HARVARD ELECTRICITY POLICY GROUP

SIXTY-FIFTH PLENARY SESSION

The Rosewood Crescent Hotel
Dallas, Texas
THURSDAY AND FRIDAY, DECEMBER 1-2, 2011

Rapporteur's Summary*

Session One.
Choosing Energy Technologies: When and Where are Subsidies Appropriate and How Should They Be Designed

Encouraging technological innovation in energy is a vital part of maintaining an efficient and vibrant power sector. The electricity industry itself, other than some vendors, spends relatively little on research and development. Compared with other industries, it is more reliant on subsidies, from customers or far more often from government, to fund new products and technology. How government selects projects or efforts to subsidize becomes a critical factor in the technological evolution of the industry. Certainly, many of the advances today in such areas as renewable energy, clean coal, nuclear power, smart grid, energy storage, system controls and electronics, and a variety of other technologies, have been nurtured along by subsidies and other forms of government support. How should technology policy interact with electricity market design? Are such technology choices by government wise, or do they constitute interference in a marketplace that would do better without such intervention? Historically, what basis and criteria did government employ to make decisions on technology choices? If government does intervene, what are the optimal ways for such intervention? How should subsidies be designed? At what stages of R&D are subsidies needed and at what point do they become counterproductive? Presumably, if they have value, it is in the R&D phase, so what protections should be put in place to assure that subsidies do not remain in place forever? What levels of either technological or commercial failure are acceptable risks?

Moderator: I think we have just a wonderful panel here today and some really challenging issues, as we read the newspapers every day and look at the latest round of Congressional hearings, and that is, what about the role of government in terms of subsidizing technologies? Is that a good thing, is that a bad thing? How do you do it? What are the rules? How do you design the criteria? How do you avoid picking winners and losers? And who in government should play the role, if any? Would it be better to have a green bank, for example, with real bankers who do this every day for a

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living--some of whom are actually a little more honest than others, of course, but we would want the honest ones.

Speaker 1.

I want to frame my presentation this morning in the context of pursuing a low carbon future. Let me explain why I'm doing it that way. First, I'm an environmental advocate, so you can pretty well bet that every opportunity I get, I'm going to make the pitch that we should be transitioning to a low-carbon future. But having said that, that's not my primary purpose in focusing on it. My primary purpose in focusing on it really is because, as we talk about the need to turn over capital stock in the utility sector, I think we have to take a hard look at the societal drivers that call for that capital stock turnover, in the first instance, and then the second instance, think about how other public policies come into play to be a complement to what is, I think, a necessary activity for the sector.

What I first want to do is show you some results from a study that just came out this past week, looking at how to move California to essentially 80% below their current emission levels by 2050. And the reason why I pick this is not because I want to convince you that everyone should do what California's doing, but because I think it serves as a nice case study for the magnitude of the effort that it will take any state or any nation to get to that endpoint. And this is probably not surprising to you, but what I think is most fascinating about this work is, if you take a look at what is projected in this study (and I should say that this study took sort of what I'll call a McKinsey-esque approach, if all of you are familiar with the study that McKinsey did a number of years ago, both on energy efficiency and how to get carbon reductions out of the economy) they basically took that approach of saying, what technologies do we have today, what technologies are reasonably likely to come on-line in the timeframe of the study, and they tried not to assume anything beyond that in terms of, you know, gee whiz innovation. And they tried to make some reasonable assumptions about what the cost of those technologies will be over time.

So with any projection you can argue with the details of the assumptions, but I think that it's a fairly well-grounded approach.

And what comes out at you from this particular study is really, I think, two messages. First of all, the enormous role that energy efficiency plays in achieving any kind of low-carbon outcome in the future. And secondly, how much of the remaining carbon reductions come from either electrification of the transportation sector or decarbonization of the existing generation fleet.

So another way to look at this is that roughly 70% of what's going to be required to get California to 80% below current carbon levels is going to come basically from stuff that you all control, stuff that utility regulators and utility executives deal with and control. And that is a tremendous challenge, but it's also a tremendous opportunity. That's the first point.

The second point is that, to the extent that we are sitting here wondering what the future looks like and therefore what risks we should take in terms of investments in new technology, I think it's fairly safe to say that energy efficiency, as an investment, is a no-lose proposition. Whether you're trying to get to a low-carbon future or you're simply trying to minimize the cost of replacing existing capital stock, this is the winning strategy.

And so I think much of what we need to focus on is not so much how we create investment strategies for new technology--clearly that's a part of this, but I think much of our focus needs to be on how we create investment strategies that help us unlock the tremendous energy efficiency opportunities that exist and that we need to harness in the coming years. And that comes through loud and clear in the second slide, which goes to the issue of the various scenarios that this study played with in order to get to the end result of 80% below 2050. You'll see that there's the baseline scenario off to the left there. That's what happens if we don't try to achieve the carbon outcome, and that is largely a fossil and hydro world, this is pretty much what we know to be in the future--what we know is a business-as-usual case. If you look all the way on the right, you can see what the world would look like under this study if we tried to achieve the 2050 targets but we had no energy efficiency mixed in.

So the answer is, yes, we can get there from here. It’s going to require a tremendous investment in coal with CCS, a tremendous investment in nuclear technology and renewable technology, and, most significantly, not only are we talking about substantial generation additions, but we are also talking about energy storage and transmission additions as well, rather significant additions to the capital stock.

All of the bars in the middle are variations on a theme and the theme is, with aggressive energy efficiency, we can significantly lower the cost of that future carbon world. And then the only question is, what creates the optimum mix to achieve the residual carbon reductions? And I call your attention to the mixed scenario there, because, unlike the other three which try to put the thumb squarely on renewables or on nuclear or CCS, what this study tells us is that actually a mixed approach is probably the most cost-effective, insofar as it helps us minimize additional transmission and helps us minimize investment in additional storage. And so that’s something for us to think about as we’re setting policy and we’re thinking about the kinds of technologies that we want to incentivize. It’s arguably smart to think about a low-carbon future through a portfolio approach, as opposed to a simple linear approach--we’re going to do it all with nuclear, we’re going to do it all with renewables, we’re going to do it all with fossil, with carbon capture and storage.

Likewise, I think we also need to pay attention to the fact that it’s not just about a portfolio of technologies and not just energy efficiency, but that managing peak demand is also incredibly important. And if you remember back to the first slide, a significant fraction of our low-carbon future comes from the electrification of the vehicle fleet. In order to accommodate that, we not only have to build new generating capacity, but we also have to find ways to be able to manage peak demand. If we allow the electric vehicles to come on and charge during normal peak times, we wind up building additional peak generating capacity and additional transmission capacity and distribution capacity, whereas if we couple our electric vehicle strategy with a strategy that also helps manage when those vehicles charge--some kind of peak pricing or some kind of demand response strategy--we can actually achieve the carbon objective with lower cost than if we allow this technology to come on to the system randomly.

The next slide I wanted to show you from this study begins to get into the question of how we pay for all of this. And I think it becomes important to think about it in this framework: if you look at these bars, they show you, over time, how the costs ramp up. And what this slide attempts to do is match the costs with the savings that accrue from the investments that you’re making, with the black boxes representing the residual cost. And so what you see is that here is a cost to energy efficiency, there is a cost to electrification, there is a cost to investing in decarbonization, but there are also savings that accrue, particularly as we begin to electrify the transport fleet, in terms of avoided costs, consumer costs, in terms of gasoline, diesel, and other fuel. And so one way to think about it is that on the one hand, in this low-carbon world, we are putting tremendous new costs onto the utility system. (By the “utility system” I mean, not just the utilities, but also the public service commissions and the RTOs and everyone involved in the process of generating and delivering electricity unto consumers.) And so one could argue that this is going to be a really tough political sell, because public service commissions are going to be squarely wrestling with the question of how to digest these costs. From a societal standpoint, though, the total energy bill may not be all that much greater than it is today, because customers are saving huge amounts of money in terms of the amount of fuel that’s being expended to power vehicles and trucks and the like.

So one way to think of this is that a mechanism for getting us to a clean energy, low-carbon future is essentially to make a tradeoff, if you will, between the dollars that we’re currently spending today for gasoline and other petroleum products (expenditures, by the way, that increasingly flow off-shore), and a world where the electric bill is higher and the investment is all in domestic energy resources. So one way to think of this is that we’re no longer sending our money to the Middle East, we’re sending it to Middle America.

So one of the challenges, I think, is not so much a question of financing mechanism, it's a question of public policy framing and how do we get people to understand and embrace the idea that by making significant investments in existing electric infrastructure, it is part of a way to transition to a more sustainable energy future and one that re-invests more of our energy dollar here in the U.S., as opposed to sending those dollars overseas, and in the process getting a cleaner and better environment as we go.

So if a significant fraction of carbon reduction is coming from energy efficiency and a significant fraction is coming from decarbonizing the existing generation fleet, it begs the question, how do we do that most cost-effectively? And I realize we're going to spend a lot of time today talking about, how we subsidize the capital for new generation and how we buy down the cost of new technologies. But I want to simply throw on the table that, in fact, the work that we've done internally suggests that lowering the capital cost of new technologies is much less a significant driver of the deployment of new technologies than simply getting the pricing right. And by that I mean, making sure that the price that's being charged, or the price that's being charged to the marketplace, fully internalizes the cost of pollution.

And in our analysis we've made some assumptions about the social cost of pollution--roughly a $39 per ton carbon price in 2040, a fairly significant Nox price in 2040, $167 per ton SO2 price, and about a $9,000 per pound mercury price. Suffice it to say that the work that we've done suggests that pollution pricing is a powerful tool, more powerful than reducing capital costs, for getting new technologies into the marketplace.

In this study we were basically asking the question, what would it take to deploy significant amounts of new nuclear power into the system, on the supposition that nuclear is a large source of low-carbon energy? And, frankly, the results surprised us. We could reduce the capital cost of nuclear by 50% (and here we were assuming the capital cost of nuclear was in the range of $3,000 a KW), so we could lower that to $1500 a KW and it still wouldn't have the same effect as simply having some reasonable prices on pollution incorporated into the economics of capacity decisionmaking. So it may not be politically popular right now to talk about pollution pricing, given the political debate that we just had over the last two years, but I think that we would be doing ourselves a disservice if we didn't keep that tool squarely on the table.

Finally, other than pollution pricing, there are four things that really will matter to getting the kind of capital stock turnover that we need in order to not only modernize our system but also achieve low-carbon outcomes. The first, given the central role that energy efficiency plays in our future, is that we need to find ways to engage private capital in financing energy efficiency, and we are big proponents of on-bill financing as a mechanism to do that. And our belief is that there is actually a fair amount of appetite in private capital markets to provide financing for efficiency. What's really needed in order to unlock the power of that capital is a certainty around the recovery mechanism, which is what on-bill financing does, and higher quality information about the reductions that are being made and the certainty of the reductions, which I believe comes from deployment of the information capabilities that smart grid technology provide.

The second thing that we think is incredibly important to getting to a better place in terms of energy is real-time pricing to end-users. Earlier I mentioned the fact that, in order to integrate electric vehicles into the system, you have to pay very close attention to peaks. We believe that pricing mechanisms are the most effective strategy to try to manage those peaks. And, in fact, those of you from PJM and New England ISO and elsewhere know better than I the role that price-based demand response is already playing in terms of helping to manage reliability on the system and avoid near-term investments in capacity. And so pricing is an incredibly important thing.

The third thing that is incredibly important is that, as we focus on energy efficiency and demand response, and I believe that both of those strategies are facilitated by investment and smart grid technology, we need to create a mechanism for cost recovery for certain basic infrastructure. And the way I would look at it is that we need to begin to think of the grid, both transmission and distribution, as a necessary enabler of a wide variety of energy service options and energy technologies, and that there is a certain fixed cost to providing that backbone, and that we should be pricing that as a fixed cost and a non-bypassable cost, in order to be able to make sure that that infrastructure is in place.

And finally, if what I've been saying to you thus far is not out of the box enough, let me suggest that something else that we should be taking a very close look at is what I call a national tariff to achieve energy independence. In the same way that we created a universal financing mechanism to facilitate the development of the interstate highway system, on the theory that the highway system was going to facilitate interstate commerce and also create infrastructure necessary to the national defense, so too I think investment in the transmission system and the distribution system in the United States has a similar role to play in the 21st century, not the least of which is because if you want to engage in a national strategy of trying to move from oil, both for environmental and economic reasons, you need to therefore invest in the infrastructure that allows you to have the electrical infrastructure necessary to support electrification of the transportation system. And so here the simple thought is, a national wires charge that creates a trust fund that then states can apply into to finance a wide variety of projects that are germane to building up either the transmission or distribution system.

And I think that in the same way that we think of the national highway system as consisting of interstate highways and then state highways that feed into that, so too I think the analogy is that the transmission system is the interstate highway of electricity, and the distribution system is the state highways of electricity, but we have a national interest in making sure that both of those are robust. And in this way what I'd be suggesting is that we're creating a tariff, essentially, that would help socialize those costs, to make sure that that infrastructure is there, in order to then be able to facilitate the other things that I'm suggesting that we need to do.

Moderator: Thank you. I can't wait to hear the debate on the state and federal regulatory models that that would require.

Speaker 2.

What I'll try to do over the next 12 or 15 minutes is to partly address some of the very difficult questions that we're supposed to address in these panel. I'm going to be presenting some of the results from a three year study that we just released last week in Washington, DC, at the AAAS. The name of the study is *Transforming U.S. Energy Innovation*, and in this study we tried to take a systems approach to accelerating innovation in the United States. And we looked at four key questions. We looked at government investments in energy research and development. We looked at public institutions administering these investments in research and development. We looked at incentives for private sector innovation, and we looked at international collaboration.

When we are thinking about energy innovation and the role of the government in energy innovation, it's very hard not to just briefly mention some of the things that we all know about. If the world is going to be providing the energy that we need, we need to be providing more energy while at the same time reducing pollution and greenhouse gas emissions, reducing the dependence on imported fossil fuels and increasing access to clean energy markets, also reducing the risk of resource conflicts, nuclear proliferation, and then finally reducing poverty is also an important goal.

Now what most studies that have looked at this over the past ten or 20 years have concluded is that these challenges cannot be met at reasonable cost without new or improved energy technologies. And another assumption from our study was that throughout history the U.S. government and other governments have played an important role in energy technology development through different types of support. Now, in the case of the electricity sector, of course, there's hardly any petroleum consumed in the electricity sector, but as Speaker 1 pointed out, if the transportation sector moves towards electrification, then the utilities are going to play an ever increasing role in displacing oil imports.

As we know, utilities have traditionally invested low amounts in R&D. On average, the U.S. utilities invest 0.1% of their revenues on energy R&D. This compares with about 3% for manufacturing, 8% for computers, and 13% for pharmaceuticals. Of course this is driven by the fact that electricity is a commodity and there's a premium on reliability, so it's to be expected that investments in R&D by utilities are going to be low, and of course equipment manufacturers do make greater investments. But over time, the U.S. government has played big roles in the development of technology such as nuclear technologies, solar photovoltaics, and coal-bed methane, so we already have many examples of cases in which supports in the form of R&D subsidies, in the form of tax credits and other subsidies, have already contributed to technologies that we have today.

These sets of technologies that I have put up on that slide are the range of technologies related to the electricity sector that are highlighted by the *Quadrennial Technology Review*. This is a review that was recently completed by the U.S. Department of Energy. It was taking a slightly longer term view on what are important technologies for the U.S. And we have examples related to grid modernization and also examples related to cleaner electricity. Increased energy efficiency is also one of the areas that was, of course, mentioned.

Now as I said earlier, the U.S. government has worked through technology push policies, through increased R&D investments, through R&D tax credits, through education policy, and also through demand pull policies, so through things like loan guarantees, things like tax incentives, production tax credits, and so forth. In talking about our study, I'm going to be focusing on R&D investments and on institutions, and then I'll talk a little bit about commercial-scale demonstration projects.

What this slide shows is the range of energy R&D investments that the U.S. Department of Energy has made between 1978 and 2012 (the 2012 numbers are the request, we're still in the 2010 budget.) What you will see here is that the total investments in R&D have, in some sense, followed oil prices. We can see a lot of volatility and we see the different colors that denote investments in different areas. And we can see that this helps to illustrate how the way in which the government has been making these investments was very much a programmatic approach. So there's a bioenergy program and there's a solar program and a nuclear program. And a lot of the decisions to make these investments are done on an annual basis, so things are not done using a long-term plan. And, again, they're made very much looking at individual technologies as opposed to thinking about all of the technologies as a portfolio. thinking about the fact that some of the technologies are complements, some of the technologies are substitutes, and there are different levels of uncertainties or risks associated with the different technologies.

What you can see here is the volatility of these investments. You can see the year to year change in budget for those different technologies--coal, petroleum, gas, transportation. If you have all their technologies you have a similar volatility. And of course this is not the way in which one would want to run a lab or even the long-time scales associated with innovation. It's counterproductive. And this is partly a result of how the budgets are done on an annual level and how the budgets are done or the investments are made without thinking about the different technologies and how they work together.

So what we tried to do with respect to this question of how to make decisions or allocations between investments in different technologies, was to actually use a common methodology to evaluate the benefits of investing in different technologies as a portfolio. We consulted about a hundred experts from industry, from academia, from the national labs, and we tried to get their sense of what the role of government investments in R&D would be in decreasing the costs of those technologies in the future. So what you can see here is something that tells you how much experts think that government investment in R&D in different technology areas would affect the cost of these technologies in 2030.

The top cluster of lines is nuclear technologies. The second cluster is looking at solar photovoltaics, and so forth. The circle in the center of each line shows the median estimate of all experts.

What we can see here is that experts foresee that the role of the government is larger in technologies like utility-scale energy storage and solar photovoltaics, while the role of the government may be smaller in areas like vehicles, where they thought that the private sector would have a much greater role by itself.

We also asked about the range of uncertainty on these questions. We used MARKAL, which is a bottom up energy economic model, and we tried to see how different investments in R&D in different technology areas affected outcomes that we care about. And here is one of the results that we got. We have a trajectory of CO2 emissions from the energy sector between 2010 and 2030. We did a sensitivity analysis to see whether we got very different results depending on how optimistic the experts were about technology costs in 2030. And we see the impact of having a much larger research, development, and demonstration budget, from $2 billion to about $50-$80 billion. And what you can see here is that there's only so much that R&D can do. So this shows the range of uncertainty around the response to the smaller budget (in blue) and the range of possible responses to the larger budget (in red). The change in investment doesn't give you very much in terms of projected CO2 emissions reductions. So this is a little bit along the lines of what Speaker 1 was saying. If you care about greenhouse gas emissions you don't get very far just with RD&D. And the same is true if you care about reducing oil imports. You need a demand side policy.

The other thing we got from this exercise of trying to see how one should allocate between technologies, is that the optimal allocation of R&D between these six technologies (transportation, fossil fuels technologies such as CCS, utility-scale energy storage, solar energy, bioenergy, and nuclear power) varies according to your policy framework. So if you have a clean energy standard, the way in which you would make your R&D bets is different from how you would make your R&D bets if you had a carbon price or if you had no policy. We also looked at what the optimal R&D investments would be with constantly low natural gas prices.

And after this exercise we came up with a set of recommendations as to what we thought investments should be, based on this methodology, in different technology areas. And we actually recommended a doubling, going from currently $5 billion to $10 billion. And that takes into account the interaction of technologies in the marketplace and also the uncertainty around these technologies.

I'll just mention also we found a point of decreasing marginal returns to R&D investments. So we didn't recommend more, unlike other studies that have recommended $25 billion as opposed ten, because we saw that with the information we have today, you start getting very little out of your R&D dollars.

The other important part of the study was looking at, OK, we are going to spend this money in R&D, or we're already spending this money in R&D and demonstration. How are we going to be managing these investments to make them be as efficient as possible? And here the concept of risk came out very strongly. First of all, this issue of whether government should choose or not choose--of course, being technology-neutral is a great aspirational goal, but when one thinks about how to manage some of these R&D programs and later on deployment programs, choosing at some level is inevitable. This is something that we believe is true.

And then the question is that, as you move from R&D to demonstration, the niche markets or early markets and diffusion, of course the size of the investments required increase, so in a sense at lower levels of investment, you have a lower probability of success, but you also have a lower loss given default. But this is of course something that is not just facing the government but is facing private actors. And what you see on this slide is a representation of how technologies, get boiled down into products, so for every 50 investments in clean tech firms, only about five of them go to an IPO and only about one maybe is truly successful. So the idea that the government shouldn't have any failures, which is one that we are hearing a lot in the press, particularly with respect to the Solyndra case, and I'm not talking about that case in particular…What I'm trying to say is that the government should really design their programs, both in R&D and in demonstration and early stage deployment, taking some risks, because if everything that the government funded had no failure, then the government really shouldn't be doing it, because it's something that probably would happen anyway.

This slide shows the set of publicly-supported energy innovation institutions, and what you can see is that they are organized in terms of level of risk on the vertical axis and stage of deployment on the horizontal axis. And in blue we have the institutions that been there for a long time—so, for example, we are all familiar with the national labs. In red we have the new institutions. What we can see is that there has been a lot of activity, a lot of experimentation, trying to get the right sorts of projects and innovation. Again, we have the Loan Guarantee Program and ARPA-E, which works a little bit like a VC firm that selects high risk, high pay of projects. And in the report we talk about the relative merits of these different institutions. And what we see is that there were gaps that justified the creation of innovation hubs and ARPA-E, but that now it's essential to give time for these institutions to really show whether they're adding value or not. So the idea that you can fun something like ARPA-E at, you know, $400 or $300 million and then cut it after two years--it really doesn't give you enough time.

So we came up with some recommendations in terms of how make these investments effective. And the first one is that a portfolio approach should be used and it should consider uncertainty and the interaction of technologies in the marketplace. And what we also found is that most of the R&D subsidies are really not learning from experience. For a lot of the grants and cooperative agreements that are being awarded by the U.S. Department of Energy, nobody really knows what a lot of these agreements are or what really comes out of them. We know about specific projects that were successful or unsuccessful, but when you ask people why they decided to give $20 million to this company with a level of 50% cost share, nobody can tell you really why they did 50% as opposed to 80% or 25%. So it's very hard to make decisions about these funding opportunities if it's not clear what would be crowding or not crowding out private investment. ARPA-E is taking a more active management strategy, following projects very closely and making decisions about whether or not they're working or not working. And again, this problem with information is also not being applied to projects with other countries.

And finally, on this question of institutions, we do detailed case studies on the national laboratories. We had a hard look at the National Renewable Laboratory (NRL), and we found three main things that we recommend improving in NRL. The first one is that there's a little bit of an island mentality. There is insufficient interaction between the users, the private sector, and researchers at the lab. The incentives are not to create technologies, the incentives are more to publish scientific articles. We also recommend a restructuring of contracting to increase lab autonomy, but also accountability. And then finally, we recommend putting in place incentives for entrepreneurship. There are some examples at the Sandia National Lab that are really starting to address this, but this is something that is really missing and would help the relevance of the work done at the labs.

To conclude, I'll just talk briefly about the question of technology demonstrations, which are these first-of-a-kind expensive projects that are very relevant for the electricity sector. We convened a workshop last year to talk about what the government should do in terms of financing these projects. And I'll just briefly talk about some of the findings from that workshop, in terms of what the government could do.

The first finding, which wasn't completely unanimous, was that there was some need for financing at this stage of energy technology demonstration that wasn't being met by the private sector--again, this wasn't a universal conclusion. What was a little bit more universal was a set of principles that should guide such an institution intended to support these first-of-a-kind projects, should this institution be created. And I'll just quickly go through these principles. The first one was the need for a long-term policy--something that came up again and again in this workshop was that one couldn't make 20 or 40 year investments on their one-year policy. The second one was the need for commercial viability and credibility. The third one is materiality. These things are risky, so it's not worth doing them unless there is really the potential for a great benefit to the U.S. Fourth was the need to disseminate information and to really understand the balance between protecting intellectual property and getting the greatest benefit for the public. And fifth was having an exit strategy. Again this is something that ARPA-E is starting to do, but it's something that is not really present in a lot of other programs.

And the other principles are basically these: having a great involvement from the private sector; cost sharing (right now, a lot of the programs have a very rigid level of cost sharing that is required--50%. Again, this is not really based on much evidence.); having clear targets and objectives; having a portfolio approach; and, in the areas where it makes sense, having international partnerships.

So I will now wrap up with some of the report's general conclusions. Again, the first one is that there are many reasons for government support for the development and demonstration of technologies. For example, providing options for the future--technologies that may be valuable should a particular future scenario materialize, or technologies that may be expected to be cost-competitive when environmental externalities are priced out, or when costs come down in the future. We also found that the current decisions on energy R&D investments and other support policies don't really properly account for technologies in the marketplace, and we saw in general that there's an increased need for monitoring current activities and learning from previous projects. We found that there wasn't much learning going on regarding how projects are chosen, how projects are managed, and how they proceed. And then finally this idea of providing support from demonstrations, following a set of principles was another of our recommendations.
And I'll just finish by acknowledging the rest of the team that worked on these report. Our co-principal investigators were two professors at the Kennedy School, and then we have a team of great researchers working on this report. And thank you for your attention.

Speaker 3.

Today what I'm going to do is talk specifically about smart grid. I'll be telling you about some of the things that I work with now. Specifically, I'm going to talk about federal money and the role of federal money in the smart grid demonstration area--how the dollars are coming into that area, how those dollars are finding homes, and then what it is that we're buying with those dollars. And when I say we, I mean all of us.

"Smart grid," of course, is a lot of things. I think most definitions that you see will involve beginning from a one-way grid that supplies energy from generator to customer. The new grid provides two-way paths for both energy and for information. It's a very information-intensive grid that puts a lot of technology out there--on poles, in homes, in substations, all over the system. I think "smart grid" resists definition because it's putting a lot of flexible technology out there. If it doesn't do it today, wait until tomorrow--there might be an app for that. So as things come up, this system, with a lot of flexible technology out there, will be able to do a lot of different things.

The federal government support for smart grid started with the Energy Independence and Security Act in 2007. This created an R&D and demonstration program for smart grid technologies at DOE. It also provided federal matching funds for portions of smart grid investments. This was small potatoes compared to what was coming in 2009. I noticed in one of Speaker 2's graphs, she had R&D budgets through the years, and the tall modern-day bar on that graph was the ARRA, the American Recovery and Reinvestment Act of 2009. This provided $4 billion for smart grid investments, and these were to be applied through two specific programs, the Smart Grid Investment Grant Program, or SGIG, which was focusing on existing technologies, tools, and techniques, and then the Smart Grid Demonstration Program, that focused on demonstrating advanced concepts, innovative applications, and smart grid and energy storage. So we'll talk about how those two programs have been implemented.

The goals of smart grid support are easy for anybody to find out. One of the things that I really believe is happening here is that with all of this money that's going out, DOE is intending to provide a lot of information, so information on all these smart grid projects is readily available. I went to smartgrid.gov and mined that for information to share with you, and these are the goals that they provided.

The goals of the support program are to provide fact-based information from actual projects, assessing impacts, costs, and benefits of the full spectrum of smart grid applications in transmission, distribution, metering, and customer systems, and also to assist and public and private decision makers in identifying the most cost-effective smart grid technologies. Notice that the goal is not to pick technologies, it's to provide information and it's to assist those entities in making their own decisions about what they ultimately deploy in their systems.

The way these dollars find homes, for both of these smart grid investment programs, is, first, with competitive solicitation. The utilities designed a project, they write it up, and they apply to DOE for the funding. DOE then selects among these and awards grants to some of them. These are all cost-sharing projects, so the original $4 billion that was provided with ARRA turns into $8 billion total invested by government and utilities together.

This graph shows how the money has been distributed among transmission distribution and metering. The problem with the information that this comes from is that everything else is lumped into "cross-cutting projects," if it combined more than one or two things. I would guess that a lot of these cross-cutting projects involved distribution technologies, with some advanced metering, because there's a lot of that out there. Everybody is doing a little bit of advanced metering, and others are doing things with various technologies and storage and what have you, and I'll show you a few of those projects. But that's why most everything seems to be lumped there. But a lot of this money is going into areas that you would think of as distribution, it's just showing up here as "cross-cutting."

Once a project is selected in one of these programs, the winning bidder provides a metrics and benefits reporting plan. This becomes a negotiation with DOE over the information that this company is going to have to provide to DOE as they go through their project. One utility executive described it as, "Well, first you take the money, and then you report, report, report, report, report." Especially in regards to the SGIG, because if you notice here, in the SGIG projects, of which there are 99, the companies filed "build" metrics quarterly. And "build" metrics answer the question, what have you done with the money lately? What have you put in the field as far as smart grid investments, smart grid assets? And those are listed out and provided to DOE. And you may be able to find some of this information on some of the websites. And then the "impact" metrics are filed semi-annually on these projects, and these are measurements that are taken off of the various assets and projects and are intended toward being able to produce a cost-benefit analysis.

The demonstration projects are similar, but the deal on how much information you have to provide and how often you have to provide it is somewhat different. The technologies that are being placed in the field are many. As I said, everybody is putting out a little bit of automated metering, but there's distribution automation, which is basically smart reclosers and other little devices. There are a lot of neat little devices that are available for distribution now that just weren't available before. There's a sectionalizer that looks like a tube about this long, about that big around, and there's a knot in the middle of it. And that knot in the middle of it has the intelligence in it and there's a USB outlet on the little knot and they can plug the sectionalizer into a computer, program it, stick it up in a cut-out, and this thing will provide the sectionalizing service right there on the spot. It's a very small, very neat, and these guys see these things at the shows that they go to. Volt/Var control--everybody's looking at voltage control. All of this makes the distribution systems much more visible than they used to be. That is, there will be an operator sitting at a screen, maybe several operators sitting at screens, and they can see and view a lot of things about the distribution system that they really, in the past, just did not know. The information wasn't available. Intelligent universal transformers are an interesting box of electronics that can do various things. So there are a lot of technologies that are being deployed as a part of these programs.

EPRI is participating in a number of participation projects through its smart grid demonstration initiative. Here are a couple of examples of the kinds of projects that are going on. Southern Company has a number of things going on at the distribution level, working with volt/var control, a lot of solar and solar storage integration that they're working on. Of course AMI is installed all over the Southern Company system. Southern Cal Ed is doing some things that are more associated with neighborhoods and homes, looking at zero net energy homes, home storage, and community energy storage in a concentrated area in Irvine.

So what will be accomplished through these programs? These programs are going to provide a lot of data. Once they get going they'll also establish experience that the utilities need to be able to prove the values of these technologies. DOE, with collaborative support from EPRI, is working to extract value for the public from the smart grid demonstration projects, providing data and promoting comparability and transferability of results in order to make the information that comes off of these projects useful to a lot of people, not just coded information specific to the individual projects. And EPRI is providing methodologies for cost-benefit analysis, looking at the data that's coming off, making sure that the right things are getting measured, so that we can do a proper cost-benefit-analysis.

In keeping with that, EPRI and DOE collaborated to produce this first report, "The Methodological Approach for Estimating Benefits and Costs of Smart Grid Demonstration Projects," in January of 2010. We have continued to provide additional information that is intended for those utilities which are doing smart grid demonstration projects, helping focus them on the things that they need to do to provide transferable results. The intention here is to maximize learning, and not just maximize the learning of the utilities that are doing these things, but to maximize the learning shared by the industry. For learnings to be maximized, we realize that the methodologies have to be credible and that the results must be verified. We try to apply the scientific method in these endeavors, where possible, where it's applicable to do so.

The general process looks like this. Beginning with the assets that you're putting in the field, those assets provide particular functions, those functions have impacts that should be measurable, and we want to concentrate on the measurable part here. Those impacts then go on to have benefits, or costs, that then, in a cost-benefit analysis, we can monetize and combine. Within the documents we provide tables to facilitate this for people so that they can begin with those assets and find a list of benefits. We then take them through the process of designing experiments to extract what I call the answers to the physical question. The physical question is, does this stuff work, and what do we have to do to demonstrate that it works?

The economic question is really a separate one that you can't necessarily apply the scientific method to, but once we've determined that it works, and the extent to which it works, and we have that data, is it worth doing? So that is the overall thrust of that cost-benefit analysis process that we are putting in place and that we are going out and working with those individual utilities to bring them into that discipline and make sure that the data and the analysis is in place so that we can all learn from it.

So in summary, these matching government funds have been made available for a wide spectrum of smart grid projects. The funds were limited in amount. It was a lot of money, but the funds were limited in amount and it's not an ongoing subsidy of any kind. The recipients decide what they want to demonstrate, subject to approval by DOE. Experimentation is encouraged and the point of all this is to provide information to the industry. So in keeping with that, DOE is providing a lot of resources, at SMARTGRID.GOV and at Sgiclearinghouse.org. The smart grid information clearinghouse is being maintained and put in place by a group at Virginia Tech. Both of these are very informative websites that are still under development, and a lot more information will be going in there.

Speaker 4:

I'll try to break my talk into three topics: are subsidies important, when are they important, and how should they be designed? And what about new technologies? And I will have one caveat in that, we don't have a blank sheet of paper right now. We have decent penetration right now of renewables into this grid. And so I think the comments have to recognize that we're down that road pretty significantly.

So with that said, when are subsidies appropriate? If we want to continue the growth of renewables, we're going to need an incentive program. And I say that because I've spent a lot of time with utilities. And set aside cost--so let's say that we're cost-competitive. What utility CEO in his or her right mind would go about and do what's going on right now? If you think about the implementation of electric vehicles, of wind, of solar...First of all, reserve margins are OK. Do I need to go out an add hundreds and thousands of megawatts? Do I need to put a 550 megawatt solar project out in the desert today to meet my load? Answer probably is no.

And certainly we have the prospects of coal decommissioning coming into play and of nuclear decommissioning, especially in light of what's going on now. And if you went back five or seven years ago, all anyone would talk about was how reserve margins in certain part of the country were in awful shape. And so maybe the current adequacy of reserve margins is a temporary thing. But I think we're in a state now where people aren't looking to add lots of generation just as it is.

The second thing is system reliability. If you're a utility executive and you're thinking about keeping your job, the way you lose your job as a utility CEO is blowing up system reliability. And you go to your PUC, and you have to show them that the customer satisfaction numbers are way down. And so now suddenly what we're going to do here is ask someone to bring in an intermittent resource that is pretty hard to control and hard to gather. And at the same time we're going to allow distributed generation, so we're going to allow your wealthiest customers to start to get off the grid. Because it isn't the lowest half of your customer base that's putting solar panel roofs up on their roof, it's your wealthiest customers, the people who pay on time, who don't need the programs that will help those people move along. So, you know, you have intermittent resources, you're losing your best customers, and then you think about something like EVs, which are coming forward and they're not going away, I mean, think about how that just completely shifts the shape of the load that you were dealing with.

And then you add on to this the impact on rates. Again, central station power is going to be higher-priced power. So the stuff on the roof, while those people go away, the stuff that you have to buy out of the desert is going to be higher-priced. You're now paying more for ancillary services, so suddenly you're having to deal with the fact that the sun goes under a cloud or the wind doesn't blow, or the wind blows too much, and so you have to have all sorts of other services on there. The smart grid comes with a lot of other costs as well. And so what you're ultimately ending up with for utilities, is you're having more stranded capital across fewer megawatt hours, being supported by a less robust customer base.

So, again, I'm surprised as I sit here today that utility executives didn't put on a bigger pitched battle over the past five to ten years to prevent all this from happening, because if you are looking at it from the dynamic of a utility CEO, he or she is looking at this, and this is the biggest thing that's probably ever happened to them in their entire career. The world is changing around them in such a stratospheric way that it's just amazing to think that they haven't fought a pitched battle.

Now the good news is that we've reached the tipping point. I think the utility executives realize that with 10% of our generation, including hydro, already being renewable, and in the next 20 years this could go to 20%, this fight is over. It's not worth fighting it anymore and burying your head in the sand. You're going to have to deal with this. And so most CEOs realize that this isn't going away. But if you go back to it, if you let people just stop for a minute and say, "What would I choose to do as the person who controls the grid?" I think most people whose job it is to make sure the lights stay on would say, "This should go much slower, at a much less aggressive pace than it has."

And so I think, to answer the question of whether incentives appropriate, which is the first question, is that this won't happen without incentives, even setting this at levelized cost of energy, because there's too many biases to push the people who control that power coming online to just essentially say, "No, I'd rather slow this down or do it at a different pace." So I do think that incentives are going to be required.

We are working with companies today who can essentially allow all their appliances to talk within their home and can control their demand and look at how they're going to use their appliances from their office. When you think about the increase in sophistication of plug load and control at that endpoint, it's only to get more complicated for people who are used to thinking in terms of, I have power over here, I have load over here, and all I really need to do is move the power from here to here, and then, you know, in an exciting day, I'll turn on the gas peaker, and that will be the really big day for me. And so that world is gone. And so to continue to push that forward, I think we need the incentives.

So then the question is, how should they be designed? We could look at carbon policy, we could look at a number of different things, but for us I think what it comes down to really is, should we have renewable portfolio standards, or should we have feed-in tariffs? And I think if you sat there and asked anyone on the developer side, nearly everyone on the developer side would tell you that a feed-in tariff is the way to go. They're financing-friendly. And if you think about from the developer's standpoint, they love the feed-in tariff. You know exactly what the number is that you're going against. So there's a certainty with the feed-in tariff. And also, from the standpoint of development, if you have the land, if you have the transmission, you're going to be able to get your project done. You don't have to then go deal with the utility and work on a reverse auction dynamic. That also creates more certainty for the supply chain, which I think is obviously a good thing.

But the experience that I've seen is that feed-in tariffs just don't work, and they haven't worked very well, and I haven't seen one that's been well designed today. What we've seen, if you look at Spain, if you look at Italy, if you look at Germany, is that the feed-in tariff just can't catch up with the pace with which the market is moving. And ultimately you have the subsidy being even greater than you would have hoped, or thought that it was going to be in the beginning.

When you look at a place like Spain, in 2008 they put out a feed-in tariff. They thought they'd get some interest, and they ended up being a third of the solar market that year. Everyone rushed to Spain, people were opening up plants in Spain, Spain was the new place to be. And so when we look at feed-in tariffs, we haven't seen one that's worked.

So I think the RPS is probably the better policy tool. One, it provides a utility more discretion. There was a recent RFP out of California where they went out and just said, we need renewables. Solar ran the table in that auction, because the reality is that the solar bid developers were willing to be more aggressive as they thought about their capital costs, as they thought about their financing costs, as they thought about how things were going to be, than the wind developers. And so for the first time since I can remember, we now have solar projects in California being cheaper sources than wind. But if you'd set up some sort of broad RPS, you would never have guessed it, and you would have said, "Well, we'll set some aside for solar, we'll set some aside for wind, and that will work out." And you wouldn't have had the right result, which is, let's get the cheapest power that meets the renewable resource requirements of California at the time.

I think an RPS also creates a lower burden on the consumer, again, because of that reverse auction dynamic we like a lot. I know I spend a lot of times with developers who absolutely hate it, wring their hands over what the number is that they should put in to the auction. But I think it keeps people honest and it keeps people bidding the cost curve forward. People are taking a view on where solar will be when they have to deliver a project in a year or two, and then they're pushing the supply chain to do that as well. And so I think that continues to push prices down and allows the subsidy element to subside over time. We're seeing less and less of a subsidy embedded within these renewable portfolio standards. And the good news for people like myself is that renewable portfolio standards are still financeable. They're 10 or 15 year contracts and those can be financed. So my view is, when we look at how we encourage the build-out of large-scale renewables, let's set targets in conjunction with the utilities and allow the market participants to work it out. And I think we've seen examples like the recent California auction where the market participants have worked that out.

And I would say one thing on demand response, which is that I think demand response needs to be part of those targets. We need to make sure that people realize that that can be part of meeting your renewable portfolio standard. That will encourage another group to come in and see that they have an opportunity to bid in to some of these auctions. We've seen demand response win some of the auctions recently, and I think you can see those technologies develop.

One of the comments that Speaker 2 made is that long-term consistent targets that allow the supply chain to respond will allow the supply chain to drive down costs, which will reduce the subsidy over time. And I think that a national renewable portfolio standard which has a target would be in the best interest of the country, and one of the easiest ways to try to move this forward, as opposed to trying to write legislation that's, you know, 500 pages long, where we're going to have everyone try to pick something apart.

Now everything that I said just assumed wind and solar and smart grid were central, and threw everything else under the bus. And so what about new technology? And I'd say a couple of things. One, new technologies will not get built without credit support, and capital dollars for power are huge. A hundred megawatt wind project costs in the neighborhood of $200 million. A 50 megawatt solar project costs about $150 million. These are big numbers. But the problem with it is that, unlike drilling an oil and gas well offshore or somewhere, the returns are low, if you think about the capital providers who go into this. The returns on solar or wind or any kind of power project are in the neighborhood of 6 to 10%, and in contrast, if I'm drilling a well out off the Gulf of Mexico or anywhere, I'm hoping I'm going to make a 25% type return. So that will encourage a type of risk and risk appetite that you're just not going to find when you're making 6 or 10% type returns. And so these are not the kind of returns that are going to attract technology risk. And so, in the absence of some form of credit support, I don't think you're going to see near-term adoption.

And I've lived this, I worked with a company called Clipper Wind. Clipper Wind was a U.S. turbine manufacturer. I sold it twice to United Technologies, in two steps. You know, they had a billion dollars of product in the market, but couldn't get financed. I also sold John Deere's wind business, which had Suzlon wind turbines within it. They also had a manufacturing problem, and couldn't get financed. And if you think about what's going on in Europe right now, the people who finance these large-scale projects--they're not the commercial banks in the United States, they're typically coming from Asia and Europe, and those banks are now re-trenching. And so the project capital dollars are getting smaller and smaller and the projects they're going after are going to be more and more of the highest quality, because that's where they're going to want to put the dollars.

So, said another way, I thought the DOE loan guarantee program was a great idea, because it will help finance new technologies. I think ARPA-E is another great program. I think they've been very actively involved in pushing technologies forward. But in the absence of that, I think we're going to be stuck with the technologies that we have today. Maybe they'll improve, but if you're looking for new revolutionary wind turbine technologies, which are going to bring the cost down by half, which, you know, throw current the current technology up in the air and start over, that's going to be extremely difficult to get done in the absence of any sort of external support, which you're not going to find in the private sector.

So the obvious issue is that the government's required to pick winners, and the government may not be well-positioned to do so. I mean, it's human nature. I sat in some of these sessions, and you'll talk to some person who's very smart and very hardworking, but in the back of their mind they're thinking about sitting at a table like this, with a much more hostile audience on the other side of this mike, asking them, "Why the hell did you approve that project?" And that slows things down tremendously. It makes it very difficult for someone whose job it is to pick these technologies to actually go ahead and pick one, because they're going to be scared to death. And as the person who signed all of the loan guarantee documents for Goldman Sachs, on behalf of First Solar, it scared the hell out of me.

And that was a company that, at the time, had a $10 billion market cap and has gigawatts and gigawatts of panels out into the market. So I can only imagine someone who's picking up some brand new, you know, perpetual motion machine, and having to guarantee that--how they'll feel. So we've got to think about what is the way that we can push that credit support forward, that gets us around this bureaucratic gridlock. ARPA-E has been a great program that has been able to fund winners and losers. The question is, how do you scale up ARPA-E to do something that's much bigger. But again, we're going to need that if we want new technologies.

So, in conclusion, I think incentives are in place and the shape of the grid is changing. We need to move from a reactive mode, because we need to lead the market with policy. But I think the policies have to be simple. People don't want big bills, they want over-arching plans that define what we're going to do and provide people with a runway of certainty and let the market then try to sort some of these things out. And it's imperative that utilities and regulators shape that dialogue and embrace that dialogue, because these things are moving forward and we're going to have blackouts or other issues here pretty quickly if we don't get a good thought process that is put around it.

General Discussion:

Question: My first question, for Speaker 2, is about how there's only a downside in some ways for government officials, because intellectual property rights, to the extent to which they accrue, often times the government doesn't take any interest in them. And so whoever they're giving the money to ends up with the intellectual property rights. So one of the questions I had is whether you looked at this question of whether the government ought to take intellectual property rights, or royalty rights, so that when you have a Solyndra or some other kind of failure, that gets balanced off the successes in other areas, and you can get more revenues to do new programs. So what happens to the intellectual property rights?

And the second question goes to Speaker 3. One of the criticisms of the Obama Administration on smart grid programs is that we're not getting the full benefits of experimentation, because we're giving the money to utilities. We're not looking at smart metering from an unbundled standpoint, or looking at varied experiences. And of course we all know part of the motivation for that was to fund things that were "shovel ready," to get the money out the door very quickly. And so I wanted to ask Speaker 3, from the standpoint of designing these subsidies, whether the complexity of the government agenda-- in this case you've got two agendas, more efficiency and stimulating jobs--how much that really impedes our ability to derive the most experimentation and the most knowledge.

Speaker 2: We didn't look at intellectual property rights (IPR) in a lot of detail. But one thing to keep in mind is that decades ago, a lot of the IPR from research funded by the government was kept by the government, and there wasn't enough commercialization, and that's why the rules were changed to allow the entity doing the R&D to own the IPR and be able to commercialize it. So in a way, having a lot of that would be kind of going back to something that we know results in less commercialization of energy technologies.

What we did talk about was, in order to try to get some of the bang for the buck for the government, is to really have one of these information dissemination programs, such as the one that Speaker 3 described, which is something that is relatively new from their Recovery Act, or of trying to get as much public benefit as possible. One alternative may be to have some sort of option and saying, "If I'm going to be the government and providing funds, and you don't use this technology, maybe I can offer it to other entities to license it." But I am not sure that the private entity wouldn't do this by itself and say, "Well, you know, maybe I don't want to do it. But somebody else wants to do it." So I guess that wasn't a complete answer to your question, but I think that it would be a tricky move, or it would be tricky to do it right.

Question: I was struck by the lack of any reference to natural gas in the first segment. And the question I have is, how do we square either the need for subsidies and the appropriate design of subsidies with both the economic reality that we now have other alternatives that don't need to be subsidized, that are providing some of the benefits you discussed? And related to that is the political reality, which people touched on, but no one addressed how to move forward from, which is the political reality post Solyndra, post the collapse of the super committee on the budget side. It's just the whole economic situation that we're facing, that there's an inability to take the good work that people are doing, and get it approved by and get it through the political process, because I think that's really going to be the tough road ahead. Does anyone have thoughts on both the first part, the fact that there are now other alternatives economically, and the second part, on the politics?

Speaker 1: There is definitely a school of thought that says that the issue of pollution pricing comes back around in postelection discussions about how we get our fiscal house in order. And that it becomes part of a larger discussion on tax reform that people more expert than I in these politics tell me that both sides of the aisle are actually itching to have, but are keeping their powder dry until after 2012. I think in the same way, the idea of a wires charge is not as farfetched, maybe, as it first seems, because in fact I think that part of the issue with the revenues are that people are much more willing, I believe, to go for additional revenues when they can see a very specific cause and effect, and also when there is a shared distribution of those benefits. And so I think that both of those things actually bode well for what I've been talking about.

On the natural gas thing, I agree with you. You know, natural gas is a low-cost option right now, and it's the thing that people gravitate towards. And really the only, the most effective strategy that one can have to try to deal with that is to require every energy source to pay its full freight in terms of its environmental impact. We're not there yet.

Moderator: My answer is, to everything these days, is replace Congress, replace them now. [LAUGHTER]

Question**:** I have two questions. One is regarding a subsidy that I don't know if I've heard mentioned here today, production tax credits for renewables. And the other is regarding feed in tariffs. I want to visit about that, also.

But regarding the production tax credits for wind, in particular in Arkansas, we have become a manufacturing hub for wind. But I think a common theme that we've heard from you is that a lack of consistent policy doesn't encourage innovation, and it also doesn't encourage investment. And if we are going to move forward toward energy independence, toward a better economic development platform across the country, this may be a way to do that. I know that there is a lot of debate about that. I'm sure many of you have read the really intriguing debate in the papers recently about the pros and cons of a production tax credit for renewables versus more traditional sources of energy. But I wanted to get your thoughts on that.

Speaker 4: If it were up to me, I'd throw the production tax credit out. It's created so many distortions in the financing and the boom and bust of this investment. I mean, a production tax credit lowers the cost to the utility by spreading it across the tax base. A renewable portfolio standard will just force people to buy renewables, and the price will be set by the market. The issue that we continue to run in with the production tax credit is that it only gets rolled over every year or two, and it, and when it does, you see a boom and bust cycle. I think you'll see wind stop in 2013. I think it will come to a grinding halt, because I do think that the production tax credit is going to lapse for a period of time. It will come back. It will always come back--when we stop building wind in the United States, people will say, "Maybe we need that back." And so it's lapsed before, and I think we'll see it come to a grinding halt. But we spend a lot of time trying to think about ways to deal with how to we monetize the production tax credit, and you've seen Google come in. You've seen some other people come in. But it's not a very good instrument.

The grant in lieu was a great program. I think it put cash in people's hands. It spurred development. But the production tax credit--going out and finding tax equity and the friction around tax equity, and the number of players around tax equity--I mean, the amount of brain power and time and money and lawyers' fees and other things spent around this, it's significant.

Our view is, if you were going to keep it, can we change it? Some of you will be familiar with the master limited partnership model. Can we pass that credit through and allow people, retail investors, to be able to use that tax credit? In much the same way, we have a MLP model, and could we change the law to do something like that? That would then allow that to be useful, because I think you could find people could monetize it. But if you show up to a treasurer of, pick Apple, pick United Technologies, pick one and say, "Listen, I've got this highly illiquid investment that I want you to invest in, but it's got a good yield. Don't worry, you'll be fine." It's not a very long conversation. It's very hard to find new people to invest in this. So my view is, it's an evil that we have, but we'd be so much better off if we could either modify it so others could use it, so we could spread it out, or we just got rid of it and let us realize the real price of wind and just use the renewable portfolio standard.

Question: And I'll jump in with my second question. I went on a fact finding tour to Spain recently and learned so much about why wind is working well there and why solar went berserk. And I asked what was the key to its success regarding wind development. And they said the feed-in tariff. However, it was the reason for the exorbitant cost that rate payers will absorb over 25 years for solar. And so I wonder in the same way that you talked about modifying the investment tax credit, in a glass half full world, if you could modify it, maybe with a cap on a feed in tariff, is that a possibility?

Speaker 4: I mean, if you look at Spain, it has gone back and tried to cut back what they told people they were going to give them. And no one would ever go back into Spain if that had actually occurred, and so that was part of the issue. I look at the feed in tariff (and by the way, I like wind. I just think that with the production tax credit expiring, people will just stop building.)

Question: You're absolutely right, and I didn't think you didn't like wind.

Speaker 4: All right, good, because I have several wind turbines in my office, little ones. [LAUGHTER] But I guess I would say that the feed-in tariff results in wind and solar projects--I said they get low returns. They should get low returns. This isn't high risk. It should be an 8, 9, 10% unlevered-type return business. It's not a high risk business. And what you see with feed-in tariffs is those returns going through the roof, because capital costs start to come down. And so it doesn't seem appropriate if what we're asking people to do is we're trying to incent this new technology.

I do like the renewable portfolio standard. It won't solve all problems, but what it does do is, it forces the builder of that project to think about what's the right price for that product. It's kind of that reverse auction dynamic. And I think you get to a better pricing dynamic for the people who are paying for the subsidy, and especially if you're pulling out the production tax credit or things like that. That's going to be even more apparent. So I prefer what it does, and people can have a lot of different opinions on that. But the feed-in tariff just results in excess returns going to people when you don't need it to incent the capital to be deployed. The capital will get deployed at 9 and 10% unlevered returns. You don't need 15%. That's excess rent, and excess rent at a time when you have people who are paying prices above what they can pay for something fired by natural gas. It just doesn't seem appropriate.

Speaker 2: Can I add something on the Spain comment? I'm actually from Spain, and one of the things that maybe could be solved is that this big, very fast capacity growth over a couple of years for solar was funded by money coming from the central government, and the decisions about building the plants were made by the state governments, and they have different motivations. They had an industrial policy vs. local policy situation. So in that case, one mechanism would have been to have a more centralized system for making decisions, and not just complete outsourcing to the regions, and that way we'd be led to incentives to allow firms to build when the time had passed and to get as much as they could. So that was one of the problems that was very important in Spain that could have been solved if they had thought through the dynamics and what would have happened where the incentives were for the region.

Question: Let me ask this question. One thing that hasn't really been talked about, particularly at the stage when a technology is ready to be deployed, is, should we be picking the technology? We've wrestled with this in Texas. Do you have multiple RPSes for different technologies? Or should you let the market decide what it is? What happened in Texas, obviously, with the RPS, is that we got a lot of wind.

Moderator: Let me just ask a clarifying question. So are you saying, perhaps one RPS for renewables, one for energy efficiency? Is that it?

Question: No, I mean, within the renewable bailiwick--because what happened, at least in one of the regions, is that when we started looking at a non-wind RPS, every owner of every technology came in and wanted their piece of that. And we've always been a little shy about saying, "Well, we're going to pick the winner and loser," because I just don't think we're that smart. And I probably would rarely agree with anybody from the Environmental Defense Fund, but if you're putting a cost on pollution, probably that is the more effective way of deploying these technologies rather than the positive incentive.

Speaker 1: We've certainly done our share of advocacy around renewable portfolio standards, even in Texas. And we think we've seen positive benefits from that leadership. But that being said, right, the thing that has always discomfited us about renewable portfolio standards and production tax credits and all these sorts of mechanisms is that they come at the problem with the presumption that there is a specific technology or suite of technologies that it is imperative for us to deploy. And that is in some ways putting the cart before the horse. Right? The question is, you want to supply reliable, affordable, and I would argue clean energy to consumers. I don't think anyone affirmatively wants to go out and supply dirty energy to consumers. So you want to supply reliable, affordable clean energy to consumers. And if you agree that those are the three primary objectives, then the only question is, how do you do that most cost effectively? What mechanisms do you use? And it is very difficult for one to judge what the optimum mix of technologies is. And in fact, from across the nation, that's going to change. Right? I mean, what looks good in Arizona is not the same thing that's going to look good in Wisconsin. And so I do think that having reliability standards in place, having pollution pricing in place, and then doing what the public service commissions do best, in the case of vertically integrated markets, and in the case of deregulated markets, the market-clearing price of energy will tell you what's most cost effective within those two constraints.

Speaker 4: The only comment I'd add, and there are a lot of people in this room smarter than me in general, and in particular on this idea of system design, but I do think the renewable portfolio standard needs to be elevated to the federal level, because in Texas, wind is going to carry the day. In Iowa, wind is going to carry the day. In California, in the desert, solar, as we saw recently, is going to be cost competitive. But if we could set a long term, ten or 20 year renewable portfolio standard, and allow states that are going to produce excess can sell that to places that aren't, then you can allow all the various technologies, because on a federal level, we have a diverse set of resources which will allow a certain level of different technologies to come to the forefront. At a micro level you're not going to see that. I mean, with Texas having the wind, and also being isolated from an interconnection standpoint, it becomes more difficult, and so maybe the solution is to go to a federal level. But there are a lot of smart people in here who can think about system design. But as you look at what any individual state has, that can be the problem with the renewable portfolio standard, because you can get stranded on the one project.

Question: The thing that struck me as I was listening to all this is that we're talking about subsidies and how effective they are. It depends an awful lot on the market structure. And it's the market structure in the electric industry that's driving it. I heard that, or at least implications that would come out of that, in things that all of the panelists said. So I guess the first question kind of in general is, should we be talking first about what the right subsidies are? Or should we maybe be talking about how we can modify the market structure so that the utilities have incentives to put in new equipment? If you look at the cell phone industry, it's been around for probably 30 years, and they're already on their 4G system. If you look at the electric grid, it's still pretty much the way it was 100 years ago. The example that brought that home to me was when SDG&E was putting in its smart meters about a year ago, they had one person who objected. He didn't want his meter changed. The reason was that he was their 500,000th customer, so his meter had a gold dial in it. That meter was put in in 1971. They're just changing it now, after 39 years. That to me is an incredible thing that needs to be changed. So do we need to address that before we even talk about how the subsidies are going to work?

And then the second question is more specific for Speaker 2. When you showed that chart that showed the expectation of what subsidies would do in different energy industries, and it was much higher in the electricity industry than it was in, say, the fossil fuel industry, did you look at how that is tied to the market structure, given that there's more competition in the fossil fuel industry? So whereas the electric industry is much more regulated, is that why subsidies end up being more effective in those industries? And then if that's the case, going back to the first point I made, does that mean maybe we'd be more effective with our subsidies if we also worked at changing the market structure?

Speaker 1: I'll be the first one to argue that we need to create the financial mechanisms that reward investment in innovative technologies, and to some extent the idea of creating some kind of fixed user charge for the grid is an effort to try to think through what that stable funding source might look like. But that being said, I always bristle to some extent when people try to compare the utility industry to telecommunications, because the requirement for universal service and the requirement for reliable service in the electric utility space is at such higher tolerances than they are in the communications space that I think that it makes it difficult to compare the two. The 4G phone drops your calls a lot, and you sort of put up with it, and you look for carriers that do better. But frankly, if we lost electric service as much as your calls were dropped, there would be pitchforks at the PUC.

Question: Can I just ask a follow up with that? Because that's one of the arguments I've heard a lot with the electric industry. But I mean, I think that was similar to what people in wired telco used to say when they thought about cell phones, that "Yes, they're going to be wonderful. People will adopt them. Everyone will have a cell phone. But they do have those quality issues. No one will put up with that. Everyone will still have a wired home phone." And I think the latest statistics show that something like 25% of the people don't even have a home phone anymore. They're all on that cell phone. So even for your 4G phone, which drops calls, people have decided, hey --

Speaker 1: Yes, and the economists in the room have sophisticated language to describe this. I'll inarticulately try to make the argument that the utility functions are completely different. Losing your call for five minutes is an annoyance. Losing it repeatedly for five minutes over the course of a drive to your grandmother's house or your in-laws' house is annoying, but you get through it. Losing your electrical service on a regular basis, or even just an irregular but somewhat predictable basis--I would argue creates far more social and economic inconvenience. But again, that's not by way of trying to excuse the utility industry from an obligation to innovate and for us to figure out ways to enable that to happen. It's just by way of saying that the systems are just very different, and they provide different functions. And so there are things that we can learn from telecommunications, but we can't draw the analogy too tightly.

Moderator: I might argue, taking the moderator's prerogative, that one thing would be simply eliminating the barriers to entry for new solutions, which is in effect what restructuring in the telco industry did, among other things. And then we also do have the issue of power quality, largely hidden, and hugely expensive issues in this US. Anybody else want to take a shot at answering either one of those questions?

Speaker 2: I'll answer the question about the graph. You're talking about the graph that showed the role of R&D investments in different technologies. That doesn't reflect industry structure. That reflects the belief that the government's investments for R&D can decrease cost of those technologies more or less. It's more reflecting the technical potential or the science behind it that the industry structure. We do have answers from people in industry, in the private sector, in the universities and the national labs, but we were more interested in what can be done to reduce costs more through R&D than through deployment.

Question: The question I was asking is not what you asked, then. But then once you got the results, did you do a correlation with how regulated the industries were? See, what I'm postulating is that it's the more regulated industries where the government R&D would be most useful. In the same sense that the other statistic you put forward was the percent of revenues spent on R&D. If you look at the highly regulated industries, where the sales are highly regulated, the utilities are investing in R&D at a rate of, what did you say, .1%? Whereas if you look at manufacturing, it's 3%.

Speaker 2: I see what you're saying now. But we didn't see a big impact of that.

Question: So there are many themes running through here. I want to set aside what I think is the most important one, which is prices, prices, prices. I get the market design idea--get the prices right, that that's the most important thing that we could be doing to help with these problems. And a lot of the policy discussion is mixing different objectives, because we haven't solved that problem.

But let's suppose we did. So let's set the pricing issue aside, and assume we had good prices in the marketplace, and these technologies were going to be competitive. We still have the classic argument for R&D and government related to spillovers and getting started on technologies. And there, what we should be looking for are things where the distribution of social benefits is much wider than the distribution of private benefits, so the private sector won't want to go in, but there's a big tail out there where the social benefits might be huge, if we get success--big success and a big spillover effect. We should be spending money on those through the government to get the R&D done on that kind of process, taking advantage of portfolios and all those kinds of things.

Then I say, "Well, how do you do that, if that's what you're trying to accomplish?" So help me with this--particularly Speaker 2 knows more about this than I do. But ARPA-E was modeled after DARPA, from the Defense Department, the Defense Advanced Research Project Agency. And my stylized view of DARPA is that they had three critical characteristics. One is, they had stable and significant funding, so this went on for a long period of time. Second, it was populated with people who had vision and good taste, and I think that's actually important. I mean, it's easy to find things that are going to lose money on average. It's hard to find things that might pay off really big and be game changers. You want to have a portfolio. You don't put in everything, but you do it to have somebody there who's picking things that have the chance to actually succeed, and supporting them over a long period of time. And then the third characteristics was that it was highly non-transparent and protected, which meant that nobody sort of knew what they were doing, and they could get away with it because it was the "D" (Defense) part of DARPA. And it was inside that big operation. And that allowed the people with good taste to exercise their judgment over long periods of time.

Now, it seems to me all three of those things are not replicated in ARPA-E, and are going to be hard to do. In the first place, we don't have stable funding. I mean, they were funded through the stimulus money, for crying out loud. So that went away. They do have some talented people there, but they don't have this ability to operate in a protected way and make decisions based on their own judgment. It's much more in the light of day, and they're worried about that meeting when you're on the other side of the table, looking at a much more hostile crowd, and they're going to be asking you about these things. And I don't know how to solve that problem.

Now, it might be that I have an idealized view of what DARPA did, and it really wasn't that good. But what do we do in order to get that kind of investigation of lots of different technologies that on average are going to be private losers, but might be big public winners, and select from those things way before we know, when we've got congressional oversight and all the other things that go along with it?

Speaker 2: I can try to start. I think you don't have an idealized view of what happened in DARPA. I think that is what happened in DARPA. What I wonder is whether these non-transparent and protected characteristics are necessary for it to work. I guess that keeping things non-transparent and protected helps with the long-term funding. So if we set that aside, if we did manage to get sustained funding for ARPA-E--and they are being open about their competitions and about the characteristics of the winners--I think we still have to see whether or not this more open model can work. What I'm hoping is that there's going to be support for a sufficient amount of time to allow for some of these big winners to happen.

So I guess if you take out the relationship between non-transparency and long term funding, I'm hoping that that may work. But I don't know if you were implying that ARPA-E was the only thing that the government should do in our R&D, assuming that there's a price on carbon. I think that there are other models to promote the spillover benefits that would be legitimate roles for the government to fulfill, such as the role that the national labs are currently playing, having government facilities to test, to investigate turbines and catalysts for bioenergy. So I think that in addition to ARPA-E, there are a couple of other roles that the government could play.

Moderator: I wonder if you redefined the goals as ones of economic and environmental development and national security, you could make a stronger argument for the three characteristics that you outlined. I also wonder--and this is with all due respect to DOE, but this is not what they do--whether if you created an entity to actually do this that might have greater freedom and greater experience actually in making these kinds of investments and loans and whatever.

***Question*:** One of the questions that I have about these energy technologies is how it's going to affect the wholesale market. But I think in stepping back for a moment, the big question in my mind is, why are we trying to pick winners and losers? And I think this implicitly goes back to what Speaker 1 was saying in his presentation, when you look at the different technologies that are available out there and their cost effectiveness. And I ask that, because in the process of picking winners and losers through renewable portfolio standards, production tax credits, and so forth, we're distorting wholesale market prices downward. So as I see it, renewable portfolio standards expanded throughout any RTO market. If we have a lot of wind, for example, like we see in ERCOT, there are going to be periods where prices are going to be extremely low in the energy market. But at the very same time, without these policies, these resources would not be commercially deployed. Somebody's got to pay for them somewhere, and they're getting paid for through retail rates or through the tax codes. So for example, in retail rates, who's paying for renewable energy credits? Retail customers. So effectively what we're doing with these policies is that we're actually diverging wholesale prices and retail prices. We're actually biasing wholesale prices downward, and retail prices upward. And I think one of the things that Speaker 1 mentioned in his presentation was getting real time pricing for retail customers. Real time locational marginal pricing (LMP) would be the ideal for that.

Fundamentally, why aren't we getting the prices right for pollution? If we're really worried about climate change policy, why aren't we putting a price on carbon dioxide emissions and CO2 equivalents? And letting the technologies, whether it's wind, nuclear, solar, energy efficiency, then duke it out with the prices being right? And why wouldn't those be financeable? Because all we're succeeding in doing is actually making it much more difficult to get price convergence between the wholesale and retail level, which has implications for how we think about the evolving market design at the wholesale level. So I'd just like to get some reaction to that.

Speaker 2: I can say something. I think that, as was mentioned earlier, getting the prices right for pollution is the optimal thing in terms of economic efficiency. So I agree with you that that would be the right thing to do. But even if we get that right, and we have something like ARPA-E, I think that what Speaker 1 mentioned about having a way of supporting some of the technologies that are more different, that we're not going to try out within the short term just based on the right pricing of pollution, would be something complimentary that may be needed, although it would be less essential or less important, given that with these long term signals that pollution is bad, there would be more innovation in the private sector to reduce pollution. But I still wonder whether some of these other supports to innovation wouldn't be necessary. But I agree with you that that should be the ultimate goal, but it's still something very hard to do right now.

Speaker 4: Both scenarios, I think, can be financeable if we had appropriate pricing. So if you're asking me as someone who's going to go out and finance these things, I think having the right pricing for pollution will work, because we'll go out and finance what makes economic sense, or having an RPS works. I don't know if you all saw the statements by Carol Browner two days ago. She essentially gave up on a carbon tax. She said it's probably never going to happen. So the first question is, do we want to incent low carbon generation out there? So that's one. And then two, what's the right way to go forward?

And there are lots of people who spent a lot of time on this, but I can't imagine any sort of carbon legislation getting through anything that looks like the government in any time in the next decade or two. So if the answer is we want it, I think we're going to have to come up with something that appears simpler, that is less controversial. Because I agree that in an ideal world, you'd price everything appropriately, and the market would sort it out. When you have someone from the Democratic administration who spent her time trying to push this thing through giving up, I think that's relatively indicative. I can't imagine us being able to get that through. Now, maybe that's not the purpose of this conversation, but if it's going to describe to me what we can do in the next two years to five years, I just can't imagine carbon, especially if it's continued to move backwards in other parts of the world, just being able to be successful. So if we do want to incent this, which is a question, are there other ways to try to push this forward? And that's why I default to the RPS. But again, that's an opinion.

Speaker 1: I don't know. I'm thinking to myself, maybe that's my opportunity. I can walk around now and say, "Carol Browner does not want a carbon tax." [LAUGHTER] And maybe that will… [LAUGHTER].

Moderator: I think one of the issues is, we also don't want to pay for anything, whether it's infrastructure or carbon or anything else. And by the way, would you trust this Congress to design an appropriate carbon tax that would send the right signals anyway?

Question: The attention given to Solyndra, isn't that only about the one quadrillionth example that government simply cannot allocate capital efficiently? And this whole web of subsidies and mandatory RPSes, feed-in tariffs, production tax credits for one industry, checks handed to companies like Solyndra, are just different forms of subsidies. And even if Congress won't pass a carbon tax, isn't that a political decision that the country in effect made by electing the Congress? And there is a huge economic cost to this massive web of subsidies that we have. And if the country's not willing to pay a carbon tax, so we can use the price mechanism, isn't that just a decision? What is the benefit of all this incredible web of subsidies, which are distorting the market, wasting money that we don't have? We're as deep in debt as Greece, quite frankly, in terms of GDP. There's a cost to that, too. So why shouldn't we just admit, if the fact is that Congress won't pass the carbon tax, that we're not going to go the other route, which is to have this massive web of subsidies, which is doing us as much damage as anything else?

Speaker 1: Well, you know, one thing that we haven't talked about, but it is starting to get some traction, is the idea that, yeah, maybe you do, in fact, get rid of, you know, a whole web of subsidies, right, not just the subsidies that are being directed at the renewable energy industry, but the stuff that goes to the fossil fuel industry and the nuclear industry as well, and let people compete on that basis. And I raise that actually with some seriousness. And in fact, if you look at IEA and their analysis of what fossil fuel subsidies mean around the world, their belief is that you can get, I forget exactly what the number is, but sort of 10-20% of the carbon reductions that you would hope to see under a proactive policy, simply by just getting the fossil fuel subsidies out of the industrialized economies. So, you know, there is something to be said for going down that road and being a true free market purist.

Question: When we talk about subsidies, it's about payment and who's going to pay, and subsidy to me, it's just another way of putting it on the bill. And you know, inside the Beltway, I don't think they could get together to do a pothole, let alone the Eisenhower Electric Highway that Speaker 1 is talking about. And there are all those good things--energy independence, and all of these goals that we should have as a country, and I really agree with you. But as we look at the rollout of the EPA rules, for instance, and the benefit proposition about what's going to be saved in healthcare and all that, how is it that information about benefits is transmitted to the public, so they get on board this train with a fundamental understanding of what they're paying for, what the benefits are that will come out of it, and so they will not come to my commission, in the big yellow bus, and not want to pay for this? You know, I think we have to move forward as a country. We've got to get it together at some point in time to be able to do this. And how is information about the value propositions trickled down to us and to the person on the street, so that we get a fundamental understanding of what exactly we're going to pay for?

Speaker 1: So first of all, on the Eisenhower thing, that's literally no more, no less than basically the Federal Highway Trust Fund that we've had for 50 plus years, and that may not be the most efficient thing that we've done, but has been effective in creating a system of roads in the United States. And part of the rationale for it is, as I've thought about it, the recognition that the specific benefits of deploying smart grid locally are not always all locally realized. And it's the same issue that we have with transmission. Right? The costs that we impose locally are not always realized in benefits locally.

And so you're talking, just to put a round number on it, if you put a one cent per kilowatt hour on all the retail electricity sold in the United States, you'd have a pot of money of over $37 billion per year, which is more than we have in the Federal Highway Trust Fund right now. So you accumulate real money very quickly, and then it would be up to the states to figure out how they wanted to spend a share of it.

But that being said, your point about how you make this real to the public has really surprised me. And maybe the car companies are being conservative. Right? But it has really surprised me that no one has made the argument that at eight cents a kilowatt hour, just to pick a number, it costs 75 cents a gallon to fill up your car. So even at New Jersey rates, where I'm from, 16 cents a kilowatt hour, it would cost me $1.50 a gallon to fill up my car with electricity. OK? If you went into a room of consumers in New Jersey and said, "Who wants $1.50 a gallon gasoline?" I'm sure every hand would go up. And then if you said, "And all of it would be manufactured in the United States." OK? And 80% of that would be with no carbon pollution. People would be cheering. All right? Then you say, "Here's now what you need to do in order to get that. I've got to put this thing on your house. OK. Your electric rates are going to go up by this amount. OK?" And that's how you're going to get there.

Question: But who is doing that communication?

Speaker 1: It falls to organizations like Environmental Defense Fund to do that. But ultimately I think it's got to be governors who see the value in that. You know, it would be nice if a president could do it. It would be nice if a Senate majority leader could do it. It would be nice if a Senate minority leader could do it. I mean, anybody can grab this mantle. But assuming it's not going to come from Washington, I think that this is a powerfully interesting thing for the governors to take on, because they're much closer to their constituents and can sort of understand. You're giving people an opportunity to take money that they're otherwise sending to Oman, and you're saying, "Here, put it in Arkansas."

Question: Isn't the problem with the analogy you just used, that you're just looking at one portion of the cost? And you know, there's the cost of the vehicle itself, and how much more expensive it is. You do have to sell it to the public, so we're going to tell the truth about the whole cost when you add all these things together, and not just the cost of whatever the electricity equivalent is of gasoline.

Speaker 1: Absolutely…and no one had nailed me down as to where I would put my R&D money. Battery technology. That's the one thing the government can and should be doing right now, figuring out ways to buy down battery technology, because not only is that the key to getting a cost-effective electric automobile, but it's also the key to getting the energy storage that you need to integrate the renewables. That is the critical path.

Speaker 2: I think part of the problem, or part of the reason why we are where we are today, is because the costs haven't been really talked about openly, and because the benefits haven't really been discussed honestly. The focus a couple of years ago was on jobs, and there's really not that much good academic work showing the link between investments in wind and jobs that are not displaced from somewhere else. So that's part of the problem of why we are where we are today, that the goals and the costs haven't really been discussed as honestly, perhaps, as they should have been.

Question: Yeah, I'm going to bring us back briefly to the feed-in tariff topic. And I'm going to assume we have a renewables policy, because I'm from California, and it really doesn't make sense to operate under any different assumption. So assuming that we are trying to pursue the renewables that we want, the problems that have been previously identified associated with feed-in tariffs, consistent with what we heard today, is that the feed-in tariff pricing causes trouble. You know, we set a price high enough to attract what we think is going to be the right level of participation. We get it wrong. We pay too much. If we set too low a price, we simply wouldn't get anything. So administratively determined pricing is a problem. But that doesn't mean that feed-in tariffs are necessarily bad. It just means that our method of pricing in feed-in tariffs is bad. If we're talking about a lot of small development, feed in tariffs do actually provide some administrative efficiency in getting projects built. So if we could price properly, recognizing the actual markets, recognizing the locational differences…and in California we have tried to put in place programs like that. We have one auction-based feed-in tariff that Edison developed that worked relatively effectively. We're trying to develop a market price-based one now that would move pretty quickly over time to reflect conditions of the market. Then isn't the problem really bad pricing, rather than feed in tariffs?

Speaker 4: Yes. I mean, from the capital markets standpoint, feed-in tariffs are so much easier to deal with, so much easier to finance. And again, what the capital markets need, what investors need, on both the debt and the equity side, is long-term visibility. Whether they're meters, or they're wind turbines, or they're solar panels, or they're fuel cells, these are 20 year assets. So that's unlike any other technology that we have, whether you look at telecom, or you look at other industries like the Internet--those are three, five, seven year assets. These are 20 to 25 year assets that are being deployed. And to be able to deploy 25 year assets, you need long term clarity. The supply chain will tool up. The projects will get built. And so the feed-in tariff is a problem of pricing, again.

But from the standpoint of financing renewable portfolio standard projects or feed-in tariff projects, either/or will work, because if you have long-term clarity, projects get built. In an environment like what we have today, where interest rates are where they are today, money wants to flow into renewable projects. The variability of wind and solar is quite low. I've got a much better chance of getting paid off by investing in a solar project or wind project, where I can get an 8% equity return. Where else am I going to get that in the capital market today? Where else can I get 20 year 8% cash on cash returns? Nowhere. And not any time soon. So again, feed-in tariff or RPS, either/or will work, as long as there's clarity.

Question: Part of the issue is that here we are talking about innovation, and yet solutions are socialist-based, where everything has to be spread to everybody, so individually, nobody has to pay their fair share, which is also one of the problems with real-time pricing, that we're not letting the consumer see what the true cost of power is. To the point about changing the business model, it's interesting that we're talking about subsidies and tax credits, etc. But for utilities, especially this generation of electric utility executives, who will chase subsidies and tax credits or ROEs, why are we not looking at creating more of a financial incentive for them to either invest in these innovative technologies or clean coal, energy efficiency, transmission, etc.? As opposed to just having them make these investments up front, or getting the regulatory certainty up front? Why not have the regulatory certainty after they've made the investment through ROE incentives, to either what is added to rate base, or onto some purchase power agreement, or some other leasing option that they have in place with some other vendor?

Electric utilities in general have to have regulatory certainty up front. And then they want a risk-adjusted ROE. Well, instead of giving that to them up front, why not give them that ROE incentive after they've integrated it into their portfolio, whether it's that they added it to their rate base, or added it through some lease payments, etc.? But give them an ROE incentive instead of focusing on the subsidies. Can we find some incentive that's on the financial side that will spur the utility executives that exist today and in this economy to take action, as opposed to not taking action?

Speaker 1: Well, you know, to some extent we did this with Duke down in North Carolina with their "Save-A-Watt" model, which was basically a performance-based efficiency program. The more they invest in efficiency and the more they hit their targets, the higher the return will be on the capital that they invested. So it certainly is a workable model. I think one of the things that we haven't really spent a whole lot of time on this panel talking about is, at the end of the day, what should we be spending most of our time on--trying to figure out how to give utilities returns on investment? Or how to create markets that attract capital and more or less have the utilities get out of the way and do what the utilities do best, which is manage the monopoly functions of the system? That's a huge question. And we don't have time to really explore it in ten minutes. But I think implicit in a lot of the discussion that we've been having this morning is that well-structured markets with strong price signals can do a lot to bring technology to market.

Speaker 4: I was silent because my parents told me, if you're not going to say something nice, you should be silent. But I've overcome that here in the past couple of minutes. I will tell you, if you are waiting on the utilities to do this, we're going to wait a long time. That's not in their DNA. I've spent a lot of time with utilities over the years, and they do what they do well. But being dynamic is not what they do. And so I'll go back to the original question, which is, do we want this stuff, whatever that is? And if the answer is yes, it starts with telling the utilities what to do, as opposed to hoping that they'll get to the right answer, because for the CEOs of the utilities, that's not how they got their job. That model is going to change, by the way. I think I would be very worried about my utility stocks if I owned them today, because I think five years from now…If you look at, one of the benefits of natural gas prices going down is fuel cells. Fuel cells are suddenly going to be much more economic. And so when we start to see distributed generation and the smart grid, and you look at what's about to happen to some of these utility CEOs, I don't think they have any idea about what's about to hit them. And so if you're relying on them, and you go back to what's got them to where they are today—inertia-- I mean, I just think it's not going to happen.

Moderator: And actually last but not least, smart customers who actually see prices and know what they're buying and when they're buying it and how much they can buy.

Question: This kind of dovetails onto the prior discussion that we were just having, and you know, I was kind of interested in what Speaker 4 said, because coming to an investor and saying, the new efficient use of capital is to sell less of my product…how does that sound? Does that sound like a real winning combination? And how do we get paid for that? Because while some of the costs do go down, let's face it, a lot of them don't. And the regulatory costs are included. And the fixed costs certainly don't change. So utilities like growth, either in use per customer or in customers, because it hides those increasing costs, and we have to go before our PUC less and less. If we change that model, especially in a flat economy, which we're in now, and we add energy efficiency, and we add distributed generation, the pressures are higher. And the reason that the utilities don't innovate is because they don't get paid for it. Why would I take on a developer's project for a regulated rate of return? Even if I'm successful, I've lost. I've lost that delta between what the developer would get paid for that project and what I'm going to be allowed to recover in rates. So why would I ever do this?

So if energy efficiency is going to be a big part of our future, my question to the panel is, how do we accomplish this? Because if we don't change the way people pay for energy, then we're going to pancake rate cases. And I can tell you, politically, that's a death spiral. If we do want to change it, you're going to run into people like the AARP, who think decoupling is the Devil. And politically you are going to run into a huge problem as well. Even though the policy might be there, the will may not be there to change it.

I understand the need for rate certainty. I agree with that. I think that private capital would come into the marketplace if they gave rate certainty. I think the utilities would invest a whole lot more if there was rate certainty as well. And finally, when it comes to increasing the fixed charges, you move into a situation where when you do that, you again run into those advocates who argue that if you increase the fixed charges, you decrease people's incentive and/or ability to conserve, and that's contrary to energy efficiency.

So I don't have a solution, but I'm interested, and we've talked a lot about what the solutions are. But we haven't really talked about how you pay for it. I want a Ferrari. I really do. But I'm unwilling to pay for it. So how do we get to this energy efficiency as a solution, get the returns that are needed for the capital market, and do it in a way that the people are going to pay for it? Because the American way is not get less and pay more. That's a very difficult political message to send. So I'm interested, and I'm sure you all have thought about it, but I'm interested in what those are. Because we face those every day. And I could sure use some good ideas.

Speaker 1: So in your discussion (and you made a lot of good points) you did first draw a distinction that I would draw between the fixed cost associated with maintaining the transmission distribution system and everything that that entails, which arguably should be recovered through a fixed charge--it's the cost of being connected--versus the variable charges that go along with supply. And there, it's less convincing to me that energy suppliers are owed recovery. This goes to what Speaker 4 was just saying, which is why I think utility executives really do have to think very hard about what the future looks like, because it's not at all clear to me that the old rules of simply build large base-load generation, and spread those costs over 40 years and a growing rate base and growing consumption, hold anymore. And that is the first fundamental truth that I think many in the business have to sort of wrap their minds around. And I think some are.

I think, second, what you hope to be able to do is to create a mechanism by which the utility in some ways becomes the bill collector for the cost of the efficiency investments that go on at the customer sites. But the capital that's being deployed is not just simply that capital which is on the utility's balance sheet, but frankly is on a whole host of players' balance sheets--institutional investors, private equity funds, the wealth of capital that's out there that's far in excess of what exists in a very really minimally capitalized industry, if you really think about it. And so that's the second piece of this, is that there is money out there to finance energy efficiently. And by the way, if you allow customers to see real time prices, they will see real time benefits from the investments that they're making, either in the fuel cell that is now sitting out in the side of their house, or on the insulation that they just put up in their attic, and the change out of the lights that they just financed through on-bill financing.

I don't underestimate how hard it is to convince the AARP that life will be better after these changes. Because Lord knows, we've argued with them, too. But there are also ways to document the value of what we're talking about here, and it is hardly like business as usual is so favorable to low-income consumers and consumers on fixed incomes, because one way or another, we are going to spend the next 40 years turning over the capital stock. What I constantly have to remind people when I go around the country is, look, you're looking at me as an environmentalist, and you're thinking that, boy, if I just went away, this would all go away. Well, no, the fact that coal fired power plants are 40 years old, that most of our T&D

infrastructure is 30 or 40 years old, that our nuclear power plants are 40 years old, that basically we've spent the last 40 or 50 years living off of the investments that we made 40 or 50 years ago, and that it's time to reinvest, I didn't bring that to the table. That's there. All I'm trying to figure out now is how do we move forward with the next wave of investment in the cleanest, lowest cost ways possible?

Moderator: Maybe we should point out, too, that AARP is actually a for-profit insurance company, bank, and lobbying organization and not exactly totally interested in real people. But that's for another day. [LAUGHTER]

Question: I just wanted to pick up on a point that Speaker 1 just made about the mechanisms by which we might focus investment. We have revenue decoupling in many states now in the United States, and as part of that mechanism, there are capital trackers, which allow the utility to go in and pitch a capital plan to the state regulators, at which point the state regulators have an ability to agree, disagree, or maybe even ask the question, how does this plan make the grid smarter next year than it was last year? The grid doesn't become smart overnight. It becomes smarter every year. And every year, utilities spend millions and millions of dollars on the infrastructure, and I think there's a role for regulators to play in questioning how that money gets spent.

I spent several years at National Grid pitching our capital plans to regulators, and I would go out of my way to highlight those aspects of our plan, but I was really I guess underwhelmed at the scrutiny that we got in terms of asking that question, how does this plan make the grid smarter next year than it was the year before? So I think that there's a mechanism out there, because it's not like the utility is just going out and dumping capital in the ground over ten years, and then going in for recovery anymore. With revenue decoupling, those budgets are put before the regulators, and they have an ability to weigh in and to ask the question whether or not the budgets are meeting public policy objectives. I don't have a question.

Moderator: Good point anyway.

Question: Every once in a while at one of these meetings, I have this incredible déjà vu moment where I flash back on the very first meeting I ever attended of this Harvard Electricity Policy Group, which got started when open access to the transmission system was passed at the federal level. And the thinking of the day, after trying to do this through central planning during the two decades of the '70s and the '80s, because consumers couldn't see that nuclear was going to pay off, or that IPPs were going to pay off, the weight of accumulated mistakes in trying to get the prices right through regulation just put us on a completely different path for about half the industry in the country, going to markets.

And so I think the question of how do we get the prices right is the wrong question, because we're never going to get them right, if by right you mean, "We know this answer of this much money for this technology, it's true today, and it's going to be true 20 years from now, and ultimately everybody's going to be happy with it." We're always going to be wrong. We have to place bets, because it's a capital-intensive industry. And so the R&D problem (and I don't think there's an easy answer to it, given our political system) is really about, in that context, where do we place our R&D money? And how do we figure out what the role is for the central planner? And then how do we extricate ourselves from setting those centralized prices before the cumulative bill gets so big that you have to worry about the people in the yellow buses who come and visit the public utility commissions and say, "Why should we pay for this, because you did this, and you were wrong? Look at the evidence." So there is no easy answer. It's the system we live in.

I think what we're trying to focus on in the R&D is, how do you do that? And I don't know how you do it. But I think that's how we got to where we are now with markets. And so every time Speaker 1 would talk about the old industry, I was feeling very schizophrenic, because in about half of it, in terms of capacity, we have markets that you can say, "Well, let's let the market take this risk, as opposed to us having to do it, fixing a price, and taking away the risk so he can finance the project." I don't see that as a very good way to go, having lived through the train wreck of having done that with the independent power producers.

Speaker 4: I'll say two things. One is, our country works very well in crisis, and I think we find solutions pretty well in crisis. And the good news for those of us who don't live in California is, I think over the next five years, we're going to have a crisis in California, and that's going to be the microcosm that will allow those others to be able to look at it. Because if you look at what's going on in California, you have a huge amount of people going off grid, so you have people who've realized that with the decline in panel prices, all that's gone on with the Chinese, etc., that you have a number of people going off grid. You also have the lower natural gas prices, which are going to allow fuel cells to start to move into that economy. You have a huge penetration of smart grid. The consumer is going to gravitate towards the right answer, and I think what you're going to see is a lot of the wealthiest customers going off grid. You're going to have the same amount of stranded costs that are going to sit there, and so you're going to have these rate cases that are going to start to come forward. Or you're going to have a huge amount of stranded capital and not enough megawatt hours to put against it, because efficiency's going to start to work. People are going to come off the grid, whether through solar or fuel cells. And then they're also going to be able to improve themselves. I mean, the technology that's going on around efficiency that's available to people, especially if they've got smart meters, is huge, and that we're seeing right now.

And so again, I don't know what the answer's going to be, but I do know where we're going to probably find the test case that's going to help us figure out what the answer is, because I would not want to be one of the three large California utilities right now, or over the next five years, because I think they don't know what's coming. I don't think any of us do, but we're going to have a test case very quickly to help us figure out how this is going to work out.

Moderator: And by the way, for those of you interested in history, the last California test case is still wending its way through both the FERC and the courts. So I hope that's not true, but I suspect that it is. When it takes a utility three tries to get meters right, something is really fundamentally wrong. [LAUGHTER]

Question: I want to close on my Pollyanna note about why Carol Browner might be wrong. And if you go to Europe, and you look at the gasoline tax, it's very high. It's probably too high. It's been high for a long time. People don't like it, and they complain about it, and it's sustained over time. I think the simple explanation for that is that the governments are addicted to the money. And they want the money. And we're looking at this revenue spending crisis that we're in, and this is definitely a crisis, and the super-committee failed, but the super-super-committee is going to be formed in order to address this problem. And we're going to have to pull something out. And going to the numbers behind Speaker 1's chart there, we're talking about north of a trillion dollars here for new tax revenues that could come from pricing pollution. And it's not just CO_2. It's the particulates and so forth of the things that are associated with coal. So there's a lot of money there, and it may not be done because it's energy policy. It may not be done because it's environmental policy. It may be done, and it may be done quickly, because we need the money.

Session Two.

Reliability and Economics: Separate Realities or Part of the Same Continuum?

For resource adequacy in generation, or for transmission and distribution lines, reliability planning has been conflicted about explicit consideration of economic tradeoffs. In one sense, reliability councils and NERC have been given a formal mandate to virtually ignore economics, but the underlying economic theory is rooted in concepts like the value of lost load. Probabilistic standards have been debated and applied, and decisions regarding the building of facilities and the allocation of the costs associated with them, have been made on the assumption that the reliability standards are not to be challenged. Indeed, there is a bureaucratic incentive not to displace existing reliability criteria because of concerns about overall economic efficiency. One is far more likely to be faulted for service disruptions than for overspending on reliability. Experience with electricity markets may have created new interest in opening this topic, again. To what extent should we inject economic thinking into reliability? Indeed, is reliability nothing more than a function of economics anyway? Who benefits from more stringent reliability standards? Is the overall public interest well served, or are there cross subsidies flowing from the bulk of customers to those who require higher levels of quality of service? What are the criteria that best balance the overall level of reliability required with economic efficiency?

Moderator: I think we have a great panel here today to tee up a conversation about reliability and economics--are they separate realities or part of the same continuum? And just a little bit more background on me. I grew up on a farm in Iowa. Even back then, it was a pretty reliable system. We could depend on electricity most days of the year. But if something went out, it usually took a while to get it fixed, and you know, we just dealt with that. It was OK. It wasn't that big a deal.

And even today, I've been in Washington for a few years, and I've had my series of outages. But if it weren't for losing the value of the food in my freezer, I could probably buy some batteries. We were out for a couple of days, and we actually as a family had a good time in our sleeping bags around the fireplace last winter. It was a bonding experience.

So some of us can absorb that. Some of us in society can't. But we're all paying for the same level of reliability. We don't really have any choice. Is there a point where we should have choice? Or should we continue to totally socialize a reliable system at 60 hz to power the Google server farm? Is that the same need and cost associated with what I need with my family and in my house if all I'm really worried about is getting the freezer back on time? I don't lose a lot of value in frozen meats. So I'm just trying to get your head around what we may talk about today, and that may or may not be applicable. But it sounded like a fun story to tell anyway.

Speaker 1.

For me, the issue about reliability and economics and whether they are separate or part of the same continuum is really not an easy issue to resolve. But from my perspective as a state regulator, the two are almost inextricably intertwined. I'd like to give you just a state regulator's perspective, and certainly there are a number of state regulators in the room, and also a bit of an idea from a regulatory perspective about our regional work and what I view as our regional obligations and interregional work as well.

So I went back to where our enabling statutes came from, and what gives me the duty or mandate or authority to act in this area. In Arkansas, our enabling statutes requires that our commission find and fix "just and reasonable and sufficient" rates. It also requires that we determine the reasonable, safe, adequate and sufficient service to be provided by public utilities, so you see there some of the issues regarding economics. But it also requires that we ascertain and fix adequate and reasonable standards to be observed by public utilities, and reasonable standards for the measurement of quantity, quality, pressure, initial voltage or other conditions pertaining to the supply of products, commodities and services rendered by public utilities.

As you might imagine, when I first became a commissioner, even that statute scared me to death. What on Earth? I mean, how an I determine the quality, the voltage sufficiency of commodities provided by electric utilities, and gas as well, for that matter, but particularly in transmission and generation planning? Many commissioners across the country deal with these same mandates. And again at home, as many states do across the country, we have integrated planning resource statutes that we must abide by, which really aid the commission, as well as the utilities and the people we serve in planning, and so the utilities come in every three years, file their IRP plans, and if there is a concern, we address it. If not, we all have a better and clearer understanding of what lies ahead, and going to a point made this morning, clarity is very important in this process.

Regionally, also from my perspective, both the Southwest Power Pool Regional State Committee and Entergy Regional State Committee have Section 205 filing rights under the Federal Power Act to direct transmission planning and cost allocation processes in both the SPP and Entergy. For both committees, state commission members provide collective regulatory input on matters of regional importance related to the development and operation of the bulk electric transmission system. And just a few of the duties that are assigned to commissioners that participate in this process include deciding whether and to what extent certain cost allocation methodologies are used for transmission enhancements, deciding and helping shape what type of rates are used for regional access charges, determinations relating to FTRs or financial transmission rights in certain instances, and deciding which projects should be constructed based on economic and other evaluations. This list isn't exhaustive, but it certainly demonstrates that we know that we have our work cut out for us as commissioners, but we certainly think we're up to the job.

Considering these duties, both reliability and economics are inseparable. As the saying goes, and I do embrace it, today's economic projects will likely become tomorrow's reliability upgrades While some may not acknowledge this evolution, it's certainly becoming more evident with our work with EISPIC (the Eastern Interconnection States Planning Council), for example, and I also acknowledge that our colleagues to the west were well underway with this effort long before EISPIC began. And recognizing the fact that extra high voltage transmission provides benefits to markets beyond simply delivering remote renewables to markets, transmission defines and enables markets and should be properly valued for all of its attributes to lower consumer costs, improve efficiencies, provide optionality for future resources, and in improving the ability to respond to future mandates, such as, for instance, EPA regulation implementation--I think that's a very large elephant in the room that we all will have to grapple with at some point, and at some point very soon.

I also acknowledge that the utility industry is conservative by design, and that's a good thing, and the industry must therefore be prudent with regard to being a good steward over capital investments, because they are so costly, so intensive by nature, and because of the nature of the infrastructure, the regulatory compact, because of their monopoly status, and coupled with the long life of major transmission assets.

Replacement of aging infrastructure will certainly provide a unique opportunity in the next couple of decades, as the bulk power system evolves from a patchwork quilt of local systems toward a more efficient interrelated system. We were talking about Spain earlier, and one of the regulators there said that it seems as though the U.S. is like a lot of different countries, which is true. I mean, in every state, there's something different going on, different laws, and of course, the utilities remind us of that every day. What do you want me to do about it? But we certainly can learn from our EU friends about the importance of working together, optimizing efficiencies, as we move forward with a substantial amount of investment.

EHV (extra high voltage) transmission line corridors may be one of the most valuable assets for the utility industry and US energy markets going forward. FERC Order 1000 will have an unprecedented effect of never before seen cooperation and collaboration, which seems to have been lost in this transmission system over the last couple of decades, and this collaborative work, as we all know, will require regions and non-RTO utilities to optimize their work on both reliability and economic fronts. So therefore, I would suggest that we simply can't pay enough attention to this work as regulators.

When I first became a commissioner, it really was a different world. For me, that world changed in Charleston in 2009, when there was an unprecedented meeting of the FERC and a particular utility commission. There was representation from four commissions and one municipality to take up the issue of transmission. And I think at that point, my life as a regulator changed, and it really highlighted for me the importance of getting involved and insuring that we were doing our part to provide the services to the people that pay for them.

We're focused on reliability and economic issues because we have to insure not only that investment costs are prudent and in the public interest, but also, and equally important, that the investments are sufficient to ensure that rate payers may be able to rely upon our electrical grid to fuel their homes, their businesses and hospitals and nursing homes, for instance. So mounted on top of EPA regulation implementation, and for instance, pipeline safety costs, we've heard a lot that recently, are transmission costs. And with the series of severe weather events that we've seen all over the country in recent years, this balancing act is even more difficult.

Situations such as the Connecticut snow storm, the power outage in DC, and brown outs in Texas really draw our attention to exactly how reliable our grid is, or how reliable it needs to be, because these issues and episodes could happen potentially anywhere. And we also, in addition to all of this, must plan and make sure that our grid is not susceptible to security breaches. So we have a great deal of work to do to meet both reliability and economic build-out requirements nationwide.

I certainly acknowledge that there are some differences in both the reliability planning models and the economic planning models, and certainly advantages to both. For instance, reliability planning in accordance with NERC standards, some may perceive to be more formulaic in nature, and therefore some would argue, maybe more precise in the ability to determine an outcome. Economic planning, such as the analysis employed by the states, and also used for project evaluation in some regional efforts, tends to be more complex, with figures that may be more difficult to ascertain. I acknowledge that as well. But one benefit of our state work, and certainly at the regional level, is the import of transparency, and also the involvement of a tremendously diverse and large number of stakeholders, who all bring their concerns and positions to the table, and I believe it's through that, that we reach a better result. With our collective planning by utility companies' regional organizations, state and federal regulators, NERC and other stakeholders brought together, such as in forums like this one, focused on the fundamental concepts of reliability and economics, I'm hopeful that we will continue to chip away at these difficult issues, and that we will work together to achieve a more efficient, reliable grid. Thank you.

Speaker 2.

Reliability is a very broad term. I think you can break it down into three large categories, the transmission system, the distribution system, and resource adequacy, which includes generation transmission and demand response. And I understood the description of the session to focus a little bit more on resource adequacy. So that will be most of what I'm going to talk about.

Transmission system operation—there are issues associated with this that can cause large-scale outages. I'm not sure there are that many really interesting reliability cost tradeoffs in the transmission system. We're often talking about very low probability events with very big impacts. So it's kind of tricky there to really bring economics to that, and then find an interesting problem.

With respect to the distribution system, I think we already do make tradeoffs. We decide how much tree trimming to do and how soon to replace all the cost components and that sort of thing.

I think where it really gets interesting is resource adequacy, and there I think one of the questions for the panel is whether we should inject economics into reliability. Resource adequacy, I think, is one place where we inject reliability into economics. And this is what we'll be talking about a lot today.

So I'm going to take you back. I'm not going to ask for a show of hands of who remembers the EPRI study, "Costs and Benefits of Over/Under Capacity in Electric Power System Planning," from 1978. Some of those insights are still true today. The graph on the left, Over/Under, is showing how cost varies as you have a larger planning reserve margin (PRM). That's what I'm going to be talking about a lot today. And some of the insights from the Over/Under study are that total cost is minimized over a fairly wide range of planning reserve margins. With a larger margin, you're buying more capacity. But you're getting some variable cost benefit and less frequent chance of outages. With a lower reserve margin, you save on the capacity, but you're probably going to pay a little bit higher variable cost and risk more of the cost of outages. So it's a very flat curve, but it's also asymmetric as you get out of that flat range. On the upside, there's a larger planning reserve margin. There's more capacity cost. But on the low side, that's where you start getting variable costs of generation and outage risks and outage costs rising sharply. So it's asymmetric.

And in that study at that time, the important driver of the optimal planning reserve margin was demand growth, which was at that time 2% to 7% per year, and hugely uncertain. In the studies documented here, there are some instances where they assigned a 20% probability to 20% demand growth over three years. So they were looking at a very different situation with respect to demand growth.

They also had very long plant lead times. They were talking about coal and nuclear back then. So you're trying to meet very rapid demand growth with very long term, long lead-time resources. And one of the important observations was that planning flexibility is valuable, and that particular model actually represented how uncertainty resolves over time and how you can adjust your planning mix and accelerate or delay resources in the pipeline over time.

And then with respect to the Value of Lost Load, I was interested to get out a CPI inflator and multiply the Value of Lost Load they used there, and I got the same number that I think is often used today, about $3,500 per megawatt hour. They were using about $1,000 back then. So Over/Under is kind of how it was done back then, and it showed that really PRM was not a real important decision, because it was optimized over a broad range.

So the common industry practice has been one day (of outage) in ten years. Unfortunately, that report didn't really say what the one day in ten years was. They didn't talk about it that way. But my guess is it was probably within that wide range. That's the common practice. It's very conservative. I'm not going to go through that today. It's in papers I've written, and I'm not the first one to suggest that it's a very conservative resource adequacy criterion. It's roughly two orders of magnitude more delivered reliability to the customer than many customers get in their distribution systems. So if there's 120 minutes per year, as kind of an average amount of outages for distribution system disturbances in the US, according to LBL, if you take one day in ten years, and you reflect the fact that every time you have an outage or a rotating blackout because of resource adequacy, you don't hit all your customers, you get something more like one in 50 or 100 years for a customer. So it's much more conservative.

In addition, if you look at how we calculate the planning reserve margins based on one in ten, you see lots of conservative assumptions in there. So what we call one in ten is probably often something more like one in 50 or 100. And of course, doing this very conservatively makes a lot of sense for utility planners and for the regulators who would have to take the call from the Governor when there's a rotating blackout. So there's been a large constituency in favor of very conservative approaches.

I want to contrast the circumstances from the time of Over/Under to today. Things have changed a lot. Back then, there was huge load growth. Today, according to NERC's report out earlier this week, we see 1.2% US average load growth, much slower load growth and probably a much narrower range than back then. For incremental capacity back then, they were talking large coal and nuclear, long lead times, big investment. Today, there's a lot of flexibility from shorter lead times, lower investment, life extension, natural gas that builds pretty quickly, renewables, demand response. Lead times are shorter.

So the Over/Under is different today. The over risk of having too much capacity is probably greater today because of the low load growth. You may not see excess capacity get absorbed as quickly as you would have decades ago. And the under risk is probably smaller, because you have a lot of flexibility from these various resources. So the Over/Under has really changed.

This chart is from NERC's report that was just released this week, showing how forecasts of load growth have been declining. They were about 2% for decades, leading up to about '03, and now they've just been declining. Expectations of peak load growth have been just declining year by year. And this data is for PJM over eight base residual auctions of their reliability pricing model capacity construct. This is what they report as being the incremental capacity that they've seen in the construct, and 82% of it is kind of , low-investment type stuff, like demand response, like upgrades of existing plants, like withdrawn or canceled retirements, or incremental imports. And only the remaining 18% has been major new generation with long lead times, of which 12% was natural gas, which is probably more like a three year lead time.

So when it comes to injecting reliability into economics, competitive wholesale markets also change the whole picture Let's remember why we have administrative planning reserve margins in competitive wholesale power markets. It's partly the sanctity of the one day in ten years criterion and concern that market participants collectively might not act to provide enough total capacity to provide the high levels of resource adequacy that we have grown accustomed to and expect. Some think of adequacy as a common good, although I think that's probably changing with increasing price responsive demand. There also are and have been concerns about the incentives for capacity construction, especially years ago when the focus was on merchant generation almost exclusively, there was a concern that there were not adequate incentives in our current wholesale markets for new capacity, with the shortcomings that you had limited demand response and some shortcomings with respect to pricing when reserves are low.

So getting back to Over/Under today, with a wholesale market, at least in principle, you're looking for market participants to make their own assessments of future demand and of reserve requirements, and to make their own decisions about what to build, what to retire, whether to contract, whether to hedge. So in principle, you'd like to see market participants do that, and perhaps in aggregate, the over/under of how costs change with total capacity is maybe not very different, in terms of the relationship between cost and the actual reserve margin.

But in practice, what this graph is suggesting is, if you were to set a very low administrative planning reserve margin, it would not be a binding constraint. Market participants collectively would act to bring forth a larger amount of capacity, so a low PRM wouldn't have any impact, and so you would kind of lose the bottom end of the curve. It just wouldn't happen. Whereas the high end might be very much the same. To realize a larger PRM than what market participants on their own bring forth, you'll need some mechanism to bring it forth.

So naturally, when we talk about resource adequacy and planning reserve margins, we talk about mechanisms for realizing them. And I think of it as kind of a hierarchy, indicated in this graph, from, at the bottom, an information only approach—doing PRM study, and reporting it (and that's actually what the recent FERC order does require PJM to do, to do a study and to report the result. It doesn't require anything more than that). The next step would be to take that planning reserve margin, allocate it to your load serving entities proportionately, normally, and have some enforcement mechanism, perhaps a penalty if you don't actually bring forth that amount of capacity to the delivery year. An easy next step beyond that is to have a voluntary mechanism, an auction or something, to help LSEs buy and sell capacity to make it easier for them to fulfill their obligations. And that's pretty much where our Midwest ISO is today. And then the next step beyond that would be a close-to delivery year mandatory residual auction to achieve the PRM. So rather than leaving it to load serving entities, anything they haven't come up with by, say, months before the delivery year, you'd have an auction, and the RTO would actually acquire it. And that's pretty much what New York does today. And then at the top of the hierarchy, the most proactive and the most significant intervention in the market is where you actually have a years forward mandatory residual auction, and that's what PJM and New England have. When you have a mandatory, and especially a forward, auction, it changes the over/under from the standpoint of consumers or capacity sellers, because through the auction mechanism, the way these work, the capacity price and the capacity cost rises very quickly with a higher PRM.

This graph shows the capacity auction supply curves for PJM. Note that the bottom axis is between 100 and 150. So a few percent increase in the PRM can pretty close to double the capacity price. And what that means is that the total cost, and especially the cost of capacity, is very sensitive to the PRM. And that's why we spend so much time in PJM fighting over planning this whole resource adequacy and planning reserve margin and load forecast issues. The impact of an administrative years-forward PRM on the actual delivery or capacity is actually complex. I mean, often in over/under we assume that if you set your PRM at 115%, that's what you're going to have. But PJM actually goes through this whole process. So three years forward, PJM sets a PRM. It runs through the auction. It sets a capacity price that about 90% of the capacity that is not self-supply is going to earn that price. But then the next year they update their load forecast. They update their PRM calculation. There's an adjustment auction where they can buy more capacity or sell, if they have too much or too little. And then one year forward they do the same. And then months forward. So in the delivery year, and through this whole process, market participants are making their own decisions about contracting, about retirement, about sponsoring new generation. So the actual delivery or capacity is a function of the PRM, but it's also a function of these adjustment auctions and the actions of market participants. So there's not a real strong connection anymore between the administrative PRM that you choose and the actual cost in the delivery. So that over/under relationship is kind of a little different.

I'm only going to talk about this briefly, but the same questions about resource adequacy and bringing economics to bear can also be raised around transmission planning. PJM uses a bright line test to decide whether a transmission line is needed or not. Essentially, NERC says to PJM, "Have a test for transmission need and apply it." PJM comes up with a test. Within that test is actually a one day in 25 years resource adequacy standard. What I'm illustrating in this graph is, as you'd expect naturally, that as you change the amount of transmission, the Loss of Load Expectation (LOLE) in a constrained area changes. Obviously, if you have more transmission, that LOLE is driven very low. If you have less, it's higher. And it's a smooth relationship, as illustrated here. A bright line test basically takes one point there and says, if we're on one side, we need it. If we're on the other side, we don't. So there's not a whole lot of economics coming into that.

So to conclude, the one day in ten years criterion is overly conservative. And I'm not the first one to say that. If you look at the cost of capacity, and you balance it against the probability and cost of outages, you would suggest a lower level of reliability than that. And the capacity over/under that flows from that has changed significantly in recent years with a lower load growth rate and more short lead time resources, and an increasingly manageable peak through demand response and price responsive demand.

Traditional, conservative PRMs based on one in ten harm, in my view, both consumers and markets. It preempts market decision making to impose a PRM on the entire market. The excess capacity depresses energy and ancillary services prices and reduces the value of smart meters and smart devices that realize their value, especially when prices rise, when reserves are not so high. Large PRMs also result in large transfers of wealth from consumers to capacity sellers through these capacity constructs. And forward capacity markets, such as we have in PJM, tend to become entrenched and create a constituency in favor of more conservative PRMs.

With respect to the economic evaluation of planning reserve margins, I think modeling the economic impacts of a resource adequacy criterion and a resulting PRM becomes a lot more complicated in a market context, and the results will necessarily depend on a lot of very questionable model structure choices and assumptions. You've got a connection between the PRM and the actual reserve margin in the delivery year. You've got a connection between the reserve margin and energy and ancillary services prices. We all expect that higher energy and ancillary services prices will stimulate the market to build more capacity, but it's very difficult to model that. And so you've got some multiyear dynamics going on there that it's really tough to get at. And this all brings in sort of the theory versus the practice of how forward capacity markets are supposed to work.

The general over/under approach that I illustrated there, I think really isn't well suited to modeling the dynamics of power markets. Some people have used another approach. Professor Benjamin Hobbs has used a different modeling approach, but it also has many limitations.

Another whole topic that I could have gone into is that communicating these analyses is very difficult, and I've seen multiple instances where in reviewing some reliability-related analysis, the regulatory body was attempting to drill down and really understand how likely a certain reliability violation is. And I've seen sometimes where they drilled and drilled and just didn't get to it. I mean, knowing how it was done, I have some understanding of it, but I've often seen that just never get there.

With regard to resource adequacy for restructured markets, on the one hand, I definitely think we should bring economics into reliability, but in my view, the PRMs are a market intervention that should remain focused on resource adequacy. I think the purpose is to protect the market from unacceptably low reserve margins leading to unacceptable risk of frequent outages. I guess I think of it as a guard rail on the highway, rather than the PRM telling us to drive in the left lane or the right lane or the center lane. It's more of a guard rail, just to make sure we don't go over the edge, rather than to optimize the economics or to try to send certain price signals. The evidence from capacity markets is that those price signals from capacity spot markets are not that effective.

I think the longer term goal should be to phase out the administrative PRMs or to see them become non-binding through further development of demand side price responsiveness and better pricing when reserves are low.

I think everyone agrees that reliability is paramount, but when you apply it to resource adequacy, it results in these very conservative policies that I think really kind of stunt market development and will discourage the development of price responsive demand.

Question: To what extent, as you looked at your analysis of saying that this is too conservative, did you look at the impact of the fact that various regions and ISOs are interconnected, and what happens in one will affect the reliability in another?

Speaker 2: Really, what happens from a resource adequacy perspective is that when one RTO is in trouble, they can look to get some assistance from their neighbor. OK? That's usually how it's brought in. I think when one RTO is short, they don't have too much impact on their neighbors, because their neighbors probably have their own resources that are kind of under their control.

Question: I would ask you to think about what happened back in 2003.

Speaker 2: Well, OK, that I would say was more of a grid operational issue than a resource adequacy issue, although they're intertwined.

Question: Coming from California, one of the things we're look at and examining now is whether for resource adequacy, PRM is exactly the right thing. What we're seeing is the need for flexible resources as we get more and more of the intermittent renewable. Just having capacity on the system becomes less important, and having units that can actually respond when you need them is becoming more important. I'm just wondering if you're thought about that and how that fits into your comments.

Speaker 2: Let's hold that one.

Speaker 3.

What is reliability? In this discussion, you already saw that for some people, reliability is all about transmission planning, economic projects, reliability projects. For some people it's all about storm outages in Connecticut. For some people it's about EPA regulation and what that does to reliability. And even if you look at EPA regulations, some people talk about resource adequacy, and other people talk about transmission security in localized areas. And the third group of people talks about what will happen when all the retrofits will have to be put in, and those plants will have to be on an outage simultaneously, and can you maintain reliability there? But I'm not going to talk about EPA regulations.

What I thought I should do is put a few numbers together. Speaker 2 has already mentioned that there are distinct types of reliability, and when you talk about resource adequacy, people often say, "Well, but what about the distribution system? Why are you talking about resource adequacy, when most of the outages happen at the distribution system?" If you talk about distribution system outages, people say, "Well, you can't forget about resource adequacy." The reality is, there are three components, and they're additive, and we need to look at each of them separately.

There is some research on what the total cost of not having a reliable system is, and there are several studies that are listed here, and the combined impact of costs associated with power outages is about $100 billion a year. Now, how much of that relates to generation resource adequacy? Well, you know, not as much as you would think. But outages are costly. The cost to customer of outages is pretty high, ranging from about $1,500 a megawatt hour for residential customers, to $70-80,000 a megawatt hour for the commercial/industrial customers. So the cost of interruption is very high, and we need to take that seriously.

When I try to figure out how much exactly of power outages relates to generation adequacy, versus transmission or distribution system reliability, there is not a lot of good data out there. The Carnegie Mellon folks cited on this slide did some work a couple of years ago, and it's more about the reasons for outages. And a lot of the reasons are sort of undefined, because there might be an equipment reason. But that equipment reason might really be related to a storm. So you don't really know whether the people who classify these reliability events classified it all the same way. But when people say, "Let's just put the distribution system underground," the reality is, a lot of the outages are on the ground equipment outages. There was a huge outage in Con Ed in New York City a few years ago. It all had to do with underground equipment. So even undergrounding isn't really the solution to a lot of these things. And we need to keep the whole picture in mind when we talk about outages.

There's also some evidence, at least, that outages have increased over the last decade or so. Some people attribute that to the dilapidated grid in the US. But the reality is, other people document that the frequency of major storms has doubled in the last decade or so. And it might just be a temporary blip, but that's what does cause a lot of the outages. But we do have anywhere between 30 and 70 major power outages in the US a year, with up to 10,000 megawatts of lost load at the time.

But now let's go to my favorite topic, resource adequacy. That is a topic that has been brought to the forefront in the context of capacity markets, because interestingly enough, the capacity markets have really crystalized the economics of reliability, because all of a sudden, there's a transparent price signal for the reliability, or the adequacy standard that we have been imposing, and that adds up to a lot of dollars.

So why do we have resource adequacy standards in the first place? Well, I think there are a number of attractive benefits, in addition to reliability, because there's a common good free ridership problem out there. Do customers really know how much reliability they want or need if extreme events happen so infrequently? What does it do to the energy market? What about competitiveness of power markets and so on? Speaker 2 mentioned that resource adequacy really distorts the market. Well, sure it does. It changes the ancillary market to a two part market, one for capacity and one for energy. But we do that in a lot of markets. You know, car safety standards are one example. Why not leave it up to the customer how much safety they want to buy? And I think the thinking is that there's sort of a minimum standard that you want customers to buy, because maybe they don't know exactly how severe the impacts of not having enough could be. Flood insurance is another example. Why are there mandates to buy flood insurance? Well, because customers often would forego those choices in exchange for short term savings.

Will the usefulness of resource adequacy standards fade away with demand response? I mean, if everybody has demand response, why do we need a reliability standard? Well, I do think the importance of resource adequacy will be reduced by demand response, because demand response adds non-firm load to the system. You will still have firm load. People still don't want to reset their alarm clocks every time they go on a demand response event or something like that. But demand response does reduce the amount of firm load, and with a reduced amount of firm load, the resource requirement that we need to supply that amount of firm load is going to be less.

Speaker 2 mentioned one in ten, of course. That is a standard that has been around for a few decades. But it's not well defined. And even when people define it as 0.1 event per year, they don't measure it the same way, and as Speaker 2 said, the assumptions of how you measure and model that can vary tremendously. But some interpret it as 2.4 hours in a year. And the difference between doing those two things could be four or five percentage points on the reserve margin. So one in ten means different things to different people, and it hasn't been updated in decades.

When this first came up for me recently in the context of PJM capacity market, we put in a recommendation that one should look at this to see whether the reliability standard is still economically efficient. Well, the reality is, that really went nowhere, because the RTOs said, "Well, our job is to implement the reliability standards. Those are NERC standards, and we can't do anything about this." When we talk to NERC, they said, "Well, we're just implementing reliability standards. We're not involved in the economics of it." So who is putting these two things together? I mean, nobody in the industry really is. Except possibly FERC, which now had jurisdiction over both economics and reliability, and that's probably where it will come from.

So how do you determine the economically right level of reliability? Well, of course, we know what the cost of incremental capacity is. It costs a lot to add reserve margins. And we can sort of estimate how much it reduces the likelihood of lost load just from generation inadequacy, and we have a sense of what the value of lost load is. But if you add a combustion turbine to the system, you also get the option to dispatch that combustion turbine in place of higher dispatch cost resources. You might have demand side resources for $1,000 a megawatt hour that you don't have to dispatch. So as you add a combustion turbine as sort of a standard capacity product, you do get economic benefits with that of avoiding higher cost dispatch options, or buying emergency power at $6,000 a megawatt hour from your neighbors. But you also get reduced price volatility. It does reduce price volatility in the energy markets by design. There are some financing cost advantages, and that kind of tradeoff is what has been modeled by Professor Hobbs in his probabilistic model. But there are a lot of other things. So let's not go into the details.

The interesting thing about that is that in SERC, there is no one in ten reliability standard. In SERC, reliability or reserve margins are being determined often with economic modeling. Most of the states in SERC have recently had a case in front of them to figure out what is the economic optimum reserve margin. And Southern Company has invested a lot of money in taking a reliability model and updating it to be able to do the economics as well, and what you get is this chart. That's just the under/over curve that EPRI first came up with in 1978. But one of the interesting things here is (and for full disclosure, Speaker 2 and I don't agree on the assumptions going into some of these models, and we had a good fight at a recent webinar, that we can repeat in about 30 minutes)…But what is most striking about this is that you do get the U shape, as you see here. In this case, the biggest impact was really the cost of expensive emergency purchases. The probability of incurring high costs in extreme events is much larger than the value of the lost load. And it is interesting, because during the California power crisis, very little load was actually shed. It was a resource adequacy shortage, for the most part. Most of the impact was really high cost power. And that's what you see here, too. This chart is based on scarcity and purchased power curves that have been observed in the market. And we can tweak the assumptions, but the value of lost load is not all that important. The cost of high dispatch emergency resources power purchases is more important. Now, this is for an integrated utility. So this is a cost of service framework that wouldn't necessarily apply the same way to an RTO. But nevertheless, the other thing that you see here is that this gets an optimum lowest average cost reserve margin of about 12%. But the one in ten standard could get you to 15% or to 10%, depending on how you define it. But that chart was average cost. That's the average cost of all possible outcomes. Those outcomes are very high cost, low provability events, and you can't see much on this chart. But what you can see is that all the high cost outcomes are sort of to the right of 95%. So we are talking about one in 20 year events that are really high cost. The scale here is, each line is a billion dollars. The average cost at a 12% reserve margin is only about $100 million.

So that's the problem with reliability. Most of the time you have enough, but when you don't have it, it really makes a big difference. And if you factor in that risk profile, then you might want to increase the reserve margins just to reduce the extreme events or the total cost of the extreme events.

Now, the other interesting thing that that kind of economic reliability modeling did, which I thought was quite interesting, is it actually tells you what the resource adequacy value of different resources is. What is the capacity value of energy-limited resources, like demand response? And it all depends on the penetration and the resource mix. One very interesting thing about intermittent resources that came out of this analysis is that the capacity value of wind depends on whether you have other limited resources in the stack. If you have demand response that can only be dispatched ten times a year, or combustion turbines that are only allowed to run for 200 hours a year, that will increase the value of intermittent resources, because it isn't so important that an intermittent resource runs during the peak hour. What is important is whether the intermittent resource is running during those hours to save you the energy-hours to be applied to the peak?

Generally, I think when we ask consumers to pay however many billion dollars for capacity, I think everybody would be better off to understand what consumers are getting for that in terms of risk mitigation, etc. But some of that economic modeling also highlights the importance of unlikely events, such as weather or water conditions. I mean, Texas right now is in a situation that might only happen once every 20 years. But when it happens, it is really scary, and when an ice storm knocks a distribution system out, people sort of understand how that could happen. But if people don't build enough generating capacity to supply load that is something you could have done something about. That's a whole different ballgame.

Takeaways. I think we do need to recognize that reliability means totally different things to different people, and we need to address all these things. And customers are affected differently by those reliability events. But we also need to recognize that with demand response, with consumer electronics and smart meters and so on, the value and cost of reliability is changing over time. I do not believe that we necessarily can assume that a reserve margin should be a lot lower today because load growth is lower. Weather uncertainty might have increased. The dependence on power might have increased, too.

Question: Just at the very end, you talked about a reliability simulation. And you mentioned the value of the internment resources depending on other factors. And I was wondering if you could explain that a bit more. It seemed –

Speaker 3: It seems counterintuitive?

Question: Yes, that's correct.

Speaker 3: Well, let's say you have a resource like a combustion turbine that for environmental reasons can only run 300 hours a year. Wind might not be blowing when the load is the highest, but wind might be blowing enough to help that CT save the 300 hours to the high load periods. So if wind blows during the 50 highest load hours, that saves one hour of that energy-limited resource to be running during peak. So if you have some hydro storage in the system, if you have other energy-limited resources in the system (demand response is a good example), that will actually increase the reliability value of intermittent resources.

Question: I just had a couple of questions about the two pie charts that show causes of power outages. Over on the major outage events, you have equipment failure of 31%, weather and fire at 40%. Is it just sort of arbitrarily decided that something is non-weather equipment failure? And the same thing in retail outages, where you have tree-related outages versus weather outages. Did they just arbitrarily decide, well, in this thunderstorm, where trees were uprooted, and they're outside the right of way, that's weather, versus trees that were in the right of way that weren't trimmed?

Speaker 3: The reality is, there's some arbitrariness to that. There are some guidelines on how folks fill this out. I think you fill out the primary reason. But if weather knocked over a tree, and the tree became the primary reason for the outage, one utility might fill it out one way. The other utility might fill it out the other way. But looking at this, we know fairly little about how that all really plays out, and I tried to go into the notes, and it would just say, "cause, animal, bird," dropping 10,000 customers out. [LAUGHTER] You'll find anything in those results.

Speaker 4.

As I'm sitting here listening to my colleagues (and I think they all make some very good points) my problem is that I just don't get it. I listen, and I wonder why I see something that's blue, and everybody else talks about orange, or whatever color. And I'd like to try to kind of open up how I think and see if it makes any sense to you all.

There are about five things that I'd like to talk about. First of all, we've heard that what we really need to talk about up here is resource adequacy. That's the issue which economics really relates to.

We have a way of thinking about reliability, and it's been evident in terms of the discussion that we've had here. And what I'd like to argue is that that way of thinking is completely linked to a specific paradigm and a specific structure, which we all are very comfortable with, and learned in college in some cases, or learned in our jobs, and lived it for years and years, if you're in a control room. And in turn, that institutional structure is fundamentally related to the technology that gave rise to that structure.

A little bit less obvious is the next idea: that I believe that new technology, coupled with essentially the forces of competition, represent a fundamental paradigm shift, not just an incremental paradigm shift, but fundamental. I had a conversation about resource adequacy. And I said, "You're still hanging the ornament on the Christmas tree, and I've thrown the Christmas tree out." I think the world is a very different place, or at least potentially is a very different place now.

The third point I'd like to make is that if we don't recognize that we're in the middle of a fundamental paradigm shift, and if we don't behave and make decisions accordingly, we're going to incur a lot of costs. And I think the financial and economic crisis of the last few years has indicated that I'm not sure that the US has a lot of fluff that we can afford to be inefficient as we may have been in the past, or to overzealous in our application of resources.

And then I'd like to suggest some ideas that we can all think about as we go to dinner.

So first let's deal with ideas about resource adequacy and reliability. I believe that a discussion on resource adequacy is really just a subset of a discussion on reliability. Resource adequacy does not and cannot exist as a separate topic or even a definable topic, because the reason that you have resource adequacy is in order to accomplish some reliability goal. So while we can have a discussion about resource adequacy requirements and so on, what you're really talking doing is making some implicit judgments as to how reliable system is and how this will translate into fewer blackouts, brownouts, or whatever you want to call them.

So I believe that any discussion on resource adequacy is really just a subset of a larger discussion that must take place on reliability and what we mean by that. So by disaggregating these two ideas, we obfuscate the real issue. And the real issue is, how do we operationalize reliability? It's not about whether or not we should have 10% reserve margins or 8% margins, or whether we should have a one year reserve product or a five year reserve product. It's really about, as an industry and a country and an economy in particular, a competitive economy--how is it that we're going to define and then operationalize reliability?

So how do we define reliability? It's a very difficult term. You know, I put up a couple of easy definitions. "Consistently good in quality or performance," which really doesn't accomplish much, because then you have to look and say, well, what is good? What is quality? And what is performance? Even what is consistent, for that matter? You have to have some benchmark of what does it mean to be good? Some people would say Tim Tebow is a good quarterback. He's five and one as a starter for the Denver Broncos. Some people would say he's terrible as a quarterback. So we have different metrics out there in terms of what those words mean, which we would then have to endeavor to define.

And I put another definition up there. "Capable of being relied upon or dependable," which kind of seemed like what we're headed for in electricity. But what do we mean by dependable? So it is difficult to be precise when it comes to reliability. Now, maybe that doesn't matter. But the problem is, it does matter. And the reason it matters is because we need to operate a system, and the performance of that system is going to be gauged on how reliable it is. So it's not as though we can just talk about it, throw it away, and go have a beer. Because somebody somewhere, a control room operator, a system operator, is going to take what we said, and they're going to write rules. They're going to buy software. And they're going to operate the system according to however we define reliable. And then we're all going to pay for it.

So I went back all the way to the '60s and the blackout, and I tried to get real definitions. Somebody somewhere surely has written some academic tome on the definition of electricity reliability. And I was unable to come up with one. In the industry so far, what we've done is, we've created lots of metrics, which are almost like busy work. Were you reliable? Well, we established a one in ten year standard. OK, were you reliable? We operated to a one in ten year standard. Were you reliable? Did you win the game? Well, we didn't have a blackout. OK, so does that mean you were reliable? In some definition, maybe. We do not have in the industry an accepted definition of what it means to be reliable. We have various components--so many frequency excursions or so on. But then that hasn't been linked back to why we say that is reliable.

So the cornerstone, near as I can tell, of reliability is this idea of "Loss of Load." Having load go black is a bad thing. It's a negative event. And so, at the cornerstone of all of our discussions on reliability is the idea that we don't want people to go without power. That kind of goes without saying, really. But what does that mean? Does that mean any loss whatsoever? Well, not really. All these people are like, "Oh, if we could only solve cancer." I said, "we can solve cancer. Are you willing to devote the resources that it would take to solve cancer, to solve world hunger?" Well. So we're already into a world of tradeoffs, which is what economics deals with. So are we really talking about no blackouts? No. One in ten? Well, what does that mean? Any loss? And in what sense are we talking about voluntary or paid-for reductions in load? So if I get paid for, or if I voluntary shut off, does that count as a loss of load? No, it doesn't. How is that encapsulated in our paradigm? Would we prefer a lot of short occurrences in terms of time? Or would we like longer ones, but occurring at less frequently? So one day in ten years? Or 2.4 hours every year? Which is better? If I had a definition of reliability, I could say, this one's better than that one. But we don't have a definition of reliability. If I have one really bad peak occurrence every 20 years, is that better than every night when you sit down to the evening news at 11:00, your power goes off? Because this matters now in terms of how we run the system, what investments we make, how we dispatch the system. Would we like outages that are predictable? I've been doing work in other countries, and when the power goes off, everybody accommodates it. They know when it's going. They know at certain times it's coming off. I worked in India.

The system operator says, "Well, we're not going to have power that week."

"Well, why not?"

"Well, my daughter's getting married."

(I'm not seeing the link.) [LAUGHTER]

"I've told everybody, my daughter's getting married. Don't expect power."

"The power plant? Is that the wedding gift?"

"No, no. You don't understand. I'm not going to be there."

Well, still dumb American.

Finally, "I'm not going to be here. The plant's not going to run. Nobody's going to get power."

"Oh, OK."

"But everybody knows about it, so we're OK."

So, is predictability what we're trying to do? Again, it matters in terms of how we run the system, what investments we make, the risk parameters on our dispatch models, and everything else.

So hopefully I'll have convinced you that it's relatively difficult to operationalize the concept of reliability. And we're really lacking what I would say are explicit answers, but we do have implicit answers that have allowed the system to run. So where did we come up with this paradigm that we operate under? The legacy of our paradigm, that we are essentially living through the capital expenditures of, is the paradigm of the '60s, which is diminishing average cost, which meant that big generators were preferred to little generators. And so we had large generators. And then the decision became, do I locate close to the fuel source and transport the electricity? Or do I locate close to the load source and transport the input fuel?

Now, we are living through those expenditures. Now, in that world, it makes sense to say, "Well, size matters." We don't want ruinous competition. So we're going to establish monopolies. We're going to regulate them. And what does the monopoly get? The monopoly gets a franchise. Nobody shall compete with them. And then we will, in return for giving them this nice thing, we'll tell them, "You've got to meet load. Your job, since I've given you this monopoly position, is to meet load." And that makes sense. In that world, you can talk about things like a provider of last resort. You can talk about how "the load must be served." We have to meet load. Load is a given.

How many of us, when we started in the industry, and we would draw that demand curve, we wouldn't draw a demand curve. We would draw you draw a straight, vertical, inelastic line. And people don't speak about it. The asset values of virtually all our generators reflect this paradigm, and virtually all of our transmission assets reflect this.

This is competition. Reliability is competition between new and future technology and old technology. It's a fight for asset values. It's a fight for market capitalization. It's a fight for money. So under this older paradigm, it's natural for loss of load to be considered a negative. Absolutely, there's no other conclusion you can reach. I'm not here to criticize that. What that does, is it establishes an implicit property right, that the consumer has the right to have continuous power 24/7. We get a natural idea that demand is inelastic. Our investment reflects that. Real-time pricing, real-time metering, demand response programs, demand management, demand shifting--is anybody going to tell me that the investment in that technology hasn't lagged behind the investment in generation technology? Monitoring technology? It's all lag.

Again, it matters. If we had had a different definition or different concept 20 years ago, we'd have a very different capital base that we'd be working from, and we'd be talking about this in a very different way.

Into this mix comes demand response. Somebody looks and says, "You know, I'm willing to change things." In 1994, Fisher &

Paykel took us on a tour in New Zealand, and they had washers and dryers and dishwashers and everything else that would response to prices. They just needed meters that could actually translate those prices into the device.

Demand response represents not just new technology, but disruptive technology. And this is where you get the real effect of economics. Because now, instead of a centralized, central planning problem, you have a very different problem. You have a disaggregated problem with disparate information with disparate objectives, utility maximization and so on and so forth. Name me a system operator that looks and says, “Wow, I want to go work for them, because they’ve got a lot of interruptible load. I really look forward to dispatching that system.” No. In fact, they are happier if they’ve got load that is constant. It’s hard enough managing the transmission and the outages and the generation. You throw a variable quantity in there on them, and it’s just a mess.

As a result, let’s look at some of the rules that have been passed. Some of the rules look good, but who is ever going to really be called? There’s a good chance that interruptible load is going to be about the last guy on the block called. This is because the dispatcher really doesn’t want to call him. And it’s going to take some market participant to say, “No. Call me. I want to interrupt. I’ve got the contracts. I’m ready to go.” So demand response is essentially the tip of the spear as we’re moving from a centralized and aggregated decision-making process, to one that is decentralized and disaggregated. I hope that the guys at ABB and Siemens and Areva are busy fixing their dispatch models to accommodate this. In the meantime, what we’re trying to force demand response to look like a thermal generator. It has to be monitorable, like a thermal generator. And we’re trying to do the same thing with intermittents, we’re trying to make them look as though they’re a thermal generator, because that fits our paradigm. It fits the legacy of how to manage the system.

But demand response isn’t the only one that’s out there. You have smart grid, distributed generation. There’s a ton of disruptive technologies that are coming down the pike. So that’s what I mean when I say, I think the ball’s already passed. We’re just kind of waiting for the implementation now. We know the technology works. We know that people will do it. Just let them do it and get out of their way.

Renewable policies are basically orthogonal to the new technologies, because the ideal institutional structure for a renewable policy is that, is a national utility. Because I’ve got wind over here. I’ve got load down here. In the old world, boy, I’d have to build transmission. But now I’m crossing four states, 12 different jurisdictions. But if I just had one big national utility, I could get it all done. And then you’ve got little demand response going, build what you want. But if it’s too costly, I’m just shutting off. Go ahead. Just don’t force me to pay for it.

So basically what happens is, the new technology comes along. It’s disruptive to the old technology. And then we put it on steroids, in effect, by introducing competition by allowing people to implement it and use it, instead of kind of keeping it in the closet and letting the utilities kind of drag it out every once in a while for emergency conditions. Now we’ve got active demand response increasing in the market. And there are no captured customers that can be forced to not use it and the benefits of it.

So in terms of suggestions, this is a difficult problem. This is not a problem where we’re going to say, “Well, we all settle on an 8% reserve margin.” It’s much deeper and more fundamental. These are a couple of quotes from the Jobs biography: “The best way to predict the future is to invent it.” And that’s what we’re doing right now as an industry. Nobody knows what it’s going to be like five, ten, 15 years from now. We are inventing that future. Decisions by FERC, decisions by the state commissions, decisions by the private sector are inventing that future. And if we don’t take into consideration the effects of this new technology, we’re just going to invent yesterday all over again. Except it will be more expensive.

On the concept of reliability, I was happy to hear Speaker 2 and Speaker 3 use terms like “insurance,” “risk management,” and “risk.” Let’s start thinking about reliability as a form of risk management. How are we going to manage the risk of an outage? And what is the appropriate way to manage that risk? So how do we hedge? These are terms that are very familiar. I've also heard people use the term "tail incidences." We've got things that happen infrequently, but when they do, they have very bad consequences. Haven't we just been living through what were told was a tail effect in the credit crisis? We're living this world in terms of reliability. We're living that world financially, in the financial sector. And that language and those tools need to be transported in terms of management.

Well, can we learn from that? How best do we manage risk? What is the appropriate insurance? To date what we've done, and what resource adequacy really is, is a physical response. It's physical risk management. And there is a place for physical risk management. But right now we don't have some of the other things that we need around that. The key ingredient is correct pricing. We need correct scarcity pricing signals to incentivize the correct behavior. We need to have a policy that does not bias one technology over another technology. And new rules should be evaluated to see whether or not they're unduly preferential to any one given technology. We should take a probabilistic approach.

I'd love to be able to walk into an operation and say, "What's the probability I'm going to have a stage two outage?" And get an answer like, "Well, sir, it's 96.3% based on this." That's what you can do in a financial shop. You could ask, "What's my value at risk right now?" The answer might be wrong. But what asking the question does is, it focuses the attention. "Why is it there?" And so on.

And finally, I think the solution needs to be appropriately flexible, appropriately diversified, and appropriately integrated across regulatory regimes, state boundaries, different markets and so on. And I would encourage people to think that one size does not fit all. The technology allows for and encourages multiple uses, and we ought to take advantage of that, as opposed to a one size fits all type of solution.

Moderator: Well I know one thing. As I looked at the economics of reliability, the market's much stronger for economic consultants on resources adequacy than on transmission and distribution reliability. [LAUGHTER]

General discussion:

Question**:** One of the things the California ISO is really concerned with now is not so much just having capacity but having capacity that has a flexibility to respond--either load following or regulation type capacity to balance out the system. To me, that is one of the big changes that has to happen over the next few years, especially in California as the state gets large amounts of renewable resources. You are probably going to see a planning reserve margin, if you just count up the overall capacity, of 150% or 160%. But a lot of that is not able to respond when you need it. It is the intermittent-type stuff you can't count on it.

What becomes more important is not so much having all that there, but having stuff that you know in April or October when the wind is blowing or stops blowing or starts blowing that you can actually have control and do what you need. I am just wondering how that factors into your discussions of resource adequacy and reliability.

Speaker 3: Well I can get us started. I think that is a different concern and a different constraint. I would actually say this is very distinct from resource adequacy. Resource adequacy is just that--to avoid generation-related shortages. If you believe that adding so many renewable resources creates regulation needs that the ancillary service market cannot attract by itself and you are really concerned about this, because it takes two years to build a combustion turbine to do that, I think you would have to impose a different constraint and say, "Well, every zone in the CAISO needs to have that much regulation capacity," and it almost becomes a constraint like the resource adequacy requirement, a separate constrain--we have environmental constraints, we have RPS requirements, we have resource adequacy requirements. We have all kinds of constraints on the system already, and it creates a separate market for flexible resources.

Now, I would hope the ancillary service markets can be tuned up to the point where regulation becomes just so valuable that you will have resources enter with added flexibility. And I have been talking to some developers and they are banking on flexible resources becoming much more valuable. So they spend extra money to build resources that are more flexible than they need to be right now because they think they will be very valuable in the ancillary service markets down the road.

Speaker 2: I would just add that this is another dimension that has to be evaluated. I think someone mentioned earlier that wind only counts for like 13% of its nominal capacity value, and to really evaluate what wind is worth as capacity or another intermittent resource, and what other flexible resources are worth when they companion with that, and kind of help to solidify it is a complex modeling exercise and obviously is going to depend a lot on the amount of diversity. On a large system with more interconnected diversity, the intermittent characteristic isn't going to cause quite as much of a discount, because you will have that diversity. But it is really hard to model that sort of thing, because obviously it depends on how likely it is that the wind over here and the wind over there are out at the same time. But it is kind of another dimension, as Speaker 3 suggests, that merits analysis.

And you know you hate to see the intermittent resources get heavily discounted if in fact through diversity and other flexible resources they are worth more than they often discounted to, I think.

Speaker 4: If I heard you right, it is not just a frequency or regulation problem--it is quick start, it is the location... You know, you could be going along and have everything fine, you have got the right amount of regulation, and then something happens, and as a result of that happening you need something somewhere else. Not to just replace capacity. So, you need quick start, you need flexibility and you need locational signals on all of those as well as time of year because there will be times of the year when the problem is worse than at other times. So again this is back to my point on correct pricing. Let's make sure we are pricing the things that are important correctly. If that is a valuable market to CAISO, then they need to make sure they are setting the right price signals to show the value of what that is to the marketplace.

Speaker 3: But you might also have a situation where the additional flexible resources either become so attractive that people enter just for them, or that you need to require people to build flexible resources to balance the system such that the reserve margin requirement is no longer a binding constraint, at least not in the transition period right where your system isn't flexible enough, but you are right at your reserve margin, and whether or not you have a resource adequacy problem, you need to add resources to balance wind or solar or whatever you have. So I think I am back to the point that these are separable constraints and it doesn't help us to try to do something with resource adequacy that is really two different things.

Speaker 4: In New Zealand there was a similar problem in that the older generators could stay on line when you had a frequency decline, and it really became a competitive battle between the new gas units and the older units.

Speaker 1: Certainly, this discussion emphasizes the important of planning and not only the importance of diversity but reliability at ground zero if you will, and making sure that we can all respond when we need to. And with the implementation of EPA regs, we are going to have that discussion again.

Question: Let me just give you a little more context from California, where in addition to seeing the tremendous increase in renewable resources, the other thing that is going on in California is that there is a state initiative to retire once-through cooling units, which happen to be a lot those older units that have a lot of inertia, and are located where the consumption is happening and tend to be the big giant spinning units on the coast.

Part of the big concern is that those are the units that now provide a lot of the stability to the system, and a lot of the regulation and flexibility, and when those disappear--when they are either retired and not replaced or possibly replaced with a different type of unit--the question is, how are we going to ensure that there is still enough capacity to keep this system spinning? And part of that is also that there are other things going on, such as increases in distributed generation, which don't necessarily get counted in. You have to figure out how to count them when you are looking at your reserves, and I just think there is going to be a big change, and I don't think we understand yet what is coming, in terms of looking at how these resources are going to be integrated or exactly what the impacts of that are.

There was a study of what would happen if some of the renewable generation that is located in the Imperial Valley were to suddenly drop offline. And, initially, transmission planners look at it and say, "Well, we deal with that." We talk about what happens when there is a loss of a thousand megawatts out there. The problem is that is a contingency and then there are different rules that apply as to what you can do.

A market processes dropping off line instantaneously, and then you get 30 minutes under the NERC rules to recover. It is a process that happens over the course of maybe five or ten, fifteen minutes and you can't use your spinning reserves. You can't use the NERC rules that allow you to exceed the normal capacity on a line. You have to do it differently. So I think there is going to have to be a change in the way the markets work to accommodate that. I don't even know that we can understand what it is yet until we start seeing some of these things happening.

Speaker 1: I think this is a glimpse of the benefit from FERC Order 1000, also because I know that as a regulator I will look to the leadership of our RTO to give us guidance there. They have the experts. They are able to do the modeling. So I would hope, and I am smart enough not to speak against my colleagues in California on this point, [LAUGHTER] but I am saying to you that I would as a regulator take into strong consideration any concerns by our RTO regarding an issue such as that. So I think it is an opportunity for leadership, also.

Moderator: And we do appreciate California helping teach us all how to do this right. [LAUGHTER]

Question: Having lived through capacity shortages, I guess I would observe that it is nice to talk about this, but as the planner or former planner and now the region is the planner, if you have a loss of load event due to inadequate generation, you are going to be spending a lot of time at your state capital, at your state commission, listening, and having an investigation by NERC (which incidentally does not have a standard on resource adequacy, contrary to what most people think. They only do assessments), and FERC, so it does matter. And I would suggest that this conversation really needs to happen with a whole lot of state regulators in the room to speak to what they will accept. Because ultimately, they are the people on-line.

But now having said that, it seems to me from these presentations that we have two issues here. One is, how do you do the resource adequacy calculation? For example there is a lot of mention of price responsive demand. Can that be integrated into the present probabilistic analysis in the same way that load growth uncertainty is? The second issue is changing the one in ten standard--or I always learned it was 0.1 day per year, and not one day per ten years—and it seems to me that is going to be a lot more difficult because of the commons problem that Speaker 3 mentioned. You start saying, "Well, industrials will accept one day in five years, but residential customers may not." And so if you look at this, how much is doable in a faster manner by going through and having, I would call it updated, inputs or updated assumptions in the probabilistic models, as opposed to overhauling the 0.1 day per year?

Speaker 4: I would just like to make one comment. You used the phrase, "What the industrials will accept." I'd like to raise two things. When Hurricane Ike came blowing through Houston I accepted a nine day outage. And what that taught me is that if I want to hedge, I better get my own gas generator. And even then I might not be hedged, because something could happen to the gas generator and so on and so forth. But it really wasn't a question of hedging on the first thing. It was a question of understanding, and understanding what risks I did face and how I could manage those risks and insure against those risks.

I think we are in a very different world now, in that I don't look for a centralized solution now. We could have had a capstone turbine put in our housing development. We talked about that in our homeowners' association. So there are more solutions out there now other than just saying, "I either get it or I don't." That may be your solution.

Speaker 3: To the questioner, when you first started talking about the state capital and spending a lot of time there, I was thinking, "Well, maybe that is cheaper than building another power plant." [LAUGHTER]

Speaker 1: It is more painful though.

Speaker 3: You bring up some very good points, obviously. In terms of the modeling aspect of this, I don't know exactly how all the RTOs are doing it right now, but there is no barrier to considering price responsive demand and other DR as a resource. Even if the modeling keeps load a vertical demand curve, you can do a work around by adding the demand resources to the modeling. It has been done. But I am not sure that is being done every time.

In terms of spending time at the state capital, of course it depends what city the state capital is. [LAUGHTEER] That kind of probabilistic analysis is being done in several of the SERC states at the state level. And the interesting thing is that the reserve margin that tends to get picked is not the lowest average cost reserve margin. But it is often the lower 95 percentile lowest cost reserve margin. So you do put in a premium to avoid those extremely costly--whether monetarily or personally costly--events. And you are right, it is easy to say, "Well, you know, let's save money on that," but once you are short it becomes a real problem for a lot of people, not just personally but in terms of overall system costs.

Speaker 2: Your comment that any time there is an outage there is going to be this kind of witch hunt looking to assign blame is obviously a real barrier to making sensible economic tradeoffs. Because if you make a sensible economic tradeoff, and then the one day in ten weather event occurs, nevertheless, people are being blamed for not having built the extra 200 megawatts that you could have done and then avoided the outage.

You asked how Price Responsive Demand (PRD) works in the one in ten calculation. I mentioned this in my article -- it kind of makes it impossible or meaningless. Because if you think about it, if you have a lot of Price Responsive Demand on your system, and you are trying to model a one in ten outage likelihood, you've got situations in the future with a lot of PRD where you are putting the price up to three thousand, five thousand dollars per megawatt hour in order to activate all the PRD, and you probably put the Value of Lost Load in there for an involuntary outage at about the same level. So from a value perspective it is kind of indifferent. It is about the same value--three or five thousand dollars. But to calculate Loss of Load Expectation you are trying to distinguish between the PRD, the load that you chased away, and whether you actually involuntarily curtail someone. So as you get lots of PRD, the whole calculation of one in ten sort of becomes both arbitrary and meaningless.

You also brought attention to the fact that there are very different Values of Lost Load (VOLL). Another thing I didn't mention is that the cost of self-providing reliability has come down a lot in recent years. Those industrial and commercial customers that have a much higher value can put in onsite back-up generation and basically protect themselves from the grid. And then effectively, if you have backup generation your willingness to pay for reliability from the grid is very low, because you are self-providing reliability. So if you take that into account, then it again suggests that you ought to probably be using a lower VOLL for your resource adequacy analysis.

Moderator: I would just add, to that first part of that question about the fear of outage and spending more time at your capital or commission than on planning your next asset, that I think that fear is one of things that brought me to this whole conversation about economics and reliability as we implement EPAct '05.

After the '03 blackout there was a notion that Congress could pass legislation and we would stop having blackouts. [LAUGHTER] And there is some natural bureaucratic protection of the commissioners from our staff that don't want to get dragged to the Hill for the next blackout, because try as we may to legislate or regulate away a blackout it is not going to happen. There is going to be one at some point. Where do we draw the line about how much we do to make sure it doesn't happen?

So this on the record conversation is about costs and is what I think needs to happen so we can at least rationally explain our reliability decisions. And that should be part of an open public process and transparent record so that we can make the case that it is not our fault, if you will. There is a rational explanation about how we balance those two.

Question: I very much agree. You have a NOPR out on what is in the industry called Footnote B. That is ultimately the issue there. The cost versus transmission loss of load. And it is being handled in a very transparent manner, because it is all regulated at FERC. That is easy. It is a little harder, when we have 50 states plus the District of Columbia, to come up with that kind of thing on a national basis.

Speaker 1: I have been thinking, throughout this panel that this is such an imperfect process. We work very hard, we try our very best, whether you are a utility, an RTO, an ISO, a state commissioner, or a FERC or NERC commissioner. And I began to think that we are really only as strong in terms of reliability as that next event that knocks our feet out from under us. We don't really know when we've reached that point when we are resilient.

I hope not to be hauled over before the capital. I was mentioning to them that we have had two back-to-back hundred-year ice storms in less than 30 days. And it was just devastating, crippling, paralyzing, and what can you do to prevent that from happening again? I don't know if there is anything.

Speaker 2: You winterize a bunch of plants, and then that winterization doesn't have any value for the next 150 years, perhaps. [LAUGHTER]

Question: This happens to be one of my very favorite topics because it does present that collision of economics, technology and public policy that I think this group handles so well. I would like to suggest that we have heard from a couple of different people today that different sets of customers really do want different amounts of reliability. And technology is now offering us the opportunity, particularly for those of us that have the resources, to go out and get what we need. So we start with that as a given. We also start, though, with a premise that there is some adequate level of reliability that it is acceptable to socialize across society. It is okay to go get "better" and "best," as long as you are providing "good" to every customer. And so I would ask the panel, how do you set that level of "good" reliability? How do we figure out where that cross point exists?

And I would ask you to think more broadly than just resource adequacy because I too have had the opportunity to visit a small state capital to explain what happens when you hit not one *day* in ten years but one *event* in ten years. Commissions don't care that you say it is the first time in ten years. They just you know it is still a problem. So please look wider than that, and tell me about how we look at that intersection to determine what is the appropriate level of good reliability that should be cost socialized?

Speaker 2: When we are talking about major blackouts, where you lose a big chunk of the transmission grid and you lose a lot of customers, that affects people even if they are self-providing reliability. That has just enormous impacts. So I think when we are talking about resource adequacy we are really trying to talk about something different from crashing the grid, because those are really sort of different situations.

I don't think there are a lot of economic trade-offs around all of the practices that we should follow in order to minimize the likelihood of those large-scale blackouts. I don't think there are a lot of interesting tradeoffs there. When you talk about resource adequacy, then, you are talking about getting in situations where on a really hot day you are like one or two percent short and you are going to have to activate all your interruptible load and all your emergency generation, maybe appeal to the public, and ultimately you might have to have rotating blackouts that affect one or two percent.

So I think part of your question was, "Well, how do you decide what is the right level of resource adequacy reliability?" Ideally, when you have those rotating blackouts, they affect a fraction of your customers. Ideally, you would impose it on those customers that it has the least impact on. And even better, you would compensate them in some way. In which case you'd ask, "Who is that?" It is your residential customers, so you would use their Value of Lost Load. That would be the best approach. If you thought you could always get away with only curtailing low value residential customers, then that would the right number to use and that would imply the appropriate level of common reliability that you ask about.

Speaker 3: Yes, I think that is right. The one in ten standard doesn't really distinguish between different customers and different value of lost load, anyway. But if you do ask that question, and you say, "well the lowest Value of Lost Load is $1500 per megawatt hour," we can at least agree on that, and everybody can buy themselves more by either doing interruptible loads that isn't that costly or back up generation. You can do that kind of economic reliability modeling at the different values of lost load and get different optimal reserve margins. And then in a regulatory setting, you could figure out what is the acceptable level.

I don't think that is happening very often, but it is being done in some jurisdictions. And then the question is, are you planning for a five thousand dollar per megawatt hour value of lost load or a two thousand dollars per megawatt hour value of lost load? And many of the industrial customers are self-providing a high level of reliability with backup systems and all kinds of expensive equipment. So I think we are already moving there. But I do think the one in ten is still a hindrance in that process, and the reality is that we don't know if it is a good standard or not, because we are not really exploring the economics in most of the jurisdictions. So that is one piece.

The other comment that Speaker 2 made about the resource adequacy being the issue that was economically interesting, I don't think that is quite right, because even before distribution we have to figure out how much of an investment do we want to make in the distribution system for storm hardening or for tree trimming? How much transmission are we going to build to improve the grid reliability? There are economic questions everywhere. That doesn't mean that the transmission grid is necessarily planned today with the economic trade off consideration in mind, but the reality is, even in transmission planning, economic questions pop up much more often, and many lines are being added today, not for reliability threshold purposes, but for economic reasons that also have a reliability benefit.

Speaker 4: If I may add a comment, that is a tremendously stimulating question. When we wrote the rules in New Zealand we had a very intellectually interesting debate about when and if we should have *force majeure* in contracts, and just what that meant, and how that transferred risk around the market place, and were we sure that we were going to get risk essentially located with the people who were best able to manage it. And so we had an outside consultant look, and we found that the U.S. had the most liberal use of the *force majeure* concept in the world and it was a big debate in the market. And I think what you are really trying to do is A) have people reveal their preferences, B) avoid the free rider problem (I'll say it is worth a lot but I'll rely on him to pay for it), and then C) to get the incentives aligned to the people who can beset manage the risk that comes out there. As an end use customer, I really have no ability to affect transmission decisions. Yet I pay for them and it seems to me that in some sort of perfect market world, I want the person who is paying to make that trade off as to whether they should invest or not, and so on and so forth. And I don't think we are at that point or anywhere near it yet in terms of the contracting or the regulatory regime that is around it. So you start with some real-time pricing. You start to look at some more meaningful contracts, and so on. But it is a really, really fundamental question, and I think that we have to look at.

Speaker 1: I would add certainly within one of the regional organizations with which I work we do hear from stakeholders like large commercial and industrial customers, wholesale, merchant plants, and so on. And that is what I meant when I referenced a transparent and diverse stakeholder process. That is important to me as a regulator to get a better understanding. I know that I will never be able to comprehend the modeling and the formulas. But it is very important to understand how our decisions will impact end users.

Question (cont.): How do you hear from the residential customer? I often refer to this as the hair dresser conundrum because of the discussion I had with my hair dresser. Who says, "Yes, I want good reliability," until I say, "Well, don't you have that thing that lets you cycle out your air conditioner?" "Oh yeah, it is great, I get five dollars off a month and I never know the difference." So customers, even if they don't understand it, are making those economic choices. How do you hear from those people?

Speaker 1: In Arkansas, our Attorney General represents residential rate payers—Consumer Utilities Rate Advocacy Division is very engaged. To their credit, in recent years they have been attending to some of the regional efforts. I think it is probably quite painful for them on top of the rate cases that they have to work on, and we have implemented energy efficiency programs, and now there is very laborious work on this issue of transmission. In certain venues, we don't always hear from the residential consumer and that is unfortunate. I say that as the former legal services attorney and a former consumer attorney. The decisions that we reach are only as good as the input that we receive, and so it is really very unfortunate, and it concerns me that we don't have more of a residential voice in the process.

Speaker 2: You will hear from that hair dresser when her air conditioner goes off for six hours on some hot afternoon. [LAUGHTER]

Question, cont.: No, because I have done such a good job explaining it to her in advance.

Moderator: I think Speaker 2 made the point that it is a tough political environment to have this discussion, because how do you have a discussion about less reliability? Because even though it may make sense from an economic standpoint, the minute the lights go out and some consumer is upset the political entity is going to be breathing down somebody's back because they have to respond to that person. Rationality will leave the room once you enter politics and an outage. So it is hard to have this conversation about lowering reliability somewhere based on cost factor.

Question, cont.: For what it was worth, if I said, "Gee, what if I said we could make it once every twenty years instead of once every ten if we made your electricity about 20 percent more expensive?" The answer would be, "no, no, no, I don't want to do that."

Moderator: That will be fine until it goes out, and then somebody who wasn't a part of that conversation will –-

Speaker 4: That exact thing happened in New Zealand when the central business district was blacked out due to overheated lines. The line got cooked, and the immediate response was that this is never going to happen again, and Mercury Energy said, "Absolutely, we are with you 100 percent." And when they started putting the cost down, it was like, "Well, maybe we have to rethink this in terms of what it was going to cost to actually put in the new lines and prevent that from happening again."

It would be interesting as you are eating dinner or something, if you would write down all the risks in the industry you know--weather, dead squirrels, bird droppings, whatever they are, and then line them up like a line diagram. Who owns those risks? Just see how far you get. One of the things I always ask the RTOs is, what risks does an RTO actually own? What are you responsible for, and if something goes wrong you stand up and answer questions like, did you have the right process in place? Did you have the right auditing processes in place, and so on and so forth?

Comment: I think one of the problems is that RTOs are not accountable to the states in a legal manner. They have to listen. They are not accountable to the states. Yet they have the responsibility for resource adequacy, and I think there is a disconnect. In the old days, the utility was accountable for everything to the states and to some extent to wholesale customers.

Question: I would like to ask a question about another disconnect here which I think is coming and is consistent with some things that have just been said here. The first news conference after the 2003 black out that NERC held Mike Gent got up, who was the head of the organization at the time, and with complete clarity he said that this was not supposed to happen. Not that it was a probabilistic event, and sometimes you have to live with it, you know, so on and so. No, he said that this was not supposed to happen and they were going to figure out what happened. And it turns out there was human failure, and things didn't work the way you thought they were working, and all that kind of story. But this does point out that we actually have very stringent rules for how we operate the system in the short run. Contingency constraints, and all of the other kinds of things that are in there, for which we are not even asking whether or not we want to evaluate them.

And what I actually in the end care about is actual disconnects and actual blackouts, not planning disconnects and planning blackouts. So I am much more interested in having a very flexible real system and having real contingency constraints and having real operating reserves, and not the planning, so that we actually don't have to have the big problem. In the past, because we didn't have much flexibility, particularly on the demand side (the vertical demand curves story), we essentially thought of this as having a lead-time of ten years. Because that is what we had to do to get the equipment in place, so that if we had no flexibility in the short run we would still have excess capacity around, so we would be able to deal with it. And that forced us into the planning tools that we now use for this reliability analysis. Those analyses are extremely different then the analysis we do in the short run--like over the next five minutes, the next fifteen minutes, the next hour. We have an enormously greater amount of information in the short run about the configuration of the grid, and what plants are available, and what we can actually do, and all this stuff.

When we take this problem out ten years and we ask what it is going to look like then, it is really complicated. As a matter of fact, it is so complicated that it is impossible.

So what has actually happened in practice? What we have done is develop a whole bunch of rules of thumb and ad hoc approximations and things like making sure we have enough transmission capacity for one day in 25 years (which we don't talk about very much but that is what the rule is in PJM for moving into zones), and making sure we have enough resource adequacy within the zones so it is one day in ten years. There is all this kind of stuff that goes on and on. And there is no connection between this long-term planning and the short-term operating conditions and standards and so forth.

Now if I were given the task at PJM of doing the long-term planning, I don't have a better way to do it. So I am not saying they are using the wrong methodology and they don't know what they are doing. It is really hard. And if you tried to write the full-blown problem, it is impossible. It is beyond our computational abilities, so you have to make up these rules of thumb.

But the disconnect I see here is that as the system gets more flexible in the way that we are all talking about here, it is going to become more and more an interesting question as to what is the disconnect between these two things? Because it is not true that we have a ten year lead time now, we have a much shorter lead time, which is turning units on, and tougher contingency constraints, and more operating reserves. And when it starts to get to be serious money, like if you had a capacity market and the prices are really high, and you are paying a lot of money… Isn't this going to cause a breakdown in here if you really lift up that rock and look at the assumptions that are in these planning models, then you ask, where did this come from? And the answer is someone made them up. You know. [LAUGHTER] Aren't we moving towards a real confrontation between the real reality that I am worried about, which is what actually happens, and this long-term planning, which is such an artificial kind of thing, and we have a lot more choices and availability, and isn't that going to cause a reform in the process some way?

Speaker 4: It is already there. I mean, in one way it is called underfunding in the FTR (financial transmission rights) world. There is already a complete disconnect in terms of the models that are used, the language that is used, the characterization of the transmission system, the characterization of the load forecast, everything else. They might as well be on two completely separate pathways.

Speaker 3: Oh it is not that bad. [LAUGHTER] These models all talk to each other somehow. [LAUGHTER]

Of course you bring up a very good point. But I actually think the disconnect is not so much between the operational world of running the system minute by minute and the models that are used there and the resource adequacy model. But

I think you put your finger on the button, which is we don't really know exactly where the one in 25 or the one in 10 comes from and what it does. And maybe what it does today is different from what it did 40 years ago when this was first implemented. And it wasn't any current analyst who came up with this, it is probably his grandfather or something like that. But Speaker 2 has been on a multi-year effort to raise these questions, and I think these are good questions. And I do think we have the tools to shed at least some light on these questions and what these economic tradeoffs are. But the reality is nobody wants to touch that, because who knows what we might find.

Speaker 2: We have simplified the resource adequacy problem down to a uni-dimensional thing--do you have the megawatts? And that works well with a capacity market which defines a sort of homogeneous capacity product. I think part of what you are raising is that when you are trying to run a real-time system, it has to do with the intermittent resources and reactive power and there are just so many dimensions. None of that is particularly planned. I guess if an RTO sees a problem in those areas they will raise it, but the typical resource adequacy problem deals only with this sort of one dimension, and the reality is getting more complicated all the time. When people were thinking up capacity markets about eight and ten years ago, at that time nobody was really thinking about building anything but gas fired generation, and everyone was thinking in terms of merchant generation, so it really seemed like a very simple problem. But now the kinds of resources we are bringing on--I can't even imagine what is inside that box dealing with the seconds and minutes and all that. And I agree it is very, very far from the resource adequacy picture.

Speaker 1: And I also commiserate. I feel like sometimes I am in the twilight zone. With one of our regional efforts it seems like whenever we meet there is a new model and like 50 new acronyms, and what does it all mean? And what will it ultimately accomplish? Your point is very well taken. I don't know if we have the courage to take the hard step to look at the rules and make sure that they are truly accomplishing what we hope they will accomplish.

Speaker 4: How do the real time activities inform the planning process? The way you talked about it was that we do the long term and then more forward into real time. What about backwards? Every Monday the real-time people could sit around and go, "Man, you guys were really bad, because I looked at that thing you came up with two years ago for what was going to happen yesterday, and it wasn't even close." So as far as I am aware there is no loop necessarily imposed in there that the real time feeds back into the planning process. I am sure it does, but in terms of an RTO process I am unaware of how the real time-activities actually come back and condition transmission planning efforts.

Question: I think that ERCOT is going to provide a very interesting case study for this. Today ERCOT issued their reserve margin report, and they forecast that our reserve margin will drop below four percent by 2015. And we don't have any requirements when we drop below our reserve margin. We don't have a load contracting requirement. We've become very efficient in our dispatch and continue to become more efficient. We already have significant transmission construction, RPS, load response, and distributed generation. How would you suggest that we foster resource adequacy by 2015, which is when we are reported by ERCOT's estimation (by our own estimation it is going to be much sooner) to drop below four percent?

Speaker 2: I was reading the NERC long-term resource assessment, and they showed ERCOT having reduced their estimated planning reserve margin by 15 percent between 2010 and 2011, so I am kind of curious as to what is behind that.

I see that right now that they are considering a list of enhancements to their short-term markets. They are not considering a longer-term capacity market or anything like that. They are taking the approach that we need to improve the price signals that we are creating in our close-to-real-time markets, and that is the way we are going to attract additional resources and demand response. My understanding is that that is the approach. In one way ERCOT has an adequate reserve margin right now. They are probably one of the only places in the country that doesn't have a considerable amount of excess capacity.

So I'll be interested to see where they go from here with it.

Speaker 4: What were the price assumptions? When you say, "four percent reserve margin," I immediately say, "At what price?" Because I would expect the prices to go up.

Question, cont.: Part of the calculation is interruptible load, but in this calculation it isn't characterized in the four percent…So we have an offer cap of three thousand dollars, which is essentially a defacto price cap as well.

Speaker 4: And retail rates right now in Texas are somewhere in the 10 cent range…

Question, cont.: They are, so whoever said we should pay an extra cent per kilowatt hour today, that would be a ten percent increase right on the top of our –-

Speaker 4: Two years ago I was paying fourteen and a half cents in Texas. So I would assume that your retail rates, with nothing else happening, you are going to be looking at sixteen 59 eighteen cents, and we would expect then, if Eric Shubert was right years ago, that we in fact get a reduction in load, so that four percent doesn't get to –-

Question, cont.: Well it is very interesting. I don't know if we are going to be able to shed enough load voluntarily by then. Do we think we can take that to the bank and say, "Well we expect prices to go higher, we maybe could build generation." You know I think this is going to be very interesting.

Speaker 4: And the other question that needs to be asked is, are the people going to let the prices go there? From a political standpoint, are we going to say, "Look, there was evidence out there, there was four percent, things were getting tight, prices went up, retail rates went up, and that is what you get"? Or are we going to say, "No, no, we have got to do something"? And then that whole thing that you just worried about happens.

Speaker 3: It is interesting, though, because Alberta has an energy-only market, too, and we looked at this very closely last year and it actually works, and there is no missing money problem, and there is capacity being built just based on energy prices. And so it can be financed. Maybe not at 80 percent debt, but maybe at 30 percent debt with companies that have the balance sheet to do so. But the reality is that it works, and I would say that after fixing some of the price signals in Texas, you will see investments, too. It has worked so far. The only question is whether you have the nerves to see if it works. And most people don't have the nerves, and that is why we have resource adequacy requirements.

Comment: Over the last year, whenever I have been approached by various generators, I keep asking, "Show me the capacity market that works, that pays for new generation to actually locate." And they can't. And then I say, "Well, here is my capacity market: I'll pay for new generation by reverse Dutch auction." And they look at me and say, "You mean we don't get paid?" And the answer is: not for being here. And this actually goes back to the connection between reliability and economic--it is true that under the current design (which is in the process of being changed) reliability and operational deployments by ERCOT have had the effect of depressing the price signals, and we are reversing that.

And in terms of the nerves, the answer is yes, because most energy in Texas is sold in bilateral contracts anyway. And so, generally speaking, unless you are on a variable rate, at least for residential, you won't see any immediate change. And for the large industrial consumers, a lot of them, this really goes to tomorrow, and I think to a certain extent they already are paying real-time in many cases. A number of the very large industrials will form captive REPs (retail electricity providers), and they buy their electricity in the day ahead market. They are a price taker. And what we saw this summer and what we continue to see even as we expand demand response is that you also see a lot of passive load response that happens.

And so, I'm not trying to sound Pollyannaish, but I am also hearing from developers who have got projects in the works, and they like the way the forwards are moving, and they are looking at the same numbers and are deciding, "You know, I think I want to be first in in order to capture that."

Speaker 3: Fitch has stated in one of its reports that despite all the challenges, ERCOT is one of the most generation investment friendly or attractive markets in the U.S., which is somewhat surprising given that it is an energy-only market, and nobody gets a capacity payment. But it is amazing what prices can do if you get them right.

Moderator: I think you have a little higher tolerance for risk in Texas than in the average state in the country, and that may benefit you.

Speaker 1: In Texas they go big or go home right? [LAUGHTER]

Speaker 4: But for people who aren't familiar with Texas, the Public Utility Commission down there I think as somebody who has lived in Ohio has done a great job in terms of the ability to choose and putting the information out there. It is very easy to switch. It is very easy to see what the terms are and the prices, and you know that when macro economics are picking up and gas is getting tight, you know your rates are going to go up, and as a consumer I think you do see elasticity in this market in terms of people actually responding. I know in talking to people in my area that there has been a lot of demand response in terms of just managing to the contract once they have signed it.

Question: I just wanted to respond to the question a few minutes ago about the transmission planning process and resource adequacy. The ISO New England has identified gaps in the process and actually performed a pilot study to identify more closely what those gaps are and is just beginning a strategic initiative to really address those gaps.

On slide nine, Speaker 3, you talked about how some utilities and state commissions--Georgia, Florida, and Alabama, I guess--have really taken steps to consider the costs and the economic benefits of the target reserve margins. How is that going, and can we look internationally? Are there any other international examples that we can look at to learn anything that might help guide us?

Speaker 3: We can look at what some of those states have been doing. The utilities usually sponsor the studies of what the reserve margin should be or whether it should be revised based on the economics within their Integrated Resource Plans. And this is all assumptions-driven, and I am sure there are plenty of fights over what the right assumptions are. But in the end, state commissions pick a level that they feel comfortable with based on the analysis presented.

Internationally, I think it works very differently. Much of Europe doesn't even have the idea of planning reserves or resource adequacy; they just have operating reserve standards. But it is very hard to gauge that, because a lot of is dominated by planning by incumbent utilities, and you don't really know how they make their investment decisions about how much capacity should be added. So I don't know that there is something obvious to look at internationally. But the reality is, we do have tools to analyze these questions. And I wrote a paper that this chart is based on. This kind of analysis is being done, and it can be done, and the case study that we have in this example that I have projected here is a generalized version of what was actually presented in a state proceeding.

Question: My question sort of goes to Speaker 3 and Speaker 4. I have struggled in Illinois I have got a real-time pricing program with very low uptake. It is basically just a pass-through of PJMs prices, which is basically just the energy price. Because the capacity costs, the reliability pricing model (RPM) costs, are basically covered over all hours of the year. Because we don't have a single clearing price that reflects capacity and system conditions, I think everyone acknowledges that we don't have a sufficient on-peak/off-peak differential to basically get to the world that Speaker 4 is describing of new technologies etc. I know all of the environmentalists—for example, Speaker 1 from this morning was talking about real-time pricing…In terms of our electric vehicle roll out, they are all asking for it. But we already have it. But it is just not sufficient. What is missing is the single clearing price that reflects actual system conditions locationally, that we are not getting from the market.

My question is, given the structure, and acknowledging that the three year forward market is basically flattening energy prices, how do we get there? How do we get to this point at which the price that we have provides sufficient accurate information to justify investment in new technologies that may be lower cost? Obviously, ten years ago, when the capacity markets were started, we weren't there. But now it is becoming more difficult for us to present a product that has the value that we need and can actually have a market effect. There seems to me to be a missing money problem here. For example, if I administratively put this price together, and I had all of my flat rate customers switched over to RTP, and they decided to curtail during the peak, then the obligation for the RPM is missing. So who pays that dip, and how do we get from the three year forward to an energy-only market that is the world that Speaker 4 is talking about, where technology can come into play and we can have more real-time interaction?

Speaker 3: I think there are two distinct issues. One is just the fact that the energy price is just a small portion of customer bills. So the first think you need to do is get the T&D costs allocated to the right periods, so they don't pay a flat rate on all the fixed costs. Capacity is a fixed cost, too, so you have to allocate the capacity costs, just like transmission or distribution costs, to the periods that contribute to the need. The second problem that you mention is the three year lag. If you do something now, under many of the rules you don't get the benefits until three years later when this is first reflected in the new forwards. There, PJM has been trying to integrate RTP into the forward construct right now so you get the benefit immediately, and I think this will help.

Speaker 4: Did I hear you just you wanted variable transmission costs?

Speaker 3: No, I am saying, don't charge it all out on a KWH basis. If you build a distribution system for the peak, charge it more on peak …

Speaker 4: So, some variance in the rates. I think that is a great idea. You want people to see the effect of their decisions at various times of the day and year and everything else. So you need to get people to understand that my actions here caused these prices. In gas, it is called the MDQ the Maximum Daily Quantity. In a sense, we over-build the transmission system to handle that, so the people need to see that that one hour that they used energy cost them more in transmission. And PJM can calculate that price *sans* the capacity component. It would be an artificial price, in a sense, but it would be a representation of the real system price, which what you are looking for. So you can calculate that number. You can charge the transmission on a different basis in terms of when it is peak. Then in terms of the people who aren't on the RTP and who actually respond and reduce their load, they aren't the ones causing the need for the capacity right? So, the people who don't respond who aren't on RTP are the ones that should be paying for the capacity. So they should see the cost of their decision not to be variable in their behavior. So I think the variable transmission and distribution is great. I think you need a real price from PJM, one that is not just a simple add-on or on top of whatever the LMP is, because that won't reflect the variance that occurs. PJM should be able to calculate that. And then I think you need to pass the missing money, as you say it, on to the people who actually caused the need for the capacity.

Speaker 2: Adding transmission distribution capacity, putting all that in the price, is peanuts, is pennies, if you have a lot of excess capacity and your variable costs are low. When you have less excess capacity, so the prices actually rise, the variable costs rise, and then the shortage pricing that PJM has proposed kicks in--that is when you are going to get prices that are really going to stimulate price-responsive demand and that sort of thing.

Question: I just want to close with a story that is flip side of the fear of going to the state capital. I had breakfast two days ago with the First Chairman of ANEEL, which is the Brazilian FERC. And he reminded me that his second day in office the city of Rio de Janero was blacked out entirely. And a congressman went on television and demanded, "What do we need a regulator for if he doesn't get out of the capital, go to Rio with his tool kit and fix the problem?" [LAUGHTER]

Moderator: That reminds me of my reliability story. For those of you that don't know, about 25 years ago I was in the restaurant business. My first year of owning the restaurant we opened in the spring, had a great spring, summer, fall, past the holiday season. And then that first winter hit. And we didn't know whether we would really survive the winter after January sales dropped off. Then we had the best ice storm that ever could have happened in that town, because literally it was a 100 year ice storm. You know the co-op communities all share crews. Well they brought all these crews in and they needed somebody to feed them. So they had an open tab at my restaurant and bar for a month. There was about 30 guys. You can imagine how much they were eating every day. [LAUGHTER]

So that is my personal reliability story. It saved my business through that first tough year.

Session Three.

Real Time Pricing: Is It Necessary to Get Retail Price Signals Right?

A recent HEPG raised the issue of whether it was time to get Real(time) on retail prices. The session covered the problems, political and otherwise, associated with mandating real time prices, as well as discussing experiences from various pilot programs. The logical next step is to drill down to see precisely what is required in order to provide retail consumers meaningful, actionable, price signals, from both economic and institutional perspectives. Purists (and economic logicians) would contend that nothing short of prices that fully reflect the real time costs of production and delivery of electricity are required. While such a pricing scheme may not be achievable, or worth the effort, it would be possible to charge customers based on real-time production costs. Many contend that there are other forms of dynamic pricing, such as critical peak pricing or time of use, which will provide signals that can produce substantially the same benefits with less controversy. The question is how much, in terms of efficiency in pricing, is lost by accepting less than real time prices? How diluted are the price signals from pricing methodologies other than real time? How do customers react to different forms of dynamic pricing? On the institutional front, there is the issue of who should offer the prices: the RTO through demand side response programs, the utilities on either a voluntary or mandatory basis, or, in retail competition states, the energy suppliers of ESCO's? In competitive retail markets, should the default product be real time? How is customer response affected, if at all, by who offers the dynamic pricing signals? Can RTOs and state PUC programs be successfully coordinated or do concurrent programs at both levels run serious risks of undermining each other? From an efficiency point of view, does it matter whether it is the RTO or the state PUC that operates and oversees these programs?

Moderator: This is really a continuation of a dialogue that began in Nashville on real time pricing, and the topic is real time pricing, is it necessary to get retail price signals right.

Speaker 1.

I think one of the big issues that we're facing, thinking about dynamic retail rates from a wholesale market perspective, is how do we actually translate that into actions that the operators see in the control room and actions that we can see in the marketplace, so that we don't over or under dispatch the system? And so really we can't do any of this unless we have, the right price signals at the wholesale level, and in some ways transmitting that down to the retail level, but not necessarily having that as part of the retail rate design.

So what are dynamic retail rates? There's often a great deal of confusion. All dynamic retail rates are rates that change the retail charge--or it could be a retail rebate, if you wish--in response to changes in system conditions or prices at the wholesale level. And so essentially what we're trying to do is we're thinking about linking what's happening in the wholesale market with the rate that's being charged. It could be actual wholesale prices that trigger the dynamic rate. It could be expected prices, as is the case with Southern Company's program, where they look at day ahead prices and then they trigger dynamic rates for their large commercial and industrial customers.

But one of the important things here about dynamic retail rates is that in general, the price levels that will be triggered at the retail level will be known in advance. But I think one of the things that came out in yesterday's discussion was, technology and are we there yet? I think if we had this discussion 20 years ago, even 10 years ago, I don't think we could have this kind of discussion, because IT had not caught up with the concepts or the ideas. But I think now we're in a position where information technology, smart grid technology, however, you wish to define it, automated metering infrastructure, two-way communication, actually enables us to try to harmonize retail rates with wholesale rates and wholesale market conditions.

So if we just think about different dynamic rates on a continuum, obviously the ultimate dynamic rate is really real time LMP, and then you get down to things like critical peak pricing, or a peak time rebate-type rate. And I make the distinction here. Oftentimes I hear in the dialogue that time of use rates are dynamic rates, and they really aren't dynamic rates. Time of use rates, as they're implemented, are invariant. Everybody knows that during certain hours the retail rate will be 10 cents, in other hours it'll be 20 cents, etc., and that doesn't vary with wholesale system conditions. It's that way every day of the year, 24/7/365. And so that's not a dynamic rate, because the prices aren't changing in response to wholesale market conditions per se, and so I think it's an important distinction that we need to make here.

Now if we think about the enabling technology to allow this to happen, this chart is an example of AMI deployment or expected AMI deployment across the PJM footprint going out to 2022, so going out more than 10 years. Right now we're just in the early stages of AMI and smart grid deployment, but that's going to ramp up very quickly. And so the question is, understanding that this is going to ramp up, understanding that a lot of the states in the PJM region have proceedings before them if they haven't already acted, to install smart grid technology and automated metering infrastructure, we're trying to get ahead of the game in thinking about how this is all going to work. Because one of the big issues that's come in front of us in the stakeholder process from some of the commissioners in our footprint is that, "I have this proceeding before me. I need to understand how this is going to benefit the customers in my state. What can PJM do to help to at least put the institutional infrastructure in place so that regardless of how I come up with my dynamic retail rates, my customers are going to be able to benefit from this?" And so in some sense, we've had to start thinking about this question even long before AMI is being deployed, so that in a way, at least for the commissioners that are pushing this in some of the states, they have something to hang their hat on in this case.

So I won't get into too much detail. Obviously, real time LMP is the ultimate dynamic rate. There are different ways you could implement this. You could expose customers entirely to real time LMP--probably not politically a very palatable option. There could be a rate where customers actually purchase a block of energy at a fixed price, and then at the margin are facing the real time rate--something similar to what we see with Southern Company. Obviously, you have to come up with some sort of baseline consumption level for that. But again, real time LMP would be the ultimate dynamic rate, and if we think about getting consumers to respond to price, this may be where we go many years down the road.

And you can see here how a real time rate, just as an example, would compare to say a flat rate or say a time of use rate. So again, if we were exposing customers to these prices, we might be able to get a lot in if they had the enabling technology and they had the ability to program their appliances and the technology so that certain appliances would go off at certain prices, other appliances would shut down at even higher prices. We're not talking about actually curtailing the full usage here. Again, the metering technology and AMI technology is out there now, so we don't have to curtail whole houses when we reach a certain price. There are different ways in which we can curtail consumption, whether it's your washing machine, your dishwasher, air conditioning unit, water heater, pool pump, etc. And you can program those to go off at different prices.

Now, of course, the usual suspect in terms of dynamic rates that we're more used to seeing, is critical peak pricing or peak time rebates. The essence of these types of dynamic rates is that they're going to be triggered by certain set of system conditions, at least traditionally at the retail level. Not necessarily wholesale prices, although that would be the ideal. Under critical peak pricing and peak time rebate rates, customers know, when that rate is called, how much power is going to cost. So, for example, if a customer is on a flat rate--let's say that's 15 cents a kilowatt hour normally, but the peak time or the critical peak rate is say a dollar a kilowatt hour--they know that it's going to be a dollar a kilowatt hour, but they don't know when that rate's going to be triggered, and that's what makes it dynamic.

The same is also true for the peak time rebate. It's just the mirror image of the critical peak pricing rate, but with a twist. With a peak time rebate, obviously, you're going to save money, you're actually going to get a check back from the load serving entity or the distribution company for reducing your consumption during that critical peak time in the form of a rebate. But the extra twist here is that now we have to put ourselves in the position of almost treating that energy as if it were a supply resource, so that we actually have to come up with a baseline consumption level by which to measure reductions to pay it through the rebate.

So from a demand side perspective, with the critical peak pricing rate, there isn't a rebate. The customer just saves money knowing that they're not going to consume as much energy during that time. This gets rid of the baseline problem and puts demand back on the demand side. I would say that the peak time rebate rate, in contrast, while it looks like the mirror image, actually starts treating demand response as if it were a supply resource, with all of the attendant problems that have been discussed at length in front of FERC.

Now graphically, what would this look like? A critical peak rate might look something like this, where, you could be on a time of use rate or a flat rate, it doesn't matter which. And then at the critical peak time (here it's between hour 14 and hour 17), the critical peak rate is triggered, and voila, you're facing a price of about $1.25 or $1.30 a kilowatt hour. With the critical peak rebate or peak time rebate--again just the mirror image, when that critical peak time is called, you're getting a rebate, again, measured against a baseline consumption level for that energy.

Now if we think about what is happening within the PJM region, what are we seeing? Now that we're starting to see AMI deployed in places like the District of Columbia, Illinois, Delaware, Ohio, some in Virginia, some pilots going on, we can see that there are different tariffs that are deployed, but for most of those tariffs you see, you'll notice the lack of real time LMP, except for Illinois, where we know that ComEd has a real time LMP rate. For everything else, we're talking about critical peak pricing or a peak time rebate rate. But then we get down into the other rates, time of use rates. Again, time of use rates really aren't dynamic rates in the sense that I've defined them here, because we know what the prices are at each hour of every day regardless of the system conditions. But you can see that there's some more experimentation that's going on at the retail level within the states in the PJM footprint that can enable some of this interaction now between retail rates and wholesale prices and wholesale market actions and operator actions.

And, of course, the punch line in here is that if we're thinking about dynamic retail rates, and we're thinking about trying to translate this to the wholesale market, really what is it that we need? What is the common currency, the lingua franca if you wish in order to make this happen? And it's LMP. LMP can tell us everything we need to know here. We can translate this dynamic retail rate into price responsive demand, and I won't say anything further because I don't want to get into ex parte type issues, but we can translate that into price responsive demand that we at the wholesale level at PJM or any other RTO for that matter can actually see a demand schedule by price and quantity and we can dispatch to that schedule, as long as we understand and we know from the load serving entities or the distribution companies how they're relating wholesale prices to when they trigger that dynamic retail rate--regardless of what the price level is under that retail rate. There must be some sort of LMP level that they're going to trigger that. This means that we don't know in which hours it's going to be triggered. Customers don't know exactly how long it's going to be triggered, but they know that there's a wholesale LMP rate out there at which that dynamic price is going to be triggered.

And so if we're looking at the dynamic retail rate, there's that LMP level that then translates into a schedule that is submitted into the PJM energy market so that the operators know that when LMP hits a certain level, demand is not just taken as given. They know. They can say to themselves, "Oh, I see this demand schedule here. I see that actually demand is going to be reduced. That CT that I might need, I'm not going to have to dispatch it now because I know at that price, demand is going to come off the system." Not only does this obviously increase market efficiency, but it gets rid of one of the vexing problems that I think all RTOs face, which is that sometimes you dispatch resources because you're trying to be safe, you're trying to maintain reliability. Sometimes it turns out you might not have needed that resource and then you have to make it up through uplift charges. But if we have this information, we don't have to worry about uplift charges, not nearly as much, or at least in theory we shouldn't have to worry about it nearly as much. As this price response to wholesale rates being translated down into the dynamic retail rate becomes better understood and well known by the load serving entities that are putting this out there, we're going to get more and more efficient in the energy market dispatch.

Now, there are some dynamic retail rates that don't work for this translation, and that are those dynamic rates where you have preset hours with notifications that are, you know, unrelated to wholesale market conditions or real time LMP. So, for example, right now, for a lot of the peak time rebate rates, the critical peak pricing rates, there is a prespecified set of hours that that rate applies to--let's say from 2:00 p.m. to 6:00 p.m. or 2:00 p.m. to 7:00 p.m. So if it's called, you know it's going to last for the entire five hours. And there's also oftentimes a limit on when that peak time or when that critical peak rebate's going to be called or critical peak price is going to be called. It could be 10 times a year, it could be 15 times a year, 20 times a year. Whatever the retail regulatory authority has decided, you know, there's that limit. Again, that's not dynamic. What happens if we're in a summer like we had here in Texas this last summer, where we've got high prices all the time? I would want to call that rate far more often, but if I'm limited, then it's no longer dynamic. It no longer serves the purpose for which it was intended.

So let's just think about how this might work. Let's just think about triggering a critical peak price, let's say when the LMP is greater than $500 a megawatt hour. So if the LMP is below $500 a megawatt hour, in the most simple example, we're going to face whatever the rate is, whether it's the flat rate or the time of use rate, take your pick. But once LMP exceeds $500, then all of a sudden we trigger the critical peak rate and the critical peak rate will be there so long as the wholesale price remains at above $500. If it's for one hour, the critical peak price stays in place for only an hour. If it's for six hours, it stays in place for six hours. And then again with the translation back down to how we're going to dispatch this at the wholesale level. The same is true with the peak time rebate.

There's one other thing, though, that's actually very important and that's come up recently in the application or the calling of demand response, at least within PJM, that really draws our attention to the need to have the locational price signals. We can't really just use a zonal LMP. We need to get down to the buss level, and why is that? In certain situations like we've had in the Washington D.C. area, where I have a certain voltage problem and I need demand response on the right side of that constraint, if I call demand response in an entire zone, I may actually end up making the problem that I'm trying to solve worse. And so we actually need to have that location-specific price signal.

Another example would be in the Alleghany zone or, you know, the FE Alleghany zone now after the merger in PJM. If you're on the western side of Beddington-Black Oak or AP South, you're going to face a very different set of prices at the nodal level than you would be on the eastern side, on the downstream side of that congested interface. And so what we would want to do is call any price responsive demand that's on the eastern side. So you could be in the same zone, but prices could be different. Not everybody in the zone is going to be called for the critical peak rate. It's going to depend on your location, and this is more than just theoretical. We do have even more than a proof in concept. PJM has actually put out a pilot for its own employees, where we've employed AMI technology. I've got some in my house, and we programmed our appliances to respond to the nodal price at the buss that is geographically closest to us, or the set of busses that are geographically closest to us, and we send those signals. Now for some of the employees that are on that pilot program, there have been days where they're not called. I live closer in toward Philadelphia. I live in Valley Forge, as opposed to out further west. I get called, and some of my colleagues don't get called. Again, based on the price, because the prices are different at each of the busses, and so we can get that kind of granularity we believe in trying to make this translation from retail rates to wholesale rates if we can actually use a reasonable approximation of the buss LMPs that each of those customers are facing. So that's really important.

From an administrative standpoint, though, while that piece of it at the wholesale level sounds complicated, it actually we believe makes things easier from a retail rate design perspective, because the retail rate authority doesn't have to think about designing different dynamic rates for different parts of the system. They could design the same critical peak rate for everybody in the system, understanding that people in some parts of the distribution company system may get called more often, some get called less often. It only takes one retail rate to get the kind of response that we need in terms of price and also in terms of location in this case. So we believe that, you know, it's going to be administratively easier.

Moreover, from a wholesale perspective, one of the things that makes me nervous about giving any presentation like this is that I'm getting into the issue of what retail rate design is. That's not our bailiwick. It's not a place where we belong. We shouldn't be there. And so one of the things that's important about using LMP as the universal translator is that it gives complete freedom to the retail rate authority to design the dynamic retail rate that it believes is best for its customers and that is, you know, quite frankly more politically palatable than real time LMP, if that's the case in the short term. And so there may be some jurisdictions that decide the critical peak rate may only be 50 cents a kilowatt hour. Others may decide it's $2 a kilowatt hour. Others may decide they want to do a peak time rebate instead. All of those can work, so the flexibility to the retail rate authority to come up with the retail rate structure that it believes best suits that area is still preserved, so long as we're linking it somehow just through LMP to when it's triggered in that wholesale market context. So, you know, this is not a situation where the RTO is trying to step into the retail rate design game. We don't belong there, and quite frankly I don't want that kind of responsibility. That's a tough job for y'all.

In conclusion, just to think about how this all fits together, if we're thinking about this concept of how we're going to link retail rates and wholesale rates and wholesale market actions, we're really talking about understanding what is the locational marginal price at which we trigger the dynamic rate. That translates to usage, we can get a schedule to PJM, to the operators, translates into the feedback to the impact on LMP, to the extent there is impacts on LMP. But this is something that is more than just a theoretical curiosity. The technology allows us to actually do this now. We've arrived at that point, and again with the pilot that we've done, with the PJM employees (and by the way it's just because we're curious. We have no financial incentive here. It doesn't change our rates. I still have to pay the same bill to PECO every month whether, you know, my appliances were shut off or not) but it does work. And we've been able to do this with some fairly straightforward and simple GIS technology to map busses to residences.

Question: Your last statement about how you still pay the same bill to PECO--if your appliances are off, doesn't that change your bill?

Speaker 1: Oh, certainly if I'm using less, it changes my bill, but what I mean is that I'm under the same rate structure. This is not something that we actually went to the various distribution companies to say, "Change our rate structure." We're just doing it because it's interesting.

Question: A question about LMP. Do you only key on the energy price, or any of the other ancillary prices for scarcity or anything like that?

Speaker 1: Right now it's just on LMP, and to the extent that we could get an order on shortage pricing or scarcity pricing to implement that. That'll all end up being translated into LMP anyway.

Question: I had a question back on the slide where you were showing the states and the pricing structures they had in place. It's a very simple question. What do the numbers mean within the box?

Speaker 1: It's the number of programs.

Question: You had on one of your slides, as an example, when the LMP is greater than $500, then it triggers this critical peak. I know in the California ISO we have times when during the ramp, you know, 10 minutes before, 10 minutes after, we'll get some price spikes. In the PJM program, is there sort of a minimum run time, for the critical peak? Like, once you call it, it has to run for an hour, or so many intervals, or can you have a critical peak that's just for, you know, five or 10 minutes?

Speaker 1: What we've done in our pilot with our employees, is it could trigger for only five, 10, 15 minutes. So we actually are keying to the real time LMP, and you know, with the issue with ramp, that's a very interesting one. Do we really want to be calling people to turn off certain appliances when we hit that ramping period? I mean if we're getting that price, and we have a critical ramp, actually having those customers coming off the system temporarily until we can get some of these other resources up actually helps us in system operation with the ramp, as opposed to keeping them on and creating more stress.

Question: As far as the utilities in your service territory, have they pushed back at all as far as the ability to sort of locationally dispatch customers, so that certain customers are being triggered where others are not? In California, we've talked about real time pricing and that has been something that a couple of the utility folks I've talked to say, that under a retail rate as opposed to a program, everybody has to be treated the same. So if I trigger my critical pricing in some part of my service territory, I have to curtail everybody or expose everybody to that price. I can't just expose some customers to that price, versus under a program I can do that. So I'm wondering if, when you've talked about doing this through rates, if you've had any of that kind of feedback or push back?

Speaker 1: To date we haven't had any push back with respect to triggering the critical peak rates differently for customers in the same service territory, but I think the view that we had (and again this is ultimately going to be decided by the retail regulatory authorities) is that everybody's facing the same rate design. So in that sense they're being treated in a nondiscriminatory fashion, and it's just based on system needs as to who's going to be called for the critical peak rate. And again, what we're doing now with our limited demand response, where we've had to call on resources to solve problems in very localized areas, we're actually calling on resources not by zone, but we're actually going down to the zip code right now. Because, again, we don't want to call the wrong set of resources to actually make the problem worse. So there's already some precedent for that, but I think the ultimate answer's probably going to lie on a state by state basis on how they have to implement that. And to date we haven't had that kind of feedback, and to the extent that some of the commissioners that are in the room that are in the PJM footprint could give us that feedback, I'd be thrilled with that knowledge.

Question: That's a very good question in terms of clarifying what you meant by "dispatch." On the one hand, you said the dispatcher would know a kind of an improved forecast if you will, because they know the elasticity of the demand curve, and so on, but are you actually implying that they would actually be part of the dispatch and have to put in real time offers, or is it more an enhanced knowledge about the demand curve?

Speaker 1: What we have in mind is really enhanced knowledge about the demand curve, so that when we dispatch supply resources, we don't dispatch that CT. We're not actually sending a dispatch signal out to them. Again, we send the wholesale price and it's the Retail Rate Authority that sets the price at which that critical peak rate is going to be triggered. And the LSE then operationalizes that by providing us a schedule that we use so that gives us that better forecast. Sorry for the confusion on that.

Speaker 2.

So the title was about real time pricing, which is the code word for Hogan to say really good things about real time pricing and agree with him, and of course, we all want to have these great meals and stuff, so [LAUGHTER] I'll be a good supplicant. But it is a full-time job trying to get efficient pricing, and you feel a lot of time like Mitt Romney does--that you're playing whack-a-mole, and every time you knock down one competitor, you get another, and so this is kind of what we're doing in trying to hold RTP up. You constantly have to withstand somebody else's three letter or four letter or five letter acronym. You're playing whack-a-rate constantly trying to keep RTP at the top of the heap—and people come up with all kinds of other pricing methods. There's VPP. There's VIPP, there's HIP…we can go on here. There's a flat rate, a buy-back rate, and then the all-time favorite, the optimal binding mandatory curtailment rate. So we're playing whack-a-mole all the time, and every time you think you've discredited or shown that a certain rate doesn't work, somebody's got another one and suddenly it's being touted as doing everything.

Part of the problem with making sense of this is that there's no sound basis for comparison. People will just put a list up and say, "Well, with my rate, I reduce load by 38%." Then next year a new pilot with 47 customers did 42%. Well, read the bottom line. They're telling me the percentage reduction, but the price is now $2 or $2.50 a kilowatt hour. The question you ask is, why are you paying this much, can you justify it?

So I'm going to try to offer you a way to think about these rates in that context. If you think about how we run the system, we plan the system years out. Months ahead we do operational planning, about which plants can be in or must be in. The day ahead we do scheduling, which sets a set of LMPs. 90 minutes ahead, what we call real time, we do a second set of LMPs, essentially to reschedule generation. As you get closer, you're down into ancillary services, which can be 30 minutes or 10 minutes or five minutes or four to six seconds (it varies).

So where do we fit in customers in this regime? Well, there's a whole set of, let's call them directed demand response--you can have DR as capacity, meaning you can bid in the capacity market and PJM and New England and New York--vertically integrated utilities call it an interruptible rate--it's the same thing. You are relieved of some or all of your capacity charge. In return you agree to curtail load when and if you're ever asked. And we can also have bidding programs, kilowatt hour bidding into the ISO programs. There are emergency programs, and the ISOs and utilities have always done that. And you can have direct load control like what Speaker 1 just discussed. In fact, his is pretty crude. He's got his appliances. They now make software programs so that your toothbrush and your dryer and your mixer can negotiate as to who gets to run for the next seven seconds because we're streaming prices from PJM [LAUGHTER]. I'm sure this goes well with PJM, but I'm not sure I want PJM running my life that closely.

Speaker 1: Big Brother's watching.

Speaker 2: Big Brother's more than watching.

But there's another way to do it, and let's call this price-based demand response. Essentially, let's take price signals and give them to people and let them decide. It's kind of a novel idea in a market-based economy that people are smart enough to make their own choices about when to use and how to use it, and that we would be smart enough to give them the right price. But taking that leap of faith that we could do this, then you have a whole array of things you could do, and what I'm going to do is talk about that space.

So what I'm going to propose as a way to evaluate this is welfare economics. But I will use no mathematics. I'll use only pictures--but don't try this at home, because this is very tricky stuff. And we purposely as economists keep it very mysterious, because if you understood what it was, you wouldn't need us [LAUGHTER]. But the constants are relatively simple, and graphically you can get a feeling for it.

So I'm going to set up a criterion, and then I'm going to compare three or four rates and see how well they do. And, of course, RTP is always going to be best. The question is, how bad is second best or third best or fourth best?

So on this graph we have a vertical demand. Everybody knows this. It's written on the back of your wrist. Market supply does this at times, demand shifts out or supply shifts back, either way, so that you've got a much higher LMP. When people have a flat price, they don't know that LMP is high, so the market clears at a high price--set off the bells and alarms. Suddenly, bad things are happening, or at least we think bad things are happening, because we've got a mismatch on the market. People are spending money based on one price, matching their value to that price, when in fact the price is a lot higher. So we have resource allocation problems.

OK, so let's fix this. Well, so what if the demand curve was downward sloping, or at least part of it was downward sloping? Well, then what happens is that people see that high price, and they adjust their demand down, so now the LMP went down, the quantity demanded went down, and the market's back in equilibrium, but the LMP has dropped from where it would have been way up there to something lower.

So we've got to interpret this in terms of dollars, and welfare economics does that. Welfare economics says the area above the price but below the demand curve is consumer surplus. That's the missing money, folks, for those who worry about it. Producer surplus is the area above the supply curve but under the price. Now when consumers respond to a high price, some of what used to be producer surplus under the old LMP becomes consumer surplus. Well, "boohoo" on one side or "Yay" on the other, depending on the way you look at it, but from an economist's point of view, this is a wash. We treat this as transfers, because we're not able to say it's good or bad.

So where's the gain? We can't count the consumers' lower bills or the consumer surplus as a gain. The gain is what I call a "welfare wash." When the price goes up, people use less electricity. We rematch the value of electricity with the price of electricity. We save scarce resources. So instead of providing people with electricity at a false lower price, by seeing the higher price and adjusting, they use less electricity. That makes more resources for valuable things like wine and iPods [LAUGHTER].

Because everything is done on price and quantity, you can measure all this. So if we can characterize the supply curve and characterize the demand curve and demand elasticity, we can actually start measuring that welfare triangle, and we can also measure the other triangles. But here's a little problem. This is really nice so far, and this works if people are just given the prices and respond, but if you're an ISO and you're allowing customers to bid into the day-ahead market and you're paying them market price, then we're missing something. We've got some missing money. That's the missing money because we have to pay those people who curtailed because they acted as a resource. Essentially, the result is the net welfare is the difference between the green and the red. Now here they look to be approximately the same. When prices are really high, it takes a small amount of load responding to reduce prices. The welfare triangle is big, that little payment thing here is small. It all works well.

What happens when I'm way down here on the other part of the supply curve…I won't do the whole thing…essentially, this is what happens. The dead weight loss is still there. There's always a dead weight loss. There's always a gain to customers reducing in society, but now I am paying them. Look at the difference of those two triangles. What's the issue on 745, the FERC issue, is that the criteria that's being used to decide when customers should bid or not is not a welfare criteria, it's some other criteria. And as a result, it'll allow people to bid at very low prices. The reason why the ISOs that started this had these high threshold prices was this very reason. They did these sort of calculations and said, "If I let customers bid at prices below 100 or 125, I'm going to have net welfare losses." That's where those came from. We've now reinterpreted it by some other thing, and at the risk of getting people bidding at very low prices which seems to be good. It creates benefits to them, but not to society.

Let's compare three rates and see what happens. So I've got a proposed three-part TOU (time of use) rate, with an off peak, a shoulder peak, and a non-peak. I've got a CPP (critical peak price) rate, where we keep the background TOU rate, but with no established peak prices, only off peak and shoulder prices, and then real high prices dropped in under certain conditions. And, third, let's look at a hybrid rate, VPP (variable peak pricing). Now VPP is a TOU rate, so it has an on peak and off peak. The off peak rate is set ahead of time, so you know what it is for certain. The on peak price for these four hours is the average day-ahead LMP. So I don't get a whole new price schedule every day. All I get is a new price schedule for these four hours. Why those four hours? This was done for PJM. 95% of the density of LMP can be captured by only using those four hours. (This was true three or four years ago.) So why bother with five or six hours? The longer you make that period, the harder it is for people. So the argument for VPP is that it's almost like RTP, or could be, without the hassle of worrying about prices in every hour. I know what my price is except for these four hours, and I get that for certainty a day ahead at the average LMP price. It's hooked to the LMP, just not every hour.

So let's see how well these guys do. Let's do a welfare analysis. This chart is for customers over 300 KW in New England. It's not all customers. Only those who were price elastic over a .05 ever got in the screen. So two-thirds of the customers are lost right away. So we we estimated the LMP for ISO New England every day, and then we had the demand curve for every day. We looked at an extreme year and a high year and the status quo year. These are participant savings--bill savings for the different rates and different years. If you want to look at it this way, this is what people gained by being on this rate, acting in the way that we have modeled them to act, which is being price elastic.

You'll notice, of course, that the extreme year the benefits are higher than in the status quo year, but what's always true is that the good old three-part time of use rate wasn't doing very well here, in terms of cash savings to the customers responding to it. But notice how relatively close even CPP, VPP, and RTP are. They're all producing within 75% or 80% of one another, and they're all significantly higher than TOU.

This next chart shows the average coincident monthly peak reductions. They're higher under CPP, because CPP is being dispatched in this model for the purposes of trying to reduce peak demand, so you reduce your capacity requirement and capacity savings. That's the way we saw this CPP as being used. So essentially, yes, it does a lot better, but that's because it's dispatched specifically to try to reduce the coincident peak. But you also get a non-coincident peak reduction by CPP, because the problem with the CPP is it's trying to guess when the peak is. So as we go through the summer, we don't know whether tomorrow is going to be one of the peak hour for that month or not. So CPP has some inefficiencies built into it, and so consequently we end up whacking the mole when we don't want to. We end up having some unintended but unavoidable consequences, because you have to forecast the CPP.

This chart shows all consumers electricity bill savings--the biggest gains go to those people who respond, but there are secondary effects. If you change the day ahead real time LMPs, that lowers the price volatility in the real time LMPs, so the 5% of people who buy their LSEs buy there. But it also has a hedging effect, so we calculate what we think the implications of lower price volatility is on the hedge price, and then associate it with other customers. So everybody else is gaining something and again you notice that the performance of VPP and RTP is pretty equal, although if you look at the VPP and RTP, it's starting to show a difference. Especially in extreme years, there are more benefits to other customers, meaning everybody else gains by having some people who respond. Good citizenship pays.

But here's the problem. This chart shows the net welfare resource savings. The CPP loses in this comparison. The problem with the CPP is there's not a perfect coincidence between high LMPs and the peak summer month. In fact, it's less than .5, so consequently the CPP is out there pushing people back, telling them to reduce load. You're way down on the supply curve. A lot of the CPP days, the prices were only $50 a megawatt hour, not $500. It generates those net negative welfare effects.

What do we do with all this? We took this, and threw out CPP. With the other three, we designed a rate for Connecticut Light and Power. The entire model was done to then apply to Connecticut Light and Power, using the Connecticut zone supply and their customers over 350 KW. It was going to be a default rate in the market. We only did three things. We did three-part TOU, VPP and RTP so you can see the comparison. The VPP's doing fine. The proposal was three-part RTP. We proposed VPP, because nobody would buy RTP.

But essentially in this chart you can see how close they are in terms of participant savings, and again what happens in other years and extreme years is that they're still pretty close. RTP starts to win more and more as you have more extreme prices, because that's what it was built for, right? It's the king of the welfare game. VPP, because it's restricted to those four hours, in extreme years, there are more high prices outside the four hours. The VPP can't catch it. The RTP always catches everything, including the middle of the night presumptively.

This last chart shows the VPP implemented resource savings. So this is the welfare savings and notice how close VPP and RTP are, and again the differences get bigger as you move away from average years, but in status quo years the VPP does on a welfare basis about 90 to 95% of what RTP can. And even out there on the extreme year, it's doing about 80% on a welfare basis.

So what's the conclusion? The conclusion is that there is a second best, that we may not have to ride our high horse forever on RTP. Now I realize in saying this, I'll be expelled from this group, and that's too bad because I enjoy you, but anticipating this is going to happen, I ate and drank a lot last night, kind of a last supper thing. So it's OK [LAUGHTER]. I'm happy delivering this message. The answer is that we're doing this too simply. I'm not trying to create work for economists, but it's too simple to compare the average reduction by rates that do drastically different things, that are intended to do drastically different things, and there has to be some sort of consistent background. So CPP may work well in some circumstances and it may not in others, but we need to up the ante instead of arguing about who created what rate today or what's best, is flesh it out and do it at a more sophisticated level and start thinking about these things, because those surprises happen as you saw in the CPP.

Question: I'm just curious if you could maybe differentiate what you are using as CPP in your presentation versus how Speaker 1 was defining it? Are they the same thing? Because your VPP looked a little bit like how Speaker 1 was talking about CPP.

Speaker 2: No, with the VPP, every day, you get a new price schedule. Under CPP, it's a certain number of days, right?

They could be the same nominal price if you wish, but the LMP is always going up and down. So with VPP, every day you get a new set of peak prices based on what the LMP is.

Question: I had a question related to Order 745, where in essence we're paying demand to get off the grid. And I wanted to ask your opinion in regards to the red triangle showing deadweight loss in your net welfare chart--whether in your opinion that's going to get much larger with the proliferation of PV solar, for example. So there are subsidies for solar, but now there's an added subsidy because, you know, they can go behind the meter and get payment just like demand response.

Speaker 1: Yes, that's part of the problem of good intentions of letting people bid into a wholesale market as you create artificial payment streams that may encourage people to do things that are adverse to maximizing resource value instead of encouraging it. So anything you do on the customer side is good, no matter what you do is good because of welfare economics--it's just going to move it all out. It's when you start paying people that we worry about the net effects. And if they lower the the bid floor in the ISOs to $40 or $50 a megawatt, why you open up all sorts of opportunities to perhaps adopt technology that's not cost effective except by the circumstances we created. And that's, that was the whole point of this and why originally the floors were a lot higher. The floor was intended to make sure, on net, on average, that there was a positive net welfare.

Question: This is a two-part question. One is, could you state again what you meant by saying that for the VPP, the five hours or four hours captures 95% of the RTP, and what does that mean precisely? And the second part is how did you deal with negative prices in these simulations?

Speaker 2: I never get a negative price in the simulation because it's a statistical representation, so it's not a dispatch, so the supply curve can't go negative.

Question: But in reality there are.

Speaker 2: In reality there are, which means that customers will get paid to use, which creates another interesting --

Question: Right, they're pretty extreme cases, I mean in terms of stresses on the system so --

Speaker 2: Yes, and remember because of the approximation methods I'm having to use to pull this off, I've got to have an equation that's differential and all that, so we lose some of that detail. It's not a production cost, it's a statistical representation, as I said.

What we did is we took the density of prices. So we did a distribution curve of price densities from the low $25 a megawatt hour to whatever it was--$1200. Essentially, we took the hour in the middle of the day that had the highest average price, and kept adding hours until maybe 90, maybe 95% of all LMPs were included, and that happened at about four or five hours. Going outside of them --

Question: 95% of the averages for the hour, not 95% of the LMPs?

Speaker 2: Well, no, it effectively turns out 95% of LMPs above $100 are all stuffed in those four hours. To get the rest, you have to go out to eight to 12 hours, or 16 hours arguably. You can have a midnight price sometimes, or a two o'clock in the morning price that's above the $100 threshold. So essentially trying to make a compromise between RTP, which lets every hour be in, and something that's a little more convenient to customers. So it's a compromise. By the way, that's how we've always done TOU prices in rates departments, right? We're basically taking some look at where the distribution of variable costs are and making a decision on how many hours should be in the TOU rate.

Question: Was the RTP a day ahead RTP?

Speaker 2: Yes.

Question: And can you explain a little bit more about why the CPP's days were not necessarily coinciding with the high price days. Wouldn't you call a CPP event when you expected prices to be high?

Speaker 2: No, because the CPP they were interested in was to reduce capacity payments to the ISO, by reducing their capacity obligation. So we designed it specifically to try to capture the peak hour in each of the four summer months, and hence that converts into a lower capacity requirement next year. That's usually what CPP does well is to chase capacity, peak demand. So consequently, it's chasing a different metric than the prices are because they don't coincide. Speaker 1 talked about a different kind of CPP, which would be almost like what we're doing with this VPP thing, is you're just embodying the LMPs inside it, not trying to make some alternative decision about what's going on in the market, in which case they would be the same or almost the same.

Speaker 3.

I want to talk about two basic issues and some false conclusions. First, I want to talk a bit about a particular program that I've worked with that provides one data point on how responsive one particular type of consumers is to real time pricing, and we'll show some information on that, and we'll do some of these welfare calibrations that Speaker 2 was talking about. And secondly, I want to kind of calibrate in one setting this question of whether real time pricing is risky for consumers in the sense of really increasing the volatility in the bills that they'll see. And after I provide these two data points, I'll talk briefly about some policy implications.

So first I want to talk about this question of whether consumers are responsive to real time pricing, the basic issue, of course, being that if consumers aren't very responsive to real time pricing, there aren't going to be very big welfare gains from implementing that relative to time of use or flat rate or other pricing structures.

So the one data point that I'll provide is from the ComEd Energy Smart Pricing Plan, and this was run as a randomized trial in the summer of 2003 in Chicago. And some of you may know a fair bit about this program. This is an example of the day ahead pricing structure that Speaker 2 was talking about. The price in this program is a kind of fixed distribution charge, plus they take the day ahead price from I think it was PJM West. And in addition, on top of this, they would call people on days when the LMP was going to be over $100 a megawatt hour, and there were nine such high price alert days during the summer, and so you expect to see more responsiveness when people are actively made aware of prices.

Now there are lots of different experiments like this, and it's important to do lots of different experiments because different customers are going to differ, of course. So in this experiment, these are going to be residential customers. This is going to be a short run experiment. It was announced early in 2003 and we have data for that summer. So there's not going to be any evidence here about the kind of advanced technologies that Speaker 1 and Speaker 2 talked about that could really increase elasticities over a long period of time. Furthermore, there was relatively small price variation in the summer of 2003. On the flip side, this is kind of a self-selected group, so they may be more price elastic compared to even other customers in the same area. So I think some of these considerations suggest that this might actually be a lower bound on the long run elasticities than you would expect to see for other kinds of customers.

This slide just shows you what you end up seeing in the data. This graph shows demand response under the program by hour of the day, going from hour zero to hour 23. The left-hand side of the graph and the red dots show the average prices that were observed in the experiment on summer days, and obviously the prices are higher in the middle of the afternoon. And the price is in cents per kilowatt hour. And then the nice thing about this experiment is that because there was a randomized treatment and control group, you have a very, very clear sense of how much the guys in real time pricing are conserving. The control group were customers that were on the normal, flat rate price, and people were randomized into the treatment group.

So what you see is that the treatment group is conserving it looks like about 50 watts on average, on the average summer day of this experiment. Now this is compared to an average baseline usage of just short of a kilowatt. So they're conserving about 5% on an average day. And basically what's happening here, of course, is that consumers are seeing on these summer days that prices are higher and what's likely going on is that they're using their air conditioners less. So the price elasticity here, when you kind of just output a reduced form price to elasticity ration, it's about -0.1. And one of the things to emphasize is really the importance of running randomized experiments and providing credible estimates of this elasticity.

Now on the high priced days--the nine days when consumers get the phone call saying that prices are especially high--you see very large incremental conservation.

So a couple of important takeaways. I did Speaker 2's welfare calculation, because I took the same classes that he did, and I can tell you that the average bill savings for these guys being in real time pricing compared to the flat rate is $13 per household per year. That's 2.7% of the energy charges on their electricity bills. The compensating variation or the consumer surplus part of Speaker 2's graph is about $10 per household per year. So in other words, if we're increasingly in a world where we have minute by minute meters on people's houses, and we start to implement real time pricing, this is the sort of gain that we can expect to see, if households respond in the same way. So that's a free $10 per year per household for households like this, and while that's a small amount of money per household, it really starts to add up when we're talking about 100 million households in the United States.

Another really important takeaway that both Paul and Bernie emphasized was the importance of information provision. On these high price alert days you see massively increased elasticities.

The other thing that they did in this experiment that was pretty fun was they gave people energy orbs, and these things change color depending on what the prices are. And just giving people that device looks like it roughly doubles people's price elasticity, even though it's very clunky, very old school at this point, especially compared to what we might see, you know, in Speaker 1's futuristic world. But rolling that out, you know, broadly is going to be in the future. When we get to that, we're going to see a lot more than just what we saw with the energy orb. So I think that's going to make a big difference.

That kind of bleeds into another point I want to make on this, which is that I think that often when we're doing these calculations, we're really focused, implicitly or explicitly, on the short run welfare gains. So in other words, given the current capital stock, we're asking how we expect consumers and markets to respond, and what does that mean for the kind of welfare gain triangles that we calculate. Now, some people have said that in the long run, we're all dead, and that's certainly true. But Speaker 1 made this nice point that rolling out real time pricing and smart meters over a much broader set of consumers on the residential side is going to take a long time to implement, and it's going to take a long time to pay off. So what we should really be interested in is not the elasticities that I just showed you, which are what you get after the first summer, but what we would expect to see as technology advances over the next 10 to 20 years. And as we give people the right price signals, they start to demand more advanced technologies like Speaker 1 has in his house, and that's going to substantially increase elasticity. So that's on the demand side. On the supply side what this means for understanding welfare effects is that we don't just want to know the existing short run supply curve or the existing dispatch curve, but we actually want to know a lot more about what plants are going to enter or not enter over the next 10, 20, 30 years as demand responsiveness changes. And that's the way that we should really start to care about doing welfare calculations.

Severin Borenstein has a paper that does this, and I have a paper, "The Smart Grid, Entry, and Imperfect Competition in Electricity Markets," which talks about strategies for understanding how to calculate these long run welfare gains, which are really going to take the form of reduced entry of new power plants.

The second issue I wanted to bring up is the question of whether real time pricing is risky for consumers. And so the basic argument that you sometimes hear is that real time pricing is going increase bill volatility for consumers, and that might make it not very politically palatable for people. And what I want to do is understand how large this effect is. So I'm going to take market level data from PJM, the market level average LMPs and aggregate load data, and I'm just going to do this on NERC Peak days. And I'm going to compare two different price structures. I'm going to compare real time pricing based on those average LMPs, and I'm going to compare that to an hourly TOU structure that gives people in every hour that quarterly load-weighted average price, so this hourly TOU structure still gives a little bit of the price signal, but the idea is that it may be easier to understand and certainly results in less bill volatility for consumers.

Many of you can probably already see where this is going to go. I'm going to be illustrating what statistic folks call the "law of large numbers"--and by the way, because I'm illustrating a basic statistical principle, what I'm going to show you is going to be fairly general. You can take your own data from your own market or different years in PJM, and you can do these calibrations differently, and they'd look a little bit different, but the general point is going to be the same.

First of all, what I've done in this graph is I've taken the TOU prices and the real time prices that you would see and I've graphed them by hour of the day on the X axis. The red dots are the average TOU prices that you would see. These are the load weighted average prices over the period that I'm looking at in PJM. And then for each hour there's a dot above the red dot and a dot below the red dot, and these are the 90th and 10th percentiles of the distribution of real time prices for that hour. OK? And you can see that these distributions are pretty broad, and this is actually a pretty mellow set of years in PJM. And so if you did this in other years, those 90th percentiles would, I think, even be a bit higher.

There are two basic takeaways that you have from this first graph. One is that the time of use price really is very attenuated in terms of how it reflects the real price in the market. So even with something that is hour by hour average prices--this time of use structure that I propose--there's a lot of variation in real time prices that you might want to pass along to consumers. However, this depends on how responsive consumers are at the hourly level, and I want to make a distinction between two different kinds of elasticities. And think about how you yourself would respond to real time pricing versus TOU pricing. Imagine me telling that you're going to have real time pricing. One response is, "I know prices are typically going to be higher in the afternoon so I'm going to use my air conditioner less or I'm going to buy an Energy Star air conditioner." The other type of elasticity that you could have is, "I'm going to get up every morning and I'm going to check what the real time price is, and I'm going to use that to kind of reoptimize every day." And it's really important that we gather some more data on what those different elasticities actually are for consumers. The way to do that would be to randomize consumers into either this TOU structure or the real time pricing structure that actually gives people that daily variability on top of the TOU. And notice, by the way, that in Speaker 2's calibration this is a real issue, and in lots of calibrations like this. So we'll assume a particular elasticity, 0.05, 0.1, etc., and we'll say how does the real time price compare to the TOU price under that elasticity? But if you're elasticity as a consumer is, "I'm going to buy an Energy Star air conditioner," you have no incremental elasticity to real time pricing compared to TOU. If on the other hand, you're in Speaker 1's world, where you've got automated hookups of your appliances to the real time price, then you're going to have elasticity to that real time price. So really getting a magnitude on these differences between the two elasticities is very important.

The second issue from this graph is that you can see that at the hourly level, real time pricing is extremely risky for consumers. Put yourself in a world where you're a consumer who can't be bothered--so a residential consumer, and you guys are busy people. So you're in a world where you can't be bothered to look at the real time price and you're not going to be very responsive, but you might be worried that your bills are going to go up and down in ways that are kind of annoying or unforeseeable. If you got a bill at every hour and looked at that, you can see that the volatility is quite high. Some hours you're going to get kind of massive bills (although you're only counting in cents, really, as a household per hour) but some hours you're going to get very high prices and some hours you're going to get very low prices. So it's risky at the hourly level, and this graph just illustrates that.

So what I've done is for this graph and for the next two is taken a ratio of the real time price to the TOU price and made a histogram of ratios at the hourly level. And what this graph says, for example, is that if you look at the far right, there are a substantial number of hours where the real time price is more than three times the TOU price. So this is risky at the hourly level. Now what I want to do is add this up at the daily level and, of course, some days are hotter than others, but even within those hot days, the hours might start to cancel out. They cancel out a little bit, but you could see if you got a daily bill and you were worried about daily bill volatility, there's still going to be some days where you pay twice as much or more than you would under time of use pricing. However, customers get their bills often at the monthly level. So this is now a histogram of the ratios of the bills that you would get for real time pricing versus TOU pricing if you were an average consumer in PJM. And you can see that in many months there are going to be some days or hours with high prices but those end up being kind of canceled out by days or hours with lower prices. And it actually is very rare that you would get a bill for a given month that's more than 15% more than the TOU price that you would have or less than 85% of the TOU's price that you would have.

You can do this calibration in different markets in different periods, but the basic insight that I'm trying to get across is that once you aggregate to the monthly or even to the annual level, this riskiness in real time pricing really I think is not as high as some people are proposing.

To conclude, many utilities, as you all know much better than I do, are installing residential smart meters for reasons other than real time pricing. Once these are installed, there are substantial aggregate efficiency gains possible for moving customers to real time pricing, and Speaker 2 has calibrated this, and I've calibrated this in my presentation, also. These may be small gains per household, but we're talking about billions of dollars across the country. That's even stronger for bigger customers, and in a material sense, the law of large numbers says that this is not going to have a large increase in bill volatility.

Some closing policy implications. I think the nice thing about markets is that we can let firms offer different pricing structures, and we can let consumers decide what sort of pricing structure they want. So you can imagine a retail market where some firms are offering the flat rate price and some firms are offering the real time price, and customers can say, "I want to pay a little bit more but have a flat rate price." And that's their choice. It's not fully clear to me why regulators might have that much to say about how competitive suppliers would set prices, as long as the market's fairly competitive. However, when I go to seminars outside of the electricity arena, looking at things consumers choosing between insurance plans or individual retirement accounts and consumers choosing between different mutual funds or IRA options, one of the things that you see a lot of is that consumers often don't choose the cost minimizing option for themselves, and one of the things that really helps is when the regulator can mandate easy and understandable information provision about what the options are that are out there. So I'm going to propose that the role for the regulator when there's a competitive retail market is to let firms offer whatever they want in terms of pricing structures, but there's a very important role for making sure that information disclosure is out there and customers understand what the expected bills would be under the different structures and how the different pricing structures work.

On the regulatory side, there's no clear economic reason to avoid real time pricing, and I think one of the things that would be very useful is that if as regulators we decide that we don't want to have real time pricing for whatever reason, it's important to kind of present the sort of tradeoffs that Speaker 2 and I have put some numbers around today. So if we want to decide that we don't think that consumers can handle the volatility or complexity in these decisions, that's OK, but I think it's very useful to say, "This is the tradeoff we've made and this is going to cost you an extra billion dollars a year around the country in your electricity bills as a result of this." So just being very clear about what those tradeoffs are would be very useful in the decision-making process.

Speaker 4.

I think it was Mark Twain that said it's better to be thought of as a fool then to speak out and remove all doubt [LAUGHTER]. As I sit next to three PhDs who are obviously brilliant, I realize I'm not, and perhaps the definition of market failure is that there's a few hundred of them and probably a couple hundred million of me, [LAUGHTER] which is I think the challenge that faces us in this exact instance.

Technology is facilitating opportunities within electric markets. I'm impressed when I see developments in states like Texas, where literally hundreds of products are being marketed to consumers, and then you see a state like Michigan, which has kind of an awkward, hybrid, little bit in, mostly out restructuring. Very, very few products are being offered with very, very low levels of market participation.

And as the wholesale markets and to some extent retail markets continue to develop, the technology is going to help move us further towards opportunities like real time pricing or price responsive demand. It takes a little bit of work to get there, and again one of our challenges is that we need a measured approach, we need the technological acceptance of things such as advanced metering infrastructure--and I think certainly the regulators in the room can speak to some of the challenges we have there. We did a series of field hearings around the state this fall and in the ones that I conducted probably 90% of the people that attended these hearings were there to complain about the fact that somebody someday might want to put an advanced meter in their home and they didn't want it. And they had lots of really good reasons from information they'd gleaned off the internet [LAUGHTER] as to why they shouldn't have these devices in their homes and why it wasn't in their interest. So that's again one of the huge challenges that we have here.

The expectations for regulators in regulation is low average prices, economic growth, high levels of reliability, market efficiency… And I think that those expectations track very closely with the expectations of the customers. So as I listened to the presentations this morning, some of the things that I think about are that we have customers that truly like the certainty that regulation provides. In other words, they like protections from some of the price volatility. Now, we can make the economic argument that it's in their best interest [to have real time pricing], but just a perception of that one bad day can cause somebody to say, "Well, I'm not going to take the benefit of the other 364 days of the year where I might be saving, because I've got that one day that could really cause harm or raise a bill to a level that I would deem unacceptable." And we certainly saw that. For example, in Michigan we have natural gas choice that is not limited by a cap. With natural gas choice what I find customers sign up for is the certainty. Many, many customers will sign up for rates that are in fact higher than they could get from their regulated utility, but it's a price that's set for a year or two years, and they like that certainty of knowing that this is what they are going to pay. It doesn't matter what the market does—"If the market goes up, I'm protected but if the market's down, I may lose, but I like having have that certainty from a month to month standpoint as to what I'm going to be paying."

Another example certainly would be interruptible rates. You know, the customers that are able to get on interruptible rates love them, except when they're interrupted, and then all hell breaks loose and our phones ring off the hooks. You know, "How did you let this happen?" And we try to explain, "Well, you benefited for, you know, most of the year to have that interruptible rate." But in their defense, some of these customers don't have the ability, particularly if you're a manufacturing operation (Michigan, as you know, is a large manufacturing state) you don't have the ability to shut down your systems sometimes, and so we do have manufacturers who will be running with high penalties, because the risk of losing production, potentially losing customers, is much greater than the risk of paying a higher utility price.

One of the things that I think we need to examine as regulators is, what is the economic efficiency that's lost without having such things as real time pricing, and I don't know that we have done that kind of review. But certainly we would need to start with market segmentation, looking at the industrial load, looking at the commercial load, looking at our residential customers, and they're going to be different. There are going to be different outcomes depending on the ability of those customers to participate. I'm not so sure that there's a very high operational opportunity from a residential customer, whereas certainly an industrial customer is highly manageable, but also operational realities that may dictate accepting higher prices under certain circumstances.

What are the some of the things that as regulators we would want to look at or we would want to try to do, accepting the fact that we don't have one market, or purely market-based regulatory regimes around the country? We have to kind of experiment to see what works and what doesn't, so we need such things as pilot projects, trial periods for exposing customers to price signals, to see how they react. Whether or not programs would immediately move into a long-term commitment, I think that there's going to be some reluctance to some customers to signing up for a long-term commitment if they don't have that opportunity to participate on a trial basis.

One of the things we've talked about a little bit is using actual real time prices versus perhaps a day ahead market establishing those prices, giving customers a little bit greater level of certainty. And I think there might be a higher level of customer participation if in fact they have that opportunity to see, on a day ahead market what those prices might be, as opposed to being surprised with true real time prices.

I guess just to try wrap up a little bit, in my view I think real time pricing is in fact a natural or perhaps more accurately a logical progression of the development of the markets and to a very, very large degree, I believe that's facilitated by advancements in technology, which I think is going to change to a very large degree how the electric utility industry operates in the future. I got my first cell phone in 1990, and I could sometimes make a phone call on it if I was in the right place. It cost me an arm and a leg, and I actually didn't use the phone, because I was afraid I'd go over my 10 minutes a month, [LAUGHTER] and the penalties were going to be huge. Now we have to these amazing little computers that we carry around with us today that do things that back then I couldn't even imagine. I just wanted to make a phone call from my car.

But to get there as a regulator, to deal with the pressures that we're going to get from the political side, that we're going to get from customers, which are certainly going to drive the politics, we need to use a measured approach, to continue to develop the marketplace, to continue to take advantage of the RTOs, doing a better and better job of getting price signals out there, and then we need to work with our utilities to find ways of getting those price signals to the customers.

So I think education and marketing is one of the key things that we need to develop and get people to understand the opportunities, and we as regulators need to be on the forefront on the education side, and the market participants need to work on the marketing side. And as a regulator, I do believe one of our jobs is to move as far down the road to markets as we possibly can. And so we need to facilitate that in our regulatory structures. We need to be responsive and find ways to get out of the way and allow the markets to operate, while maintaining our responsibilities and expectations of providing some level of protection.

General Discussion.

Question: My question is probably mostly directed to Speaker 3. I agree with your conclusion about how real time pricing doesn't materially increase bill volatility when you're looking at a max price of $80, but I'm wondering, in a market that has a short supply of resources or a very tight supply of resources, with an offer cap of say $3,000, like we saw in Texas in August of this year--I think those are the things that probably concern regulators more than anything. What happens to your conclusion in a tight supply situation with a thousand or three thousand dollar offer cap in those sustained prices over maybe two weeks in a month?

Speaker 3: I'm very sympathetic to that question. That calculation that I did is very easy to do in other contexts, in other markets, and you're right that the comparative static is that in markets that have higher offer caps and more volatility, and in particular more volatility that's correlated across days and months, you're going to tend to see more volatility at the monthly level. So, I'm on board with that. I was more trying to calibrate a theoretical point, which is that, even if you see a lot of hourly volatility, once you look at that at the monthly bill level or the annual bill level, a lot of that cancels out. And how much a lot is will vary, I agree.

Question: I have a really simple two part question, and I'm going to pull it right from the description that we got for the session. And I'd like each of the panelists to answer it. From an efficiency point of view, does it matter whether it is the RTO or the state PUC that operates and oversees these programs? And who's better?

Speaker 4: I guess from my perspective I'd maybe go off of something that Speaker 1 said. I think the RTO needs to ensure that the proper price signals, for example LMP, are evident. But I personally think that the distribution company, the utility, should be where the actual administration of the program would take place. And the reason why I say that is because I think, as we saw, there are different forms, different variations, of rates that can be provided to customers depending on what they're looking for, so you might have a time of use rate or you might have critical peak pricing as opposed to real time pricing in its truest sense, which would be LMP versus a day ahead market. I think the fact that you could have different variations of that and different products requires that that be done by the distribution company as opposed to the RTO.

Speaker 1: To piggyback on Speaker 4's point, I think it's the RTO's responsibility to get accurate, real time LMPs out there. And regardless of whether we're talking about a competitive retail environment, where the competitive LSEs will come out with innovative rate designs for their customers, or a regulated paradigm, where the regulated utility will come up with that through a regulatory-approved tariff design, the common theme is that that has to be translated somehow to the customer response base as it relates to LMP. And so effectively, you have to have the two parts. The wholesale market is just operating and providing the LMP. You've got the other market participants, whether regulated or competitive, that have to provide us that information back on how they're going to respond to those prices.

Speaker 2: Yes it matters. It's always going to be more efficient if it's done at the retail level, because supply is not demand--they have different identities. We've just tried to mask that. And I think that it's about time that we accept that. That means regulators and utilities and all of us have to stop complaining about why customers don't do what we want, and show them the benefits that you've seen Speaker 3 and others are demonstrating. The benefits are there, we just haven't tried very hard to sell it, in my mind. That's our job now, to let the wholesale market set the prices. We'll pass them on in a variety of efficient ways, and go home happy and paid, or at least happy.

Speaker 3: That question in particular is not one that I've studied, so I don't have much to add to what the other panelists have said.

Question: Well, the good news is that you came up with the answer that I was hoping you would come up with. I will mention one other thing, though, and that's that when I've talked about volatility being bad or making customers unhappy, at least some of the stakeholders in New England say, "That's what we offer a product for, you shouldn't worry about volatility, we can offer that product."

Question: This is in the spirit of second best and trying to think about this in a slightly larger context, and it's related to the last comment. We often think that we have control over this, but we don't, if we have retail access, because somebody could offer critical peak pricing, or they could offer time of use rates, as long as they maintain revenue neutrality for themselves (in other words, not getting cross subsidies across different kinds of retailers who are at different tariffs) and so we could have all of these options, and there will have to be a default option, just because of the nature of the electricity system, so that if the couch potato doesn't say anything or doesn't do anything, they have to end up on something, and the question is what should that something be, and it seems to me that the necessary condition for going forward is to make sure, first, that you have real time pricing for all of the retailers. In other words, when they're purchasing to sell to their final customer, they have to get real time prices, because otherwise you can't maintain this revenue neutrality and all the other kinds of things--you get the cross-subsidy problem. And then, second, you have to design an acceptable default mechanism that's going to deal with a lot of the political context.

And that leads me to what I consider to be sort of a nice second-best package, which is New Jersey. New Jersey has this default mechanism which is a rolling flat rate, which is the Basic Generation Service (BGS) auction, which is an opt-out. If you don't want to do that, if you want to go to some other rate or retailer or so forth, you have to positively elect to do so, but if you don't elect to do so, then you're under that rate, which is handled through their auction. The suppliers who win the auction face the real time price, they internalize all the risks, all the other kinds of problems, and get the cost going, and it creates a virtuous incentive, which is for those customers for whom it's really beneficial to be on real time price, they have a very strong incentive to do so. They'll bleed off into the real time pricing option, and won't take the BGS option, and then that'll become more and more people for whom it's not worth the trouble. And so then you'd end up with some on the BGS auction and some mix on the other, and if you consider transaction costs and all the other kinds of things going on, why isn't that package pretty nice?

Speaker 2: Well, I think that we should realize a portfolio is correct. If a residential customer wants to buy electricity for his residence for 20 years there should be a price for them to do that. That's an efficient market. And if someone wants to take the streaming five minute prices and take the risk, they should. The question is, how do you get people interested in a portfolio, and demanding that competitive suppliers provide a portfolio? And I don't think either entry point on either end is going to do it. Forcing RTPs just means everybody will come in, and do a flat rate. There's nothing wrong with the New Jersey way of procurement, but it's still a flat rate with a premium, so I guess I've always thought--go somewhere in the middle. A TOU or this variable TOU thing is in the middle of the portfolio. Let the market establish that, then let people sell up or down, and the risk premium should start being revealed—customers should realize they're paying a premium.

Question: So you're proposing that the VPP could be the substitute for the BGS.

Speaker 2: No, no, no the BGS would procure, but to supply a VPP, and that's what Connecticut did --

Question: That's what I mean. So you'd have an auction to procure, for tranches and then the suppliers have to sell to customers under VPP.

Speaker 2: Right. Or be billed out if it's a default rate, but yes.

Speaker 1: But I think you bring up an interesting question here, and I think that in a game theoretic sense there are two very distinct equilibria. There's the equilibrium that you just described, where you eventually have everybody going to real time prices, because the first group that immediately knows it's going to benefit leaves, and then that cycle just leads to higher and higher default prices. That is certainly one equilibrium, but I think the other equilibrium, the one that we're really in right now, is the equilibrium where people are afraid of the black swan events. Or they're afraid of volatility, and there's this sort of bounded rationality that's keeping people from doing that investigation to say, "Wow, I am going to actually benefit from real time price or benefit from some sort of dynamic rate." And they just say, "It's just not worth my time." If I look at the numbers that Speaker 3 put out, ten dollar consumer surplus gain, $13 per household per year, and if I think about the transaction costs of my time to actually investigate what I want to do and go look for another supplier, I can see why people say, "Why bother?" And so I think that I'm in agreement with Speaker 2. I mean in an ideal world, and again I'm not trying to force retail rate design on any of the states within PJM here, but I think for a default rate you have some sort of price responsive rate like VPP, and at least from an operational standpoint, thinking about this as an RTO, as a system operator, I at least can now get some price response in this that helps me manage the system in real time operations with a little bit more rationality than I can today where everybody is on that flat rate when we're in that equilibrium that we're in today, which is one in which almost nobody could be going to the dynamic price or nobody going to the real time LMP.

Speaker 3: I think there's a very interesting issue around the default option and how aggressively we should kind of push people to move off the standard offer. And this is I think very deeply related to some research that's going on in other areas of economics. Actually one of the really important lines of research in the intersection between psychology and economics has been the default option in retirement portfolio choices. There was some research actually out of the Kennedy School about 10 years ago that showed that people very frequently would leave large amounts of money on the table in their choices of 401Ks. In other words, they would not actively make a choice to go into a new 401K election, and they would leave lots of money on the table by failing to fill out one form. And so as a result of that there was some legislation passed a few years ago that encouraged firms to help their workers make more active choices in ways that would help them save more money. So the basic insight that people don't want to make active decisions is, I think, a fairly general one, and it probably applies here.

So the idea that we're not seeing a lot of people switch off the standard offer into real time pricing, I think isn't really a huge statement on whether people will like or dislike real time pricing. It's much more of statement about how people are kind of averse to actually making a choice. Now the difference between 401Ks and real time pricing is the amount of money to be saved. And you know, if we're talking about $10 a year, it may or may not be worth actively making those choices. However I think again, this comes back to a question of information provision. In other markets like the choice between Medicare Part D plans, people often don't make the choice that's best for them, but when you give people something very easy, send them a one page piece of paper that says, "Here are the plans, here's your usage of drugs or electricity, here's what makes sense for you"—if you make this very simple for people, that actually has big impacts in terms of the amount of people that switch off into a new plan. So I think those sorts of insights are worth bringing to bear here.

Question: One of the things that I think will be important if we end up moving in this direction as quickly as some of your predict (and I think it's going to be a little bit slower because I know I'm not going to run out and buy new appliances that talk to my smart meter) is that if you are actually looking granularly at the system, I think we're going to have to have metrics on ISOs that enforce some discipline, so that in real time we're not depressing the price through leaning on the ties, the regulation, or SPSs (special protection systems), or tap positions on phase shifting tap changers. I mean, people need to be able to model and predict, and if in real time the ISOs are intervening to create price suppression, that reduces my incentive to take an action at that particular location. So, how do we enforce and track that kind of activity at the ISO?

Speaker 1: I'm going to push back pretty strongly here. Where is there price suppression coming into this?

What we're talking about is sending price signals out to demand and putting demand back on the demand side. In contrast to what Speaker 2was describing under Order 745, we're talking about here saying, "Demand, you make a choice. The price of power is this, you consume this…" I don't calculate a baseline, I don't do a settlement for them in this area. So we're letting customers actually choose how much they want to consume at various given prices. That sounds like how markets work as opposed to price suppression.

Question: Well, I think there's a lot of incentive for ISOs to actively intervene (and maybe that's not the right word) in real time through those activities which are not transparent to anybody that cannot do power flow modeling and understand what's going on. And so what I'm suggesting is that in real time we may see a different set of prices if the ISOs weren't actively doing that. And so there's an intersection there between the incentives for ISOs and retailers and if the ISO is basically hedging those costs for retailers and creating some cost shifting at different busses, it reduces the incentive for retailers to take some of those activities on.

Speaker 1: So, what you're suggesting is that RTOs in general today are taking actions that are outside of the market with the express purpose of hedging those prices?

Question: I don't think that's their express purpose. I think that's the result of their actions. There's no question that those out of market actions are occurring. Whether or not they're actively thinking that they're hedging somebody else's risk is a different question.

Speaker 1: I think the issue is that what having good price responsive demand does is it prevents us from actually dispatching a CT when it turns out we didn't need it. So to the extent that we're actually forecasting that demand in the short term, we dispatch a bunch of units, we didn't need those units and I now have uplift that I have to pay, and it may have other implications in terms of setting prices as well… I think price responsive demand and the ability to actually have that active participation on the demand side actually helps us get the prices right, as opposed to the situation that you may be talking about.

Question: I don't think there's any money ultimately in the commodity itself. It's a property of a commodity that it should have very little markup, very little profit, if you will. So, in the industry if we look and ask what the interest is from a commercial standpoint I think it's in risk management, because it is a risky, it is a volatile commodity in terms of its hour to hour deployment zone.

But I guess what I would be interested in is what we talked about here in the real time pricing. Real time pricing is like a virus, if you put it in, because to my way of thinking, where we make money in our retailing right now is in mark up. Essentially consumers, if I want to put on my Occupy Wall Street hat, consumers don't have the knowledge to properly evaluate the risk that the other people in the market do. So, in effect, we as consumers are paying more than we should be for that risk. And that's where the retailers make most of their money, is the mark up from wholesale to retail price.

If you go elsewhere in the world, if you go to New Zealand, Australia, you're going to see retail mark ups of 5-6%, which are less than half of what the retail margins are here in the United States. So, putting real time pricing in place, is going to directly impact the retail businesses. Which will in turn directly impact the structure of the industry, because in other countries, you can see relatively high concentration ratios, you have integrated Gen Co's and retail because the retail activity is best viewed as risk management and it is a hedge to really gas E&P and generation development. So, as the margins in retail have collapsed, Gen Co's go out and essentially match their load with the retail, and we get reintegration. We just spent 20 years trying to disintegrate the industry, and yet if we allow people to depress those margins, there's no money in the retail, Gen Co's take over, it becomes a hedge to their generation portfolio and the profit in the industry is based on the E&P and then it's just a question of risk management, and what you're going to see is, if other markets are an indicator, a lot of churn, but really no change in market share, relatively high four-firm, or eight-firm, or even two-firm concentration ratios, which would probably fail most of your Herfindahl tests. So, I'm just wondering whether or not you guys have thought through not just the one year or immediate effects of real time pricing, but what are the effects on the long term industry structure, and what are the impediments to that in terms of regulatory legislation?

Speaker 3: I guess I would draw a distinction between the markup and the pass through of the energy charges. So, for example, in the example of the Chicago program that I talked about, there was an equation for what the price was. And it was price equals constant distribution charge plus energy charge. And for the treatment group that energy charge was a real time price, and for the control group that energy charge was a flat rate tariff, so the energy charges come through at zero profits, at zero markup, and all the markup then happens through the distribution charge. So I guess what I'm not clear on is how real time pricing versus any other price structure kind of necessarily will impact the profitability.

Question: What if you incorporate the distribution charge in the retail, as we do in Texas? So, the retail guy, the only money he makes is basically on the energy component. And when we allow a customer to see the real time price, eventually they're going to say, "What's my markup that I'm paying for this price certainty?" and more and more people will start to get off of a flat rate from their retailer as they look and say, "Gee, that markup's pretty high," 40%, 16% 18% whatever it is. And, "I'll take that risk, I'll manage that risk myself," and so the retail business becomes less and less profitable if where they're making their profit is the markup over the wholesale price versus the retail price.

So, that's the subsidization in terms of, they're making money on distribution, and if you take that out, so you've just got a purely dedicated retailer, you're going to force them out of business. Which isn't a bad thing.

Moderator: Well, but if you have ease of new entry, I mean that's an offset a bit against the --

Question: Well, at a risk adjusted return of 6%, who would be a retailer at a risk adjusted return of 6%? So you need that physical asset behind you to actually manage that risk. That's the game.

Speaker 2: But, what the generators want is someone to dump the risk off on. It doesn't mean that they have to become retailers to do it. If there's that much spread in there, then there's room for someone to say, "Mr. Generator, you want a fixed price, here it is, and I'll take the risk on the other side, and I'm going to create the portfolio." So, to me it's irrelevant who does it, unless there's collusion. If the risk margins are zero, what are we complaining about? We're complaining because the risk margins shouldn't be zero, and --

Question: Well, we've overpriced that risk margin in the market now. People don't have the information, they don't see what Speaker 1 sees every day.

Speaker 2: That was my point earlier about how we make that worse by allowing them to have a flat rate as a default service. We need to up the ante somewhere, where you no longer get that, and instead you have to buy that, and when people have to buy, I have great faith over time that people will buy well, or buy technology and go on real time pricing, but we're asking the competitive retailers to sell something nobody wants, and consequently they don't, because there's no margin in it. But, I think if we restructure the market, those margins would…

Question: So, I agree with everything you said, but I'm just wondering how is somebody in the middle going to do a better job than the actual generator? So right now the generators sell to the marketer who sells to the retailer. As those margins come down, I think you'll eliminate essentially the retail industry, and I also think you'll eliminate that marketing, and you just link the two. You eliminate the transactions cost because the margins are so tight, and generators sell directly to the customer.

With the internet and everything else, you can expect the transactions cost to come down. A power shop can send you an email as many times as you want about your usages, what you've spent up to that hour, so on. It's all automated, so it's very easy.

Speaker 2: It may not collapse. I don't think generators know anything about selling electricity to consumers. Now, they can buy a company to do that, but I think unless they recognize the diversity, they're not going to be able to hedge. So, they need somebody in the middle. Now whether the generation buys up the Enrons of the world, and we all become consolidated, the results still could be efficient because of the inherent competition. But still, somebody has to get in and do that, and I don't think we have to worry so much about the final concentration, unless that itself is a worry. Is that what you're suggesting?

Question: In the long term I just wonder what this is, isn't this going to become a volume business, not a margin business? Volume needs to get spread across wide ranges. We need similarity of rules, similarity of RTO operations, so we start getting into things, what is holding things back if I want to do business in California, ERCOT, and MISO? Let's get standardized rules, standardized terminology, standardized commitment processes, standardized dispatch, all the way across…

If I'm close to the marginal cost, every piece of that is very important, so I don't want to have to hire 26 people to watch this market, that market and this market, while one person tells me what to do and then I get on with business, because I've got other things to manage. So, I think there's long running implications which are fascinating that we haven't really thought quite through.

Speaker 1: I think you're exactly right. I mean, as long as we're getting prices down to the retail customer, that are marginal cost and regardless of how they get there, I mean, if you've got no transaction costs in the middle, then so be it. I mean the whole point is that we're trying to get a competitive outcome. And that would certainly be one way to get there.

Question: There was some discussion earlier in several of the presentations about welfare economics and the price signals passing through from wholesale to the retail side. I think, at least in California and to some degree in many other places as well, there's kind of an elephant in the room that we haven't addressed, or as economists, maybe it's really a can opener, an assumption that we've all been making.

We were just talking about the distribution portion and we just kind of set it aside. When we're talking about these price signals to consumers, and the welfare economics, we're acting as though we are, through the real time pricing for instance, sending the marginal cost of production through to consumers at the retail level. Speaker 1 explicitly said that he was not going to deal with the retail side, but the reality is, when we're talking about sending these price signals through, and you're sending through large fixed costs through volumetric rates, or in the case of California, much worse, a tiered rate structure, so that you're already starting out with a 40 cent marginal price for your higher-tiered customers, then I'm trying to understand what we're actually gaining, if anything, in efficiency, from these marginal improvements in our real time price signals. Except for extreme conditions (you know, CPP-type conditions, you can see that that may blow past the otherwise distortions in the retail rate), but except for that, does it really make sense to be playing around in a margin with sending wholesale price signals through to retail as if we actually were sending a retail price signal through to customers that achieves social efficiency? Because if you actually look at social efficiency, most of our rates suggest that consumers are consuming less electricity than they should from the get go by a fair amount.

Speaker 3: I would like to second that. There's actually a nice paper by another one of Professor Hogan's colleagues that looks at natural gas markets, but the insight's the same, the basic idea being that these distribution charges are passed through on the marginal rates, and to the extent that they are fixed costs they should be passed through kind of as monthly adders. That's a big distortion, as is shown in this particular paper, and you could show the same thing in the context of electricity. I think that's worth thinking about.

There's another point which I think you were getting at also, which is, in real time price, are we passing through the short run marginal cost, or are we passing through the long run marginal cost? So, in a place like PJM, you've got a capacity market and you've got an energy market, and in many of these programs we'll pass through the energy market price, and then we'll socialize across all hours the capacity price, and that is not going to give the right long run marginal costs at these peak hours. So I think there a lot of other distortions that we should be thinking about as well.

Question: Yes, and again my concern with regards to some of the welfare implication calculations that are done is that they all seem to be done as if we were starting from sort of equilibrium supply and demand as our price. And if you actually put in the price that we're really doing, you might get a very different answer.

Speaker 2: The answer is right now you file a rate case, and you claim to be representing what your customers want at the same time as your own financial interests. And we've been doing that for years, and it's always a difficult job. You end up with one rate or two. I think what we're asking is to say, let people decide. You're still going to be made whole, and if it ends up to be the same way it is now, it seems like a funny thing to do, but first of all there will be positive welfare gains, and second we'll have the assurances that we've tied the wholesale and retail market together the best we can. As the earlier questioner pointed out, everybody ends up hedging, and it looks like we didn't do anything, but it's the process of getting there and assuring ourselves that we've exhausted the possibilities to get people to respond to prices, and if they want to pay the premiums, then our job is to build a system that does.

Question: Although I don't really want to belabor the point, you talk about positive welfare gains. I'd suggest that you're trying to modify the price signal to tell consumers when they should be consuming less, when in fact, based on welfare economics, they should be consuming more, because they're being charged much more than the marginal cost, or rather, they're not consuming as much because they're being charged much more than the marginal cost to produce, and I don't know if those welfare gains are real. That's why I'm saying that there's this other problem that I think fundamentally affects the economics that you guys are doing in looking at sending wholesale prices through at the retail level.

Speaker 2: I didn't draw it, but if the price is too high overall, and lots of hours it is, there are welfare gains for people to expanding. So it's not one way, welfare isn't like energy efficiency, it's all one way, there are both sides. For most of the big RTP programs I've been involved in in this country, the result has been customers have increased their usage. And some substantially. It's not a net reduction, they just move it around, and then because it's a better set of prices, they find things to do, because there are now lots of hours or several hours to do things. So I count welfare benefits equally both ways, including pricing electricity off peak, when we've got lots of capacity and we're not getting people a price that reflects it.

Comment: The place where the criticism is most relevant is on the average efficiency pages. But, for load management, which is relative, it still works.

Speaker 1: But it's an interesting empirical question, are the efficiency gains of moving from a rate design where you're putting fixed costs into the volumetric charge and moving to something that would be optimal such as straight fixed variable or optimal two part pricing greater than what we would do by moving to real time pricing but keeping this inefficient design in place? I think it's an empirical question, and it's an important one that we should try to eventually get to, but at least, so I don't trip over the wholesale/retail jurisdiction issue from my perspective, all we can do is send the right prices from the wholesale market, and that retail question is something that public utility commissioners are going to have to grapple with.

Question: As a former manager of an RTP program, I've been concerned with the lack of coincidence between the day ahead and real time LMPs and the system peak for quite a while. Most of the problem seems to be tied to the existence of capacity markets and actually installed reserve margin, where you have a plethora of generators bidding into the day ahead and the real time markets, which tends to reduce the scarcity pricing that happens in those markets. So I guess my question is, who should be responsible for figuring out how to collect capacity costs in the hourly prices? I mean should it be the ISO? Or should it be the LSE? So that we can actually restore sort of the signals that really should be there, that actually would prompt people to shift their load or whatever. Is that an ISO responsibility?

Speaker 2: No, the first thing to do is kill the capacity market, and then most of the problem goes away, but the second thing goes back to some of the earlier points, which is that these market structures we've decided we need press weight on and they squeeze out of the middle those margins that otherwise would be there. So if we didn't have a capacity market, if you bought capacity every day like in Texas, then essentially both sides would be afraid of the implications of volatility, so there's big room for somebody to come in the middle and say, "I'll take that risk, I'll guarantee you a price," or, "I'll sort the capacity out this way." I think from your perspective, you didn't have many degrees of freedom, you were nothing but a default service provider, so you had less ways to do it.

Those decisions should be made at the retail, not the wholesale.

Question: Well, yes, the LSE can redesign their capacity adder to restore the missing signals, but I don't know, is that where it should get done? That's the question.

Speaker 2: At retail is what I'm saying.

Question: I want to tie the issues we've been talking about on this panel together with the first panel on reliability and understanding the economics and ask people to think about quantifying what is the cost of this current system that we have, where at retail we've been extremely reluctant to pass through efficient prices, because of all the concerns people have already raised, and at wholesale we also have a lot of rules like bid price caps and markets, like the way we plan for reliability and then spread the cost like peanut butter, rather than let the reliability costs really show up in these peak hours, and the way we don't do a very good job of scarcity pricing--all those things are linked. And I believe they're there because we're fundamentally afraid that the retail customers will show up with lighted torches and pitchforks and call for all of our collective heads in the process. And we've seen some pretty impressive numbers about the welfare losses, even within this system that's already pretty messed up at the wholesale level. I haven't seen anybody actually try to quantify this. What are people's thoughts about what the welfare losses are as a result of the way we make decisions at wholesale to provide for reliability and then charge for it, and I'll throw creating capacity markets in there to try to make up for the missing money and all of that. We have quite a kludge at wholesale, which really has its origins, I believe, in our concerns about retail customers.

Speaker 1: I am going to answer this, but I'm going to answer this by asking first, a metaphysical question. [LAUGHTER]

Is reliability a public good? Or let me be more precise. Is resource adequacy reliability a public good, or is it a private good? If you believe it's a private good, then all the discussions around, "Well, we could have customers go out and they can contract with as much capacity as they want to buy the option and then have a certain strike price associated with that option for energy when they want it, and they may only want to hedge a certain percentage of that, and then they may be exposed to the rest in a spot market, be exposed to scarcity prices or shortage prices, whatever you want to call them, and all of that. And customers will respond to prices when we get into those situations, we'll be able to maintain reliability, because we have the ability technologically to curtail specific customers who decide they're not willing to pay, and they can come off the system…"

If you're in the camp that believes that resource adequacy reliability is a public good, now we have a tragedy of the commons. We now have this capacity market construct, whether it's PJM, New England, New York, whatever the case may be. And we're doing this because we want to avoid involuntary curtailments, because we are not sure that if we get into a situation where we have to curtail load, that I'm curtailing the load that has the lowest willingness to pay. I may end up curtailing the wrong load, because it's involuntary. And I'm doing it based on location and system conditions. It may be that the load that I'm curtailing for reliability reasons may have an extremely high willingness to pay, but I'm not seeing that. It's not being reflected to within the wholesale market. It's not being reflected to the operators. And so it's based on the thinking that, "Well, gee, we all benefit from that reliability, so we're all in this together," and so I think that we actually have to have that discussion first, and answer the metaphysical question. Is that a private good or a public good?

If we can all come to some sort of consensus on that, then I think we can actually move forward. My hunch is that in this room, we're probably mostly going to say that it's a private good. In which case, that definitely colors where the market design goes. At least philosophically, we would. But, then we also, as an RTO, we've got planning reserve margins that we have to abide by, there are certain NERC standards that we have to operate to, and that creates a set of issues.

Question: But, my question goes to, let's look at those standards and see if really all of that is needed, and again, to me it's not so much the standards themselves, although that's an issue, it's how we spread the cost consequences of those standards to rates that get flowed through the retail that blunts the price signal relative to where it really ought to be during those hours which really determine how much capacity you're going to need if you're working towards whatever your annual peak is.

Speaker 1: I don't disagree with you at all, and I think that the way that we could converge there, is trying to get the right prices out, to expose customers to the extent possible to something at least approximating real time prices at some point, because eventually then if there's that price exposure and if there's that price risk and they can choose to manage it in whichever way they want, we effectively are saying that reliability is a private good and the price of that is being reflected in real time LMP, and then they can reflect the fact that, "Well, gee, I may not be there at the system peak," and then they don't have to buy as much capacity or have the same kind of capacity obligation through the capacity market.

Moderator: That's actually a good topic for another panel, which would be, do we really need NERC? [LAUGHTER]

Question: I'm going to the quantification issue of the benefits, because if you put in RTP, and you have a capacity market which flattens the energy prices, the range of volatility and the range of opportunity for gain or loss is greatly depressed. So, to broaden the discussion of what's on the table here, and what are the consequences of not doing this, we have to address all the things that we're doing at wholesale that also have revenue flattening consequences that limit the potential that really could be there.

Speaker 2: Let me go to reliability. I consider reliability to be a public good in the sense that I can't buy more reliability, or you can't provide somebody more reliability, without a whole bunch of other people getting it. That's a classic public good. And it's asymmetric. I can take away somebody on a circuit's reliability, but I can't give the others more without raising the standard. And what we've done is, instead of setting a low standard and letting people buy up, because there's no way to buy up, we set a high standard and then we're paying people to buy down to maintain it. And one of the arguments is that storage technology comes along, so people who want a higher level of reliability can go buy a storage device and stick it in your garage, stick it in your building. If that were to be the case, then we should be lowering the reliability, because it probably is too high.

Now we would have a symmetric market. Those who wanted more would buy it, would provide the reliability in another way and gain the benefits to themselves, but nobody else in that distribution system gains by my having a storage battery unless I sell it to them. But I think that's down the road.

And the answer to the capacity market question is that it's standing in the way and it's going to be in the way. It's not an excuse not to fix the prices. What comes first? I think we've got to try the best we can to get diverse prices out, and then maybe we'll hold our breath someday and pull the plug on the capacity market and say, "Guess what, we're confident the market will take care of everybody's needs, let's just let it float and go back to an LMP." Maybe that'll never happen, maybe I drank too much of that wine last night, figuring it was my last [LAUGHTER]. It's gone to my head.

Question: My question goes all the way back, to an earlier part of this conversation. There was a question about the wholesale role versus the retail role to do these rates or products or programs, and one thing that concerns me is that we get quite a bit of that in California, that the ISO is taking over turf from the PUC or the retail entities, and in fact it comes down the question being posed as a turf war or a jurisdictional war.

My concern is that I don't think that it's an either/or proposition. It's not mutually exclusive. In fact, I see it as very much symbiotic between the wholesale and the retail. In fact, in California what we've done is we have approved demand response. But it's important that the wholesale market create those products, those programs, those integration mechanisms. It's like we designed the plug so that the retail entities and the third party providers can turn around and face the customer and produce a program or product that can then translate into the wholesale market and integrate in the wholesale market.

So it's not the ISO and our proxy demand resource, our reliability demand response product that is being sold to the retail customer. No, it's that wholesale interface, that wholesale entity that has taken their retail program and translated it into our wholesale product. So it's not an either/or proposition, it's symbiotic. They have to work together, but we can't have retail programs work in a vacuum as they've done for a long time in California, that have no way of translating into the wholesale market. They're completely customer facing and the customer is important, but they're totally customer facing. They're sort of designed from the view of, "What do you want, customer?" without any relation to how it would actually translate in the wholesale market and provide reliability and market benefits. And so that's really been our perspective in California, which is to insure that there's that integration, so that we're not starting any kind of turf war with the retail entities. We just want to say, "Here's how you plug into our market, develop your programs so that they can turn on and plug in."

Speaker 1: Amen.

Question: Thank you. I wanted to ask a question that goes back to a couple comments and a point that Speaker 3 made in his presentation, about there being a risk markup.

I was struck by that, because in the end of the day and by and large for all retail locations, the risk is still born by the customer. There's still a pass through, even though it's kind of smoothed out. So, I was sort of perplexed by calling it a risk premium. The customers will end up paying for it later on with a revised baseline and their recovery of differences between flat tariff and the actual real time wholesale price.

But I wanted to get back to the point that was made in Speaker 3's presentation, and ask Speaker 3 to comment on this. You showed some data about the volatility of real time plans in conjunction with monthly averaging and your data used a time of use alternative that sort of was constructed temporarily at the same time, which obviously is inaccurate, and so I was wondering if you could comment more about that, and if you'd tried to look at something over a longer rolling average, knowing that the time of use rates in some states are averaged for three years and in some states are recovered every year and you have volatility, and the time of use rates is actually very significant. And that volatility, hopefully in the end is just a reflection of the same underlying pricing using different averaging methods. And so I guess I'm agreeing with your fundamental position, which is, what's so scary about real time pricing? There's volatility in the current rate structure anyway, and the volatility may actually be of a similar nature. Now it's true that you may have outliers, but if everything is normally distributed you might actually not have that much. Of course it's not normally distributed and you have a couple of months where you have very high pricing. So, you would find a little bit of discomfort there, but I want to say, is it really a problem? And why do we have so much concern about the real time pricing volatility? So, if you could address that.

Speaker 3: Let me just make a quick comment on the calibration that I did. You caught on to something that some others also may have caught on to, which is, if I had extended that graph to the quarterly level, there would have been a histogram with the point mass at one. Right? So, by construction, the TOU tariff that I put together was the quarterly load weighted average prices. And so that's not necessarily what you would do. And so that's why I didn't bother showing the quarterly stuff, but I mean there is a general point, which is that those TOU prices have to end up being in expectation something like what the real time prices would look like, and so if you were to construct my example differently, if you average over a month or over a year, eventually you'll end up with the total bills being the same in those two structures. And that just has to do with averaging and the retailer zero profit condition. So that's right.

And as you also point out, kind of the general insight is still the same. Once you average over a few months or six months or a year, things look a lot less risky, and we could calibrate that in lots of different ways, and I haven't calibrated that in so many other ways. I was just kind of doing something suggestive. So, yes.

And to the extent that there's any markup or risk premium put in there, which I had argued conceptually makes no sense, but if you want to talk about it that way, the customers already own the risk, why would they pay a risk premium? Not only that, the temporal mismatching of the TOU rates is also suggestive of a conundrum of charging some customers for the consumption of others in a different time period, because it's delayed.

So in that concept it seems to me that the time of use rate has not a lot of benefit from a volatility reduction perspective and maybe would have just been an outcome that comes back from our historical way of doing business, as opposed to what makes sense given current technology and current metering. I don't know if you'd agree with that.

Speaker 2: No I don't. [LAUGHTER] Because the problem with this is that people are trying to use rates to do too many things. And rates are meant to do one thing or two things well. A time of use rate in the long run will get people to make capital expenditures, because they don't want to continually pay high prices. But you've got to be patient. So, everybody has no patience, now we've got a problem, we have a capacity problem, "Oh, time of use would take five years, let's put a CPP or manufacture something with three letters." But you go to Arizona, with a severe problem because of the air conditioning--when the retail load started growing, they thought they had time, and so both of the utilities put in time of use rates, and now Salt River has 180,000 out of 700,000 customers on TOU rates, they're now diversifying the TOU rates, and Arizona public service has 250,000 out of a million customers. It didn't happen overnight, they stayed with it and the rates have evolved. It just doesn't happen fast. It's not very flashy, but it works in every other market, I don't see why we don't have more patience for it. And I think it's an easier sell to customers. They're used to buying things, so it makes sense.

We're trying to tell them, "We've got this terrible problem in society, and prices are changing and I want to foist it on you." No wonder we have trouble selling real time pricing, that's why I'm looking at these things like TOU or this variable TOU. It's just a modification of it, as a way to get in the market. We've got to get in there somewhere on a transaction, where we show them you're dumping risk off, you're getting a benefit because you can pay less because essentially you, by taking the risk of the prices…

Question: You're saying "dumping risk," but you're just moving it around. The customers still own it, in general, as an aggregate.

Speaker 2: But that's the whole point, that some people want it and some don't. We should differentiate and let people who want to pay a hedging premium pay it and have it. They have a right to that. But, right now we socialize it, and we do it in a very clumsy way.

Question: I agree with the socialization aspect. I don't see where the premium comes in. It's just, you know, sort of averaging, as opposed to having a risk management process.

Speaker 2: Not if some people stop. If people say, "I'm just going to take the streaming prices." Right? The risk moved over to the supply side now. The argument is the portfolio has to move together too, your point's well taken.

Speaker 3: How about one more thing on the issue of risk aversion and consumers being willing to pay a little bit to get rid of risk? So that's a perfectly natural thing, you know, we all have insurance of various forms. And economists, when we define something as rational or not, we don't take a stand on the level of risk aversion that we want you to have. So some people can be risk averse, some people can be less risk averse, some people can be risk seeking, that's all kind of the individual's choice.

You can generate welfare gains, however, when you see the same consumer being more or less risk averse in different contexts of his life. So in some contexts we would go out and actually take a fair bit of risk, and in other contexts we might be highly risk averse. And you see people buying certain forms of homeowner's insurance, for example, where they pay quite a bit of money to insure themselves against actually very small variations relative to their total annual income. And so what tends to happen in these settings is when you actually come to consumers with information about the amount of risk they're buying away and how much they're paying for it, you can get people to make decisions that are internally consistent. And so I think this is a story about kind of being clear with consumers about information provision.

So if we come to them and say, "Listen, you're paying $10 or $50 a year for a flat rate tariff that changes the variance in your residual income by $10 or $50 a year," they might say, "Wow, I'm paying definitely $10 a year to reduce my variability by $10 a year? That seems like something that doesn't make a lot of sense." And so if we can kind of help consumers, again, with something like a one page sheet that says, "These are the rate structures that you can have, this is the volatility, this is the difference in expected cost," I think that sort of thing would be useful, and we'd see more consumers making internally consistent choices about risk.

Speaker 2: We did some survey work a few years ago and we told people, "You've got the rate you're on now, but if you move to time of use, you're going to save 5%. If you move to a middle product, it looks something like this VP, you'll save 10%, if you'll just take these streaming prices, you'll pay 15% less. Take your pick." We did it for residential, commercial and industrial customers. About a third of the customers took the flat rate, which means they're paying the 15% premium. By the way, I reversed it, and there was no Tversky and Kahneman anchoring. When I put it the other way around, it got them to think about, "I'm going to impose a real time price on you, buy it back," it was symmetric. But about 10 or 15% of both residential, but more industrial, moved up and took the risk thing, because the premium 15% is artificial, but people didn't seem to have any problem about doing this, they could work their way through it, it's not that hard. It's hard to imagine when we do it in abstract terms or social welfare, but when you put it in dollars and cents, people are pretty good decision makers, and so that was kind of an indication to me that if we actually had that, somebody has to come out with all these products and make a statement about what those differentials are, then I think it's possible for consumers to start making those decisions. Right now it's just very abstract.

Question: I think this question's been asked at least two or three times today, but let me just try to recast it slightly differently. I've been around these programs for a couple decades. I remember working 20 years ago on one of the first programs in real time pricing, and the very first thing that struck me about it was that more than anything else real time pricing took a product that was sold by utilities as a kind of a single good, if you will, and it split it up into multiple goods. It took this one good and made it a physical commodity, and it also made it a transaction of risk. So you kind of had this physical transaction and you had this financial transaction.

What I hear a lot about today is a tremendous amount of discussion about the merits of real time pricing from an operational efficiency perspective, and all these welfare studies seem to be very focused on the physical market and operational efficiency. And I guess the question is, have there been any similar welfare analyses done on what real time pricing has done to financial markets? Have we achieved capital efficiency? Or risk transfer efficiency? Or financial market efficiency, either at the consumer level, in terms of customers making decisions about whether or not they want to pay up for someone taking volatility out of the equation for them, or generators making investments? Has this unraveling, if you will, created a situation where investments and capital market efficiency is not where it should b?. Is there a similar welfare analysis that's out there, that focuses more on the financial side of this kind of unraveling as much as it does on kind of the operational efficiency? And I say that with a lot of very strong belief that there is a pretty compelling need for operational efficiency, and so I'm a real advocate of real time pricing from an operational efficiency perspective, but it's kind of this lingering question about whether or not it's done what it needs to do or if it hasn't done it will it eventually do what it needs to do more from the financial perspective?

Speaker 2: Well, the analysis I showed you is a copout, because it's a short term equilibrium analysis, so we cop out because we pay no attention to the transfers. We say, "Who cares if it went from consumers or producers?" But you asked the larger question about what are the longer term implications of that in capital markets and capital liquidity, and that's where the generators have launched the argument about missing money, or "Where's my money?" Well, I know where it is, it's in the customer's pocket where it belongs, because you charge too much. But, I don't know of anybody who did a general equilibrium model and tried to say what would be the implications if customers actually start responding to prices, would we not be able to raise capital? I haven't seen anybody who's tried to take it at that level. But you're asking the larger question, and we've been answering a smaller question.

Question: And I would love to hear some of the answers to my question, but I'm also responding to the previous question here, about the intermediaries taking this markup out of the market as well, but in some markets they've been driven down to low margins and then driven back out. We're back into this vertically integrated or virtual vertically integrated utility space that was maybe optimal from a financial perspective, but now you're back in this boat where we're really not operating efficiently.

Comment: I think on that last problem, what someone said earlier, would be my answer, which is that I don't care whether we have vertical integration between generators and retailers, as long as we have open access to the critical links in between, basically the transmission, with the wires, and as long as it is realistic to think that people could actually enter if you get significant deviations where things are beginning to be too expensive. And that's a hard question to answer, do we really have that kind of competitive entry possibility? The best way is when you can observe it, so that's real important, but sometimes maybe just the threat of entry is enough. But that's the test that you would be thinking about, was that the inefficiencies couldn't grow large and couldn't persist, because entry would take them away, and then it might be the most efficient way to do it, to have generators vertically integrated with retailers, and what do I care as long as the regulators are setting up the rules so that there are not cross-subsidies built into the tariffs and that kind of thing.

Moderator: Well, and at least in Texas, we limited the overall percentage of the capacity that you can own. And so you're not going to have one or two, you're going to have at a minimum five or six.

That goes to the market power concern. And then finally even if you match resource with load, it doesn't guarantee that they do it right. As one of our large combinations found out this summer.

Speaker 2: I'm not sure what the equilibrium that you're asking about is, but capital stock in the generation business takes a long time and a big investment. Household and business stock, or the way they use electricity--burned into the idea that I get a flat price because I get it, is incredible rigidity. Well, which one we going to blow up? I'm a believer that the financial market is the easiest thing to make, because financial people, if they see risk, they come in they absorb it, and they leave. That's the thing that we could start with, because it has the most flexibility, and then everything else should follow by this. Now that's a leap of faith about whether markets ever meet that beautiful equilibrium, but I don't see another good way of entry. I don't want a world where we're going to give everybody their own generator and lose the scale economies, but I'm also mindful of rigidities of how people use electricity, so we've got to start somewhere and I like the portfolio idea, I like taking risk, I like people doing that, making several commodities--they're still commodities, but making commodity choices out of it and let that work its way through. I think that'll help us.

Moderator: There's been a lot of talk about the benefits of real time pricing, but particularly in a competitive market, or competitive retail market, you really don't see it. The question is, how do you get it? How do you encourage it or how do you sell it to customers?

Speaker 2: Well, I think we now know opt out doesn't work. The big experiment in Chicago essentially just put people on and said, "Welcome to real time pricing. For the next year you're going to get a new set of prices every day." Hardly anybody opted out because it was sort of safety first, but less than 10% of the customers responded, so you can lead a horse to water, but you can't make it drink. I think people thought the nudge idea might work. You can't nudge people unless you stick their feet all the way into the fire. I think it's just hard work. It's hard work we've never really steeled ourselves to in this industry. We've solve all the other problems, and we've not faced it. It's good marketing. Speaker 3 just did a nice consolidation argument about feedback and the effect of just giving people information about how they use it and how that's affecting costs. It's not a cure-all, but it appears to work. Well why don't you combine that with price, and then maybe with technology, and those things will get the ball rolling. It's just things that as an industry we haven't tried. We haven't really emptied the closet on how to retail it. We're still sort of bound in by regulatory requirements and financial requirements. I think competitive suppliers mean well, but a competitive retailer is not going to spend time with 150 customers trying to explain TOU when he could, when I can sell you the flat rate like you had before for 4% less. It's not on their back either.

Comment: I think that the other important sales point on RTP is that the average rate contains a cross-subsidy. So, half of the people gain from going to RTP, immediately. And I know when we were pitching the program we were talking about that. And then of course it creates incentives for people to reduce their bill. But half of the people gain immediately when you go to RTP because you're unbundling this average price where some of the people are cross-subsidizing the other people on the rate.

Speaker 2: That residential real time pricing was offered in Illinois as an alternative. Essentially the same structure in north and south, so Ameren in the south, ComEd in the north. 2008 or 2009 may have been the first year, I can't remember. Ameren has about 1,100 customers, ComEd has about 20,000 – 25,000. It's growing quickly. Not to point fingers, but Ameren sort of farmed it out to someone to do it, and basically what Commonwealth Edison did is it went to the Community Energy Network, which has a big community social network on the north side of the city, so it ranges from all sort of rental cars that are around to energy efficiency services. So they're using their contacts, they have a great way of communicating with people--both social media and community media. And they're signing people up, and growing fast, and people appear to be responding. In the last study I saw, it appears that we're getting a nice response.

So the difference was that they had someone who knew how to deliver the message. These these are middle income customers at best, because it's North Chicago. It's not big three story houses with three ton air conditioners in them. So I think if you look at that, it says they have a network in place and were using the network. And that's encouraging to me, but if you start from flat, it's very expensive to start knocking on doors and getting people to even listen to you about these rates.

Speaker 1: I think what you've pointed to with the retail rate making is the issue that we're using electricity rates and rate design to carry out various pieces of public policy, whether it's to subsidize low income customers, because the perception is that they will not be able to respond to real time rates, or to cross-subsidize different customer classes, and to do so in a non-transparent way on purpose, so as not to upset the others who are actually doing the cross-subsidizing.

And I think one of the things that the discussion of moving towards real time prices does is it creates transparency. And in some cases it creates transparency in an embarrassing way. “Oh my God, we’re cross-subsidizing this group?” We’ve got residential customers cross-subsidizing these C&I customers, for example. Or vice versa, and then you start unraveling that policy that’s been put in place.

And so I think there’s a lot of that inertia that needs to be overcome as well. In some cases these rate designs have been put in place under one set of reasons, but there’s actually something underneath that that no one really wants to talk about. And I actually found this to be the case in thinking about decoupling. All the consumer advocates were just dead set against decoupling, “Oh my God, now we can’t do all of these programs,” and it finally became transparent that the rate design that was in place, it was to actually implement these cross-subsidies, but to do so without creating too many waves. But, it’s a point that we all have to think about in how we address something that’s actually underneath all of this.

Comment: I think there’s a role for the regulators to play here, too. In New York when we first went to RTP, I think it was the large customers, C&I customers who wanted to be on RTP, and that was part of the rate settlement that they go there, but the regulator took it a step further several years later, when they extended mandatory hourly pricing to C&I customers down to 100KW, which the utility started to implement in waves. There’s a huge difference in New York versus New England in terms of the receptivity to hourly pricing, because the regulator has really, drew a line in the sand and said, “OK, this is where we’re going.”