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HARVARD ELECTRICITY POLICY GROUP
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RAPPORTEUR'S SUMMARY*

Session One.
Courts, Contracts and Competition

Greater reliance on markets requires many things. One of the principal challenges for market design is to develop the right incentives and frameworks for investment. Getting the prices right is essential, but is only part of the market design story. Defining and providing long-term transmission rights is an especially difficult task closely connected short-term operations and pricing. The companion long-term energy contracts must be an essential part of the plot, as underlined by their absence as hedges in the California crisis. There has been much controversy over many aspects of market design, but there is general agreement that the status quo, even in the formally organized RTOs, is a work in progress with critical elements that are not up to the task of supporting investment, especially voluntary investment by market participants.

In an ironic twist of fate, on the same fateful day in December two announcements highlighted the tensions. The FERC, reversing its recent course, announced it would be sponsoring a series of conferences to address competitive market issues including "the availability of long-term contacts and market design issues affecting wholesale markets." And for its part the U.S. Court of Appeals for the Ninth Circuit announced a new set of standards for reviewing "high-rate" challenges to long-term contracts. Does the new standard formalize a "lower of cost or market" rule? Will parties make investments with the current market design and the new standard for contract review? Can market design be modified to meet the test of providing both better incentives and enforceable contracts? If not, then what?

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

Speaker 1.

I am going to discuss the 9th Circuit case. I will start my discussion from a legal point of view, not a markets perspective. Let's begin with the Federal Power Act; crucial for today's discussion. The rules are set by statute unless Congress changes the Act. In it, neither power markets or contract sanctity are an end result. They are not even specified. As the 9th Circuit emphasized, a market based scheme is simply a method used by FERC to achieve its fundamental obligation to ensure rates and contracts are just and reasonable. The end is reasonable rates; market methodology is just a means. Both sections 205 and 206 of the Federal Power Act focus on wholesale power contracts and explicitly require just and reasonable rates. They provide FERC with the authority to modify contract rates. This is the starting point of the 9th Circuit's decisions and it should underscore our discussion this morning, particularly if markets and contracts are the predominant regulatory scheme to supply wholesale electricity.

Since those December decisions, there has been much public comment and frenzy. Some argue that the decisions mean the end of contracting and long term markets. They are wrong: the sky is not falling, it is not the end of contracts. Instead, the 9th Circuit's decisions are a reaffirmation of the use of markets as a proper means to achieve just and reasonable rates, provided those markets are functioning and workably competitive. The decisions were drawn from the extraordinary facts of the Western energy crisis of 2000 and 2001. This was a crisis which saw peak and off-peak spot and forward prices spike to exponential records and maintain that spike for the better part of a year. Rolling blackouts became a daily occurrence in California, even during non-peak winter months. Organized markets in the state melted down. The PX ended up in bankruptcy. The ISO could not procure enough power in a real time basis to keep the lights on. PG&E went into bankruptcy, and the IOUs were insolvent. Traders used schemes with names like Death Star, Ricochet, and Fat Boy. They bragged about causing harm to grandmothers and sang parodies extolling the benefits of withholding. Those facts provide the context for the court decision and FERC's orders.

FERC identified the spot markets in California as dysfunctional and ordered refunds of spot market transactions in a series of unprecedented orders. In December 2000, FERC called on the state and the IOUs to enter long term contracts. They also promised to assess the justness and reasonableness of the rates for contracts entered in 2001. Ultimately, the state of California did step in because of the insolvency of the utilities. The state was spending $100 million a day to keep the lights on in the spot market. Ultimately, the state entered into 52 long term contracts through the CDWR [California Dept. of Water Resources].

The contracts became an issue in one of the two complaints before FERC. As the crisis abated, the role of manipulation, withholding, and other dysfunction came to light. The California Electricity Oversight Board and the CPUC challenged the contracts under section 206 of the Federal Power Act at FERC. They argued that the markets were broken, the rates were unjust and unreasonable, and contrary to the public interest. FERC denied relief in a two to one vote, finding that the complaints were simply buyer's remorse. All three commissioners have left the FERC. The majority ruled that justness and reasonableness of the rates was irrelevant. Contract sanctity prevailed because the contracts were entered into by parties with market based rate authorities. They were presumed just and reasonable without need for review. The evidence of manipulation and dysfunction in the market and its effect on forward prices, including the conclusions of FERC staff, was deemed irrelevant.

The FERC relied on the legal doctrine of Mobil Sierra. This case originated in two Supreme Court rulings issued in 1956. The Supreme Court reviewed decisions of the Federal Power Commission that allowed a seller in one gas and one electricity contract to unilaterally raise rates because they were too low. The court reversed the decisions. It distinguished the private interests of the utilities from the public interest of the consumers. The Court held that the FPA [Federal Power Act] is not intended to free a utility from the burden of a contract merely because it turns out to be improvident. The purpose that the commission is given under section 206 is to protect the public interest as distinguished from the private interests of the utilities. In the Sierra case, the court recognized that the public interest is in the low rate. Thus, if the utility is to be relieved from that contract, it must meet a three part test, demonstrating that increasing the rates was necessary to further the public interest. The FERC applied the Sierra tests rigidly to conclude that the contracts were not contrary to the public interest.

The 9th Circuit reversed FERC and remanded the proceedings back to the Commission for reconsideration. It instructed the Commission to determine whether Mobil Sierra applied, using a particular test that the court articulated. If it did apply, then FERC should apply Mobil Sierra and consider the public interest in a way that considered the context of the case. The public interest was derived from the consumer power purchases for the public by the state. If FERC concluded that Mobile Sierra does not apply, then it must determine the just and reasonable rates for the contracts by another method. The court ordered FERC to consider more evidence, including its own staff conclusions.

What the court did is hardly remarkable under the circumstances. The California crisis inflicted financial harm on California consumers. The Court reaffirmed FERC's paramount obligation to protect consumers from unjust and unreasonable rates. In their quest for deregulated power markets, the majority of former commissioners prioritized contract sanctity over these more important obligations. The Court recognized that competitive markets are an acceptable method for determining just and reasonable rates. Functioning markets tend to produce rates in the zone of reasonableness. However, FERC may do so only if the markets are functioning and workably competitive. This was not the case in 2001. If one's going to rely on a market system to develop competitive prices, then the market must be competitive in the first place. Case law from the Supreme Court and the Circuits have made clear that competition alone may not produce just and reasonable rates. Agencies like FERC must "retain some oversight over the system, to see if competition in fact drives rates into the zone of reasonableness, or to check rates if it does not."

The Court also considered Mobil Sierra. Both the Court, and FERC acknowledged, that FERC has to do a meaningful review of all rates and contracts, a plenary review. The court emphasized that the review can be done through a market-based methodology. At the time when contracts were entered, FERC should have had a regulatory scheme reviewed both contract rates, and consideration of the market's competitiveness and performance. If both conditions are satisfied, the Mobil Sierra presumption applies, and the contract rates are just and reasonable under the FPA. Clearly, the contracts still need to be reviewed under these obligations and conditions. I expect we'll see more litigation over this issue.

For today's discussion, the more interesting question is what the implications are for contracts entered into after today. In the three months since the 9th Circuit decision, there has been no rush to undo contracts. There has been only one complaint filed at FERC relying on this decision. It is a complaint filed by CARE [California Alternate Rates for Energy Program] against the California Public Utilities Commission and two private sector parties over the approval of recent contracts. These decisions have not made contracts unenforceable. The decisions, while important, neither create an "insurmountable burden" (a phrase from Mobil Sierra) to successful contracting going forward, nor undermine the enforceability of contracts in functioning, competitive markets. There simply needs to be a consideration of whether contracts are the product of a functioning market. If they are, that's the end of the inquiry. If FERC cannot determine that a market is properly functioning then rates cannot be presumed to be just and reasonable. Certainly that is the case for the markets in California in 2001 and rates should be determined another way, such as cost of service.

This framework provides a high level of contract sanctity, particularly in light of all the enhancements that FERC has made to its market monitoring, oversight and mitigation methodologies, and its more vigilant market enforcement. All these came about after the crisis. FERC's unlikely to find that its organized markets aren't competitive in today's context. However if FERC is going to rely on markets, it's got to monitor them and make sure they're working.

Speaker 2.

I will discuss what FERC can or can't do to satisfy the 9th Circuit decisions, and what we have lost if they're not overturned or ignored broadly. Let's discuss some preliminary issues first.

During California crisis, the prices we saw in the spot market and the forward markets were not the wrong price. Prices in California, including unmitigated spot market prices, are well below the cost to attract new entry over an 8 or 10 year period. California needs new entry. If there were mischievous acts committed in California, they were balanced by some of the forward contracts. California had a sophisticated operation to determine who to contract with and what to pay. They used Navigant, who did extensive modeling to figure out what to pay. They built a virtual system with different flexible products that they sometimes paid a premium for. They did it for an all-in price that didn't require a rate increase, about $70 a megawatt hour, which was their target. That price is close to their own experts' estimate of new entry cost. Overall, they didn't pay more than the cost of new entry for needed capacity in the middle of a crisis. They got a good deal.

Nonetheless, what can FERC do to deal with these decisions? Can they fix the market-based rate program, achieve more oversight? The decisions have some significant hurdles that may make it impossible for a contract to gain public interest protection. This is a problem. Let me explain. The court did not let the filed contracts fall into the public interest standard. Most of the case discussion is about market-based rates but the Court's assessment of contracts was chilling. They argued that FERC didn't approve them, it merely accepted them, thus they did not warrant public interest protection. Well, the FERC really never approves contracts. Approval acceptance distinctions are very arcane, and true approvals rarely occur. Even contracts under cost-based rate making wouldn't satisfy these requirements.

Further, there's a requirement of perfect knowledge. Economists argue that contracts address the fact that participants have imperfect knowledge. They're a hedge against unexpected consequences. After California became aware of manipulative acts and dysfunction in the spot and forward markets, they get a court review. Not only do you have to have a contract accepted, but the market-based process has to be sufficient enough to preclude a participant from coming in after with a new problem. That is very difficult to litigate and resolve. It's an unmanageable risk. It demonstrates a naiveté on the court's part about contracts.

The Court also limited Mobil Sierra to basically a buyer protection act. It makes Mobil Sierra asymmetric. If you're a seller, and this remains the law, you never want Mobil Sierra protection. this is very difficult for the FERC to remedy, if not reversed.

Are we limited to crisis conditions? I've been trying to define what a "dysfunctional market" is since 2000. The FERC may have used it to replace "unjust and unreasonable" or "not competitive." Is scarcity or market power a dysfunction? When there's a crisis, that's when you need a contractual hedge to function most effectively. Contract protection is needed most in the heat of a crisis, when you're most vulnerable. One contract participant complained that "I came in with a fire hose and put out the fire, and everybody's complaining about the water damage." A serious concern is that the next time there is a crisis, nobody will supply a hose.

So if we can't cope with these decisions, and they're not reversed, what have we lost? Well, we live in a time when the energy industry regulation is becoming increasingly political. Mobil Sierra provided a nice bond of protection beyond politics. It goes beyond an administration or Commissioner change. More than anything, the Court created a hurdle; a heightened standard of just and reasonable, and also of public interest. It tells counterparties that there is not an additional bond of protection against regulators bending to political pressure and undoing your deal.

There is now increased risk for these contracts. There's going to be a risk premium to compensate for that risk. The country needs \$300 billion generation infrastructure over the next 15 years, and \$800 billion in transmission. If we assume a one percent risk premium on the cost of capital for that investment, that's \$3 or 8 billion a year, depending. That is only new capital stock. It will be larger when you include existing infrastructure. The short term benefits of undoing a contract do not compare to this risk premium, or to the efficiency gains of competitive markets generally. It probably reduces dynamic efficiencies that competition is supposed to bring, and may warp efficient new entry. I'm concerned that we could end up losing a real significant amount of the savings competitive markets can bring.

Speaker 3.

Does the decision by the 9th Circuit Courts of Appeal lower the bar on the enforceability of contracts? The case is somewhat confusing at times, in part because it's over 19,000 pages long. I am sympathetic to both sides of the argument. On the one hand the Court states, "even if a particular rate exceeds marginal cost, it will still be within a reasonable range if that higher than cost base price results from normal market forces and is part of a general trends towards rates that do reflect cost." This sides with contractors. This is a strong endorsement of market forces, even when market prices are different from current cost, because they signal scarcity in the market and the need for new entry. has to occur, and the price is reflecting that. The decision is strong on contracts, and upholding the role of markets as providing just and reasonable prices.

Alternately, the Court doesn't make a strong case, at least from an economist's point of view, that the prices paid in California were not market prices. Those prices indicated peculiar scarcities and market signals just as the paragraph stated. So, it goes both ways.

However, I want to focus on a different issue relevant to the enforceability of contracts, the case of sovereign debt. Sovereign debt is a peculiar type of contract which refers to the debt contracts taken by governments. They are the ultimate "difficult to enforce" contract because countries don't have assets outside. Generally they don't have assets or money laying around to be attached. Thus it's very difficult to get something from them if they walk away from a contract. There's no court system that can enforce any penalty on a country that doesn't pay.

The puzzle, from an economic perspective, is why sovereign debt exists at all if it's not enforceable. There's a whole literature devoted to it. I'm going to specifically discuss how these contracts are set up in a context where enforceability is limited. Clearly, electricity contracts are not yet nearly close to this situation. Rather, this is an intellectual exercise to see what happens with these contracts. If electricity contracts do in fact become less enforceable, then this provides an extreme vision of where the industry may be going. The analogy is that if we have electricity contracts which are unenforceable, a supplier is thinking they will sell electricity to someone, and their customer can walk away from the contract more easily. However, to be clear, there are extremely clear differences between the two situations at the present.

Four things happen in sovereign debt markets. First, the price typically goes us. I have some data on how much more expensive the price is. The price simply reflects the risk that people may walk out of the contract. Second, volumes shrink. Typically, the amount of trading and issued debt in these markets is very small. With electricity markets there would be fewer contracts. Third, the term of the contracts become very short. Finally, contracts become clumsy. Clumsy simply means that many characteristics one would like in a contract can't be used because of the lack of unenforceability.

Argentina provides some good examples. It's a weird country, they change the rules all the time. Very few contracts last for a long time. In the early 1990s, they reformed their electricity sector. They set up new rules and had a huge increase in installed capacity. Argentina had a large monetary devaluation crisis in 2001 decided to pacify all the electricity rates. This led to a large flattening of all projects and increases in generation. Currently, people don't really know what the rules are going forward in the electricity market. New capacity has stopped being built. These things do matter.

Why does sovereign debt have these characteristics? Well, when a contract can be enforced, a contract is a contract. It goes by the rules. When a contract cannot be enforced, it becomes a game. Since the other party may walk out from the contract, you have to anticipate what they are going to do. You need to anticipate and protect yourself from unintended events that can occur.

Two important ideas in economics affect this game. First is the problem of asymmetric information. For instance if you buy a new car from the dealer, the moment you cross the curb, it's worth 20% less. The person who's buying the car from you doesn't know if there's a problem with the car, or perhaps with you. The same problem occurs in markets, you don't know the quality of the other party in the transaction. When that happens, the market shrinks dramatically because one is unsure as to what's going to happen in the transaction.

The second problem is time inconsistency. In a contract, a juncture occurs where one person wants to do something different. That juncture is referred to as time inconsistency, because reaching that point in time, people want to do something different. Once you reach that point, people will do that other thing. So you want to price that beforehand and anticipate that it will happen. This is a difficult problem.

Here's one example. Consider privatizations, a typical problem in emerging markets. Imagine a lot of risk in an economy, and the government is privatizing an asset. The person who's buying the asset assumes that the government may wish to expropriate them in five or ten years. They must anticipate that. It affects how much they will pay for a facility. So they pay very little and buy the asset, and get huge returns. In 5-10 years the government notes that they are making huge returns and decides to expropriate the asset, in part because the returns are so large. It becomes a self-reinforcing prophecy. In electricity markets, if suppliers worry their client is going to walk out, they'll charge a higher price. Down the road, the price seems very high so there's even more pressure to overturn it. It is also self-reinforcing.

The contracts become short because long term debt has volatile changes in the risk premium. Further, it's more likely your client will walk out from the contract. They are higher risk, so contracts become shorter.

There's also moral difficulties that the buyer can create for the seller. So you sell a contract to a buyer who promises cheap electricity to everybody. If the price becomes very high the client has a stronger case that it's in the public interest to change the contract. Thus, if the contract is less enforceable, the buyer can make the enforceability of the contract more difficult to sustain later on. In the case of sovereign debt, this is typified similarly by the fact that countries can't issue local currency debt. If they issue local currency debts, there's an incentive to generate inflation later and reduce the value of the debt. That's why emerging markets can't issue domestic currency debt. They have to issue all debt in foreign currency because that protects the lender. This effect is substantial. One can see examples of this in many Latin American countries. The vast majority of their debt is held in foreign currency. There is a similar problem in long term contracts.

Sovereign debt also has lessons on prices over the long term. On the one hand, being able to bring down prices by reneging on a contract ought to at least create good prices for the consumer. However, sellers will anticipate that that will happen and charge the price higher *ex ante*, anticipating that that may occur. This is what happens in sovereign debt. On average, emerging countries pay more than the U.S. The defaults do not compensate. Lenders charge a premium that is sufficiently high and which compensates occasional defaults that they suffer. In electricity contracts, we would expect the prices to increase to a point which compensates for contract reversals, creating overall higher consumer prices.

Overall, emerging nations paid more of a premium to take on debt than the U.S. or other advanced industrialized nations. The deviations to this pattern occur when significant defaults occurred such as the Argentine fiasco in the late 1990s. In those situations, investors were burnt quite badly. From 1992 to 2001, there were very large risk premiums to remedy for past defaults in Brazil, Mexico, and Chile.

Finally, the contracts themselves change. The lawyers write a lot of provisos and covenants to generate protection. If contracts have become less enforceable, the same thing will happen in electricity contracts. Sovereign debt contracts have a variety of mechanisms for protection. Cost sharing clauses are set up so that if a country defaults, or defaults on everybody and then starts paying again, they have to pay pro rata. If someone tries to recover money, they have to share it with everybody else.

There are also clauses that are *ex ante* punishments; a punishment for a client who walks out from a contract. In sovereign debt, this is done by cross default and acceleration clauses. If a country defaults on a particular bond, everybody else can feel they've defaulted on their bonds, and ask for full repayment immediately. That wouldn't work in electricity contracts, but fines could be used instead. Money would be attached to an escrow account that is transferred to the seller if the client defaults. The clauses can be *ex ante* or pre-anticipated punishment.

Finally, negative covenants are used, which are common in corporate law. In these, a corporation is restricted from actions that make it more likely to default. A typical one in sovereign debt is a negative pledge clause. Here, the government cannot issue debt that is collateralized after they have issued a lender's debt. It can't issue debt that is more secure than the lender's. A negative covenant in electricity could be that you force your client to hedge changes in electricity prices. This sort of thing is certainly possible.

I'm certainly not sure this is where we are now with electricity contracts today. If it becomes apparent that contracts have become less enforceable, we may see some of these features. There could be fewer transactions. Overall, prices could become higher. There will be shorter contracts and new contractual provisos. All of these issues need to be considered.

Moderator: Overall, prices do seem higher, but not necessarily in some specific cases. If I look at bonds and long term bank debt, was Argentina better off defaulting?

Speaker 3: Well, I have data until 2001, the moment of their default. In the short term that is certainly the case. More recent data, and data from contracts in the next five years, would have to be examined to determine if that is the case long term.

Speaker 4.

I'm going to discuss this just prices in the context of the FERC. The commission has overseen contracts in the context of Mobil Sierra for 20 years. This oversight depends on who the commissioners are.

Let's start with some brief background on just prices first, say 3000 years. It starts with Aristotle trying to determine what the just price is. The Romans believed that any negotiated price was just fine. The Roman army sold itself a couple of times to people who became kings, but were overthrown, because the Roman army sold itself again. That's a breaking of the contract.

This debate in the Middle Ages ended with essentially three Christian views. The first, held by the Dominicans and the Jesuits, said that the free market price was the just and reasonable price. The Franciscans believed in cost of service regulation. The Protestants had the work ethic, or the Calvinist view, which was everything was labor.

In the Rousseau v. Smith debate in the 1770s, Rousseau laid out the Mobil Sierra doctrine, although he didn't know it at the time. Interestingly, Adam Smith, the quintessential neo-conservative economist, in his work "Moral Sentiments" argued for something called sympathy to make markets function, which could be interpreted as altruism.

The current definition for a commercial contract is simply a promise that the government will enforce. However, if the sovereign is also a contract holder, it's going to be tough. The optimal breech of contracts theory in economics says that your reputation will fall, which would affect governments as well. If we examine non-FERC regulated contracts there are several things that allow participants to leave them. Contracts aren't as inviolate as we may think.

The Federal Power and Natural Gas Acts were different than the acts that preceded them. In essence, the Commission has been told they have to balance between market power rents and confiscation. This balance is enormously difficult. Some have characterized this as the regulatory compact. Most of this debate took place with cost of service regulation in the background. Simply, a company surrenders itself, gets a monopoly franchise in return for cost of service regulation, and there's a whole set of rules to adjust prices under cost of service regulation.

The Interstate Commerce Act preceded the Federal Power Act. It's almost an anti-contractual arrangement. Common carriage almost precludes contractual arrangements. The contractual arrangements show that FERC regulates all the pipelines under the Interstate Commerce Act, and they find a way around the common carriage issue.

In juxtaposition, the Power and Gas Acts seem to contemplate long term contracts. However in sections 205 and 206 (or 4 and 5 of the Gas Act), the standards are asymmetric. It is more difficult for the buyer to change the contract than the seller. However, in 1944 the courts told FERC that a bunch of calculations were not necessary to get the right answer, the end result is all that counts. Ultimately, this is not very much guidance at all.

In the 1950s, the court ruled on cases where the rates were considered to be too low. This is judicial activism. The Mobil Sierra doctrine is around, but the commission can always find the contract to be unjust, unreasonable, or unduly discriminatory.

Contracts are a good idea, but the fact that they can be adjusted or nullified is just a fact of life. For instance, almost all natural gas pipeline contracts have a Memphis clause, which allows rates to be reset based on a cost of service calculation, and FERC will validate it. It's an explicit clause in these contracts that lets FERC adjudicate the rate after a filing. The Memphis clause does not occur in power contracts very much, but was almost generic in gas contracts. This was the background in the cost-of-service world.

When market-based rates were introduced in the 1990s, the courts said competitive markets can or will produce just and reasonable rates. This brings back the balancing problem again. California seems to be the test bed for a lot of this stuff as for as it goes with Mobil Sierra.

For instance, El Paso Pipelines had demand contracts for California customers and full requirements contracts for east of California customers, who were smaller. The full requirements contract allows one to take whatever they want, and they just pay a volumetric rate. As the east of California population grew, they were taking more gas than required, and interfering with the contractual arrangements to California. The Commission corrected it. The east of California customers were a bit miffed but everyone else was comfortable.

This brings us to the 9th Circuit decision. The most troubling thing is that the FERC has this contracts review. If this is meant literally, both long and short term contracts, it's a huge problem. There's a massive amount of trading in these markets. It's not logistically possible.

Market-based rates were never contemplated by the FERC in the 50s, not until the late 80s. The market-based rate program at FERC starts in California in the 1980s where they gave Transwestern Pipeline market-based rates for sales for resale because they couldn't figure out a decent cost of service rate. They determined that Transwestern had no market power because their sole customer was Southern California Gas who had many alternatives. Transwestern offered a contract to SoCal Gas who were uninterested and Transwestern complained to FERC that they needed protection from their own market-based rate adjudication. Amazingly, the Commission did protect them. They're still on a learning curve.

One issue is that *ex ante* mitigation in the ISOs can satisfy a lot of the requirements of the 9th Circuit decision. In the ISOs, the Commission looks at the bids and adjusts them if are out of whack. They call this the "conduct and impact test" in the eastern markets. This process satisfies the considerable factors, broad scope, and timely review construct that the 9th Circuit is looking for.

The next troubling issue, addressed in Order 890, is that the Commission is embarking on mandatory planning conferences. They're going to do IRP and competition simultaneously, an interesting wrinkle. The Mobil Sierra doctrine is a double edged sword. The entities complaining about long term contracts and wanting the Commission to break them are also arguing that they are desperately in need of long term contracts. It's true, these long term contracts are going to become very expensive.

It will be an interesting debate going forward. I'll leave you with one of my favorite quotes from Ronald Coase, often considered to be a very conservative liberal economist, "Stock and produce exchanges are often used by economists as examples of perfect or near perfect competition. But these exchanges regulate in great detail the activities of traders (and this quite apart from any public regulation there may be). What can be traded, when it can be traded, the terms of settlement and so on are all laid down by the authorities of the exchange. There is, in effect, a private law. Without such rules and regulations, the speedy conclusion of trades would not be possible."

Question: On the regulatory compact, isn't the obligation to serve a critical part of that compact, too?

Speaker 4: I guess it could be. But there's no obligation to serve at the federal level. At the state level, it's a very important construct. There's been arguments at FERC about a federal obligation to serve. They currently have a fascinating debate that says that everything they regulate, with one exception, has a must offer requirement. The exception is sales for resale of electricity in interstate commerce, but they're all regulated under the same set of laws.

Speaker 3 - comment: In my presentation concerning sovereign debt I discussed how borrowers were paying in excess of the US Treasury rate an *ex post* premium of 1.5 or 2%. To clarify, that's the excess return on average. It doesn't look very dramatic. However, there is a dramatic effect on the volume. For instance, in the 1930s, you had debt default in many countries, and the sovereign debt market was closed until 1975. There was no lending whatsoever between 1930 and 1975. In 1975 the market for debt for emerging countries reappeared because of the recycling of petrodollars. Default occurred again in 1982 and the market closed again until 1992. There are huge effects on the volume of trade.

Question: Is there research analyzing the premiums and overall volume effects in these markets comparing treasuries versus high yield bonds? Has there been comparative review of sovereign debt laid against that backdrop?

Speaker 3: Absolutely. The emerging market debt has patterns which are similar to the junk bond market in the US. There is a correlation, even though the spreads are not exactly the same. They're a little bit higher for emerging markets.

Question: Is there a concern that the people who came in with a fire hose to put out the fire were also the arsonists?

Speaker 2: If in fact that's the case, then they should certainly be punished. However, there were other people who rushed in, because they saw an opportunity to make money. That's the whole dynamic, one wants the market to attract people when prices are high and the incentive is there. Those folks, the non-arsonists, were patently demonstrated not to have been arsonists, not even to have been fellow travelers of arsonists, never having been an arsonist in another state and so on. [LAUGHTER] They were just nice folks trying to put out the fire and getting compensated for it. The decision creates an incentive for people not to respond when you need them the most.

Speaker 1: How much did they charge for the water?

Speaker 2: Let's assume they charged a lot. They charged the going market price that was created by the arsonists. Even if we assume it's an unjust and unreasonable price (which I'm not willing to agree to in general), it's still not their fault. We shouldn't create a disincentive for them to come in and help.

Speaker 1: The law is set up that they have to charge a just and reasonable rate. If they were charging an unjust and unreasonable rate for the water to put out the fire, then the law requires relief for that charge.

Speaker 2: They could simply decide not to supply the water. The law doesn't require them to do that.

Speaker 1: That would be the choice of the market.

Speaker 2: Is that what we want?

Speaker 4: However, the FERC can construct an obligation to sell all the time. Must-offers and regulatory-must-runs are not uncommon. It's not necessarily a good thing. Nonetheless, it's very difficult to leave the market, the FERC can limit this. Once you build a generating facility, you don't even have the right to shut it down.

Speaker 1: Good enough. The state offered and attempted to prove that certain suppliers were the arsonists. They weren't just going after the kind, benevolent water deliverer.

Speaker 2: But the court didn't find them to be the arsonists. I would make the distinction to send the arsonist to jail and reward good Samaritans.

Speaker 1: In most states, laws will send good Samaritans to jail if they try to extort the situation.

Speaker 2: The court decision makes no distinction whatsoever. Perversely, if one qualifies for the public interest standard in a high price situation, there's not attention to the counterproductive effects of undoing the contract, and responding in the next crisis. Only the particular contracts are considered. Forget about customers in other states, or customers ten years from now. It's a narrow lens that the court requires for the FERC to consider.

Speaker 4: The conditions that the 9th Circuit puts on contract review are the messy problem. Timely review of every contract for just and reasonableness is almost impossible.

Question: An observation, the contracts under discussion were late in coming. In the summer of 2000, there were many contracts being offered at a nickel. The California PUC went out of their way to discourage those contracts from being signed. Nonetheless, that's all water under the bridge.

Going forward, the big problem is the contract reviews, with no distinction with respect to size, term, or anything else. Even thought there's only been two complaints filed by CARE on two contracts, this problem could become much larger. Where do you think this is going?

Speaker 4: I don't know how you review all these contracts. It's impossible to function.

Speaker 3: Couldn't a practical solution be that FERC says the markets are working fine here? If so, then the market prices are going to be considered just and reasonable. Occasionally, they may determine that the markets are not working well, and then they reassess.

Moderator: What does FERC have to do to ensure that the markets operate efficiently, such that a market price is a just and reasonable price?

Speaker 4: They're working their way towards this already in terms of mitigating market power and avoiding confiscation.

Further, the demand curve for reserves will help push the price up in times of scarcity so that assets aren't being confiscated. There is a legitimate role for mitigation. The *ex ante* mitigation in ISO markets satisfies the Mobil Sierra and the 9th Circuit decision. They're moving to get short term energy prices to a point where they're close to competitive prices. Once there, one can argue that bilateral contracts don't need review, because everybody has a just and reasonable alternative if they want to buy.

Speaker 2: People can get used to the idea that they don't get public interest protection. There is an undercurrent in the Mobil Sierra and other cases that came out recently, and in the complaint that CARE filed, which implies that market-based rates themselves are unlawful. That would stop market trading completely.

If it's true that the Commission already has enough protections in place to satisfy the oversight portion of the 9th Circuit's decisions, then why wasn't it enough for Dynegy to file its contract? The need to eliminate the post-hoc examination of the market. I don't see how FERC uses their conduct and impact test to take care of those considerations.

Speaker 4: The conduct and impact test probably eliminates 80-90% of the problems. It gets FERC close. If the 9th Circuit oversight requires perfect oversight then maybe market-based rates go down the tubes.

Speaker 1: The difference between 2000 and 2001 versus today is improved market mitigation by FERC. If somebody in 2011 decides they paid too much for a 2007 contract in PJM and goes to FERC they have to demonstrate that the market was dysfunctional. One can distinguish between functioning versus non-functioning markets. FERC would look at the factors that the 9th Circuit articulated. Considering the mitigation and monitoring in the PJM market, I expect they would find the conditions sufficient to produce a competitive spot market which disciplines the bilateral forward market for that contract.

The most troubling part of the decision is the review of every contract, it can't be done for short term transactions. The other things can be done, and they have been achieved to a great extent. It makes a subsequent challenge a very high burden for either Mobil Sierra, or just and reasonable. If a company has to show that a contract is not the product of a competitive market, that's a big burden. Once FERC makes a decision on this in a different context than the California energy crisis, it will show the market that burden, and confirm market based rates going forward.

On the Dynegy filing, they filed their contract under the rules in existence. It was an informational filing. There was no opportunity to review, nor to challenge the rates in that contract. That is different than making a determination that the rates were just and reasonable. FERC could amend its filing rules to put in place a mechanism for filing contracts. Those rules could be set up to give safe harbor for long term contracts. For a short term contract, a 206 complaint doesn't do you any good because one would literally have to file the complaint at the same time they entered the contract. That isn't going to happen.

For a long term contract, you could set rules. For instance, have a protest period for 30 days after the filing of any long term contract. The buyer and seller submit it jointly. A protest date is noted in the federal register. Who would be the potential parties to complain? State commissions, public advocates in various states, consumer groups. If they do there is a proceeding. If not, FERC can enter a contract approval. This is conditioned by the fact that there is a functioning market with proper mitigation and monitoring. It would be virtually impossible to alter a contract in 2011 in such circumstances.

Question: What is a workably competitive market? How and when does the determination get made? That's a fuzzy situation. Is it essentially a political determination? At the time of contract evaluation, would you also have to evaluate the market?

Speaker 4: A competitive market is hard to define, if you look at the Coase quote. All markets have rules. A competitive market creates just and reasonable. The FERC's conduct and impact test, along with the demand curve for reserves, moves towards just and reasonable. The Justice Department and the FTC probably don't like that idea. The Commission is proactively and *ex ante* making those rates just and reasonable. It generally satisfies the criteria.

Speaker 1: What do we do in bilateral or unorganized markets?

Speaker 4: If the alternative, real time market is a just and reasonable rate, then the bilateral contract is a recourse contract. Those markets are an alternative to paying the real time price; a hedge. Those rates are correct simply because there is a just and reasonable rate that one can go to.

Speaker 1: In the Midwest in '98 or '99 prices spiked to \$6000 or \$8000. Under the court's decision there's no conduct and impact test. If you signed a contract in that heat of that moment, or its aftermath, fearful of new price spikes, couldn't you say that the market's weren't competitive? The Commission has to assess whether the market was competitive or not – there's no pre-existing structure to use.

Speaker 4: That's a risk you take in non-ISO markets.

Speaker 2: The question is when and how the Commission will determine a market's competitiveness.

Speaker 4: The Commission is making the determination continuously; it doesn't wait for a contract to be filed at FERC. They're actively and proactively making these markets produce just and reasonable prices.

Speaker 2: Let's take the bilateral case in a non-market portion of the country and someone wants to enter into a long term contract. The FERC is certainly not determining that those contracts are occurring in a competitive market.

Speaker 4: I don't they've made very many competitive markets. There is a market based rate program where they let vertically integrated utilities demonstrate that they don't have any market power. They pass it less and less, and only outside their own control area.

Question: Let's suppose that there is a relatively dysfunctional market. Can the imposition of burdens or risks associated with contract sanctity create barriers to that market so that it can't progress to a robust well functioning market? Is that a reasonable concern?

Further, is it in the public interest to be able to progress to a well functioning market? How would one characterize the sovereign debt market? Are there certain sovereign markets that do function well, such as the U.S. securities or treasury market? Can one characterize sovereign debt as having a functional market with a lack of contract sanctity?

Speaker 3: It is a functioning market, except that there are these risks that these contracts cannot be enforced. In fact, it's pretty remarkable how right the market gets the premium in terms of what the *ex post* risk of defaults is. People anticipate what may occur in those markets and they price it right.

Countries certainly build up credibility. When the U.S. was formed as a nation, there was a debate as to whether the debt of the colonies should be respected or not. They decided to honor the debt and that's why the U.S. market continues to be robust. The prices simply reflect the risk.

Speaker 2: That's a different view of what a functional or dysfunctional market is than the 9th Circuit had. There's no FERC regulating the rates. If generators simply stopped responding in moments of crisis when the lights go out; that's not going to be a tenable solution.

Speaker 4: The market just described is probably as close to a laissez-faire market as you can get, because there is no government to enforce the contract.

Question: These cases examine attempts, essentially by the buyer's side, to get out of contracts. Will these cases affect the ability of suppliers to get out of contracts, particularly through bankruptcy? For instance, the Calpine case working its way through the court and through FERC. When a buyer look at the potential for a supplier default, increased default risk means that they want higher credit provisions, or higher collateral. This also creates a premium in the contract.

Speaker 3: In sovereign debt contracts, countries do a lot to prove to the lenders that they're in good shape so this risk generally doesn't appear. They try to run up reserves, run up budget surpluses or whatever. That's the analogy in sovereign debt, I'm not sure about the electricity market.

Speaker 1: I'm familiar with the Calpine case. It's one of several cases in the last few years in which suppliers have gone into bankruptcy and sought to reject long term contracts. They do it because the financials of the contract were not in their favor at the time of rejection. So in Calpine's case, it identified a series of contracts that it sought to reject in bankruptcy and avoid the contract. Under the Federal Power Act there is the obligation to serve clause so the question is whether this trumps bankruptcy law. The sellers, in particular in the California crisis, have said the Federal Power Act is the pre-emptive body of law which pre-empts all state law claims except in the context of bankruptcy.

Speaker 2: The FERC's gotten the bankruptcy cases completely wrong. Further, there really isn't any obligation to serve. There's a lot of ways that someone can leave a contract. It's like the Paul Simon song, 50 Ways to Leave Your Lover. One can prove mutual mistake, fraud in the inducement. Bankruptcy creates an organized breech. The legal remedy for that is to pay damages. However, the damages are diluted by the fact that you're in bankruptcy. All these things exist in wholesale electric contracts, credit departments deal with them. The problem with the Mobil Sierra cases is they are a contract breeching without paying damages.

This is very different than common bankruptcy, because there's no damages involved.

Speaker 1: There's a distinction because utilities don't sell widgets. They sell a commodity regulated and governed by the Federal Power Act and its provisions. Anyone investing in this arena knows it is a regulated commodity that requires just and reasonable rates. A wholesale power contract is clearly a filed rate. On the one hand, the sellers resort to the filed rate doctrine, because it is a filed rate. In this context, they cannot bring a claim in state court, at least in California, challenging the business practices of these contracts. The filed rate doctrine precludes them all. The contract has to be subject to jurisdiction in at least some circumstance.

Speaker 4: The filed rate doctrine is only a doctrine. You won't find it in the Power Act or in the Gas Act. Most of this law was that most of this law was made in the context of cost of service regulation. It doesn't contemplate markets and market-based rates. Lately, it's become difficult to have a rational discussion.

Question: I've been told there will be legislation soon in which the Illinois AG is invoking 9th Circuit to challenge all of the Illinois auction results. They cite many of the criteria for allowable contract default that Speaker 4 discussed in their presentation.

The indicia of market failure here was the fact that the contracts were well above the seller's marginal cost. Second, they were out of sync with the bilateral market. Therefore, it's a clear demonstration of market failure. They invoke 9th Circuit and since the contracts cannot be reviewed, they want them abrogated and refunds paid.

So clearly the 9th Circuit decision seems to open the door, and we can expect more of these types of cases. Second, we really do need some hard and fast definition of a workably competitive market. Is the Commission prepared intellectually or legally to make that determination? Further, in Illinois, what kind of seller is going to come forward after these contracts get redone; what kind of prices will people have to pay?

Speaker 4: It seems that long term contracts may disappear. Using the criteria discussed in sovereign debt cases, they price in the risk of default, and then at about year five or so, arguing that there's been no default, it's time to default. Nobody signs more than a five year contract.

Speaker 1: FERC should develop a competitive market definition for the purposes of power markets. If they're going to rely on markets to produce just and reasonable rates, they should know what a competitive market is. It should be possible to test and define it.

Second, there's a big procedural difference between a change to a long term contract versus a default. If a party stops performing, they are liable for the cost of a replacement contract. It's the measure of damage. Further, it goes to a state or federal court, not FERC. The only way to change a contract is to go to FERC and ask them to modify the contract under section 206. This is a big difference from the developing world where they can stop paying and there's nothing that others can do. The burden is on the party seeking to modify the contract to prove necessity.

Speaker 3: We'll have to see how the Illinois situation plays out. Even if a particular rate exceeds marginal cost, it may be fine. So we have to see how the decision is actually applied. The two conditions – prices above marginal cost, and contracts out of sync – are not what an economist would see as a problem in a working market. This challenge could get dismissed completely, and then it's not a problem at all.

Speaker 2: It's possible that this FERC will remand and hold against California because they haven't proved that the prices in the contracts are beyond the normal oscillations around long or marginal costs that one would expect, given the various risks that existed at the time. There is a concern that a differently composed commission has a different view about a working market. They could decide that if one is paying materially over the cost of fuel on a short run basis, it's a problem.

California doesn't have scarcity for reserves or a capacity market. This creates a new yard stick that could be laid against current contracts, similar to the arguments made against the contracts in the 9th Circuit decision. It's not clear how the standard will be applied down the road.

Speaker: If FERC, on remand, determines that the contract rates in the California market were just and reasonable and the product of a competitive market, then that precedent would ensure that no contract would ever be touched.

Second, subsequent FERC commissioners have to be able to use their regulatory authority; look at the facts and make a determination. If not, then we don't need a regulator. Invariably, when there's public interest there are political changes, whether they're just and reasonable, and a different commission can decide issues differently. Until Congress changes the law, the Commission has the authority to determine just and reasonable.

Speaker 4: The debate in Chicago, Connecticut and the East is about divestiture contracts that took place ten years ago. There's no sentiment by the Commission to correct that issue. The arguments are that utilities sold off assets too cheap and that the Commission should go back to cost of service and calculate generator rates based on original cost. I don't think the Commission will do anything with it.

Question: What do we do going forward if there's an emerging emergency? I can't envision how a company with no obligation to get involved would decide to do so. For one thing, there's no timely way for a company or anyone else to determine whether the market is truly functioning.

Speaker 4: Let's consider FERC's order in December 2000. They tell California to get out of the spot market and enter forward contracts. In the order, they recognized that it could create a seller's market in the forward market. They said they would establish a benchmark to assess those contracts, and consider the justness and reasonableness of the rates. In essence, they issued a decree that said public interest is less important, there's a fire and we need people to come in. However, they also said when you come in, we've reserved the right to look at the justness and reasonableness of the rates. That didn't slow down suppliers from coming in and bidding. CDWR received something like 120 bids from sellers, or more than that, for power. Many made bids at very high prices. However, FERC did follow up on its order.

In the future, if FERC in a crisis declares that a market is out of alignment and that any contract will be subject to a just and reasonable review, I'd be surprised if that would dry up supply such that the fire would burn the building to the ground while the generators sat there.

Speaker 3: Maybe the suppliers come but at what price? There's certainly some uncertainty there.

Question: Do "must offers" extend to Canada or the publics, for example? Over 20% of the power in California is imported from out of state. While there's a must offer obligation on in state generators, or perhaps even FERC regulated out of state generators, how does that extend to publics and other countries?

Speaker 4: The Canadian provinces have filed reciprocity tariffs. FERC could cut that deal with them, that there's a must offer. However, the munis are not necessarily subject to this.

Question: How is the public interest defined? In Mobil Sierra, it seems public interest is promoted as a reason for contract non-enforceability. However, we've heard how unenforceable contracts have a clear cost to the public, however measured. Is it possible that FERC or the courts could say that there's a public interest in having stable contracts, even if they don't know whether a contract is just and reasonable?

Speaker 2: One problem is that the 9th Circuit has tightly determined how the Commission is supposed to apply the public interest standard. That may be the most difficult part of the decision. The public interest standard collapses back to the J & R standard. The Commission has to give "predominant weight" to the financial interests of the consumers. It doesn't leave a lot of room for the important countervailing factors that you're raising. This is distasteful. The 9th Circuit is a reviewing court. The Commission is supposed to figure out what is important in a public interest inquiry but they aren't given that freedom.

Moderator: The public interest here is defined as the public who are the particular buyers for the term of that contract for the power that they were supposed to get, not the public as a whole.

Speaker 2: I'm not sure it's limited in term. Ultimately the broad public will be worse off.

Speaker 1: Mobil Sierra defines private and public interest differently. The public interest is the interest of the ultimate consumer. The return that the shareholders of the utility make is not the public interest. FERC is supposed to care about the consuming public. That is the focus of the 9th Circuit. When the buyer, the state of California, is buying on behalf of consumers there's clearly a public interest. The 9th Circuit decision could be read in a way to account for those factors – i.e. public interest may be in functioning markets, and not just strict cost.

The 9th Circuit has been criticized for setting specific factors of public interest. However, the sellers, i.e. the plaintiffs, strongly argued for the three strict factors of public interest that the Supreme Court set in the original case in 1956. Either Courts should be able to set strict tests, as both the Supreme Court and the 9th Circuit did, or not.

Question: Anyone that offered contracts during that time in California knew they were dealing with an unstable market situation, and that there was risk of future review. Alternately, generators were needed to supply the power and enter the market under a high risk situation in which no one knew what future prices would be. Is the risk these generators took worth some compensation beyond cost of service that could be considered just and reasonable?

Speaker 1: FERC still has to look at the actual rates and determine if they were just and reasonable. How does one determine a just and reasonable rate in a market context? One way is to demonstrate that the market was competitive, if so then the prices are fine. If you can't rely on the market, then one has to resort to long run marginal costs. Certainly one has to factor in the risks associated with the contracts. Even under a cost of service approach, there is a risk assessment. It's a different and enhanced risk assessment in a market context, but it needs to be done. However, many of these contracts with the state of California were for 11 years without gas, supply or delivery point risks. There's less risk proposition than one might think otherwise.

Question: Weren't the contracts undertaken in a market situation? Weren't they auctioned?

Speaker 1: It was a bidding process, the state of California issued an RFP. It was a unique situation. I know of no utilities that have bought $43 billion worth of power procurements in less than three months. There will certainly be arguments about how competitive the market was.

Speaker 2: The rates will be high anyway. If there's the expectation that these contracts are going to be broken, there needs to be a high risk premium on a cost of service calculation, and so the rates may end up higher in any case.

Speaker 3: There are a number of ways that economists have for determining market competitiveness. It could be an interesting debate. One key issue is entry, do people come in and compete. There were a lot of bidders so that would make the case for a strong market.

Question: We've heard that the traditional formulation of Mobil Sierra acted as insulation against changing political winds. We've also heard that we may see long term contracts disappear. Long term contracts are essential to the political sustainability of the competitive market model. They solve the intergenerational equity problem. The competitive market model depends upon scarcity pricing. It costs a lot, there's a lot of investment risk associated with new entry. Prices sometimes have to get high for a sustained period of time, longer than the election cycles. Long term contracts solve that problem, and in essence they hedge customers. If they disappear, then markets could also, because the real volatility and lumpiness of markets in the short term will not be politically sustainable. Perhaps capacity markets may be the safety valve here. What is the outlook for the competitive market model if we have to live with the 9th Circuit's decision?

Speaker 4: I'm not sure what the FERC can do about long term contracts. This is a strange confluence of events today. There are risks in FERC abrogating contracts but just as much in determining future energy costs. Every technology has a huge risk associated with it. Intermittent energy has intermittent energy tax credits. The future of coal is risky given climate implications. There are huge projects that will be bringing huge amounts of coal from one region to another, and nobody knows what the future of coal is. Nuclear is still unclear. Natural gas has its own volatility problems. Everyone wants long term contracts, but they have significant risk. We just don't know how to sign a long term contract any more.

Question: Is one of the problems that load serving entities cannot build their own generation, so there's no check or balance on the market? For instance, California load serving entities could not enter into forward looking contracts, they had to buy on the spot market, which created the problem. Should load serving entities, coupled with the state, build generation at cost of service? Then, in the RFP process, generators have to beat that price?

Speaker 4: FERC has never prohibited long term contracts. That was CPU imposed. Vertical integration, by virtue of long term contracts or by ownership, is a decision made outside of FERC. Traditionally, the franchised utility built the assets. Competition is supposed to improve on that. It opens up the market.

Long term contracts are important, but they should be a local decision, state regulators or the munis. FERC should concentrate on issues like transmission, that make the short term market as competitive as possible.

Question: How do we distinguish between arsonists and firemen? Second, given the notoriety of the California market, how do we know whether the sellers haven't priced contracts with risk factored in already? If so the risk premium was paid in the contracts, and the 9th Circuit results were part of that risk.

Speaker 2: The argument is that the sellers either already priced the risk into their contracts with California, or they should have priced it in. If they didn't, they're fools. They've been compensated for the risk they took.

Speaker 1: It's a very good argument.

Speaker 2: It can't be the right thing to create a self fulfilling prophesy in which we lower the threshold for modifying or abrogating FERC regulated wholesale contracts. Thus sellers should price them as they will, get their money while they can and if their number comes up, then they lost the risk. This will create even higher future risk premiums. There's a lot to be said for contract stability and certainty. Needlessly creating risk premiums that needlessly increase prices is a bad thing. Correcting that by maintaining contract stability is one of the easiest ways to lower cost to consumers.

Speaker 3: I don't know if contracts being signed today carry that premium, it's worth looking into. I also don't know if the contracts in the California case priced in this risk. Maybe yes, maybe no. One can proceed the Evo Morales way, Bolivian president, and expropriate industries that were bought cheap.

Or one supports markets that dispel uncertainty. Then, in the future, the risk will not be in the contracts and they'll be cheaper. That's the way that one should go.

Question: There's a mantra that we need long term contracts for the market to work, and we need an alternative. The alternative is that buyers build it themselves, it's not a contract actually. They own the physical asset.

The results from the sovereign debt example that are a concern are not the high prices but the decrease in volumes. A market can function with high prices, but not without volume. Then the regulators begin to believe it's cheaper if the utilities own it themselves. That's rate based investment; physical ownership; it's not a financial contract. That's what's happening in capacity markets and in other areas. We're going in that direction.

Some might say that's not so bad. However these markets support financial contracts and the FTR, the Financial Transmission Right. FTRs are the only solution to link distant generation to load over a long period of time that solve the problem of contract paths and TORs.

This ends up in a situation where power plants can't get built competitively. It completely unravels the assumptions that allow the market to operate, and puts us back into the rate based solution.

Speaker 1: Utilities are restricted often from doing more than a 3 year contract. If they weren't, then the person who bids into an RFP knows there is an alternative that will make their rate just and reasonable. This creates a check on prices.

Speaker 4: When you can't get efficient entities to come in and build plants, you get inefficient entities. They build them with current technologies, the equivalent of cost of service. Inefficient generators get built which costs consumers. The new technologies in coal, nuclear, renewables, or even natural gas depend on efficient operators who have incentives to be efficient.

Session Two.
A Consensus of Inaction: Demand Side Opportunities and Consumer Culture

The willingness to reduce consumption in response to high prices is a critical element of a competitive market. There is a consensus on the need to have effective demand side participation in competitive electricity markets. The consensus has led to only modest action. There are both supply and demand side reasons for the lack of widespread and effective demand responses.

On the supply side, interruptible tariffs were fixtures of regulated markets long before effective competition emerged. In competitive markets, it was hoped that those arrangements would be greatly enhanced by customers selling back supply in competition with energy sellers. The practice has not been as effective as desired. Many have observed ineffective market rules enabling more vigorous demand side responses. Others have suggested that the price signals have, for regulatory or other reasons, been diluted. What defects, if any, in the market rules or price signals have had adverse effects of demand side response? What can be done to remedy the defects?

On the demand side, the reasons for the limited demand response may be more submerged in custom, culture, and behavior. Why have some customers responded and others have not? While some of the reasons for the varied responses may be found in the nature of commercial and industrial processes and consumer behavior, culture may explain more. To what extent are plant and facility managers given incentives to increase production rather than to produce profits? The debate over the decoupling of sales and profits for utilities may have the mirror image issue in many industries that might do better financially if they decouple production and profitability. To what extent does the centralization or decentralization of decision making in corporations play a role in capturing or foregoing the opportunity to effectively respond to energy price *signals? Do businesses devote inadequate attention in general to energy management? Are the stakes ever sufficient and efforts uncomplicated enough to entice small customers to respond? Succinctly stated, to what extent is the disappointing response to demand side opportunities the result of corporate and consumer cultures that have failed to adjust to new opportunities?*

Speaker 1.

I will focus on demand response in the ISO context, particularly on reliability-based and economic programs. I'll focus on the New York ISO in particular. New York has 162,000 GW hours a year. Their peak load last year was 33,939 megawatts. There is 39,000 megawatts of capacity. in the state. There are 324 active market participants, an active group. They have a co-optimized energy and reserves market with day-ahead and real-time markets on the energy side. The co-optimization requires that they simultaneously solve for energy and ancillary services in the markets, on both a day-ahead and real-time basis. They have scarcity and shortage pricing, for reserves and in the demand response programs. They have an LMP locational energy market.

Electricity clearly faces problems of inelastic demand and supply. It's still a challenging problem. Demand response helps create that elasticity. Further, there's reliability benefits. There's a potential to reduce market power, but that hasn't occurred a great deal in New York.

New York has opportunities for demand response in the capacity markets. This is a reliability-based program where participant's only obligation is to operate during operating reserve deficiencies. They are opening their ancillary services market to demand response this year.

For several years they've had the opportunity for demand to participate in the energy markets. The two programs are the emergency demand response program and their ICAP special cases resources program. The ICAP provides opportunities for people to participate in the capacity market and the other pays them for energy reduction during operating reserve deficiencies. These are initiated by the ISO, the customers do not get to determine when they will participate.

They have 1,600 to 1,800 megawatts of load reduction in the emergency programs. There is 389 megawatts in the economic program but the percentage that participates on a regular basis is only about 10 to 15 megawatts.

New York is considering opening their markets for ancillary services participation too. It's a challenge in two ways. First, from a modeling standpoint to schedule the resources. Second, from a settlements standpoint. They have to meter monitor and provide a proper settlement that reflects a balance in load and financial settlements, both day ahead and real time. They're still figuring it out because some resources may be in bilateral arrangements where both parties load is not visible to the ISO other than as a load. It needs to be explicitly identified as being scheduled. These programs have to be able to fold indirectly into the market design as completely as possible.

During summer peaks, New York has had almost a thousand megawatts of load response. Similar for PJM. Despite this strong response, there's a limit to the wholesale market, it can only go so far. There's a real role here for retail programs that allow people to see "real time price." Retail and wholesale could truly function as complementary programs.

The interesting program is the day-ahead demand response program. It allows demand response resources to offer into their day-ahead market and offer as if they were generation. They are scheduled as a generator would be in the day-ahead market. They provide the same kind of bid that a generator would provide, incremental energy and minimum generation. There is also a minimum start-up cost bid. It is scheduled or not scheduled the same as all other bids. If it's accepted, they have a financial obligation to carry through with it in real time. A resource with 5 megawatts of load reduction can be scheduled as if it were 5 megawatts of generation in the market.

389 megawatts are registered in the program, but there is only about 5-6 megawatts scheduled a day. There are about 25-30 resources but only about 5 that are more constantly active. When the program was put in place, these resources could bid at any level they wanted. They could be price takers. They could put a zero incremental bid. Soon the ISO realized that the offers were being scheduled around late November, late December, or the Fourth of July weekend. Generators were scheduling themselves during plant shutdown, which was not the intent of the program.

To counteract that, they instituted a minimum offer now at $75 per MW hour. It did have quite an effect. It reduced participation somewhat, but smoothed out the participation and addressed the issue of free ridership.

Last summer they saw about 75% more megawatt hours scheduled by these resources than the previous year. It still only averages about 5 to 6 megawatts on a typical day. It is not yet creating major price sensitivities or elasticity. Every year they file a Demand Response evaluation with FERC. There's a tenth of a percent reduction in LMP as a result of these resources being scheduled. So it's still small, but it is measurable.

There are about 5-7 reasons there isn't the response one would like from these programs. First, the resources who participate most in these programs are also ones who can participate in reliability programs. They're the ones who step in during operating reserve deficiencies. They have greater potential for being scheduled in reliability situations, and can potentially be paid more, so they wouldn't bid in at day-ahead.

Second, LMPs really aren't equal. Many of the resources that have the kinds of facilities and operating characteristics for this kind of program operate in the western part of New York, which has the lowest prices. Average prices are probably less than $50 a megawatt hour. If they have a $75 floor price, there's a small number of hours when they can participate. The larger industrial resources that are upstate see lower prices. New York City covers half the load in New York. It has a lot of resources participating in reliability-based programs but not in economic programs. These are commercial and light manufacturing-type programs. The city resources have to aggregate to participate, because there is a 1 MW minimum in the day ahead market. The aggregation requires a third party to do the scheduling and that complicates matters

Participants have to be able to provide meter information to the ISO for settlement purposes. There's tons of meters that measure load, but unless you've got an algorithm for figuring out what the load should have been during that period when you didn't consume it, then you've got to do calculation. The ISO has a method but the calculations are done after the fact. If a third party aggregator is involved, some of the savings go away, and the payments are delayed – this creates a disincentive.

Another issue. There's benefits in the state creating economic incentives for businesses, particularly in the upstate region in New York. Bilateral contract prices aren't necessarily consistent with an LMP market. These bilateral resources do not see any deadweight loss so their strike prices are pretty much irrelevant. There's no benefit for people in bilateral contracts to schedule through the ISO programs.

Further, the New York State Department of Taxation told the ISO to make sure all the contracts are sale for resale-type contracts. Otherwise the ISO is held responsible for collecting sales tax and gross receipts tax. This requires a shell organization or a third party to treat this as a wholesale transaction. This creates logistic and bureaucratic transaction costs.

Now our markets operate on a day-ahead and real-time basis. Certainly people can submit offers for up to two weeks in the future, but you're only being scheduled for one day at a time. And they felt that that provided a bit more risk than they were willing to accept, based on their process. So I think some of that has precluded some megawatts that otherwise would have participated. And I think that is somewhere between five and seven comments, so I'll stop there and see if there's any clarifying questions.

Question: Are any of the ISO customers also retail customers of utilities?

Speaker 1: Yes.

Question: Can you clarify the timing of the decision on exercising reliability curtailments versus the day-ahead? How does the greater of LMP or $500 interact with the operating reserve and the LMP calculation?

Speaker 1: The ISO must provide 21-hour advisory notice for the reliability-based programs. They need to notify people by roughly 5 p.m. the day before. The schedules for people bidding in the economic program are in by 5 a.m. of that day. The $500 in the ISO's reliability-based program is used as a scarcity pricing mechanism.

When they activate the reliability programs, the software checks at 5 minute intervals to see whether the demand response resources were needed to preserve their operating reserves. If they were, the $500 or their strike price, is used to set LMP for either the eastern state or the entire state, depending on which reserve criterion was violated. There are times when these resources set price for all suppliers in the state.

Question: Could you define what you mean by ancillary services demand response?

Speaker 1: All of the reserves markets, 10-minute spin, 10-minute total and 30-minute, plus regulation markets.

Question: Is there any correlation of the little amount of day-ahead DR to actual day-ahead prices or real time prices?

Speaker 1: There was some. Every offer submitted is typically at the $75 floor. A lot has to do with the resource location. There is some bidding in the spring and fall where prices were typically lower.

Question: Can you clarify the load reduction calculation you discussed? You have to have a baseline to calculate load reduction, but if the entities are always price-sensitive, how do you calculate a baseline?

Speaker 1: You don't really want to know the answer to that, do you? [LAUGHTER] Normally they just look back ten business days and pick the five highest periods if they were scheduled from noon to four, they find the five highest noon-to-four periods over those 10 days. They average the like hours of each one of those periods, and that provides a proxy load. They can move back further, 30 days is the maximum.

Question: When emergency units come on and the $500 is triggered, do they assess whether they were actually needed? Can they be called on and running but not setting price if they weren't actually needed? Or do they always set price when they're running?

Speaker 1: They dispatch resources on a 5-minute basis. If they are needed, they will be setting price. If not, they won't be. It's an imperfect world.

Question: So what does set price in those instances?

Speaker 1: When they aren't being called, the marginal generator that's supplying the system sets price.

Question: Is the challenge in aggregation that third parties are not allowed, or that there are not many of them?

Speaker 1: The business model isn't evolved enough for these folks to participate in the economic program. It certainly has in the reliability program. There are 25 to 30 entities in that program.

Question: They're choosing to go there for the reasons you outlined?

Speaker 1: That's right.

Question: Can participants be in both the economic and the emergency programs? Can you do both at the same time?

Speaker 1: Yes. an exclusion was considered but there was concern that it would reduce participation. They can actually do both at the same time. If they've got a day-ahead obligation in the economic program, they have to satisfy that first. And if they give us any additional energy in megawatts, they get paid for that.

Question: Small demand isn't allowed to participate because it was a burden on the optimization program. Has that been tested, or is it an assumption?

Speaker 1: They haven't tested it. It's an observation of the ISO that it would create a heavy burden. There's anecdotal evidence from PJM that supports that.

Speaker 2.

I'm going to focus on three things from an end-use perspective. What is demand response? What are the benefits of demand response? What are the barriers to demand response? I'll specifically look at these issues from the perspective of a large global industrial group.

Many of these businesses are extraordinarily electricity intensive. Electricity is a raw material for many of them that can be as much as 40% of their input. Low prices and little volatility are critical. These industries have a high load factor and steady consumption.

A definition for demand response is the ability of electric consumers - industrial, commercial and residential - to modify patterns of electric use at times of peak load to affect price and reliability. Industrial load can often respond in a more efficient manner than some generators. They can provide a precise amount of load rejection or virtual generation at the time it is needed. However, they need the right incentives. These incentives should be equal to those of generators or other DR providers. Simply avoiding peak costs isn't enough. There's been a reluctance by planners and system operators to depend upon demand response as a planning tool. Historically it wasn't always dependable, but with proper incentives and conversely with penalties it is reliable now.

DR can relieve transmission congestion as well as reducing overall load. Doing this may be faster than redispatch of generation, minimizing the amount of time that the grid is under contingency conditions. Oftentimes reducing the system by just a few megawatts can relieve a problem. Even a reduction of 50 megawatts can significantly impact locational pricing.

Responsive load can also reduce the need to use less efficient generation in times of peak demand. However, demand response is not the same as energy efficiency. Energy efficiency involves using less energy for the same process. Demand response means using energy so supply is economically and environmentally optimized. It can reduce the need for new generation, especially less efficient, rapid start units. It can fill a void while generation tries to catch up with load growth.

It can be seen as a form of alternative energy because it reduces the use of fossil fuels. Also it may complement some alternative energies if it's used to match up with generation such as wind and solar. It provides environmental benefits because demand is shifted to times when environmental sources are available, and reduces the need for environmentally destructive peak units.

It can help moderate prices. When load is able to respond, operators of the grid will avoid starting higher cost units.

Let's look at the barriers to demand response. There needs to be a paradigm shift to occur for both system operators and for users. Operators need to rely upon demand response. The responsive load needs to be incentivised, and penalized for non response, the same as a generator incentives.

On the industrial side, manufacturers need to change their mindset of making product at any cost to weighing the value of shifting production energy prices. This requires a change in management incentives for industrial plants. Plant managers are rewarded based on production goals based on making product at any cost, versus weighing the value of making metal or product in one hour and making less during another and trying to make it up later, in response to energy prices. That's a shift that needs to occur for the industrial sector.

This can be difficult because the stability of the industrial process cannot be disrupted in certain situations. Moving the electricity input around does upset the process, and if there were production people in this room they'd be throwing things at me. There needs to be a mindset change to allow for upsetting the stability for a short term, in return for price moderation. Many large industrials have the necessary monitoring equipment in place to begin responding but policies need to support that response. There was a comment earlier that noted that no meter can measure load reduction.

Instead of programs for demand response, markets for demand response need to occur. The rules are not fully developed in organized markets, and don't always provide incentives that reflect the full value of load responding. Industries are ready to provide responsive load to the grid to help moderate prices, not to make tremendous profits from selling their load back into the system. They want to be able to continue to operate in North America.

Question: In New Jersey steel companies have been complaining that their participation in demand markets responding to price signals has caused a lot of wear and tear on their equipment and that it may not be as worth-while as they had hoped. Now many of them are considering long-term fixed contracts at coal prices. How does the wear and tear fit into the stability issue when industrials consider participating in demand markets.

Speaker 2: There's no doubt it doesn't work for all industrials.

Question: Is the decision to participate in demand response programs influenced by hedges or long-term contracts?

Speaker 2: That would depend on the structure of the contract of course. Generally, yes. A long-term contract at coal-based prices would be different than one indexed on gas price.

Question: What's the distinction between demand side response programs and demand side response markets.

Speaker 2: Demand response programs were perhaps mandated by states or by public service commissions. That's a program. They say, we're going to have an interruptible program, get on this and we'll give you a better price. But an industrial may never use it. Markets create real participation, with benefits for both sides.

Question: A quick ballpark estimate. If the culture became more open to variation, what are the possible shifts in load? 5%, 30%?

Speaker 2: It depends on the product needed, and the flexibility that they're allowed. If a participant can provide response on an hourly basis, with smaller loads – e.g. 20,50, 100 MW – then it's easy. If the period is for 8 or 24 hours, and it's 300 megawatts, that's much more difficult. 10 or 20 MW would be even better.

Speaker 3.

I'm also to going to consider some issues for industrial users, particularly users who spend up to 75% of their variable costs on electricity. Some of these facilities use machines with 30,000 horsepower. However, in some cases they can shut them down without significant disruption.

There are logistics and inventory concerns, and some small amounts of wear and tear, but the net benefits of providing demand response will exceed these cost factors. Some of the facilities I've seen that have used interruptible arrangements had a very difficult time implementing them. There initially was a lot of resistance from the plants. As discussed earlier, it took a robust change in culture.

Some plants had concerns that by taking an interruption they would run their customers out of product, incur excess premium costs to supply their business, or wreck motors. These facilities needed a great deal of internal coordination and selling to convince folks that the benefits outweigh the costs and risks. In some places, some of the early naysayers have become some of the strongest advocates, now that they see how it affects the economics of their plant.

As some of this change evolved, plants in some states actively tried to improve flexibility in this area. They would install sophisticated metering to better dispatch through an entire system. Telemetry would be used to link with central or national offices. They coordinated plant maintenance activities so that the down time was put to good use. Some plants have watts transducers on their motors to facilitate demand response.

One of the largest issues is for large companies with multiple facilities. They're taking this concept one step further by optimizing multiple factors, developing mixed integer mathematical programs that address a specific facility, but also a bunch of facilities in an entire region. They optimize that whole region, telling the plants how to run, assigning customers to plants. The bottom line is to optimize the total costs to supply that entire network. In that scenario they may even have one plant that is sub-optimized, but for the good of the whole.

I have three issues to discuss. First, demand response should have all the opportunities of generation to provide energy capacity and ancillary services. Secondly, it should be encouraged and fairly compensated for the significant economic and reliability benefits that it brings. Third, all qualified load should be eligible to participate in demand response.

Clearly DR is efficient, reliable, and environmentally friendly resource that really ought to be getting tapped into. In some places demand response has been hindered by generators who see demand response as an increase in competition. Sometimes facilities have access to one kind but not the other in ancillary services, energy and capacity. Sometimes there's no access at all. In certain areas of the RTOs, demand response gets lower priority than the development of new markets or capacity constructs in the stakeholder process. There have been filings to get demand response into ancillary services markets that get addressed after demand curve capacity markets, it becomes second priority.

In some RTOs there's extensive talk and references in the market tariff, but no significant action or opportunity from a customer's perspective. Demand response has not been integrated into their operations, but that doesn't stop the RTO from wanting utilities to call for interruptible customers when there is a problem. Even metering requirements are a barrier to entry. Being able to look at interval data every few seconds is overkill for demand response – they could simplify meter requirements significantly.

Second, demand response should be fairly compensated for the significant, economic and reliability benefits that it brings. Minimum prices and event durations can be helpful in motivating demand response. An opportunity for 500 MW for a few hours is more motivating than opportunity for a few MW for five minutes. Having a demand response event be a few hours long is not unlike the cycling requirements of certain generators. Once they start up, they want to be running for some period of time. There should not be generation offsets to demand response. If load is balancing supply and demand in the marketplace by DR, it ought to be paid to do that.

Ease of use is another way of encouraging demand response in places where systems are well automated, everything from a CBL determination to settlement. If it's simple and easy for the customer, they'll be better response, than if they have to render an invoice to the RTO to get paid.

Demand response should be made permanent in the tariff as opposed to being a unique program, whose future may be uncertain. This creates regulatory certainty and let's participants make real investments towards changing their systems in ways that will accommodate DR. Existing programs which have performed well historically should be maintained. In some places, there is movement to get rid of interruptible rates and replace them with less compensatory mechanisms at a time when the need for DR is high. In one state existing programs are being eliminated, and the replacement is weak. There's a potpourri of new programs that are unappealing and unlikely to gain participants.

The full value of demand response created by load should go to load. Some generators have discussed a new concept of stranded cost. If demand response ends up lowering the LMP and the compensation that the generators are getting, they want full compensation as if the DR hadn't occurred, which obviously defeats the purpose of the entire program.

Finally, all qualified load that can provide demand response should be eligible to do that. Inappropriate barriers to entry should be eliminated. These include metering, or federal state conflicts. There's been jurisdictional issues that have delayed implementation of DR programs.

Demand response should be encouraged where there is none at all. There have been situations when industrial facilities have gone to a utility to leverage demand response for mutual benefit, with no positive response by the utility. The same facility then wanted to expand their presence and load on the system and were told there wasn't sufficient capacity. So on the one hand, the utility has plenty of capacity, they don't need any demand response, and alternately, they don't have enough capacity to provide.

Demand response can serve multiple needs. If demand response capability is providing value into one program, that shouldn't restrict it from providing in another demand response opportunity, as long as they don't conflict. For competitive markets to have a prayer, demand response has to have every opportunity to participate in these markets.

Speaker 4.

I am going to discuss the Community Energy Cooperative, an energy program of a Chicago nonprofit called the Center for Neighborhood Technology. CNT spent the last 30 years working on developing strategies to build sustainable urban communities in the intersections of environment improvement and economics. In Illinois, deregulation was driven by large industrials, utilities, and others. However, CNT was interested in what they could do to encourage energy efficiency and lower residential energy costs. They focused on real-time metering and demand response. Before I discuss this program, let me focus on some general policy issues.

Do the rules for consumers encourage them to change their demand in response to prices? For the most part no. First, lack of transparency. Initially the local utility had an hourly rate for large industrial customers but to find out what the prices were, you had to sign up for the rate. That didn't make any sense. You couldn't find out the cost of a product until you had agreed to buy it. This has changed in the organized markets. Price transparency in PJM, MISO, or ISO New York occurs but this problem still exists in other areas. For instance, the prices for industrials in real time pricing programs in Georgia are not available, they say "we can't show those, those are our marginal costs." This is a real problem; prices shouldn't be secret.

Second, a proper evaluation between risks and rewards is needed. If the program is asking people to pay for something differently and there's some risk involved, there needs to be some rewards. Revenue neutrality, the need to keep all prices the same, even as they're unbundled into their components is really an issue. Built into flat rates is an insurance premium. If people pay variable rates, then insurance premiums should go away. Our concern with a lot of variable pricing rates is that doesn't always properly happen. If the risk and insurance built into rates is unbundled, then it creates an opening for variable rates that can account for them. This increases motivation for demand response.

Third, there's a lack of connection between wholesale and retail markets. In theory, customers should make changes in demand which create benefits that accrue up to the wholesale market. This can only happen if there are connections between the wholesale and retail rates.

Even if the rules are wrong there are some options. I want to discuss a case study in Illinois called the Energy Smart Pricing Plan that's run for the last 4 years. This was a residential real-time pricing plan with 1,500 participants in it. First, people in the program saved money. They reduced their peak demand. They loved the program. In satisfaction surveys, people said, "no one's ever explained to me what in my house uses energy." The education, the control that they felt they had by knowing more about prices, and being able to pay differently created a lot of value. There was initial inertia, but once they got exposed to it and learned a bit, they really liked it. In California, too, when the critical peak pricing pilot ended, a large portion of the people in that pilot program wanted to stay on the rate.

How did this succeed? First, they addressed transparency a couple different ways. The rate structure was very simple. It was a pure real-time pricing program. Each customer had an internal meter beside a regular meter reader with hourly usage and prices. There were no base lines or variations. Second, they made the prices public. They were available on the websites, via a call-in phone number for those without internet. They educated participants about the general shape of the programs. Told them, "don't worry if the price is seven cents in a particular hour, or 7.2 cents. You need to know the general shape the day, which days are more expensive or less."

Some participants have paid under a cent per kilowatt hour for power recently. Obviously they pay a lot more for some hours, too. For the most part people had far more hours with very cheap electricity, and far fewer with price spikes. Further, the program unbundled and shifted risk. Participants created savings by actually reacting to the volatility of prices. They reduced peak demand usage.

The next challenge is to demonstrate that a program like this can have an impact on the wholesale market. Part of the problem is residential customers for a 100+ years have been encouraged to be passive consumers. During the California energy crisis, 2% of load was being used to dry clothes at peak hours; discretionary load that could have been shifted.

There have been no incentives for people to change their usage. Successful programs had to start from scratch to inform people about prices and usage, and how they could change it. Several different things were done in Chicago. First, price availability. Second, during price spikes, letting customers know about them specifically. They used a variety of educational tools. A website to look up hourly usage, little flyers with education on general energy efficiency as well as peak demand reduction times. They used something called "the price light" that could be placed in people's living rooms. It's a simple device with a pager that changes color hour to hour depending on what the price of electricity is. Green, yellow, or red, to bring the prices into people's consciousness.

There were definitely periods when people saved money, and also some periods where their general prices were higher. Over the life of the program, people saved about 10% off their bills on average. There were periods of several months where most people didn't save. Overall, people could handle that volatility. Even after high-priced periods, almost everyone signed up for the program for the following year. People understood that over time, that there was a long-term value in markets, even if there would be short-term rocky conditions.

Most of the people in the program had no particular automating technology. They would reduce their load by turning down their thermostat, air conditioner, turning off lights, maybe putting off running their washer or dryer. They received as much as 15% reduction on peak demand time through behavioral change. With automated technology, such as an air conditioning cycling switch, load response got even better.

However, there are some differences from critical peak pricing programs. Even on summer days that weren't high priced, there were still 4-5% reductions. People were becoming more energy efficient and aware all the time. They would set programmable thermostats to turn off AC in the afternoons if they weren't home. Energy conservation was occurring throughout the entire summer, not just the peak demand times. Then on the peak demand days, the results were still similar to the critical peak pricing pilot programs.

In a situation with time-based rate structures, for small consumers a rate's not enough. You need a program support to manage this stuff, get them educated. There has been discussion about the failure of aggregators to come into the market and play the intermediary role between the utility and the customers. Legislation in Illinois passed last spring set up a structure where the large utilities hire a third party to run this program, to do customer outreach, education, energy management systems, etc. It also looked at a framework to look at the costs, and understand what costs should be borne by the program participants, and what costs should be borne by the entire residential rate base.

Initial estimates for a program with 10% of residential customers on real-time were about $16 million a year. Analysis showed that it would create about $30 million of benefits. Most of those benefits go to the participants, but some of the benefits go to other residential customers as well as to C & I customers. Further analysis looked at the benefits of making initial participants more demand responsive, rather than signing more people to the program. This would be accomplished by improving the quality of education, getting more programmable or smart thermostats, or cycling switches. Adding non-participants gets rapid increase in cost savings, and increasing education improves savings as well, but not as drastically. Further, these benefits also accrue to non-participants by the spread of some benefits to non-participating customers and also by the reduction in overall wholesale costs. What I've discussed are program extension models – they still need to see if real-life programs can extend the benefits as they've been modeled.

Currently CTC is working with Ameren, a downstate utility in MISO. They are a different market than in Chicago. The urban program has been renamed as the Power Smart Pricing Program, utilizing smart thermostats and other enabling technologies. CTC is hoping to have 3% or 4% of residential customers in 4 years. The program will be reevaluated then, on a mass market level.

Restructuring focused mostly on the supply side. There was an assumption that people would magically find opportunities on the demand side. However, this can't happen without a model in which the incentives are right for consumers, suppliers, and a third party administrator. Illinois has abundant capacity right now and that makes it easier to implement a new program like this. It was important to get this started during good times so that they could get it up and running, learn how it works, understand their markets, and participants. One can't wait until there's a crisis to start looking at programs like this.

It's hard to get customers to move to new rates. Once they're on them, they want to stay on them. attaining that change in perspective is the biggest challenge. Illinois has a lot of program administration, marketing, and education costs to educate consumers about their options and price.

Question: How big was the program? What were the general social and economic status of the customers? Did customers have to pay for the special meters or were they were socialized?

Speaker 4: There were about 1,500 participants in the pilot program. The demographics were wide ranged. They weren't a utility so they couldn't just send people letters saying congratulations, you're in a pilot program. They had to go out and recruit people for this program. Overall the demographics looked reasonably like the ComEd service territory. Mostly single family, but not entirely. Probably about 60-something percent suburban, but also a lot of people in the city of Chicago. There was a substantial segment of non-English speaking and low-income participants. There was income diversity as well.

The meters were paid for through some grant funding.

The challenge was that ComEd had a bundled rate that didn't distinguish between energy distribution and transmission, plus it had been lowered by the legislature by 20%. The price per kilowatt hour everyone was paying for was a completely artificial number. One of the challenges in the pilot program was to unbundle all those pieces so that the commodity energy component would be the only part that was floating indifferent. The new rate designs in Illinois now have done that. Everyone pays the same customer and distribution charge.

Question: Is the territory summer or winter peaking?

Speaker 4: It's summer peaking.

Question: What is the metering technology?

Speaker 4: Our price models use information ComEd had on file for an interval demand recording meter. This is not without any AMI. These are solid-state meters that record half-hour usage and are read once a month by a meter reader using a probe. The incremental costs for one of those meters over a standard residential watt hour meter is $5.36. In states doing system-wide rollouts of meters, these costs will come down quite a lot. The meters still cost $130 each, plus $70 to send someone out to replace it. Over time, those costs are just going to go down.

Question: Could you expand on the price light? Did everybody get one?

Speaker 4: There was only a limited pilot of it, and everyone loved it. Evidence shows that demand elasticity increased for people with stronger visual reminders like the price light, or an alert, phone call or email. Unfortunately it costs about $100, plus a couple bucks a month for a pager signal to go with it. It's not cost effective. As a demonstration technology, it's wonderfully powerful. Two of the Illinois commissioners requested ones for their office. It was very valuable to have this thing in their office that's changing color on a day-to-day basis educating them.

Question: Let's discuss the potential cost of this benefit study that you have. It says $16 million per year, but it sounds like most of that cost should be upfront, and then the subsequent years should be much lower? What about the education costs?

Speaker 4: The cost of education was built into that. It should be upfront cost. However, we modeled using ComEd's rates. They charge for meters as a monthly meter lease in perpetuity. Will these meters really cost $5.36 per month for the rest of eternity? Personally, I don't think so.

Question: What real-time price did you use?

Speaker 4: This was the PJM, ComEd zone day-ahead price. A small change in the programs now in effect is they use the PJM and MISO real-time prices with the day-ahead prices as advisory prices. So far, it ends up being pretty much a wash. Sometimes the real-time prices will spike up a bit higher than the day-ahead prices and sometimes the real-time prices go down to zero. The real-time prices, if you average them out over a period of time, are almost identical, if not a little bit lower.

Question: The prices were hourly or daily?

Speaker 4: Hourly.

Question: For speaker 1, did your modeling for the demand response program in the New York ISO include savings to the utilities as well? Depending on the technology, the utilities may benefit in terms of their internal operations. Is that reflected anywhere?

Speaker 1: Not yet. The modeling was looking at impact on wholesale markets. Reliability or operational improvements weren't modeled into that. They certainly want to but it's hard to do. They have a four-year window to develop new evaluation tools. That's their challenge over the next four years. Those are important costs.

Question: In some states customers of utilities are prohibited from participating in

DR; particularly those that have tariffs. Others do not allow companies to participate at the RTO level.

It's interesting that the parties activating these DR programs are not the utilities or the companies, but rather other marketers. Is this the genesis of the market for demand response? Third-party suppliers who participate in the savings?

Speaker 2: In New York, people have set up business models that use this as their primary business activity and demand reduction. It allows all sorts of variability in the third-party aggregators. They're not all created equal. There's sometimes a little bit of prism shift between the rules and requirements of an ISO program versus what a retail aggregator will tell to their customer.

Speaker 3: For some companies it can be a real advantage to have a third party do this work. It allows them to keep the focus on their core business.

Speaker 4: Marketers of demand response can aggregate; that's a good thing. If a marketer is bringing value or service to a company in a way they couldn't better do themselves, that's fine. If it's forced and that third party has to be an intermediary, that is inappropriate.

Question: The CTC program had to look for the clients for their program. So, probably the people who took the program are people who are more interested in reacting to prices. Is it possible the savings numbers would be lower because this is a biased sample of people who are eager to participate in the program? Alternately, did the lower income participants save more? If so, that's a terrific sales speech for the program.

A second comment. Real-time pricing is moving into other dimensions. For example, in highway pricing. For instance, the city of Santiago (and other cities for that matter) has congestion pricing in which the price for the main highway changes with the time of day. There are big signs that tell you what the price is.

Another example is a colleague's recent paper on coastal fishing markets in India. The prices of fish in the different coast markets were very different. There was lousy transportation infrastructure between cities. Once the fishermen gained cell phone access, they could call to see where the prices were higher and lower. The prices evened out completely amongst inaccessible cities. Information really pays, and it can have a big impact in the future.

Speaker 4: Congestion based pricing models are praised by policy people in transportation. Real time parking prices are another model being looked at in dense urban cities like New York, Boston, or Chicago.

CTC examined the selection bias issue and found less than they expected. Ultimately it didn't matter because they're not advocating real-time pricing as a mandatory rate. They see it as an optional rate. The inelasticity of demand in electricity price means that one only needs fairly small changes to get a big impact. Not all residential customers need to be on real-time pricing. You need to get 5, 10, 20% of them on, in conjunction with the C & I programs. That combination of things can mitigate prices during periods of high demand.

The challenge is finding the right people. They are still trying to figure out how to predict who will be the most demand responsive. The participant with the best load shape in the CTC pilot program was a conservative Republican state Senator from a rural area. He lived in an old stone farmhouse and pre-cooled it. He didn't have to run his air conditioning. Demographically, one would not expect him to be the one with the best load shape who was able to reduce his demand the most.

In terms of the low-income question, an important issue is that they pay their own load shape. For any residential rate that's averaged over a class, they're paying the profile of that class. So, if you are low income and have less air conditioning than the overall residential customer class, you're subsidizing them. People with less air conditioning are subsidizing more air conditioning by other people. The people who had less air conditioning, fundamentally their average price was lower. They didn't have the same demand reductions because they have less demand, but they benefit by the lower average price.

Question: As we know, gas prices are volatile, and there's not a lot of peaking gas coming. Coal with the CO2 legislation coming makes it a very unpalatable option. Nuclear is at least 7 to 10 years out. There are few resource options. However, the most successful DR programs in New York or ComEd have flat-lined to a certain extent. If one wanted to double or triple that, how would you do it? For speaker 4, if mandatory is not the way to go, how does one select the right customers and achieve a 10 to 20% demand reduction?

Speaker 2: Currently New York is long in capacity for at least two or three years. They have a comprehensive reliability planning process that looks 10 years ahead and incorporates all solutions for capacity. It goes to market solutions first, then backstop. So far, there have not been market-based, demand response solutions. That may be in part because capacity is not yet an issue. Their current program hopes to grow to 3-4% in the next four years.

Question: We've heard about the problems in the organized markets for getting demand response put on the same par with generation, and governance issues too. What can be done for implementation?

Speaker 3: Well, a simple response is to give customers at least 50% of the vote in the stakeholder process as they are the ones ultimately using the electricity in the first place. That's probably not a realistic expectation. But that's my suggestion.

Question: In some places utilities administer demand response programs, other places it's RTOs or ISOs. Does one model work better? Does one model facilitate third-party aggregators better?

Speaker 4: I don't think there's enough information yet to be able to answer that. There's been greater participation where there are ISOs but it's still an experiment.

Speaker 3: When one considers regulated markets versus the RTOs there are good and bad ones, or nonexistent ones in both jurisdictions. Industrials would look for full interruptible rates with a capacity credit based on avoided cost, the capital cost of building a unit, and deployed during peak times. This favorable outcome has been seen most in certain emergency type RTO programs like New York's. As a general rule, industrials are not interested in aggregators.

Speaker 1: Traditional residential direct load control programs are run primarily by utilities. In Connecticut, ISO New England is running a program, and they've hired a third party to go out and get smart thermostats into homes to do load control. It'll be interesting to see how successful it is.

Question: Is there a critical distinction between the wholesale rate and a retail rate? They are both real time. Is there a distinction in what LMP or pricing one uses? The wholesale would be nodal, whereas the retail rate is aggregate. Is that distinction critical?

Speaker 2: In New York, they have 11 load zones, and those prices compared with the nodal price are generally not too far off. There probably isn't a lot of difference in the kinds of signals that are seen. That probably doesn't hold true in New York City as much as it holds true in Buffalo, but in general it's pretty consistent.

Comment: FERC's new state of the market report includes a discussion of demand-side management. It's the best place to get a quick look at the national progress.

Question: Demand response is largely motivated by high prices or the threat of high prices. Do the existing price caps, or big caps in the organized markets provide a disincentive? Should we be systematically raising those caps to motivate additional demand response?

Speaker 3: It is a double-edged sword. One would think that higher prices would get more demand response. That's probably true. Unfortunately, it's hard to advocate for across the board scarcity pricing at this time because there are real concerns about how the competitive markets are functioning. as was discussed a lot this morning. Scarcity pricing can work only in conjunction with all of the other necessary elements for a competitive market being implemented.

Speaker 1: Residential customers aren't doing sophisticated economic analysis of their usage. The mere act of saying prices are high tomorrow are the incentive. As prices go up, I'm not sure you would see more demand response. I think it would plateau. Price caps contain the $7,000 megawatt hour prices that ComEd saw in 1999. The best path is a balance between volatility and extreme risk.

Question: Speaker 4 discussed revenue neutrality and the fact that it was not implemented in the CTC program design. What will happen when rates rise in all hours, and it's not revenue neutral for those customers and they have to shift progressively more and more to beat the standard tariff? Permanence of demand response programs seems to be valued, but the nature of permanence in markets is that things change. The value of capacity is going to will change. Are policy-makers willing to live with the flexibility that's required to have permanence in demand response programs?

Speaker 1: It depends what the timeframes are. In Illinois the utilities no longer own generation, there's an annual auction. The flat rate is set on an annual basis and the variation is really an annual true-up. If market conditions change, the auction results will be higher the next time. That's occurred in New Jersey and Maryland. We've seen markets change and it takes a bit for things to catch up. If prices are set based on an auction derived flat rate or a contract, including embedded costs, the advantage of real-time pricing is you're not paying those. If prices go down or up, you see that faster. It will levelize over time. The experiment over the next four years is to see how that plays out. The issue may need to be revisited.

Question: OK, but if it's rebased, the utility's standard residential rate would be rebased on the marginal being factored into the overall embedded rate, right?

Speaker 1: Not in regions where the rates have been unbundled. Everyone's paying the same distribution rate. The utility holds an auction, suppliers are bidding, giving them a full-requirements contract for the next year at a set price. That's the price to beat. There is no longer a distribution company cost, it's all market-based. It's a very different world. In a regulated environment I'm not sure how this would work.

Question: I think the CTC residential program is just terrific. I've been trying to figure out what could make this go bad? The selection bias and transparency concerns have been discussed and addressed, they don't worry me. However, the concerns about scarcity pricing and the bid caps are backwards. Better scarcity pricing in the operating reserve demand curve with higher prices can make a big difference. The capacity charge for the capacity market flows through this as well. If there is higher scarcity pricing, it lowers the capacity charge because the capacity markets net out so that people who do respond to demand in the time profile actually do better; even though the highest scarcity price seems higher. The average prices that they will pay will be lower. It's bid caps, so market power problems are not a concern. They won't get the very high prices very often but better scarcity pricing and reduced metering costs over time look good for this program.

Speaker 1: Earlier, as I discussed this issue, I was realizing I didn't quite have the right answer. My response was from a retail marketing perspective trying to address how to articulate the program's value to customers. Fear about unmitigated price swings is important to get the right price signals to people and the caps do affect that. In New York's pilot program they created an artificial price cap of 50 cents a kilowatt hour that they bought options for. Afterwards they decided just to self insure.

One option would be to create some small level of hedging built into the price as a premium service. You could say to customers, do you want the full range of prices that could become very expensive, or for a dollar a month, we'll guarantee you won't pay $7 a kilowatt hour?

Comment: With price caps, the market for demand response becomes more attractive to aggregators. At a low load level there's more margin to be made, and therefore, there's a service to be provided.

Question: For interruptible programs there is a difference between generators and interruptible facilities that get paid a capacity payment. In that situation, industrials argue they should be paid a fair price, it's a resource and should be treated like a generator. However, the interruptibles are only used in the context of Emergency situations. Thus, the interruptible resources are associated with very negative public perception. Some people are going to go home or may they lose a shift. For instance, California a formal emergency has to be declared by the ISO in order for them to call their interruptible program for reliability. It's very public, and has extensive public relations concerns associated with it.

Speaker 2: Generally this is not too relevant. If facilities want to be treated as a generator, they will act as a generator.

Speaker 1: In New York, this has been folded into their emergency operating procedures. It's probably more seamless. If it were done repeatedly, it would make the news.

Question: In the CTC residential program, you cited two reasons for participation. One was the money savings, and the other one was a sense of control. Was one more important than the other?

Speaker 1: Money. The other was impact on the environment. Many people mentioned environmental benefits. It's a good thing because they didn't want the program to be labeled as simply something that crazy environmentalists would do.

Question: Potentially, one of the economic benefits of demand response is lower installed capacity costs because resources could respond. They wouldn't have to build capacity to meet that load need. In PJM and New England, they're starting forward capacity procurements. Can demand response be maximized under those forward capacity procurement metrics? Is DR willing to commit as a resource three or four years forward?

Speaker 2: Demand response resources, at least some of them, are willing to make that kind of commitment.

Question: They can clear as a resource in a 3-4 year forward auction?

Speaker 2: I think they'll consider it.

Speaker 3: I agree. They may need temporal flexibility on their participation.

Session Three.
Transmission Chickens and Alternative Energy Eggs

A public policy focus on developing cleaner and more secure alternative energy sources presents an interesting challenge for transmission planning and investment. In many cases, the potential sites for environmentally attractive renewable and other alternative energy is where the sun shines or the wind blows, and this may be far from load centers. The transmission connection is then an essential requirement. Yet building more transmission presents an environmental challenge of its own. Partly as a result, the lead time for transmission investment may be greater than for the alternative energy development. Like a "field of dreams," the mantra may be "to build it and they will come." But the evolving policy for transmission expansion, bifurcated as for either reliability or economics, may not support investments that are not needed for reliability and may be more expensive than many substitutes. How can transmission planning and investment operate its part of the puzzle to make good on the policies for alternative energy? Is there a serious conflict here? Is there an easy fix? Who needs to do what?

Moderator: There's a frenzy of interest in renewable energy and transmission. It's all one big machine. One can put all of those wind farms out in the boondocks but they are just pinwheels if you don't have an effective grid. It takes enormous investment. Wind assisting resources, demand or supply side, that complement it too. Policy makers have got the point now that if they like wind, they love transmission. So, how does one finance transmission and remove the risk and worry?

Speaker 1.

I'm going to discuss the boom in the wind energy industry and then discuss some of the transmission problems in this context. Obviously policy makers want more wind. There are renewable portfolio standards (RPS') in 20 states and the District of Columbia; greenhouse gas initiatives; possible federal RPS legislation; rising natural gas prices; a one year renewal of the production tax credit. It's a strong push for wind energy.

Further, wind energy prices are falling, an 80% drop in 20 years. Large wind, depending upon the financing, is at four to seven cents a kilowatt hour and it's inflation proof. There's no future fuel price risk and it has a high energy payback ratio. This ratio refers to the amount of energy one puts into an electricity generating technology over its entire life compared to the amount of energy that comes out. Since there's no energy or fuel cost, it rates highly on that measurement.

Worldwide installed capacity as of December 2006, is 74,000 megawatts. Germany, Spain, the U.S., and India leading the way. Cumulative growth is accelerating rapidly. Worldwide annual growth was 15,000 megawatts in 2006. North America had strong growth until 2004. Uncertainties over the production tax credit [PTC] meant that a lot of turbines went overseas because the financing was more certain. It had a big impact on the U.S. market. Growth has been more consistent in areas with more consistent policy. U.S. tax committees like short increments for a variety of political and economic reasons. Wind advocates are pushing to get a longer term PTC creates regulatory and economic certainty.

The United States has been characterized as the Saudi Arabia of wind. While California is second in total wind capacity to Texas, it is 17th in potential. There are 16 other states that have more potential than California. There is a remarkable amount of wind energy potential in the United States. It could provide as much as 20% of the energy, not necessarily capacity, needed.

Transmission is a big problem for achieving those kinds of numbers and potential. It's harder for transmission for some unique reasons. Wind is location constrained, one can't choose where to be on the transmission system. It tends to be built in small increments compared to the most cost efficient and economic amount of transmission. For instance, the Tehachapi project in California is 4,000 megawatts but most projects come in much smaller increments. Wind projects have a short lead time compared to transmission. Finally, it has variable production.

The biggest problem is that wind projects can't go forward without assurance that transmission will come in and vice versa. FERC data from their wind policy paper a couple of years ago shows the cost on a dollars per megawatt hour basis for transmission for wind and other technologies. Wind pays more for transmission in many systems, in some cases more than twice as much. Most people believe this is because of variable production and relatively low capacity factor. That is a factor but the real driver of these differences comes in imbalance penalties and losses, ancillary services, that are not necessarily megawatt hour driven.

Second, there are significant differences between different systems in different regions. These costs are very policy driven. The tariffs and the policies embedded in them drive significant cost differences in transmission.

FERC policy strongly affects the chicken and egg problem. FERC divides the world into gen-ties and network upgrades. Gen-ties are direct assignment costs. The generator pays for them as they are deemed to be benefiting the generator to get them to the grid. Network upgrades are charged to the generator typically and then credited back to them in the transmission rates that the generator pays once it starts generating.

In trying to deal with the Tehachapi chicken and egg problem three years ago, Southern California Edison Company made an innovative filing at FERC. There were three phases to the Tehachapi project, one was a gen-tie and the other two were network upgrades. Edison asked the FERC to roll in the cost of all three phases into transmission rates to socialize those costs rather than charging the gen-tie portion to the generator. They also asked for 100% abandon plant relief to address the problem if they built it and the wind development didn't come. FERC granted the relief with respect to the network facilities but not the gen-tie. They said that if an ISO had endorsed the request they might have been inclined to grant it.

There are a variety of good federal and state initiatives that have small effects. OATT reform at the FERC; Conditional Firm Service Imbalance Penalties, those are transmission related and certainly help wind. There is a proposal being floated around for a federal clean energy super highway similar to the Texas proposal for renewable energy zones.

State initiatives include the California RPS and CPUC Code 399.25. It says that you try to put the cost of transmission facilities into transmission rates at FERC, but if FERC denies the relief and it is transmission needed for the California RPS, the state will provide a backstop rate recovery mechanism through retail rates. The Texas competitive renewable energy zone proposal which designates areas rich for renewables and provides transmission incentives for those zones. There's a Colorado proposal sitting on the governor's desk, SB100, which is similar. It creates energy resource zones not tied necessarily to renewables. It creates extended planning processes and grants an expedited CPCN process and allows prudently incurred costs to be recovered during construction.

The California ISO followed up on the FERC request for endorsement. It filed a petition for declaratory order for a renewable truck line proposal. The ISO proposal is a financing mechanism only. It does not roll in the cost of transmission into the transmission access charge and leave it there. The costs of transmission would be rolled into the transmission access charge and generators would repay those for their portion of that system as they come online. If all the planned generation shows up, the net effect is zero; It would be a continuation of FERC policy to have the generators pay. This proposal reduces the risk that the generators do not show up to make that repayment.

The eligibility criteria for this kind of treatment requires that the generation be location constrained and other characteristics typical of renewables. The line has to be cost effective via a market test. Finally, it has to be clear that the generation will come down the pike.

Question: Who is going to own the facilities in the Cal ISO case? The utility?

Speaker 1: My understanding is, and I may be wrong, they would be owned by the utility but operated by the ISO.

Question: The wind advocates in Pennsylvania assert that Pennsylvania has the second largest wind farm east of the Mississippi and I'm trying to reconcile that claim with the top 20 states for wind potential. any thoughts on that?

Speaker 1: The potential is based upon wind surveys and not necessarily how they've been developed. So, for example, California is number two on the list of actual capacity installed but it's 17th in terms of potential. There isn't a lot of penetration in some states that have significant potential. You could have a state with relatively low wind potential but with a very high percentage of the total capacity and a very large wind project. There is commercially viable wind in 46 of the 50 states.

Moderator: The National Renewable Energies Laboratory is an excellent source for information in this area. best source. Their wind map is a credible and technically sound survey.

Speaker 2.

I'll focus today on activities in California and its ISO. They're finally at 2006 so when they look at five year statistics, they don't have to include 2001. [LAUGHTER] What are the incentives to get wind and renewables to the network?

The planning process starts with a long term forecast by the Energy Commission. This helps with identification of potential resources in the state, as well as potential transmission corridors. Generation, transmission owners, and the ISO all work from this information. The generators to know how much business is there and potential locations for investment. Transmission owners for the longer term procurement process. The ISO for scenario transmission planning and coordination with the transmission owners. The scenario plans allow folks to look at the bottlenecks well ahead of time. The transmission owners do their procurement plan in coordination with the ISO, with oversight by the PUC. This process moves into siting. The Utilities Commission in California produced a ruling about three months ago to streamline the entire process. They are letting the ISO make determinations as a reference point, rather than putting the burden of proof on the ISO for siting worthiness. Finally, there is a FERC application for rate recovery. There is the Energy Commission, the Utilities Commission, ISO and FERC, as well as generation and transmission in the private sector.

There are still holes in this in terms of transmission for renewables. By 2010 the California RPS, the Renewable Portfolio Standard, calls for 20% of energy consumption. It is the most aggressive goal in the country. Wind is the majority of what is coming. There is about 6,000 megawatt total of renewables in the state and over 7,000 megawatts to be added. It's a massive effort. By 2020 that percentage is supposed to be 33.3%. So, by 2020 this is 20,000 to 25,000 megawatt of renewables.

The common challenge issue for FERC has been discussed somewhat already. Let's consider the Tehachapi area with about 4,000 megawatts of potential. There are roughly 20 developers whose entry will be scattered over time. Being one of the first actually turns into a real disadvantage. It's been hard for them to take the first step, and some wind developers in that area have been waiting for 15 years. The common challenge solution addresses some of these financial issues.

There have been concerns with discrimination in that wind is being treated differently from other generators. However, if you treat them all the same, then wind can't compete – that's a different kind of discrimination. The philosophy is to basically build and the other half will come. There have been concerns about stranded costs but those are allayed by extensive determinations of potential for the area.

The regulatory process in the state has identified areas that have high potential for renewables. The ISO uses those rankings, as well as interest and contracts already underway in those areas, as indicators of potential. Once there is a critical mass they work to minimize the risk and move projects along. When developers see that transmission is already there and an area is identified as high potential for easier permits then it makes it really easy for them to come in, especially if the standards call for a minimum amount of renewables by a certain time. The generators pay a prorated share as they come in.

The ISO does several things to encourage these projects. For the developers, developing financing not funding, is the first hurdle. That is the first barrier the ISO tries to remove. What is the criteria to ensure that investment is not going to be stranded? First, these are generation interconnections, not network facilities. Network facilities are dealt with differently. Second, the project has to facilitate access to an area with a significant source of non-transportable energy; generally renewables. The transmission is under utility control and must serve multiple power plants. If it is just one plant, they must do their own investment like everyone else. Cost effectiveness is the last concern. There is sensitivity to increasing transmission rates beyond a reasonable amount. Transmission cost in California is 3% of the consumer bill. The total revenue requirement of the transmission owners is about $600 million in a total market of about $20 billion in retail volume. There is a cap that any project should not be greater than 5% of total cost over 10 years. For instance, in Tehachapi there are interconnection requests of over 5,000 MW and the area's potential is 4,500 megawatt. Once they saw that transmission was actually getting built, it got rolling very fast.

A variety of states have RPS'. There is no way every state can meet its own standard on its own in a cost effective manner unless the whole region works together. Regional transmission initiatives are an important issue.

Fuel diversity is also important regionally. Last summer during the worst heat wave of the summer, the wind was not blowing at all in California. Turbines were only putting out 5% of their installed capacity. However it was blowing in other western states. The wind in California and British Columbia blows in wintertime and summertime respectively, so regional diversity matters. Innovative regional solutions are the next great challenge.

Question: Renewables are 20% by the year 2010 in California. Are those projects already in the queue because that's only three years away?

Speaker 2: Some major contracts have been signed, some are in the queue, and some are being signed as part of the holder's adequacy portfolio. If they don't make 2010, transmission construction and logistics will only really push it back to 2011.

Comment: All the energy will be deliverable in the 2010 timeframe, but everything should be able to be sent on transmission by 2012.

Question: Could you characterize the relationship between the California ISO and the FERC for these transmission issues?

Speaker 2: The transmission owners file with FERC for cost recover with accompanying ISO support.

Question: The determination of need is reviewed by the state PUC and not by FERC. Then the burden of proof at FERC becomes very large to show need.

Speaker 2: FERC's approval of rate recovery occurs for reliability or economic reasons. There is a new third category for renewables. They assess benefit based on the determination of the proponent and the support of the ISO. Sometimes there are two of these goals in parallel. Some people go to FERC first to ensure cost recovery before the state process is complete. FERC will now make that determination ahead of time.

Question: California doesn't go on its own to tell FERC these processes are needed. The transmission owner does?

Speaker 2: Yes.

Question: The California ISO would support the need?

Speaker 2: Yes, through the CPC and NETS.

Question: Is this a transfer of regulatory authority from FERC to the ISO, to some extent?

Speaker 2: Well, I don't know if it is transfer of authority but more of a support of the proposal. FERC relies on the determination of the ISO to some extent.

Question: When we hear that generators pay pro-rata share is that based on some determination as to a level of capacity is expected to be built, or something else?

Speaker 2: Yes. If the ultimate capacity is 4,000 megawatts, then that's the base and the generator pays their portion of that planned capacity.

Question: So there is no definite number. Perhaps they pick a conservative number and it can be adjusted over time and modified?

Speaker 1: It is also based on the capacity of the line being built, which is based on the capacity of the projects it is serving.

Question: What is the mechanism for determining cost effectiveness? How are the ancillary services impacts addressed? Is capacity value accounted for? What kind of a calculation is done for cost-effectiveness?

Speaker 2: The ISO realized that determining the economics of renewables in the project justification would create major debate. Instead they determine the economic value from a fuel cost point of view, they took the RPS as the law. The policy makers have determined that renewables have value because there is a 20% RPS mandate.

Question: So if there's 4,000 MW of wind, the only question is what's the most cost effective way to get the transmission to the wind in the system.

Speaker 2: Yes. They decide skip over the debates about whether the economic assumptions were valid or not.

Question: The ISO says that each project is not to increase the rates by more than 5%. How many projects are envisioned here? Is there a cap on the cumulative rate impact?

Speaker 2: There was a suggestion to put the cumulative impact of 15%. Right now the transmission is about 3%. In my mind, even if it doubles, it is still not a big deal.

Question: Has the ISO done any operational analysis on what's needed to integrate these intermittent resources over a short period of time? Is the integration addressed by the ISO?

Speaker 2: They are working on it now. It's a massive change in the generation landscape. GE and the Energy Commission are also examining this. This is an active and evolving analysis that is a challenge.

Question: Shouldn't that planning take place concurrently so that infrastructure to support intermittents is in place?

Speaker 2: The 2010 plans should be completed by July '07.

Speaker 3.

I'm going to discuss the Texas Solution to the Poultry Dilemma. They are making sausage which is never a pretty process, but it seems to be going in the right direction. I'm going to discuss some background for ERCOT because it is different, and these issues affect transmission and renewables.

ERCOT has a postage stamp transmission rate and all transmission is paid for by load. When a generator comes in, they post security for the new interconnection facilities and there is no clear line between a generator tie and a network cost. Some utilities do it a little closer to the generator and some of them break it out further under the network. It depends on the particular circumstances. The security is to ensure that if the transmission builds the facilities, the generator is definitely going to come. Utilities are responsible for upgrades. All upgrades and interconnection costs are rolled into transmission cost paid for by load. There's no point to point firm network transmission service where a generator would pay for an upgrade and get credits back. All upgrades are paid by load.

In 1999 the legislature established a renewable portfolio standard of 2,000 megawatts by 2009. There is a Renewable Energy Credit Program where every megawatt hour generated by renewables generates a REC and competitive retailers have their load ratio share of the RPS converted to a megawatt hour basis each year. Competitive retailers don't have to buy directly from the renewable generator, they buy REC's, decoupling it from the power.

Right now there is 3,000 megawatts of installed capacity wind generation. There's 1,700 more megawatts with signed interconnection agreements being built. Significant local upgrades will allow that to be put onto the system. This includes opening 138 kb lines, adding phase shifters, etc. Once this capacity goes above 5,000 megawatts in the west Texas area, they will need to add bulk transmission facilities. There's about 21,000 megawatts that are queued up in the interconnection process, so significant transmission is obviously going to be needed.

There's a 62,000 MW peak demand. Most of that load density is located in Dallas, Houston, Austin, San Antonio; the eastern half of the state. There is about 100,000 MW of potential wind capacity in west Texas and the onshore coast. From the west Texas area, it's about 150 to 200 miles between the significant load and the basic wind resource.

The security that generators have to put up is a big issue. Transmission owners want financial security from generators to ensure the facilities are there when transmission gets built, and also when they apply for a CCN [certificate of convenience and necessity] or go in for rate recovery of the transmission. The wind developers have been unwilling to commit to the security. They are only paying for a portion of those facilities for the four to seven years required to complete the transmission. That's the chicken and egg problem.

The Texas legislature passed a bill in 2005 to try to break that dilemma. The bill increased the RPS to 5,880 by 2015 and a target of 10,000 MW of renewables by 2025. They allowed the PUC to pre-approve transmission lines to serve the renewable energy zones regardless of whether the renewable generation showed up or not. The PUC, after consulting with ERCOT and the Southwest Power Pool would designate CREZ's [Competitive Renewable Energy Zones] in areas where there is extensive renewable resource potential. They can consider the level of financial commitment by generation developers and designate a plan for transmission to span that 150-200 mile gap. ERCOT has also implemented studies to begin this process, in collaboration with the PUC. These examine wind potential, sites, and potential transmission routes in an open planning stakeholder process.

There are four areas with wind resource potential along the Texas coast. The best areas have less resource potential, but the resource is coincident with the peak demand. There's also the central west Texas area around Abilene, the far west, and then the panhandle area. ERCOT conducted extensive analysis of potential transmission upgrades that examined upgrade levels, production cost savings, transmission costs, revenue reductions, etc. They tried to provide the PUC with many different options because it's not clear how far the PUC is willing to go in designating CREZ's. Now the PUC is adjudicating the case, and it is contested so it will be decided in 180 days. Other parties have now nominated CREZ's and related transmission lines; or alternate proposals to some of the plans in the analysis. These alternates have not yet gone through a stakeholder process.

This is where you get into the sausage-making to some degree. It's unclear how the commission will consider these alternatives without similar levels of scrutiny in a stakeholder process. The Commission's rule making left considerable flexibility on how much and which CREZ's to select. They can look at a wide variety of factors. In terms of financial commitments the generation developers have a wide variety of ways to show commitment. Significant resources already on the ground; interconnection agreements; land leases; and letters of credit instead of full security. There is a lot of political will behind renewable resources. The economic development benefits of all that wind resource is significant. I expect we'll see this process moving forward quite easily.

Speaker 4.

I'll be discussing some of these issues from a California perspective, particularly their PUC. There has been an extensive effort there to work collaboratively with other agencies like the ISO, and also to work with better efficiency on transmission issues.

A report by TechNet, a bipartisan coalition of companies primarily located in the Silicon Valley, came out yesterday reinforcing the need to address climate change, and to really support development of green technologies. It includes a section on transmission that emphasizes this issue as a bottleneck for renewable development. They argue that utilities should be able to recover necessary investments in transmission facilities to accommodate new renewables. Currently these are subject to FERC review, despite the fact that they are undertaken to meet state retail energy renewable portfolio standards. These jurisdictional issues create uncertainty of cost recovery, maintaining the delay in investment. The report is a good sign of increased understanding between transmission, renewables, and transmission cost recovery.

In California the PUC permits transmission lines proposed by the investor-owned utilities. Two laws oversee this, the CPCN, a certificate of public convenience and necessity, and CEQA [California Environmental Quality Act], the state environmental statute. CEQA requires a thorough review of need and alternatives; generation, non-generation, and re-routing options. The PUC has to complete the process in about 18 months. There is also the state's new increased RPS, 20% by 2010, and their global warming act that affects greenhouse gas emissions. This creates enormous pressure to site transmission for renewables. Other factors still create hurdles too. Development financing, project site development. Clearly, transmission is the most daunting.

The state previously had a typical state permitting approach. They didn't talk to the utility before they filed the application. They'd find haphazard staff to assign to it. Then they'd look for an consultant for environmental review. All of these things took many months. They'd spend at least another three to four months going back and forth with the utility arguing about what information the utility should have known the PUC wanted. There were enormous delays, and sometimes there was still inadequate information. The PUC has done extensive work to streamline the process, without legal changes, mostly internal changes in the process. Now, all of the utilities file a quarterly report with their transmission staff that looks ahead two years for transmission upgrades or new projects. It allows the PUC to plan ahead for staffing and logistics. Serious meetings begin six months before the anticipated filing of the application, mainly to communicate the information they need ahead of time.

For instance, a major issue for transmission lines are spring bloom studies that examine flowers blooming along the right of ways in the springtime. If it's not done in spring or early summer, it has to be done a year later. Now, the PUC hires the environmental consultant at least three months before the application comes in, and the information they need is set up ahead of time as well. When the application is filed, it's solid. Then they can spend a very productive 18 months actually doing the analysis and review that's necessary. There's also a new quarterly internal transmission meeting within the commission where all staff – administrative judge, technical staff, environmental consultants – get to meet. This streamlining has made a big difference.

California has a new backstop rate recovery law. If FERC does not provide adequate cost recovery for a new transmission line that is needed for RPS, then the commission has legal authority to impose cost recovery through the distribution rates. This has changed the thinking of utilities because they know there is cost recovery.

Finally, the PUC is actively talking to the ISO, the utilities, the generators, the environmental community. Their understanding of the concerns is much stronger. They have an open docket asking for transmission proposals needed to meet the RPS. Parties have been able to go to the PUC and prioritize the most important projects. The backstop rate recovery came out of this. They are actively looking at other transmission project areas around the state and beyond the state.

Early on, the PUC formed the Tehachapi Collaborative Study Group. This was discussed earlier, but to remind you, it's $6 billion in generation and the new 250 MW transmission line is another 1.8 billion. It will be the largest wind farm in the United States. It's very complex series of new transmission. Some are small, at least going down to 20 Megawatts, maybe smaller, and aggregating up to 4500 Megawatts. An awful lot of new projects scattered all over. So, the Study Group had a PUC project manager who has been in weekly meetings or conference calls with the ISO, the utility, and the stakeholders for the last six to nine months. And he will continue to be doing this. The PUC consolidated 11 separate CPCN applications into a single project with differentiated timelines. The first two portions were just approved recently. They've created joint EIR/EIS' with federal agencies to streamline things as well. Most of the project is networked to help move regulations away from the new proposal at FERC. It didn't go through the new state backstop rate recovery process either. These were pre-empted.

There's also been a lot of coordinated pre-permit work. For instance, the PUC is reviewing all the public outreach material that the utility is distributing to the community to make sure it's accurate from their viewpoint. There are going to be hundreds of people affected by transmission lines bringing in renewable power from Southern California into Los Angeles. They are attempting to work very hard in a pre-emptive manner on the education component of the transmission lines to help ensure things go comparatively smoothly.

Question: Texas has a postage stamp process for recovery of transmission line. How is California doing it?

Speaker 2: All the transmission is postage stamp in California also.

Question: Texas and California are easier because there is a single state ISO and the same people are going to pay for it. Regional issues are more difficult. With lots of states involved and the possibility of moving costs from one state to another, especially if there are different RPS standards, it is very difficult.

Speaker 4: They have to start talking. California will probably have to go out of state at some point. It's always a negotiation.

Speaker 3: There is discussion about Federal legislation to deal with regional issues. Regional conversations occur relatively well with the Western Electricity Coordinating

Council, everything west of the Rockies, and parts of Canada and Mexico too.

This chicken and egg problem is about financing and the risk of building and no generation actually appears. The California ISO proposal has various market and cost effectiveness tests to provide real assurance that the generation will be built. Planning and developing a transmission project is front-end loaded, but costs are back-end loaded. The real cost to rate-payers is during construction; late in the process. Developers are often asked to make financial commitments early on, they don't know if the production tax credit is going to be extended, they don't know what the transmission costs will actually be. If the developers can be asked for commitment a little later, when they have more certainty, but also when the transmission development costs are not yet exorbitant, that could help. This can work well if the PUC is helping to coordinate. By the time that the transmission folks are about to pull the trigger on spending real money, greater financial commitment can be legitimately required from the developers. Their certainty is higher at that point.

Speaker 2: Multiple states certainly have different standards. With four or five states involved, you have to take a long-term vision. Further, the cost of transmission in the overall bill is comparatively small. The simple approach, if a state is connected to a transmission project, then share the cost by load share. This is easier than endless allocation discussions. Further, because FERC and DOE are accountable, there's someone accountable for making it happen.

State RPS' are a new driver for the same need. No state is going to be able to meet it in a reliable way in a cost-effective manner without regional integration.

Question: We should be locking the legislators in the room and not letting them come out until they agree to something.

Speaker 4: The conversation needs to occur with the people who control the dollars. California now meets on a regular basis with commissioners in the other western states. On September 14 the next joint commission workshop will be in Santa Fe on renewables.

Question: Who's getting the FTR's from these new transmission projects? And as the entities come on, do they get their FTR's or what?

Speaker 1: It's the builder. For new transmission, it's the sponsor. In California they are called CRR's. However, this is still under discussion there. One proposal involves load ratio share based on contribution to payment going to the generators, but it's not settled. If the generators are paying, then they ought to be entitled to the FTR's. This issue still needs to be addressed.

Speaker 3: The proposal is still in preliminary stages. The ISO has petitioned the FERC for a declaratory judgment on the concept. Assuming that the FERC approves the concept, then they're going to develop tariff's with the FERC to resolve some of the remaining issues. Embedded is this idea that, as the generators come online, they pay their pro rata share of what would traditionally be thought of as gen-tie costs. They're going to insist upon some sort of rights of use to the line they're paying for.

Question: Has anybody evaluated the final cost for customers in California of the wind generated energy from the Tehachapi project?

Speaker 4: The PUC sets a market price referent that compares costs to a new natural gas-fired plant. There's public goods funding available to pay above-market costs of renewable generation, and to delay any significant rate increase. All the projects selected to be RPS generation projects in California have been at or below the market price referent. The public goods funding hasn't been needed yet.

Question: What is the final cost is to the customer for transmission and generation?

Speaker 1: There's a $4 billion transmission forecast. That will add about a mil to a mil and half to the transmission system average charge.

Comment: There's nothing new here. In the early Twentieth Century, California and other utilities built transmission literally to nowhere, to link with large hydro resources in the California Sierras. Likewise, the 1960's and 70's, California hooked itself up to Four Corners, New Mexico and Utah; to bring coal resources from remote places to California. It's not unique to do this for renewables. It's important to look at this within the context of regional or national assets. California has got the top 20 wind sites. Most of them are in the northern tier that could serve places like Chicago and the mid-West. But, they're in places that are underserved by transmission. It's the same thing for other renewable resources; geothermal, biomass, solar. Ensuring that the renewable resource mix is accessible to our markets is a very important issue.

Speaker 4: From the perspective of the wind industry, this is not about subsidies. There are lots. The problem with transmission is incorporating a new kind of technology into a transmission system built for different technology. That is not a new problem. Transmission policies and tariffs had to accommodate ramp rates for nuclear facilities, those sorts of things. Each time a new wave of technology impacts the transmission system, we have to solve for the characteristics of that technology.

Speaker 2: There are some differences. Large hydro or coal had single owner or developer, sometimes the government. There was one location with the whole concentration. That was much easier to implement. Hydro and coal had long lead times, 5 years. Wind developers build these wind farms in a matter of months.

Question: The high-level coordination between transmission and generation is excellent. That was a big loss when deregulation was implemented. The coordination took place within vertically-integrated utilities, or groups of utilities, for hydro or nuclear. It's good that it's back.

Cost allocation and sharing are still important though, those battles will still take place. With major sources of wind coming in, what about ancillary service requirements? Who pays for those?

Speaker 4: There are a lot of cost studies for wind integration. There are serious issues above 25% penetration for variable resources like wind or solar. They can be managed however.

Question: Within the same level of ancillary services?

Speaker 4: Yes. Considering all of those things. The California Energy Commission has done a couple of studies. New York and Minnesota have some. If you go to the AWEA website, you'll find those. It's a problem, but it's a solvable problem.

Speaker 4: Operators that get into resource planning and planning are designing something much different. Supply- or demand-side resources to help manage the wind integration. This changes planning, but it's do-able. An ancillary services market helps. MISO's new ancillary services market will help them.

Speaker 3: IEEE did a whole issue of their publication on this question. You can find it on the AWEA website. It's the best technical resource on this issue. It was about a year ago.

Speaker 2: The 20% RPS level in California is not a prohibitive type of change. Demand response is another tool to go hand-in-hand with renewables, especially with current technologies.

Question: Given the experiences in California, Texas, and PJM, it seems that ISO's and PUC's are taking over what used to be integrated resource planning at utility companies. Let's favor wind power, build rate-based transmission, give wind power an advantage. In PJM, the push is more towards coal. PJM is deciding that coal is the better choice and creating transmission to coal powered plants from the West to the East for economic reasons. What are the impacts on the competitive markets?

Speaker 1: In California, they've done integrated resource planning at a governmental level off and on for about 30 years. A state law was passed, 2001 or 2002, that now mandates resource planning by their commission. The utilities file 10-year resource plans with them – generation, transmission, and demand side. There are public hearings, plans are adopted, and these drive authorized procurement activities for the utilities. The legislature wanted somebody accountable for procurement. Within that, they want to continue to ensure competition. It's a bit of a hybrid system.

Question: In California, the IRP mandates that utilities will buy X amount from these wind farms? Or do these wind farms sell their product into the market?

Speaker 1: They are power purchase contracts between the generator and the utility. For instance, in Tehachapi with 4500 Megawatts, Edison, who is building the transmission, has contracts on 1500, but the rest of it goes to the other utilities. There is a loading order there. At the top is energy efficiency demand response, then renewable resources, and then clean fossil-fired generation. The utilities are mandated under the state law to achieve certain percentages of the RPS. There are competitive solicitations for renewables overall, but not competition between wind or solar or anything like that.

Speaker 2: These decisions are made by the legislature, not the ISO. I'd call it coordinated planning, not integrated. The ISO identifies transmission bottlenecks, and the utilities are expected to come up with solution options to relieve congestion. This has resulted in significantly less congestion, and it makes it easy for generators and utilities to set up contracts. RMRs (reliability must runs) are down by 70%. The procurement process of the utilities accounts for costs and transmission bottlenecks. They try to locate procurement sources in the areas that reduces congestion cost. In this new system it's a coordination between utilities, generators, and the ISO. It seems to work.

Speaker 3: It's important we define our terms. There's never going to be a pure market or pure planning. There has to be enough planning to ensure capacity. A level of planning is necessary to create markets for preferred technologies, environmental, or economic reasons. But, within those different markets, one can still have a very competitive kind of situation.

California is setting certain priorities, like the RPS program. Then there's competition in that renewables market. In a real time context, all of these resources are producing energy and competing in a real-time market, similar to PJM. The competitiveness depends on the specific market context.

Question: Some of the renewables have telemetering and controls problems. There are load frequency control and stability problems. Is there a silver bullet in all this with the carbon legislation that's coming our way? For instance, can these markets be integrated with transportation issues? Plug-in hybrids for the commute and being able to time shift?

Speaker 1: This is something that needs to be examined. It's important enough to look at.

Speaker 4: There's a pilot program with the national renewable energy laboratories to model the estimated benefits for this kind of program. Preliminary rounds show significant emissions and economic benefits potentially with plug-in hybrids. There's also a test facility to make hydrogen through electrolysis, another wind-supporting technology. So far that is expensive, but may be cheaper soon. There's promise here.

Question: There are some contradictions here. It's too cheap to meter this transmission, but it's also so incredibly valuable that we need to get the government involved in ensuring it gets built. Building this transmission is a tremendously profitable opportunity for a business. Clearly, environment, siting, and aggregation make it challenging.

Overall it's still not clear what the effect is on markets. Is there a different way to consider this to make these processes more market compatible? Let me give you an example that I was thinking of here. Perhaps it's only the financing. If so the siting and environmental is still preliminary. If that's true, then it's like the Chilean highway system, a big infrastructure investment that covers a lot of territory and it's a big expense up front. One can auction off the right to run the Chilean highway system and let them charge whatever the market will bear for using it. This addresses the risk but there's a concern they would ask for to much money. This undermines the argument that the project isn't risky, and isn't cheap. Everywhere we look the government is going to decide. It isn't much risk, we'll put it in rate base. Everybody else is going to be asking for subsidies too. I wish we could think more about how to design this hybrid system in a way that's actually going to work.

Speaker 2: investors will not build a transmission line at risk. Even the merchant transmission folks have gotten regulated rates. This market model is great but no one will do it. Groups will invest, but only if they get a regulated rate of return. If that's the case, the regulators have to get involved. That's the only mechanism we have now, unfortunately.

Speaker 3: If you're an investor, most of the risks arise out of acts of the government. Those are the real risks; regulatory change, environmental, permits, etc.

Speaker 1: When regulators identify an area as resource rich, or a CREZ, do they want to ask for proposals for merchant transmission. That's an appropriate issue.

Question: There are people making merchant transmission investments. It doesn't get very much publicity. Most of the transmission investment at PJM has been by people where the people making the investment were taking the risk.

Speaker 2: Yes. For some reason that hasn't occurred in the west.

Question: Texas is an IRP-type program. The RPS doesn't drive it. They exceed that. There's big profit in wind there. of a certain amount but every time that amount is set, the developers more than exceed it. Instead, gas is expensive there, and all transmission is built by utilities as a matter of policy. If there were merchant transmission and some of the differential between gas on the margin and wind would have to be shared with merchant transmission. The transmission lines, especially when you're talking about hundreds and hundreds of miles, may wind up being still a common carrier.

Speaker 3: There is a difference in California between an IRP process and their coordination. They are not telling anyone that they have to build this transmission. They are getting proposals and reviewing CPCN's in the traditional way.

This is the post-restructuring problem of how to plan transmission. This issue is bounded by renewables, and a bunch of small developers. It's an almost insurmountable free-rider problem. As long as transmission is arguably a monopoly, the regulators will be there. There is a difference between this coordination and a traditional IRP process.

Question: In California the market is still broken. There is no transparency beyond the state either. There are no signals beyond North South of path 15 or North South Path 26 in the entire western interconnection to build transmission on an economic basis.

There is a concern about how long California continues in this non-market environment. Can they make a mid-course correction? There's a lot of hope that it'll go there. There's no infrastructure or model to support true economics yet.

Speaker 4: Merchant transmission has been built in California. It's a rate-based regulated model, but it didn't come from the utilities.