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HARVARD ELECTRICITY POLICY GROUP
FORTY-SEVENTH PLENARY SESSION

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RAPPORTEUR'S SUMMARY*

Session One.
All The King's Horses and All The King's Men:
Can Humpty Dumpty Be Put Together Again?

The continuing critique of electricity restructuring, and some actions to undo what has been done, presents a policy challenge for government and industry. Many have been rethinking the entire issue and some, in states with restructured retail markets, are advocating a retreat to either the old monopoly model, or at least some variation of it, at the retail level. Reintegration and cost based regulation are finding advocates in many places. In some jurisdictions, the Rooseveltian policy of using public power as the "stick in the woodshed" to discipline prices has found strong advocates. For many reasons, not the least of which is high prices and fear of capacity shortfalls, there is sentiment for resurrecting some, or all, of the old paradigm. Most of the public debate about returning to the old model, or variations of it, has focused on retail market structure and not on wholesale competition, but it is not clear that de jure restoration of monopoly power in retail markets can be effectuated without affecting the competitiveness of wholesale markets.

What are the key initiatives in states? Can vertically integrated utilities which have been divested themselves of generation be reassembled without raising the same significant market power issues that disaggregation was intended to resolve? How will dispatching of generating units, transmission operations and expansion, and market operations be affected? To what extent will re-imposition of monopoly supply in the retail market, or significant pieces of it, have, on demand response to wholesale prices? What impact will debates about utilities, either investor or publicly owned, have on investment in independent generation; particularly at a time when the capital markets appear to be valuing independent generation more highly? What are the short and long term consequences of re-

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restructuring? Will re-verticalization and/or restoration of monopoly retail supply actually produce the sustainable lower prices, more reliable supply, and more appropriate risk allocation that its advocates are trying to achieve?

Moderator: In 2006, the 50 states plus the District of Columbia were categorized as follows. Not restructured, 26, adopted restructuring, 18, adopted for large customers only, 2, delayed start dates, 2, repealed restructuring, 2, restructuring suspended, 1. That's the state of California. However, within the adopted restructuring category Virginia has recently adopted legislation suspending retail competition, both Maryland and Illinois are backing away from their progress toward restructuring. California appears to be reconsidering some aspects of retail competition.

However, Texas is considered to have the most successful restructured state in North America. Their residential switching rates are approaching 40%, their C&I is in the 80% category. However, even Texas just completed a legislative session where the primary topic was electricity prices. This background will function to incite a robust discussion of the options.

Speaker 1.

The better question to ask for this session is, "should Humpty Dumpty be put back together again?" 12 years in an industry that's been developing over the course of the last 100 years is a short amount of time. The amount of change in the past 10-12 years is dramatic. Any conclusion about the success of energy competition at the wholesale or retail level is inappropriate at this point. It hasn't been tested to any significant degree. It's naive to do so.

Second, it's naïve as well to think that we can return to the past regulated system. The structure of energy delivery, its pricing – at state levels in particular - may be modified but we have competitive wholesale energy markets and that's going to continue for the foreseeable future.

The original goals of restructuring, based on extensive review of laws, federal regulation, and relevant literature, was not to lower prices. Instead, it was to increase the amount of competition in wholesale and retail energy markets. Increasing competition was supposed to enlarge the number of buyers and sellers, improve the availability and accuracy of pricing information, and allow private companies to enter into competition with the existing utilities freely and fairly. These factors were expected to lower prices and provide a wider array of previously unavailable retail services.

One local New England retailer has 15 different product offerings. They include fixed, flexible, block and index price options, options that can customize for a specific customer, green options, and demand response options. In traditionally regulated jurisdictions the only option is either take it or leave it. Lower prices is the ultimate goal, but that shouldn't be the only measure of success of this market.

Competition was expected to achieve these benefits through wholesale generation efficiency and innovations in electric retail service. We're moving along that path, but there's a lot of opportunity to continue moving forward; greater efficiency, more innovations, incentives to lower prices. Notwithstanding the APPA report that came out this week, we have seen greater efficiencies in the generation and delivery of electricity. Electricity rates compared to other commodities in the past 30-35 years have fared pretty well compared to other products like medical care or gasoline. Despite the increases in electricity prices, it is a better value in comparison with other products over the long term.

The Brattle Group, in a forthcoming report, looked at EIA data and broke apart restructured states and non-restructured states. States that went through a restructuring process had historically higher rates, oftentimes cited as the justification for moving into restructured markets, and non-restructured states had lower

prices. Since 1997 the rate trends have been consistent. There are some big drops and subsequent increases largely due to legislative mandated rate reductions but after those have come off both restructured and non-restructured environments fare well.

Has competition delivered the benefits that we all were hoping? Maybe not. However, we haven't seen the dramatic run up in prices. If you look at states like Michigan that went through a restructuring process, they allowed for retail competition but still regulate the utility companies. Currently we are hearing about rate increases in restructured states like Illinois and Maryland that look dramatic because they are coming off legislatively mandated rate reductions. However Michigan had rate caps that came off for industrial customers, commercial customers and residential customers respectively through '04 to '06. However, these costs are consistent with traditional base rate increases and the dramatic increases in fuel and purchase power costs. The regulated and partially hybrid regulated states, have been consistent with the restructured states.

The biggest threat to the competitive environment is the politics of energy regulation, what's occurring in Maryland, Illinois, or Connecticut. Mostly, these reflect unsatisfied public expectations. One can put all the charts in the world up on a screen and customers don't care if they're paying higher rates, particularly dramatic increases coming off rate freezes. This is regardless of the fact that the overall rate increases over time are probably reasonable.

The good old days of cost based rate of return regulation and integrated resource planning were not that good. They make a decision today and more than likely when those resources are coming on line they're going to be wrong. Either the utilities or the regulators. There's a lot of second guessing. That regulatory uncertainty leads to risk and financial pressures.

Some quick fact background. Electricity is a $358 billion industry. It's been built with 1950s technology over the past 40 years. The 2003 Northeast outage reminds everyone of the impact on the economy. Most estimates center around a $6 billion impact from that blackout. Unreliability is a critical concern.

There are four important groups to consider going forward. Investors want stable returns. Generators want high margins and stable predictable sales and contracts. Marketers want prices to reflect the underlying market which has inherent volatility. Consumers don't like volatility, they want low stable prices. This is being debated right now in Texas, Illinois, Connecticut, and Massachusetts. A reliable, affordable, environmentally friendly power system is what we need. It should provide essential public services, an economic framework for efficient transparent markets, operational effectiveness and something that supports the evolving needs of our society.

What do we need to do? Stabilize energy markets. First, anything that eliminates some of the uncertainty surrounding these markets is important. Provide for the public good. While there's been dissatisfaction with the public when it comes to energy, the issue should be dealt with directly and then we must move on. The debate keeps dragging out and that ensures uncertainty. Second, protect the environment. That's obviously the thing to do today and it's being addressed in a later session. Third, educate and empower the consumer. They are more intelligent about the energy decisions they make. They ask whether the washer and dryer they're buying is Energy Star compliant or about CFLs. They look at different energy saving options. Anything more we can do to empower the consumer to make smarter decisions is critical. Fourth, unleash innovation. Smart metering technology, fuel cells, etc. We have a system that's based on 100 years of history. We're just on the cusp of the innovation potential right now.

Estimates vary on what it will take. $10-20 billion a year for ten years is necessary to update the grid. That works out to the price of a pizza per family per month. It's not a lot of dollars overall. When there are unreliable systems consumers pay for it. They can pay for it in an

unpredictable manner via blackouts, or predictably as a long term upgrade investment.

The role for regulators has changed. Electricity is no longer a declining cost commodity. We should not treat is as that. If consumers are empowered and educated, regulators can support open and transparent markets with a reasonable amount of regulation. I used to carry around the rule book for the New York Stock Exchange. Essentially it's the code of conduct, the rules that govern its operation. It's one of the most competitive markets in the world yet the rule book is quite thick. You need supportive regulation.

In order to support R&D infrastructure investment we need a national energy policy, which we don't really have. We need a more robust national energy policy that supports fuel diversity and energy efficiency gains.

Regulators used to protect consumers and deliver punishment when utilities didn't perform, and discouraged investment in excess generation. That role has evolved to support and protect the establishment of markets, establishing incentives, becoming an arbiter between consumers and companies, ensuring openness and transparency, and technological advancement.

Where do we go from here? We can rely on the past; repair, rebuild, return to basics, support the status quo and yesterday's technology. We can try to be happy with struggling to achieve an 11% return on equity from a utility company perspective. Or we can look to the future, rely on new technology and business opportunities to expand the system and support a 21st century energy infrastructure.

China demonstrates what a growing economy needs as far as electricity is concerned. There's no difference here in the United States. We need to have that robust developing system. A back to basics strategy is not going to get us there. Open transparent efficient markets will provide the best option for consumers in the long run.

Speaker 2.

Speaker 2: I'm going to discuss some of the activities in Connecticut, especially the Connecticut Office of Consumer Counsel. I'll focus in part on residential retail competition, which really isn't policy at all. China was just mentioned, but China is building based on a back to basics, regulated strategy – they are building based on the old monopoly model.

Connecticut has a lot of politics. There, deregulation has turned out to be a weak form of re-regulation in which the state sends out a lot of ratepayer money to well connected folks and hopes that more will come back without the traditional prudence protections. Instead of getting valuable and efficient products, they end up paying for things like fuel cells which isn't a very good investment. There are jobs in fuel cells in Connecticut, however and the only efficient market in that state is the political market at the capital.

There is a strong role for government here. Government has to think 20, 40, and 60 years out even if the market participants won't. They're bound to make some bad choices, but that will be better than the coming capacity shortage if they leave it to the market. My greatest concern is not cost overruns, it's capacity. I have seen slides from generators that show that New England will have a capacity shortage, 0% capacity overhang, by 2015. That's an extremely dangerous position; we need to react. It's possible that market signals would solve this if they are right but the states can't take the risk that market signals fail.

Can you reassemble Humpty and move back to the regulated model? Yes, one new plant at a time. Slowly is best, and one or two new plants at a time is best in order to see how it's working out.

If a state gets the traditional utility back building a couple of new plants, it gives coverage to see how it goes. It gives them time to build back their expertise for running generation plants again. Presumably, they're not going to have them buy back $5 billion worth of equipment.

Instead, have them build a couple of peaking plants. It's not a capital intensive investment like a base load plant but it can have a direct effect on reducing peak power prices. The big problem is the peak power prices but states try to solve the problem with people whose entire business plan revolves around the existence of high peak power prices. However, the traditional utility companies have no focus on peaking prices, but they are still blamed when there are rate increases because the public has limited understanding. If they build peaking plants, it'll reduce the market power of existing merchant generators. The traditional utility bids in at cost of service. That will drive down the clearing price for all market participants and bringing lower power prices as well as reducing market power.

The big problem is getting plants built. If a merchant already owns a fleet of plants, it probably won't build because they will do better in a shortage. However, the merchant fleets also discourage new entry because they own many of the existing sites, and they threaten to build new plants if new entrants threaten to show up. They drive out potential competitors because if you already have a site that's permitted and you send out your plans to build, they scare the competition. It's extremely difficult for new entrants. Existing market participants want a shortage to develop. A shortage is valuable and a surplus is dangerous if I'm a merchant generation owner. They have no incentive to build baseload because the shortages work so well with peaking units.

So how does financing work? Richard Stavros in Public Utilities Fortnightly talked about the "build mode" and getting policies right to enable it. Locational margin pricing is not going to incent much, especially for base load. If you build base load the signal that locational margin pricing is supposed to provide collapses. The price signal exists ahead of time, but not after the base load is built. LMP will not cut it. Similarly, not many people think that a five year payment stream in the forward capacity market will lead to new building either. Perhaps as part of a package, but not by itself. Long term contracts with the utility can work and they are starting that in Connecticut. They are implementing this through RFPs. The problem is, they are paying an awful lot more than if they had just had the utility build it. They're close to buying the plant twice and then not getting the plant after 15 years. Awfully expensive.

For financing new base load plants either utility owned generation or long term contracts are the way to go. to help deal with the financing. At the NECPUC meeting in 2006 there was a gentleman from MISO who talked about four scenarios. Lots more renewables, new coal, new nuclear, or the default which is new natural gas plants. He talked about the governors making those choices. I think that's honest, it will be governments that make those choices because of siting difficulties. If that's the case, why send out these large price signals? The theory is that it will get new nuclear and coal to be built but we all know that doesn't happen. Pay as bid wouldn't work either so there's got to be a third option. Perhaps one splits the peaking and base load markets. In an emergency a windfall profits tax could be implemented. Sending out a large market signal to coal and nuclear when it won't respond isn't particularly wise.

The forward capacity market won't lead to new projects because it was designed and negotiated with the folks who already own generation in New England. New entrants were not at that table. They ended up giving payments to a lot of people who didn't need them. Further, the eight, ten, 15 year income stream that you would need to build is still insecure, but the capacity market was cheaper than LICAP so they took it. I'm still surprised that that negotiation led to a settlement because there was little social interaction between the parties. There was a government and traditional utility side, and there was the merchant side. They didn't eat together, they didn't ride the elevator together but they settled. It has a lot to do with Judge Brenner of FERC.

Ultimately, for building nuclear or coal in New England, the king is the government. A new nuclear unit will involve a long struggle and probably occur at an existing site. Unless they want to pay for it like a single source

procurement, they've got to work with the current owner for an expansion to get past all the siting and financing problems. This can only be done in regulated setting in New England; they'll deal with the financing and get the output at a reasonable rate. It's the same for coal but especially in the regional greenhouse gas initiative (RGGI) states coal is very unlikely unless there's some real technology improvements. If you don't choose, you still have made a choice and you've chosen natural gas if not nuclear or coal. We'll probably see 1-2 more rounds of natural gas plants.

However, in Connecticut the theory that deregulation would shift the risk from ratepayer to developer really hasn't happened. Even the CPUC who claim to support deregulation has entered into the 15 year contract that we talked about. In Connecticut they're either over-earning or have an RMR contract.

Markets have also not brought a diverse set of plants. Diversity is a public benefit that the markets rarely provide. If you want diversity as a policy you have to buy it. The best example of that is renewables. The states keep saying they want more renewables, RPS at 10% of load. However, it's only so long as it's far enough out of anybody's term of office. [laughter] These are largely political choices. Even if you think the market should make these choices, it's probably not going to. States will be making more of these choices with utility owned generation, with long term contracts. They will hoard the benefits so that regional generation planning is unlikely to move forward either.

Speaker 3.

Part of my vantage point is that I'm a life long liberal Democrat. People like me are associated with regulation and I came to the industry with that vantage point. However, I'm going to discuss how my thoughts have evolved in that regard.

Can Humpty Dumpty be put together again? Yes. But that's not the right question. The question is rather, what's he going to look like after he's put back together again, how much is it going to cost, and would people be happy that he's reconstructed?

I have three issues to discuss. One, what's driving the push for reintegration that is making it the subject for conferences and state legislature policy. Second, what is reintegration? Especially, what does it look like from a legal standpoint. Third, I'll discuss the current activities of the Illinois legislature up until last night on May 31st.

What's driving the reintegration efforts? As multi-year state rate freezes have come off there've been significant increases in electricity prices and there's a dissatisfaction with competition because it has been associated with that. The rate freeze in Illinois for a ten year period of time was followed in the northern portion of Illinois by an average electricity price increase of 23%. That is an easy, powerful and simple message for politicians to latch onto but it's obviously a more complicated question than that. A more fair question is what the rate increases have been relative to states that are still regulated? Who's fared better? If we reintegrate and put Humpty together again, will we stop these price increases? Is the price adjustment after the ten year rate freeze a one-time adjustment? Finally, what are the non price implications of re-regulation?

I've tried to read all the studies looking at prices in various states. The conclusion that I reached is there are some who say the prices are higher in deregulated states, others who say the opposite, but overall prices have increased roughly the same in the regulated and the deregulated jurisdictions since 1999. That's what the data reflects overall from EIA and other sources.

Let's discuss the price increases from '96 to '07 in regulated and deregulated states split between those with and without RTO markets. If we contrast these prices with the Henry hub price for gas, it shows clearly that price increases depend on whether states regulated or deregulated the price of gas. It has nothing to do with electricity regulation directly.

Price increases during this time, both within and without the RTO markets, have both been up about 34% on average according to EIA. Further, in deregulated states the cost of labor has increased more than regulated states. Similarly, the cost of fuel in non-regulated states has been higher because they are more natural gas intensive states. Thus, while the increases in prices have been roughly the same, the deregulated states have absorbed greater fuel and labor costs and yet maintained the same approximate price increases. This is a strong argument for the deregulated model. Even if one finds different statistics that counter-act this argument, we haven't had a dramatic price impact as a result of regulation or deregulation. Further, we are in transition, and we'll have to see how this all plays out from a pricing standpoint. While electricity is up 34% in the last 10 years, residential natural gas is up 95%, number two heating oil, up 269%. Comparatively, the electricity industry has price stability not being experienced elsewhere.

So, if price is a draw, what are the implications for rebuilding Humpty, for reintegration? What other things will happen? Are their other things that deregulation has brought on positively or negatively that have to be in the dialogue?

I wasn't in the utility industry when restructuring started but there were a parade of horribles in a number of places. People have forgotten what Humpty looked like, what the inefficiencies were, how the plants operated, how expenditures were being made and who had to bear those expenditures and inefficiencies. There have been greater efficiencies realized in the operation of plants. Further, the long term implications are important for consumers, for state government, and for the development of new generation.

The previous speaker is skeptical about whether merchant generators will develop new generation without an enormous price incentive to do so. Since 1999, merchant generators have developed 167 gigawatts of new electricity in the country. It seems that new generation has come on despite deregulation.

Second, who's supposed to bear the risk for the decisions about new generation, building, uncertainties about fuel costs and market, etc.? A central tenet of deregulation has been to put risk on the people who were previously running nuclear plants at 47% efficiency. Private entities have to bear the risk of knowing about new technology and of looking at how markets will unfold. Even as a liberal Democrat I have more confidence in the generators bearing those risks than the utilities under a regulated "Humpty Dumpty" regime.

Let's examine a legal standpoint on reintegration. It's popular for politicians to say we want it, we want re-regulation. There are a couple of possibilities. The plants have to be owned by different people; they can't be owned by the deregulated companies. States can't take back the power plants that the utilities have sold or divested, they're going to have to buy them back at fair market value. That's an enormous undertaking for states that are financially strapped across the U.S. Alternatively, they can construct new plants but there are costs associated with that, along with technological uncertainties. Re-regulation through things like generation taxation are replete with a lot of problems. Will costs simply be passed onto consumers, are they legal? These legal and economic problems can create enormous hurdles to reintegrating.

Let's get an update on the Illinois situation. The transition period ended in December of '06. There was a reverse auction conducted to establish power prices. There was a long process before the Illinois commerce commission with broad participation by political and consumer groups and the utilities, the generators. There was broad bipartisan and regulatory support for the auction process. There were 14 successful bidders in the ComEd territory and the price increases were 23% on average. When you account for inflation, those increases are slightly below the average rates in the ComEd territory in 1997 when rates were frozen. The rates were frozen and reduced by 20%. In fairness the Amren territory in southern Illinois had

extraordinarily low rates and rate increases were significantly higher; almost 50%.

As a result there is now an enormous political battle. There are various factions in the state legislature that have proposed legislation. There are a variety of different possible components for this legislation and the situation is very fluid – I'll focus on the ten most important. First, a rollback of supply charges to 2006 rates. So all the increases are gone. Two, refunds of what has been collected this year in excess of the 2006 prices, plus interest. Three, a generation tax of $70,000 for each megawatt of name plate capacity multiplied by the capacity factor. That comes out to about $16 a megawatt hour, about $2 billion in tax on the generators in Illinois. Four, creation of a special fund called the consumer-over-build-and-reimbursed-for electricity fund. The generation tax money would be put into the fund to be used to offset the expenses that utilities are incurring because of their contracts in excess of what they're entitled to collect from the consumers.

Five, create an Illinois power authority; a public body that will acquire and operate generation and be exclusively responsible for procurement in Illinois. Tied to that is that only Illinois coal will be used in new generation and the Illinois pension funds will be the investment mechanism for the Illinois power authority [laughter]. Six, prohibit utilities from being members of ISOs or RTOs. Seven, remove all current ICC commissioners. Eight, prohibit utility boards or officers from having any association with affiliates or owning any stock in affiliates. Nine, prohibit any utility from having an affiliation with a power producer. In other words, divestment. Ten, prohibit any cutoff of electricity for any reason for any customer until March 2008. Obviously this would affect utilities a great deal.

I'm hopeful that we'll take a good hard look at Humpty Dumpty and decide that the road on which we've traveled is worth traveling a little bit longer.

Speaker 4.

I'm concerned that the panel topic description and questions betray an assumption of the desirability of promoting markets and deregulation versus a "retreat" to the old monopoly model or a variation on it. And even the choice of metaphor implies this, whether it's Humpty Dumpty, putting the toothpaste back in the tube, or the genie in the bottle. Of those metaphors the one that is impossible is trying to patch together an egg that's been broken. Toothpaste can be put back in the tube. It's a messy process, I don't recommend it without appropriate equipment. [laughter] The genie was put in the bottle at one time, back in 1935 at which time the country was faced with many of the same issues. The industry was much less developed but the issues of market power and customer access to affordable high quality service were on the table at that time.

The public interest here begins with the recognition that because of the physical nature of electricity and its role in modern society, electric markets always become infected with market power. Attempts to promote efficient competition add huge costs and are usually futile in the end. That's what our experience has been, most spectacularly in California. Some say the California experience was an exception. I don't think that's true. There have been concerns for market power in other regions of the country that have moved towards deregulation.

Let's address the questions. First, can vertically integrated utilities which have been divested of generation be reassembled without raising the same significant market power issues that disaggregation was intended to resolve? I like the term reintegration. I think that's the appropriate term to be used here rather than re-regulation. Well, disaggregation itself has created market power problems. FERC has demonstrated its inability and disinclination to address market power where divestiture has taken place. Reassembly of vertical integration under state regulation and reducing customer exposure to wholesale markets resolves market power issues in the interest of consumers. It was done in 1935 and can be done again. It takes

political will and a recognition by consumer groups of what their interests are. That recognition is beginning to take place in many deregulated regions.

How will dispatching of generating units, transmission operations and expansion, and market operations be affected? Dispatching and operations decisions should be made on the basis of system efficiency and reliability, not market efficiency. Market efficiency is impossible in an environment distorted by market power. Regulatory mechanisms, because of the physical nature and the economic nature of the electrical system, are the only way to address system efficiency and reliability.

The construction of physical systems based on self sufficient local control areas with diversity exchanges on the economic margins, or at the seams, is the right model. It is superior to proliferating high voltage, long distance transmission and the attendant systems which scar the landscape and increase instability. That's one of the reasons for the last big blackout on the east coast. The current transmission system was not created or maintained to perform the services that it's called upon for.

There is no legal impediment to reestablishing self sufficient local control areas. In fact, small scale generation is easier to install and engineer on distribution level loops if control areas are reduced to traditional scales. That's why Illinois' proposal to get out of ISOs and RTOs will be good for them. of getting the state out of any tie ups and dependency on ISOs or RTOs.

How will re-imposition of monopoly supply in the retail market affect demand response? I argue, provocatively, that demand response to wholesale prices is a fantasy of market worshipping economists. It assumes functional and efficient markets which don't exist anywhere. To the extent that an integrated utility is exposed to wholesale markets, appropriate rate regulation can permit a feedback loop between wholesale prices and demand.

There's going to be a wholesale market. It existed before the current push for deregulation began in the late 80s. However, that wholesale market should only be the exposure of utilities. Retail consumer exposure should be minimized. In California their jeopardy was caused by the degree of their exposure to these poorly regulated wholesale markets afflicted with market power.

What impact will this have on investment in independent generation, particularly when capital markets appear to value independent generation? Unlike traditional utilities, independent power producers have made their investment with full knowledge of the regulatory risk of a possible return to a cost-of-service regulation. Independent power producers touted the fact that they were taking full risk. It was a regulatory risk as well as a market risk. If, as proposed in Illinois, the state gets into the business of building new generation, the market power of the independent power producers would be destroyed and they would be unable to recover anything more than their short term marginal costs going forward. The market value of their assets would be severely diminished. Condemnation of those plants and the payment for the reacquisition of those plants within the regulatory structure at fair market prices could occur, but not a fair market price on today's prices, but one in which they do not have that market power.

Actually, capital markets and rating agencies value vertically integrated munis and co-ops more highly than any other assets. Private equity firms are speculating on energy policy debates, with a view towards flipping acquisitions and taking advantage of climate policy driven subsidies. It's speculation that affects consumer costs, but it's not a sound basis for policy on infrastructure planning and development.

Next, will re-verticalization and/or restoration of monopoly retail supply produce sustainable lower prices, reliable supply, and more appropriate risk allocation? Electricity prices in traditionally regulated states have risen at lower rates than in states that have restructured. Different analyses come down on different sides

of this. It's certainly true that in deregulated states there's more exposure to gas generation and therefore prices have reflected the steep rise of natural gas prices. However, there's a reason for that. Deregulation was based in part on building new combined cycle gas turbines which were going to be cheap when there was $3 gas. It's not $3 anymore but the market prices are set by gas generators on the margin and prices have gone up. The increased dependence on gas fired turbines was brought by deregulation.

Where cost of service regulation still exists there are effective mechanisms for mandating and financing construction of new generation facilities. In deregulated areas, some are calling for the reestablishment of that aspect of traditional regulation, for instance Michigan, Ohio, California, and Connecticut. States should enact resource planning to ensure that conservation, efficiency and renewable resources are included in plans for resource adequacy. Electricity is a social goods product, a fundamental responsibility of government.

Finally, it's a myth that vertical integration has been reduced. Corporate and contractual structures that integrate fuel supply, fuel transport, electric generation, fuel and electricity commodity trading, energy finance and retail delivery have been proliferating. Vertical integration continues but it's difficult to discern because of deliberate obfuscation by the federal regulators. There is a deliberate effort to obscure this accelerating integration. It's done outside of the oversight of financial and energy regulators at all levels.

Examples include the so-called restructured utilities like Entergy and Exelon. There are also integrated oil companies with positions in all fuels plus electric co-generation, financial entities like Berkshire Hathaway that have positions in renewable electric generation, pipelines and finance, energy trading firms like Sempra Energy which has positions in all of the above including retail electricity and gas. It's not regulated and enables corporations with extensive integration to operate without oversight or regulation. It is a bad thing for consumers and introduces great elements of instability into the economy. It's not a good thing for the country going forward.

Moderator: The rising default price in Texas rose with the price of natural gas. Hence, they had a recent legislative session devoted entirely to electricity. However, customers that switched from their legacy provider realized savings. However customers in Texas still have some important questions that relate to this panel and that I hope will be addressed in the Q and A. One, people ask why don't consumers get the benefit of a diversified fuel mix? Those who live in a muni or a co-op area have lower rates from a diversified fuel mix whereas the deregulated areas are driven by gas price. Two, is it reasonable to assume that the elderly and low income can shop for electricity? For 100 years their paradigm has been that power comes from one supplier. Can we believe that they will learn to switch? Three, will markets meet resource adequacy needs and, also take natural gas off the market in an environmental context where you cannot build new coal?

Question: I'd like to get the other panelists response to speaker 2's proposal to reintegrate by having the utility build one or two cost-of-service peakers that go into rate base and move towards cost-of-service in a deregulated state. Is that an approach? What are the implications?

Speaker 1: This is possible. there are opportunities and ways could be reassembled. The question is the implications for how long will it take and how much will it cost. There have been discussions of risk and I would argue the *whole thing* is about the assignment of risk. Who is going to pay? Once reintegration or re-regulation occurs we'll see higher prices for some customers and lower prices for others, with people saying what a great idea this was, or alternately saying look, we're back to the 1970s or 1980s and we're paying to much. The prices will be different in different contexts

The one thing that is certain is it's better to take the risk in generation development and assign it to people that can actually manage that risk in the longer term. It shouldn't be the consumer.

Speaker 3: I don't have too much to add to what was just said. One thought is that in utility company polling customers say in the abstract that prices are too high and deregulation in the may have been a bad idea. When you ask them if they want the state or the utility in the business of constructing and operating power plants the response is overwhelmingly no. They want people with demonstrated competency to continue to do it. That doesn't answer the question but it shows there is a difference between the political perception and the practical reality in terms of how people's opinions.

As a side note, the first capital market investor report out of the Illinois legislative meetings last night is titled, "Venezuela in Illinois." [laughter]

Speaker 4: Rate basing new generation in deregulated states is under active consideration in a number of states. The problem is that under the present system needed generation is not being built, especially base load. Utilities are concerned whether it's legal for them to build new generation. They don't feel they have assurances of recovery of their investment through rates.

It makes a lot of sense to rate base new generation, particularly base load generation in states like this. One complication is that the utilities with retail competition can't be certain of their load going forward. Load is fairly predictable if you have a monopoly arrangement. In Michigan for example, customers are free to go back and forth between regulated utility service and competitive service but the utility is the provider of last resort and has to make arrangements for adequate capacity going forward. There isn't a regime in these states that effectively assures that the obligation for capacity going forward is shared.

It creates uncertainty and the risk to consumers is that if you rate base new generation and then load leaves the regulated utility then the remaining customers, usually captive, have to suffer the consequences. They pay for the investment that's made. If states do this they have to recognize this contradiction and end retail competition. It's inappropriate to allow large customers to arbitrage these differences at any given moment between the electricity markets and regulated utility service.

Moderator: There are things that can be done short of putting it in the rate base. For example, Texas proposed calling nuclear "renewable" and giving it benefits associated with renewable portfolio, or for clean coal to be exempt from market power calculation. These things don't go in rate base but the state hopes to create a little bit of extra incentive to do it beyond market incentives.

Question: I've seen battling charts that argue about the benefits of restructuring and price hikes. Let's assume for purposes of the discussion that the cost spread between restructured and non restructured states was about the same now as it was a number of years ago. If that is the case, what is the significance? Do we continue with the endeavor or modify it? If the charts show little change, what should we conclude?

Speaker 1: Did restructuring provide the benefits to consumers that everybody touted when the process started in the mid 1990s? The jury's still out for a number of reasons.

In Illinois and some of the Midwest states there were a number of distortions such as legislatively mandated rate reductions and recovery of stranded costs that has not allowed the development of the market in a non-distorted environment. There have been efforts by utility companies that counter competition.

The other significance of the charts is to show the underlying fuel costs associated with the price of electricity. The reality is we're all going to pay it. When a utility files for a base rate increase it makes the front page but in Michigan they've passed a $262 million fuel increase, and a subsequent $134 million fuel increase and those go pretty much unnoticed by the local media.

Speaker 3: The perception has been that there have been wild price increases as a result of

deregulation. It's not a good thing. If the price increases weren't both substantial and also volatile the debate might not even exist at all. However, the charts show that it's the fuel price increases have caused the increase in prices, not deregulation. If that's the case, then we don't really need to change this. A maturation process still needs to occur. We need more than ten years to see how markets develop. If we stop the train in the middle of the road because prices are too high when the prices would be high anyway then that's a problem.

Speaker 4: I recall one of these seminars a number of years ago when a regulator from a deregulated state was asked what they would consider to be success in terms of deregulation. The response was, "if it doesn't make things any worse than they are presently." That's not a good reason for overhauling an industry. Further, the price data shows that consumers have not benefited from deregulation in terms of prices and yet that was held out as one of the major benefits, if not the major benefit, of deregulation.

The story in each individual state is also important. In California one of the things that pushed them towards deregulation was the stupid implementation of PURPA that added billions of dollars to their electricity rates. That was a regulatory decision that encouraged the move to deregulation.

That QF [qualifying facility] cliff was being approached at the time that the energy crisis occurred. Without deregulation, electricity rates would have dropped much more than the mandated 10% in their legislation. Instead they embedded the excessive QF costs as well as other costs into rates because of the partial deregulation project. In Michigan and California regulators have nullified legislative mandates to make certain charges non-bypassable so they could promote competition. In Michigan there's a credit given to competitors to compensate for what was supposed to be a non bypassable charge. In California something similar was done. There's been a lot of fiddling with the system and the numbers on all sides. But certainly deregulation has not led to a decrease in prices for consumers.

Comment: There's a dilemma with the framework we've been discussing. It's been suggested that higher prices triggered a lot of the dilemma. However, a 23% rate increase after ten years is not terrifying. That's not the issue. Instead, people don't trust these markets or the design.

The real problem and the thing giving fuel to this political firestorm, is that we haven't taken Humpty Dumpty apart at all. For instance, in Illinois and other states there are distribution companies and generators owned by the same corporate entity. Even if decisions aren't affect, it still drives the public crazy – it seems inherently unfair to them even if the operations are legitimate. I'm not alleging any nefarious behavior but it seems to the casual observer that if ComEd is buying from Exelon Generation, they're buying from themselves.

Question: What state, if any, is the paragon of virtue for either getting it right with deregulated markets or implementing cost of service effectively? Second, if you were king for the day what three provisions would you include in a national energy policy act?

Speaker: I admire states like Oklahoma, Utah, or Arkansas. Sure, they use coal but they have very low prices. Nebraska is entirely muni and has low prices. The northeastern states have more of an environmental framework. Vermont's made a lot of the right choices and is experiencing better rate results because of that.

In terms of provisions that I would include greenhouse gas provisions. Something like cap and trade, or address coal usage. Something that drives nuclear plant development. If you really want a paragon of virtue world wide it's France.

Speaker 1: For restructured states, it depends on the metric to measure success. For instance, switching statistics or customer options. I'm supportive of what Illinois has done. Texas and New York are also good examples. In cost-of-service states low cost coal, or public power, or

a function of the assets in the ground tend to make them successful, so I'm not going to answer that part of the question.

As king for the day I'd focus on the social aspect, low income, serving customers that a market may not serve. Consideration of renewable energy and promoting technologies that can't move forward on their own. Finally, you have to look at transmission.

Speaker 3: I will answer the second question with a three word answer, spent nuclear fuel. We have to find a way to deal with that problem because it will retard the construction of nuclear plants in a way that will be very detrimental to the country's energy wellbeing.

Speaker 4: I would focus on states that are diversifying energy resources and working to reduce the use of energy. This is accomplished by states that handle integrated resource planning well and implies a high level of regulatory authority. I'll hold off naming any specific states.

The second question. We need an updated PUHCA enacted, it should have been reformed, not repealed. The federal government has to prevent inappropriate monopolization and market power. I would also ensure that FERC pursues its powers under existing legislation which it hasn't done. For instance, the interpretation of the federal power act in which FERC has determined that prices based on market outcomes are just and reasonable. Those two would be enough.

Moderator: The answer is Texas. Before deregulation in 2001 the all-in price of power in Houston was 9.67 cents per kilowatt hour. You can get offerings in Houston today at 11.5 cents per KWH despite the fact that the price of natural gas has gone from 2.80 to almost 9.0. Their residential switching rates are approaching 40%, and for large C&I customers they're 70-80%.

Question: Delaware is a hybrid restructured state because IRP is back as well as the ability to long term contract. Some industry folks argue they are in a better position to predict the future in a market environment with a carbon tax, capacity costs that are rising in the wholesale market, unstable fuel source costs, wholesale market design issues, uncertain transmission plans and others. Why is the market better able to predict the future than the state.

For instance, Delaware has faced oppressive LMP costs and there has been no relief. The high LMP market signals are not providing relief the way they're supposed to. I worry that the market won't step up to meet generation needs either. Why would a policy maker trust the market when it never responds to price signals.

Speaker: Trust is a tremendous issue. Regulated markets were working pretty well until uncertainty interjected into play. In fact, the states or the regulated utility's inability to address those uncertainties in an economic way occasioned the movement for deregulation. The uncertainties continue to exist. The track record of dealing with uncertainties by utilities in the regulated context was poor. The economic and efficiency incentives in a deregulated marketplace will kick into gear. There's no backstop of the public or rate based dollar to take care of mistakes.

Speaker 4: Independent generators have an incentive to create market power and to protect their market power. That's where they can make money. In a truly efficient competitive market they don't make very much money. They may lose money, they may go bankrupt and they're at some risk. The interest of independent power producers is diametrically opposed to that of consumers. Regulation can be good and bad. Winston Churchill said democracy is the worst form of government except for every other type. The same is true with regulation. Regulation rarely produces optimal outcomes. On the other hand it has the possibility producing decent outcomes.

Question: At a recent FERC conference a panelist discussed the inability of distribution utilities to get long term contracts. The IPPs on the panel said that if a distribution utility can build its own generation at a lower price and get

in the market competitively it should. If so, what's wrong with having utilities reintegrate or build their own generation if it's cheaper than competitive alternatives on the market?

Speaker: There's a concern for risk. Over the life of that plant the risk of that investment is directly on the backs of the consumers.

Question: But if you're signing a long term contract with a generator it's exactly the same risk. If the utility can't get a price it likes in the competitive market or it doesn't want to rely on short term spot purchases, what's wrong with the utility reintegrating or at least partially hedging its risks by building its own generation?

Speaker: Again, it's the risk. There's nothing inherently wrong with long term contracts. The problem with long term contracts is when the risk associated with it is assigned directly to the consumer and it's inflexible moving forward.

Question: Currently we're somewhere in the middle between markets and regulation. If a state attempts reintegration one plant at a time as described earlier and it doesn't work, what would you like to fix most about the market? And if a person thinks markets are really good and they're not working, what would you like to fix in regulation to make a hybrid strategy work better?

Speaker 2: I think I'd want to break the law of one price that gives the same clearing price to coal and nuclear units as it does to natural gas units. I don't know exactly how to do that. Perhaps breaking up the market into base load and peaking sectors, or base load, intermediate and peaking sectors. I'd like to consider that. Sending out a price signal for nuclear and coal is not they are built.

Moderator: In retail deregulation, customers should be forced to make an affirmative choice away from the incumbent utility, like they were when telecom was restructured.

Speaker: Deregulation is not necessarily broken forever, it can be fixed and adjusted. In the market context, I agree with the other speaker, we need to address the market power issue. Let's not scrap the entire system just because of that. In the regulated environment I would suggest the elimination of fuel costs for the utility companies. Any time there is a direct pass through at cost, there's very little incentive to control your costs or benefit the consumer. Make utilities act like they're in a competitive market.

Speaker 4: I agree that market power is critical. There has to be some effective way of addressing that issue. How you get there without something that looks a lot like cost of service regulation, I don't know. Second is creating incentives for new investment where it's needed and appropriate. If you limit market power, it may limit the ability of price signals to incent investment. However, if there's a stable wholesale market that is still divested of market power, it might be attractive for certain types of investors to participate in.

Question: The common ground among the presentations is that capacity markets don't work. Either price signals are at zero or infinity, or fuel diversity is never gained. With re-regulation, long term contracts coupled with other policy changes could make capacity markets work in a way that would still allow market risk to reside in the private sector.

There's a false premise that re-regulation protects consumers from market risk. Utilities get a guaranteed rate of return on investment so most of the market risk on capacity development is borne by consumers. Do contract mechanisms, long term contracts, still preserve the virtues of the market, allowing more allocation of more market risk to private capital but not going all the way to re-regulation where utilities shift risk to consumers.

Speaker 2: In the context of risk-shifting, most generators are over earning or have an RMR contract, a cost of service contract – they aren't carrying any risk. It will only change if there's a capacity surplus and that is unlikely to happen. Risk shifting is a red herring. I'm concerned with reward shifting. Will the customers, having taken the risks either way, also get the rewards?

I don't really believe in risk shifting so it's hard to answer the question.

Long term contracts. There was a recent RFP process in Connecticut. There were two base load bids. That is not competition, and the state is going to overpay extensively and they won't even get to own the plant. Perhaps long term contracts are the way to go but I'm not sure it would be better than utility owned. Certainly regulators can screw up but they can also do a good job.

Speaker 3: There are two ways that the long contract mechanism may not allocate risk to private capital. One, the contracting party builds the risk into the cost. The risk is borne by private capital but paid for by the utility. Two, if a long term contract that turns out to be overpriced the consumers still bear the risk. The markets really are unpredictable.

Speaker 4: Long term contracts don't shift risk, it's paid for by consumers. One of the major costs of power generation is capital costs. The price that capital markets charge for that money is based on their perception of risk. Investors get paid for the risk and it gets built into long term contracts. If one could figure how to have the independent generator compete on equal terms with the utility for offering a long term contract versus the embedded utility service then might provide some discipline. Trying to figure out how to do that is very contentious and probably impossible. It's an illusion to say that consumers can be spared exposure to risk.

Question: How do we balance the need for affordability, reliability, and carbon constraints?

Speaker 4: Political regulation is the best and most appropriate way to internalize externalities. There are going to big challenges in this industry going forward. It's going to take a lot of regulation.

Speaker 2: The short answer is to work with whoever has a nuclear site to get a new nuclear plant built. That way you can meet your environmental issues, as long as the waste siting problem is addressed. Stabilizing prices while building is critical. On top of that, long term contracts and utility owned generation.

Question: I am intrigued by the concept of takings discussed earlier, and also on the issues of equity ownership. Could you comment further?

Speaker: It would be a regulatory taking for regulators or legislators to destroy this market which investors have in good faith entered into, built facilities with the expectation of returns or had the opportunity to receive certain types of returns.

However, I don't believe there's a legitimate legal argument to be made there. It's within the regulatory power of the state and federal government to intervene in markets this way. They have taken on the risk, and part of the risk is regulatory risk. There are examples in other industries where this kind of intervention has taken place. If proponents contend that restructuring is going to bring lower prices, stability, and social benefits that don't occur then public authorities can basically devalue these investments by appropriate mechanisms. It's not a taking in either a legal or a moral sense.

Moderator: Concerning equity ownership. Since KKR announced their acquisition of TXU eight coal plants are off the table, they've announced a 15% discount to their prices, and they've announced a doubling in energy efficiency and renewable products. It remains to be seen how it plays out in the long run but so far it's working out well for Texas.

Question: I've heard coal, nuclear and natural gas discussed as resources but not energy efficiency, which California has identified as the cheapest, fastest, and lowest risk electric resource. How can it become incorporated?

Speaker: Both efficiency and conservation need a lot more attention. That isn't going to happen in a market environment. It takes an integrated resource planning approach. It's part of the whole package.

Speaker: It is incredibly important but it can be incorporated into a market environment. Consumer efficiency can be pursued independent of whether you're regulated or deregulated.

Speaker 2: I focused on building the next round of plants, some areas will need more power plants relatively soon. Energy efficiency will not solve that whole problem. Nonetheless, it should be a critical part of any state's strategy.

Speaker: Regulation does not provide a better mechanism to provide energy efficiency. There have been no voluntary energy efficiency programs by regulated utilities, they're always ordered by a commission. The technology has been available, it just hasn't been implemented. However, the market has created incentives. There are now two very large scale demand response firms that are doing well because the price signals exist and they are reacting to them.

Moderator: In Texas they have a TDU program in which 20% of demand growth must be met through energy efficiency including an aggressive rollout of smart meters. Every possible resource will be needed for the next 100 years, including demand response.

Question: To clarify, there are municipal utilities who are doing demand response very well and they are not being ordered by any regulator.

Speaker: There are exceptions certainly.

Question: Both deregulated and regulated states ,have had the same percentage increase roughly, in which case since the deregulated states started with higher rates, that they actually had higher levels of increase? Is that a correct interpretation of the data? I would have thought that efficiency would have gone into play more in the deregulated states. Is there some other phenomenon that's pushing it the other way?

Speaker: The prices did start higher in deregulated states. I tried to emphasize that in deregulated states the cost of fuel and labor has been appreciably greater than in regulated states. It's not an apples to apples comparison. If one accounts for fuel and labor costs, it's a least level, if not net savings for deregulated markets.

Question: Given recent smart meter implementation and the potential of having real customer response to pricing it seems that putting Humpty Dumpty back together would hamper the customer empowerment that some states are just beginning to see.

Speaker 2: A renter in an 800 square foot apartment with an air conditioning unit in the window will not be helped by a smart meter. If one has a 2,500 square foot house with central air it may be that they are part of the problem and a smart meter should be imposed on them. I don't believe the bottom 70% of the population will be helped by that.

Comment: Experience has shown that the expansion of markets is needed to get generation diversity. In this case the markets have much more participation and innovation. Before markets there were TLRs, wheeling rates, and reliability concerns because of lack of visibility. How will we solve these problems if we go to reintegration?

Session Two.
Beneficiaries of Transmission Expansion: Who, Where, When and How Much?

All infrastructure investment influences the market and creates different distributions of impacts. For most investment, the voluntary nature of the commitment of capital implicitly avoids any need to identify all the beneficiaries and calculate the benefits. In the case of large scale transmission investment, the benefits may be widely different for different groups in an interconnected grid. If the investment is done under regulatory mandate, the issue of who benefits is material for many reasons.

For example, the principle of the "beneficiary pays" presumes an acceptable ability to answer the questions of who, where, when and how much? Traditional electricity system planning models provide a framework for calculating costs and benefits, but the information and decision framework was developed in the context of vertical integration. With separation of transmission, generation and load, the locus of the decision changes . In the restructured market, how do we approach the determination of benefits? What assumptions and information are required? How do we deal with uncertainty? What are the criteria? Who decides? How do the process and protocols interact with hybrid systems of market design? What is being done and what is the experience?

Speaker 1.

I'm going to discuss this issue in terms of the Maine PUC which has a unique dual role. Their PUC has a classic regulatory role where they hear cases and balance the interests of utilities, shareholders and ratepayers. Second, on regional matters they're supposed to be exclusive advocates for consumers. In the area of transmission expansion there's a conflict because consumers have a different perspective regarding transmission cost allocation than the broad interests in the classic regulatory structure.

The Maine PUC still really supports markets, despite the pressures. Supporters need to honestly address where and why markets are not working. Second, they need to implement changes so the value of competitive markets is realized for consumers. That's a real challenge. Transmission cost allocation is the single regulatory event that is impeding the growth of markets. A lot more transmission is needed if markets are going to work.

I'll discuss why should beneficiaries pay, how much they should pay and why we should care. There's a dichotomy in New England between resource states like Maine and import states like Massachusetts or Connecticut. Maine is probably the biggest resource states with extensive siting opportunities and natural resources. It's a nice synergy. Load states need the power and resource states need the opportunities for economic development. Transmission is the key to that relationship.

Locational marginal pricing provides an incentive for a state like Maine to create more investment but not share it with New England so that the LMP stays low. Maine and New Hampshire have a lot of generation compared to its load and export a lot. However, where there's congestion they have an incentive to continue building more generation there to leverage the high LMP costs.

Clearly there's a need for new transmission. There's approximately 1,000 to 1,600 megawatts of new generation planned in Maine in a market that already is constrained. It's diverse, an awful lot of wind. There's one project that's an 800 MW wind farm. These resources are needed for environmental, diversity, and reliability reasons. There are not alternate sites in the load states, the transmission is clearly needed.

There are massive disincentives for building transmission to relieve congestion. New England has a socialized transmission system. If new transmission is built, Maine has to pay 8% of the cost. That 8% gets Maine somewhere between a $50-100 million negative market effect to benefit others and levelizes prices in the load regions.

The utilities in Maine that want to build transmission have to justify a reliability project which has to weigh up against the cost of the transmission, but also the overall market cost in Maine of the adjusted LMP prices. That's a very expensive justification. The only way to do this is a beneficiary pays system.

Currently, all transmission costs above a certain voltage level get socialized by load ratio share. This means clear advantages for Connecticut and big losses Massachusetts, Maine and Rhode Island. The current transmission cost allocation does not allocate value to individual loads based on their location, and it also doesn't value market costs.

I am proposing a new regulatory allocation. TCA [transmission cost allocation] should value the market costs when determining beneficiaries. These market costs are driving decisions at the PUC regulatory level much more than the transmission construction costs.

There are a couple of reform options loosely based upon the MISO 20-80 allocation. The winners and losers change if market costs are included in the TCA. And while the winners and losers change, there are overall savings for the entire system because congestion costs are reduced. Further, there is increased reliability. Currently, folks in southwest Connecticut only pay 24% for transmission line that will create huge market savings for them. However, the line may never get built on the resource state end because they are absorbing the market cost losses.

There's a way to assess these market differences called a contract for differences. You can buy a contract in every organized market for the difference in the energy market price between one zone and another. The contracts can go out for a number of years and cover the risk of cost convergence. They can't cover it forever and after 5-7 years there's a risk premium built in.

I propose that the beneficiary pays the cost of the CFD [contract for differences] for a period of time. They should not pay it forever because things change. There is market uncertainty after 7-9 years. Regulatory risk, changes in investment strategies, in technologies, etc. The CFD can be used over the medium term to value the true choice of generation in one position in a region versus another. This provides a buffer to the export state to provide political benefit and avoid rate shock. The CFD must end within a reasonable enough time frame to make the market more liquid and relatively seam free.

Question: Suppose you're in the traditional vertically integrated load in a multi state utility and Maine was part of that system. Is Maine's view colored by the fact that they have LMP which makes transparent the inefficiencies in the system?

Speaker 1: LMP exposes the true cost of electricity. Until one starts exposing the true cost of generation in the places where it's built, one can't make economically rational decisions. There are regulatory vehicles to do that in a vertically integrated world but in a restructured environment that's the best tool.

Speaker 2.

I'm going to discuss some issues facing transmission companies operating in multi-jurisdictional markets and multiple states. Many of these are regulated markets.

Depending on whether you're a customer, a land owner, a regulator, a shareholder or a neighboring utility you have different perspectives. Transmission needs to be built fast, cheap, out of sight, with transparent planning processes, for high-quality continually available power, in a way that accommodates terrorist attack scenarios and reliability needs, to access remote renewables, with advanced technologies, using incentives but not disrupting base rate, and don't designate anyone as a beneficiary. To the contrary, this is not impossible. Everyone's gotta give.

There hasn't been significant investment in transmission over the past 30 years and the consequences are expensive congestion and declining transmission capacity per mile. Regional markets have evolved, and these markets can help economize expansion projects. Regional projects are driven by four key elements, reliability, security, resource expansion (particularly renewables), and overall economics. The key hurdles are cost recovery, investor certainty, routing, and getting ahead of the growth. The Energy Policy Act is a start. National interest corridors are in place although there's a current push to repeal some of that. Backstop siting authority, transmission incentives are good too. So are mandatory reliability standards.

FERC has implemented some of the Energy Policy Act provisions. Order 890 calls for

greater transparency, standardized transmission calculations and conditional firm service and regional planning. The California ISO's proposal for generator interconnection funding and financing was approved by the FERC. The Cal ISO model is a good model. FERC continues to remain fuel neutral thought there's interest in the renewable expansion going forward.

This leaves cost recovery and routing. I'll focus on cost recovery, beneficiary pricing and classification models in the cost recovery environment. With classification there's a perception, especially at the state level, that it's scientific: all projects are reliability, economic or generator. However, most every transmission project crosses at least two, if not all three of these classifications. Generally, projects can be classified for one purpose locally. For instance, a project might relieve 100 megawatts of congestion locally and still add 600 megawatts of transfer capability sub regionally. Projects have a different perception locally than at a sub regional or regional level.

Further, a project can benefit a single entity or sub region while harming another sub region not far away. Finally, projects are not time static. A reliability project today will change its composure over the next several years and become an economic project. There are advantages to the classification model. It stimulates interest and investment. It clarifies what types of projects will receive what types of cost recovery long term. However, an entity with limited need for transmission may be saddled with costs from projects a distance away. There's still uncertainty in cost recovery, especially because of a state's interpretation of some of the classification models. Beneficiaries will dispute their classification. Finally, the determination of classification occurs once and doesn't account for the changing nature of projects.

The beneficiary model is considered to be impartial enough to appropriately allocate costs to all beneficiaries. It's helped get transmission get built in the MISO and SPP footprint in contrast to the postage stamp rate. State regulators are starting to understand the beneficiary model a little bit more. There are some unintended consequences, however. The costs are spread across entities who have already made the investment or saddled on a small transmission asset base with large load requirements. If an entity is facing a major build-out, not all the costs will go to their load serving retail customers.

Let's look at SPP and MISO. On reliability projects in SPP 33% goes to postage stamp and 67% through a sub regional beneficiary model. In MISO it's 20-80. On economic projects, 100% of costs are direct assigned to the beneficiaries in SPP, whereas it's still 20-80 in MISO. In MISO a sub region is equivalent to the size of SPP, whereas in SPP a sub region is a control area. So sub regional beneficiary allocation doesn't mean the same thing in each region. On generator outlets 100% of the costs go to the generator participant funding and in MISO it's a 50-50 split. The real debate in SPP is whether high voltage highway byway projects need to evolve to a higher postage stamp level. In MISO the debate is whether license plate is the right model going forward for all investments.

Three's a variety of problems. One, a FERC approval is not the end of the story with respect to payment. In a highly structured market any FERC approval comes back to the states for classification and assignment. Some states may not allow retail ratepayers to pay for third party upgrades through postage stamp or beneficiary allocations. Two, another concern is that renewable generators cannot afford the generator outlet costs. The generation will not get built. Third, the states may not allow ratepayers to pay for transmission that moves power from one state, or one region to another. In multi-state situations the rate recovery mechanisms can get quite complicated, and often lead to costs for some participants that are enough to kill the project.

To address these issues there are some ideas. First, while a project does have multiple benefits and classifications, it's got to be kept simple so that disputes don't arise. Second, a generator

investment tariff should be implemented that allows states to proactively build transmission to the generators as they're sited, planned and approved, similar to the Cal ISO model. Finally, states should lean toward postage stamp more aggressively than the beneficiary model in the multi-state projects but not go there overnight because we're gong to lose everyone in the process. The lower voltage load serving projects work on a beneficiary model because you're typically dealing with one or two states that need to approve that recovery.

Speaker 3.

I'll focus on the RTOs role, especially at MISO. RTOs have to talk people into believing that the risks aren't so bad; they can go ahead and build stuff. The bottom line is, as a lineman told me once, nobody ever talked electricity into a house [laughter]. Utilities have done a very good job at wringing the value out of their service territories. To improve on that, utility mergers function to increase company size to increase value. Similarly, RTOs are attempting to work up the scale of transmission systems to increase the efficiencies.

There are plenty of impediments to investing in transmission, mainly local. The typical thing in rural areas is "why should we suffer the infrastructure to help the city?" There's not a consensus on energy policy. A coal plant licensed in one state may have trouble getting outlet transmission approved in the adjoining state because they dislike coal's CO2.

FERC tariffs are almost irrelevant in terms of the cost recovery. Most of MISO's states are traditionally regulated utilities. Typically 10% of their asset base is transmission and typically 10% of that load is wholesale electric resale service under the FERC tariff. It's 1% of that utility's revenues. They're not going to take a lot of political risk for 1% of their revenues.

Fuel cost is generally passed through to consumers via a fuel cost adjustment [FCA] or in the market. Recovering fuel costs doesn't cause regulatory headaches. Whereas if you build transmission, they've got to open up a rate case to ensure recovery. From a risk profile standpoint an FCA is easier than a rate case with some uncertainties.

More impediments. Current pricing remains balkanized. Stakeholders are forced to vote with their short term pocketbook. Utilities dislike paying transmission costs that a neighboring state utility is incurring and sending a bill. For a utility it's an external cost that they can't control timing or management. Utility members of the RTO will threaten to leave because of these cost allocation. There are squabbles between states who say we built our transmission, why do we have to pay for that other state's?

Transmission planning criteria has lost track of the fact that transmission's job is to minimize the energy price over time. That question was bundled with the regulatory work around a base load plant where the choice of the fuel was the most important cost question – the transmission cost was buried to a certain degree. Over time transmission planning has only looked at capacity requirements at peak to maintain the system for reliability and planning. Transmission lines were only built for economic reasons. Generators could always be built at a small town to serve need. There really isn't anything like a reliability project, they are simply to maintain the economic project that was originally constructed.

The impediments and uncertainty around energy policy have led to a five year planning horizon for investments. A large transmission project doesn't even get regulatory approval in five years. The Arrowhead project from Minnesota to Wisconsin was introduced in 1980 and will be energized this year, 26 years. Determining who's going to benefit 26 years away is difficult because the landscape is going to be dramatically different. I'll discuss proposals for extending the planning horizon presently.

MISO has two sets of regional expansion criteria and benefits [RECB]. RECB I took a series of reliability based projects that everyone could agree on and set them to cost share on a formula. It's modest cost sharing because everybody

agreed to the projects and most of those benefits are local. Nonetheless, there are still two MISO members that have threatened to leave because of this criteria.

RECB II is broader cost sharing. It has primordial criteria that states it will be cost-shared only if it's obvious to everybody that it's beneficial to everybody. It's a high threshold. FERC gave a positive order to MISO on it with a requirement to move the basic criteria into more of a public interest standard.

Utilities are good monopolists and not used to ceding control. The RECB standards that MISO is trying to implement goes against that grain. Two members have threatened to leave MISO as a result of the 20% postage stamp rate on reliability projects. RTOs are accountable. They are voluntary organizations and members can vote with their feet. Imposing a FERC tariff on membership is fraught with risk, particularly if that membership can vote with their feet. MISO has already experienced one defection in the past.

MISO's strategy is to reduce the barriers to investment. They're trying to change the planning objective function to identify all the value drivers of transmission, not just that reliability criteria or energy. They've engaged all their stakeholders to identify criteria. That will take time, but it's more likely to get everyone on board. They're trying to move to scenario planning instead of predicting the future. This would include alternate scenarios that can help characterize and manage risks.

For example, there's a strong wind lobby in their stakeholder community. One of the future scenarios is a national 20% wind mandate. That scenario looks at what a transmission system would need for that. Other scenarios look at carbon taxes too. MISO tries to identify common transmission elements of those scenarios and to focus on those.

While transmission and generation don't compete at fundamental level, they do interact. The generation for a reliable, competitive market is affected by transfer capability, generation and transmission transfer capability together. They need to be optimized to maintain the lowest price for the consumer. Finding the critical middle point between generation and transmission is the difficult question.

Question: Can you clarify MISO's position on highway transmission?

Speaker 3: On highway byways MISO wants to go to postage stamp. Beneficiary allocation breaks down with multiple state commissions. While sub regional allocation and classification works in theory, philosophically and politically that is not the way to approach building the interstate grid. Rolled in pricing to get the high voltage highway built is probably the way to go.

Speaker 4.

I'm going to focus on what PJM has been doing. There are three primary drivers of expansion in PJM. Reliability violations are not controversial other than siting issues. More recently, PJM has pursued expansion based on economics. They moved the economics benefits analysis to the markets team, not the planning team. Third, there's voluntary investment , particularly for merchant generation interconnection. Voluntary also includes financial transmission rates and capacity rights. FTRs have not created a lot of interest so far, and capacity rights are still new.

I'll focus on economic expansion because it is crucial to the issue of who benefits. PJM has started to do simulations based on market conditions so they can look out in time. They use various input assumptions and attempt to characterize variability into the future. They attempt to take unknowns such as fuel price, demand, generation, emissions, carbon and other environmental and then look at metrics. They create a production cost metric, an average cost based metric. Marginal value is examined, LMP and congestion costs. They also account for generation revenue, transmission losses, capacity payments, and look at the marginal value to the market of the expansion. The problem is that economic metrics are not definitive, as reliability metrics are. Thus the

scenario proposal helps us create a variety of transparent information for all stakeholders to see. If an economic expansion is ultimately warranted, it has to be approved by the Board, and then PJM sets up for the FERC process. Doing the review, assumptions, and cost benefit analysis transparently is critical.

Let's look at a practical result. So for the 502 junction line that goes through Loudon County, Virginia they show a base line production cost and then savings in annual production costs with various scenarios. Scenarios include high and low fuel and/or load, emissions, etc. The analysis for 502 is well behaved. The scenarios show savings in all scenarios, most do not have all scenarios going in the same direction. The also consider marginal value, market value, congestion cost savings (load payment minus generator revenue). For 502 the scenarios show savings as well. For other lines and projects the results aren't nearly so obvious. One could look at the scenarios and say why isn't the line built? Siting through Loudon County, Virginia won't be an easy thing but otherwise this demonstrates clear economic benefits.

In essence, PJM has decided that producing a single number or a bright line test will not work. Instead they show all the information to everybody and bury them in a sea of information [laughter]. Then they upgrade to a very large simulation using a production cost program both with and without the upgrade. The cost of transmission upgrade is allocated based on zonal power distribution factor for load beneficiaries. It's assigned based on power flow analysis to the load who benefits. They also looked to see how that would compare with LMP. And we wanted to see how well that assignment would match what the market benefits would be in LMP and they were very close.

The problem is that lines like the 502 are such no-brainer's that they are always reliability upgrades in any case. The empirical studies they've done show that you have to be pretty tight on the transmission system to justify a line purely on economics. However, they believe the economic benefit will evolve as a a reason to advance an upgrade in addition to other data, but not as a stand alone.

I have two last concerns. There's an issue in having the expansion planning process driven by economics, even on the books, because it creates a tension between a merchant investment versus and RTO mandated backstop. One other thought, if they're going to allocate the costs a certain way they've got to give up property rights similarly.

Question: The PJM forecasts are half relying on the RPM capacity model being successful, and half relying on projects in the queue being built. Are those assumptions used only for economic planning, or reliability planning too? In the reliability planning, they're not considering new generation other than signed interconnection agreements?

Speaker 4: That's a complicated question. Generation scenarios 20 years out need to assume some additions – simply from load growth. The assumptions grow generation uniformly based on what's already there, or based on what's in the queue, or based on RPM. Three scenarios. Reliability violations are driven by what is already in the queues. It's a different metric.

Question: Are there scenarios where a generator could pay as a beneficiary?

Speaker 4: Yes, a generator could pay. I haven't heard details at stakeholder meetings but from a practical perspective there is a set of beneficiaries who are able now to get to a market previously unavailable. Whether that's going to result in them being assigned cost or not I don't know. They could be benefiting.

Question: Do you have any examples of a beneficial project but can't identify the beneficiaries?

Speaker 4: No, I don't think so. One could argue about how they've been identified but LMP allows easy identification. The only ambiguity is that if benefiting load also has forward transmission rights as hedges, then technically

they benefit a lot less. There is some ambiguity around that because the metric doesn't account for their FTR hedges.

Question: You mentioned that economic expansion metric likely reduces merchant incentives. That seems counter intuitive.

Speaker 4: Imagine somebody builds a small incremental upgrade based on the property rights that may be valuable. They'll be worried that the RTO will order an expansion that takes away all their value into the future. It's a risk.

Question: You mentioned that both reliability and economic projects are a no-brainer. A previous speaker asserted the distinction between them is iffy. What is the working definition in PJM between a reliability versus an economic upgrade?

Speaker 4: A project with a good economic upgrade will move up a reliability upgrade by 3-5 years. The only economic upgrades that will probably occur are ones that will become reliability based later in the scenario. Their studies show that projects based solely on economics generally will not be needed in all of the scenarios. The cost benefit equation won't be satisfied because the system isn't stressed enough. That's what they've seen so far.

Question: Assume a company is in PJM with a postage stamp allocation for a high voltage facility. How does they explain why customers in a nearby state should pay for a facility that is getting a substantial increase in load payments.

Speaker 3: Tell them it'll make the market better. Seriously, the reality of cost allocation for all the consumers is the projects in composite change the flows within the market and reduce congestion costs for everyone. A complete portfolio of projects have to be analyzed together. Evaluating the transmission projects as a portfolio is important but it's sometimes hard for state commissions to grasp. So MISO has a $3 billion investment in projects that cost about $500 million annually but save about $2 billion in congestion relief annually. It's a 4-1 payback. Are the benefits evenly distributed? No. But in general everybody benefits, yes.

Speaker: Some states sill change their position over time. Minnesota likes postage stamp for the next seven years, and after that they no longer like it. That's because the transmission footprint will change drastically at that point. If clearly Illinois is at a loss in the PJM situation even if the portfolio is for the benefit of the overall market, the commissioners in Illinois care only about who they're representing.

Question: A question for speaker 1. His proposal is an interesting way of acknowledging the fact that there is a transition cost for people who go from license plate to postage stamp. Having a finite call for difference contract payment to the resource states but it doesn't last forever is good. The CFD concept is well known, but how would it work? Who would pay it and what's the mechanism?

Speaker 1: My preference is for known market based vehicles because they are best to transfer wealth. They are most efficient and better than regulatory vehicles.

The Maine PUC is unusual because they are the largest load serving entity in the state. They have traders, they call them utility analysts but they trade every day. They're in the market all the time. They learned that in New England when you get out beyond five and a half years there's a significant risk premium that's built into the market. They were surprised by how big it was.

This informed them in two ways. Thus a CFD should only hold value until significant risk premiums come into play. Second, the CFD is set by traders independent of PUCs and LSEs and it's an efficient accurate market vehicle that will capture the value of reliving congestion.

Who pays it? There are two groups of people who benefit when you relieve congestion? Load and generators. The payment discussion still needs to be determined in Maine. They also need to discuss how to value market costs in building transmission.

Moderator: You're envisioning something where transmission investment is made and the cost differential on LMP goes away and is socialized but there's a contract, a CFD, which undoes some of that for five years. Is it a mandatory requirement? You don't go to the market and say who wants to come in and participate in this contract, right?

Speaker 1: The contract for differences occur independently. They assess transmission projects. There would be a regulatory requirement to purchase it, but the supply would occur independently. A regulatory event for the contract would not be as accurate as the market.

Question: Two speakers discussed states refusing to pass through costs assigned to the state's utilities by the RTO. In an RTO world all transmission is FERC jurisdictional. If FERC assigns a cost to a utility then a cost incurred by a utility cannot be rejected by a state commission. What is the risk that a state commission will refuse a cost allocation decision under a FERC tariff? Perhaps they will refuse to site the land and force the process to the backstop? Is that a correct analysis?

Speaker 3: The mismatch of stranded cost has to do with the period of time between rate cases where the utility has a stated rate. So transmission costs are escalating because of investments in other states and going to the utility. The utility needs a retail case to recover those costs. It's an earnings pressure question, not a recovery question.

Question: Earnings pressure between rate cases? The utility has to decide whether it wants to file a rate case?

Speaker 3: Yes, that's true. when they do that they might go in for a transmission case and come back with a wind mandate. Other things get examined in a rate case so they don't necessarily want to go that route. The costs are recoverable but the process can create other problems and create earnings pressure until the rate case is resolved. At least two things happen when you fight with your state commission, you either lose or it's worse [laughter].

Speaker: For some utilities it requires coordinating cases with different commissions. Second, transmission expenditures might not be broad enough in their overall investment portfolio to require a rate case. It is an earnings issue. Finally, with due respect to state regulators, they'll get it some other way. The costs can be passed through with the FERC jurisdiction but they'll take it out in other areas if they don't' feel it's appropriate for their state.

Question: It seems to me there are legal remedies for that.

Speaker: For utilities that are under severe cost pressures, any cost is too much cost if it's an incremental increase.

Question: For speaker 4, can you discuss the distinction between reliability and economics and the time lag issue in further detail? What are the factors that PJM relies on for those distinctions?

Speaker 4: There are clear criteria for reliability set by PJM, MAC, and RFC. The analysis that would justify an upgrade is well defined. Even the assumptions about load growth are fairly well defined. The economic analysis is more subjective. PJM's analysis shows that unless you there is a severe transmission bottleneck already in the future reliability-wise, you won't find an economic analysis that clearly calls for a project.

An economic project strong enough to be supported by a cost benefit analysis, is probably a project that will have a reliability violation some years into the future. It's going to advance a reliability upgrade that would be triggered at some point in the future anyway.

Question: Economic cost can certainly drive an argument for generation build.

Speaker 4: Right, but the revenue that a generator would receive is different than looking at change in production or congestion costs from a transmission line. PJM does not want to do generator planning.

Question: There's general agreement that transmission is not a panacea to all problems, it's not going to eliminate all congestion. With reliability projects some states are going to disagree that their customers should pay for these big backbone regionally planned projects. If the states have trust, and there's transparency in the regional planning process, and that process is producing the right transmission in the right places, and it's not facilitating coal by wire from the west to the east, and there's diverse solutions – all of these things can create buy-in for the states to pay for the cost of the regional market. Is the issue simply getting states to understand these issues?

Second, if economic projects are going to provide benefits, why don't the RTO members who are going to pay decide whether they want to participate? Why don't they have a choice?

Speaker 4: For economic upgrades, if you look at the power flow effects plus the load payment effects, and identify customers who benefit, then allowing them to choose may be the way to go. It's not necessarily an easy thing to do for the RTO. It's a choice that needs to be made within the stakeholder process.

The reliability upgrades require transparency. An independent transparent process is critical.

Question: There is a concern that the transmission planning process could be more transparent at PJM. there is an perception that how the models are run and what is considered sometimes results in projects that are not the best solution, that facilitate coal by wire into states that want to address the carbon issue. New Jersey, for example. You could resolve reliability issues in New Jersey by building north to south versus west to east but the reasoning for the West-East solutions are not clear.

Speaker: If there's a way to make it more transparent than it already is that would be a great thing.

Speaker: The reality is the reliability tests are premised on a dispatch of some generation to some load and economic projects are premised on a different dispatch of generation to the same load. The continuum of reliability to economic is a false dichotomy. Reliability projects produce big economic benefits. Ultimately one wants the least expensive dispatch within the cost confines of transmission plus generation in total. Finding ways to do that is what makes sense.

Speaker: The other thing that's true is coal by wire and wind by wire end up using the same wire. One should consider whether a wire enables consumers to make choices about what generation they might purchase?

As far as consumer choice, the historical model is to rely on state commissions to place that vote for consumers. The PUC and siting process tend to address the public good issues. Working within that existing regulatory paradigm works very well.

Question: Does the PUC oversight function differently with FERC backstop siting authority? Certainly a PUC should have oversight, but it shouldn't be generators or transmission owners making the decision. It shouldn't be someone who's not going to be paying for it.

Speaker 3: The backstop provisions only applies if the DOE defines a national interest corridor. For that to happen all the states have to agree that it is. Thus the backstop doesn't have a substantive effect on the outcome.

Speaker 1: What about the distinction between cost and reliability. There's part of Maine that's not electrically connected to NEpool, it's connected to New Brunswick in Canada. It's a sparsely populated large area in the northern part of Maine. They rejected a transmission project proposed a couple of years ago. The reliability value didn't warrant the investment of ratepayer dollars. However, ISO New England's mandate is to keep the lights on regardless of costs. FERC's flag is just and reasonable rates. So it's similar to ours. A planning process should account for economics to some degree and it doesn't in New England.

Question: Almost all of these problems come from the fact that generation can't really be sited

where it's needed. Energy is sent over long distances. All these issue would virtually disappear if we could site generation where it's needed. Can you comment?

Speaker: I think you're right. It's exacerbated by the environmental policies of the states and they won't be going away.

Speaker: The environmental question is an important one. Transmission was originally built to move hydro to load centers. We're back to the future with this but now it's wind, and coal is in the same places strangely. Nonetheless this problem will not change anytime soon.

Speaker 1: If we make costs transparent it will help. Then a town can decide whether they want to build a local power plant, or ship in the energy. If everything is valued correctly then places can make better decisions.

Question: Concerning economic projects in PJM. Since transmission projects are generally lumpy and bumping a reliability project incrementally up to the next larger lump could be lower cost then this tips in favor of the economic analysis?

Speaker 4: Yes. The scenario planning and other techniques helps make this kind of planning more feasible and certainly more useful. There's a close interrelationship between them, they both require a substantial bottleneck.

Question: We've heard how it's not worth it for a utility to file a rate case for an incremental cost of investment for transmission upgrade. Transmission is relatively cheap to total benefits. This discussion is one of those academic debates that are so vicious because there's so little at stake [laughter]. Do I have that wrong?

Second, Colorado will soon be an exporter of solar and wind to markets in Phoenix and Los Angeles. They have proposals for fat transmission projects, some nonstop or with off-ramps. There is political support there because of the economic development. Is this taken into account?

Speaker 3: These areas have enormous wind potential. There is extensive political support to get transmission in place, and to recover costs. It's an externality that needs to be considered in the debate. This kind of class five wind, even with transmission taken into account, is still cheaper than lower class wind in the eastern markets. The biggest problem is still who pays. It's unclear whether states with an RPS mandate are willing to pick up transfer costs.

Second, regarding the low overall costs of transmission. This makes me lean towards postage stamp - everyone pays a share of the freight along the path because it benefits all paths.

Speaker 1: Small states like Maine are very cost sensitive. Even $70 million a year is about 6-9% rate increase, and that's enormous in a state with a manufacturing base. Perhaps they are unique though.

For the economic development, Maine is in support of any projects as long as they don't raise their rates. That's the marching orders for their PUC.

Question: California used to have two choices with Path 15 (it's now built). They could spend $300 million to upgrade path 15 or go to Idaho and invest $50 million in a project that would accomplish the same effect. Practically, there was no way to get people in Idaho to make an investment that would benefit the people in California. But is that really true? Why not go there, have California ratepayers pay for it and even to accommodate the NIMBY mindset, kick in an extra $25 million for Idaho customer rate relief. Why not? Why doesn't the beneficiary pay for a project that benefits them get something done outside of the jurisdiction. I'd like your comments.

Speaker: The political barriers are a reality and the most efficient thing doesn't get done because of it. If it's within an RTO or one market, there's a potential. It would be a good approach.

Question: Building significant long distance transmission makes me depressed. The pressure

is there for both wind and nuclear – neither are close to load center. The veto for a project is just too easy. What can get it done?

Speaker 3: MISO's trying to lengthen the planning process so that large projects can develop momentum. A five year planning horizon is never going to build a 765 KV line because it probably needs 15 years. This is one adjustment. They're trying to set up scenarios that can accommodate goal-gas, carbon-sequestration, or nukes, and in many cases the line has to go into place in any case. They share that with the states so that they are up to speed. For the last 15 years there's been risk and the industry has chosen not to do anything. The new approach is to understand those risks and take sensible action.

Speaker: There's no silver bullet. I have 2 sub-regional success stories. In the western footprint of MISO, North and South Dakota, Iowa, Minnesota and Wisconsin have formed a regional planning group called Cap X 2020 to launch projects to benefit reliability and economics of the region, generator outlets too. The MISO tariff allows them to allocate costs among beneficiaries in the region with state support to move projects forward. It'd be nice to see this model go beyond this sub-region.

Second, the regional planning process in Colorado, but also with utility players in Wyoming, New Mexico and Arizona is focused on the high plains express development project. It's moving forward to satisfy reliability, economic, economic development, and generator expansion needs of the west. I'm optimistic that the states will support a regional tariff for this project.

Neither of these models are formulaic or programmatic but they provide a model for building transmission with multiple stakeholders and jurisdictions.

Question: Can these RTO cost allocation processes work in non-RTOs? Costs would be allocated based on load. For example, a project in the west tied to the western interconnect so it'll be allocated based on load to all the entities in the western interconnect. Or Southern proposes a regional line to North Carolina and it's allocated based on load. Is that good policy? There's supposed to be regional planning in order 890. Should these RTO processes be a model in all systems to satisfy Order 890?

Speaker: Sure. 890, parts of 888, 889, part of 2000, part of the 1992 Energy Policy Act, part of PURPA – they are all concerned with ensuring access to the transmission grid. The openness of the grid provides benefit to new participants. The only way that it works is if there is a cost allocation mechanism that allows that public good to be funded. There's a public good assumption behind open access. A public good theory cannot require a non-beneficiary to pay for it. That would be like asking Iran to pay for our military [laughter].

However, who's the beneficiary in the future? A transmission asset has a 75 year life. Defining who's going to benefit across the 75 year life of that asset is clearly impossible. So balance it by ensuring it's available for future participants and they pay for it, but also get it funded now or it will never be constructed. Obviously if it's a DC line that's a different proposition.

Question: What is the optimal level of congestion in the context of economic projects? If we look at a variety of projects is there an average? And if that's not answerable, should there be more or less congestion than what exists today. Which is cheaper, congestion or transmission?

Speaker 4: My comments are geared towards significant transmission projects. Certainly, there are isolated areas in the market with significant congestion and the upgrade would be less comprehensive. Perhaps just a transformer. In those simple cases the optimal is comparing upgrade costs versus congestion fees, for those who pay it. There is still the problem that congestion charges are hedged by some folks via transmission rights.

PJM attempted to define something called "unhedged congestion" some years back, it was difficult. Honestly, if the property allocations are

right, it's best to let the market decide the solution for the small stuff. The issue for long haul transmission is that the market can't do them. There's too many externalities, hence the economic planning debate within PJM. The best metric for that is LMP.

Speaker: The answer is to expose prices. If prices of delivered versus remotely sited power are transparent, then your question is answered. Simply the amount of congestion that's less than the cost of new transmission.

Speaker: It's hard to reveal the price today of a transmission line's effect that won't be done for 15 years. Modeling helps but that's hard to model because fuel choices and amount of generation are so variable. MISO has modeled a robust transmission system in which they reduced current reserve margins of 20% to 12% with extensive transmission. That provides a net present value of about $5 billion. So if one can build transmission for less than that then it makes sense. There's other variables that affect the congestion costs and the modeling. If gas is displaced with coal it changes the equation completely because gas is at eight bucks.

What about wind? Its marginal cost is zero but its capacity cost is about $1,900 a kilowatt. How does one value that in the modeling? It's very important. If it's modeled because of a renewable energy standard, then only modeling the marginal cost is incorporated. If so, then an awful lot of transmission can be built for free energy. However, one needs to show that capacity value some place. That's what makes finding the optimum point so hard to determine. It's deliciously complicated.

Question: The west doesn't have any transparent signals that reveal congestion, when we need to build. They have limited markets. All the markets outside the ISOs are limited to one or two wheels away because you've got pancaking. WEC is a unique organization because their jurisdiction is not coincident with a footprint of an ISO. It overlays the western interconnection, some ISO, some PUC, and some neither. It's a mish-mosh of governance. Some utilities want to build stuff regardless of price signals because there aren't any. Where does this take us? There are NERC reliability standards. There are renewable resource areas and the desire for transmission. How do non-RTO areas address this?

Speaker: Excellent question, and a perfect characterization of how complicated it is in the west. The recent decision by the Arizona PUC on the line from Arizona to California makes these concerns very current. The west is using a sub-regional approach so far. With the advent of Colorado potentially being an export state the process is driven by planning first and policy second. The biggest issue for developers is to substantiate the need first, and then determine how the projects will be paid for. We won't see postage stamp in the west across WEC. They may end up with a regional tariff that resembles postage stamp in a sub region form around a specific set of projects with established need.

Question: I'm surprised by the fatalism about the ability to create win-win situations here. Consider the natural gas industry. When they needed long line transmission they offered free gas along the right of way. There were taps off the pipeline. Finding barters or bribes is an honored way to move things forward. Sometimes it's extra fire stations or school funding. It happens all the time. Your comments?

Moderator: Anybody want to stand up for bribery? [laughter]

Session Three.
Climate Change: If The Debate Is Over, We Must Know What To Do.

The Supreme Court has ruled that the EPA has jurisdiction to regulate carbon emissions. The international scientific consensus leaves little doubt about the importance of human contributions to global warming. Many states, particularly in the Northeast and in the West have undertaken their own

efforts to reduce carbon emissions. With the most basic scientific debate on climate change essentially over and the clock ticking, there is still considerable debate about what to do, including the scope and timing of measures. At the center stands the electricity system. For a problem that is inherently global and inherently long term, there are inconvenient truths. Solutions must be broad and sustainable. The unintended consequence of global warming calls for persistent evaluation of the consequences of what we intend. The early steps are at least as important in choosing the path as they are in moving down that path.

Where are we going? And how will we get there? What has been the early experience in crafting controls, and how does this apply in the case of electricity? From a corporate governance perspective, what is a company to do in the face of such uncertainty? What should be disclosed to shareholders about future liability and compliance? What anticipatory measures would be economically viable and remain consistent with fiduciary obligations to both shareholders and customers? Should investment strategies be deferred until there is more certainty? What stance should be taken in regard to implementation issues, such as auctions, grandfathering, trading, and leakage? Will corporate strategies diverge between generators, load serving entities and vertically integrated utilities? Ultimately, how will participants in electricity markets contribute to the solution and how will that contribution interact with the larger national and global strategy?

Speaker 1.

Climate change concerns have gone mainstream. From last year's Time magazine cover story with the polar bear to Sports Illustrated. This coverage is often replete with misleading statements, particularly from an economic perspective, but the coverage is extensive.

The real inconvenient truth in Al Gore's film is that meaningful reductions in carbon dioxide and greenhouse gases will be very costly for the United States; approximately equivalent to the cost of all other environmental regulations at the federal level. That's just for the modest short term targets in the Kyoto Protocol. That does not mean that action should not be taken. It means that we should recognize the costs if we're going to design effective and sensible policies.

We've seen calls for economy wide climate regulations, the TXU buyout plan, and AEP's announcement in March regarding carbon capture and storage. The Kyoto Protocol came into force in 2005 without US participation. The direct effects on the climate change will be trivial at best, with or without US participation. However, scientific evidence and economic analysis now point to the need for a credible international approach. This is a global common problem and unilateral actions by single countries or narrow coalitions will never be sufficient.

The Kyoto Protocol has been criticized, particularly by economists. First the overall costs are much greater due to the virtual exclusion of developing countries. Conservatively, the costs of achieving targets are four times the cost effective level.

Second, the agreement generates trivial short term climate benefits over the compliance period of 2008 to 2012. It fails to provide any long term solution for a long term stock, not flow, environmental problem. The stock of greenhouse gases in the atmosphere, not the flow at any particular year, is the real concern.

Third, these insufficient short term targets are excessively ambitious and costly in that they would foster premature capital obsolescence particularly for the United States. This is because the base year is 1990 and the United States sustained remarkable growth over the 1990s, approximately 35% increase in gross domestic product. That translates into an extremely ambitious target. A 7% reduction translates into a 30% reduction compared to business as usual. The Kyoto Protocol is too little too fast and there is a better way forward.

Now let's get positive. A sensible and effective international climate policy framework should be based on sound science, rational economics and political pragmatism. The Kyoto Protocol is none of these. A viable strategy should include three principles. First a means to ensure that all key nations, both industrialized and developing, are involved. That's more than the G8+5. This is key for cost effectiveness but it can address distributional equity as well. The key developing countries have to get on the global climate policy train, but they don't need to pay for their tickets. There are policy instruments to achieve that. Second, a long term chronology to get to where we need to be, determined by good science and economics. This is longer term, not the time path of action implied by the Kyoto Protocol. Third, an emphasis on market based policy instruments such as cap and trade systems to keep costs down in the short term and more importantly, induced technological change to bring them down even lower in the long term.

I've discussed international policy architecture at an abstract level. Posted on the HEPG website is a paper, "*Getting Serious About Global Climate Change in the post Kyoto Period*." A new book will be out in the fall by Stavins and Pizer that examines six alternative architectures for the post Kyoto period.

Let's look at domestic US policy. How will the United States respond when it adapts policies to reduce net emissions of greenhouse gases? And I do say when, not if, since it is going to happen, probably in the next Congress, not this. The most attention, has been on cap and trade programs because of their advantages. That's partly because of theory but mostly because of experience.

Cap and trade systems are a cost-effective approach that can achieve environmental targets at minimum cost, and send price signals downstream for long term technological change. In the case of climate change this would be a system of upstream carbon rights trading similar to the approach among refineries when lead was phased out of gasoline through a lead rights trading program in the 1980s. That program saved about $250 million annually. It's similar to the 1995 Clean Air Act amendments to cut SO2 emissions by half with savings of about $1 billion annually compared any other approach. It's also similar to the EU's system and the RGGI pact in the Northeast, and to potential policy in California. The EU's system has issues which we will discuss.

There are also carbon taxes which are the price equivalent of a quantity based tradeable permit instrument. There are advantages of a taxing approach instead of a permit approach, there are also some disadvantages, most importantly politics. There are also hybrids of taxes and permits and that's a very attractive approach. This is tradeable permits plus the government offers to sell additional permits at a specific price on an ongoing basis. That places a cap on costs and eliminates upside cost uncertainty. It's been referred to as a safety valve system within the cap and trade formula.

Most political attention has been focused on the cap and trade approach. There are a number of legislative proposals that will be addressed by another speaker. The implied allowance prices in 2030 range from $14 per ton for Senator Bingaman's earlier bill with a safety valve to $100 per ton for the more aggressive ones. $100 per ton translates into about a 400% increase in the price of coal fired electricity, 100% increase in the price of gas fired electricity, and about $1 a gallon in gasoline.

What are the implications for the electricity sector? Let's compare EIA forecasts of emission reductions for the electricity sector at $14 and 50 per ton in 2030. It translates into reductions for the electricity sector of either 16or 60%. All other sectors are at 4 or 7%. Clearly emissions reductions affect different sectors differently. The difference grows more pronounced with more stringent policies. However, one of the advantages of an economy wide cap and trade system is that emissions reduction efforts adjust to exploit the emission reduction opportunities wherever they turn out to be cheapest. So if forecasts are wrong the cap and trade approach still gets us cost effectiveness.

80% of the sector's CO2 emissions are from coal fired generation. Significant emission reductions mean reductions in coal fired generation. Using 2006 capacity as a baseline there are significant retirements and net capacity changes as the price increases up to $50 per ton in 2030. By placing a price on emissions, a cap and trade system increases the cost of coal fired generation relative to other fuel types. The impact on the electricity sector depends entirely on how stringent the cap is.

The issue of carbon capture and storage is also critical. After a cap program hits $30 per ton, the modeling shows that coal plants will begin to come online because at that point carbon capture becomes affordable. What's going to replace conventional coal fired generation in a carbon constrained world? Again, as the cap price increases, the EIA predicts relatively consistent increases in both nuclear and renewables that are robust, along with less robust but still consistent increases in demand response. Gas use remains relatively flat. However there is enormous uncertainty for natural gas. The exact same modeling looked dramatically different just a few years ago when gas was cheap.

Further, there's no attempt by EIA to model NIMBY opposition to nuclear, or attempts to make siting it easier. The renewables reflect a 20 fold increase in biomass and a ten fold increase in wind generation. There are rational feasibility concerns for doing this. There is tremendous uncertainty for all of these fuel types, along with the amount of demand response, and the progress to new technologies in coal and otherwise.

Let me tie together the domestic policy outlook with concerns for US participation in an international climate agreement. The Bush administration has had a global climate policy since the first term. It emphasized slow stop and reverse emissions growth which are cost effective by most models. It makes sense but dates and specific targets are needed now for the stop and reverse. They embrace market instruments as well which is good but these require binding constraints, not voluntary programs. The administration's critique of Kyoto is appropriate but they need to develop a detailed effective alternative now. Even in 1997, neither Democrats or Republicans voted for the Burt-Hagel resolution. I do not expect the Congress to ratify anything that looks like Kyoto no matter who occupies the White House.

State and regional level initiatives are going to continue both in the northeast, the northwest, possibly in California. The real question is when the U.S. will get serious about national and international level programs.

Question: If natural gas costs go down what do you see?

Speaker 1: You would see more natural gas. It would cut into renewables and nuclear more than coal. It will have a large impact on the modeling.

Question: Can you convert $20 or $30 per ton or $50 per ton into roughly rule of thumb dollars per megawatt hour in terms of the dispatched cost of a typical coal plant?

Speaker 1: I can do it in terms of percentages of cost. $50 per ton will be a 200% increase in cost for coal fired generation and about 50% increase for gas fired generation.

Speaker 2.

I'm going to discuss the litigation risks that stakeholders will face under pending environmental legislation, agreements, and rulings. Massachusetts versus EPA was just decided recently at the Supreme Court. It regards greenhouse gas emissions from motor vehicles, not from stationary sources. Importantly it creates new standing which will have lasting effects. Standing is the right to go to court to assert an interest in recreational, aesthetic or other protection in this case. The court did not hold that greenhouse gas emissions from stationary sources are regulated under the Clean Air Act. That issue is still open and pending elsewhere. It make auto companies liable for the harm from greenhouse gas emissions or require EPA to regulate mobile

sources yet. It did change who can go to court though.

An issue in this case was if one stops some greenhouse gas emissions, will it stop the harm to Massachusetts or other coastal states? At the rate that China, India, Indonesia, Brazil, and others are increasing greenhouse gas emissions, the impact would be fairly modest. The court made that irrelevant. While this is true, it's probably a 10-15 year process before we'll see actual end result regulation. It took 12 years after a lawsuit required EPA to regulate lead to get effective lead regulation. The only effective remedy will be a legislative result that will also take time.

What's this doing to litigation? Over all there is a trend towards increased litigation. Regulators were being sued already, and under this ruling more suits will be coming. Particularly suits for failure to regulate. If you're a state or local government agency there are suits pending for long term land use planning by county agencies that did not take account of global warming and greenhouse gas emissions. If you make a product that produces CO2 you are vulnerable. California has sued six auto makers alleging they produce a product that causes damages via the release of greenhouse gases. Even if we all use cars. For industrials there are suits for failure to obtain discharge permits for CO2 emissions. Connecticut is suing five utility companies under federal common law for public nuisance regarding global warming issues. If you're an insurance company you can be sued too. Insurance is critical for nuclear, large fossil plants and they are being sued as well. which is essential if we're going to underwrite obviously nuclear plants don't move without an insurance backdrop, large fossil plants don't move without insurance, class action here alleging that the Hurricane Katrina developed unprecedented strength because of global warming emissions. Several of the insurance plaintiffs have been dismissed to date leaving an energy company as the main plaintiff in this litigation. If you're a credit agency supporting power plant development there's a suit against one of the World Bank agencies and the US Ex/Im [export-import] Bank for failure to consider the NEPA [Nat'l Environmental Policy Act] impacts of electric global warming gases.

Now, some of these will, or have been, dismissed, in the early stages, held over and stayed, will be determined to be non germane or non-justiciable. However that was said about tobacco, asbestos, and MTBE litigation. It is possible it could have a large impact.

As a side point. If we are warming the plant by 2-3 degrees Celsius over the next century, fossil plants operate less efficiently as temperature goes up. Operating efficiency drops, emissions per megawatt hour increase, gross generation capacity drops, and transmission efficiency is decreased. It's a minor impact but noticeable.

Funny, you can find shelves of books on the impact of oil on our society in cars, in suburbanization, in sprawl. You could not find a single book three years ago on the impacts of electricity on society. It's equally important and particularly as it has increased the speed of information transfer. Petroleum increased things 10-100 fold in terms of the speed of goods transfer. Electricity increases knowledge transfer at exponential levels, a much greater impact on society.

I want to emphasize and remind us of how intractable this problem is. Even if the world flat lines CO2 emissions as of today we are going to get a significant 3 degree increase over the next 300 years. Even with drastic reductions we are going to have increased atmospheric CO2 concentrations for the next 100 years. This is an immense problem that's not going to go away.

There's a disconnect between the RGGI scheme, the California scheme, and the Kyoto scheme. It creates confusion for utilities and companies that are trying to think globally and operate in a global environment. Kyoto has three mechanisms: clean development programs [aka CDM, clean development mechanism] in developing countries that earn credits for carbon emission in your own country; joint implementation in other developed countries that won't get you credits; and emissions trading.

The EU approach only regulates CO2. With CDM the projects are mostly in Asia and south and central America, not Africa. CDM projects address all greenhouse gases, not just carbon. Most of these projects are methane capture in rural or waste treatment situations. It's being done very inefficiently. Lawyers counsel their clients to do the most cost effective investments. Projects capture methane and flare it, usually up the road from installed coal generation. Flaring converts it to CO2 which is about 95% less damaging than methane. However, it could be used to generate electricity as landfill gas but there's no infrastructure. So they're flaring to get credits in the EU while up the road they're burning diesel fuel to meet the power demands of some of these developing countries.

The carbon market in the EU is huge, in the multiple billions of dollars. The volume of carbon trades is up. When people game the system or the allocation isn't right, the price of EU credits drops extensively. The goal is to push the price up to make credits more valuable in the second round that starts in 2008. The EU only trades CO2 so you can't trade methane, you can't trade SF6, you can't trade HFCs or PFCs or any other potent greenhouse gases that are 1,000 times more damaging for heat dropping.

There's a disconnect between the different policy approaches. For joint implementation and CDM under Kyoto, you can trade any kind of gases and CO2 equivalents. In the United States RGGI only regulates power plants. In California they're regulating more than power plants. In the EU they're regulating lots of heavy industry and power plants but only for CO2. None of these programs align.

Electricity will be the biggest target for these policy approaches. First it uses an immense amount of carbon and greenhouse gases, and second, it has a history of regulation. Regulation is embedded and there is a past tradition of passing on costs to consumers.

The RGGI market deals with ten northeast state and regulates generators. The big debate is whether the allowances will be auctioned. Some of the policy mechanisms may be legally challenged in terms of their constitutionality. There is some ability to use outside projects as offsets. Doing this requires an MOU (memorandum of understanding) between states that's difficult. There's leakage concerns for outside states. Leakage is power coming in from a non-participant like Pennsylvania or Ohio. If there's even a 1.5-2% inflow of power from other states the RGGI benefits will be erased. This will probably occur. In any case RGGI will probably get challenged in the courts and held up for 5-10 years. It will get a constitutional challenge the way it's been set up, due to issues of commerce clause, federal preemption, the compact clause of the constitution, unauthorized tax because of auctions instead of allocations, etc.

California's proposals put the burden on load serving entities, it includes municipal utilities and it tries to limit power contracting to the equivalent of efficient combined cycle plants. This will knock out a lot of peaking capacity that is badly needed in the state, and may result in some gaming.

There's a lot of patchwork regulation right now. RGGI is only 10 states. There's RPS' in 22 states. Maine has a 30% standard by 2000. That sounds really ambitious but they count all historic power and hydro which is more than 30% to start with. Maine was in compliance the day it started. Massachusetts looks less ambitious; 4% by 2009. They don't count preexisting resources prior to 1998, exempt waste energy and hydro, a lot of biomass so even though they look lax, they have stricter standards.

For all actors in the system, climate change becomes an issue for regulatory risk, for disclosure, not getting sued for failure to disclose, for capital expenditure buildout, etc. There are carbon risks that affect operations of plants. There are disclosure risks. There's no required carbon disclosure in the United States but it ends up in SEC filings.

Climate change becomes a new paradigm for all aspects of this industry. For operation, for capacity, spending, planning, disclosure;

everything. It's a new lens. However, when critical situations emerge, the country always favors energy over environmental protection. In California in 2001. Government Davis tried to suspend the environmental laws immediately.

There's important environmental constraints at a time of need for resources given growth and plant retirements. There's also a need for quick start capability. There's a mismatch between running a lot of spinning reserve at inefficient fossil fired plants inefficiently and the need for new quick start capacity. Unfortunately, that quick start capacity is not going to be served by intermittent renewable resources. It has to be served by either stored hydro or gas fired or duel fuel fired peaking units with quick start capability.

Question: In the context of economic regulators what basis are the suits based on?

Speaker 2: My example was where the county was sued for a land use plan and a variety of zoning regulations that didn't take account of the carbon impacts in the plans. We'll have to see what happens, there are questions as to whether there will be non discretionary duties. There are interveners in Massachusetts who argue that the siting board, which approves all power plants greater than 100 megawatts, is shirking its duties if it approves a fossil fired plant before forcing renewables instead. There's clear differences in the acreage needed for a fossil plant around 5-10 acres versus a renewable that takes up many more.

Question: Why not Africa? You alluded to it earlier?

Speaker 2: Africa has largely been left out of this. The African governments have been slow to mobilize and encourage this. A lot of them have not set up designated national authorities needed to make local approval. China was very quick out of the box and they were the first to impose a significant tax on the transfer of the credits coming out of China. China sees this as a growth area. Institution building and capacity has been very slow to respond in Africa, and the World Bank is now trying to develop some of that.

Speaker 3.

I'm going to discuss aspects of carbon market regulation and trading in the EU. The EU has the largest carbon market, the largest cap and trade scheme, and it's driving the international carbon market. Morgan Stanley has set aside $3 billion US dollars to invest in the carbon market. Blue chip companies are putting significant sums of capita aside to invest in this area. Many hedge funds in the US are putting a lot of money into this space. It's the fastest growing market in the world; it's here to stay and investors will be checking the carbon price on a day to day basis just like oil.

First I'll differentiate between a tax and a trading scheme before going into an analysis of the EU program. Since climate change is a global problem, the most effective way to value it is to put in place the same carbon price across the world. This can't be done politically. Carbon tax levels are subject to domestic politics. A trading scheme makes it easier because people can put in place their own emission reduction obligations and then carbon markets can be linked to set a common carbon price. It sets a common price but addresses different obligations on different countries. That's important because historically the problem of climate change comes from today's developed countries. When people say the Kyoto Protocol is flawed because it doesn't involve the developing countries, there is no way a developing country would take an emission reduction cap in 1997. They can be involved now, but it was not going to happen in 1997.

Taxes create many opportunities for exemptions of various kinds. Recently there was a Financial Times editorial which argued for a carbon tax because it's much easier to implement than an emissions trading scheme – that is simply untrue. A tax will not be applied uniformly. There are lobbyists asking for exemptions, differential rates. It's the same political game as the allocation of free allowances for an

emissions trading scheme. Some argue that a tax is more certain because the price doesn't change but government budgetary processes arguably change tax costs and rules just as much, and they have similar levels of complexity. Any policy can be as simple or as complex as one wants. It's not specific to a tax versus an emissions trading scheme.

As a side note, I've looked at a lot of the modeling work on the costs of addressing climate change. They aren't doomsday scenarios. The EU Commission goals of 20% below 1990 levels by 2020 don't cost an arm and a leg. It's cheaper to do something than to ignore it. Making small changes in lighting and air conditioning habits can have very strong impacts.

Both the EU emissions trading scheme and the Kyoto Protocol are not EU derived. The Kyoto Protocol has U.S. influence all over it. The Clinton administration got what it wanted in negotiations but it was still not voted in by the U.S. The Kyoto Protocol is based on the acid rain program, as is the EU emissions trading scheme. It's a market based instrument, and a cap set with the option for offset projects as a way of reduction emissions outside of that cap. Offset projects are the same as the Kyoto Protocol discussed earlier.

The EU emissions trading scheme got a lot of attention when the price fell very dramatically in the space of a few days in May 2006. Some have argued that this shows the program is a failure but that's not true. It was easily fixed. The EU emissions market was an ambitious political project put together very quickly. They were very concerned that the first period from '05 – '07 would be too tight. If that happens you can get a catastrophic failure that sets explosively high prices. They went in quite gently and there's a risk that they were too gentle and over allocated. That's what happened.

They only release data once a year. The over-allocation wasn't realized until the first year's worth of emissions data was released in May 2006. Everyone realized the system was long and the price fell very fast. That has been swiftly corrected. The '08 – '12 emissions cap has been set with significant emission reductions from 2005 levels. So the system is very tight going forward. The first period is at 30 cents and the second '08 – '12 is just over 22 euros per tonne.

It has been a successful program. It's a classic design, textbook, like the acid rain program. The issues going forward are likely to be corrected, it's still evolving, but the overall market is structured well. One never gets anything perfect right from the start, least of all when it's subject to politics.

The successes? It's a source based system that addresses emissions at the smokestack. Energy intensive industry is given a cap for the emissions that go up into the air from their plant. It's a simple direct way to tackle the problem that is very cost effective..

Monitoring and reporting standards are very high. They're taken from the GHG [green house gas] protocol from the World Resources Institute and World Business Council for Sustainable Development project. The registry where participants hold and track the tradeable allowances is a bit like an Internet banking system.

Compliance is so important and the EU scheme gets it right. It's a fixed high penalty. From 2008 entities have to allowances equivalent to their emissions and a fine of 100 euros each missing allowance. Further, you still have to make up the shortfall the following year. It's strict and non-compliance is more expensive than compliance so no company will simply pay the fee.

The new 4 year cap requires substantial emission reductions from the 2005 emissions levels. It's a free market. There are no restrictions on who can participate and that promotes liquidity. Governments and the European Commission do not intervene under any scenario. This helps ensure both price and regulatory certainty. You can reduce emissions by investing outside of the EU using the Kyoto Protocol project mechanisms – CDM, joint implementation - that's primarily what's driving the international carbon market.

The Kyoto Protocol would have been affordable, despite the original emissions targets that were very stringent, by investing in offset emission reduction projects outside of the US. This would have been much cheaper than anything within the US. It's completely the case that it would have invested outside of its boarders. The 5.2% reduction target under Kyoto was on the basis of US inclusion. It's a shame because much of the model is a good structure for delivering emission reductions into the future.

The EU emissions trading scheme has filled the gap in many ways. There are companies in the EU with employees based in China searching out emission reduction opportunities. There are billions of tons of reductions coming now from those project mechanisms. Two billion tons in the pipeline right now according to the UN. There were more wind turbines that went up in China in the first quarter of this year than all of Australia throughout last year. It's because of the EU emissions trading scheme allowing for offsets that reduce emissions in China.

Even thought the '05 – '07 EU market was long, it has still delivered emissions reductions, particularly in China, India, Brazil, etc. The other reason is because of the source based approach, the cap at the smokestack. The price of carbon was incorporated into the price of electricity from day one. Electricity in the EU incorporates the carbon price. It's increased gas plants and decreased coal dispatch. This all occurred even when the market was long – with the adjustments the new period should be significantly better.

So what are the lessons learned? First, the EU didn't have a basis for harmonizing verification. The monitoring and reporting of emissions in the EU was harmonized, but third party checking wasn't. That's going to be addressed in the review, there's concerns for inconsistency and quality of verification. They need to ensure that monitoring and reporting are not separate from verification..

Data release. The big drop in price occurred in 2006 because they had data for the first time. There's a question of frequency, perhaps increase to a quarterly basis. There are concerns with the way in which data has been released in the EU. The market is primarily run by officials from the environment departments of governments. They're used to standard control mechanisms and not necessarily managing a market. Data release has not always been professional. Data release without summary data alongside it, for example. This means it's difficult to tell whether the data is bullish, bearish, or neutral. It can be easily misunderstood and send the market in the wrong direction without enough additional summary information. The data has been released without any advance notice which can significantly change the position of key players in the market. Setting key times that are adhered to with plenty of advance notice is critical for good market management obviously. Imagine on May 2006 where the price is falling really fast, if you decided to go into a meeting or the toilet at an inopportune moment, you could have found that data was released and your position has changed in a matter of a few minutes. Some government officials have come close to breaking insider trading and market abuse rules.

Allocating emissions allowances has been an issue. Obviously the first 3 year period was short. It's good that it was this way so that corrections could be set into the next period of five years ('08 – '12). They set a three year period on purpose so that corrections could be implemented quickly. We now need longer periods than five years. Electricity investments have planning horizons of at least 10 to 15 years. This is being proposed to EU officials and it's likely that the next periods will be extended to at least eight years. So the third period will probably go from 2012 to 2020.

The market failure in 2006 has been used by some who are not enthusiastic about trading schemes. Why did the EU price fall go so far? I've explained why it fell but why did it fall from about 30 euros? Why weren't the signals about the market being long reflected before they released the emissions data? The signals should have been seen before.

Free allocation to a high percentage can have unforeseen consequences in terms of price bias. IN the EU the power sector had a higher level of emissions reductions than other energy intensive sectors such as cement, refineries, paper. Those industries successfully argued for an allocation of allowances which was roughly equivalent or even greater than business as usual emissions. Whereas the power sectors were all short. The power sector went out aggressively to get out of being in their short position. Those with a lot of allowances weren't urgent to sell them – they were OK in terms of compliance, wanted to take time to understand how the carbon market works, go to their board, ask for permission strategy or selling. Thus the market was artificially short until the first release of data. There was an artificial short in the market. Sellers weren't there, buyers wanted to buy and the price got pushed up to about 30 euros.

I'd advise other market designers that if they want to compensate sectors that can't make the same level of emission reductions they should use auction revenues. Don't compensate through the free allocation of allowances because the people with the extra allocations do not participate in the market and a price bias due to human behavior occurs.

Outside the EU we see Norway and Switzerland looking at something similar. Australia is also implementing something similar at the state/territory level. In North America there's a mixed result. RGGI's got a structure with the cap and trade but there's a risk that it's going to make the same mistake as the first three years of the EU emissions trading scheme and go long. The EU didn't know they would be long but in RGGI they know it's going to be long before it's even started. Hopefully that's an incentive for political leaders to make an adjustment ahead of time. RGGI also has an enormously complicated way of trying to access offset credits.

There is fear in the U.S. of a price above $7-10. The EU price has been around $20 with little drama. It's all fine. Proposals for price triggers or price caps is unnecessary and not investment friendly for the market. It compromises the environmental goal for no reason and scares people trying to invest in emission reductions. It's great for entities with a compliance obligation. They may not want to do anything because with a price cap they can just treat it as a liability and pay the tax.. If you want a real market, investment, and innovation then these sorts of things are a bad idea.

California might go load based. That's also a problem. It's complicated but suffice to say that it doesn't get emission reductions in a load based system. There's a myriad of complicated reasons. People don't get the return on their investment because it's hard to source the electron. They really need to do something else and use a source based approach.

Canada, quite bizarrely, is going for intensity based targets. That means there is no idea what the environmental obligation of the market is. It makes it difficult to determine what the price should be and is very complicated. It'd be nice to see some of these newer markets learn from the lessons that the EU got.

Some argue that they need to do something different because it's just different in their part of the world. It's just simply not. This happens all the time. There's no reason to start reinventing the wheel. Stick with what's worked; the U.S. acid rain program and the EU scheme are working proven models that can work anywhere.

Speaker 4.

I have two observations. First, it's difficult to overstate the acceleration and the pace of activities in Washington surrounding climate change right now. State level activities, the change in Congress, the Supreme court rulings have all contributed to this. Second, a survey conducted every year for the past ten at Stanford University asks people what's the most important environmental problem facing the world right now. For the past decade a variety of answers all were up around 10%. It was toxics or water or air or climate change or energy, everything was right around 10%. This spring climate change was ranked by more than 30% of

the respondents as the single most important environmental issue. It's a dramatic shift – climate change has clearly emerged to dominate the agenda as a primary issue.

I'm going to delve into the major characteristics of proposals in front of Congress right now. There are basically six. In each of those I will focus on their rigorousness, coverage, allocation, price stability mechanisms, offset provisions, and technology policy.

I want to emphasize that things are constantly changing and that each of these may be modified as we go along. There's an incredibly wide range of proposals, ranging from policies that suggest stabilization of emissions like the Udall and Bingaman-Spector proposals to others that propose a 50% cut in emissions over the next 20 years. There are also proposals that emphasize only electricity sector emissions but they similarly suggest 50% emission reductions in that sector. So a range of policies in stringency, and also in terms of the sectors they are covering.

In the next six weeks there are going to be a lot more estimates of the economic impacts of these different proposals. I'll focus on MIT's recent assessment of cap and trade proposals [MIT Joint Program on the Science and Policy of Climate Change. "Assessment of U.S. Cap-and-Trade Proposals," April 2007, Report no. 146]. that considered three scenarios. There are three columns that assume different reductions in green house gasses with corresponding results in carbon dioxide price and impact GDP.

The first model represents proposals that flatten emissions over the next 25-30 years allowing for 287 bmt [billion metric tones]. They are closest to the Bingaman-Spector and Udall proposal. There is mid level model that lowers it 203 bmt until 2050 – probably closest to Lieberman-McCain. There's an extreme model that averages it at a very low 167 bmt that is the extreme being considered by Sanders-Boxer.

The flat-line model stabilizes emissions in the range of $20 in the next ten to 20 years rising to maybe $70 around 2050. Those prices are consistent with a global stabilization path of about 650 or 680 parts per million CO2. The other two models lower us to 550ppm per tonne of CO2. The flat-line model is roughly consistent economist Bill Nordhouse's estimate of optimal path balancing costs and benefits.

There are varying impacts on GDP. The flat-line model only reduces GDP by a fraction of a percent. The more stringent targets have an economic impact of 1-2% of GDP. There's certainly questions about the overall impact of 1.9% of the GDP.

Coverage is important in terms of whether the policy addresses upstream or downstream sources. If they focus on downstream sources they can only address about half of the CO2 emissions in the economy. Downstream models can get a lot of the other important non CO2 gases just because they're fairly concentrated but in terms of CO2 it's just about 50%. There is a question of how much CO2 one wants to address in the policy.

Economics would argue that if there are more emissions covered in the system then there are more opportunities to find cheap mitigation opportunities. It means less pressure on the electricity sector too. However the upstream model, regulate at the point of fuel extraction or processing has been encouraged by economists worried about efficiency.

Bingaman-Spector talks explicitly about upstream for all emissions, Lieberman-McCain talks about upstream regulation for the transportation sector. I've heard recently from people at EPA that this will only address about 60% of CO2 which is a disadvantage.

There are issues with contracting and whether or not costs can be passed through. It's idiosyncratic to the fuel. Oil prices will get passed through right away but that's less true with coal. There are two things that threaten an economy wide upstream system. One, pressure from coal mines that do not want to be regulated. From a coverage standpoint it doesn't matter if we regulate coal where it's combusted rather than where it's extracted. Either is fine. It

just needs to be consistent to rest of the system. One wouldn't want a whole bunch of gas fired generators saying you can't be regulating coal at the power plant and not gas.

The second question is whether a sector by sector approach will win the day. Some Congressional proposals have very detailed sectoral regulations spelled out, the pressure in California is sector based. The President's speech yesterday was not an endorsement of sector based approaches but an emphasis on collaboration at the sectoral level.

Some power companies would prefer the sector based approach because they feel like they could get a better deal if it was just them at the table negotiating their own deal. However, from an economics perspective this fragmentation is the same as a tax based approach. There could be extensive inefficiencies and complexity.

Allocation is also important. Economics has emphasized the idea of marginal cost pricing. If power companies have to buy one more input, a carbon permit, in order to generate electricity they're going to pass on that price to their consumers in a competitive market. Obviously it may function differently in regulated sectors. This means the allocation question is complicated. In the electricity arena it means considering upstream allocation to coal mines that are losing markets as coal is used less and downstream to large electricity users who will see their power prices rise. If it's a larger program than just electricity then there'll be allocations to different sectors horizontally as well.

Only the Bingaman bill spells out the allowances for the upstream fuel producers, the electricity sector and other sectors. They are also considering auctions. Certainly in RGGI it's already been mentioned. In the proposals before Congress auctions have a role of somewhere between 15 and 50%. In one proposal 85% would be grandfathered free to existing sources. It's 50% in the Bingaman and the Udall bills. That percentage has also been suggested by the National Commission on Energy Policy.

Federal proposals will have a broader allocation to different kinds of entities but also an emphasis on auctions because the allocation is harder and because people are beginning to realize that the real impacts are downstream with the end users. The only way to get the money back is do something with the revenue from an auction.

Next concerns price stability. The previous speaker addressed the situation in the EU extensively and I realize it will probably not happen again. There are other reasons why rapid shifts in prices occur other than information revelations in a market. There can be shortages. We saw that in the U.S. NO2 program. They had a price spike up from about $1,000 a ton to $6,000 a ton at the beginning of the program during uncertainty about Maryland entering and later when the budget program shifted to another program and there were restrictions on banking. In both cases there was a huge spike in allowance prices due to a shortage or a perceived shortage.

With CO2, different than SO2 and NO2, the concern is the accumulation in the atmosphere over very long periods of time. It isn't efficient to have a 30 euro price one day and a ten euro price the next day. From the environment's point of view it would be better to have a little bit higher emissions the day it's 30 euros, take those 30 euros and buy three tons of reductions the next day when it drops to ten. The environment would be better off and the economy wouldn't care about the difference. The uncertainty of huge drops or high variability lowers investment motivation; simple option theory of investment.

There three approaches to providing more stability. One is a large bank. That's what happened in the SO2 program. The program was long in the initial years such that the program accumulated a bank equivalent to an entire year's worth of emissions. That did not cause the program to have a zero price. It allowed the program to have a fairly constant price as people could weather variations in demand in the electricity markets. The problem with CO2 is the reductions are not that significant, so the ability to generate a large bank is hard.

Second is the possibility of borrowing. That's in the Lieberman-McCain proposal and the electricity sector only Feinstein-Carper proposals. It's in the Kyoto Protocol too as a provision if you're late over one period you pay it back with an interest rate in the next period. This borrowing puts a limit on how much the price can go up because people know if it's going to come back down they can borrow against the future. In reality if there isn't a compliance deadline there should be market mechanisms where people can short the market even without borrowing. If one is worried about having a shortage when the compliance deadline hits then borrowing is necessary to avoid price spikes.

The third option is a safety valve proposed in the Bingaman-Spector legislation and recommended by the National Commission on Energy Policy. It has transparency, people don't have to guess what the long term price is likely to be in order to determine what the current price ought to be for banking and borrowing purposes. These mechanisms all avoid the volatility that is disruptive both for environmental and economic goals.

Offsets are a dividing point. Some are quite favorable about them and others are very negative. I tend to be in the middle. They can be a valuable part of a policy. However, if one sets up a system where offsets are depended on to keep the price of the system low you introduce a second goal in the design of the offset program which is to make sure there are a lot of offsets. It's important that offsets don't get used simply to help keep the price lower, and instead are used to achieve policy goals that are truly valuable.

Second, offsets are a subsidy. They're not the same as something under the cap which is basically a penalty for emissions. They're a subsidy to reduce emissions. The difference between a subsidy and a tax is that people may enter a market in order to collect a subsidy to get rid of the emissions in that market. In China there's been people entering or staying in the market for CFCs in order to collect credits for reducing their HCFC emissions. It's still worth doing but one needs to consider how to set the crediting mechanism so there aren't any perverse incentives that might encourage over-entry into a given market. So with those caveats, offsets can still play a positive role.

Technology is complicated. Prices in Europe, and prices that are anticipated in a US program, are not going to be high enough to encourage carbon capture and sequestration. Without pricing as a strong driver then technology policies must fill in the gap. There's a variety of ways to do that that I won't get into but it's important to have them.

There can be important price impacts. Higher prices of CO2 obviously mean less coal use. Clearly this has political and energy security implications. At approximately an average of $18 per ton, coal usage drops slightly from 2006 usage levels. Second, household energy costs (excluding gasoline) vary at different prices of CO2. Households will sustain about $100 in additional costs annually at $12 per ton and around $200 per year at around $22 per ton. The $200 per year is about a 10% increase in household energy costs. Obviously that has important political implications.

Question: Do you have any analysis that shows how much the price of electricity in Europe has increased before Kyoto and after Kyoto?

Speaker 4: There are a number of studies. Look at the EIA web site. There has been a concern about electricity companies collecting a lot of money in higher electricity prices at the same time they were getting free allowances. So a lot of people have looked at this but I don't have data at hand.

Question: Can you discuss the safety valve mechanism for removing volatility from carbon prices?

Speaker 4: Sure. So first, banking is one mechanism that can reduce volatility. It puts a floor on the price. The reason the allowance price has gone to zero in the first period of the EU ETS is because you can't bank allowances into the second period. If you expect prices to be

high in the future you're not going to let current prices go down because people are going to buy them up.

Banking acts as a floor and prevents the price from going too low and it also prevents the prices from going too high because one can draw down the bank instead of letting the price go up. The bank can only work if you have time to accumulate it. It doesn't help one face a shortage immediately before you've created the bank.

Borrowing is good if there's a shortage right away there's a mechanism one can borrow from the future when you think the price is going to be lower. Both banking and borrowing hinge on expectations about what the future price is. To the extent that expectation about future prices is somewhat volatile it doesn't completely dampen fluctuations in the price but those fluctuations are driven by expectations about long term price is. If there's a new report that suggests climate change is a big problem or expectation that participation in the program is going to change maybe that would drive that would drive fluctuations.

Finally, the most certainty about a maximum price comes with a safety valve. Here, the government sells additional allowances at a specified price. If the market is under that price the extra allowances are irrelevant, but the market will not go above that gov't allowances at the high specified price.

Question: The verification issue is critical because that's a potentially important additional cost adder. In India or China, Africa what does it cost to verify the reduction numbers are accurate?

Speaker 3: It's not cheap because the people need to be very well qualified. Emission reductions have a financial value so there's a big read between financial auditing and emissions auditing. However, if a company is organized with its data then that auditor needs only a few man days. The costs can be managed and it's not a big chunk of your overall costs.

Question: So is that saying under 1%?

Speaker 3: I don't want to put a number on it because there's fixed cost so the bigger the project then the smaller the percentage becomes. It's small.

Question: Does this work with the big accounting firms?

Speaker 3: You'll find that all the big financial auditors in the EU are there but there are also certification companies with a history of environmental certification that are training the financial angle.

Speaker 1: Carbon offsets have to be designed so that they're effective. They are always good for the entity buying them, selling them, the broker but they have to be verified so that they truly are good for the environment. There need to be very stringent criteria for good offsets but stringent criteria drive up transaction costs and make offsets more expensive.

Speaker 3: That's true. The criteria and procedures for the CDM are quite rigorous. There's been some controversy around one of the industrial gas projects; HFC23 destruction. Generally the projects are seen as useful, stringent, and environmentally beneficial.

The voluntary market is a different story. Companies offering these offsets for people to voluntarily offset their plane ticket for example are suspect. There are no standards for these. Unfortunately they can discredit the carbon market generally even though they are totally different.

A simple quantitative cap on the number of offsets that can come in is a pretty blunt instrument. It reduces certainty when you're investing in projects because you're not quite sure if you're going to be able to sell your project before the quantitative import limits hit. Policy makers should consider qualitative criteria that would be better for project developers and would improve projects that you want in that particular jurisdiction.

Speaker 2: The pro formas I've seen for quick return projects often show that more than half the cost is for transactions like verification, lawyers, folks to work it through the UNFCCC process, etc. Half the cost is actually for the carbon reduction. Again, a lot of the quick investments are being made in developing countries with 12 and 18 month paybacks. That's not necessarily a bad annuity if you can keep it in place and verified to get your money back in the first year or two and watch it just keep on generating revenue because of the need to reduce carbon. These offsets need to be very stringently structured.

Speaker 1: Instead of looking at the voluntary CO2 market, some companies should buy into the SO2 allowance market? If they buy one of those SO2 allowances and tear it up then the company has changed the statutory cap enacted by the US Congress. They have lowered emissions, period. That's a real effect. If entities are allowed from outside of the EU or any other program to make purchases from that program and retire them then that will be real advice.

Question: How do utilities facing an integrated resource plan, proposals for wind generation, for demand side management, gas and coal plants. Given the uncertainty surrounding Congress, how can a utility make a sound economic decision?

Speaker: A price for CO2 to factor in is important. Companies are probably developing their own forecasts. I expect we'll see a $15-20 price in the US. If the current political trend continues it could be higher. You need people who can give you a good forecast. But this one was free [laughter].

Moderator: Some PUCs allow for adding in environmental externalities that can be estimated in an IRP. The commission ultimately decides whether they're reasonable or not and factors that into their decision.

Question: I've seen an $8 per ton price factored into an IRP recently. Is that a stab in the dark?

Speaker: Most proposals start around $10 and go up from there so that is probably low.

Speaker: One company I know has done this. They've set a probability distribution of potential future permanent prices and also run probability distributions on the future of nuclear and associated constraints. They run calculations and Monte Carlo simulations and run option analyses from there. They fed that into their decision making.

Question: Some people argue that the EU ETS [emissions trading system] has shifted value from countries which are naturally short. Is this an issue? How is it addressed? How does one address new systems to allocate and distribute targets among different countries that have different carbon intensities and different starting points?

Speaker 3: The background to setting the caps under the EU emissions trading scheme is the targets under the Kyoto Protocol. Those are the starting points. In any case, everyone is going to be short 2008 to 12 because the whole system has been tightened up quite substantially.

Speaker 4: That is a problem if different regions are gravitating to different levels of commitment that one can loosely define as a price. Both security and political concerns can certainly interfere. There's also questions about countries that want greater technology investments and others that want higher reductions. Currently I think that domestic political pressure for different types of policies is more important than the need for global harmonization. Countries need to get their own houses in order and then they can harmonize internationally after. Having quantity based mechanisms, whether they initially have a safety valve or not, does at least leave the door open towards eventually integration. I don't see the United States being incredibly long merging with the EU that's incredibly short. It's not politically sustainable.

Speaker 2: The EU is less unified than it looks like. Slovakia has recently challenged the decrease in allocation they have in the new phase and other eastern European countries are

thinking about doing the same. If you look at the RGGI system there was horse trading where more reluctant states were given allowances to entice them. When this is imposed on coal burning or other fossil plants who will bear the compliance burden there will be challenges to those allocation schemes. A lot may unravel.

Question: The problems that people had in the first EU round occurred in the U.S. when financial transmission rights were first introduced. People were holding on to them to see what happened with the market and it became short even though it shouldn't have. The solution was to create auction revenue rights which had exactly the same appearance, it's just that they got the money instead of the right and then everything was liquid and solved the problem immediately. It's an interesting parallel.

It seems that there's a lot of uncertainty, even after mechanisms to reduce volatility are used. It adds to the bias in the industry against large commitments to long term investments that are not flexible and can't change. We see this with large generator projects and big transmission lines. We can't remove the uncertainty but we do need to address it. Any thoughts on this?

Speaker 3: One can address these big investments in the context of a well-designed emissions trading scheme. There is more regulatory risk because it's a market that's been created by a government. A proper cap, an emission reduction obligation that goes well beyond business as usual emissions so everyone knows that it's short, is critical. It should be at least ten years out, but with a long term political signal going out 30-40 years representing a real commitment to the model. A lot of jurisdictions are beginning to understand and consider this. With these things in place you get full participation and a very liquid market. The EU ETS has unlimited banking and borrowing going forward to that also reduces uncertainty. There are movements obviously, it's a market, it needs to move in tune with all the other related markets like gas, power, oil to some extent, weather patterns, etc.

A price cap seems strange because such things aren't used in other markets. It's not like we're worried about the oil price going above $70 so we'll put in a price cap. So why is the environmental market so different? Further, there's a concern with the safety valve because people can play games with that in the market.

The overall worry is a bit unnecessary because any sophisticated mature liquid market doesn't have a massive amount of volatility.

Speaker 4: A fundamental problem is that the willingness to pay is not known and there's uncertainty there. Even if there a policy process is passed in the United States, there will be information about that willingness to pay at that moment but that may change over time in response to science and politics. Generally, regulatory policies in the United States have been supportive of past decisions. Further the need is so great for these big, admittedly irreversible, investments that the uncertainty is not going to be that great of an obstacle.

Speaker 2: The uncertainty is going to cause people to back off. There's a lot of uncertainty even in these models, California versus RGGI versus EU. In many places the smart investment would be renewables and conservation but even that is a problem. Massachusetts can't even get wind projects sited, on or off shore. There's aesthetic zoning laws, nuisance laws, etc.

Question: RGGI has moved from free allocations to an expectation of allowance auctions. There's a concern that this makes it more liable to be legally challenged, why? Second, are there best practices for running auctions to minimize volatility and increase predictability. Perhaps limiting participants?

Speaker 2: The legal questions. If it is announced by an executive agency instead of a legislature is that an authorized tax within the state? The compact clause of the constitution says that states may not enter into compacts without the pre-approval of the Congress. RGGI is a compact. That may not win but it's a challenge. There are commerce clause issues in the leakage problem and how RGGI will address

it. Limits on leakage can be challenged under the commerce clause but if leakage is not addressed it may weaken RGGI. There's preemption challenges in terms of the supremacy of federal law. The auction changes the tax definitions.

Speaker 3: RGGI's auctions would be unique because there isn't a market that already exists. An auction by itself doesn't promote price discovery very easily. People prefer to discover the price on a gradual basis through a market and the auction results can achieve parity with the market prices.

With the starting auction, some may start trading beforehand on a forward basis. That could be helpful. Especially if the prices can be released anonymously. An auction mechanism that helps price discovery would be helpful. Don't use sealed bid but instead use an ascending clock where the total aggregate demand is released after each round and people get an idea of the dynamics. Otherwise small companies without experts will be terrified and end up over bidding. Ensuring that the auction is the same across the RGGI region is helpful. Develop the design and rules via auction experts. Have seminars ahead of time to explain rules, and even run a mock auction so people will understand the software. Set a time table for auctions in the quantity that you're going auction off for each point. If it's being done on a quarterly basis, declare in advance the dates or weeks and the quantities. All these things create certainty.

Speaker 4: There are reasons for preferring sealed price auctions because they make people more honest in their bidding. Certainly more smaller and frequent auctions as opposed to single large ones. It gives people a chance to see what is happening regardless of whether it's sealed or not.

Speaker 3: Oh, I wouldn't limit participation in an auction. You don't want any risk of collusion and the more participants the more accurate the price. There's a huge literature on auctions.

Question: In regulated areas the value of free allowances would go back to rate payers but in a competitive market the value of the allowances would pass through on the electric price. This is a big price divergence between the regulated versus the deregulated area. Does the free allocation of allowances set up a path that could make deregulated power markets seem less attractive?

Speaker: Those who are discussing allocation are keenly concerned about this. They're concerned that prices in the cleaner deregulated regions may rise more than prices in the dirtier, more coal intensive regulated regions. There's been discussion about allocating downstream, not regulating downstream, to utilities instead of allocating to generators or setting different rules in regulated versus deregulated regions. It definitely needs to be considered.

Speaker 1: This question demonstrates that the burdens of an economy wide climate policy that it is cost effective in its own micro terms will have different burdens on different sectors of the economy. When one allocates these valuable allowances, think about who's bearing the burden and compensate various parties. Doing this also attracts political capital and support for the policy which is actually the attraction of cap and trade programs in the first place.

I would suggest different allocation mechanisms for the two kinds of markets based upon the cost burden. Unfortunately then other interest groups will begin to argue about relative cost burdens. Fortunately, the good news about a cap and trade program compared to other policy instruments is when normal political forces occur like rent seeking behavior or interest group lobbying, it doesn't mess up the policy or the environmental target. It affects distributional burden but it doesn't affect things overall.

Speaker 3: In the EU electricity prices are largely unregulated so free allocation wasn't a problem. If you distribute it to people that don't enter into the market, then price biases can develop for allowances. I do wonder if a better way of doing this is to auction them off and compensate people via a vehicle like auction revenue rights.