're talking about more miles of transmission and more miles of pipeline per end use, which is going to serve increase the fixed costs piece of energy delivery.

I assume that changes things a little bit, but in all delivered energy the fixed cost is a big

piece of it. That's true, even in the US, New York City's densest in the country and they have some of the highest fixed costs of delivery infrastructure. The energy piece of that **is** relatively small. So the reliability and resilience in our system is all about having capacity to meet the peak, because we know that demands vary over time and they're not going to be spread out, especially with regard to space conditioning. I think that those issues would be similar. The cold climate in Alberta is going to certainly be a factor in thinking about what the technology mix is. Population density necessarily doesn't make electrification harder, I don't think. But maybe there's an angle I'm missing there.

*Questioner:* What I can add is it's mostly the barrier of cost that is pretty high. So you'd have to pay that regardless of whether you change something or not. Let's say our transmission cost is about to the order of \$40 per megawatt hour if you convert that to a unit cost number. That number is already pretty high, and pretty much same on the gas side. So that is something you want to avoid. You are going to pay that number, regardless of whether you move to electricity or gas. That will make our decisions and ratemaking and tariffmaking a bit difficult.

*Respondent 1:* It also depends on the supply-side integration, to what extent you're trying to integrate renewables, or where the capacity is located and how far you have to move things to meet the generation. Carbon-intensity goals as well. So I think it's true that every region is going to have a different configuration.

*Moderator:* Any other panelists?

*Respondent 2:* Well, only that, in places that are spread out a lot, people probably drive a lot, so I can imagine that depending on the grid, the benefits of electrification of

transport could be substantial in such an area, presumably both maybe carbon-related, resource economy issues aside, and other pollutant-related perhaps.

*Moderator:* The other panelists want to kick in?

*Respondent 3:* The only other thing I want to mention is that NREL is wrapping up also a North American renewable integration study, which does have an electrification scenario for Canada, the United States and Mexico. I think that'll be coming out in the next few months or so. We worked with the Canadian federal government on that study.

I haven't been closely involved in it enough to be able to provide insights, but hopefully that study will be helpful when it comes out. I'm happy to put you in touch with the authors, if that would be helpful.

*Moderator:* We have another question.

**Question #8:** In the chat, somebody had complimented the idea of figuring out what the carbon price is for electrification. I'm curious about two sensitivity analyses connected to that carbon price that came up. One is the degree to which load can be managed. So that price seemed to assume that there's going to be a doubling in electric demand and therefore a doubling in the need for electric infrastructure.

What sensitivity analysis had been done or what analyses have others done that would allow us to better understand what the carbon price would be if there isn't truly a doubling as that analysis assumed?

The second sensitivity question that was on the chat list is, what happens to that analysis or the others, if we move into a world in a year or five years with very high gas

regulations? We're seeing restricted pipeline construction, sharply restricted fracking, methane restrictions on gas production and transportation. What does that do to these analyses on electrification? Thank you.

*Respondent 1:* I think you were referring to my chart. So let me tackle this first. I was moving through the analysis so quickly that probably some subtleties were missed. The chart where I showed that electrifying all residential gas uses effectively doubles the peak electric grid output, that is an assumption based—we assume that just to illustrate the magnitudes here. It does not assume any sort of load shifting.

Let me pin that idea for a second. Also, that was not the key case that drove the cost numbers that I presented later. Let me come back to that. On the load shifting, I think there is some load shifting that's possible, and it could change those numbers, depending on how you model that. We did consider those elements as we were trying to scope out the study and how to model this. We set it aside for several reasons. One, that a design day on the gas system may not last hours, it may last days sometimes. And so there's only so much load shifting that possible over a four- or five-day winter event, for example, on any given system. So that's one concept.

The second, I'm going to set that aside. In terms of the cost numbers, the costs are based on our policy case that starts in 2023 and only goes through 2035. That was just the assumptions that we did. And that policy case again was: no new natural gas, fuel oil or propane starting in 2023, and then continuing with that through 2035. Then we just stopped the analysis there and certain impacts were evaluated after that time. But what that does is it only really electrifies about 60% of the residential sector.

So we're not getting to that. And it's only space and water heating, we're not looking at close cooking or close driving or other end uses, residential gas end uses. So we don't get to the whole 100% case and effective doubling of the grid that I presented on the chart. I'm sorry if it comes off that way it was. It was really just trying to illustrate the ideas and some of the costs associated that we actually modeled, in terms of a carbon price of electrification or whatever.

It's really the cost per ton. So you add up all your costs and you divide it by the amount of emissions reduced. Again, this is a 60% case, where you electrify 60% of the residential space and water heating, but you're on a trajectory to get to 100% by 2050. That's what the costs reflect. There are two different costs, because our analysis assumed different scenarios for how you meet that new peak electric demand on the grid.

That's related to, if you allow new natural gas to be built, or if you're only assuming renewables and battery storage for your incremental generation requirements. The renewables-only case was the more expensive of the two. And again, this is all assumptions, this was not an optimization exercise that probably would have produced lower results, because it's an optimization exercise. What we were trying to do was, again, a few years ago when we started this exercise, try to get our arms around what are the implications of some of these policy ideas that were being floated out there.

Since then, I think that there's much more sophisticated ways you might think about modeling this, more ways you would optimize it and so forth. So will those costs come down? Potentially. But they can also go up, depending on where you are in the country as well. Those were just average cost of emissions reductions for the whole

country. Again, it depends where you are in the country. Those could go well up or down depending on where you are. I'll leave it there.

*Moderator:* Other panelists want to respond?

*Respondent 2:* I would just respond to this question of backing out the marginal CO<sub>2</sub> production costs. I'm not sure that's the best framing. I tend to be a little bit skeptical of one number per ton CO<sub>2</sub> for a given activity, given how interrelated all these things are and the dynamics of economies of scale. I mean, the more you do, the more it costs.

It really depends on what's going on in the rest of the system. I find it hard to separate these things out. At the same time, I think you can get some information by looking at, if I put in a carbon price of  $x$ , what kind of response do I see based on how adoption changes? I think you can get more information that way. For example, with electric vehicles, you don't need a carbon price to make it cost effective. To the extent that it reduces emissions, that's without marginal costs, unless you want to say you need additional incentives to nudge people behaviorally and that has a cost. Do we try and back that out? But just from a sort of technical, economic perspective, certain electrification activities are in the money without a carbon price.

If you talk about electrification that's not in the money without a carbon price, and you start saying, "OK, well, if I introduce the current price of \$50, \$100 over time, what does that do?"

It depends so much on the dynamics of the stock turnover, when people do it. Do they consider early retirement of equipment? Are they doing the standard of life? That regulates the scale of the response. Circumstances vary



a lot, so a single number for electrification of space heating just isn't meaningful to me. I think there's just such a wide range of circumstances and climates that give you different break-evens for so many different situations. Maybe the best you can do is a curve.

What we've tried to do is show and the implications of hitting the decisions with a carbon price and showing how those decisions change in the magnitude of the response that you get over time with the given price input. So that's how we framed it. There's a report that goes into more detail and showing how those effects play out.

That's what I would recommend in terms of thinking about it. I know it's not as simple as the McKinsey curve. But I think it's more accurate.

*Moderator:* Any other responses?

*Respondent 3:* A couple of thoughts. Carbon price, either explicit or implicit, will not be found in recent or near-term NREL studies, but a couple of thoughts on it, more generally. I caution against the idea of the marginal price, especially when the question is only about or is primarily focused on 100% of something. Just because we all know that those curves get very steep as you approach 100%.

We have studies looking at renewable integration and you start to see an inflection. And then at some point, you start to see an almost vertical line, so I agree with the last point that I think a curve is needed at the very least, for those sorts of metrics.

The other note I wanted to make is that this incremental value of flexibility is something that's been a strong focus of our electrification work, and it will definitely be

the focus of our production cost modeling study that's coming out. Essentially, what we've done for each of those studies is to look at different levels of flexibility. So, different levels of consumer participation, but also different magnitudes of flexibility, how much they're willing to shift their loads in time.

If we look at that and we can look at the marginal value of more flexibility, as you look at bringing more customers online or increasing the level of flexibility under a range of generation portfolios. So we can look at whether it gets more or less valuable with variable renewable integration, under base case assumptions, under high electrification or reference.

And that's sort of how we've been addressing this question is to look at how an incremental increase in flexibility. What the incremental value of that would then be. So it's starting to get a couple points on this curve, for example, without fully answering the question, but it's a way to leverage modeling results without having an implicit or explicit carbon price in your study, for example.

*Moderator:* Next question.

**Question #9:** I guess my question is, with regards to vehicle electrification and particularly how it affects the coasts versus the center part of the country. One of the questions in the chat had to deal with regionalization and it strikes me that there'd be a bit of a difference in terms of timing, in terms of adoption between when you might see it on coasts versus when you'd see higher penetration in the center part of the country.

Is that something that your studies have looked into and are things that are factored into the models?

*Respondent 1:* We do. The model that we use to look at electric vehicle adoption is a regionally results model. We do look at differences in income and distances driven on a daily basis to inform at what point electric vehicle adoption becomes cost effective, accounting for electricity rates, but also sort of the performance of vehicles over time, if their range increases.

It's not something that we've published on directly, but our model results are published online, and you can look at a specific state's EV adoption over time and you would be able to compare them. We haven't done an analysis on it, but the data is available to look at for the electrification feature study.

*Respondent 2:* I would just say that, in the very near term, what is driving the fact that there's more adoption in California and the "coasts," I think has more to do with customer preferences, certainly income is part of it, but information and some factors that I think, or at least the model assumes, become less important over time as the market matures and broadens and you have these same choices available to everyone in the country. It's more driven by "What are the relative economics in my state?" And then, well, the differences start to go away when you look at the structure of the decision with regard to EV adoption.

Because electricity prices vary a little bit. In fact, they're more expensive on the coast. California has the most expensive electricity prices and yet highest EV adoption, so I don't think electricity prices is all that strong a driver. The variation in how far people drive is important, but that varies at the household level. But there's a wide distribution, no matter where you go, I think that you will see that being an important driver.

But I don't think there are necessarily that many differences between middle of the country versus the coasts, in terms of how far people drive. Cities are an exception. So I think that the fundamentals of EV adoption are going to be similar throughout the country, not to say that there aren't going to continue to be barriers in certain areas, for I would say non-economic reasons. But those are a little bit harder to model.

*Moderator:* We do also have to distinguish between electrification of personal vehicles and electrification of mass transit.

*Respondent 2:* Indeed. Of course, energies for mass transit is automatically orders of magnitude lower than for personal vehicles.

*Moderator:* That is the reason to think about it. I think pretty exactly that reason.

*Respondent 2:* In cities, I think you have a wider range of options for things like ride-sharing service or autonomous vehicles and a base mobility as a service model that could displace vehicle ownership. But there are cities like that throughout the country where that could work.

*Moderator:* Last question.

**Question #10:** Thank you. Well, I'll try to make it a doozy then, here before happy hour. A lot of the electrification conversation that's come up recently is in a policy context and is heavily focusing on what the barriers to entry are in the new space. I thought some of the intriguing points of the analyses that were put forward were for what some of the sensitivities were to endogenous adoption in the space.

So I'd be curious to know what the degree of granularity within the existing framework for avoided cost there is. We talked about the

importance of rate design versus the end use of the cost of the technology. But also, going forward, it wasn't totally clear to me if it was more of a focus on the state of end-use technology, because the modeled electricity costs, the avoided costs, were presumed to be fairly flat or if that was because after a wide range of sensitivities, they didn't matter a lot.

But from the industrial space, we saw that a lot of adoption and consideration of electrification was very much a focus, not just on overall cost profile within a given footprint, but also very much like the rate structure. So you see the transmission cost allocation and coincident peak, things like that.

I'd be curious for new analysis going forward, how does more granular analysis of the avoided costs in the electricity policy context move the needle in this space at all?

*Respondent 1:* Can I go first? I'll try to be brief. I know you're at the end of the hour. For the end-use customers' perspective, we assumed a flat retail price. But when we're modeling the cost implications, that cost was not flat. We looked at the actual cost to generation, capacity costs and dispatch costs, as well as how the changing shape affected the average T&D costs.

The resulting impacts on the price and the system costs reflect that structure to a certain extent, but the idea is that the customer didn't necessarily pick up on all that, because the customer was facing a flat retail price. The question for me is what happens when a customer, you have more efficient retail pricing and the customer can better see the implications of different choices on those elements of the cost structure, particularly on the fixed-cost component. And if they're seeing that better, you have different

decisions. That's the part that I think is really interesting that we're trying to do now.

*Moderator:* Anybody else have thoughts? I want to thank the four panelists for a terrific job on the presentations. Thanks very much.