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RAPPORTEUR'S SUMMARY*

Session One.
Carbon Dioxide Emissions Controls and Electricity Markets

While the Federal Government opposes mandatory requirements to reduce CO2 emissions, a number of states are moving ahead with their own control programs. The most notable are the RGGI program signed by nine northeastern states and California's proposed emissions standards. It seems clear that, absent federal preemption on CO2, there will be quite diverse responses to climate change concerns.

What impact, if any, will these programs have on electricity markets? Will they influence investors in terms of types of generating resources that will be constructed and technologies employed and, if so, how? Similarly, how, if at all, will dispatching of units be affected? How will locational decisions in regard to plants be affected, and what impact, if any, will that have on grid constraints and congestion prices? Will states with CO2 controls be more inclined to impose resource selection decisions rather than letting the market decide? Might we see renewed efforts by states to monetize externalities in resource selections or return to something akin to the Integrated Resource Planning? Will the fact that some states have CO2 controls and others do not, distort the efficient functioning of bulk power markets? What political responses, if any, are likely to result from the fact that some states are imposing emission standards and others are not?

Speaker 1.

I'm going to focus my remarks primarily on the Regional Greenhouse Gas Initiative (RGGI) here in the Northeast. I'll give an overview of RGGI so you understand the program. It is a consortium of seven states. It started with nine, but two states have withdrawn at least temporarily, Rhode Island and Massachusetts. The RGGI states agreed to develop a cap and trade program to stabilize carbon dioxide emissions from electricity generators until 2015, and then reduce emissions 10% between 2015 and 2018. Each state is allocated a certain cap or target based on several factors. The primary factor is its consumption between 2000 and 2004, closer to 2003. They've tweaked it to account for issues like population and other issues raised during the political negotiations. States have the flexibility to decide how they will allocate those permits. Most states will distribute 75% to industry, and the public sector will sell or auction the other 25%. The proceeds from the 25% portion will be used to fund strategic energy programs.

There are limited offsets for predetermined categories of projects within the region, such as afforestation. Under certain circumstances, a larger menu of opportunities outside the region is available. They've also put in a safety valve in case the price goes up significantly.

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the speakers.

"Significantly" means seven dollars a ton for carbon dioxide, in some cases ten dollars a ton. To put that in perspective, despite the current plummeting of the carbon dioxide price, Europe is currently paying $18.50 for CO^2. These triggers will allow more generous access to offsets and a longer compliance period.

The benefits are to put states ahead of others which will have to do more later, to implement reductions now that will be more expensive later and to promote efficiency, renewables, and technologies. A fourth is to reduce greenhouse gases, but this is a global problem and it's hard for a sub-regional solution to have a big impact on a global environmental problem.

Those first two are interesting. There is a contrary view which says that technologies later will be better than the technologies today, and it might be less expensive to reduce carbon dioxide at a later date. This is at least debatable and controversial. The third benefit, to promote energy efficiency renewables and new technologies, leads some to ask if this is the most efficient program to stimulate the development of these options.

A fourth benefit that isn't cited in the RGGI document but is in a lot of the literature, concerns the opportunity to experiment with procedures and initiatives that might be considered in a national program. The benefits here are very real. The bigger question here is who captures most of those benefits? Is it the region that pays for the program, or the nation as a whole? One implicit benefit is that it will put additional pressure on the White House and Congress to act. There is growing pressure on Congress to act right now. There is an emerging view that between now and 2012 the nation will actually act on this issue.

The cost projections of the program are low. There have been numerous studies and only one that predicts high costs. Proponents are claiming cost increase between three tenths and six tenths of a percent increase in electricity rates by 2015. The impact of RGGI will increase as power capacity increases in the region. The impact will be mild in its first year in 2009, and then will ratchet up to 2015. Even in 2015 the impact on rates is forecasted to be almost negligible; no more than a $16 increase for homeowners. In both California and the RGGI states numerous studies argue that economic growth will increase, and thousands of jobs will be created. This would occur because of the program's emphasis on using funds for energy efficiency programs, renewable programs, and other developments.

The cost of this program depends on how you design it so I'll focus the rest of my presentation on the program design. In the northeast, fluctuations in natural gas prices will dwarf any economic or ratepayer effect from RGGI. Second, the impacts of the RGGI program will depend on two key variables. The first is the method by which the allowances are allocated and the second is the degree of competition in the region. In the northeast there is a significant degree of competition.

There are three options, with many variations, that are usually considered. One is grandfathering using historical emissions. The second is generation performance standards. This simply assesses how many megawatt hours a generator produces in a given year. The third is auctions in which the revenues are recycled by the government.

A second question is which part of the industry should hold the allowances? In RGGI the generators would hold it, but in the California design either the load serving entities or the distribution/marketing companies would have them. The third question is whether the allocations will be updated or revisited in succeeding years. That can have a significant effect on the distributional effects of whatever program is in place.

The northeast's substantial use of competition means that the marginal price of electricity at any given hour or half hour sets the price for the market for that hour or half hour. For most of the year, that price is driven by natural gas costs. In a competitive electricity market, carbon allowances become a very valuable asset. A Resources for the Future assessment – their studies in this area have been very good – estimated that carbon allowance values might exceed the compliance costs by a factor of ten on average. That is significant.

The choice of allocation method has large distributional impacts. In a competitive market in which the marginal cost sets the clearing price, firms will attempt to charge customers for the value of the allowances as they would any other opportunity cost. Hence grandfathering involves a large distributional shift from consumers to producers. In the single year of experience for a program like this in Europe, this prediction has been borne out. Most of the utilities in Europe took the value of the allowances that were distributed for free, and added them to their cost of electricity. They can't always put it on, there are market forces that force them to eat some of it, but they pass it through if they are able.

The RFF studies also show that electricity rates will be higher under an auctioned approach, but the efficiency gains will be significantly greater relative to grandfathering. Thus there will be short-term upward pressure on price if you auction, but there will be subsequent downward pressure as the efficiency gains begin to lock in. Auctions will raise significant revenue, and how this revenue is used will be crucial. At a national level there's discussion about using revenue from an auction to reduce taxes. If you select certain taxes, you could actually substantially reduce the impact of the allowance system on the GDP and economic growth. Money would be aimed at other energy programs that would complement RGGI. However, there is also a line-item that allows the money to be reimbursed back to ratepayers, as an option that states would have.

New generation has special concerns. Allowances are somewhat akin to a subsidy that is given to low or non-carbon emitting sources. Hence, all other factors being equal, one should expect more renewables, more gas facilities, and more nuclear power plants. Nuclear is unlikely in this region for other reasons. Two problems are going to emerge. One is the issue of leakage, and the other is lack of fuel diversity. The RFF study notes that if there are no transmission constraints or other complications, new generating plants will locate outside the RGGI states. Those are big assumptions concerning transmission and complications. Nonetheless, leakage is going to be a key problem. For instance, RGGI states could forgo building a gas-fired facility, and purchase power from a new Midwest coal facility, and thereby increase carbon emissions. Renewable facilities will be easier, especially if states make them eligible for allowances. However, siting large-scale renewable projects is a challenge in this region, particularly in Massachusetts. It's hard to take up that much land with an energy project in a densely populated area of the country.

The region is already considering significant power imports from Canada. RGGI will be a contributor to the pressure to buy power from Canada, but it will only be one of several pressures. This will also be a leakage problem, but not entirely due to the RGGI program.

The second concern is the lack of fuel diversity. This has been a big issue for the last 10 years here. If we had known that the price of natural gas would go from \$2.00 per MCF to \$7.50 per MCF we wouldn't have built all those gas facilities. Currently, the marginal price of electricity is set by high gas prices. If RGGI provides incentives to build more gas facilities, will it make us more reliant from 85% of the time to 88 or 89%? RGGI will make it difficult to attract other investment other than renewables, imported power, and occasionally gas. We could have even higher prices than the national average in the northeast ten years from now.

There are other questions that I can't answer. I don't know what the impact of RGGI on the availability of ancillary power will be. This is a substantial issue. Groups that opposed RGGI were concerned about what would happen if three nuclear plants go out at once? Could RGGI be a constraint in our ability to get emergency power? The generators and Associated Industries of Massachusetts were concerned about it. Will RGGI affect Merit Order Dispatch? Probably not substantially, maybe a couple of percent. However, they're giving more permits to facility types that are already the most expensive. The RFF study showed that coal is not the lowest priced facility for most hours, even in other regions of the country. It is not your marginal unit for most hours of the day.

Can RGGI integrate seamlessly into a national program if and when one occurs? It is a precursor to a national program, and therefore it should be able to integrate effectively into whatever national program is developed.

To summarize, the design of a regional program like RGGI has a significant effect on its economic cost, and distributional impact. Leakage will be a challenge for any regional program. However, there will be benefits in terms of learning, but these will not be primarily captured by the region that pays the cost for the program.

Moderator: You said that RGGI proponents indicate that this will have a small economic impact by the year 2015; about 0.3% to 0.6%, or about $16 a year. What cost per ton was that based on? You noted that Europe is seeing $18.50 a ton. What tonnage cost was the basis for the economic impact study?

Speaker 1: There are several studies. They made some assumptions and plugged it into a macro model and came up with these figures. Generally the analysts think that with the safety valve triggers, the price will not go much beyond seven to ten dollars a ton for CO^2. This is a third of the price in Europe.

Speaker 2.

I want to build on the presentation by speaker 1 which lays out the groundwork of RGGI. I will focus on some highlights, revisit some of the contentions that were presented, and make some predictions and pronouncements about how RGGI is likely to unfold.

While it is a seven state agreement, the scope of the agreement has to be tempered somewhat. This is because 70% of the units that would have been covered by RGGI if Massachusetts had signed the agreement are already under a carbon constraint derived from current Massachusetts regulations. Similarly, Maryland has pending legislation that would require it to join RGGI or develop its own in-state carbon constraint. The scope is still unfolding, and may likely expand.

An important issue is the modesty of the carbon constraint. The goal until 2014 is mere stabilization and then it ratchets down two and a half percent a year after that. The modesty of that goal has sometimes been lost in the debate.

A second significant issue is that only a portion, 3.3% of the obligation of the emissions, can be covered by offset projects.

Third, this program – like any other that might emerge – has price dampeners if not outright caps. For example, when one considers hot summer and cold winter scenarios that might affect compliance, RGGI has provisions that expand the pool of available offsets if prices spike, or extends the compliance period. The caps are set on a three year compliance period which allows operators to borrow and bank within that period easily. If there are price spikes, these volatility provisions address them.

Fourth, the RGGI regime is import hostile because the parties have agreed that they need to address RGGI attributable increases in non-region imports. There are no specifics, but it's in the memorandum of agreement. There is a strong sense that RGGI cannot be allowed to send imports through the roof.

There are some other details worth noting, first in terms of the cap. The cap is not only modest, but it's padded because it's based on historical emissions. Emissions now are actually five percent below the cap. This will certainly moderate the price impacts.

Second, there's uncertainty about how auctions will take place. The most likely result will be state by state differences in whether they auction 25% or 100% of the allowances for public benefit. New Jersey will probably have over

50% of auction revenues for public benefit in energy efficiency and renewables.

As I mentioned, the import constraints are undefined. They could range from very soft constraints or they could be very concrete. A strict example would be to require states to eat allowances for RGGI attributable increases in imports. It's certainly unclear whether the program is going to go in that direction. It will be easier for them to have strict regulations if they do it sooner rather than later.

There's skittishness about the number and cost of offsets that will be available in the market, particularly since RGGI has a bias for in-region offsets. If companies go out of region they have to use offsets at a two to one ratio; two tons of offsets for every one ton of compliance obligations.

A significant challenge for the program involves congestion and capacity. For instance, New Jersey has been trying to transmit their way out of capacity limits, reliability problems, and congestion. However, recent PJM analysis of transmission and forecasts going forward show that they can't increase capacity unless there's more in-region capacity. That coincides with problems in the northeast with over-reliance on natural gas and price volatility.

Financing new capacity is a significant problem. This is in addition to concern about whether some nuclear plants are out of commission, re-fueling on a coincident basis, or will be re-licensed. Oyster Creek and Vermont Yankee are both up for re-licensing. While imports from Canada seem likely, Vermont has questioned whether they can renew their contract with Hydro-Québec. These external factors are as important to understanding RGGI as the basic elements of carbon constraint and how the offset process works.

Some fairly safe predictions that can be made, although I predicted that Massachusetts would be crazy not to sign RGGI and they could never walk away from the agreement. Of course, they were the one state that did pull out. Nonetheless, we're likely to have an EU deja vu. When one considers that the reductions are modest, the cap is padded when compared to current emission levels, offset availability is limited and never factored into the RGGI modeling, auction processes will generate investments in energy efficiency and renewables, it's likely that there'll be some initial volatility and then prices coming down. They won't come down to EU levels, given the modeling that's available. However, they will be significantly lower; below the seven dollar range that the RGGI negotiating partners thought was the upper limit of acceptability.

Second, in terms of generation or dispatch, and I'm differing with the first speaker's point of view, the issue of allowance allocation is irrelevant. While it makes a big difference to individual companies, it is not important for which units generate, what power is dispatched, or what the price is for the consumer. For any given generator, their generation decisions are the same whether they're given the allowance or they have to buy it. The result of the carbon constraint is going to be the same in either case. This is hard to convey, and I'm happy that the New England ISO acknowledged that in their RGGI comments. The amount that can be passed through to consumers will not be different whether the generator is given an allowance that it can use or sell, or whether it has to buy that allowance; the value to the generator is the same either way. Now that this is being recognized, the right answer in this process is that 100% of the allowances should be auctioned the to the degree that political constraints allow. It will help create and drive the market, maximize the investments in energy efficiency and renewables, and will not affect the markets for consumers.

Imports must be dealt with concretely. To avoid moving generation outside the RGGI region, a provision for using allowances to deal with extra RGGI attributable increases in imports is necessary.

The combination of many of these issues mean that resources, regulatory attention, and public support for dealing with problems that otherwise have defied public policy attention will change the landscape. It could drive regulators to truly address how we develop more capacity within these constraints. The first speaker stressed the fact that the three primary resolutions will be renewables, natural gas, and nuclear. Nuclear is probably untenable due to political factors. Renewables face natural constraints in congested areas. Natural gas has price volatility that dampens enthusiasm for new capacity. I expect the combination of carbon constraints combined with the historically unaddressed problems of congestion, reliability, and capacity will strongly support the development of more carbon efficient coal.

Integrated Gasification Combined Cycle [IGCC] is one of the most promising technologies for the future. Fuel diversity and capacity issues mean that regulatory attention and support for these technologies will only increase. There are ten governors on record supporting development of IGCC capacity. Minnesota has a mandated power purchase agreement, and a similar arrangement in Ohio. We can probably see something similar in the RGGI region. The technology also addresses the challenges of financing construction of new plants.

These factors will reduce carbon emissions, address longstanding problems of capacity, reliability, and congestion. Environmental groups, which historically have often been a source of political resistance for new capacity, could be on the other side of the equation. This is dependent on regulator acceptance and enthusiasm for power purchase agreements as a financing mechanism for more expensive technology like IGCC. In the recent licensing of a combined cycle gas plant in Astoria, Queens, the National Resource Defense Council [NRDC] was supportive. They have been an explicit endorser of IGCC technology. So these things taken together, could allow the region to demonstrate leadership on climate change, but also for other problems that have gotten inadequate attention over the years. We have a perfect storm of those elements coming together in a win/win. And this is occurring not only in the RGGI region but also in California, the west coast, Ohio, and Minnesota. That may be RGGI's greatest legacy of all.

Speaker 3.

I want to talk about the challenge we have in global climate change issues. Innumerable studies, including the inter-governmental panel on climate change, generally see a dramatic reduction requirement for carbon emissions; 60 to 80 percent below business as usual by the end of the century. This is a century-scale problem with enormous scope. It's critical to keep this in mind.

Reductions by developing countries are critical to the success of any initiative. There's also a strong desire on the part of regional policymakers in California and elsewhere, at all levels, to do address climate change. They don't want to wait for the national scene to coalesce around positive action. California Governor Schwarzenegger's June executive order to dramatically reduce California initiatives is an excellent example of this.

These proposals are likely to be costly. The investor-owned utilities have few compliance options because they've done quite a bit under command and control regulation for issues that affect greenhouse gas reductions. Some of the compliance mechanisms in RGGI, especially offsets, are needed in California. Developing low carbon technology will be a longer path, but will be vital. A sustainable system of investing in technology is needed so investors have more certainty. Regional regulatory programs usually don't provide that certainty.

Many utilities believe this century-scale problem has to be connected and addressed not just on a regional or national basis, but should involve cost-effective international agreements. Developing countries are not making commitments for reduction that are binding. We must provide those nations with economic incentives in the global interest to address global warming. The proposals in California need a commercial CO^2 removal and storage technology, or some kind of serious offset or safety valve mechanism. If not, they will probably increase electricity costs and reduce fuel diversity, especially with the cap proposal currently being considered with no trading.

A 1996 article in Nature magazine plots the kind of carbon reduction necessary for reductions in global warming. The size of the gap between current growth and needed reductions is enormous, even with a relatively moderate concentration limit. These analyses also show that emissions can go up and still avoid serious climactic change in the timeframe that's required. The question of where and when flexibility exists is important for any analysis of climate change and greenhouse gas reductions that is economically efficient.

EIA's international energy outlook shows that developing nations will exceed the CO^2 or greenhouse gas emissions of industrialized countries as soon as 2009. This trend magnifies over time, so it's important to get these nations involved.

Now I'll focus on issues in California. The governor's executive order requires the reduction of greenhouse gas emissions to 2000 levels by 2010, to 1990 levels by 2020, and to 80% below 1990 by 2050. The last goal is a very aggressive target and timetable. Even 2020 is quite aggressive. That's a 25% reduction from the "business as usual" cases plotted by the California climate action team, the governor's team that did much of the analysis. It's a 145 million metric ton CO^2 reduction. For comparison, the national McCain-Lieberman bill, S139, proposed a 17.8% reduction.

The climate action team report is a mix of command and control program approaches, and an allusion to a cap, or perhaps a cap and trade program. There are several elements in the report that can achieve pretty closely, but not exactly, the 2020 reduction goal in the governor's order. Many of these are underway already. They include the public utilities commission California solar initiative for investor-owned utilities, things like methane capture and so forth.

They are considering a climate cap and trade program that would take into account trading credit options, offsets – all the usual elements – and address the leakage problem that could occur with the Western states interconnected with California. There's a mandatory reporting requirement. You can determine how comprehensive the cap is by looking at who is doing the reporting. Clearly, it's not an economy-wide cap. Most studies say an economy-wide cap is the most economically efficient way of getting at GHG [green house gas] reductions, but it's close to being comprehensive.

There's extensive debate about the cost of these programs. The climate action team sees a $4 billion net gain by 2020. I'm very suspicious of that. If you look at RGGI, there's some cost impact, even with the safety valves. Similarly, the EIA analysis of the McCain-Lieberman bill or other national programs, show 26 – 40 % increases in electricity prices. It's hard to see why California could make gains. Further, it assumes that government regulators will implement regulations that are more economically efficient than the market which is certainly a controversial proposition. They are going to update this analysis on a dollar per ton basis, and that has not yet been done.

The California PUC has a highly developed program with a variety of different measures. The legislature is also interested in this topic, and they have two main bills. AB32 establishes mandatory greenhouse gas reporting for all significant sources, and requires the California air resources board to adopt regulations in 2008 to achieve the governor's reduction goals. It would go into effect in 2012. To a degree, this is kind of a delegation or blank check to the California Air Resources Board to do the hard regulatory work in the design. Many of the critical design factors are not specified in this bill.

Bill 1368 has a CCGT (combined cycle gas turbine) performance standard. This means that no baseload power procured of three years or greater duration can be implemented without meeting the CO^2 emission rates of a current combined cycle unit. This regulation ultimately bans coal. However, the bill is still being written. There are no details that define baseload, a new plan; these all need to be worked out.

Comparatively, California's pretty clean, from a generation standpoint. Most regions use a lot of coal but in California it's only about 20% as of 2005. Further, there is extensive use of renewables, much more than the rest of the country. Since they have gotten more of the low-hanging fruit, there are many challenges, particularly transmission adequacy, to get at other green resources.

Another concern is that the CPUC approach to IOU regulation on greenhouse gases leaves out the municipals. The legislative bills also don't address this issue. The Los Angeles Dept. of Water Power [LADWP] has extensive reliance on coal, which they own. It would be very difficult for them to achieve compliance in a reasonable period of time, but they don't have to because they are a municipal. In terms of carbon intensity, LADWP is on par with the country, around 50% coal, while California on average is only 20%.

Many of the leading edge utilities with significant renewables are concerned about how they can increase their renewables and reduce carbon. Southern California Edison has reduced $5.4 million metric tons of CO^2 this year through energy efficiency programs, and they're spending $675 million over the next three years. These carbon reductions will certainly be expensive.

Companies have concerns for fuel switching too. Some big coal plants have been shut down, but other contracts would be extremely difficult to change. The costs are extensive there also. Fuel delivery cost projections by the EIA show a factor of 3 between natural gas and coal.

Climate action team analyses show that demand will increase above forecasts by a factor of 1% to 3% because of global warming effects that are inevitable in California. Let's remember that none of these regional programs will make a significant difference in global warming. In fact, strong research by Wrigley in the early nineties shows that if all Kyoto countries and the U.S. maintained the Kyoto reductions through the end of the century, the temperature forecast models of the IPCC would change only .08 degrees Celsius. However, Kyoto ends around 2012. There needs to be some relevance to these programs. It doesn't mean that we shouldn't pursue reductions but it does mean we should proceed cautiously.

Ultimately California needs safety valves and offsets make a lot of sense. If the policy goal is greenhouse gas reduction, wherever you do it is irrelevant. The gases distribute in each hemisphere at about a 30 day rate, so the location doesn't make any difference. On the basis of cost and environmental superiority, it makes sense to go to places outside of because everything in California is more expensive. This is partly because they've already done so much, mostly by efficiency improvement. New gains will be more expensive, particularly since the easy things have been done. Forestation is limited in California, and there are questions about its legitimacy for some environmental advocates. However, offsets in other parts of the world can be regulated and measured with a great deal of validity. This approach makes sense.

Another concern is that if the price of electricity does go up substantially, the more you discourage the use of electricity and encourage the use of fossil fuels substituting directly for that energy use. Regulation needs to ensure that the role of electricity is maintained in the system. That's how we get cleaner.

These unilateral mandatory sub-regional programs are not really sensible from a factual standpoint. The politics are understandable and I'm resigned to that. If we do move forward, the programs should be comprehensive, that's the economically efficient way to accomplish this. Many studies support that primary idea. All emitters, all greenhouse gases should be included. We should take a long term approach rather than a focus on dramatic short term reductions. Short term approaches force premature retirement of capital. A focus on investments in transferable technologies that lead to a low carbon future are absolutely critical. California has a dramatic record of being an innovative state. It should provide leadership with technology and for the design of a national program.

Ultimately, we all need coal. There's a huge amount of coal reserves in this country. The U.S. has the most reserves, followed by Russia, China, and India. China and India are using their coal rapidly now. We need to use that coal in a clean carbon efficient manner.

Question: In your charts concerning power usage, are you referring to what's consumed or simply the generation that located and available in the regions you identify?

Speaker 3: They refer to consumption.

Speaker 4.

I agree with many of the points the previous speaker made. However, I hope to impart a greater sense of urgency. There is a clear role for the RGGI program in the Northeast, and in California's upcoming program. They are early adapters; others won't follow if someone doesn't lead. We cannot be casual in our approach to this problem.

I will focus on issues with the CPUC [California Public Utilities Commission]. First, I want to provide context in California, so I'll give a quick overview of state climate policies. Then I will discuss initiatives at the PUC, and I'll close by discussing the biggest challenges for the PUC in the future.

California can and should make a difference on climate policy. The governor, his likely competitors this fall, most decision makers, certainly most people in the legislature, and the majority of Californians share the view that it's time to move on. California is the world's sixth or seventh or eighth biggest economy, depending on exchange rates and the value of the dollar. They're also the ninth largest emitter in the world. On a carbon intensity basis, they're lower than a lot of other places. Nonetheless, their total greenhouse gas emissions exceed that of many countries twice the population of California.

Further, California has a track record of groundbreaking environmental policies. California regulations have been copied repeatedly in American and global markets. The governor's greenhouse gas targets are very significant, especially the 2050 reduction. The targets are the equivalent to California joining the Kyoto treaty. The climate action team was created to investigate options to meet the targets that the governor set in Q1 2005. The action team's report was released this year and endorsed by the governor.

The report includes policy recommendations to reduce emissions for all sectors of the economy. Different approaches are recommended for different sectors based on source of emissions. For example, the primary emphasis for personal vehicles is tailpipe regulations for auto makers. The electricity standard, accounts for about 20% of statewide greenhouse gas emissions. For all sectors with large point sources, the report proposed a multi-sector cap with market based compliance measures. It would include cement manufacturing, oil refining, oil and gas extraction, and solid waste landfills.

The PUC has several initiatives to reduce greenhouse gas emissions from the companies they regulate. They're setting policies that prioritize acquisitions of low and non-carbon resources, providing incentives for utilities to take greenhouse gas emissions into account as they procure new resources. They're encouraging R&D for new technologies. Membership is complete now in California's voluntary climate action registry, so they can track emissions. These policies are consistent with the state's energy action plan.

They are using a loading order, which is simply a priority list. This is an effort to shift the energy mix over time to cleaner and less carbon intensive resources. First on the list is energy efficiency and demand response programs such as AMI and critical peak pricing. The PUC will soon make a decision on replacing six and a half million meters in the PG&E system with advanced meters. Other resources will include renewables, including solar, and, clean and efficient fossil fuel sources.

California's emphasis on energy efficiency is not new. During the oil shocks in the early seventies, they began reducing the energy use of buildings and appliances via the creation of the energy commission and mandated programs. Within California, per capita consumption has stayed flat for the past 30 years, even as it has nearly doubled in the US overall. The NRDC estimates that if the US had matched California's record on energy efficiency and electricity, 500 large, 500-megawatt power plants over the past 30 years would have been unnecessary. that is nearly a quarter of US generating capacity; 780 million tons of CO^2 per year.

Same on transportation. Instead of freezing CAFE standards for 21 years, the U.S. could have increased them by five miles per gallon ten years ago. We would be importing 1.5 million barrels of oil less per day.

While much of the country lags behind California, there is still more potential there as well. They haven't got all the low hanging fruit. They plan to invest in all cost-effective energy efficiency available over the next decade. The PUC has told the utilities to spend another two billion dollars over the next few years on energy efficiency to reduce projected growth and energy use by 50%.

The PUC expects energy efficiency and renewable energy policies will go a long way toward meeting the governor's goal. They have the most ambitious portfolio standard in the country. California has a statute that says by 2017, 20% of sources for the IOUs will be renewables. However, the PUC, in the energy action plan, said it has to be done by 2010.

By 2020, Governor Schwarzenegger wants one third of electricity sales coming from renewables. That's a heck of a challenge but not impossible. The PUC's new solar initiative was adopted in January. It will provide $3 billion in incentives, essentially photovoltaics, over the next ten years to finance PVs and other solar technologies of existing and new buildings.

The PUC is implementing policies to internalize the cost associated with greenhouse gas emissions when utilities acquire resources to meet growing energy needs. In 2004, they adopted a carbon risk adder policy that requires utilities to adjust bids for new fossil fired energy by eight dollars a ton of CO^2. This is to account for the potential cost of complying with likely carbon mitigation regulations in the future. They see it as a critical rate payer protection measure and an environmental measure.

They are working on a policy that requires all utilities' long term supplies have emissions at least as clean as combined cycle natural gas plants. A similar statewide standard currently up for legislation would encompass municipal utilities like LADWP.

This past February, the CPUC adopted a greenhouse gas emissions cap on load serving entities. This load based cap applies to all sources of supply used for load, including imported electricity from other states. The proceeding to implement the load based cap is still underway and currently the PUC is focused on the relationship between the performance standard and the cap. They are looking at adding market based solutions whereas the original cap performance standard is a command and control approach that has a technology forcing effect. They are determining if they need both a standard and a market mechanism, or if the performance standard cap will serve only as an interim measure. They are serious about adopting a cap and trade system. The cap and trade system will eventually provide a unifying framework for utility procurement incentives. The carbon adder, and very likely the performance standard, should become unnecessary.

Several issues must be addressed to do this. Allocating allowances is a particularly thorny question, as recent experience in the EU's emission trading market demonstrates. The PUC has a preference for administrative allocation, but they aren't firmly committed to this approach. Most academics recommend an auction, and some of the RGGI states are at least partially relying on such a system.

A major challenge is limiting leakage, increased emissions outside our borders that offset reductions within California. The western grid links California extensively with neighboring states and countries, especially British Columbia. The import issue could intensify. New proposals to deliver coal by wire could increase the potential for carbon leakage. For example, the frontier land proposal, which would link California all the way to Wyoming.

The PUC's decision to use a load based cap will hold utilities accountable for emissions from all their supplies, in-state or out-of-state. However, there are formidable measurement and tracking issues when accounting for emissions from imported energy, especially spot market transactions. The PUC expects to work closely with the RGGI states, who are similarly seeking to ensure their emissions goals are not undermined by leakage and increased importations from the Midwest.

A further challenge is a hybrid market structure. Unlike states that have required full divestiture of generation, California retains a hybrid market structure. Even when California went through deregulation, utilities only had to vest their natural gas generation. And now, that's all changed. The post-deregulation hybrid market means the PUC's policies must be applied to utility retained and merchant generation. On the retail side, they control emissions from the ESPs and the IOUs. Further, without legislative action on municipal utilities, emissions will not be capped. Expansion of the municipal share of energy deliveries could become another source of leakage. The legislature must address this.

Another issue is the form and design of flexible market based compliance measures. The PUC is considering whether to permit a wide range of compliance options through offsets or training. Instead of direct emissions cuts, utilities could find lower cost reductions elsewhere. They could invest in projects that reduce emissions from other sources, and this could occur outside California.

Alternatively, they could aim to accelerate commercialization of advanced coal technologies, integrated gasification, or combined cycle generation. Capture and permanent geologic sequestration of CO^2 could also be explored. Gasification and sequestration are proven technologies, but putting them together and reducing costs is a significant challenge. This approach could give US firms an advantage in bringing this technology to China, India, and other developing nations; potentially vast markets.

Al Gore's recent movie really documents the need for a paradigm shift. He's been dealing with greenhouse gas issues and global warming for 30 years. Much of the time, we get lost in the minutiae or cost effectiveness of a particular program. We have to be concerned about cost. But I'm less concerned about marginal cost impacts than I am about the overall outcome of policies. It's the biggest challenge facing us environmentally.

Additional Commentary from an unscheduled speaker on the EU approach and situation.

Comment: Since January 2005 the EU has been practicing emissions trading, and the Common Market is in place. Allocation of allowances truly is a critical issue. The legal framework in Europe works fairly well; there are no special complaints about that. Using market mechanisms to solve the problem has been shown to be feasible.

One problem is that European law gives each member state the right to determine allocations. These are called subsidiarity principles. There is a common goal, but then each government does it its own way. There have been different allocation strategies and this has led to some market distortions. Strange outcomes can occur, for instance, electricity prices going up without any apparent reason. Utilities have then been explaining the theory of opportunity costs to the public and to regulators. It's always more difficult to explain to consumers. [laughter]

Spain decided in February to recover some of the windfall profits of companies from last year. This will be a difficult political and legal decision. However, the Spanish utilities have more or less accepted that they have to pay back what they got in 2005 as extra profits for CO^2.

These trading practices started in Germany. They arbitraged very well and very consistently, and soon France was exporting large amounts of their nuclear overcapacity to Germany. Soon, for the first time in many, many years, we saw Italian generators operating. Italy usually imports about 16% of their electricity consumption, mainly from France but this was reversed because prices were so high in France that even some old Italian power stations were competitive. If the allocation is not properly distributed, this can lead first to a transfer of money from consumers to generators without any visible effect in the short term, because the money is necessary to build more efficient power stations. However, in the short run you don't see any new power stations being built, it's very difficult to justify to consumers. Distortions can affect an integrated super-national market considerably. Ultimately, the market mechanisms work well for emissions trading, but allocation of the allowances is critical.

Leakage has not happened in Europe. Instead we are seeing new projects; nuclear power stations being now built, more renewables, and more gas-fired facilities. The investment strategies of the utilities and the investors, seem not to be very deeply affected by emissions trading.

Question: I'm concerned about the compatibility of the evolving structure of greenhouse gas controls with the future system for greenhouse gas controls as they are likely to evolve. How well do they fit together? Are there current policies that might become problematic, or make it harder to go further? As an example, some have made the argument that Kyoto made it harder to include developing countries by excluding them initially.

My second concern is the compatibility of the emissions policies and the electricity market operation. For instance, California is focused on loads meeting emissions requirements, as opposed to generation, to avoid leakage. This creates implicit assumptions about how long-term arrangements can be made with specific plants. Are there incompatibilities between the GHG policies and the market? This is particularly important for the long-term effort; and obviously if we don't get the long-term effort in GHG, we haven't solved the problem.

Speaker 2: The hope is that by leading, the states will define what the regulatory system to be looks like. This begins with a rational negotiation among states with divergent interests and electricity markets. Then it requires moving forward and discovering what the warts are. Folks in RGGI got to learn from what was happening in the EU; particularly the price volatility problems. This led to some of the price-dampening mechanisms you see in the RGGI agreement. Did RGGI anticipate everything? No. California is looking at how utilities are replacing generating assets and incorporating climate issues into that process. RGGI is learning from California there. The work in RGGI and California will help define what the parameters should be, and help ensure that some of the nightmare price spike scenarios don't happen.

The various regional parties have had an eye on ultimate compatibility with other trading systems, including the EU trading system. EU certified credits are not yet recognized, at least at the outset, but that's the direction people want to go.

There is an incompatibility from the emphasis on transmission as the solution. For instance, Pepco Holdings recently announced a new 500 KB line moving up the spine of the Northeast corridor. Pre-RGGI and natural gas spikes, and without other regulatory issues in place, that might be the right solution. When one accounts for the units that must be retired for other environmental reasons, such as mercury and other criteria pollutants, there's got to be more of an emphasis on generating carbon-efficient generating capacity within region. We can't eliminate the transmission focus altogether, but we need more of an emphasis on in-region capacity. This will make systems more compatible, and ensure the impacts of RGGI salutary with respect to electricity pricing and delivery.

Speaker: I agree with many of the points just made and have two additional. It would have been far more efficient and effective to do this nationally, but that decision was made in the 2000 presidential election, wasn't it? The advantage of the federal system is that states can act in the absence of federal action; especially when big states act.

Similarly, it would have been better for Kyoto if India and China were involved, but they're not. One way to address that is to help them. The carbon problem is the same for them as it is here, and they realize that. We need to help them meet their energy needs in a more effective way. And that is beginning to happen. China's turning to Japan for energy efficiency. California has sister state agreement with Jingzhou Province, to help them improve energy efficiency. This is what this country ought to be doing.

Speaker 3: Regulatory program design can lock in technologies for an awful long period of time. Coal to gas is not going to do it; we have to go beyond gas very quickly. We need fundamental basic research on innovative technology to accomplish that. There's not nearly enough – it's ineffective and unfunded.

The work with China on energy efficiency transfer is a leadership hallmark for California. One could design the GHG program so that efficiency gains for China could be subsidized by California utilities as offsets. This could be a least cost method that the PUC knows how to measure and account for.

Experimentation is important but we need to be. There's an awful lot at stake. Prime Minister Blair's statement that countries will not sacrifice their economic well-being in order to address the greenhouse gas issue is correct. Cost-effective reduction methods are needed, not just regulatory-induced methods.

Speaker: The people who wrote RGGI, and some in California, are among the top people in the country working in Washington on this same issue. These programs represent, at least in terms of their framework, what people would design in Washington if they could.

The greater concern is when the nation is actually going to do something. If something were going to happen in the next 12 months then there's no worry. What happens if the nation does something in six years? The worry here is about locking in technologies, but also about locking out technologies. Further, the price of energy may drop, as Dan Yergen has claimed, in the 2010, 2011 period. The country will create very different programs with $80 oil versus a period of $35 oil.

The consensus right now is obviously cap and trade. Six years from now, policymakers may think it's a carbon tax. Some analysts might say a carbon tax has a snowball's chance in hell. However, things do change. We need to treat it as a dynamic situation.

In terms of compatibility of the existing operations, programs like RGGI do restrict flexibility. However, the effect is so small and its impact so low, that it's negligible. The restriction on flexibility will be very slight until 2013.

Question: No one has discussed output-based allocations in terms of updating. I mean updating in terms of how output changes over time. One concern in parts of the EU is that if you have an output-based allocation that updates over time, it encourages utilities to generate more power to capture these valuable allowance assets. If you have an updated <u>input</u> allocation, it encourages more coal-fired generation because it's less efficient than natural gas combined cycle and they can capture more allowances. It's important to address the distributional consequences of allocation, either free of charge or by auction, but also to discuss the efficiency properties of these allocation mechanisms.

The problem is that for plants that shut down, they lose their allocations, which provides an incentive for utilities to keep old, inefficient units running when they should have been retired. Whereas if you allow them to keep an allocation over time, they have the right incentives to shut the plant down when it should be.

Second, I am also concerned about transmission congestion in the RGGI region. If we consider the constraints moving west to east, it seems that congestion is the friend of a carbon cap, given the location of coal-fired generation. Alleviating these constraints, moving power west to east, means more coal-fired generation would be used. The frontier line from Wyoming to California is a similar issue. So does it really then make sense in a carbon-constrained world to alleviate these constraints? Or could alleviating transmission constraints reduce carbon emissions in some contexts? This needs to be considered.

Third, the carbon program regions have separated generation from state oversight. However, when we consider cost-of-service regulation in states where leakage may occur and is brought into a carbon program, there are different state regulations or state policies. Those interactions with the carbon market are unclear at this time. Resources for the Future has done some analysis of this issue with the sulfur dioxide, but generally we don't know how state regulation will interact with cap and trade programs until we simulate them.

Fourth, if we go to a national market, there's the question of opting out. For instance, New York just opted out of the cap and trade program in the Cleaner Mercury rule. How could that affect cap and trade programs?

Speaker 1: I'll address these issues working backwards. There are easy provisions in RGGI to opt out. Every state would want that. It doesn't seem a large issue. Second, the leakage issue and interaction with the regulatory rules of other states is an excellent point. There's certainly going to be some trial and error. No matter what program you put in effect, you're going to find a number of anomalies that will occur. Third, the question of transmission constraints is important. In effect, RGGI is working to make it easier to leak. This is occurring with the Quebec power lines and the efforts to overcome seams issues in New York. This is where one policy is running contrary to the other. Clearly these need to be addressed.

The toughest problem is how to design the allocations. There's two things here. There's the output, and how you structure it, the fact that it can become perverse. Second is updating. Analysis of updating suggests that rents to the utilities are significantly less if you update, and that consumers benefit. Generally, the generators oppose updating. I am told that Sweden is one of the few countries that has adopted updating for NO^2. It is hard to pass politically, because the generators are very good at assessing the financial implications. The design issues are critical to avoid various perverse incentives.

Question: If we look at how Eastern states are implementing the Cleaner Interstate rule, especially for nitrogen oxide allocations, there are many different proposals. The proposals in the majority may tell us where national carbon policy will end up in terms of allocation.

Speaker 1: It's hard to persuade regulators not to reflexively give the allowances to generators, on a production-based or mission-based basis. Nonetheless, it happened in RGGI when they agreed on the minimum auction of 25%. Beyond that each state will do as they wish.

The perversity of conflicting policies that are pro leakage and anti-leakage could be addressed pretty readily. If states have to reduce their allocation of allowances due to any RGGI-attributable increases in leakage, then that will create the right incentive structure. Further, since congestion and over-reliance on transmission and reliability are problems in the North East, they should fence off allowances for new capacity. Obviously, some criteria in terms of carbon efficiency would be necessary. While a straight public benefits auction of 100% is not desirable, the remaining 50% could be used for re-powering that is more carbon efficient or increases capacity. These adjustments could address the enthusiasm for transmission and the countervailing notion that a carbon cap will lose integrity if it leads to transmission increases.

This is not just a regional program problem. A national program would have similar problems with Mexico and Canada. Making states cover RGGI-attributable increases in transmission by consuming their allowances would help. Distributing allowances on the basis of policy merit for innovative technology, more carbon-efficient re-powering, or new capacity would also be useful.

Speaker 2: I'll just address the transmission and leakage question. Having a load-based cap, a carbon adder, and applying a CCGT measurement to make coal responsive can all be part of the solution. California's use of a loading order that prioritizes energy efficiency and demand response programs like advance meters is also useful. However, there's significant resistance to these things.

In terms of the Frontier line, Wyoming is now talking about IGCC and carbon sequestration. Originally, they thought they could build pulverized coal plants in Powder River and couple it with a little wind power and ship it to Salt Lake, Las Vegas, and Southern California. The policies in California will have a strong impact on the decisions in Wyoming. That is a way of dealing with leakage. There are also competing interests. New Mexico wants to sell wind power to Southern California, on a much shorter transmission path, and use coal as a backup. The California policies are technology-inducing. They may be command and control decisions but they're positive for California and the West generally.

Speaker 3: For allocation, if you do it by grandfathering. there's going to be some perversities. Auction mechanisms work more realistically, given that this is a valuable asset. Right now it's 25% but if we get more politically comfortable with auctions, then it will increase. Massachusetts has pending legislation to join RGGI which may pass. In any case they will require 50% under auction if it passes. This is really the most efficient way to handle the allowances.

Speaker 4: Let's remember that RGGI is a multiple state program and California a single state. It's not clear that there will be any trading for California. It is pretty clean, with the exception of one of their neighbors. The same trading questions get more complicated when one considers cost effective strategy and policy for a single state.

Question: There's been little discussion of the Midwest and that's where the coal-fired capacity is. For instance, Ohio has the dubious distinction of being ranked first, second and third in the nation's worst air pollutants. How do we get a program going in the Midwest where the real problem is?

Second, how do we finance IGCC without shifting 100% of the burden to ratepayers? In Ohio, AEP tried to get full recovery, up front, from ratepayers, to build one of these plants. They say there's no way to get these things built without some kind of public financing. How do we go about getting these things financed and built in a way that's more equitable?

Speaker 1: Well, the Midwest does have some initiatives. Other analysis shows that the costs of IGCC don't have to be fully covered up front. If regulators are willing to accept long-term PPAs [purchase power agreements], you can finance an IGCC plant effectively and show consumer benefit too. This is only detrimental if projections show that electricity rates will go significantly below the current market; very unlikely. Minnesota is doing something like this currently.

Another example is Pennsylvania's incentives for IGCC. They're coal-dependent and dirty so they're still standing apart from RGGI but they've seen the writing on the wall. They're aggressively trying to get an IGCC plant implemented.

Unfortunately, if there were a regulatory commitment on carbon ten years ago it would have changed investment decisions in some states to pursue pulverized coal. Similarly, if the Bush administration had started with a strong mercury rule. Pulverized coal can meet a weaker mercury standard with a combination of low-NO^2 burners and SCRs, but not with a stringent mercury standard. Even the Midwest is seeing real incentives put on the table, rather than regulatory standards. These incentives, even in the form of a PPA, can be done fairly. Longer-term PPAs are necessary to give the capital markets confidence to move forward.

Question: What is the length of the PPAs in Minnesota?

Speaker: I don't have the specific Minnesota data. As an alternate example, even a combined cycle gas plant can be hard to finance. New York just had a plant go on line in Astoria that they financed with a 10-year PPA. That's not enough for an IGCC plant, but 25 years should bring IGCC to parity with pulverized coal.

Speaker: As a quick side note, some missionary work needs to be done among ratepayer advocates to reinforce to them that addressing climate change is in the ratepayer's long term interest. For instance, in New Jersey a lot of the ratepayers are also homeowners who could be under water if we don't take climate change seriously.

Speaker 4: There's still significant challenges for carbon capture and storage. Financing IGCC without that doesn't do much. Currently we're plumbing the plants for the future but that's not enough. There are extensive regulatory questions for sequestration. No one is doing much work on that. There's some work being done on permitting and liabilities; what the liabilities are for such storage concepts. There's strong research looking at methods other than gasification as a way to remove CO^2. Chilled ammonia extraction is promising. These issues complicate the financing problem. Certainly longer term financing helps but we need separate programs aimed at basic technology research and addressing key regulatory questions.

Speaker 2: BP also has a new approach to sequestration. They have a large refinery in Carson, California. They are going to put in a new 500-megawatt power plant. It will take petroleum coke, a low value part of the petroleum chain, and convert it to hydrogen, use that to generate electricity, and sequester the CO^2 underground off the coast of California in an oil project called THUMS. This will get more oil out of the ground than normal; it's almost like a closed loop program.

Their partner is Edison Mission Energy, and the two of them will come to the CPUC for recognition of this project. It would be outside the normal RFO process. I would hope that the PUC would define an exception process to approve such a project.

Speaker: Even before sequestration, the CO^2 benefits in terms of the greater efficiency of IGCC are demonstrable and worthwhile. If we replaced older coal capacity with IGCC, we would meet RGGI-analogous goals just by doing that. There are significant benefits even prior to sequestration.

Question: This is a question for speaker 3 concerning RGGI. You stated that there will be benefits, but only a small portion will be captured by ratepayers in the implementing states. However, three out of four of your explicit benefits would seem to accrue to these ratepayers. Can you please clarify? Second, what are the larger benefits and who's the beneficiary?

Speaker 3: Well, the explicit benefits outlined in RGGI may not be as useful for particular states. For instance, New England will not benefit greatly by its reduction of greenhouse gases under RGGI. In terms of global climate it's not going to make a large difference.

A second benefit is that it's to the states' advantage to get ahead of the curve, to make investments now rather than wait. It is an advantage if a region learns how to do this better so that when a federal program comes into play they have an advantage over other regions or companies. However, most New England companies are service-oriented, they don't actually use a lot of energy. However, for companies that do use energy, there will have almost complete compatibility between future federal programs and what they have done in RGGI.

A third argument was that doing more now would promote technologies and get the region ahead of the curve. However, technologies may be less expensive, higher quality, and more efficient later. So maybe it's better to do less now and more later. Of course, that assumes a linear damage function for climate and that's probably not accurate.

Another benefit is the promotion of energy efficiency renewables and new technologies. The question is whether RGGI is the best way to accomplish that. If all one wanted was energy efficiency renewables and new technologies, as opposed to reducing greenhouse gases, then there are other things that could be done. However, there is huge benefit to the country overall in having regions adapt cap and trade programs. Folks in Kansas don't have to pay expenses and they can learn from the New England and California mistakes. RGGI and California are doing a great service to the country.

My last argument is implicit. Someone has to lead and others will follow, others in this case being Washington. If that occurs it's a great political step. The states and the regions can set an example and then Congress will have no choice but to embrace a climate plan they've been resisting for 15 years. I hope that happens but I'm not convinced that RGGI and California by themselves will carry the Congress. Congress will act because of other factors now in play.

Question: What is the most persuasive argument to get a utility to adopt a proactive policy toward greenhouse gases? If regulators in Oklahoma make arguments to utility executives about greenhouse gas concerns and question the construction of a giant coal facility in southern Oklahoma, they simply say yes, but it's the cheapest way to go. How do we address this?

Speaker: There isn't an argument to give them. Utilities go where the price signals are. It's all about incentives. You need a cap and trade or a carbon tax program. A recent speech at Harvard University by a large utility CEO addressed the importance of the climate problem. A questioner asked why his company had just built a 700 megawatt coal facility. His response was, that was some other guys in the company doing this [laughter]. They said, you're the CEO! There was no further explanation. He later said privately that climate was never discussed in the meeting to make the capital decisions to build the facility. Until states get the price signals right, take the externality of greenhouse gas concentrations and say they have to be paid, then you'll have these situations.

Question: There seems to be a dynamic tension between competitive markets and controlling greenhouse gases. We should make a differentiation between taxpayer obligations and ratepayer obligations. The IGCC program discussed earlier puts taxpayer dollars at risk not ratepayers. No utility is being pushed to enter into a long-term contract. It's the state regulatory authority that will be involved. It's useful to keep market solutions active, and try to move costs to taxpayers rather than ratepayers when possible.

Speaker: There's two issues there. RGGI advances market solutions generally. Oddly, although we've commodified carbon reductions through cap and trade programs and renewables with renewable energy certificates, we haven't done that with energy efficiency measures. Is there a way we can commodify energy efficiency with similar market dynamics?

Comment: That may be a false syllogism. I think ratepayers and taxpayers are by and large the same people.

Question: There is a distinction without a difference here in large part. However, the governor tried to pass the California Solar Initiative for two years and it never passed the legislature. Then he came to the PUC and asked if they could do it. It only takes three votes at the PUC to increase rates to fund a program. Candidly, it is a tax in effect. We should be blunt about it. They committed $300 million a year for ten years to the solar initiative. There's sometimes a false dichotomy here. There are subtleties because of munis, but the ratepayers always pay.

Question: What is the role of demand response in some of these programs?

Speaker: It's really huge. The overall system will be much more efficient if we go down that route. The Italian utility UNEL has replaced 30 million meters with a 2 way real time system. The system was put together by IBM and Echelon, a company in San Jose, California.

California utilities had no interest in doing this until the PUC strongly suggested they look at it. Their commissioner took the CEOs of San Diego, Edison, and PG&E to Italy and spent two days looking at it. PG&E now has a PUC application that will put 6.5 million meters on their systems. They have a pilot project in Vacaville. You can't have critical peak pricing or demand response programs without a useful meter.

Question: This discussion has a significant credibility. These programs will spend a lot of ratepayer money because carbon dioxide and global warming are a problem. Nuclear power has been off the table for the entire discussion. These plans will increase rates, drive up the cost of our one domestic energy source, coal and push utilities to import more LNG from the Middle East. I'm not sure that's leadership.

Speaker 3: You're perfectly right. If you are sincere about climate you have got to look at nuclear. The country is waiting to see what the Southeast does. There are six applications for new nuclear facilities at one stage or another in the Southeast. If they build some, and environmentalists don't hold it up for a long time, and it's a reasonable price, it's worth thinking about. However, it's a nonstarter in New England. I'm just making an observation. If you're serious about climate you've got to entertain the nuclear option.

Speaker 1: We need to recognize the extent of taxpayer subsidies that have been made in nuclear power as part of the equation. Especially in terms of liability and limitations. It's not just a regulatory impediment. Certainly, many of the RGGI states have nuclear capacity. There's political and economic reasons for the complete lack of proposals in the North East. It's a combination of political constraints, siting issues, and economics. They are more difficult in RGGI states because of high population densities as well. It's unfair to say it's been taken off the table.

Speaker 3: It has been taken off the table in California by state statute. It says until the waste problem is solved there will be no more nuclear plants. That was 1976 and it's been upheld by the Supreme Court. There's not a senior utility executive in California that would want to build a nuclear plant today. They're still concerned about the cost. Diablo will cost $5.8 billion. They're often 9-10 times over their estimates. The costs are so large that there is a chilling effect.

It's not off the table. The national commission on energy policy that the NRDC and others were involved in has opened the door to nuclear again. The consumer energy council of America just put out a report that was supportive of more nuclear. There is a growing awareness that there is a role for nuclear in dealing with climate change.

Session Two.
Wholesale and Retail Electricity Market Models: Will they Mesh Well or Cancel Each Other Out?

The original game plan for restructuring retail electricity markets in most states was that there would be a transition period during which utilities sold all or some of their generating assets (or at least removed them from rate base and separated them out functionally) and recovered stranded asset costs, while freezing or capping retail prices. Generally that transition period was to end in the 2005-2006 timeframes. The assumption, of course, was that the introduction of competition would allow for many new suppliers to enter the market, thereby reducing the role of POLR providers and, of course, resulting *in lower prices, so that by the end of the transition period, consumers would, at least, from the point of view of price, be no worse off.*

We have now found ourselves at the end of the transition period and have high commodity prices, still lack the critical supplier mass required for effective retail competition (especially for small load customers) in most states, and the POLR function is no less important now than it was during the transition period. Few, if any states, have developed fully competitive retail markets, with multiple suppliers, meaningful price signals to end users, effective demand side response mechanisms. State regulators, and legislators as well, for fear of higher prices and/or fear of supply shortfalls, have been scrambling to take steps to deal with the situation. Some states, notably New Jersey, have put in place a bidding process for POLR supply that is designed to capture the trends in the wholesale market. Other states have put in place other types of procurement methods, including other types of bidding processes and/or encouraging rate base construction by utilities. Some of these have been heavily criticized for being biased in favor of supply side options and incumbent utilities.

To what extent will the lack of evolution of competitive retail markets and the response of the states to that circumstance spill over into wholesale markets, rendering them less efficient, less competitive, and less robust? In a larger sense, how symbiotic are retail and wholesale markets? It stands to reason that one cannot have retail competition without wholesale competition, but are we about to prove the converse true as well?

Speaker 1.

The transition to competitive markets over the last decade has had mixed results if you look at the standard deviation of benefit cost studies of market success. I'm starting from the perspective that we're dealing with a net positive. The political driver for restructuring was a generic expectation of lower prices. However, there was never a benchmark or a time horizon to measure success.

We can and should accept the reality that markets performed as designed. Similarly, politicians do act politically and have done so consistently. The only surprise is how political they can act given a fertile opportunity. Efforts to forge a consensus on a uniform national model for retail competitive market were valuable, created an educational base, and hopefully avoided a repetition of some of the mistakes made earlier. However, they diverted a lot of time and resources from general efforts to create a sustainable retail market model.

Many policymakers were attempting to raise red flags were dealing with a political environment of getting it done quickly rather than getting it done right. Extended rate freezes and caps, usually for a 12 or 18 month time, were needed to move the process along. Conversely, they insulated the political process from any near term consequences of the market functioning or more accurately, "dysfunctioning."

Competitive wholesale markets also lacked political accountability. FERC commissioners have commented, even through the California crisis, that they never felt directly pressured to act other than the abuse at a Congressional oversight hearing. They don't have the real world context and political pressure that a state PUC or legislator might have.

Retail markets have been considerably more fragile over this time frame and the default response we've seen has been ad hoc administrative intervention. Nonetheless, retail competition, while facing challenges, is not terminal. There are clearly some success stories, and it has a viable future. The early debate on the benefits of competition created unrealistic expectations of lower prices, particularly for the small retail customer. Neither the time horizon nor the baseline were defined. Lower than what? The current debate lacks clearly stipulated baselines. This is exacerbated by immediate exposure to market outcomes and unprecedented price volatility. The California debacle continues to complicate the debate. Finally, there is a skewed allocation of benefits. The benefits are not uniformly distributed among rate payer classes. Instead, a few large customers are perceived as the big winners.

The current status of state retail access is probably not going to change in the foreseeable future. There are 28 states with no access. 23 states have access statutes in the books, but at least 7 of those will not follow through with any real action. These circumstances will not change in the near future.

There are extensive legal and practical barriers to removing retail access, even though we hear that rhetoric in some jurisdictions. They discuss the status quo of the good old days although it's not clear what the good old days were or what was really good about them. The U.S. lacks the option to pursue the big bang approach as the UK did.

So to answer the question posed to this panel, can competitive wholesale markets survive the absence of retail competition? The answer is yes. We have the key elements of a workably competitive wholesale market. Bid based security constrained dispatch and unit commitment, locational pricing, incentives for market entry and expansion; all of the elements associated with a workably competitive and efficient market. They can exist even with dysfunctional retail markets or without them at all. The follow-up question is to what degree can policymakers enhance the benefits of wholesale competition by well designed retail competition?

What are the implications for regulators? First, do what you want to do but do no harm to the other guys. Federal regulators can proceed with their agendas and also respect state decisions. The recent FERC NOPR has that effect. There is clearly an attempt to provide incentives, but to do so in a different political context.

Similarly, state regulators can be negative or agnostic regarding retail competition. However, the actions they take can avoid undermining some of the positive benefits of competitive markets. Commodity price volatility, fears of supply shortages, and perceived inequity in benefit allocations are driving increased intervention by state regulators. We'll always have these kinds of interventions. The question is whether they jeopardize the progress that's been made at the wholesale level. Here, the nature and substance of arrangements for standard offer POLR service is important. The retail challenge has been to optimize efficiency benefits of the market through price exposure balanced with the political imperatives of mitigating volatility. Achieving this balance in a consistent manner is the key challenge and it hasn't been achieved.

There are two alternative models for the standard offer service. Auction rights to serve default customers and RFOs [requests for offers]. Both are compatible with wholesale markets. The auction model has long term benefits. It's an efficient form of price discovery. Proponents argue it provides outcomes more closely linked to the wholesale market and it limits suppliers from capturing excessive rents. We don't have empirical data to substantiate these claims. RFO outcomes are difficult to gauge because there's not access to baseline cost data.

To sum up, political intervention in retail markets is inevitable, wholesale markets need to be flexible to accommodate political intervention. The challenge to FERC is to demonstrate how these interventions can decrease the efficient functioning of markets but simultaneously avoid political confrontation and implicit threats of preemption with the states.

State retail models can affect wholesale markets in a variety of ways. Command and control mandates with regard to resource planning and portfolios. States can suppress demand side response, not withstanding all the rhetoric. State limits on cost recovery from wholesale purchases when pricing outcomes don't fit the political parameters. Incumbent preferences and lack of transparency occur both in auction and RFO implementation. Finally, constraints may be imposed – NIMBY, parochial, however – on transmission upgrades and expansion.

Speaker 2.

I will focus on the status of Ohio's retail programs. Ohio passed a restructuring law in 1999 with a transition period from 2001 to 2005. They were supposed to have full competition in 2005 but instead went to a different model. By late 2004 there was extensive switching through aggregation. There were over 450,000 customers in northern Ohio who were part of an aggregation program but that program imploded and the supplier left. The publicly stated reason was due to certain MISO charges and other unexpected charges.

The retail market in Ohio collapsed at that point and there was little switching in any of the four utilities. And that decline in shopping led policymakers to reassess. Why did it not work? The legislature created a framework and then left the details to regulators and stakeholders to determine in proceedings.

There were electric transition plan proceedings that stymied the market before it could even get started. The first problem was cost allocation. A lot of costs were moved into distribution that should have been generation related. Costs in distribution and transmission meant less costs that a customer could avoid if they switched to a competitive supplier.

Second, the utilities in Ohio applied for $11 billion in stranded costs and received it. If the stranded cost is subtracted from the generation price, the generation price of the utilities was well below market? It was a perverse outcome that varied from utility to utility.
There are also regulatory transition charges in place until 2010. In the northern part of the state these charges are 2-3 cents, very significant.

Given these circumstances, it's no wonder that competition did not materialize. The solution taken by the Ohio commission with the utilities was to file rate stabilization plans. The idea was to increase the transition period and provide stable rates for customers. However, they don't because they allow for annual increase in rates. They do provide revenue stability for the utility companies. These plans were supposed to promote competition but there's been no increase in competition. In fact, the problem is worse because the utilities are able to recover costs associated with generation that should be bypassable, and they're being treated as non-bypassable charges.

The distribution companies can now recover the cost of power plants. For example, CG&E's RSP, and the recent decision allowing AEP to recover phase one costs for building a power plant. These are distribution companies in a deregulated state with corporate separation. These recent decisions are in an application for re-hearing and most people expect these cases to end up in the Ohio Supreme Court. While court appeals on the rate stabilization plans continue, there is the whole issue of lost opportunity. Had they gone to a competitive market with appropriate bid structures in place, customers in northern Ohio would be saving money. A competitive bid today, a year and a half after the first court decision is less effective because of price increases and volatility. It's much more challenging and the public ends up believing competition doesn't work. In fact, it could have worked and it's really a question of lost opportunities.

Ohio is in a gray world between deregulation and regulation because of these hybrid rate stabilization plans that will be in effect to '08. Another effect is that it's created uncertainty in the market because companies and other stakeholders don't know where they're going from here. Another concern in this hybrid world is that the rate stabilization plans allow utilities to apply for increases without a full rate case review. It's not helpful to customers, especially when they are being required to pay for costs that should be bypassable.

Ohio did have one auction in northern Ohio, but it did not work. The devil is in the details. It's important to structure a competitive bid so that marketers can provide a product. It's important for regulators to listen to marketers to find out what they can do to make it work. Regulators need to create mechanisms that can keep prices competitive.

The other problem is that prices in the wholesale market are short term. There are no incentives to build base load capacity. Will the capacity be built through RTO incentives, or does the state need to step in? Financing new construction is critical. Switching the entire risk onto rate payers isn't the answer, but a mechanism that shares the risk is needed. The fact that deregulated utility companies are building generation because that's the only assurance of having capacity built is counterintuitive to the whole competitive market structure. There's a lack of long term bilateral contracts in wholesale markets. The clearing price is based on the highest cost units (gas prices), not the least cost units so this increases customer prices. The wholesale market was never perfected before the retail market. We kind of got the cart before the horse and what we're all struggling to do now is to fix that.

The one competitive bid in northern Ohio tried to bid out 100% of the load on a three year basis. The second year it tried to bid it out 100% of the load on a two year basis. That's simply a bad way to do it. Nobody wants to put all of their investments in one basket. Companies would want to hedge and have a combination of options. A competitive bid for the wholesale load for POLR should combine the competitive bid process, wholesale competition, along with integrated resource planning. This would result in a portfolio approach and diversify a state's portfolio mix.

Energy efficiency and demand response should be prioritized in portfolio options. The portfolio should be a combination of long and short term. The long term could be financed in part by a stream of revenue supported by the POLR load. Those details and whether you can go out to 25 years is part of the conundrum but it's one way to do it. The short term piece would be a laddered approach. A portion of the short term would be auctioned every year. If the POLR diminishes then the short term bids would diminish. This would protect the integrity of the long term contract supporting the POLR load. Incentives for renewable energy on a short and long term basis could be included. Overall, this would lead us to least cost planning for the POLR, or at least something in the realm of affordable. It would avoid having to switch 100% of the risk onto customers without knowing the true cost implications. This solves the inherent problems when an entity builds a plant like an IGCC without a competitive bid. There are no price cap guarantees.

The wholesale market is itself a work in progress. Prices will go up in regulated and deregulated states. We need to continue to strengthen the wholesale market. In Ohio, they need a new framework for 2009 when the rate stabilization plans expire and there is a new transition. Creating a competitive procurement generation strategy for POLR load would allow for competitive bidding in the wholesale market and improve the situation in both retail and wholesale.

Moderator: Can you give some examples of non-bypassable charges that are bypassable?

Speaker 2: One example would be environmental costs associated with upgrading generating facilities. Ohio has many coal based plants that are being upgraded to come into compliance with EPA regulations. In some plants they are bypassable and some aren't.

Speaker 3.

I'll focus my comments on New York. In March the state issued a report on the impacts of competition in wholesale and retail markets. There was a wealth of data and performance indicators for the wholesale markets although they never found a way to model the reality that didn't happen, the counterfactual. On the retail side, there was much less data. Clearly, having a wholesale and a retail market functioning together is the optimum solution. However, a vibrant retail market is not necessary for the wholesale markets to perform. In New York the retail markets were an evolution derived from a regulatory approach, not legislation. Wholesale markets began in late 1999 and retail markets followed very slowly afterwards. Nonetheless, the rumors of the demise of the retail markets are greatly exaggerated, to paraphrase Mark Twain.

On the wholesale side New York's utilities divested all of their generation with a couple of exceptions. New York has a robust spot market. Their ISO model is one of the premier models in the country. The markets are working well short term. There are load pockets, demand curves, and an array of mitigation measures for market power.

Consider the following information from the report. From 1991 to 1995 they built almost 4,800 megawatts in New York state. In 2000 to 2005, 4,200 megawatts, roughly comparable. The 4,800 megawatts in '95 came as a result of state legislative and regulatory policy. About 15% of those megawatts were in very bad locations that didn't need additional supply. Some were PURPA contracts and some of those run to 2045. Some of those contracts are five times the current market price. Those were the regulatory solutions in New York in the early 90s.

The market has been kinder. Some of it is timing, some of it is other exogenous factors that you can't attribute to competition. Nonetheless, the 4,200 megawatts investment since 2000 has all but 30 megawatts in constrained zones where, in most cases, locational capacity signals have sent the price signal to build. It's a rousing success. Half those megawatts were built with shareholder money, most of the rest with bond holder money. It's nice to have investors making these investment decisions and deciding long term how these costs are going to be allocated.

On the retail side, about 40% of the load is now with retail providers and ESCOs. Over 75% of the large commercial and industrial customers and almost half of the smaller business load are with competitive ESCOs. This is due in part to addressing wholesale market issues first. They set policies concerning consumer protection, electronic data interchange, uniform business practices and identified best practices for ESCOs in the early part of the move to competition. Assessing retail markets is difficult because there are few quantifiable measurements. Migration is one of the few measurements. Migration to ESCOs in New York has been pretty steady, accelerating over the last 18 months.

The prices during competition have gone down from '96 to '05. That's tariff rates, people who stayed with the utilities. New York didn't cap retail prices. There has been an effort since the early 90s to pass through fuel and market volatility on the wholesale side to retail customers so they have an incentive to move to suppliers who hedge properly. The three utilities who had the biggest drops in price had the greatest fuel diversity, mostly a mix of hydro, nuclear, and coal. The downstate congested areas are where new additions have occurred, mostly fossil fuels. Furthermore, in the western part of the state which is not congested, wholesale prices went down.

The big winner in a successful retail market is demand response. It brings efficiency to the wholesale market and allows residential consumers of all sizes to make choices on their energy usage. In divestiture New York took efficiency programs away from the utilities. The State Energy Research and Development Authority runs the programs. When the markets opened they aligned the retail price signals for demand response and the retail demand tariffs with those in the wholesale market. There's been cooperation with the New York ISO and they've been aggressive in this area with strong success.

This year New York went to mandatory hourly pricing for customers over 5,000 megawatts, 16% of the load. Every customer has between eight and ten ESCOs that they can go to for electric and gas. There's a full array of value added products including hedging, blended products and fixed products.

Even more interesting is that as of '05, demand response is in the wholesale market. There's about 1,000 megawatts participating in the market as capacity, another 600 megawatts for emergency, and about 400 megawatts that bid into the day ahead market just as though they were energy. They're bidding demand into the day ahead market. Mandatory hourly pricing should increase those that are bidding demand because they're getting the right price signal for the first time.

One of the big challenges is infrastructure. The New York preference has been for full divestiture of merchant facilities. There are also regulated backstop solutions with the ISO that ensure the lights don't go out due to supply problems if the market doesn't produce enough. They use long term contracts for new infrastructure in the reliability, environment, and fuel diversity areas. There is an RPS [renewable portfolio standard] that has a 25% goal by 2013 and a clean coal initiative which should site a a clean coal facility within the next 18 months using public funds.

Getting a price signal to retail customers is critical but they don't want customers subject to total volatility all the time. A stable product is needed that still has a price signal. You can have wholesale markets. Even if they had a fully regulated retail market you could still pass price signal through to retail customers. However, it takes extensive political will to do that in a non-competitive market. It would be very hard to say to rate payers that they're going to start passing through the day ahead price.

Almost half of the market is in ESCOs, not utilities. Two of the largest five suppliers in the state are ESCOs that have more load than incumbent utilities in the state. Recent mergers will increase that number. This affects who supplies long term contracts and who builds the next level of generation. New York won't pre-approve utilities entering into long term contracts. The utility is at risk for long term contracts.

If the utility is the majority supplier in a more regulated market the regulator can direct diversity of supply. That is certainly not the way New York wants to proceed. The concern when ESCOs provide so much supply is are they building the next level of generation? If an ESCO has 5,000 megawatts in their retail portfolio, will they build a 500 megawatt plant to secure supply, or enter into a ten year deal? New York has ESCOs offering five year fixed rates to retail customers without five or seven year long term supplies behind those rates. New York doesn't want a regulated solution for reliability but they do want the retail markets to solve the problem themselves.

The utilities still have a substantial amount of mass market supply. The state is concerned about their hedges, the nature and volatility of default service. Ongoing discussions are dealing with these issues. With natural gas there's been wholesale competition for much longer and there are default portfolios because of storage requirements. The utilities and ESCOs are forced into a hedge portfolio. With electricity it's less settled.

There are two upstate utilities with different hedging strategies. One of them has a fixed price approach to residential customers, another has passed through the volatility but with a hedged portfolio. We can see the impact of the retail market on hedging but it's not clear what the best approach is.

Question: Has New York had any ESCOs default or leave the market?

Speaker 3: They had Enron. [laughter] A number of smaller ESCOs have come and gone. Participation in the wholesale market has stringent credit requirements which functions as a screen. The trend over the last three to four years has been to much larger players who are well capitalized. Many of New York's ESCOs have immense portfolios nation wide. It probably demonstrates a degree of market maturity.

Question: What happens to the customers when the retailers disappear?

Speaker 3: The utilities have the default responsibility. About 1% of customers leave ESCOs every year to go back to the utility. In one case about 8% of the customers left the ESCOs but only 1% went back to the utility. 7% chose to go to another ESCO even though first time discount incentives weren't available.

Question: You've got 4,700 megawatts of new generation built since the market opened and distributed among merchants, public power authorities and IOUs. What is the fraction of merchant generation in that 4,700?

Speaker 3: 4,200. Out of the 4,200 about 2,000 are fully merchant without utility contracts at all. Another 500 have a capacity contract and some energy off-take, and then the rest are New York Power Authority facilities and about 200 megawatts in a re-powering of a ConEd steam electric topping unit on the East River.

Question: You've discussed utilities signing long term contracts to facilitate new generation entry but there's no pre-approval of the supply contracts. If they enter those contracts with the intention of retaining market share the costs wouldn't be recoverable because this impedes the development of competitive markets. What's the advantage for them to sign a long term contract? How do these competing processes work?

Speaker 3: I'm confused as well. [laughter] The New York Commission has a policy that says don't enter into long term contracts to hedge large customers, there should be price stability for mass market customers, until there are lots of competitive providers. There's a risk for the utility. Recovery would be under discussion for reliability concerns. They don't pre-approve but contracts are always subject to prudency.

Speaker 4.

I'm going to address what I see as a two part question. First, how does the lack of evolution of competitive retail markets, and second, the response of the states to that circumstance; how do both of these factors spill over into wholesale markets, rendering them less efficient? This is a timely question. My answers are that the lack of evolution of competitive retail markets is not itself a problem for wholesale markets but that state responses may adversely impact wholesale competition.

Let's remind ourselves about what the benefits of wholesale competition were supposed to be. A political perspective would say it was lower prices, but an economic and policy perspective would never make that claim. Economists claimed that wholesale competition could provide static and dynamic efficiencies in the power sector. Static efficiencies come from competition with a fixed capital stock. Dynamic efficiency occurs when the fixed capital constraint is relaxed and different kinds of capital flow in response to competitive rather than regulated pressures.

Examples of static efficiencies are more efficient economic dispatch, getting O&M [operations and maintenance] and cost reductions, fuel procurement savings, or improved availability. Long term dynamic efficiencies include economic new entry – what the market decides it wants to build and when, and better market risk allocation. In the middle are factors that involve capital but also involve existing facilities. these include heat rate efficiency improvements or retirement decisions. Many economists believe that the dynamic efficiencies are where the money is; a different set of capital investments and stock. A primary dissatisfaction that led to deregulation was a poor allocation of capital.

Many folks in the 70s and the 80s conducted present value revenue requirement analysis on a coal or nuclear plant that were forecasting 23-30 years out at $100 a barrel in 1986 dollars. These included assumptions that gas would be illegal for electricity use, and there would be an 8% discount rate. These resulted in huge baseload construction programs. This approach assumed that it's efficient to allocate long lived capital in one of the most capital intensive industries based on 30 year projections and 8% discounts. That's just wrong.

Wholesale competition was and is replacing that capital allocation and capital investment rule with something more sensible. Obviously none of the assumptions in the 70s and 80s were correct. Fixing that paradigm is where the money is. There's political interest in short term price decreases but the money is really in the dynamic efficiencies which occur over the long term. That should be the measuring stick when policymakers assess wholesale competition.

Given all this, robust retail competition is not needed for the wholesale markets. It certainly can complement but it's not a prerequisite. That's the answer to the first part of the question.

The second part is harder. The response of the states has created a real challenge. We shouldn't go in the directions that some states are heading. This occurs because the political debate is prices, not efficiencies. It would help if we differentiated between stranded costs that are essentially sunk costs and whether or not the current competitive structure is giving us efficiencies and will give us future efficiencies.

There are several areas that are a problem. The first is a return to central planning to pick the right technologies. That takes several forms, some more benign because there are fewer dollars involved. These include set asides for renewables. These are essentially non market transactions. A more serious issue is those that believe the market isn't building the right kind of units; base load, meaning coal plants, coal gasification, etc. This is deja vu all over again. These are precisely the decisions that we should leave to markets. The 70s and 80s did not produce the right allocations.

There are difficulties in mixing cost of service and market based new builds. It's hard to tell what's a subsidy funded by a non-bypassable charge and what's really competitive entry. Some states use the taxing authority of the wires company to make generation decisions. This is bad for competitive wholesale markets.

Vintage pricing is another concern. Regulators understand new entry is expensive so they pay a new entrant the high price and the incumbents get lower prices. That's a problem. That's occurring in New York to a degree. Relying on rate funded long term contracts to attract new entry is counter-active to competition.

The retail interaction for wholesale markets is not a prerequisite but a complementarity exists. There's two areas where well structured retail competition can reinforce competitive wholesale markets. The first is price responsive load management. For customers who can and do respond to those kind of price signals, this is an excellent trend. Obviously, not all customers can do this. In terms of mass market customers, I'm less certain that taking hourly prices, averaging them over the month and billing the customer 45 days in arrears will create effective demand response. The mass market will be less responsive.

Second is market demand for forward commitments. This represents the risk allocation between customers and generators. This is occurring a lot on a bilateral basis with large customers. It's a market determined risk allocation that works well. The problem is smaller customers, the mass markets, that have been sticky from Maine to Texas. Retail competition is not sufficiently robust anywhere to determine the right level of forward contracting. In those instances, the POLR [provider of last resort] offering is going to determine the appetite for forward contracting represented by the small customers.

Most jurisdictions use fixed price offerings; never variable priced for default service. That's the right answer. Those customers generally want consistency. That question is up for review in New York and a conversation about it will be useful.

There is a question of how much and the duration of volatility damping is correct given that we've seen extensive volatility in the last three years. Do three year contracts provide adequate insurance on a rolling basis like New Jersey, or do we need something more or different? Overall this is important but not as much as ensuring the efficiency benefits of the market are not undermined.

Question: It looks like these rate stabilization plans, or price caps really, are just another form of incentive regulation UK style. Additionally, nobody can hedge against short term risk while they're in place. Is there a way to index the price to fuel costs or wholesale market costs? Not at a

100% level but at least partially? Or perhaps that's a hybrid solution that is worse than 100% markets or 100% regulation.

Second, long term contracts for customers and auctions for the POLR could be a problem. Auctions work well with a simple commodity such as megawatt hours. However, recent empirical work on procurement auctions demonstrates that negotiations work better for a complex commodity. In this case megawatt hours along with risk management and hedging. Bilateral transactions or contracts might be more appropriate. A negotiation rather than a competitive auction might result in better outcomes.

Finally, if we consider the subjects of the first and second panels together, problems with state intervention are due in part to missing markets, specifically environmental markets. States are trying to create technology incentives through renewable portfolio standards or pushing IGCC. They do it this way because the past experience in hedging has failed. Rather than a flavor of the year like coal fired power or natural gas, we should use an environmental market that will let companies determine how best to achieve these goals.

Speaker 2: I'll comment on the first two. Indexing of pricing for customers sends the appropriate price signals but is not practical for the residential class. They will not accept volatility. Ohio has a monthly GCR [Gas Cost Recovery Rate] on natural gas and many customers are uncomfortable with monthly price fluctuations.

A demand response component or smart meters is wonderful. This should be done on a wide scale on a voluntary basis. Customers can have a real time price if they want it, in conjunction with a direct load control program. This should be an option, and it should be promoted for residential customers. Any program really needs to be voluntary though.

On the second question concerning negotiating versus competitive bids for capacity, who are states negotiating with? In a regulated environment, they're negotiating with the utility company. In a deregulated environment, who are they negotiating with? It's not supposed to be with the distribution company to build load. The advantages of bidding is that if an entity makes the bid to build a plant for X price then the price is binding. There's obviously some exceptions clauses but the price is generally guaranteed, a nice safety net from a consumer standpoint.

Deregulation occurred because of huge power plant cost overruns. A competitive bid for power plant generation ends that. I'm not sure that negotiation can do that.

Speaker 3: Certainly New York would not support utilities going to a completely day ahead product for mass market customers. New York wants price stability but with some of that volatility visible. Finding the right level of volatility is difficult. Consumers couldn't stand the day to day volatility of the gas market this winter. The regulated utilities must have a hedged portfolio but the ESCOs can offer whatever product they want.

In terms of the missing market component, there is an active market in NO^2 futures and SO^2. The cap and trade program in the northeast will provide the same thing in CO^2. Those price signals show up in the wholesale product process.

Speaker 4: There's a distinction between larger and smaller, mass market customers. The larger customers don't need a fixed price or substantially hedged default product. They can handle that bilaterally. Bilateral contracts are not appropriate for small customers. With utilities and default service bilateral won't work well because it will run afoul of the affiliate rules. There's many jurisdictions where big generators are affiliates of utilities providing the default service. It's important to keep affiliated generation in the market and the auction works well.

The markets, with respect to NO^2 and SO^2, are not missing. SO^2 prices have doubled in anticipation of requirements in 2008. There's a huge effect on prices now. Carbon will be internalized in some balkanized way as they sort that out, and probably in some inefficient ways. Ultimately, I don't see any problem for power markets addressing that.

Speaker 1: It's important to clarify whether we're talking about the large market or the small residential market. The answers diverge for those two markets. There are characteristics of certain markets that will lend themselves to a greater volatility variation. This will be driven to a greater degree in the future by the demand side response option. The more effortless demand side management becomes, the less to worry about the degree of exposure to price volatility. Over the long term, I expect we'll see options similar to buying a prepaid telephone card. You'll be about to walk into a Wal-Mart and buy a prepaid power card for a fixed amount of power and let Wal-Mart do the hedging. That would be better than the utilities hedging on behalf of their POLR load.

The issue of negotiation versus the various auction models depends on where you are. The most recent debate is in Montana where the utility wants an auction and the state consumer advocate has been arguing for a bilateral structured negotiation given the dominance of one supplier. It really depends on the level of competition, complexity and transparency. It's difficult because there's little information on outcomes.

Question: In terms of difficulties turning back the clock or going to a hybrid model, what are the practical or legal difficulties with a hybrid or cost of service model on a going forward only basis?

Speaker 1: The practical barrier is that eminent domain would be used to unscramble the egg and put generating assets back in the hands of the utility. It would be impossible to address compensation after the fact.

Question: My question was going forward.

Speaker 1: Yes, but going forward is derived from that. I assume one would want to achieve an outcome that replicated much of the regulated old world. How do regulators establish a baseline of cost of service, how do they impose a certain amount of price volatility but it can't vary more than X% from a cost based rate that used to occur in the old regime. None of the variations in that kind of an approach are particularly satisfying.

Speaker 2: It's a very significant problem. It's very difficult to value capacity on a going forward basis. It would be difficult to determine wither original or replacement costs should apply and whether ultimately customers would have a higher rate base.

Speaker 3: Why would one want to that? In New York generator availability at peak increased by almost 5% in the competitive market. It made an extra 1,200 megawatts available at peak that didn't have to be constructed. Consider also companies that derive economies of scale by owning multiple nukes rather than individual utilities owning single nukes. The efficiencies solely in that have been significant. Those efficiencies would not be available without competition.

Comment: Well, New York is an interesting example because it's been a mixed experience. Less than half of the new generation under the market system has been merchant. The answer to the question might be for reliability.

Speaker 3: There are reliability requirements for the utilities that don't go away. For example, the locational capacity requirements for reserves in New York City. If they fall below 80% then ConEd has a responsibility to procure if the market doesn't respond.

Speaker 4: Going forward, regulators could put some regulated entity back in the cost of service construction business. Laws aside, you could do that. The results would not be good. They'll be back to the failures of central planning. Those risks were what prompted competition. Second, it won't solve the problems that have really aggravated people. It won't allow stranded cost deals on the old solid fuel plants to be redone. It doesn't get at the source of political discontent and it increases risk of poor investments.

Question: Markets should be able to bring more efficient, potentially lower prices to customers. Yet, it seems that New York has denied investor owned utilities the ability to provide valuable hedging to customers that might want it by forcing them to offer only same day pricing to large customers. Doesn't that preclude the possibility that customers can get a better deal by cutting out such large players. Second, can the dynamic efficiency concerns discussed earlier apply to the retail markets when potential players are being cut out of the market? Is the retail market losing dynamic efficiency that could help the customers?

Speaker 3: What's the role of a monopolist in a competitive world? What's the role of a guaranteed rate of return and risk protection in a world of competitive products? New York's Commission expects many providers and alternatives for the large customer base. There's no need for a monopolistic service there. Alternately, no utility is prevented from hedging their products. In fact, one utility was completely unhedged on the retail side for about five years and caused concern that residential customers were too exposed.

Speaker 4: The dynamic efficiency benefits of wholesale are many times larger than retail. That is where the money is. Nonetheless, your question is why would one foreclose incumbents from being providers of a hedging service to large customers? Isn't there a loss of efficiency there? Conceptually I would concede the point. One would have to demonstrate an appetite for particular risk intermediation services of those customers; they require something that the market isn't supplying. Given that there's at least eight to ten options, there probably isn't a unique advantage to the incumbent wires company in providing those services.

Speaker: Note that a number of the utilities have unregulated subs or ESCOs that provide service to those customer bases.

Question: Are there any utilities that want to compete with the ESCOs to offer services to those large customers in their own service territory?

Speaker 3: It's not a big issue. There are discussions in rate cases. Some utilities prefer to serve customers a full array of products. I don't believe a utility has ever made that kind of a specific prioritized request and the Commission said no.

Question: I'm concerned about the original movement to competition. Consider externalities like green house gas and other environmental issues, national security issues involving foreign oil, reliability must run, and market power during peak load periods. Once the regulatory process has answered these questions, are the dynamic efficiencies from the marketplace attainable? This goes to the heart of whether competition was a good idea.

Second, has competition created an efficient allocation of resources? The merchant sector has built a lot of one fuel source, gas, in a lot of the wrong places.

Speaker 4: Good questions. On the second question, assessing the performance of the merchant sector over the last decade certainly shows they made mistakes. Markets are imperfect. Schumpeter said that competition is the obsolescence of capital. However, regulators are not fighting about the allocation of the losses. It was clear who took the risk: merchant equity holders and the banks. In the 80s and 90s regulators had to determine whether the rate payers had to pay for this.

On the first question, location matters. Transmission grids will always be constrained. Load pockets and environmental externalities are going to be internalized in a sometimes haphazard fashion. However, there's still going a debate about whether the source should be coal, biomass, wind, or combined cycles. There are a lot of dollars riding on those debates but they're not the ratepayers dollars.

It has already been worthwhile because of the real efficiency gains solely in the existing stock and generation. The existing generation is performing better. If there were smarter banks who were less willing to lend, there'd be better decisions.

Question: In New York, only about 200 MW of the merchant generation built in the last five years was actually financed prior to the merchant sector crisis. Further, banks are unwilling to finance anything without a ten year contract or better. In California, there hasn't been a single new generation proposal under a five year contract structure despite the messages by authorities there about the need for resources.

Giving the markets a chance is OK as long as there isn't an urgent need. If supplies are tight and action is needed then regulators have to act more aggressively. The market is also incomplete because in other commodities both the price and reliability impacts of scarcity can be passed through. In electricity that's a political hot potato that no one will implement, in part because electric service is integral to the rest of the economy. Certainly, it would be improper to pass through the reliability impacts of scarcity.

PJM is proposing a backstop mechanism for long term contracting. There's a similar dialogue in California concerning transitional solutions. If long term contracts are necessary because of a societal need, or if there's other societal directives like renewables or IGCC, then the entire retail market, not just a segment of the retail market, should be paying for those investments.

Some comments here about long term contracting have implied that using them means the wholesale market is being circumvented. Instead, the wholesale market can be used with long term contracts. The market will indicate the appropriate combination of terms, condition, pricing, etc. These contracts are an integral part of the competitive nature of a wholesale market. I'll take comments on all these issues.

Speaker 3: Over the last three years investor interest in procuring existing resources has increased in New York. Many equity people are buying existing resources. And a lot more are interested. They have interest in the design features of the wholesale market that can provide them some comfort level for those investments. There isn't yet a liquid futures market in New York. The financial houses and the regulators would all like to see a longer term price signal and more longer term certainty on the capacity side. The regulated reliability solutions are not optimum.

Speaker 2: These issues could be addressed in part by mechanisms to share the risk among a multiple group of parties whom serve the POLR load. These include rate payers, competitive suppliers – whether they are an utility affiliate or an independent marketer. There are other options with governmental assistance. For example, if the state had a compelling interest in an IGCC they could also help with financing.

Similarly, where a utility is doing business in multiple states and they will all benefit by the additional capacity, then they should all share in the risk. Utilities are reluctant to do that because it requires multiple processes to get a plant built. However, the states could work to provide more certainty or assurances over a longer period of time in these kinds of situations.

Sometimes policymakers are operating in a vacuum. When Ohio passed deregulation, they rescinded their long term forecasting laws. So utilities tell people they need more capacity but no one really knows. Consumer advocates don't know what is really needed that rate payers should fund. We should have a competitive market but also have that information available publicly. It would be helpful to marketers as well.

Another concern is the pricing to pay for all of this capacity. How much will it ultimately cost consumers? Restructuring was supposed to provide larger economies of scale. Each utility company wouldn't need a reserve margin of 15% because there's a much bigger system. Thus, if large unit goes out, there's still a whole lot more capacity out there. Why do we still have reserve margins of 15% instead of a smaller, more conservative number.

Speaker: If banks aren't financing then there's a pricing problem. PJM's RPM proposal occurred because PJM acknowledged they had a pricing problem. There's a region wide capacity market that is oversupplied on a regional basis.

However, in the east people can't afford to keep their plants operating so they're shutting down. That's not a market failure, that's pricing failure. RPM is designed to fix that pricing problem.

In California is it a pricing problem? Second, if the issue is reliability then it involves peaking facilities and load management, not energy producing facilities. For reliability, there's a pricing problem or a concern about the regulatory stability.

Long term contracts for standard energy facilities are sometimes strange. I'm suspicious when I hear a company say a project is too risky for them absent a ten year contract. It's a difficult proposition for me to swallow. If they're not bearing it, then the consumers are

Question: Just to clarify, I'm not aware of new merchant financed projects since the shutdown of the markets. If there's a need for new generation in a region and it's not showing up when do regulators consider alternate options. If a different risk allocation is available, maybe five year contracts with a credit worthy entity, when can they be considered?

Speaker: There are large portions of the country that don't need anything any time soon. Hopefully PJM's RPM will stop non-economic retirements; or more accurately, convert current RMR [reliability must run] contracts into market resources. Second it should promote some new entry in 1-2 years.

Speaker: The time horizon you've described without real merchant entry is probably correct. However, we've gone through these periods before. They vary depending on the degree of liquidity or cheap money availability versus tighter times with rising interest rates and more conservative banker thresholds. I'd question whether the last 2-3 years truly indicate a trend.

Speaker 3: New York has a similar planning process to PJM. Reliability is a fallback that occurs with all solutions: transmission, demand side response, and generation. Second, New York's RPS is designed specifically to be driven by market prices and handled by a centralized RPS utility. The developer is at risk for the market price. A premium is paid on top of the market price and bid through an RFP auction process. They have over 200 megawatts built. There's 1,200 megawatts of wind in the queue with a ten year premium. They are in the market for the zonal price and the capacity price. It's an indication of an increasing willingness to invest. To be clear, it is a ten year price support that is fixed.

Question: I agree that vibrant wholesale markets are possible without competitive retail markets. States and regions that have large customers engaging effectively in the market are important for establishing a demand side to the market. My concern is that the standard for success is defined by a supply side perspective. Certainly competition allocates capital more effectively. Is it a problem to focus on the supply side of the market as the standard by which policymakers measure success or failure? All the dynamic efficiencies discussed earlier can potentially be captured on the demand side. However, the demand side is largely inert and unresponsive. Large industrial customers have received good options. However, generally about 60% of the load is still on default service. How do we capture those dynamic efficiencies? These customers do not get access to new technologies or to competitive new entry for retail suppliers. How does one move the demand side of this market to capture some of those efficiencies?

Speaker: There's a consensus that the more demand side, the better. The small-large differentiation discussed earlier is critical. It's hard to make this work for the small customer end of the market. The supply side will continue for the foreseeable future to have efficiencies an order of magnitude greater than the demand side.

Speaker 2: Regulators need to value the reductions in demand in the same way that they value supply to ensure appropriate reserve margins. There's a whole market out there for the residential and commercial class. There are ways to incent utility companies to do this. For example, getting energy efficiency on the gas side with utility companies. One can decouple sales from revenues and compensate the utility for their distribution costs. A deregulated utility company can manage the programs and they are compensated for the distribution revenues, which is a small piece of their entire bill.

Energy efficiency is the cheapest and shortest term solution to mitigate demand. One issues is that industrials generally do not support utility funded programs because they don't want to support an energy efficiency program that doesn't benefit them directly. One solution is that each customer class pays for their own program so then the industrials are neutral.

If customers are able to mitigate the bill impacts, it gives them some control. Good rebates programs, energy star appliance, direct load control programs that cycle down their air conditioner in the middle of the summer. It gives them some savings. It can be done on a residential basis, too.

Speaker 3: Some regulators are requiring their utility to put up the money for enough demand response to equal close to load growth. Thus, they are investing in efficiency to effectively be megawatts.

Speaker: Certainly demand side is a good thing. If we can get back to load management participating in the energy markets, that's how we get out of the capacity markets. Second, 60-70% of the mass market may never go anywhere. If 20-30% of those customers get the benefit of choice, that's ok..

However, we do need some technology and some awareness. LMP prices should be shown with the weather map every night. That may be overkill but if technology makes people more aware then they can adjust their behavior; adjust the thermostat or run laundry late.

Speaker: The design of POLR service prevents market entry by people who could take advantage of the knowledge and technology to serve those customers. No individual customer's going to sit there and watch the 10:00 news and make adjustments on dials in their home. However, retail suppliers with hundreds of thousands of customers and technology could adjust usage in a pattern. One could get very significant impacts that would be beneficial to those customers.

Speaker: A fixed price POLR isn't going to be part of that because they could offer a lower price for the kilowatt hours that do get consumed. Large customers get options. Year round with super peak has one price, if they're willing to give 200 megawatts of relief when prices are above $300 a megawatt hour, it's another price. There's no bar for a retail aggregator under a fixed price POLR to do the same thing.

Question: Medium customers are also important. Defining that depends on where you are and the level of usage. However, consider commercial entities with multiple facilities across regions, this can become significant. They're benefiting and interested in their choices. They don't have representation through a rate payer advocate and they're not in a large industrial organization. Nonetheless, medium or commercial size customers are engaged across the board.

Second, can wholesale markets undo retail? Some recent decisions can impact everybody in the market from a retail perspective. For instance, retroactive rate making decisions coming out of FERC and MISO. These can really make it hard to be in the retail business.

While retail is not necessarily critical, doesn't it add value to the wholesale market? Wouldn't a generator prefer to sell to multiple buyers versus a monopsony buyer in a market? A generator with only one buyer may find this restricts the price they can ask. Second, without the influence of retail competition do we run the risk of backsliding on wholesale as well? Some utilities want to look backwards and are uninterested in wholesale competition.

Speaker: Several speakers cited specific attributes of retail market design which have a clear driver effect on the success of wholesale markets. Second, I don't believe there are a substantial number of utilities that want to revert back to a regulated world.

Question: I'm concerned by some of the panel's willingness to jettison retail markets, at least that's the way I understand their comments. This creates price signal distortion because these customers are not in play. Texas has 50 active retailers, active generators, and extensive product differentiation and risk management. These are key to the success of it's retail market. Customers, including the residential segment, make sophisticated buying and risk management decisions every day. Texas has five year products and also hourly products. I welcome your comments.

Speaker 3: The New York commission is strongly committed and there is significant activity even in the residential market. Since New York utilities can't auction off customers, there will always be a substantial utility presence in mass market customer service, even at aggressive implementation rates. Nonetheless, the retail market is very important to New York.

Speaker: The mass market functions very well with retail but for the foreseeable future half those people are going to stay with their default supplier. That's true in Texas too. It's not a question of supporting retail markets, but rather, what to do for those POLR customers.

Speaker: Even if two thirds of the country won't and can't have a retail market, other regulators should still design features of retail end user arrangements that will support a wholesale market.

Speaker 2: I disagree that the residential market would only be about 40, 50% tops. In one area of Ohio with gas choice, over 50% of the customers switched. Successful aggregation programs are a good tool to bring customers together. If there's a good program and good customer education, a large percentage of customers will take advantage of it.

Question: If there's an urgent problem with investment then scarcity pricing should be fixed immediately. Merchant generators are in fact building and financing new facilities without regulated purchase power agreements. These are contracts created by financial intermediaries and Wall Street folks, but not done through regulators. Others have discussed mandatory purchase arrangements, hedging arrangements, and the New Jersey model. The New Jersey program is not resource specific, regulators do not choose the technology.

Generators love those contracts. It has nothing to do with financing their plants, but it keeps the regulators at bay when prices go up. If small residential customers are unhedged, the regulators would interfere. These contracts stop that from occurring. They provide stability for the marketplace so that regulators don't have to intervene. This New Jersey approach is a critical way to do it. New York is far along with the operating reserve demand curve.

Session Three.
Regional Transmission Organizations:
Cost or Benefit, Necessary or Disposable?

Regional Transmission Organizations (RTOs) are a major and unusual institutional innovation. We have passed the end of the beginning. As experience accrues, the development pains reveal underlying tensions and challenges. Costs are visible and concentrated. Benefits are harder to demonstrate and more diffuse. The allure of new beginnings gives way to the hard slogging of implementation and adaptation. Stakeholder processes devolve into "sausage making." Differences in visions about roles precipitate seemingly endless struggles over proposals for market rule changes (e.g., MRTU in California), infrastructure investment (e.g., transmission enhancement and resource adequacy, everywhere), and new services (e.g., long-term transmission rights and forward contracts).

Complicated regulatory contexts and stakeholder processes raise questions about who is in charge, if anyone. The very framework for evaluating costs and benefits depends critically on the assumed benchmark for comparison, about which there are often unstated disagreements. And the march of events, such as the end of retail rate transitions in a time of exceptionally high and volatile energy prices, produce pressure to avoid costs and assign blame. Defections from RTOs, real or threatened, raise questions about the future. What is the proper diagnosis from the litany of concerns? How well is the RTO innovation working? What have both experience and all the cost benefit studies revealed? Is it time to rethink the design and reformulate the vision for wholesale electricity markets and RTOs? What are the alternatives? Who is in charge? Is a sense of malaise a natural part of a cycle, or the beginning of the end?

Speaker 1.

I'm going to emphasize three points. In the mid-80s, regulators didn't get the costs right. For instance, the nuclear plants and their high costs. There was a need by regulators to put risk on the generation owners and not on the ratepayers. Secondly, there's a demonstrated ability and efficiency of markets based on security-constrained economic dispatch over a large area. This has absolutely created efficiencies. My third point is that organized markets support bilateral markets. Organized markets set up reference prices, and the references prices support bilaterals. This decreases transaction costs and makes these transactions easier. This is due in part to instantaneous release of information to all participants at the same time.

There are some soft benefits as well. The threat of competition caused everybody to become more efficient. Second, the ability of transmission owners to shut out small generators was blocked. I'm suggesting that the threat of competition caused everybody to become more efficient. Especially neighbors to markets. Neighbors to a market knew they had to get more efficient. In the early '90s staffing changed dramatically because everybody was getting ready. The entire electric industry was concerned with right-sizing. From 1990 through 2001, the investor-owned utilities dropped staff. Then the RTOs got to hire them.

Second, there were production cost savings. For instance, PICO, in Philadelphia, had static or lowered rates. It was one of the highest electricity rate companies in the nation and now they're not. Retail price changes in RTO areas versus non-RTO areas are dramatically lower from 1995-2005 for residential and industrial customers, but not for commercial customers. This data is aggregated over a period of time, but basically one is better off if you've been in an RTO area for residential rates.

Studies in the PJM area have shown that there's been savings in heat rate as well. In addition to more efficient generators using less thermal energy, forced outage rates have also improved. They improved a lot until 2001 when excess generation came along. With excess generation many marginal units didn't have money to put into maintenance, because they weren't being run. Forced outage rates went up at that point.

Regional security constrained economic dispatch also creates increased utilization efficiency. For instance, when AEP joined PJM, they felt they had efficient, accurate dispatch. After joining, transfers with neighbors increased by 750 megawatts per hour, 24 hours a day, 365 days a year. That's a huge change in the way they're operated. This lowered prices for the load. This has happened with every company that's joined PJM. Furthermore, PJM installed reserve has gone down because of the extensive transfers.

Further, liquidity at hubs is extremely high. The most heavily traded electricity contract in the world is the PJM Western hub electricity contract. Liquidity and transparency provides a good reference for bilateral transactions.

Transmission is a concern because it is a natural monopoly. Thus, bad decision risk resides with retail customers. Generation is bid competitively so bad decision risk resides with generation owners.

Finally, there are significant problems for RTOs right now. For instance, retail rates reduced or held flat while fuel prices are going up are a bad situation. Second, it's hard for people to see the benefits of an RTO. Everybody knows what an RTO costs. It's transparent, they have a budget, they bill people. However, RTO benefits are hidden. These increased efficiencies are primarily based on a counterfactual case, it's always a comparison to what would have happened if we hadn't had the RTO. Further, if I was an IOU [investor owned utility], I would want to be next to an RTO, not in the RTO. The IOU can protect their market, competitors can only sell into their market if they say so. However, if they have extra generation, they can get a fair market rate for it, and if they need generation they can pay a fair market rate to meet their load. It's a flexible situation for an IOU on the border.

Question: You compared rates and retail price changes in RTO and non-RTO areas. Do those figures account for rate caps and the fact that no fuel adjustments were taking place in that comparison?

Speaker 1: Yes, they are the actual retail rates of those places in those years. It's an Energy Information Administration source.

Speaker 2.

I'm literally a father of three children, however I'm going to discuss a metaphor of three children, plus one deceased, that represent the organizations I've been involved with in a senior executive capacity over the past 8 years. When I talk about these models, these three children, I'm not defending the model I'm associated with now, an ISO. Rather, I originally argued for the creation of an RTO and an ISO at least four or five years ago.

The first child was a functionally separated fire-walled utility, a ring fenced operating division, in 1996. Many people like to promote the firewall and ring fence idea, make it look like a good model. This model will give you something, but never the intention, especially if the intention is competition.

The second one came about because people believed the structure of [FERC] Order 888, the ring fence, was not the right model. A new model with more independence from the vertical integrated utility and from the market was needed. In this company, ownership of all the transmission system was in the hand of one company, like the UK. They were government-owned and the responsibilities of transmission asset management and operation were consolidated in one company.

The third model is an independent system operator as of 2005. Finally, there is one model, or child, that died and that is a great waste. This was an attempt to create an RTO over a 4 year period. The region where they were trying to do this has spent $50 million over the last six years talking about an RTO, trying to justify a $100 million organization.

All of these models were created by public policy that promoted competition. Until the last energy act, this was the national emphasis also. ISOs do not create competition. ISOs were created to facilitate competition. Similarly, regulatory policy is designed solely to implement public policy. It's public policy that insists on non-discriminatory access, reliability, or customer needs. However, this list of policy needs is evolving every day. It gets longer and more contradictory. That is the natural state of things however, until we can achieve a more mature market.

Can competition be achieved any other way? In the past, FERC said no, but FERC today says maybe. There is some hope that the chairman will review or renew 888, and give utilities what they want. However, this is a fallacy; a vertically integrated structure in the 888 model can provide proper competition. There is no systemic way that congestion can be relieved at a fair price for others to go through the utility's system. There are capability and transfer limit problems all the time. In my experience, there was never a day where a few hours of discussion or phone calls did not generate at least 400-500 megawatts of capacity just by talking to people. Sometimes the reasons were for simple mistakes, other times it occurred for probably less well-meaning reasons.

I once tried to get for my merchant function a price of re-dispatch, because someone wanted to go through. The price was something like $10,000 or $15,000. I said are you kidding? How can I go back to that customer and say $15,000? They said, we're hydro, and we calculate the opportunity cost of re-dispatch that may result in flooding a dam, that would then spill water two years ahead. These are the kinds of situations that 888 creates.

The second experience, a company as both asset management and operator, is a model made in heaven if you can do it. It usually occurs only if transmission is in the hand of government. I can't think of a better model than this. However, this kind of model is almost impossible in the U.S. This leaves us with the ISO. It really shouldn't be up to the ISO to justify their existence, the people who made the decision to restructure the electricity industry and make it competitive are the ones who should answer that question.

It is fair to expect ISOs to demonstrate fiscal and management discipline. RTO and ISO costs keep increasing from 1996 until today. Seven ISOs cost more than one. However, these analyses don't take into account the fact that ISOs will have much higher early startup costs. These costs should stabilize over time.

ISOs and the competitive market started with no reference book and it went through a process of learning, maturing, and growing up. The difference in cost between a PJM megawatt of service now and when they began is 13 cents. However, there are a tremendous amount of valuable functions that they have added. The California ISO's operating costs from 2002 until today went down by 30%, 15% just last year.

Another concern is that congestion cost is high. It was always there, now it's just that it's transparent. The vertically integrated utility I was with never built a transmission line as long as they could dispatch generation. It didn't matter if it was less efficient because it was all cost-based. One of the benefits of restructuring is that it makes every piece of cost transparent.

Another criticism of ISOs is that they are not responsive to customer needs. These customers – generators, marketers, IOUs – can never decide on common needs. The stakeholder consultation process takes time for them to agree on what they all need. ISOs meet as often as 550, or even 850, times a year with their stakeholders.

Currently, a lot of ISOs are probably doing things they shouldn't do, and other things they should do more. They're currently at a crossroads, the startup is finished and they have to transition into a mature market now. The problem is they don't have a final vision of the market. This vision has to be derived from the lessons they've learned in the last eight years.

Speaker 3.

I'm going to present a perspective of RTOs from consumer-owned, consumer-focused, and consumer-controlled entities. Rural Electric Cooperatives have 2.5 billion miles of distribution line, 45,000 MW of generation, purchase 60,000 MW a year in the wholesale market, provide electricity in 83% of U.S. counties in 47 states, and has 40 million consumers. They supply 75% of the land area in the United States but there's hardly anybody there [LAUGHTER]. They represent about 11% of the total market.

Cooperatives are consumer-owned; if you take service, you're an owner. They're consumer-controlled; the local boards are elected by peer owners in the neighborhood. If you think regulators are tough, try your neighbor with a pitchfork. They're not-for-profit operations but simultaneously private corporations. They're often lumped under public power but they're not that. Nonetheless, their views are often aligned with public power and the municipals.

Cooperatives have a single focus. That goal is to meet members' local economies' long-term need for reliable, affordable, non-volatile electric power. They spend a lot of time on demand-side management, energy efficiency programs, and renewables in regions where renewables are available. They have different goals than other organizations.

Their perspective on deregulation particularly is not based on faith-based deregulation, nor theoretical economics. They're not interested in grand experiments at this point, nor bottom-line concerns – a euphemism for maximizing profits. The expectation is for benefits to consumers they serve. The co-ops were very involved in the passage of the Energy Policy Act of 1992. Some characterize them as against competition. I don't agree, they buy 60,000 megawatts in the market every year. They want competition that works, and generation competition can work. Those views are based on a couple of principles.

One, electricity is critical to the long-term economy, energy, and national security. Second, 85-95% of the benefits in deregulation are in the wholesale sector. Having six or seven people competing for 60-80 cents per month to do different billing in retail rates makes little sense. Further, 85-90% of the benefits of wholesale competition are in transmission access. The concept of transmission access, as contrasted to a more broad market definition, is important and I'll return to it.

Another goal of the co-ops is a focus on infrastructure development, not short-term optimization of scarce resources. Clearly, generation competition won't work without robust, equitable, independently operated regional grids focused on long-term load serving and needs. The RTOs are needed. However, to benefit consumers, there needs to be some refocusing and reprioritization.

In the Energy Policy Act of 1992, Congress did not alter FERC's just and reasonable responsibilities. Nor did it mandate market-based rates in any way, shape or form. It didn't alter any jurisdictional lines. Thirteen years later, after some heated discussions from 2002 to 2004 about Standard Market Design, the 2005 act has some more detailed changes. In Section 217.B.4 of the 2005 energy act, FERC must facilitate the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities. It enables load-serving entities to secure firm transmission rights or equivalent FTRs on a long-term basis for long-term power supply arrangements. It's a very explicit statement of where the law of the land is. It is a statement in support of generation competition.

The problem with all of this wonderful stuff is that short-term, theoretical efficiency is being placed above the longer-term welfare of consumers and the economy. It's as simple as that. The implications of the market design are that it creates incentives for auctioning off scarce facilities and that's bad. Second, it removes incentives for building infrastructure that can power economic growth, facilitate generation competition, and eliminate market power – all good.

Specifically, regional efforts to plan and build transmission for long-term economy and reliability are insufficient. The RTOs don't have enough focus on building for reliability and long-term economy. Further, LMP has not, and will not, get transmission built. Instead, it has raised prices to consumers. FERC's NOPR [notice of proposed regulation] states that the nation has experienced a decline in transmission investment relevant to load growth since Order 888 was issued, which has increased congestion and reduced access by customers to alternative sources of energy. They conclude that transmission providers have a disincentive to remedy transmission congestion on a non-discriminatory basis. Expecting a company to invest their money to build a road into their service area to compete with their own generation is completely unrealistic. Companies find ways to create resistance.

Transmission incentives don't work. LMP, various FERC "candy," mitigation well above cost – nothing gets built. Worse, generation competition doesn't work without transmission. RTO default participant funding, and LMP has re-balkanized the grids, but this time at market-based rates.

So what are the solutions? First, there needs to be more open, inclusive transmission planning for long-term reliability and economy of load-serving entities over rational regions. A discussion of what constitutes rational regions is important to solving this problem. Recently, the Ohio commission was upset because some transmission costs allocated to it on a postage stamp basis by MISO was unfair. When there are regions so big, there is no agreement between neighboring states and commissions. Fortunately, FERC has clearly identified this issue in the NOPR.

Second, an open planning process will ensure cost recovery, keep prices low, and facilitate the market. Participant funding is not necessarily a problem, it makes good sense in certain areas, but usually when transmission is needed for outside the region.

Third, long-term, fully hedged transmission service available for infrastructure development and financing is necessary. This can be a problem – how hedged should it be? No matter what, unhedged doesn't work, and a year is not enough for a 30-year lived asset.

Finally, we need to increase reliance on bilateral markets, not over-reliance on spot markets. If there's a 100 mil dark spread, and yet generators don't make enough money for their cost, so we have to have RPM or LICAP additionally, there's a problem. It means the system is fundamentally flawed.

A 2005 study showed that consumers have saved $726 billion in competition. That's equivalent to the trade deficit of this country. However petroleum production is dropping, and consumption and imports are increasing. There are troubles in natural gas, in oil, and in balance of payments. However, the "silver bullet" of LNG has a tarnish, if we continue importing LNG at projected levels, the balance of payments goes well over $1 trillion. The market shows 200,000 megawatts of new gas fired capacity in the face of this. If the markets always turn out better, why are they moving to gas-fired?

Moderator: Do you have a method for how rational regions should be determined? You imply that the ones we have now are too large or not rational.

Speaker 3: When PJM began, it was three states, a little bit of Maryland, mostly Pennsylvania and New Jersey. They didn't have those kinds of problems. The states were used to working together, the companies were used to working together. It was a smaller region. There should be a discussion of appropriate size, from a market standpoint. An 11 or 12 or 13 state RTO is probably too big. A lot of the pricing and cost allocation problems tend to go away with smaller regions. I don't have a specific answer. We need to take a look at what the RTOs are doing and rationalize it that way.

Speaker 4.

I will discuss the New England RTO. It is an integrated control area covering all six states. The policies in any one state have to be synchronized with the other states to work effectively. ISO New England has pending application to be approved by FERC as an RTO.

The independence of RTOs has great importance; especially complete independence from all market participants. I'd like to consider how that independence is implemented, and to suggest ways to increase collaboration and sharing of responsibility between the RTO and regional state governments. I'll speak from a New England perspective, but will attempt to generalize. I expect some of these generalizations would be applicable to other regions whose situations may be different.

Under the Federal Power Act, the RTO has the responsibility to attempt to ensure just and reasonable rates for consumers. State governments should be involved in decisions that will influence those rates yet they have not been so far. Consider the development of capacity markets in New England over the past five years. This is an example of how the states did not effectively participate in that process until very late. They need to learn from that lesson, and produce a rational process to engage in important decisions concerning market design.

The installed capacity requirement [ICR] reflects a complex balancing of benefits and costs vitally important to its ratepayers. States should play a major role in crafting the annual ICR, because ratepayers will be paying too much if it's too large, and are risking blackouts if it's too small. To effectively influence the ICR determination, states need an institutional method for analyzing and formulating unified positions on the issues embedded in ICR. They need to be able to negotiate and participate in litigation at FERC for their adoption. Most RTOs, unlike New York, involve multiple states. A common position on ICR is critical.

So why should ICR reflect ratepayer preferences? Ratepayers have a unique but indeterminate tolerance for risk of power outages. They say they don't ever want power outages. That's difficult to implement because we don't know how much they're willing to pay for that. For several years in New England the capacity markets provided zero for capacity during most periods, and in times of scarcity the price shot up dramatically. The market provides no real indication of what the willingness to pay for capacity is. If it is impossible to tell from a market perspective, the appropriate people to figure it out are elected officials.

The capacity dispute in New England is a classic example of a bad dispute resolution process. For years, ISO New England, the market participants, and the states argued about whether there was even a need for a capacity product. The ISO was convinced there was and was backed in that analysis by the FERC. There was extensive evidence; generators going bankrupt and units with reliability must run contracts and so forth. Both FERC and the ISO felt capacity markets could end these problems. However, the states were not willing to pay more for capacity. There's a substantial surplus in the region. They weren't sure the product, whatever capacity actually is, would be there and be reliable. There was concern that consumers were being asked to pay for something that wouldn't deliver any added value. ISO New England undertook several attempts to negotiate a settlement of these issues. This wasn't successful, in part because the states and the region had different opinions on what should be done. ISO New England asked FERC to then impose a solution on the region.

New England regulators are hypersensitive to additional costs because they have the highest electricity rates in the country, with a couple of exceptions. The region has high electricity rates and a complex generating capacity picture. Beginning in 2008, ISO New England argues there will be an insufficient reserve capacity margin and that additional generation needs incentives. There are many assumptions in these projections, and regulators don't necessarily agree with all of them. There is no question that additional capacity will be needed. The question is what is the right mechanism to get there?

FERC's conclusion was that a capacity market was needed. Without it, developers won't find it profitable to build new plants. The region's markets have been so efficient they've driven the price for electricity to its marginal cost. Generators are not recovering capital, and are trying to retire plants that are in operation. They're not building or proposing new ones.

Some of the states have litigated that conclusion, but FERC last fall was about to impose a demand curve mechanism on the region. The states were particularly apprehensive about the impact that would have. They brought extensive congressional pressure on the FERC for more settlement negotiations. This finally resulted in a new forward capacity market. Some states were part of that settlement and are supportive of it. Others are not. Thus, the states are still not operating in a uniform and consistent manner.

The forward capacity market is different from a demand curve structure. It's an auction process where the ISO implements an install capacity requirement three years in advance. It holds auctions for contracts for capacity that will be implemented each year three years out. Both supply and demand resources are eligible to bid in that market. Resources are paid if they are available and penalized if they are not available. Revenues earned in the capacity markets are netted against the energy markets. There is a transition period through 2010 where capacity payments are pre-determined. It won't be a market-based determination of price until 2010.

This will have significant consequences for New England, and Massachusetts in particular. It will likely cost Massachusetts more than $3 billion during this transition period. For the first 10 years, close to $10 billion for Massachusetts alone.

Determining the size of the installed capacity requirement is the fundamental driver of these costs. There are many questions attached to this determination. What's the initial projected demand, which demand resources are eligible to bid, how will performance be verified, how will this influence capacity price. and how will it influence the final estimated demand? The same range of questions come on the supply side. This is not a simple calculus.

One proposal is that regional state committees could enable states to participate effectively in the administration of an installed capacity market. The FERC has contemplated regional state committees as far back as 2000. It suggested the formation of regional advisory committees and then suggested that regional state committees have substantial decision-making responsibility.

There are three others already. The Organization of MISO States, the Southwest Power Pool Committee, and the Organization of PJM States. New England has actually submitted two proposals to the FERC. Both times the commission has requested further revisions. A big concern is how to make such committees effective. For instance, would a committee have Section 205 rights, would recommendations be given deference by the Commission, how it would interact with other stakeholders, what its budget, cost recovery, and staffing would be?

The New England proposal is ambitious compared to other regional state committees. The organization would advocate for policies that provide electricity at the lowest possible price over the long term, consistent with maintaining reliable service and environmental quality. A very broad mission statement.

Its scope is focused on resource adequacy and transmission expansion and planning. It would be a non-profit corporation governed by representatives of each governor. The consensus method involves a two-vote process. First, a proposal would have to gain a majority of support from the states on a one state, one vote basis. New England would require four states out of six. It would also have to receive support based on a weighted vote by the share of the load of each state. It would have a full-time staff and a budget of over $3 million in its fifth year. The funds would be collected by load-serving entities from all retail ratepayers in the region.

How could regional state committees participate by representing the states in negotiations with ISO New England and the market participants to reach a settlement on the final ICR. If there is no settlement among the three, they could negotiate a single proposal on which each of the three would cast a single vote. Two votes out of three would be sufficient to earn deference at the FERC. However, none of the states or other participants would relinquish their legal rights. This is one way to give the regional state committee more responsibility, and so far it's just a proposal.

Question: Does the regional state committee replace NECPUC?

Speaker 4: It does not. This question can be addressed over time. NECPUC is a conference of all of the commissioners in New England. It is not structured for decision-making. It does not have a staff that can do analysis of issues, especially regional analysis. Over time, it's conceivable that NECPUC could morph into the regional state committee, but that decision will come later.

Question: You discussed 205 authority or deferential treatment. Would this be narrowly constructed around the issue of resource adequacy, or around a broader base?

Speaker 4: The initial view of it was broader, but it's been clear that it would have to be accomplished under the umbrella of ISO New England's Section 205 rights. If they operate independent of ISO New England, their best option legally is to have 206 rights. They're trying to see if they can piggyback on the ISO's Section 205 rights, without simply becoming an advisory committee to ISO New England; beholden or controlled by them.

Question: What was the basis for establishing a forward capacity market based on three years in advance? Why three years?

Speaker 4: Simply put, it's a political compromise between longer commitments that could get estimates wrong and something long enough to provide a price signal and some certainty for generators. They don't want consumers to have to pay for overestimated capacity they don't need but still provide long term incentives for the market.

Question: It would be peaking capacity, or a CT, not base load, right?

Speaker 4: Yes, that's generally what we need right now.

Question: An earlier speaker argued that generators take the risk for their bad decisions and retail consumers take the risk for bad transmission decisions. Asking retail consumers to pay for bad transmission decisions raises a number of problems.

It encourages parochialism in siting lines and figuring where lines should be built. It imposes costs on a narrower set of customers than otherwise. It's inconsistent with cost causation, because the intended beneficiaries are not necessarily bearing the cost. It's perverse in terms of incentives because regardless of who makes the investment decision, the risks are socialized. It reinforces owner balkanization because the only people that could logically impose those costs on retail consumers are retail utilities. Therefore, it becomes difficult to get new investment for merchants or from particular customer groups to make their own decisions. Given these assertions, what is your response?

Speaker 1: There's several problems with your description. PJM does regional planning, 13 states, Washington, tightly coordinated with MISO etc. It involves planning over 20-25 states. This planning has to consider reliability needs and benefits, and economic needs and benefits.

LMP discloses and discovers those areas where there are economic needs and benefits because it quantifies those needs. Cost causation is also important, people who are benefiting should be paying. If Ohio is building a line to get power to New Jersey, the New Jersey consumers should be paying for all or some piece of that line. All these things need to be considered over a large regional area. Often, individual transmission owners are building pieces and then tying that all together. The RTO regional process brings everyone to the table.

These transmission facilities are billions of dollars. The most logical way to assign those costs is to assign them to retail. It's different from generation, because a generator can create anything, put it anywhere he wants, sell it wherever he wants. The region doesn't own that generation. However, transmission is a natural monopoly.

Question: So the retail rate payer means the regional rate payers for the entire region or for the state whose utility built the line.

Speaker 1: Well, the line costs should be allocated based on cost causation, who's benefiting from the line. A line across several states may be primarily benefiting people in the receiving state or it may be benefiting people all along.

Question: We've always had congestion. It's just now that it's transparent. The idea that we need to build infrastructure is another way of saying let's socialize the costs of congestion. They get socialized through infrastructure costs rather than averaging the all-in costs which LMP removed. Even if we built all this infrastructure that we need, LMP is still the right pricing mechanism because there are large price differences due to marginal losses across these large regions.

Another speaker suggested we use principles of cost causation to build infrastructure. This means that we do not have the right rate structure to recover transmission costs. What happens if a megawatt mile method is used to assess these charges. This would price out transmission services correctly, at least for the infrastructure itself.

Speaker 1: Even in the '60s and '70s, generators were built where utilities knew they could build transmission and get rights of way. When LMP was implemented, the financial transmission rights actually tied in some of those historic paths. LMP actually works right, arithmetically it's the right way to run a system. Later, with competition threatening, no one would build transmission because they weren't sure how they would be reimbursed. Now people realize you've got to build on a regional basis, and the debate is how to develop the cost causation standards. It's more difficult to do it with a larger number of regional players.

Question: If you wait until LMP produces high numbers to show that a line is necessary, then you're making a decision too late. There's enough modeling instruments that planners should be able to determine the best solution. If LMP produces high prices then a line should be built, but waiting for the results probably takes too long.

Allocating costs of transmission is arguing about a component that represents average of about 10 percent of the cost, and the savings are only 2-3% of that. We spend more money discussing how to split that cost.

I haven't seen one transmission line that benefits just this group of people and doesn't benefit the rest. This is a highway system. Everyone is going to benefit one way or another. Generators will benefit from economic development point of view, others from reliability. I don't know how much time and effort should be spent determining the exact portion of cost allocation to the beneficiary.

Speaker 3: We're trying to go to a competitive market from a legacy market. Some socialization is entirely appropriate and ought to be considered as a transition cost that needs to be paid by everybody. Once you get a reasonable transmission grid that allows the market to function well, then you can use LMP very effectively for congestion management.

Question: We've recently seen some defections from RTOs and also some different models proposed from the RTOs. Can we continue operating with these different models? Or do we need standardization. That can only happen if benefit is shown. Are we going to have sufficient benefit, can it be demonstrated, is this the model or are we evolving towards something else?

Speaker 3: The Entergy model was a four year experiment. The NOPR says that the ICT [independent coordinator of transmission] is not appropriate. It won't be around very long. It definitely violates at least the proposed rule.

Speaker 2: Well, at lot more have joined RTOs than those who defected. California has seven municipal utilities or member suppliers as participating transmission owners. They see the benefit, and others don't see the same.

Question: The fact that LMP congestion signals are still high is not necessarily evidence of a failure of the RTO. Getting transmission sited is too difficult for other reasons. Similarly for generation. Established RTOs are providing good signals. There have been three attempts to build into New York. The first two attempts were shot down because of lack of investor interest. The third attempt looks like it might be shot down because of some NIMBY efforts. In all these cases the signals are there. The completion of the loop in southwest Connecticut shows that LMP sited transmission correctly.

Similarly with competing proposals for transmission lines from the Appalachians over to the coast, and the construction of Path 15, and ongoing surges in investment in the upper Midwest area. Until 2000 there was a 20 year decline in transmission spending but since then transmission spending is up. The biggest surges are in the RTO areas, where the prices signals have shown the value of transmission.

Second, there's not a lot of co-op presence in the RTO areas. Is the co-op antagonism influenced by companies which are not in RTOs? What's the real beef with RTOs if they don't have that much of a presence there?

Speaker 3: They do not have an enormous presence in the PJM, New York, or in New England. The co-ops need RTOs. They want a refocusing on transmission, to get the transmission system built so generation competition can work.

RTOs are not a failure. MISO is an entirely different thing. There are 34 co-op generation and transmission companies that are directly affected in the MISO. They have positive and negative results. One in particular loves MISO because they're sitting on a really nice constraint, and they make really big profits selling into another area. Generally the concern is the overemphasis of the market, and the under-emphasis on transmission planning.

Speaker 2: California is often cited as a state that didn't work. However, since the California ISO was created until today, the transmission investment already in place is four and a half billion dollars. $5 billion by the end of this year. Since the crisis in 1999 until today there is 14,000 megawatt of new generation that is operational now. This includes a retirement of 6,500 megawatts of inefficient generation that did not stand the test of competition.

Question: If you look at RTO, the T in RTO stands for transmission. The SO in ISO stands for system operator. The SO means you're focusing on reliability. There's nothing in either of those two terms that suggests markets. MISO's original goal was to have a regional organization focused on the T and the SO, not on markets. Markets provide benefits, yes. But if you don't have the R and the SO, you're not going to get the benefits.

MISO now has a focus on reliability, and they've been improving what they do there. However, MISO and the stakeholders still spend more time arguing about cost allocation than they do about how to get things built. It takes seven to ten years to get something built and the real cost of getting a transmission line built is not the material and labor, it's the social impact a line causes on the neighborhoods. The focus needs to be on that, not on cost allocation.

If an RTO is doing a good job involving the public, their customers, their state commissions and building something that meets multiple needs and is an integrated part of the grid, then there's no such thing as bad transmission.

So finally, how do we refocus, and do you agree there needs to be a refocus on reliability and transmission impacts to make the RTOs necessary again?

Speaker 4: PJM also has planned transmission in the billions because they've been allowed to build for economics and not just reliability. Transmission constraints have existed for years because they didn't affect reliability but they affected pocketbooks. These lines can be built now. I do agree, you don't want to spend too much time on the cost allocation because you could talk about that forever.

Speaker 3: Michigan and Wisconsin are getting things built, in part because they have standalone transmission companies who have a vested interest. Half of MISO's transmission is in Michigan and Wisconsin being developed by standalone transmission companies. Those facilities have nothing to do with MISO's planning process.

Speaker 4: PJM owns no resources. All they do is process information, period, the end. Part of that information is the transmission plan, the states participate, the transmission owners participate. The process gives transmission companies in the PJM region almost an approval and authority to build because their way has been greased through. Everybody has been on board already, it enables the building process.

Speaker 2: Previously, ISO California analyzed a transmission proposal and decided it was beneficial or not. The big change now is that they take a much longer term view of need and benefit than they did before.

Determining where the resources come from is critical.
Building long-term transmission without knowing where the generation will come from is dangerous. Resource scenarios are necessary. Setting up these scenarios is something that the ISO now takes on. Initially, people thought that stakeholders would hate it but they have been very enthusiastic. Especially after maturing for a number of years, things are happening in a much more rational way. The scenarios help address the integration of massive renewable resources in the north and south, for the benefit of all utilities. These planning processes produce better integration for load pockets like San Diego and increase reliability.

Question: I'd like to focus on what the RTO model is, and can we have alternative models? It seems there's two possibilities. They are both predicated on overall objectives of the right long term incentives, completing investments, creating generation competition, and to change risk allocations. One is that we end up with the ISO, RTO framework with security constrained, economic dispatch in the short run, and LMP pricing and FTRs in the long run. Further, this model is a necessary, not sufficient part of the process that we have to put in place along with further adjustments, establishing long-term rights etc.

An alternative view is that there are multiple models that achieve open access, nondiscrimination, competition in generation, and long-term rights. We should spend less time trying to perfect one model and not even bother with pricing or auctioning off scarce facilities. Other ways of dealing with scarce facilities can be used, like assigning them to people. An alternative model should be just as good, there's lots of ways to skin a cat.

If we don't need the RTO model and should focus instead on important things like transmission investment, then what is the alternative model? If the RTO model is right, what's the objection to perfecting, not neglecting, the problems of transmission investment but also perfecting the other kinds of things which still need to be done.

Speaker: The principal focus is on the long run. Early on, the conceptual idea was that competition was based on transmission access. 80- 95% of transactions would be in bilaterals, there'd be a small balancing market because you need it. There could be a different mechanism than LMP to manage congestion. I don't have that model.

LMP produces problems that would go away if we had an appropriate transmission system. With an appropriate transmission system the model can work well. Without a robust transmission system, there are too many penalties to consumers based on their location.

If the transmission was built first and then LMP was imposed there would be less troubles. That would work well. I don't know another model that works. The Entergy ICT model won't work because it tightens the control by the folks with the market power. The RTO construct works well if imposed upon a robust transmission grid. The grid is not robust and therefore some of these pricing rules create unfair penalties for consumers.

Question: There are factual inconsistencies with the argument. If policymakers create a robust transmission system, the problems don't go away. Further, the existence of these problems are not acceptable. Prioritizing transmission expansion and not addressing other problems within the RTO model is an extremely dangerous policy. If there is an alternative, and you can muddle through, it's no big deal. If the RTO model is the model, then proceeding by addressing transmission expansion only is dangerous for many constituencies.

Speaker 1: It's dangerous if everything is in the spot market.

Question: Actually, the spot market is designed precisely to make it easy to do long-term contracting. It's origination was to create a way to allow for long term contracting.

Speaker 3: Certainly many co-ops are using or building physical hedges. Certainly, a five percent spot market construct is a problem. My understanding is that many RTOs have a much larger percentage in the short term.

Speaker 2: Certainly, but any customer can hedge with long-term contracts to whatever level of risk they want. The market can go up and down, but they are hedged.

Comment: There is a model that is coming together in the Pacific northwest that should work there. I'm not saying it should replace other models, other ISO's are doing a good job. Seven utilities; two IOU's, two munis, two PUDs, and Bonneville Power have incorporated an independent entity called Columbia Grid. It will have a three person independent board. It will be independent within its scope but the scope will be determined primarily by the seven members.

The actual activities are yet to be negotiated but will be this fall. The first would focus on transmission planning. The independent board and an independent transmission staff would put together transmission plans for the entire footprint of the Pacific Northwest. If there is not agreement between transmission owners on what ought to be in the plan or who should bear the cost, the organization would be empowered to make that determination. It would also be empowered to seek a FERC order for the transmission to be built even if an owner will not agree to the plan.

The second focus will be on reliability. Maybe it's an ISO but it's not an RTO; for now it's just Columbia Grid. The agreements will also define costs. The board will not have independent ability to increase its scope or increase costs. There are many Northwest utilities that are not FERC jurisdictional but the EPACT '05 has changed the landscape dramatically. These non-jurisdictional utilities who run control areas realize that FERC will enforce reliability standards. Thus, the anathema of FERC jurisdiction is there, but FERC enforcement is not. FERC will be looking over their shoulders to see what they're doing within their control area. This should be a good model for the Northwest and I'm not sure just how different it is from an RTO.

Question: Discussion in past forums have concluded that planning is hard, and no one's doing it well yet. Within that context, there's been a discussion today that suggests emphasis on infrastructure development, not short-term optimization. However, those are really two sides of the same economic issue.

Long-term optimization is about planning and capital deployment. Short-term optimization concerns how we utilize capital once it's deployed. One can't be done without the other. Clearly, we don't have either the short-term or the long-term right yet. If we did, we wouldn't be struggling so much with the planning. It's a multifaceted problem.

How can policymakers make the right capital deployment decisions for long-term infrastructure development unless they increase the focus on the short term as well, and figure out how to get it right as well?

Speaker 3: My concern is that all the RTO's time and most of its money is on the short term. The balance and emphasis should be on the longer term. Many people seem comfortable that the short-term optimization in PJM or MISO works fairly well.

Question: One speaker noted that PJM's forced outage rate has been decreasing. If that is the case shouldn't the RPM reduce the reserve margin requirement from 15%?

Congestion is certainly an issue in the RTO model. Is demand response in targeted congested areas being used? Should it be part of the model?

Speaker 1: The PJM reserve requirement has also been coming down. Reserve requirement is calculated on a theoretical basis by planners, and forced outage rates are an integral part of that calculation. It's creating benefits for everybody. It's making things a little bit more efficient.

Question: Does that mean that future reserve requirements will continue to go down if the trends stay the same?

Speaker 1: It might go down a little bit, but not a lot. It's pretty much reached the end because of the large diversity of generation sources. It could go a couple percentage points lower. Reliability has to remain the primary goal.

PJM is factoring demand side into their installed capacity accounting system, into RPM. Demand side will be a resource equal to a generator in meeting those requirements. It's being used to meet spin reserve requirements. It's been a goal for a couple of years but creating the procedure takes debate by 150 happy, friendly stakeholders. Now that procedures have been filed, demand side is going to have an equal access as a generation source.

Speaker 2: Getting volunteer demand response has reached its limit. The signal has to be to the load, and the load has to be able to respond to those prices. Certainly when a monthly bill quadruples, it changes people's behavior. Demand response has to be part of the market design and it only occurs if people see the prices.

Speaker 4: When we hear that an RTO prioritizes reliability, they're working with a loss of load probability of one year in ten. Consumers are getting a reliability level much higher than that, more in the vicinity of once in a hundred years or even more. Involving a regional state committee could allow questions about what the installed capacity requirement should be, to ask questions about what level of reliability is being acquired. Are states getting and paying for just one in ten, or are they paying for a lot more? Conceivably, one could reduce the reserve margin substantially below 15%.

With significant demand response engaged in the market, reserve requirements calculated off a peak day could be substantially reduced potentially. Defining which resources are eligible to participate, how can they bid, what's done to verify their performance, is critical to understanding reserve requirements.

ISO New England aggressively intervened to ensure that demand resources were utilized to deal with the reliability problems in southwestern Connecticut. This created a good solution, especially when the long-term solutions of transmission and generation there are some time away. They are trying to engage more aggressively in the evolution of the retail market, particularly to mobilize demand resources for reliability. They are putting pressure on state regulators to fix retail restructuring designs that are disconnected with the wholesale market.

Question: PJM cost $265 million last year. So some people want them to control their costs. I suspect PJM is already responding to that. RTO costs plus the price volatility in the markets are both problems that are probably being addressed right now.

California has $10 billion in new transmission, that's enough money to matter in terms of cost allocation. Perhaps it's time to just spread the cost, otherwise there'll be excessive controversy that is not easily resolved. Who should pay is an important issue. It really hasn't gotten a lot of intellectual time and energy yet, and it's a hard one.

Co-op utilities serve in sparsely populated areas. It's hard to justify large scale transmission lines economically to serve sparse areas with little economic activity. It seems the co-ops argue they want transmission built, but somebody else to pay for it because they exist in an economically sparse area. It's a problem. The co-ops are in a difficult situation there, but I don't think RTOs are the problem.

Speaker 3: I would agree with you. Co-ops are not blaming RTOs for an absence of transmission lines in rural areas. Cost has been an issue but recently costs have come down. Volatility certainly affects co-ops. Maybe with a more mature market that'll go away.

Second, co-ops are looking for a long-term hedge to solve their problems.

Question: What RTO market doesn't let you do that?

Speaker 3: It's very difficult to get long-term transmission price in PJM. What would you define as long run?

Question: 10 or 20 year power is available isn't it?

Speaker 3: It can't be delivered at a known price in the PJM. Uncertainty is a huge issue for many of these entities. For example, the City of Chambersburg, in the middle of PJM, had 100% of the FTR allocations for four years, no problem. This year, it has 51% of the FTRs and their price goes through the roof. They try to hedge long term, but the prices go up because they can't hedge long term in the market.

Question: Could the panelists qualify the success of RTOs on a scale from one to ten as regards, A, planning coordination, B, investments, C, operational coordination, and D, impact on energy markets.

Speaker 1: On the energy markets I'd give the RTOs a very high score because what they've done is set up markets. The markets have worked and they've created new bilateral markets throughout those regions of the country. There's more trade, more interchange. That's why we're talking so much about transmission. Transmission was originally created to get generation to their load. Now it's being used to ship power all over the country. That's an efficiency created by competition.

Speaker 2: When we talk about the scores, this is not a score for the model, because the model still has a way to go. I never give anything more than seven in anything. For California, planning in generation and transmission is a six. On investment, six. Operation coordination, eight. And wholesale prices, to my surprise when I look at the data, eight.

Speaker 3: There's been enormous strides made in some of the RTOs on planning, kudos to PJM for realizing economy and reliability are both important. Expanding to a 15 year planning horizon is good.

In terms of the markets, if the market is working well, why do we keep using band-aids? Why do we need RPM, or other things? I would not grade the market strongly in terms of price signals or congestion.

Speaker 4: My experience is in New England. I give ISO New England high marks for what they have accomplished in all four of these areas. ISO New England's biggest problem has been the inflexibility and at times counterproductive behavior of the states.