

**HARVARD ELECTRICITY POLICY GROUP  
FIFTY-SECOND PLENARY SESSION**

Chicago, Illinois  
THURSDAY AND FRIDAY, OCTOBER 2-3, 2008

**RAPPORTEUR'S SUMMARY\*****Session One.****Transmission Investment: Competitive Market Platform or Regulation Trojan Horse?**

*Transmission infrastructure is critical for connecting load and generation. Investment decisions for transmission infrastructure present complicated problems in balancing regulation in the presence of electricity markets. Every expansion of transmission infrastructure affects the viability and returns for investment in generation and load. Interactions between multiple transmission investments produce complicated sequencing issues that affect capacity planning. Interactions between reliability and economic criteria do not produce obvious rules or transparent decisions. Cost allocation becomes a contentious issue, and pressures can build to assign, or socialize costs in various ways through mandates or other determinations by regulators. A principal result is delay while looking for consensus to emerge among key regional market participants.*

*Faced with these challenges and a lack of clear regulatory guidance, regional stakeholders continue to develop new approaches to address portfolio choices, markets, uncertainty, and cost allocations for transmission infrastructure. What are the latest ideas? How do these new approaches distinguish between investments where costs should be socialized versus those where the beneficiary pays? How do these innovations address uncertainty or disagreement about the costs and benefits of alternative investments? How do these infrastructure investments interact with other investment decisions? Which problems do the innovative transmission investment protocols solve? What new problems arrive or old problems remain? How will the evolution of transmission investment tariffs affect the course of electricity restructuring?*

**Speaker 1.**

I'm going to discuss the principles outlined by a blue ribbon panel in a white paper that outlines a national perspective on allocating the costs of new transmission. It's called "A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles." This study was put out by WIRES, a non-profit transmission trade group of transmission owning utilities. It's posted on Harvard's web site. While Wires was financing

the effort, they could make suggestions but they had no control.

The reason for the panel was the concern about the bottlenecks in terms of getting new transmission built. A common national set of principles is needed. They were politically cautious not to advocate standard market design or anything like it. Common principles would allow prospective investors and people interested in building transmission would to have a national basis. FERC has principles that

---

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

apply but they vary from region to region, and there really are no common denominators. They were framed by regional common denominators and achieved by negotiations among parties in particular regions.

These principles were needed for five basic reasons. The pool of capital to invest in transmission should be expanded. With regional rules it tended to create regional clubs that made broader appeal to capital more difficult. Two was to simplify the planning process with certain principles to guide the planning rather than being free form among different parties in different regions. Third was to reduce transaction costs which in some cases are enormous; particularly if there is litigation or controversy over every single enhancement to the grid. Fourth was to reduce entry barriers. These are not siting questions or legitimate environmental or technical reviews. Rather the fact that the process itself was so complicated. It was difficult and expensive to negotiate. Fifth was to increase the amount of transparency and to make the process open to all the parties who would be affected by the outcome. Ten principles came out of their examination of these issues.

Principle number one was that there should be a careful study of who benefits from and who should pay for the enhancement to the grid. The traditional regulatory notion is the cost causer or beneficiary should pay for the benefits that accrue from the enhancement to the grid. However, what one determines is the beneficiary today oftentimes can change. This is addressed in later principles. Generally, we shouldn't deviate from the notion that beneficiaries should pay.

The second principle concerns the distinction between reliability versus economic enhancements. The panel decided it was irrelevant. There's no reliability question that isn't inherently economic and there aren't any economic enhancements to the grid that don't have reliability considerations. The distinction usually was if someone wants it built and will benefit then it's a reliability enhancement. If someone else will benefit and wants me to pay

that's an economic benefit. These distinctions became simply about who should pay. The view was to eliminate that and simply look at this as transmission enhancements. Both reliability and economic implications would be considered in terms of beneficiaries but not how important it was to build the line or who had responsibility to pay.

Three was that the appropriate standard for measuring benefits was the aggregate societal benefits within the geographic region or market being examined. What project provides the maximum societal benefits for everybody within the region? That is how priorities should be set.

Principle four was that the distribution of benefits should be analyzed for the purpose of allocating the costs. There are a number of features. Let me focus on the sub principles of number four.

First, 4A, one has to be focused on large regions for the most part. The larger the region, the more real markets and consumers gain benefits. It increases the market for investors and generators too. However, one can't lose sight of the specific impacts on identifiable sub regions. So a big focus on large regions but don't ignore sub regional effects.

Next, 4B, transmission planning and analysis should include all demand loads, existing and reasonably anticipated, within the region. Defining "anticipated load" needs to be fleshed out further but that is the basic idea. It includes who's currently going to benefit and also who will benefit over the longer term in terms of customer base or load.

Next, 4C, transmission planning should occur in a process that's open, transparent, inclusive and conducted by a credible entity without any particular attachment to any interests. This has to be an open process and no parties should be left out. A credible monitor could be the ISO but ultimately FERC would have to determine that. Anyone who has a stake in the outcome should be able to participate. We need to be planning, looking at existing and prospective load and do it in an open and transparent basis so nobody's

going to be surprised. There doesn't have to be a regional consensus. FERC policy seem to be predicated on the notion if there isn't a regional consensus it is impossible to make a decision. If a consensus occurs then great but otherwise the ISO or FERC would have to decide.

Principle five is that transmission investments involving baskets of projects that provide a net societal benefits should presumptively be candidates for broad or socialized cost recovery across the region. This is the exception to the beneficiary pays idea. We can't argue over every conceivable enhancement to the grid that's being proposed. If there's a basket of enhancements that have benefits for the region then they can be socialized. It's not worth the transaction costs of sorting out the benefits. I'll talk about figuring out the beneficiaries in a bit.

If various parts of a transmission projects are relatively controversial and benefits cut across parties, or different parties benefit from different parts of the project, why worry about who is paying for what. This reduces the arguments and transaction costs from trying to resolve it and simply socialize this. This is the *de minimus* exception to the notion that beneficiary pays. Determining when there is a big enough basket to do this is the challenge in following this principle.

Generally this could apply to huge projects that cut across the regions. Generally, and this is rebuttable in some circumstances, the larger the size of the proposed new facility the greater its potential to serve the broadest segment of interstate commerce. This can only be done going forward. We can't go back and reallocate the costs of assets that were built under a previous regulatory paradigm. If somebody's proposing a 765 project across a vast region with broad social benefits that is a candidate for socialization. If someone demonstrates that a big project has only specific beneficiaries then the costs do need to be allocated. Large projects of sufficient magnitude provide real benefits and open up the market to both sellers and buyers in the market and should be presumed to be socializeable.

Principle seven is that except for interconnections of specific new generation, cost allocation should be to customers, to demand, rather than on the generators. Ultimately that's who will pay the cost anyway. This would remove battles between various generators or resources from competing over who can best use the transmission planning or the administrative decision making process to their own benefit. Instead they have to compete in a real marketplace.

Principle eight is that new transmission investment should be supported in federal and other wholesale rates as appropriate. It should not be included in retail rate base subject to regulation by the various states. If one wishes to allocate costs to people that are the beneficiaries, then it doesn't make sense to build for state rate base because it skews the results and doesn't consider beneficiaries. States look to an administratively easier way of allocating costs as opposed to the true economic costs associated with it.

Further, it builds new barriers. States might be willing to have transmission built but if they have to pay for it and don't perceive themselves to benefit they won't. This runs counter to the principle of broad regional markets. Users should bear the cost that they impose on the system as opposed to just arbitrarily divvying them up among the states. They even suggested moving existing transmission assets from retail rate base to federal rate base if possible.

Principle nine, transmission should be subject to periodic review to determine whether the beneficiaries from the investment have changed in any major ways that distort cost responsibility. This is on a going forward basis and subject to constraints related to timing, scale and the nature of the initial cost allocation. Who the beneficiaries today will not necessarily be the beneficiaries that ultimately result. Beneficiary review and cost reallocation is necessary, with some caveats. It should be done in a reasonable time frame, maybe 5-6 years. Second, it should be a zero sum game. The investors wouldn't be affected by the outcome. All that is affected is the allocation of the cost

but the overall revenue requirement wouldn't change from what it was initially. This is consistent with traditional regulatory principles in which cost causer pays. This should reduce some of the argument in the planning process between different parties who were worried they're going to be stuck with costs semi-permanently. They know that if things change they can get relief. This follows regulatory principles, documents who the beneficiaries are, updates this information, and reduces the initial risks for parties that may reduce their incentive to get involved initially.

Finally, principle ten argues that in situations where there are a specific set of customers, and they are willing to pay solely, and the project has no adverse effects, then they should be allowed to build. In other words, there's completely free entry to transmission as long as they pay and ultimately compensate others for any adverse impact.

*Question:* How would one establish the beneficiaries? Would it apply to both reliability and economic projects? If it's an economic project driven by congestion forecasts and anticipated fuel costs, would this take into consideration individual changes such as hedging contracts? Would it get into that level of detail or would you just look at kind of broad regional changes?

*Speaker 1:* Well, they argue that the distinction between reliability enhancements and economic enhancements make no sense. They didn't get into that level of detail. Probably it would be to look at patterns of use. Who actually benefited from the facility based on whatever factor? The main notion is to determine who initially benefited and 5-6 years or so later, they would look at it again.

*Question:* Who would do the reopening?

*Speaker 1:* The reopening would actually come about in a number of ways. Parties could ask to reopen it. Ultimately FERC would be the decision maker. FERC would oversee it. However, a significant period has to pass, with a

minimum, so there aren't parties continually litigating it.

*Question:* "Cost causer" seems to be confused with "beneficiary." You seem to use them interchangeably but they're quite different.

*Speaker 1:* Beneficiary is probably the more accurate word although in many cases they're the same but they're not necessarily the same.

*Question:* Was the tenth point the concept of a merchant transmission company?

*Speaker 1:* It could be a merchant or a specific extension of a particular generator. It could be a particular industrial customer. There are several possibilities.

*Question:* You described a basket of upgrades. Is this a set of upgrades that achieve a certain goal or could it also mutually exclusive projects that are combined?

*Speaker 1:* By definition they wouldn't be mutually exclusive but it's usually a set of things that any number of parties may want to do and see benefits from. Rather than evaluate who bears what portion of each one of those this process would create an agreement on the whole basket and spread those costs.

## **Speaker 2.**

I'm going to discuss transmission development in California, and focus on California's ISO and planning processes. Right now it's all about going green in California which makes these processes both innovative, complex, and scary. The Cal ISO has stolen a page from the Texas initiatives. Their version of long lines to remote things that look green is the renewable energy transmission initiative, or RETI. This is to identify what regions are most amenable to renewable energy. They originally thought they would find five nifty places in California but that's turned out to be a little more of a detailed exercise.

The RETI process determines CREZs, competitive renewable energy zones. This is to identify big pieces of backbone transmission needed to access renewable energy areas. Also involved in this process is location constrained resource interconnection, or LCRI. This is to provide some up-front financing for generator interconnection. It's a financing mechanism where the tariff can collect socialized finances, to provide up-front financing for groups of generators that want to connect on a particular line. As those generators interconnect, they eventually pay the money back.

How do they look at how beneficiaries pay? There's more of a presumption in California than other places that it's OK to socialize stuff. There's less of a debate, especially the RETI. The costs will be socialized because of increasing mandates for renewable power and it is already deemed to be in the public interest or public benefit. They don't argue about that too much.

The LCRI process presumes that the interconnection and network cost upgrades are prohibitive and that the generators would not come on without being able to get access to this pooled up-front financing. The cost is paid by ratepayers up-front and then eventually the individual connectors, the cost causers or beneficiaries - the individual generators - will pay later.

One problem is that the ISO is not sure how many pieces of what looks like an interconnection today may get networked in a fancy way and look like a network component tomorrow. There's gray area when one looks at ten year plans. How does one determine beneficiaries? How does one determine the difference between an interconnection and a network facility? In California some projects started as network interconnections, became generator interconnections, and then reversed again. There's a fair amount of uncertainty.

California is less tightly networked and geographically remote. It is hard to determine benefits. What are the benefits for customers in San Diego from the Pacific intertie at the top of

California? In that situation there is little benefit. Those folks don't want to socialize anything up in the north of the state. It puts a large burden on central decision makers at the ISO. It pulls away from the discipline of the market signal.

They don't have good market signals in California yet. They may occur in February but until then they need non-market methods to rationalize cost. There isn't transparency and the benefits of alternative investments are not always apparent. The ISO is doing studies for the CPUC and the CEC, and hopefully they will align with the future market signals.

The California ISO is trying to step into its role as the planning authority. The original search for 5 good renewable energy locations has turned into 29 locations. 29 large transmission lines won't happen. So the ISO has to rationalize which are the best ones.

There is a lot of sunshine on the various disagreements, and plenty of opportunity to have a say. However, there is not a lot of transparency in what value of different proposals are. They don't have nodal prices, and without good granularity it becomes arguments over engineering studies. Planning engineers may argue that a substation is very constrained but there's no market signal to show that the LMP prices are already negative. The whole system in California really needs that right now.

California doesn't really talk about the costs because the government mandate for 20% and 33% renewables is in place. The main problem is to figure out how to do it best. How do infrastructure investments interact with other investment decisions? Obviously the generators are waiting to see where the transmission lines will be built. The transmission siting process itself is cumbersome in California.

The other odd thing is transmission solutions that are present before a finding of need. Currently there are situations that have solutions without actually knowing whether there's a need. For instance, everyone knows the sun shines in the Mojave desert and that's a good place to put some solar. It's one place where

market signals are less important. Hopefully the new 890 process will sort this out.

Another concern is that if there is a group that in good faith is trying to make market-based investments and a regulated rate-based solution can be imposed on top of that, then the business plans are completely undermined. It's a very delicate balancing act and the balance is not yet right.

The CAISO is trying to solve the delays in permitting and siting new transmission. They need to meet the renewables mandates. So we're trying to get some jump starts on getting some highways if you will out to the good renewable areas. The LCRI process is working to have like-minded business interests pool their resources. It could consolidate wind developers and get some up-front financing to reduce financial burdens and get them connected to the grid. This will also help reduce concerns about utility self-build.

Since transmission is socialized in California they're having real difficulty with the CRR [congestion revenue rights, aka financial transmission rights] choices. This is in part because at the top or bottom of the state there is little electrical reactivity or sensitivity. For instance, let's consider PG&E. They pay around 40% of the load and San Diego pays 10%. So on a line like the southwest power link, PG&E has entitlements to about 40% of the rights but they far less than 40% of the interactions on that line. There's a dislocation because California allocates CRRs and the transactions, even on high voltage lines, are locationally fragmented. The allocation of CRRs needs to be adjusted. They're struggling with that and I'm hoping they move to auction. It's intractable right now.

Another concern is in the LCRI process. If there is up front financing, and then the generators pick up the costs later. This means no auctions and 10 year entitlements on CRRs. They have to figure that out.

Further, this is operationally challenging. With the long transmission lines there are charging currents and other wacky voltage things going

on. This has to be considered by the planning entity. A DC segment in the middle might be more efficient.

The Cal ISO also worries that the lack of market signals creates an opportunity for a new set of stranded costs. They certainly aren't trying to do that but there's always a risk.

The biggest concern is that all of these considerations mean the ISO's process looks a lot like integrated resource planning. Without market signals it's hard to have anything else. This will need to be addressed. The ISO runs the risk of predetermining commercial decisions and biasing technologies. A long transmission line that goes to solar determines that solar is their future to some degree, and not some other current or future technology. It means the ISO has a hard time staying technology neutral.

When they get markets it'll inform the process better. They'll be able to see buses that are constrained and realize that more megawatts can't go that way. They're clearly working towards a good model and in the meantime they'll do the rest through planning.

### **Speaker 3.**

I'm going to discuss aspects of these issues in the Southwest Power Pool [SPP]. There are seven southern/mid-west states that make up the pool. The SPP regional state committee [RSC] is made up a board of directors from several states. They have the responsibility for developing cost allocations for transmission upgrades, and must file these at FERC. The basic idea was if the states can get together on a cost allocation proposal we can live with it.

They have a cost allocation working group with representatives from each of the state commissions and also open to all stakeholders within the SPP. They meet monthly.

I'll focus on a specific proposal today. There are various kinds of upgrades and cost allocation proposals within SPP. The working group worked first on reliability and deliverability upgrades. These have a region wide rate component to them and a zonal split component

to it. One third's region wide, two thirds goes among zones based upon some physical measure of zonal benefits from the reliability upgrade. Anybody that wants to bring economic and reliability upgrades together under a single measure has a challenge. It is very difficult to put dollar values on reliability upgrades that are comparable to the dollar values that you get from economic upgrades. They struggled with that issue for a long time.

There are also congestion upgrades to relieve congestion on the system. The working group uses a balanced portfolio approach. This was approved by the RSC, and filed at the FERC.

They are currently working on a third set of upgrades called EHV overlays. This is very similar to the CREZ projects in Texas. They are transmission projects to wind areas for delivery and export. This is still being developed.

Let's come back and focus on the balanced portfolio approach. It was developed in four steps. First they determine the benefit metrics. Then cost allocation, a portfolio balance, and then a transfer of zonal revenue requirements.

The benefit metrics are derived from production cost savings and savings from reduced load prices or LMPs. Retail loads in the SPP region of the states are all regulated. The non ERCOT part of Texas that is in SPP is not open access. Its retail rates are regulated there also. Retail access states look for savings through reduced prices and LMPs, whereas regulated states look at adjusted production cost savings because they're familiar with that. That's the way they do rate cases, and determine what net fuel costs are. That is the metric of choice and it uses adjusted production cost savings, which most people know.

There are some potential metric issues. One is contract dependant wholesale customers. Wholesale customers favor savings in wholesale market costs through load LMP. That is not the case in the Southwest Power Pool. There are issues for independent power producers. There's not a lot of market based generation in the SPP, but some wind generation doesn't have market contracts. If they connect to the system they

often become trapped generation in a zone. That zone heavily benefits from that trapped generation. When transmission comes in, that power can go throughout the grid and production costs go up in the zone where that power was previously trapped. They are addressing this issue.

Benefit to cost ratio is determined by average production cost savings over a ten year period. This metric avoids complexities of timing on various projects and it's a simplification. They assess these projects over a ten year period as if they all started on day one of the first year and were in place over the ten years. The reference or base case assumes that all reliability and deliverability upgrades are in place when planned or needed. This causes issues in terms of putting these models together. When they're looking forward ten years, what generation is going to be in place? That is still being resolved. Costs are determined via revenue requirements set from levelized fixed charge rates over the same ten year period. The present value of the benefits have to exceed the costs in order for an upgrade to be included.

Cost allocation was the second challenge. Of course, everybody wants to allocate cost in proportion to benefits as a principle but it's very controversial when the estimated benefits in the future have a tremendous number of assumptions built into the models that create those potential benefits. It became apparent in the process that this was a real problem. Stakeholders were not going to buy into those estimates. These upgrades are going to be there for 30 or 40 years, things will change tremendously. Even the 10 year model has too many assumptions. They didn't want to buy into a single snapshot. So very quickly they agreed on a postage stamp rate. It's not "socialized" or "peanut butter." [laughter]

They took that to the RSC and said we'll put together a portfolio of projects that balances the benefits throughout the regions. They realized that these things on a project by project basis would get lopsided, and everybody would be arguing over each project. They also realized

that things would be changing too much in any case.

So instead they're addressing it from a portfolio standpoint. This relates to the previous speaker's principles for big or large projects. Any one of these projects might not be large but together they are a regionally dispersed set of upgrades that hopefully balance benefits.

If one looks at a map of the zones within the SPP, they look politically gerrymandered. It's a challenge in trying to balance benefits across these zones. Average monthly prices in various zones have a large diversity in prices, mostly directly related to congestion. Since there's been no regional transmission planning in the past, so creating balanced pricing zones is very difficult.

SPP has an excellent independent market monitor. Boston Pacific put together a good state of the market report in 2007 and it's on the SPP website. This is from their report. Congestion in SPP by sub regions is moderately balanced. There's congestion in the Texas panhandle, some in central Oklahoma and central Kansas, a bit on the eastern side. Their map seems to show that it's balanced. However, there are certain flow gates that are much more highly congested than others. That's reflected in the prices.

So how will they deal with balancing the portfolio? Well, they're doing the reliability and deliverability upgrades and two thirds of that's going into zonal rate. The new transmission investment is going into zonal rate. If they can't balance the portfolio on a physical basis then take dollars in the zonal rate and transfer it to a region wide postage stamp rate? The concept really works. They're taking dollars from zones that tend to be more robust and have less congestion, and transferring it to a region wide rate. While they can't smooth out the physical stuff they can smooth out the financial stuff. This approach has been well received.

The balanced portfolio only includes 345 KV upgrades and higher. Some lower voltage upgrades, like transformers and things like that can be included to try to balance out the portfolio. However this won't get all the way

there. There's too much imbalance. So then zones that are still deficient, where cost exceeds benefits, are made whole by transferring their zonal revenue requirements to the region wide rate.

Let's consider how this works. In 17 zones there might be 3-4 that gain extraordinary benefits from portfolio upgrades. Their benefit to cost ratios might be much greater than the average. So if the average benefit to cost [BC] ratio is 2.41 overall. Alternately there are losers whose BC ratio is less than one, and even some who might be net losers. By creating transfers from the zonal rate to postage stamp allocation it allows some of the real losers to come closer to a BC allocation of 1. Further, the losses to the zones that have large benefits only moderately reduce those benefits. The net transfer size might be around 4 or 5 million, around 6-7% of the annual revenue requirements of a project. It's a very moderate socialization.

The benefits of this transfer approach? It gives credit to zones that have more robust transmission by reducing their zonal charges. It moves towards more of a region wide rate rather than zonal rates that are currently in place. Third, it's not a strict beneficiaries pays approach. I would call it a no losers approach. It doesn't put as much weight on the calculation of the benefits as a strictly beneficiaries pay approach does. Fourth, it provides a mechanism for creating zones that have negative benefits. You are giving them credit for negative benefits and those will show up because of this trapped generation issue that I talked about.

There were issues with a few of the tariff implementation details. The implementation of the transfer had to be addressed. The final approach is simple and fair. When 10% of the cost of the upgrades go into rates, this approach goes into effect. 20% of the transfer occurs in that first year and for the four subsequent years. Once all of the upgrades are in rates, there is a true-up to actual cost, not estimated cost. They don't true up benefits. That would be a real challenge. If 100% goes in rates before the end of the four year period then the true-up is done then and everything gets transferred.



Another concern was how to address whether a portfolio displaces or defers other upgrades that fit into the reliability or deliverability category? They addressed this by taking the estimated cost of those upgrades and treating them as benefits to the zones to which they would be allocated. Those upgrades don't get built but the zones get the benefit via the transfer process.

After the balanced portfolio is approved and before all the upgrades are built, the SPP will review it a final time for unintended consequences. Those may occur because an upgrade in a portfolio got canceled. A state could say we're not going to site this project, it's canceled. All of a sudden there's an impact on that portfolio. There may be unanticipated decreases in benefits or increases in costs from the original estimates that make a lot of difference; or significant unanticipated changes in the transmission system itself. If those things occur the SPP will review it, and may reconfigure the portfolio. There are several possible outcomes in that case.

*Question:* The framework seems to be cost benefit analysis.

*Speaker 3:* Yes, but they will look at other metrics besides adjusted production cost savings. For example, savings and losses. That would become particularly important if any of the 765 KV overlay that they're looking at right now becomes a part of a portfolio. Then there can be significant savings and losses. The basic idea is they're going to make an investment. They don't need upgrades to deliver electricity from resources to load, or for reliability conditions. These are upgrades for economic reasons, and therefore the benefits need to outweigh the costs.

#### **Speaker 4.**

I'll discuss the role of planning in competitive wholesale markets. We're in one of the most exciting eras in the electric industry today because the world of reliability, cost to consumers and environmental sustainability are

all coming together. They're crying out for change and to get infrastructure built.

I want to describe some anecdotal examples of transmission's role and why it's sometimes so difficult to do cost benefit analysis on facilities that are going to be in a system for 40 years. The bulk power system at TVA is planned via reliability criteria. One summer day in 1985 the NRC [Nuclear Regulatory Commission] came in to TVA and shut down all five of their nuclear units. They were shut down for five years. TVA had to figure out how to operate the system without them. Three of those five years were severe drought years. TVA typically could get about 4,000 megawatts of hydro during summertime but three of those years it was lucky to get 2,500 megawatts of hydro capacity. They never had a blackout or a reliability violation during that period. They had a robust transmission system that got them through that period. There was plenty of surplus power in that era all around TVA.

Let's consider New England in 2000. Nothing has been done on the system for many years. Transmission needed to be built, especially for reliability reasons. However, all the changes in their system in the last 10-12 years are substantial. There are complete changes in the way the system is being used over from what was anticipated 15 years ago. Back then there was heavy nuclear generation in Connecticut and power was flowing out of Connecticut. Many of those units are gone now. 8,000 megawatts of new generation was added in Maine, southeastern Mass, and northern Connecticut. This completely changed the flows on the system.

In January of 2004, New England had 10,000 megawatts of gas fired generation and 7,000 of it didn't come online one day. The transmission system serves so many vital roles that it's hard to see in a snapshot what will be happening 40 years in the future. Alternately, it's hard for investors to invest without certainty that they're going to get paid. This is a very complex subject.

Now I'll shift my focus to New York state over the last 5-6 years. New York has a good set of markets. They're locational and have brought the kind of needed resources in the right locations for some time. They also have a good reliability planning process and are now setting up an economic planning process. There are differences between economic and reliability planning. From a siting perspective, it's very difficult to say a project is going to save money for consumers down the road when someone's land is being taken via eminent domain. However, if the project is going up because of NERC criteria and the lights are going to go out, it's very different.

Transmission has been built in all six New England states based on reliability and NERC criteria. The economic planning process has many more difficulties. We've heard of some unique ways to address them but there is always going to be a difference between reliability and economic projects because of the practicality and siting issues.

New York's planning process is primarily a process of analyzing the future and getting information out to the investors, stakeholders, and policy makers. There is an emphasis on granular information to show the types and locations of resources that need to be made on the system, and also the benefits investors could achieve. New York has had success based on that philosophy.

A lot of new generation has been added since 2000. 6,500 megawatts, and 80% of that has been in the New York City, Long Island, and Hudson Valley area where the demand is the greatest. That's deferred the need for some transmission facilities over those years. Despite that, the loading on the system has continued to grow. However, 1,000 megawatts of merchant transmission has been added to New York. The cross sound cable, southwest Connecticut into Long Island, and then the Neptune project, PJM to Long Island, have both added about 1,000 megawatts of new capability into the system, all via private investment.

Renewable resources are increasing. By the end of 2008 there will be over 1,000 megawatts of wind generation in New York and potential for another 7,000 megawatts. There's also development of conventional hydro and wind generation in Quebec and the eastern Canadian provinces. It's all looking to get to the markets in New England, New York, and Ontario.

Other benefits have occurred because of markets in New York. Planned availability is way up across the peak periods, similar to other markets, which has created an additional 2,400 megawatts of capacity for the system. When the cost of fuel is levelized, electricity prices in New York have gone down 11% since markets were implemented.

New transmission investments include two Con Ed high voltage DC connections into the state. The state now needs a lot of focus on the existing bulk system. With all the additional loading on the system there are issues with reactive power and increased loading along the corridor. Much of this is driven by the amount of wind power in the state. This is similar to the situations in California and Texas. It's far from the load centers so it will tax their existing system. Clearly the transmission system for this new wind and increased imports has to get investment.

The New York planning process has been anchored in market based solutions. Nonetheless, planning is a continual process and there are a lot of emerging issues for the ISO. These include environmental requirements, renewables, and the economics of running and operating the system. Their 2008 reliability plan shows that reliability will be maintained in New York from the standpoint of loss of load expectation. There is now over 3,000 megawatts of market based private investment focused on solving reliability problems.

There are emerging issues affecting New York beyond loss of load expectation. There is an aging infrastructure in New York. They have a fuel diversity issue, like most of the northeast, with an over dependence on gas and oil. There are growing environmental requirements. FERC order 890 gives the New York ISO the charge as

the planning authority to begin the process of evaluating economic projects as well as reliability projects. Part of this is the congestion assessment and resource integration study, CARIS.

This is based in part on an Argentina model but there is a beneficiary voting provision in this policy as well. The stakeholders want a say-so on whether the project gets built if the ISO has determined that they are benefiting. The economic study process is two steps. The NYISO does a long range congestion study, looks at historical congestion and does future modeling. Specific alternatives are identified and reviewed. Once projects are identified and are seeking approval there's a two step threshold window that these projects have to go through. This is similar to what SPP has, and that is state wide bid production cost analysis has to be done to show that the savings from the project over the ten years is higher than the cost from a bid production cost standpoint and also from a LBMP [locationally based marginal pricing] load savings perspective. After that the beneficiaries identified by the NYISO studies have to vote in favor of the project.

A comprehensive study beginning now in New York looking at the existing system is called the STAR study, state transmission assessment and reliability study. That means all the stars have to be lined up if they're going to get something done. It's focused primarily on existing right of ways. There's a lot of opportunity in New York's system to upgrade the existing right of ways without taking additional land to get more transfer capability, more throughput capability, reduce losses and other considerable benefits to the network and to consumers.

In summary, the New York system is an effective marketplace. It's bringing in the right resources, the planning activities are exploding, and they're embracing economic planning. The proof's going to be in the pudding, they have a lot of work to do.

*Question:* I want to go to principle 4C from the national WIRES panel recommendations. It says that planning should be conducted by a credible

entity without particular attachment to interests or outcomes. I am skeptical about independence but much less so in accountability. They're saying an ISO or some similar entity should be independent of the outcome and pass the costs on to consumers who are captive customers. However, there is no accountability other than to FERC which is not the same as to the end users.

Alternately, the SPP has the RSC in which there's a degree of accountability. It's the elected officials of the end users who get to submit a plan if one emerges. In the New York case there's an 80% requirement beneficiary threshold vote which is a similar dynamic. If we are going to pay then we want a vote. We haven't discussed the Columbia grid in the northwest but there the transmission owners and the utilities are responsible to ratepayers and regulators.

This accountability strikes me as a good thing. If one pursues a model focused on independent assessment then the tradeoff is lack of accountability to end use ratepayers. If these integrated, regulated, rate-base systems seem to be doing well with transmission development then is independence the big concern? Aren't there other factors? No matter what, this activity is political by definition. So it makes a difference who gets to decide and what the lines of accountability are.

*Speaker 1:* The accountability in this model is basically FERC. The god, mother and apple pie principles refer to open, transparent, and fully participatory. This means any actor in the region who is affected by the system or wants to play a role in it, has an opportunity to participate in the process and it's transparent, it's open. The entity that's carrying it out in some regions is the ISO. One can argue about how accountable ISOs are but clearly they don't have a stake in the outcome, unlike consumers, generators, suppliers, and other actors in the marketplace.

One wants an entity that doesn't stand to win or lose via the planning process. Accountability by ISOs is certainly debatable. If we consider regions without ISOs, there's a couple right beside the SPP that are completely

dysfunctional. They don't work. The main transmission operators in those states are accountable to their stockholders, not to other participants in the process. A neutral party is needed in the planning process that has no financial stakes in the outcome.

The concern of the panel was solely about independence, not about accountability, but that's certainly a worthy concern, but not necessarily relevant to independence.

*Speaker 4:* I agree. Planning is so important, and entities are also accountable for getting something done. If nothing is done and they just sit there and let the world fall in, they've got to be accountable for that as well.

*Speaker 3:* An independent entity is needed. You have to have someone independent of the outcome looking at transmission planning. In terms of accountability, in SPP the RSC's cost allocation working group wasn't an open stakeholder process initially. They very quickly we changed that. Because you need that input from all the different perspectives.

*Speaker 2:* Well? Accountable for what? Folks at the CAISO have an awful lot of NERC self certifications that say they're accountable to ensure everything is reliable and to choose which project bag money goes into. If one of those project bags that CAISO was deciding turned out to be their own project bag (assuming they actually built transmission) I think there might be a tendency to bias an outcome and not lead to the most cost beneficial solution.

*Question:* The difference between economic and reliability planning has a practical and a theoretical difference. However we also heard that in California they're no longer arguing over whether one is the right choice but just trying to figure out how to implement it.

Most aren't at that point on the economic planning. For reliability planning, NERC has said these are the reliability criteria, everyone must comply with them. That's no longer an issue of concern. Sometimes there are projects that can solve reliability criteria that have a

better economic result, and RTOs try to take those types of situations into consideration.

Solely economic projects are different. In PJM they used to have a historic looking economic test. They would look backwards and determine the cost of congestion in an area and see if a project could alleviate it. There was one project that ever satisfied that test. Everyone agreed it should get built, it was a very small inexpensive project.

Then FERC said RTOs should be looking forward and anticipating congestion and building transmission to solve that. New York is using the Argentinean method, an excellent model. California has a model determined by the state. Texas also has complete control. In areas like PJM with so many different states and different ideas, it is much more difficult. New Jersey's looking at significant amount of offshore wind, the western states have a lot of wind projects, some states think nuclear is the solution. Nobody really knows and certainly PJM doesn't know what the right answer is.

Why are so many states and market participants not supporting this idea of allowing those who pay to have a vote? The Argentinean method – it's been discussed at previous HEPG panels – makes so much sense. At places like PJM or MISO where it would have the best effect because there's so many stakeholders, there's been little attention to it or negative reactions. Why aren't people buying into this? Is it an advocacy issue? Is there a better story to tell that would help people understand why this is an excellent solution to economic transmission planning?

*Speaker 2:* In California they vote on absolutely everything. Everybody benefits and is impacted. Part of the difficulty is in identifying beneficiaries. They presume that if you run long trunk lines out into the wilderness everyone will benefit because everyone will have green power in their portfolio. It's possible people might say I'd rather do demand response or put on my own solar panel. Determining beneficiaries is very hard to do. Alternately in California everyone shows up to the hearings. Determining

beneficiaries makes it much more convoluted, political, and difficult.

*Speaker 1:* Part of the problem is that transmission planning is not just about transmission planning. For instance, the classic battle in New England where Maine argues it's being asked to subsidize projects elsewhere. The real flow of the subsidy has to do with the captive generation in Maine that can't find its way out and Maine likes the low prices captivity produces. Debate occurs as if it were about transmission planning, but in fact most of the debate has nothing to do with it.

Similarly, in California when SoCal Edison wanted to build and pay for a line from Arizona to California the Arizona commission said no. This was not because of transmission planning. Instead it was that Arizona wanted to maintain its captive generation and maintain low prices in their state.

*Speaker 2:* That example's worse because those states aren't in the pool to have the discussion and they can just go null.

*Speaker 1:* Yes. In siting every state has the ability to do that anyway. When one considers transmission planning it's something of a misnomer. It's about other things too. The second discussion panel later today is about that. It's about renewable energy gets built. Transmission planning also becomes a question of how to get more wind generation to market.

Let me come back to this point about reliability versus economics. There's another speaker who will embellish some of my discussion on that if that's OK.

*Additional Speaker:* The WIRES panel examined whether there is a bright line between reliability and economic upgrades. Everyone agrees there's extensive gray areas in these two terms. Generally people find comfort in the fact that NERC says that certain standards apply, and reliability is the guiding norm.

However, embedded in reliability, in a very non transparent way, are estimates of the value of

lost load. It's an economic concept. One could almost put it at an infinite cost. People are always saying reliability has to be met at almost any cost. So if in fact our system puts dollar signs on the value of lost load, then really all the projects become an economic study. This kind of thinking led the panel forward. What level of cost is society willing to pay in order to meet the keep the lights on?

There's no doubt it is so much easier to site a reliability line. What the panel wanted to address is to figure out how to publicly articulate a message that says it's not just about keeping the lights on, it is about keeping prices affordable at a time when electricity prices are rising extensively. Especially in light of aging infrastructure, de-carbonizing the fleet, etc. This issue really hasn't been articulated well, in siting proceedings and other contexts.

*Speaker 1:* Half the problem is what just got discussed and the other half is gamesmanship as I discussed a minute ago. Another issue is reliability. At least reliability gets short term fixes. Thinking forward gets longer-term fixes. If folks make effort to get something sited now why settle for something they'll have to fight about again in ten years because it will need to be expanded?

Trying to pigeonhole everything into reliability, because it is politically easier, creates shorter term thinking. It procrastinates a debate that will have to occur a few years down the line. The proper way to do that is to think entirely in economic terms, with reliability being an important component of that. That's how we have to frame the debate. Part of the problem is a civics problem; it's that fact that siting regulations are either local or state. That's a broader question as to what the role of the federal government ought to be. The extent to which we localize siting decisions extends to shorter term decisions.

*Speaker 4:* Let me comment on the 80% ratification beneficiary vote in the Argentinean Model, and why other areas haven't used it. The jury's still out. People are waiting to see how it works here, this economic planning is new.

People are trying to assess best practices, to see which model provides accountability.

Reliability and economics are beyond theoretical. There are hard concrete standards to meet in planning for reliability. Obviously they work well and make it easier to site.

Economic studies are much less obvious. Some years ago the NEISO did an economic analysis of congestion in Connecticut and the study showed \$500 million a year cost every year from then on. They went through the planning process. The next year they plugged in the same inputs, but with changing fuel prices and the congestion cost in Connecticut was now zero. Gas and oil prices had flipped that year. So when one analyzes the future, the difference that each fuel type may have can have tremendous impacts. Then they go through the process and siting. There's just so much that is in play. The opposition's going to bring in their five economists who will argue that all the assumptions were wrong. Determining economic benefits is much harder than determining reliability benefits.

*Speaker 3:* Midwest ISO is starting stakeholder meetings and there are proposals out there similar to the Argentinean model. The jury's still out on that approach.

Second comment. Economic studies that are performed are not broad enough. They do not look at sufficient alternative futures. A decision analysis would incorporate a probabilistic evaluation of many alternative futures. There's a real reluctance to look at a single study based on a given set of assumptions. Economic studies have to be very robust for evaluation on a broader scale than we are today.

*Moderator:* There is a practical difference between reliability and economic. A utility was building a small 115 KV load serving line in Georgia and some stakeholders were convinced it was going to be a tie to TVA, and it was being done for economic reasons. Even if something is being built for reliability, if one is building near the seams, it can seem otherwise.

*Question:* I'd like to comment more on the WIRES report. I've read the report several times. Folks at FERC have discussed it and made up simple examples and sent them to the group. The authors have said that their proposals don't work with simple examples.

When benefits are being discussed, and there's a low probability of somebody benefiting, do we weight the benefits by that low probability event?

Where do transmission rights fit into this? Several presentations didn't have any way to deal with transmission rights. There'll be people paying for these things. I agree with about six out of ten of the principles and I either don't understand or disagree with four.

*Speaker:* It's a way to get investment on a system. By getting the TCCs [transmission congestion contract] if you build transmission. Some don't think that will work, they argue that if you build the transmission and eliminate the congestion, the TCCs aren't worth anything any more. In some of these cases even if you build, there's still going to be congestion. If an interface capability is raised 1,000 megawatts it will load up another 1,000 megawatts and there will still be value there.

For some projects getting a minimum standard of operation may be logically rolled into a tariff whereas bump up capability that is added on would be aimed at market investment and TCCs.

*Question:* The stuff that gets rolled into a tariff has some TCCs associated with it, who's going to get them?

*Speaker 2:* TCCs are the property rights for transmission investment. So it's not so much did you build it but did you pay for it and if you pay for it you should be able to use them. This helps address the distinction between reliability and economics because economic signals are the early indicators of a more immediate reliability problem if you aren't looking far enough down the road.

In California the problem is not mapping the payment to the TCCs or the CRRs but their inflexibility because they're all hard wired and not very tradable. In New York they are more tradable. Another HEPG panel could occur on how these are used, but there are clearly some answers.

*Speaker 1:* The WIRES report authors did not address that issue because it was outside the scope of the project. They state that in the report and call congestion pricing an independent variable. Most of them probably favored LMP. If the cost is being socialized then obviously who's willing to pay the congestion price is going to end up getting the prime access. If somebody pays for it and it's not socialized, then they get TCCs, you could do that. It could be structured several different ways.

Second, part of the transmission planning process will address low probability events. The lower the probability, the less likely there will be fixes. If there are fixes, it's also substantially likely that somebody's going to benefit more than others. They're probably not candidates whose costs will be socialized. If that's the case then it goes into principle ten; if you want to build it, you pay for it.

If there are consequences for it, then there needs to be a process to pay for the consequences or suffer the consequences. For the most part, those questions were outside the scope of what the authors were trying to do. One could do anything in terms of congestion pricing and still be consistent with the report. I suspect the authors personal preferences were for transmission rights and some kind of congestion management. That's consistent with the proposals.

*Question:* Did you just say that if there are clear beneficiaries this process wouldn't be used?

*Speaker 1:* The process would be used for other reasons, particularly siting. There needs to be some sort of blessing that makes siting easier. Obviously if there are clear beneficiaries who are willing to pay the cost it's less controversial. If there are clear beneficiaries but the

beneficiaries are trying to socialize the cost it's going to be more controversial unless it's offset by other sets of benefits for somebody. In that case it's a wash.

*Question:* The SPP proposal requires the states to buy in early on and the siting and environmental concerns will be less of a hurdle.

*Speaker 1:* Don't assume facts that are not in evidence.

*Question:* Let's put it this way. If the state doesn't buy into the process that the WIRES report prescribed, then the state siting process could be very challenging.

*Speaker 1:* That's probably true, but even if the state commission buys into the process it doesn't mean siting will be easy. Around 22-28 states don't even have a siting law. It means the utilities can do whatever they want. In which case it's not state buy-in but local utility buy-in, or alternatively local zoning boards that decide.

*Speaker 3:* SPP is different from the other RTOs. They use physical transmission rights rather than financial. They may use FTRs at some point. For now, physical transmission rates are reflected in upgrades required to deliver from a resource to a load. When they're looking ten years forward they have to include new resources. In the base case they also include the deliverability upgrades required for those resources but the portfolio can replace some of those. When the change case is run if you replace any of those reliability or deliverability upgrades then the costs of those get treated as benefits to those regions that they would otherwise be allocated to. That's the way it would be treated in SPP.

I'm not sure I understand low probability events. Certainly stakeholders will put different probabilities on various events. Again, evaluations of projects need a spectrum of alternative futures for evaluation.

*Question:* An example of a low probability event is an event where the city of Boston starts exporting to Maine. [laughter] It's a possibility in the future but I wouldn't use that as a

justification that Maine is going to benefit and weight it equally with the idea that Boston may benefit.

*Speaker 3:* Here's another example. SPP recently had a cost benefit study for a fairly large 765 collector system for wind in the panhandle of Texas, Oklahoma and western Kansas. This cost benefit study looks at a single year and includes a CO2 adder of \$18 a ton. That's probably a reasonable expectation. The problem is, what if that \$18 carbon never happens? Just that assumption is full of enormous variation. It could be double the cost, or carbon programs might never get out of Congress. A study should integrate these various possibilities.

*Speaker 2:* On property rights there's been papers about the incompatibility of joint owned transmission between munis and ISOs. I don't agree with that. In fact, if an entity has paid for the transfer capability of the wire they get a right, either physical or financial. The only difference is that physical rights trade bilaterally in a very opaque way and financial rights trade very transparently. This proposal is the conversation starter for creating jointly owned transmission. A problem that has been portrayed as intractable. It's easy to solve if we switch into this paradigm.

*Speaker 4:* The Boston to Maine joke earlier actually can happen. Maybe not from Boston, but there's been seven events since last December where loss of gas on a pipeline coming down from the Maritimes caused significant generation to be off in Maine and New Brunswick. At those times, the transmission basically kept the lights on in Maine, and they were importing from the southwest. It is not high probability but it happened seven times in the last six months. That's the kind of thing that a transmission system does which often doesn't get incorporated in a snapshot study of the future.

*Moderator:* Incidentally, there is a successful jointly owned transmission system in Georgia where co-ops, munis, and the IOU all work together.

*Question:* Can you distinguish between principle five and principle seven? One says that projects are candidates for broad socialization where baskets of projects are involved, but on the other hand in principle seven it seems to be more emphasizing that beneficiary pays although it's worded slightly differently. Between these two principles is there a bright line?

*Speaker 1:* Actually there are two different questions. The first one is whether you're allocating to supply or demand is what principle five is saying, then principle seven says between supply and demand where do you allocate, so they're two different questions. Principle five is a more generic application. The second one is to say do we make this a battle between generators and the answer is no, we allocate it to load.

*Question:* Got it. Second, in terms of identifying beneficiaries, does the ISO in New York review or update its analysis of beneficiaries? We've heard this changes all the time. Is there resistance to the way the ISO does this? Is there an emerging set of principles about how to identify the beneficiaries in this model?

*Speaker 4:* Those details are very, very tough. They are being worked on within the pool. There are some procedures for reliability projects that identify beneficiaries based on a longer term LOLE (Loss of Load Expectation) analysis by zone. An LOLE analysis by its nature has a whole lot of different assumptions in it; it's very probabilistic. On the economic side there's a lot of work yet to be done. To promote investment you need stability, so it's something that they wouldn't go back and relook at every year. One wouldn't want too much uncertainty. It's an ongoing discussion.

*Question:* The single most important idea that we could salvage in dealing with transmission expansion is the beneficiary pays principle. I disagree with the white paper arguments. Principles five, seven, nine, and ten contradict principle four but other than that they're OK. [laughter]



And I don't accept the idea that you can't estimate beneficiaries. You can't estimate it perfectly, that's certainly true. The balanced portfolio theory is an appealing idea.

One can't do cost benefit analysis for transmission expansion without identifying the beneficiaries. That's the whole point of it is to change the patterns of use of the system. Many analyses get a pretty good estimate and look at lots of scenarios, certainly they do in PJM. Going to probabilistic weighting is a good idea.

The critical idea here is in the New York proposal which has beneficiary pays and voting for accountability. This is how it's better than integrated resource planning. Otherwise generators or demand-side investors are going to be looking for cost socialization too. How can the California ISO integrate this with markets if they don't preserve the beneficiary pays principle?

*Speaker 2:* The prices bring out the story. What's lacking right now for the Cal ISO is that if a trunk line is dropped into an already congested bus they won't know it ahead of time. In a transmission rights system, it will show them the prices are negative and they can re-right the ship if you will. It can't be done without transparency.

*Speaker 1:* Clearly the beneficiary should pay in economic theory. However, what are the transaction costs to get there? The transmission planning processes have intense battles to shift costs to somebody else. There are dueling analyses of the benefits, and all the analysis will be wrong over time. A reasonable estimate will not be accurate over the next 20 or 30 years. These battles are blocking expansion, even when the line is needed.

Large lines in the United States have been built by imposing costs on a subset of people who really didn't benefit from it but who, for whatever reason, agreed to pay for it. We've learned they're not the beneficiaries, they probably shouldn't have paid for it. On the other hand, these projects have benefited the broader region.

If we argue about beneficiaries over the long term then we will only build baskets of things that we need on a short term basis. The transaction costs for determining beneficiaries for a long term vibrant market are just too high.

*Question:* Why doesn't the New York approach solve that problem? The process removes the problem of the minority being able to stop it. There is an independent entity. The SPP approach can be used for calculation of benefits.

*Speaker 1:* It may or it may not. It depends on who's in the majority and who's in the minority and how those costs get allocated. How do one get to a majority? Do numbers get skewered to build a majority? It'll turn into pork barreling. If that works that's fine but that's no more beneficiary pays than anything else. That's political compromise.

*Question:* I disagree. The SPP approach to a big surplus of benefits is different than beneficiary pays because of the no loser idea.

*Speaker 3:* I agree with the questioner. When SPP first came to the RSC, there were several state commissions who were very concerned about moving to a postage stamp system. Once this evolved into their balanced portfolio approach, those commissions really bought into it. It's a form of beneficiaries pays. It's not strictly beneficiaries pay, it is a no losers test. The main thing is that this approach solved the political problem, it's a compromise between socialization and beneficiary pays.

*Question:* I'm concerned about the inconsistency between centralized transmission planning and competitive generation markets. In an RTO context, suppose a miracle occurs and an entity is able to invest \$1 billion to build a new gas plant to take advantage of high congestion prices in New York City. A year later the New York ISO decides that building a transmission line from upstate New York into New York City is still a good idea because this new gas plant didn't totally take care of congestion problems. Clearly the value of my gas plant goes down when that line is built. If New York didn't have

a beneficiaries pay system, would it be fair to reimburse the owner of that gas plant in New York City for the socialized transmission line that reduces the value of their plant?

*Speaker 4:* Under New York's new process, when this gas plant builds in New York and gets siting approval and there's no transmission additions then there's going to be competition among it and all the other plants that are in the New York area. Some of those are very old or inefficient oil plants and they're going to go away. If economic analysis still says to beef up the central east corridor to bring in green, low cost energy then that project would roll in under the beneficiary pays cost allocation process. The new plant owners would again face competition from a broader area now, not just the load pocket but the broader state. The transmission investment is opening up competition to broader areas because more generators can now compete and a different fuel diversity is going to happen. The investor is taking a risk and that's what happens in markets. That's competition.

*Question:* Yes, but if it were the market deciding whether or not to build transmission I'd agree with you, but in this case it's the regulatory process that's making that decision.

*Speaker 2:* Right, and then the ISO would have to decide if they have an intermittent product like wind is there a need for firming, or integrating power, to back up wind. It gets complicated fast.

*Speaker:* This illustrates the problem of doing transmission expansion on a project by project basis rather than looking at it in terms of the total portfolio. It also illustrates the problem with running a single scenario to do the economic evaluation upon which you make a decision, as I've mentioned earlier. Both the ISO and the gas plant investor ought to be looking at multiple scenarios. Finally, this whole process looks a bit like IRP.

*Question:* Here's another hypothetical. Consider a utility and generating plant that are contemplating a long term PPA to build a new generation facility. The generation facility

would require transmission that serves as an interconnection but also for network purposes. Does the "beneficiaries pay" model distinguish between the transmission use beneficiaries and the beneficiaries from the PPA? Currently in California, if it's considered a network facility then the costs are socialized and the PPA beneficiaries have no payment at all. That has some consequences.

Second, the transmission rights in this situation are a question. In California the system might eventually determine that the PPA has needed use of the transmission so they could get rights. That determination is ex post to the decision of making the investment. There's uncertainty for those who want to make investments because the CRR allocations aren't done until after the project is completed.

*Speaker 2:* Yes, this allocation methodology is a problem. The answer is get a market going, get some forward signals going. They need to use those market triggers and commercial signals to drive upgrades.

*Speaker 3:* In SPP, if network upgrades are involved with a generation interconnection then they are assigned to the generator. The generator gets the rights. In SPP that direct assignment gives that particular individual rights to recover revenues from other individuals future use.

*Speaker 1:* In the WIRES report that's one of the reasons determining the beneficiaries needs to be reassessed. SPP has a reasonable way to do it. The report emphasized the fact that a review has to occur. Patterns occur after 5-6 years and then the capital cost can be reallocated. A similar result probably occurs in either case.

*Question:* The problem here is that the investment decision has a lot of uncertainty. Timing needs to be addressed.

*Speaker 1:* That's true. Obviously the generator in your example would propose the line and then they start figuring out who's really benefiting. What you described is going to happen the vast majority of the time. That's part of the problem determining the initial beneficiaries.

*Comment:* New York does it ex ante at the time of the expansion, you get incremental transmission and TCCs.

*Question 2:* Does New York socialize it or is New York getting the TCCs because the two partners of this transmission have paid for it?

*Speaker 2:* This is a socialized line. It's not paid for by the counter parties to the transmission. The counter parties to the transmission want the benefit but they haven't incurred all the costs.

*Question:* This is the first time in the presidential debates that the transmission system was ever mentioned. [laughter] Anybody looking at these long term energy security and climate change issues understands transmission is a part of the solution. Does the new dynamic of plug-in hybrids and location constrained resources like wind and sun that will be there forever, transmission rights of way that will be there forever, change the way we think about transmission fundamentally?

*Speaker 4:* Yes. How does a system operator balance 7,000 megawatts of wind when it comes on within an hour, and goes away within an hour? There are some great new technologies coming into play but it will require infrastructure development and smart grids for end use consumers. Demand response is a part of this. There's nine million cars in New York. If 25% of them converted to electric vehicles and they charged at night, that would be 5,000 megawatts of demand. And the wind blows at night, normally it's a turndown problem. So 7,000 megawatts of wind, and 5,000 megawatts of nighttime demand could work very well together. This vision is going to take a lot of work.

## **Session Two.**

### **Renewable Rules: Market Friend or Foe?**

*Renewable energy policies often share broad goals such as California's 20% of electricity procurement or the European Union's 12% of energy production in 2010. The objectives include reduced carbon emissions, energy diversity, regional economic development, and so on. The multiple objectives produce significant variation in policies and programs. Procurement mandates, tax support, feed-in tariffs and many other innovations present an array of details that have important incentive effects. When volumes are small, the details matter a great deal to the investors in renewable technologies, but are much less important to everyone else.*

*Speaker 2:* The rate of change requires us to maintain a technology neutrality because we don't know where that next "aha" is going to come from. We don't want to decide for the markets ahead of time.

*Speaker 3:* It does take a new way of thinking. And it does look like integrated resource planning. The other thing to remember is that even with the big transmission overlays to deliver wind from the plains area to the east, the total investment for transmission is 6% of the total cost of electricity. People need to keep these things in perspective.

The joint coordinated system plan is an agreement between Midwest ISO, southwest power pool, PJM, New York, TVA, and New England. They have been working on this project in conjunction with DOE. DOE's doing a wind integration study as well. They've got two different scenarios. One is to meet the requirements that are there today and the second study is to meet a 20% renewable standard.

They do an economic evaluation of both compared to base case. It is a cost benefit study. They assert that transmission will be 6% of the total new resources needed over this long term period.

*Speaker 4:* Yes, the investment in bulk transmission is a sliver of the total cost of power. However, even without building large lines to the plains, there's wind already located in these states that can't get to the market now. It would be comparatively cheap just to get transmission built for those resources. We all have to look at the alternatives, and try to bring the different studies together.

*But when the incentives work, and the rules produce a significant response, new questions arise. How do the mandates, subsidies and protocols interact to affect total costs? Who pays? What impacts are there on electricity market operations and investments? How can policy distinguish between goals as different as supporting infant industries (in the short run) and internalizing environmental costs and benefits (in the long run)? What must be done to provide support for renewable energy and for the operation of electricity markets? Does the experience in different regions provide insight for future program development? Are sustainable energy policies sustainable?*

## **Speaker 1.**

I will discuss California's renewable energy policies. I'll go over policy rationales and how they've evolved, how they can come in conflict with each other and three case studies to provoke discussion. These are tradable renewable energy credits, an example of conflicting rationales; learning by doing as a rationale for the California solar initiative; and the challenges of integration, from an infrastructure and policy perspective.

California has been encouraging renewable energy development for many decades. Before their renewable portfolio standard they were aggressively implementing PURPA through standard offers, which were essentially a feed-in tariff. Before the California solar initiative they had incentives to develop the photovoltaic industry. What's different now is the policies have a much larger scale. The questions they are facing are how to integrate 20, or even 33% renewables into their grid. How do they integrate policies with a cap and trade market for greenhouse gas, or will cap and trade be able to replace some policies.

California's renewable portfolio standard passed in 2002. There were three objectives. First to stabilize and contain prices by creating a physical hedge against natural gas price fluctuation, improving air quality, and stimulating growth and creating jobs. There's was no direct reference to climate change or mitigating greenhouse gases. Things are different today. AB32 is now law in California. It passed two years ago. It mandates that the entire state's greenhouse gas emissions, including in-state resources and imported electricity, be reduced to 1990 levels by 2020.

The California air resources board is the principle agency responsible for this. So far they have a draft Scoping plan which is highly conceptual. They suggest that the RPS be increased from 20 to 33%. That's been endorsed by the PUC and the governor but not yet by the legislature. Energy sector mandates are about 40% of the total greenhouse gas emission. The RPS increase would account for about half of the electric sector mandates.

The concern is that on a dollars-per-ton basis, renewable energy is a costly greenhouse gas abatement measure. This adds questions about the carbon abatement aspect of renewables in addition to other methods for carbon reduction. Further, the 20% by 2010 target is itself quite ambitious. The RETI process discussed earlier is an example of the regulatory lessons learned earlier that led California to approach transmission siting from a different angle.

Let's take a look at tradable RECs. The California PUC has been gradually liberalizing what was a strict deliverability regime in the original RPS. It originally focused on developing in-state renewable resources. The PUC's proposed decision late this year would set up a tradable RECs program. The basic idea is that somebody somewhere, probably not in California, develops a renewable resource such as a wind farm, they sell the renewable energy credits to a California utility for compliance with the state's RPS program. That utility pairs the RECs with brown power from another source, in or out of state. The null power from the wind facility gets shipped off to another load center that's accessible within the transmission grid, closer to it. It's referred to as null power because it's been stripped of its renewable attribute.

This approach allows California to reach throughout the Western Electricity Coordinating Council [WECC] Region. There are renewable pockets throughout the WECC region. This program encourages renewable development wherever it's cheapest to build, facilitates compliance for the in-state utilities, lowers compliance costs, and overcomes transmission constraints in the near term. This isn't a panacea, it doesn't eliminate the need for transmission investments but it may defer some.

The conflict is between the needs for climate change and renewables that this addresses and the original goals of state growth and air quality that this new program doesn't address. These are particularly important to the legislature which has the act to go to 33%. The fuel cost-hedging attribute of the renewable portfolio standard is also important to California ratepayer advocates. Obviously, developers are focused on stimulating the growth of the industry and utilities would like to comply at least cost on behalf of their ratepayers. It's hard to balance all these considerations because from a climate perspective it doesn't matter where one builds the renewables. It does matter if the primary goal is to stimulate in-state growth and clean California's air.

Some stakeholders believe RECs are a menace because they may ship the jobs and growth and environmental benefits to other states. Ratepayer advocates are concerned that the state loses a long term hedge against gas prices. Some argue that out-of-state RECs mean the state doesn't get any new renewables at all. They say utilities will just comply by buying RECs. Since RECs don't provide the long term contracts that developers need, therefore the state won't get any renewables, they'll just have increasingly expensive RECs. The economist in me says doesn't that mean we'll get more renewable development?

Let me turn now to the solar initiative. It's designed with progressively declining incentives that are triggered as the amount of cumulative capacity installed comes onto the grid. This provides a stable environment that promotes progressive learning by doing and experience in

the industry to lower costs over time. The reductions and the incentives are only triggered as costs go down, and learning occurs.

An interesting recent paper came out of Stanford's Precourt Institute for Energy Efficiency. They try to estimate the learning by doing benefits associated with the California solar program. They ask how would you design a series of decreasing subsidies in order to mature the industry based on assumptions about the rate at which learning occurs? The somewhat surprising but very encouraging conclusion is that the subsidies under the CSI (California solar initiative) are remarkably consistent with an economically efficient program in various contexts. It's a big support for the program as a cost effective investment and as a tool to mature the industry.

Let me come back to RETI which was discussed in the previous session. Again, this is going from 20% to 33% and is an enormous increase in the amount of renewables to integrate in California. Based on current cost projections and in RFOs the PUC expects that intermittent resources will dominate. This poses not only challenges for transmission but also on the generation side. What sort of resources are needed, whether they be peak or plants, or stepped up demand side management programs. What is needed to integrate those resources. The spirit of this RETI is how to look ahead at those pieces of the puzzle, and bring the key agencies to the table: the siting agency which is the energy commission, the CEC, the state and federal siting authorities who are siting both transmission and power plants, the PUC which has to approve rate recovery. The PUC has to determine which could realistically pass environmental and cost screens and winnow down from 29 projects to a manageable number.

It's an institutional approach to the challenge of physical integration for renewables. It does sound hauntingly familiar, very much like integrated resource planning [IRP]. Will climate policy drive energy policy? Are climate goals driving us back to a different model for the energy industry? The challenges of balancing a cap and trade program with a renewable

portfolio standard create competing, conflicting or perhaps duplicate incentives that have to be reconciled.

## **Speaker 2.**

I'm going to discuss the situation in Texas. The journey in renewables in Texas began in 1999. The move to more renewables emphasis was eerily prescient. Historically, fossil fuel is how they kept the lights on. There are three forces that make renewables an even better proposition in Texas.

First, the global demand for materials and skilled labor. The per capita consumption of electricity in China and India would have to increase 600% and 1,000% respectively to get to the same per capita usage as the U.S. Given their enormous increases in GNP and the large amounts of people, they will dwarf the rest of the world in 2050. This creates enormous pressures on skilled labor and materials particularly when it comes to central station large generating units like nuclear or coal. The EU and the U.S. are going to lose population or stay static between now and 2050.

However, Texas will be increasing extensively. Texas truly is like a whole other country, as their tourism bureau has said. They have 1,500 people moving to their state every day creating tremendous pressures on energy. They're minimally interconnected with the rest of the country, with some DC ability but for the most part it's their own provision. They're also cursed when gas prices are high because they are a "gas on the margin" state.

On a peak load day, like the summer of 2006, it was 62,500 megawatts. They have nuclear and coal running 24/7 and everything after that is gas with the exception of the wind. When gas was at \$2.50 an MMBTU this was a fairly good proposition. As it peaked to \$13 this summer, there were prices reaching the cap of \$2,250. From a capacity perspective they're almost 70% natural gas and from an energy perspective they're about 40%.

Cost increases for the capital costs in development of large central station generating units, whether coal or nuclear, have absolutely gone through the roof. Most of this is in materials but it's similar for labor. Had the state chosen one of these as the right way to go five or six years ago, guaranteed it would have turned out to be the most expensive. Fortunately, in the ERCOT market generation is completely deregulated. They allow the developers to decide what they want to build and where they want to build it.

In 1999 Texas originally started with a 5880 mw goal for wind. They were hoping for 10,000 mw by 2025. Of course they will have 8,500 mw online by the end of 2008. They have a lot to brag about. They're on a path to 18,000 megawatts of wind by 2014. There are requests for interconnection at ERCOT for 52,000 megawatts of wind.

The Competitive Renewable Energy Zone [CREZ] process begins with designating competitive renewable energy zones or areas. ERCOT brings in a wind consultant who put up wind measuring devices all over west Texas and the panhandle and measured the wind for 18 months. Then they drew boundary lines on a radius from where the wind measuring device was. There were originally 25 zones and those were narrowed down and consolidated to five major areas. The best wind on a capacity factor basis is up in the panhandle, which is very long way from where most of the people live.

The PUC had 4 scenarios for wind development, which focused primarily on the development and installation of differing amounts of transmission to serve these areas. The Commission chose a moderate case that will bring 18,000 mw of wind to the cities in the east. It'll cost about \$5 billion in transmission development, or about \$4 per average customer in ERCOT.

They now have a rule making to choose the developers, the transmission service providers (TSPs). There are settlement negotiations presently. This is a really dramatically different way from building transmission in ERCOT. Historically it bubbled up through the regional

planning group through the ERCOT stakeholder process. Then it was presented to the Commission for approval or denial of the Certificate of Convenience and Necessity (CCN). Then, whoever the legacy TSP was, they built the project. In this new process, there's an element of competition for the selection of TSPs.

The PUC wanted to look at the capacity mix at two times in the future, 2013 and 2018. This was primarily to look at integration and operational issues for ERCOT. They will see a small increase in natural gas even with all the wind, or new nuclear. They are still building coal. There are six conventional coal plants in various stages of construction presently. There are 3 firms intending to build new nuclear in Texas which would be 10 gigawatts. These scenarios assume that half of that actually gets built.

So Texas progresses from having a heavy dependence on fossil to having a higher dependence on wind and nuclear or natural gas. There are significant challenges with a 20% wind mix. The operator needs additional tools. There will be additional ancillary costs, but some natural gas production costs will be avoided.

*Question:* Has there ever been a study of what it costs electricity consumers in Texas for ERCOT to remain an island?

*Speaker 2:* Not that I know of. Their reliance on natural gas makes them subject to the volatility in that market.

*Question:* You mentioned that scenario two would cost \$4 per month per customer. Was that transmission and the wind generation power but also the ancillary and matching services?

*Speaker 2:* It doesn't cover the ancillary services.

*Question:* What about when the wind doesn't blow, does it include those costs?

*Speaker 2:* They're already doing that. There's so much wind already and they firm it up with natural gas presently. That cost was the

incremental cost above what they presently incur and for the most part that is the cost of putting up the steel and the wires and the poles.

### **Speaker 3.**

I am going to discuss the situation in Europe. The financial markets in America and in Europe are similar but the same does not apply to the electricity markets. Why is Europe different? They have mandatory wholesale and retail competition for electricity and gas. 500 million people can choose a supplier from any one of the 27 member EU states. There is regulated access to all transmission and distribution networks and a carbon trading system. Electricity prices internalize the cost of carbon. Very importantly, they do not have FERC in Europe. [laughter] At least not yet.

In March 2007 the EU decided that energy policy should not be independent any more. There is an integrated approach to climate and energy policy. This is a big reason for current policies. The energy sector, with 29%, is the biggest emitter of CO<sub>2</sub>. The other major issue is security of supply. Europe imports about 50% of its energy needs. This figure will increase over the coming years. There is only one country which is a net exporter of energy, and this is Denmark. Renewables are a way of reducing import dependency and increasing security of supply.

Denmark also has double the average share of renewables in per capita energy consumption. They are at 17% and the EU average is 8.5%. So even countries with rich fossil holdings can have an interest in developing ambitious efficiency and renewable policies, and this is the case indeed with Denmark.

By 2020 the EU plans to have 20% of final energy consumption coming from renewable sources. This translates into 35% of all electricity generation coming from renewables. Where are we today? In 2005 there are five countries with more than 20% renewables in their energy consumption. There are some good examples for the future. In terms of electricity

generation, renewables account for about 14% of total generation to go to about 35% by 2020.

Most of this comes from hydro, and then biomass, wind, etc. About 66% comes from hydro, or 300 out of 464 terawatt hours. PV (photovoltaics) and wind have the highest growth however – from 1990 until the present. From 1990-2004 the annual growth rate of total renewable was about 3% but if we take the last years it's about 10% per year growth rate.

Hydro will have an important role all the way to 2020. Some countries are further exploiting their hydro potential or upgrading existing power stations. Onshore wind will be the second most important form of renewables. We will see also an increase in offshore wind and in the biomass. The other forms of energy play a less important role.

These achievements depend to a large extent on incentives. There are 27 different types of incentives. Each member state has its own mixture of incentives, but the main ones are the feed-in tariff certificate, green certificate system, tendering, and tax incentives. These can be combined. The lesson from the last 15-20 years is that the feed-in tariff system has been the most effective in making renewables appear, not only on paper but in reality. The two best examples are Germany and Spain.

I'll discuss Spain as you'll hear more about Germany in the next presentation. Spain experienced an impressive increase in installed capacity via co-generation and wind. During the first four months of 2008, co-generation and renewables accounted for 26% of total generation. It was the first time generation from renewables and co-generation was more than nuclear and hydro. This percentage will increase when projects being built right now come online.

A common criticism is that some forms of renewables are not reliable and not available during peak hours. However, in 2005 and 2006 co-generation and renewables accounted for about 17-20% of peak during the annual peak load time.

There were 24 gigawatts of installed capacity in 2007 and Spain expects 37 gigawatts in 2011. The massive penetration of renewables changed system operation throughout the EU. Control centers for wind generation which communicate with the national control center were introduced. They predict wind generation and integrate forecasts into the national load and generation forecast in order to optimize system operation. There's been a lot of new business developing the software for these facilities and building these facilities, integrating the software and so on.

Another criticism, particularly of wind and solar, is the common argument that huge investments in networks are required but this is not necessarily always true. For instance, in 2006-2007 Portugal had one of the highest growth rates in terms of renewables. However, these only accounted for about 10-12% of total transmission investment costs.

I'll focus on four challenges. Prices, market liquidity, demand response and regulation. Prices. There is a free market for all retail customers since 2007. In theory it's possible to trade throughout Europe. The problem is that the prices did not go down. It's hard to explain why competition is not preventing prices from going up. It creates difficulties to legislators considering the introduction of new subsidies or new ways of economically financially stimulating renewables. Acceptance of new costs and price increases is very low, as you can imagine.

Alternately, renewables can have a positive impact on wholesale electricity prices and can decrease them when the amount of renewables becomes significant. For instance, data in Germany from 2006 shows they had 52.2 terawatt hours of renewables. This reduced generation from conventional non-renewable sources, resulting in wholesale price reductions in the wholesale market around 5 billion Euros.

So on the one hand renewables require incentives that are supported by consumers, but it can decrease prices. However, incentive



programs decrease liquidity in the market. 35% of electricity generation coming from renewables mean Germany needs 200 terawatt hours. This will have an impact on the competitiveness of the wholesale market. These problems must be addressed before 2020.

The most efficient and cheapest way of solving the intermittency problem of solar and wind is demand response. It also decreases wholesale prices, particular at peak load periods. Demand can be elastic and have a potential benefit. However, it requires changing IT infrastructure and introducing smart meters to interact with appliances, devices and manage demand more efficiently. There are several technologies competing here. There is no coherent regulatory framework for these devices. Some countries have already made bad decisions. For instance, Sweden introduced electronic meters but unfortunately they have replaced five million meters with the wrong meters. They are smart but not very smart indeed. [laughter]

I am originally a power engineer. The truth is that network operators are not very innovative. They tend to prevent the introduction of new technologies. It's like the electricity industry will be last to move from electromechanical control to electronic control. Regulators have to think about how to give the right incentives for network expansion, development, and system operation.

Demand response. We do not have a regulatory framework which addresses network expansion, system operation and demand response to enable renewables and energy efficiency. So what is required is a new approach. The old regulation means that you look at the system as it is today and then consider renewables as an extra cost and the question is how to allocate this extra cost. Now, in my view this is wrong. We shouldn't look to this legacy transmission system of networks, but to the future. What are the policy goals, how the system should look in the future and determine incentives to get there.

*Question:* The EU is a net importer. Who are they importing from, Russia?

*Speaker 3:* Yes, Russia is one of them. Algeria is another. They also import gas from Norway.

*Question:* Is all hydro counted as renewable?

*Speaker 3:* When it comes to 2020, the answer is yes, hydro is counted as a renewable source. But large hydro is not subsidized, only small hydro, typically less than 10 megawatts.

*Question:* You mentioned that co-generation and renewables met 20% of the peak demand. What is the breakdown?

*Speaker 3:* In 2007 in Spain, that is the information you are mentioning, they had a total installed capacity of 24 gigawatts. 13 is wind, 6 is co-gen, 2 is hydro and the rest is mixed.

#### **Speaker 4.**

Today I'm going to talk about the experience in Europe with different systems of integrating renewables into the market. Europe is currently in its 20s. Europe decided to have 20, 20, 20 by 2020 [laughter] which basically means they have 20% renewables in 2020, 20% of energy efficiency and 20% of CO2 reduction. So that's quite ambitious.

Europe started in the 80s with the oil crisis. Their solution to the supply security problem was to implement renewables. The first step was research and development. In the 90s the focus shifted from research and development to implementation. The hope was to implement large enough numbers so industry could come up with new ideas for cost reduction.

They have two basic ways to do this. The first is the quota system which is market driven in theory. The second is feed-in tariffs which are not really market driven and normally supposed to be cost inefficient compared to quota system. With a feed-in there is a fixed amount of money but the quota has the cheapest ones go to the market. There are other systems that are interacting together, like tax subsidies and tendering systems. In addition there is the European emission trading system. Renewables

don't emit CO<sub>2</sub>. They are now introducing something called the white certificate that is a tradable mechanism for energy efficiency. It's unclear how this is working out.

Each country has a different combination of mechanisms. There are feed-in tariffs in most of the countries and quota systems in others. The question is which is more efficient? We'll start with the quota system. The UK used it the most. They started early in the 90s with a tendering system for non fossil fuels; if you do not use fossil fuels you get some type of support system.

From 1998 onward they had a renewable obligation certificate which is a tradable green certificates (TGC). This got very minimal results. They had a target via a market based system but never reached it. If you don't reach the target it's not the least cost energy that sets the price, it's the price cap that sets the price. The price cap set the price for green energy in the UK and this is quite high. They received a small amount of expensive green energy. They started from ten megawatts in the 1990s to 2,400 megawatts in 2007. Germany has achieved 22 gigawatts of renewable energy sources (RES) in a smaller time frame. One has to consider that in 1990 everything was expensive for green energy; there was a high learning effect in there. The UK says we are the most windy country in Europe and we are not producing the best wind turbines in the world. This is done by Germany and Spain and Denmark. So the government is now trying to force offshore development by additional subsidies and governmental support for that market.

Germany has been quite effective when it comes to increasing green energy. The political shift that included the green party really created a priority for getting some real green energy into the market. They had ambitious targets which they have reached. Most studies seem to indicate that Germany will make its 2020 targets as well.

There is a base level of hydro in Germany, which doesn't change any more. Their hydro is fully exploited. There has been a tremendous increase in wind energy in the last years; the same is true for biomass and an even larger scale

for solar. Anyone who ever comes to Germany in the summer knows they are not a solar country. [laughter] It's not like California or Texas. Anyway they have two gigawatts of solar and additional gigawatts in local solar. Small houses that put on solar panels to increase their heat utilization.

The feed-in system in Germany may not be cost efficient but it's effective in putting up large numbers. In the 90s, Germany mandated feed-in electric energy if it's renewable. There was regulatory support to get it into the grid and money for that. Any renewable was eligible. From 2000 onward the renewable energy law implemented a feed-in system with price adjustments for different sources, particularly off-shore wind and solar. This has resulted in enormous increases. The projections for Germany for onshore wind installment are 25 to 30 gigawatts. Anything beyond that has to be offshore, there's little open space onshore. There's an increase in nearly all renewable energies. It's not like in the UK where there's some wind and a little bit of biomass but no solar. The feed-in system supported everybody according to the cost.

Let's look at a third example in Spain. They are second in wind development in Europe. In 1998 they developed a special support system based on a feed-in strategy. They had two options. The first is similar to Germany, with a fixed feed-in if you plug in renewable energy or one chooses a premium on top of the market price. They adjusted the premium in 2007 because market prices were increasing so much. There was too much windfall profit for the renewables. There's floors and caps implemented in that premium now.

They are also quite efficient in getting renewables to the market. The main difference is that Spanish developers have the two options. They can switch between the two options every year. For example, if market prices go down and the premium doesn't provide much support then they will go to the fixed tariff. They can switch back if the market goes back up. This provides increased security for renewable energy generators. The premium is the preferred option

so far mainly because market prices are quite high, and incumbents are also involved in wind park investment. This is an important difference from Germany. In Germany, investment mainly took place with small independent producers, farmers, locals. In Spain, there's a mixture. Large incumbents also participate in that system. In the UK, only the big companies seem to function in their quota system.

Balancing is an important issue for renewables and this is much more transparent in Spain. There's a clear system for how it integrates all the wind and how it functions in the market. In Germany it's highly nontransparent what's happened. The wind goes to the TSO [transmission service operator] and they make a flat base load band out of wind. This is stupid in itself because wind is always fluctuating. They sell that back to the market and then have to cope with the imbalance from the band they just produced. There are more balancing arrangements, and money for that and that gets added to the network tariff. They would argue they socialize the cost. In Spain, it's much more transparent, that's a good advantage. It's seen as a successful policy in Spain and beyond that.

There are critical problems. Cost allocation – it's not clear who will pay; particularly for network integration and management. There are problems with getting wind from the North Sea to where it will be used in Germany, the transmission infrastructure is not in place. There are no locational market prices in Europe so there's no information on congestion in the system. If a price difference exists between countries then it's clear there's a bottleneck but that's the only way to know. Within a country this is all more or less done with cost based re-dispatching. This is highly nontransparent. Upstream competition is an important issue. It's not really important how big the competition between the renewable energy generators is but it's important how much competition there is on the production side of renewable energy. Wind turbine cost drives the cost of renewable energies. Renewable energy policy is seen as industrial policy in Germany and in Spain, especially if one considers employment rates.

Especially in East Germany, there were problems with unemployment, and now firms produce wind turbines or solar panels. There are local benefits from renewable energies and these increase the acceptance for renewable energy. These become both green energy and industrial policy that affect employment and industry development.

There is a question of how much price reduction occurs on the electricity market due to the feed-in of wind energy in Germany. Some analysis shows that the market price reductions are so high that they offset what consumers have paid for the feed-in tariff for wind energy. Even after that there is still a consumer gain of three Euros per megawatt hour. This is a short analysis given fixed power plant market prices on an hourly basis with startup conditions. Of course, in the long run there will be a shift in the power plant mix, with balancing issues. In the short run there is a market price reduction.

There's also some analysis concerning the availability of wind during peak hours. Germany saves four gigawatts of peak load in the last three years, however that's not certain. Wind is not available all the time and during peaks there may be zero wind. There isn't data on that. Nonetheless, this another strong argument for demand response.

Europe is currently discussing what to do with renewables on a bigger scale. They want a single European market, and a single European renewable support system. However, now they are reconsidering. There are many different national systems. They are all somehow working and it would be quite hard to now put them into one system; especially if it's market based which means a quota system. The current policy is to wait and see.

There's a debate about whether to try an improved market based quota system, use a feed-in system, or design a hybrid. Numbers from 2003-2004 show that quota systems are worse than the feed-in systems, which mainly because they all miss their targets and end up with penalty payments.

For the next few years we will see national policies that somehow interact, that stop at the border and that's it. In the medium term they will stick to feed-in tariffs.

*Question:* When you discussed savings there were time issues. Can you explain that? It looks like it's the hours during the daytime that have the largest savings.

*Speaker 4:* Basically the analysis modeled all the hours during a year between 2006 and the middle of 2008. For each hour they took the actual wind feed-in and compared it to what the prices would have been without it. At night, during off peak, there's no impact because demand is so flat that even if there is a lot of wind it doesn't matter. During the day, even a small amount of wind can mean a big shift in the price.

*Question:* In order to guarantee a secure supply of electricity in all possible load cases nearly the full wind capacity must be backed up. Is the cost of the other generation that's needed to back up the wind included in this analysis?

*Speaker 4:* No. The analysis examines the fixed market and looks only at the wholesale. There's no analysis of balancing issue or the capacity cost. There's no capacity cost so far, only the spinning reserve market. There are other studies that analyze that issue and they show how much is still saved.

*Question:* What is the feed-in tariff in terms of hourly cost?

*Speaker 4:* For wind it's roughly nine cents in Germany. Biomass is I think a little bit below that but nearly the same. Solar was 50 cents, it's now reduced. That's 500 Euros per megawatt hour, which is really a lot. [laughter] This basically means solar is highly uncompetitive if you don't have a feed-in system. This number is reduced now. What's important is that these numbers decrease each year. If one installs something in 2006 there is a specific amount of a feed-in and that's for 20 years. But if they install it in 2007 they get a smaller number for

20 years. It's decreasing each year with a certain percentage.

*Question:* What is a typical retail rate for a customer?

*Speaker 4:* Something between 20 and 25 euro cents per kilowatt hour including of course transport, taxes and all that stuff.

*Question:* Are there similar incentives for end use energy efficiency?

*Speaker 4:* Not yet. Everyone knows it is useful; you save energy, you don't consumer fuel, and then you save money already. It's being discussed.

*Question:* Dena Grid Study One looked at the transmission requirements to 2015. Are those numbers reflected in your net savings per euro?

*Speaker 4:* No. Transmission costs are not in there. The savings were around 700 billion per year. The Dena grid study is assuming that by 2015 one billion Euros should be spent to extend the grid. There should still be substantial savings even after transmission investment.

*Question:* Dena expects grid study two in 2009 and that would incorporate the offshore. This aspect would be a much larger investment, bringing in 28 gigawatts from four different nodes. This is a much more significant investment. What would the cost of that upgrade be? The onshore wind was incorporated much more easily.

*Speaker 4:* There have been some studies concerning wind integration into the German grid on a nodal basis. They assume some demand flexibility. These show that eight gigawatts of offshore wind can be put in without too much additional effort into the system. However, this assumes that no fossil fuel plant would be running at the North Sea coastline which is uncertain. One option is to implement high voltage DC connections instead of enforcing the AC grid – this needs to be studied. That would amount to something like two billion for the high voltage DC alone compared

to the one billion that Dena is already estimating for 2020 for the onshore. That's not that high.

*Question:* Did the prices with wind include the feed-in tariff?

*Speaker 4:* No. The prices I discussed are just the wholesale price. However, the three Euro per megawatt savings includes the feed-in tariff. There's still a net benefit after the feed-in. However this only measures wind. The feed-in for biomass and solar is higher and they may not produce a net benefit.

*Question:* I don't understand the tradable RECs in the California system. What is it that is sold? What is the obligation of the wind generator? What do they have to do? Do they have to run their plant? On the other side of the equation what is the buyer buying and what is then traded and finally how is the initial price determined? Can you walk through the process?

*Speaker 1:* The core function of a tradable renewable energy credit or a TREC is that it's a compliance vehicle for a renewable portfolio standard [RPS]. So when a wind operator sells a REC to a utility with a compliance obligation under an RPS then they're selling a strip of RECs over a given time frame. The generator has to operate at least that many hours or get the RECs from somebody else who did operate.

*Question:* They're selling a strip of energy?

*Speaker 1:* They're selling an *attribute* of a strip of energy. The actual energy left over is still a commodity that California calls "null energy." That can be consumed and sold some place else.

*Question:* But does it have to run?

*Speaker 1:* It has to run because otherwise it isn't displacing brown energy on the system. It displaces brown energy and increases the ratio of green energy on the system. The energy is deconstructed into those two parts, the renewable energy credit and the energy component.

Currently prices are handled informally, and negotiated on a bilateral basis. If the commission actually approves tradable RECs then a market price regime should develop. Then one could either buy them on a spot market or via long-term bilateral contracts.

*Question:* The wind generator can't sell the same energy to somebody else, right?

*Speaker 1:* They can't sell the renewable attribute more than once. They sell the energy to one entity and they sell the renewable attribute to somebody else. California will implement a tracking system to assure that nobody sells the same REC from a given facility more than once if a trading system is implemented.

*Question:* So a municipally owned wind generator could use the wind for their own purposes but sell the attribute to someone else.

*Speaker 1:* Right. The municipality could not claim to be "green" if they sold the attribute, if they sold the REC.

*Speaker 2:* There was a lawsuit because wind was being curtailed early on in Texas. Wind generators were unable to generate as many RECs as they would otherwise. It wasn't the wind generator's fault that they were being curtailed so the Commission thought it should ignore the curtailment in calculating the number of RECs that the turbines were generating. The Commission was sued over it and they lost. Being able to actually deliver the energy is an important component of REC trading.

*Question:* With renewable portfolio standards, who is on the hook when you have a goal to reach 20% by 2020. Who has to achieve it, who pays for it, how is the money collected and what happens if the goals aren't achieved?

*Speaker 1:* In the California RPS, the entities with a hard compliance entity are investor owned utilities. It's an aspirational goal for the public power providers. There is competitive retail sector that also has a small obligation. It is a quota system as opposed to a feed-in tariff. It

has annual incremental increases to get to 33% by 2020.

Who pays? Ultimately, it's the ratepayers. The utilities sign long term contracts with developers who build new renewable facilities that sell them the energy. If utilities miss their obligations then there are penalties and options to push obligations further into later years.

*Speaker 2:* In Texas, the retail electric providers, the REPs, have to acquire a certain number of RECs on a load ratio share basis. The RPS requirements are set incrementally so that in the beginning it is low and ramps up. There are penalties also but compliance has not been a problem. Currently the prices for RECs are relatively low.

*Speaker 4:* The UK has a quota, the distribution companies have to fulfill it. Penalties are refunded to the REC generators. So it increases then the quota price they get. In the end it's the ratepayer that always pays. I think it's the same in the Netherlands. There's been discussion in the EU about importing quotas from other countries. For instance, Norway has a lot of hydro and they were discussing can we get the hydro from Norway. The ultimately decided not to so that local impacts are maintained.

*Question:* On the UK quota, if there is a quota with a price cap and the price cap kicks in then it becomes functionally equivalent to a feed-in tariff at the price cap. Why is it ineffective? Is it that the price cap was a lot lower than the feed-in tariff?

*Speaker 4:* Basically, it's more or less what you said. In the UK there are problems with investing into RES [renewable energy sources] energy. They are concerned that if they invest too much they will end with too much green energy and the quota price will go down and their investment won't pay back. There's a strategic incentive to invest only minimally. But basically it is the problem that the price cap is not as high as the feed-in tariff.

One idea is that tradable certificates may be on the wrong side of the market. Currently, a

producer gets a certificate in market in which the prices go down if you add more product. In the European emission market it would mean that instead of giving certificates for CO2 emissions you would get certificates for clean air.

Maybe it should be switched so that there are certificates for brown energy with associated targets. This would provide much more economic information about the price for any given target. We might need to think more about how to set up a better model. Maybe the certificates should be switched to the fossil fuels and then green fuels can be financed with that income.

*Question:* In California the renewable standard began for reasons separate from climate change. Now there's more connection between renewables and GHG mitigation programs. CARB [California Air Resources Board], the PUC, and the CEC want to include 33% renewables as part of the program to reduce greenhouse gas. This makes the cost of renewables in comparison to other GHG mitigation options something to consider.

In the EU, is there much thought given to the cost difference between renewables and other GHG mitigation? Does a 50-cent solar photovoltaic feed-in tariff make sense relative to costs to mitigate GHG through other options?

*Speaker 3:* No. This ought to be a question. The EU goals are solely about reducing global warming. Various policies come from that basic objective. With some assumptions you can derive a goal for renewable generation, for energy efficiency and for other things. There is some initial coherence.

The next step is less coherent. Europe should do what they did in Texas. That is, make an assessment of the resource potential for wind, for solar, for biomass and so on. Incentives should set that make geographic sense. This is very difficult with 27 nations that have different social and industry policy goals. The pragmatic approach is to fix quotas for each country which are negotiated politically although there is

always some kind of rational explanation for the final figures.

However, this can be problematic. When they were negotiating the European treaty in Nice, they reached an agreement at three in the morning and it was a very important agreement about the weighting of the votes of each country. They did not realize that they did not have numbers to add up to 100%. [laughter] So sometimes it can be dangerous.

The other question is how EU policies on renewables interact with the carbon trade. The power generators got the certificates for free in the first phase. They were extremely quick in internalizing these opportunity costs. They are not replacing old coal fired power plants by new generation which is the goal of this system.

This is partly because large utilities have other commercial strategies in terms of getting big market share in the European electricity market. Renewables are instrumental only to get an even stronger position in the electricity market.

The quotas regime is a regime which enhances the power of the incumbents while the feed-in tariff is facilitating the newcomers. That's something which we should keep in mind.

*Speaker 2:* In terms of renewables versus CO2 reduction, Texas is doing the right thing. Every proposal in Washington for climate legislation puts a big bull's-eye on the back of Texas. They're the number one emitter of CO2 per capita in the U.S. The EPA's analysis of Lieberman Warner says that GDP losses will be the worst for states with long driving distances [laughter], states using lots of air conditioning, and states with large petrochemical complexes. The value of putting in 18 gigawatts of renewables will be useful under any climate change regime.

*Question:* A recent study done by E3 for the California PUC estimated 33% renewables at \$130 a ton of CO2 reduction. If there is a carbon signal, it should include all of these tools including renewables in the language of that common metric. We're not there yet.

*Speaker 1:* There's no doubt that renewables are an expensive greenhouse gas mitigation measure. The E3 study was a part of the PUC recommendations to the air resources board about how to achieve the AB32 greenhouse gas reduction goals. It's important to remember that there are other reasons for renewables. We should consider the incremental benefit that we get from greenhouse gas reduction from renewables beyond the carbon mitigation benefits.

A long-term view is important. For instance, I mentioned the Stanford study on the California solar initiative that found an economic rationale for those program subsidies that came from "learning by doing." Learning by doing is the stuff that happens in location in the markets. That's where the benefits are realized. So localized payment programs for localized benefits can be rationalized.

The industrial policy rationale is worth considering. In California, it's more politically palatable for legislators and elected officials because of the in-state jobs and growth benefits of renewables. They want to develop industry in state, not in Nebraska, or China, or India.

*Speaker 4:* In Europe policies are not planned to perfectly combine so even a single instrument like emissions trading is then broken down to national targets that do not interact quite well. The literature on renewables and climate policy is not yet that big. Germany is just beginning to figure out how much more they have to pay given the 20% CO2 reduction target to also reach the 20% renewable target. Renewables do reduce the need for emission reduction, and they replace fossil fuels, thus they bring prices down for emission certificates. The local issues may be important too. Nations and states are just beginning to consider these issues.

*Speaker 3:* The new wind projects under construction in Europe cost between six and seven euro cent per kilowatt hour. It's the same as the forward price for electricity in central European markets. For next year it is between

seven and eight cent per kilowatt hour. Wind is already competitive on that basis.

*Speaker 4:* But the wind is not blowing steady. That's the one problem. And there is a limited supply.

*Question:* What is the metric to measure these other perceived public policy benefits of renewables How are industrial policy, economic development, or clean air measured in conjunction with carbon? How does one come to a conclusion that this is a good economic decision?

*Speaker 1:* If I could quantify all of those things I'd win the Nobel Prize in economics. [laughter] The political calculus is not always set this way.

The California renewable portfolio standard uses a benchmark of the market price referent which is the long term avoided cost of gas fired power. Any renewable contract that comes in below that referent is deemed reasonable by the PUC. It was set up this way so that the utilities wouldn't have to address an ex post reasonableness review and it had the backing of the ratepayer advocates.

In recent years there have been a few contracts that exceed that market price referent. There is a complicated set of rules and limited amount of money available to let the PUC approve a limited number of above market products. Clearly, with both RPS and carbon policy they will have to figure out how to integrate them and incorporate a carbon adder into the calculations.

*Speaker 2:* A portfolio is important for a generation resource mix. When one is considering simple supply and demand, renewables are an important part of that mix. In Texas, ERCOT is going to need between 50 and 80 gigawatts of new generation by 2028. That's 25% of what the entire country is going to need. Renewables is one of the tools for that new supply.

Second, many of the West-East transmission lines are needed regardless of renewable energy. This is in Texas, and also nationally. They've

already talked about reducing their natural gas usage. The local economic development is just a sweetener, it's not the driver of this effect.

*Question:* What if the RPS program in California is retained and a national carbon and trade program is implemented. If the RPS standards in California remain as binding then it's a good deal for other states because it lowers the cost of the CO2 permits and essentially shifts the cost from other states to California. Is this a political problem in California?

*Speaker 1:* It's not yet but it could be. They have had discussions at the air resources board about the cap and trade system. The governor convened a blue ribbon panel of mostly economists to advise the air resources board on design principles for cap and trade in California. One of the first questions they asked whether cap and trade should replace the RPS? The answer was no, but people were asking the same question.

They want to avoid federal preemption of state initiatives so they can blaze the trail to the low carbon future. It's a priority for California's political leaders and decision makers because of the view that the federal cap will unlikely be as tight as it needs to be from an environmental perspective, or able to ratchet down as fast as it can from an environmental perspective. So far it's off almost everybody's radar screen except for people I just described to you.

*Question:* In a multi-state context with renewable portfolio standards that apply in some states but not others there are difficult cost allocation issues, particularly if transmission is needed for the RPS. For example, if they have to back up the wind capacity with on-demand fossil capacity. Or transmission costs to get that wind to load, and the balancing cost. These costs get borne by everyone. How does one ensure these costs are borne by the beneficiaries of the renewable energy?

*Speaker 1:* California is extensively interconnected with their neighboring states. There is a WEC-wide renewable integration planning process. They are not yet addressing



cost allocation questions but rather beginning to analyze what the issues are. This is similar to RETI process described in the first panel. What are the best renewable resources throughout the region, where's the load growth anticipated to occur throughout the region, what kinds of transmission upgrades throughout the region would be necessary to integrate those, what are the associated conventional resources that would also be needed for firming? They aren't there yet but they're headed there.

*Speaker 2:* During the CREZ deliberations in Texas one of the scenarios was to build lines from the panhandle wind into Oklahoma and hope that most of it would come back across a DC tie back into ERCOT. The PUC didn't like this: if Texans are going to pay for all this transmission, they want every one of those electrons landing in Texas. One of the biggest debates is developing transmission across multiple jurisdictions. It may be easier to do with renewables in the mix. It's even more difficult without them as a reason.

*Speaker 4:* The only recommendation I can give is don't look at Europe when it comes to multinational [laughter] agreements. The market is not multinational, even if the grid is. Germany can't even implement its in-state projects like the national renewable support system, defined national grid extensions, or the Dena grid study.

Cost allocation for grid problems and renewables is confusing. There is no policy to settle issues of cost allocation between the nations. It's really far beyond being efficient in Europe so far.

*Speaker 3:* The European commission wanted a pan European market for renewables so that the certificates could be traded everywhere. It was a very ambitious goal. All the states had to adapt their legislation to this new system; in particular those with a feed-in regime. There was strong opposition and it's getting reviewed. The new agreement looks like each state has the freedom to decide how to incentivize. Each state has to meet a certain threshold of renewable generation. There will be a compromise trading system. If one state is unable to achieve the

target for a given year they may buy emission rights from another state. How this will happen and who will benefit from the sale of the certificates in the countries with excess renewable generation are questions for the member states. There is flexibility but it's far away from a single coherent multinational market.

*Question:* I want to revisit this issue of balancing goals and a renewable portfolio standard. Integrated resource planning seems to balance these goals. The goal is to pick a portfolio of resources, a price is put on every kind of emission including greenhouse gases, there is stochastic risk. They measure the value of a portfolio under a range of natural gas prices, electric market prices, load levels. Out of that one gets a risk adjusted cost to measure and that reflects the probabilities of uncertainties. RFPs go out for renewables, traditional resources, and demand-side. Doesn't that approach balance these goals?

*Speaker 1:* California is lurching progressively in the direction of modern planning. There is the transmission planning initiative and the PUC is asking the IOUs to do portfolio analysis for themselves. It looks like IRP. The process of winnowing down portfolios that satisfy all the constraints and that seem to go with the most plausible assumptions about future states of the world – when one does all these things it looks a lot like modern planning or IRP.

One needs a framework with an adaptive characteristic also however. The market price referent that I discussed earlier is like that. If there was an incipient carbon market in which future strips could be modeled in a feed-in tariff model, it's quite possible that feed-in tariff prices would have to be reset on an adaptive basis in response to the market. Market feedback is essential.

*Question:* What is the most efficient way to allocate resources with the objective of reducing carbon emissions? Let's put aside the other potential benefits and focus on carbon and fuel scarcity.

The tools for this are subsidies, mandates, carbon taxes, or caps of some sort. Subsidies and mandates have certain costs for the participants because otherwise people would do it without the subsidies or the mandates, right? The subsidies they receive don't get naturally reflected in the prices they use to price their commodity into the market, particularly for peak periods when prices are most extreme. The subsidies and mandates make the market dysfunctional, right? They make prices non-transparent and hurt the ability of the market function and invest efficiently.

It's comparable to CAFE standards with cars where the government fuel efficiency standards were in place consumption increased. This was because it was a non-market mandate. Subsidies hurt markets. If you had to choose between subsidies, mandates, carbon taxes, or caps; the most efficient would be taxes or caps. Can you comment on this?

*Speaker 1:* One has to distinguish between market failures which are substituting one tool for another - subsidies, quotas, taxes. Nonetheless, there's various instruments to address market failures. A subsidy is like a negative tax. It's not clear why a subsidy is inherently prone to inefficiency - a tax is a good instrument. They just work in different directions. It depends on externalities, whose price it's left out from to determine which way to go.

There's regulatory failure if the right instrument is not matched to the problem, or the problem is not addressed comprehensively. For instance, with CAFE standards there's a lot of other behavioral phenomena, it's not sufficient to isolate the vehicle. You have to look at the pattern of growth and development.

As an economist I like pure price based instruments. One just has to understand the nature of the externalities and price them appropriately by tax or a subsidy.

Earlier I discussed the example of "learning by doing," that's a positive externality. It's a textbook example of something that merits a subsidy. The real challenge for policy makers is

to match the appropriate instrument to the problem and with sufficient scope. Further there's always a political context that may have little to do with efficiencies.

*Speaker 2:* In Texas, because of legislative policy decisions, they will be tracking toward a competitive beacon. Nonetheless, reliability and price volatility have to be managed. If there's too much volatility then the whole market can crash. Energy efficiency and demand response are the cheapest way to have supply security. Further, transmission development has always been a government function. It's ultimately a combination of competition and regulation.

*Speaker 4:* If one is considering electricity and global emissions only. One sets up an emission trading system with a cap, a good penalty system, and auction the certificates. That will do the job.

If it's more than electricity including transport, heating and all that stuff, things become much more complicated. One can't give everyone with a certificate for the heating. What about cars. A tax may be more efficient than a certificate system. This is further complicated by network security, supply security, local questions, green certificates. These complications make these systems much harder to set up efficiently.

*Question:* First, a comment on tax versus subsidy. If carbon is a bad thing, a tax is more efficient. Everybody who produces it can decide how to reduce it most efficiently. A subsidy requires policymakers to decide the value of wind or solar. Cap and trade certainly gets market benefits.

Are there surveys of public perception concerning carbon and energy efficiency programs and their costs? The past perception is that these things are both good for the environment and the economy. However, people need to understand that it will cost.

*Speaker 1:* The public has been oversold and misinformed. This is expensive and it will take time. There will be benefits for some people, investors and workers, in the transformation of

the economy but that doesn't it doesn't have overall costs.

I want to clarify that my earlier comments. There are multiple externalities in the energy industry and when I said that we have to be disciplined about matching instruments to policies or matching instruments to problems.

There is the fundamental universal externality that spans the entire economy of carbon not being priced, and yet there are many other externalities that we've heard about today. A carbon cap and trade system really only addresses one, and we need to look at how policies address all the externalities.

### **Session Three.**

#### **Regulatory Treatment of Purchased Power: Pass Through or Profit Center?**

*Purchased power costs have traditionally been treated as pass through expenses for utilities. The result, many have contended, is an asymmetrical arrangement whereby prudently incurred costs are passed through without markup, but any purchase deemed "imprudent" will result in disallowances being made. In short, so the argument goes, is that the best a utility can do is break even, but, at worst, it can incur losses. Proponents of pass through treatment argue that the risks of purchasing power are substantially less than those associated with capital investment so the potential for profit rightfully goes to the actual investor, the generators, and that the consumer ought not to pay for a secondary level of profit for the middleman utility. The issue is topical as many utilities who have been out of the generation business are looking to get back into it for a variety of reasons, one of which is related to the lack of profitability and asymmetrical risk associated with power purchases. In addition, widespread interest in distributed generation and in customer installed renewable resources, such as solar panels and wind turbines, not to mention plug in automobiles, raise policy questions as to why utilities ought not to have positive economic incentives to procure power from such facilities.*

*The use of incentives, of course, might vary depending on the procurement regime employed. How can the risks and exercise of discretion in the procurement process be matched with the need for incentives and efficient compensation? Should New Jersey style auctions, pre-approved acquisition and other regulatory mechanisms approved or overseen be deserving of the same regulatory treatment as utility initiated or conducted procurements? Should PLR procurement in retail access jurisdictions be accorded the same incentives as procurement in retail monopoly markets? Should regulators, in applying incentives, differentiate between procurement from affiliated generators/ marketers, as opposed to purchase from non-affiliates?*

*Moderator:* Once renewables are built and the regulated utility will be entering into contracts to buy the renewable or traditional power, how do they pass those costs through to their ratepayers? should they be entitled to a rate of return or some sort of incentive payment?

This is a live issue in New Jersey right now with solar. The state has decided that there should be some solar and that the utilities need to encourage it. Some of the utilities are agreeing to enter into long term contracts and some of those utilities have asked for a rate of return

rather than a pass through. It is pending before the New Jersey BPU.

#### **Speaker 1.**

I will discuss activities in the northwest and Oregon. I'll focus on activities of power producers there. The Northwest and Intermountain Power Producers Coalition [NIPPC] represents these folks. There are Canadian firms as well as those from Oregon, Washington, Idaho and Utah. There are no

organized markets but rather traditional vertically integrated utilities. There is a large public power presence but there is no independent transmission system authority and this affects the power producers and how investor owned utilities are regulated. In recent years, natural gas was the preferred addition top power supplies. It continues to be significant, while coal is shrinking overall. Wind is increasing all the time.

The underlying premise of my talk is about how to maximize the value of competitively procured new resources for the utilities and how to mitigate the self-build bias of utilities. IPPs take on risks in under-performance, technology, compliance, operations and management. They provide a “price check” on utilities, and leverage construction experience, specialization, and economies of scale. The development of wind power technology is traceable to independent power. The first IGCC plant with carbon sequestration in this country will be built largely with the involvement of independent power. They take on a bulk of the risk. The risk is where the profit is.

With a 525 megawatt combined cycle plant a producer carries a variety of risks. For construction and capital costs, using conservative assumptions, there are costs in the range of \$78 million which would otherwise be at the risk of ratepayers. Operational costs, for instance if the heat rate is wrong, are even higher. Over the lifetime of a PPA [power purchasing agreement] these are on the order of \$155 million that the ratepayers would assume if it were a utility plant.

There’s risk in wind. In the oil business this is called dry hole risk but it exists with wind as well. If a site is not as windy as you thought it was, there’s a problem. Garrad Hassan is a leading consultant in the wind energy field. His analysis of wind power performance at various sites over 510 years. Site owners are right 93.3% of the time which is pretty good.

The other 7% of the time when they’re wrong can be a problem. If it’s a 150 megawatt project, and the wind output is off by 20% then that’s a

cost of \$21 million. There are examples of this. The Columbia Gorge is a very windy place. It acts as a funnel between the marine layers on the Pacific Ocean and the warm interior of Oregon and Washington. There are many wind farms there. The various operating plants have varying capacity factors. One of the worst is the Condon project which is owned by the Bonneville Power Administration. It has a 20% capacity factor. The wind is not blowing nearly as much as anybody anticipated. If one knew that in advance, the project would never get built.

One of the best facilities is Leaning Juniper which is owned by PacifiCorp, but was developed by an IPP. Portland General Electric has a 37% capacity factor on a wind farm. However, this is dubious, no one else in that area has nearly that high a capacity. If PGE is wrong then the ratepayers will be paying for a very costly plant. They’ll find out in rate recovery.

Operations are also a concern. Wind Turbine manufacturers honor the operational integrity of their turbines is about five years. A German report shows that after five years things begin to fall apart – gearboxes, bearings, shafts, etc. The costs of operations can be underestimated. The ratepayers should be bearing it.

In the northwest, monopsony is a problem. There are utilities who are the sole buyers and they exercise monopsony power in real way that distort competitive procurement.

They extract build to own transfer commitments from independent developers that would rather negotiate PPAs in good faith. They finesse regulatory regimes in subtle ways. In Oregon some utilities are securing access to ratepayer money, via deferred accounting, so they can put deposits on turbines which developers have to do without ratepayer backing. Land owners of windy property are being directed toward the utilities as opposed to the IPPs for development of their properties. The debt equity issue is also used for utilities’ self build ambitions.

The independent power producers want to balance shareholder value with ratepayer protection. They hope to maintain fair procurement rules which they are now more

comfortable with. One model is that utilities might be rewarded for acquiring PPAs [power purchase agreements] provided that an adequate assumption of risk is assumed by the IPP. Currently, PPAs don't benefit utility shareholders, whereas self-building does. Competitively procured PPAs can benefit ratepayers, in particular by reducing their risk. Thus utilities should be rewarded if they take on a PPA in which the power producer has assumed all the risk (and the utility has deferred the risk from the ratepayer).

PPA agreements have rigorous bidding rules in Oregon and are worth reviewing. Utilities must issue RFPs for all major resources. Of course there are exceptions. Major resources are those which are five years in duration and quantities greater than 100 megawatts. The utility may own their own resource but they have to bid it into the RFP. It's referred to as a benchmark resource.

There is an independent evaluator. They work for the Utility Commission staff. Overall this is a very good process. In 2005, Oregon started a proceeding, UM1276, to investigate the utility bias toward self build and mitigate it. The NIPCC proposal was to provide the utility with an incentive. They proposed to rate base 10% of the Oregon portion of the value of the PPA. There are a number of restrictions: fully vetted, fully competitive, and all risk held by the IPP. So far this proceeding is still dead in the water.

This is a corner of the country where monopsony power, the preference for self build, and yet where consumer interests would best served by robust competition are all real factors. The power producers in that area really want to address this issue.

*Question:* Why are QF [qualifying facility] projects not eligible for the rate-based PPA?

*Speaker 1:* The utilities are required under federal law to acquire those resources – they are not competitively procured.

**Speaker 2.**

I'm going to discuss the same issues from the perspective of ratepayers and some of my comments will argue against aspects discussed by the previous speaker.

The previous speaker's description of the situation is entirely accurate. The disagreement is about how to solve the problem. There is a bias for a utility to build. That's purpose of rate base is to incent the utility to do capital investment and earn a rate of return on it. That's is how the infrastructure of vertically integrated utilities functions. However, there are risks that get shifted to an IPP that benefit ratepayers. There is a problem. Utilities have a bias that is leading towards more risk falling on customers. The problem is how to quantify it, and what to do about it.

The basic model of traditional utility regulation is that if the utility makes an investment that's not prudent, then the costs should be disallowed. It's true both in traditional utility contexts and in decoupled contexts. If a utility is not following least cost and customer interest principles then the difference between those costs should be disallowed. This is the difference between the costs and risks associated with the utility self build and the IPP. In decoupling it's between supply and the demand side investment.

The discussion we've been hearing has been about creating an incentive for the utility to work with IPPs. This suggests that conducting an imprudence disallowance for a utility is more difficult than bribing the utility with incentives. This is problem because we should look to regulators to regulate properly and disallow, rather than hand out additional pots of money to make the playing field fair. The customers end up paying the bribe.

However, given the reality of ineffective regulation, is there an incentive that's reasonable that doesn't overcharge customers. The problem so far in the docket is that all the proposals ended up with higher rates and no benefits for ratepayers.

All the utilities in Oregon do self builds and some purchased power. How do regulators ensure that one is not paying them for something they would have done otherwise? The incentive gets applied to something the utility is going to do anyway and the end result is that customers pay more and get the same deal. We've seen similar problems with the utility proposals. One utility went to the commissioner and argued for an incentive on some hydro contracts on the mid Columbia River because those carry a risk. There's no build option for the utility there – those kinds of dams cannot be built today. Alternately, a contract as cheap as dispatchable hydro is something that any utility in their right mind would sign. There's no sense to be paying them an incentive on something they would have already done. It would have been outrageous if they had not done it.

The utilities want to treat PPAs as rate base. They have 20 year contract where no money's at risk and earn a rate of return. NIPPC's proposal ultimately argued for 10% of the PPAs, the utilities wanted 14% return on the purchased power. The PUC staff said let's do that but with a 1% cap on it so that rates would not be more than 1% higher than they would otherwise.

Citizen's Utility Board's [CUB's] analysis of the staff proposal took the 1% cap and the 10% figure and analyzed what the utility was already planning to do based on its IRP [integrated resource plan]. The utility would reach the 1% cap by purchasing power it already planned on purchasing. These proposals clearly don't accomplish anything.

Even a utility that's building rate base will sign contracts. There are no proposals that make a distinction between getting new and old benefits. The reason the commission in Oregon hasn't made a decision is there isn't a good solution yet.

There's some elements that should be part of a solution. First, these kinds of incentives should be paid on a case by case basis. The individual bidding has to be competitive. Third, it should be clear that there is a bias to self-build. The role of an independent evaluator is critical. They

should determine if a given context is the appropriate place for an incentive. In addition, the contract should be ten years or longer. The utilities wanted one year, the PUC staff argued for three year PPAs. However, a three year PPA isn't an alternative to a self build option. It may defer building a resource, but it doesn't shift risk. The only benefits come from the delay. The resource that gets an incentive has to be a long enough agreement that it is an alternative to building.

CUB proposed that incentives should only be for incremental purchases and based on what utilities already planned in IRP plans. What they already planned to purchase would be ineligible. It's only where they expand beyond that. There should be a cap on the incentive. Since this is an experiment, we need to ensure that no too much ratepayer money is at risk. This can be reviewed in three years. All these limitations are set to protect ratepayers.

If there is a broad incentive and it goes on what the utility would do anyway but creates a new IPP purchase the total incentive paid has to be less than the benefit from the incremental increase in IPP purchases. That's a tough thing to analyze and show in these kinds of dockets. There's always someone paying the incentive so we really need to find an improved solution to this problem.

*Moderator:* What exactly would be reviewed at three years?

*Speaker 2:* The incentive mechanism itself. Does it provide value? If this incentive for IPPs is reviewed in three years can one say it is really working? Has the incentive changed the behavior of the utility? The utilities want the incentive but the utilities didn't want to change their behavior. It's important to determine that the policy is working. If there is a benefit, fine. If there wasn't a benefit the commission should get rid of the incentive on a prospective basis.

**Speaker 3.**

Let's put this question in context. It helps to consider the goals of American electricity policy. I'll look at this question from that perspective and then come back to the financial incentive for purchases question. I'll argue that the answer is yes, but it needs to be done properly. Further, the need for an incentive is different in different regulatory regimes.

In electricity policy the consumer is the focus of that goal. The best deal for ratepayers given market and regulatory conditions, that consider price, risk, reliability and environmental performance. There are two major challenges. One is managing uncertainty and the other is attracting new technology. It's absolutely essential that every proposal help us to assess and assign risk from uncertainty. New technology is supposed to help stabilize rates, address climate change, etc. How do we bring in the new technologies and new players.

Competitive markets and competitive procurements are the best way to get this best deal. The notion of assessing and assigning risk is at the heart of things like pay for performance, PPAs, performance based rate making, or tolling agreements. However, one can no longer be ideological and say the goal is to create a competitive market, rather the goal is to serve consumers and that's what a competitive market does.

Given these goals, would the financial incentive ever help meet these challenges? It can make sense but it's essential that we do it for the right reasons so that we do it in the right way. A wrong reason is to view it as an enticement to play fair with competitors. A better way is to understand reward should follow risk in a competitive market competitive procurement. The incentives should be designed to be a reward for risk management that benefits consumers.

Let's consider four examples of an incentive that would reward risk management and benefit consumers. First, an affiliate PPA. If a utility has an affiliate unregulated generation side and it bids into competitive procurements under identical rules with IPPs. This gives the utility

an opportunity to take on risk and gain profit. It's important to see that that opportunity does in and of itself give the utility an incentive to favor and participate in a fully competitive market or competitive procurement. It will for the first time give that utility a truly symmetric opportunity to win or lose. Some argue that a utility that self-builds should have a cap but not a floor. The utility can lose a lot, but it can only gain a moderate amount. That is not fair. They should operate on the same equal playing field.

Second, tolling agreements. Competitive procurement processes are allowing tolling agreements along with power purchase agreements. In a tolling agreement the IPP will build and operate a power plant with a guaranteed heat rate but gets the utility to manage the fuel risk. Many risks are still handled by the IPP but not fuel risk. That goes to the utility and/or the ratepayers. There is a financial incentive here. If the utility manages that fuel price risk on behalf of the ratepayer, they deserve a financial opportunity to gain a financial incentive. It's a performance based mechanisms where they will be indexed to Henry Hub or a local delivery point. If they beat the index they take the profit and if they don't the costs cannot pass on to the ratepayers..

Third, renewable portfolio standards. In most RPS' there is a cost threshold. Get 20% in 2020 but not if it costs more than X. With that cost threshold there's an opportunity for a financial incentive. If a utility took the risk of getting the RPS and getting it below the cost cap then it is appropriate that they take a cut of the cost savings. Particularly if they are facing a penalty when they don't meet the RPS.

Fourth, overall rate incentives. This is a true full requirements rate guarantee. If a utility can find a way to maintain an overall bottom line bill rate for consumers then they can take a cut. If they can manage all the various aspects: competitive procurement, RPS, O&M, billing, etc., and guarantee some sort of pattern for ratepayers? This is a performance based opportunity for a financial incentive. It could involve determination of what rates might be, what a commission would tolerate. It could be judged

via peer review, performance standards. This provides real benefits to consumers via price stability, risk reduction, and/or efficiencies that is deserving of financial incentive.

The need for an incentive does vary by regulatory regime. The risk that's already been assigned varies. The New Jersey auction is a good full requirements product auction. The bidder comes in, and it can be a utility too. They bid the same way, they take the same risk, they sign the same contract. Everybody there bids three year fixed price standard contracts. The supplier is taking on a lot of risk. That includes renewable portfolio standard risk, market risk – including having to take a percent of every customer class.

Alternately, the Oklahoma RFP is for a unit contingent product as opposed to a full requirements product. These are for long term pay for performance contracts. Risks like R&D are assigned to the supplier but not fuel risk when tolling agreements are offered, not market risk because there's not a megawatt sale in your contract and not full global climate change risk. In Oklahoma there is a presumed pass through threshold but the rest is decided by the commission. In this situation – via tolling agreements, fuel price risk, market risk, global climate change risk – there are opportunities for the utility to earn a financial incentive if they were to manage those risks.

This debate has to be addressed within the broad goals discussed earlier. The right reasons are risk management to benefit rate payers, not necessarily incentives for fairness.

*Question:* The goals of America's Electricity Policy are clearly about a process that occurs at the state level. However it's not federal or American policy.

*Speaker 3:* The states are defining America's electricity policy. Congress is way behind the states. This is even with global climate change. RGGI's first preview auction last week, and renewable portfolio standards. So far the states are really defining policy for the most part.

#### **Speaker 4.**

There have been eras in which most states have gone mainly rate based or mainly IPP. Now we're really in a mixed era which makes this difficult from a regulatory point of view. I'm also focusing on the states in most of my comments today. The country relies on independent power for over a third of the capacity and electricity produced in the country.

I'm going to focus on a study done on the competitive procurement dialogue and best practices that NARUC, FERC, DOE sponsored. It focuses on states that have a rule based approach. The study is available on the HEPG website. There are two types as the previous speaker just discussed. The instances where utilities procure an incremental supply of resources. This "incremental resource selection" is different from the "full requirements service" like the New Jersey model. The study does not focus on the question of regulatory treatment or rate recovery for PPAs except in one discussion of debt equivalency. It only focuses on competitive procurements, not bilateral discussions or informal competitive processes.

About half the states are doing some kind of competitive procurement for full or incremental procurement as well as for RECs and specialized products.

The tough issue arises in circumstances where there are non-price variables that have to be considered by the regulator and utility. Most contracts are bread and butter issues for utilities; they aren't complicated. Many states want to use the competitive procurement model as a way to manage risk.

A utility has a number of possible roles in its activities vis-a-vis providing service. There's the traditional build, build or buy roles: portfolio manager, operator, investor, and fuel purchaser. There are some hybrid models that are about resource provision; e.g. putting solar on homes, etc. These are purchasing agent roles. This also includes something like the BGS service auction



role that a utility has. Those have different incentives around them.

In ratemaking 101, one learns that when activities are about contracting, utilities recover expenses but not a return on investment. On things like fuel and contracts it's a straight pass-through on a dollar for dollar for basis. Utilities won't be indifferent to this distinction. As the previous speaker mentioned, the performance based ratemaking model has been used in a number of states to create a collar, or a zone of reasonableness in which a utility can operate at current rates. There's a zone outside that where the utility has an opportunity to share productivity gains and also where they may be liable for under-productivity.

There can also be tailored or specially designed opportunities for incentives. In California efficiency delivery is tied to a model where a utility gets shared savings tailored to the earnings they would have gotten had they built a plant. Nevada has a bonus rate of return when the utility meets certain performance targets on energy efficiency. There's discussion in North Carolina where Duke is proposing its save a watt program. They capitalize expenditures on procurement of efficiency. Allowing them a percentage of avoided cost is used to overcome build versus buy bias.

PPAs have many different tradeoffs and look different to different people. There are tradeoffs between public service versus shareholder obligations. Different stakeholders have different opinions. They include utilities, power suppliers, efficiency suppliers, investors, rating agencies, consumers, courts, and regulators. A shareholder might view a PPA as a lost opportunity for earnings. Alternately, some utilities that are capital constrained might welcome the opportunity to save capital. It really depends on context and where one sits.

The power provider wants a business arrangement allocating risk and reward. However, an investor in a power supplier might look to the PPA as way to mitigate risk in their investment. Some, not all, ratings agencies look at PPAs as equivalent to debt when they are

doing a credit analysis for utilities. Other rating agencies look at the absence of a PPA and the presence of a regulated rate of return as risky. There's real tension in the rating agencies about the implications of different circumstances.

Regulators are never indifferent. One speaker discussed the fact that disallowances should be done more willingly by regulators. However, it is a very difficult job to do retroactive prudency reviews. It is a transactional nightmare that regulators don't want to take on for good reason. In Massachusetts they adopted a pre-approval contracting model. It never got used because the state deregulated more fully. However, it required the utility to bid on an incremental resource procurement contract, that's the price at which it would be paid over the life of the contract to make it commensurate to an IPP offer. However the PUC couldn't come back and ding the utility. It was a regulatory contract. It's the only way to set up real head to head competition between IPPs and utilities.

Utilities in procurements are supposed to compare all options equally, without accounting for the financial implications of shareholder earnings or rate base erosion. I do agree there are many inherent biases and black box characteristics associated with reviewing a self build proposal that bias against an IPP proposal. Alternately, a utility has to be concerned about the debt implications of a PPA and credit ratings concerns, and also potential loss of earnings. Unfortunately, they can put the thumb on the scale in a 1,000 different ways and make an unfair comparison. Product specifications, contract terms, and evaluation criteria can all be altered so that the utility's build option looks better.

The response to this is for the regulator to set fair and objective product specification, model contracts, credit requirements, and bidder eligibility requirements. Non-price factors have to be able to be evaluated transparently. An independent monitor is really critical. There needs to be active oversight by the regulators. All of these things, if done well, align the incentives for consumer value, shareholder

value, and allow a fair playing field for power suppliers.

Policy here is not just least cost. For instance, fuel diversity, or advancing technology with low carbon. Having clear criteria for evaluating those kinds of attributes contracts is critical.

Some general strategies are certainly to use real, fair competitive processes. Shared savings can be a real option in many cases – particularly as it can help pursue other policy options like efficiency. For the debt equivalency problem, regulators should address this in the cost of capital proceedings in rate cases, not in the resource procurement process. Unique and carefully designed contracting processes, like the Massachusetts proposal, can also be helpful.

*Question:* You mentioned that debt equivalence should be addressed in capital proceedings, not in procurement evaluation. But there's an issue even between different PPAs. Different PPAs have different debt equivalence impact which end up translating into customer costs. Should debt equivalence be considered when there's no utility build option on the table as a valuation technique between PPAs?

*Speaker 4:* Is it a different allocation of risk to the consumer and a regulatory risk of not being able to recover the costs?

*Question:* The more quantitative rating agency assessments consider the net present value of the fixed component of the contract over its lifetime. And that ends up being the debt equivalence is imputed. This translates into extra balance sheet impact which translates into extra costs of debt and more customer cost at the end of the day. One utility has used an approach where between PPAs they calculate the debt equivalence impact of each PPA. It's part of the overall equation in the valuation process. It translates into real customer cost between different PPAs that a utility is trying to assess.

*Speaker 4:* It's not an exact science in calculating these numbers. Nonetheless, I'm not averse to having it considered as long as it's not

a situation where the utilities own self build is getting a different treatment.

*Question:* Half the states use competitive procurement. Which of those are restructured and which are traditionally regulated?

*Speaker 4:* It's probably about a quarter of the states. But there's a lot of gray areas in this – it's hard to know which states to put in which buckets – many are unique.

*Question:* Almost all affiliated contracts end up at FERC and have to satisfy the Allegheny benchmarks for customer protections. Much of your criteria are analogous to Allegheny. Are you comfortable with Allegheny as a backstop or do you think we need to go further?

*Speaker 4:* I don't know. I have to refresh my thinking about the Allegheny standard to answer specifically.

*Moderator:* New Jersey has gotten a waiver every year of the FERC requirements based upon their competitive procurement. Their BGS auction satisfies the FERC requirements.

*Question:* Are there other shared savings examples out there?

*Speaker 4:* Minnesota and Iowa have a little bit. Massachusetts is about to embark in this way. We're going to see much more of this; especially in efficiency.

*Question:* I wanted to come back to the two challenges of managing uncertainty and attracting new technology.

There are two versions of the black box problem. So at one end of the spectrum is the purchasing through a PPA that is resource specific, kind of the plant or technology. There are lots of ways to evaluate that. There is the thumb on the scale problem for evaluating this black box.

The other end of the spectrum is the New Jersey BGS auction. This is another black box. How are these suppliers going to satisfy their obligation to provide delivered energy for full

requirements in this tranche. There's no transparency in that, it's their problem to figure out. It's another kind of black box.

The former black box in terms of creating fair bidding without utility bias is really problematic. If anyone knew how to evaluate all the things in that black box there would have been no movement to restructure electricity.

Alternately, the second BGS auction black box manages the challenges better. It puts uncertainties with the folks who are willing to take it on, and attracts new technology because there are incentives for all kinds of things that you never thought of. Given that the BGS auction is so strong, why is it not seen as an attractive model? For the record I had nothing to do with creating it.

*Speaker 3:* You've got it right. Let's consider a unit contingent RFP. The state regulators have a tough job determining how the utility is going to decide on various megawatts of wind, traditional fuels, coal, gas, and demand side. That's why independent evaluators are useful, they shine light in the black box.

This can be improved by making the modeling analysis probabilistic. It's not betting the farm on \$8 per ton carbon tax or betting the farm on \$12 gas or \$5 gas. It's about assigning different probabilities to those prices and making risk analysis decisions that account for that, or hedge it. Oregon's IRP process is open and probabilistic and it's a good model to look at. It uses open IRPs and probabilistic analyses that drive the portfolio. The utility chooses a portfolio, so much wind or renewables, because that portfolio showed up in lots of different cases.

Of course there's lots of assumptions in that context that can still be wrong. Transmission or gas costs can still end up surprising everyone. Nonetheless, the state commissions doing that get a good picture of what's behind supply going to the ratepayers.

In the BGS auctions, say New Jersey, Delaware, Illinois, Maryland, and New England. They have

substantial players coming in who guarantee a price with a backup collateral. There's no sense of a portfolio behind that however. Hopefully the bidders, who are risk managers and suppliers of various sorts, are developing a risk portfolio. The full requirements auctions provide liquidity for markets. It's nice to have a FERC approved market with state run full requirements solicitations. However, some states are nervous. For instance, Maryland is concerned that they're not getting power plants in their state. Delaware ran a BGS auction and then ran a unit contingent auction. They just got a nice article in the New York Times magazine. It would be nice to shine a light into both kinds of black boxes.

*Moderator:* In New Jersey, the BGS procures basic retail supply. The state is encouraging wind and other things in different ways. They manage those issues separately.

*Speaker 4:* The BGS style auction can really only work in a context with retail choice, organized markets, transmission access, liquid markets. It's a different situation for incremental supply. These are in typically traditionally regulated states where the utility dispatches its own fleet. They have to use the black box to address issues beyond price.

I will be surprised if we see BGS style auctions delivering innovative technologies. The supplier is going to the market for a variety of hedges. They're going to lock in their hedges at the moment of auction. If there isn't technology in the ground on something they're not likely to induce investment, especially with three year periods. Innovative technology is still a real challenge.

*Moderator:* Yes, that's been the experience in New Jersey. It's all based upon price. Renewables and technology don't get encouraged currently.

*Question:* The speakers have all advocated for ratepayers but some or all have argued that one must cut a special deal for the incumbent utility. What is the rationale for that? 20 years ago people realized that there was no arguable rationale for a vertically integrated structure. In

the traditional context a benchmark bid or some sort of special deal seems necessary. Is there a theory for that or is this just a political compromise recognizing the realities of the politics involved?

*Speaker 1:* It is a political deal; sausage-making. The Massachusetts proposal discussed earlier would be good: you make the deal, you wear the deal and that would apply to the utility just as it does to the IPP. Nothing would make me happier but that's hard to implement. The regulated world is very different than the one where the BGS auction is in play.

So for instance Utah and Oregon have a requirement that all new resources in excess of 100 megawatts be competitively procured. One investor owned utility is currently constructing a 99 megawatt wind farm; self built. It added two more 99 megawatt wind farms within sight of the first one. It will share a single substation.

In another state a utility released a competitive RFP that included a notice that it had already put a down payment at the ratepayers' expense for the combined cycle turbines it intended to use for its project which it is also going to be evaluating in its own bid.

Another utility said it would sign PPAs with the condition that the supplier sell their project to the utility for \$1 the day the PPA expires. That is the kind of world the power suppliers live in. The IPPs would just like everyone on the same playing field.

*Speaker 3:* That principle is so important. The utility should bid like any other bidder. Same rules, same bid evaluation. Utilities should see that as an opportunity. A benchmark should be just like any other bid. In Oklahoma that's the way it works. If there's a benchmark bid, bid evaluation includes an assessment of the additional risk to the ratepayer of the benchmark.

*Speaker 4:* In those states does the benchmark cover circumstances of regulatory change or carbon legislation or water quality rules. Does

the benchmark have to take those hits like the IPPs?

*Speaker 1:* The commission addresses that in real time. The classic example was eight months ago. A utility that had bid in as a benchmark coal plant wanted to rescind that offer after sealed bids had been put in and replace it with a natural gas plant. The Oregon commission did not allow it.

*Question:* All the panelists say that they favor some form of competitive procurement. Further, throughout the FERC-NARUC dialogue no one testified against it. However, we've spent the entire morning talking about bias toward building, and that there are either no rules or the rules aren't being enforced. We just heard several recent examples of clear problems. Given that this has been a problem for some years now and it clearly still is a problem, perhaps the discussion should be about removing the bias completely. At either the federal level or the state level. Everything that's been tried so far isn't working.

*Speaker 4:* The political pragmatist in me says there's no way the states are going to go for that.

*Speaker:* That's right.

*Speaker 3:* Several of us are in favor of the "you make the deal, you wear it" principle. That can be applied to utilities and also their unregulated affiliates. The financial effects are distanced from the ratepayer. This levels the playing field. The biased scale could still be a problem but it aligns the incentives. Anything that the utility puts out there and says the bid rule will be this, it comes right back at them. It addresses the debt equivalent issue substantially. Because now the debt equivalent calculation, a substitution of equity for debt, applies to all the bids and emerges bigger on longer term contracts. It affects a certain nature of contract, not who bids. It's very powerful. It doesn't take the scale away but it makes the scales more even and allows the utility to participate in a way that's fair.

*Speaker 2:* I'd have some concerns about removing the ability of utilities to rate-base

facilities. In the Pacific Northwest they're lucky they allowed utilities to rate base hydro assets decades ago. They are now largely depreciated, no fuel costs and provide a base of electricity. There are some people who argue wind facilities that are owned by utilities will be highly beneficial. In 20 years when they're largely amortized, their lifetime value will be tremendous for ratepayers. The ability to rate base an asset if that makes economic sense for customers has been a useful way to keep costs low.

Alternatively, competitive bidding is important too. It provides great incentives to do things well. It helps keep the pressure on the utility that has the 37% wind capacity claim to actually provide that output or face the ire of regulators.

*Question:* Can the panelists provide perspective on risk premium, how big that is and from a ratepayer's perspective how important it is? At the federal level, the wholesale market is also encouraging demand side participation that can affect risk profile.

*Speaker 3:* In a full requirements bid that supplier is taking substantial risk and so there's a risk premium. There is real value to the ratepayer when a supplier takes on risk. The whole point of competitive procurement is that risks are assessed, and then assigned to someone who can do something about it. It makes no sense to assign most risk to the ratepayer because they can't do anything about it.

I'll give an example of one they can't manage. This is not a full requirements but unit contingent. Consider renewables RFPs, and obviously what the Congress does with production tax credit matters is a risk. In a situation like that the regulators or independent monitor can ask that the supplier be able to bid with and without the production tax credit.

*Speaker 4:* There is a risk premium. This is customer migration, leaving load, fuel price risk, transmission congestion risk, they are all passed on to the supplier. The customer gets a hedged price. Only the monitor really knows what's going on in there.

I caution against proceedings where regulators received offers in BGS style auctions and they're asked to compare those by interveners to the short term energy price in an RTO market or an LV, liquidated damage strip of 24/7 prices for some six month period of time. They're just not the same products. And so the comparison of the product full requirements, unless you really have those comparable at the same time, the same market, the regional market, the same conditions, it's really hard to find comparable products to give that answer.

*Question:* I know the specific calculations for the Illinois auction. If you took a 24/7 forward strip for a fixed megawatt level look at the difference in all of the risk associated with load following, etc., a premium of about 25% kicks above the cost of the flat strip.

*Speaker 4:* Is it comparable?

*Question:* No. They're different, that's the point. People say the going forward price is \$50 a megawatt but it can easily get in the mid 60s for the full requirements with the risks and premiums. It's a big number but it's real. What is impressive is how low the prices are in these auctions given the risks that are in there.

*Speaker:* Carl Weinberg, the long time director of R&D at Pacific Gas and Electric said in this country if you ever really want to create innovation then it's going to happen because somebody figured out how to get rich doing it.

*Question:* The commissions all get a point of comparison from the monitors; they are well informed. In Illinois the product was a full requirements product that was the point of comparison. Now it's block energy that's the point of comparison.

When it is full requirements it's absolutely essential to get a full requirements product from the markets. A starting point with block energy is not enough. It has to be dispatchable energy, the supplier is selling and buying, they've got capacity, ancillary services, collateral. A point of comparison has to look at the full list of factors.

*Question:* Earlier a speaker mentioned that the utilities could take on fuel risk. That seems odd. Clearly there's value to the ratepayer when risk is taken on by a third party and assigning the utility that risk seems to make sense but that doesn't happen, as I understand. Utilities have very low risk appetite for externalities they can't control and commodity risk is huge. A utility doesn't have much capability to manage that very well. I don't think regulator's would have much appetite for it.

The only example that I know of is the gas side of SDG&E in the late 90s, early 2000 where they had an actual index to beat. This was prescient because they predated the really big volatility. It came from initial volatility but predated the worst of it. It brought benefits to the shareholders by beating the index. The whole project got scaled back.

In a tolling agreement the fuel risk aspect is on the ratepayers. So the transfer of risk from customers to a third entity is not happening. It would be valuable to do that. Some of the auction based full services procurement methods based on price of the electricity, do transfer that risk. The problem there is that it's just the three year term. It's hard to build and hedge against that for a longer term development process. Having the ratepayer pay that risk is a problem. In Florida, FPL has one of the largest fuel risks that it passes on to ratepayers on a regular basis. The utility won't do anything without incentive and so the default is spot or some modest reactionary process which ends up losing money for everyone.

Fuel risk is enormously important. More than debt equivalency or other elements. Further, there is a difference in abilities to manage risk. A utility is not designed to wear these types of externality risks; they don't have the expertise. It's far from their operational focus and expertise. The IPP world is different. In aggregate, not any one facility or company, but the IPP world in the aggregate is very efficient at wearing this risk.

The question of debt equivalency is related to this. The perception of risk to a PPA is related to how much risk is absorbed by that entity. A self build option tends to have less risk absorbed by the utility. It is implicitly put back on to the ratepayer through the lesser likelihood of disallowance. Focusing on these risk issues is critical – I'll take your comments.

*Speaker 3:* Management of fuel price risk would be a value to consumers. I agree totally. Second, in the full requirements auctions and RFPs, fuel price risk is taken on for the three year period. Entities won't take it on for a longer period. It has value when it's done on the short term. Third, one should not preempt anyone who wants to manage risk for the benefit of consumers, IPPs, fuel managers, the utility.

*Speaker 4:* Yes, fuel and technology are the biggest challenges. Building a facility involves offers for projects that have original equipment manufacturer guarantees for the equipment and air pollution control guarantees. EPC – engineering procurement construction – turnkey contracts are the business model. Those things don't exist for advanced technology. Advanced technology has exponentially higher risk. There's loan guarantees for nuclear and that resulted in 112 billion dollars in project proposals for 18 billion in loan guarantees. It's a new frontier.

*Speaker 1:* With respect to new technologies, there are opportunities for joint venturing between IPPs and the utilities. This will be important in the context of IGCC and maybe nuclear power. It's exciting if TransCanada approaches Idaho Power and they can partner up to do an IGCC. There are examples where an IPP built the a gas fired project and sold 50% of it to the utility and then was under contract to continue to operate it.

*Speaker 2:* Utilities can handle risk on fuel and other things without passing them through to customers. In Oregon they handle fuel adjustment clauses via a zone where the utility is expected to manage it. They create incentives for the utility to manage those risks. Only if things get particularly bad and the financial impact will hurt the utility should customers be

stepping in to take over that risk. That's the proper role of ratepayers in risk.

*Moderator:* One of the elements that's made the BGS auction in New Jersey successful is the direct pass through of all transmission costs. Suppliers do not take the risk. This has been a huge regulatory unknown there. If suppliers had to manage that risk it would have been much less successful.

*Question:* This conversation is confusing because the settings are so different for competitive procurement. It is a different animal in a deregulated state doing a full requirements auction compared to a regulated state doing competitive procurement to compare the regulated cost based utility to a proposal from one or more IPPs. Reward should follow risk in either setting.

A regulated utility should not be rewarded for risks that they are not taking. A regulated utility is a different animal than the IPP. It is a fiction to align the interests of the ratepayers with the shareholders. The more ratepayer money pays out, the happier shareholders are and the less happy the ratepayers are. That's the inherent tension of a utility. That's why there are regulators.

The exception on incentives is if there is no obligation on the part of the utility to do something; then one might want an incentive. For instance, a fully depreciated plant. Under traditional regulatory theory if a plant gets sold all of the proceeds go back to the ratepayers because the utility has already been rewarded for its investment. However, there might be a situation where the regulator wants the utility to keep up the plant. This isn't required under prudence so an incentive might be needed. However, these are rare situations.

One way to approach this is the portfolio approach. Don't make a utility look like an IPP. Instead, it's prudent for the regulated utility to have a portfolio of resources that are both owned and contracted for long term, short term, medium term, different kinds of resources.

Wind, coal, nuclear. It should be clearly defined which resources that the utility has.

How does one evaluate the risks of the regulatory asset that the ratepayers own if the utility builds? How are the risks of owning versus PPA actually evaluated. Particularly if ratepayers get to own the asset after it's been depreciated – that has not been discussed. Competitive procurement is useful in both contexts, but is not comparable in each.

*Moderator:* To clarify, the ratepayers own it. You mean the utility, right? The ratepayers never really own anything.

*Question:* The utility legally owns it but it is a regulatory asset and in traditional regulated states all of the profit would go to the ratepayers if it were fully depreciated. That is a big issue. It's both stranded costs and stranded benefits. It only occurs if the utility owns the facility, not an IPP.

*Speaker 4:* The Massachusetts model discussed earlier addresses many of these concerns. It would work in a traditionally regulated state like Washington or Oregon.

My knowledge is that regulators have a very difficult time operationalizing the risks inside the black box in clear metrics. I'm very appreciative of what regulation is. They need tools to discipline cost rather than just traditional regulated cost of service regulation because prudence problem in the black box after the fact is so difficult.

In a traditional regulated market, there's no market for a fully depreciated facility. There's no market value.

*Question:* Consider a gas plant that a utility built and has had for 40 years; it's fully depreciated. It still has value. These are real cases that have occurred in the last ten years. There's a real plant that's fully depreciated that still has a lot of value. One can sell the plant for \$300 million into the market.

*Speaker 4:* I was describing a situation where it would stay in regulation. However, if it's a 40 year deal the discount rate takes it to zero anyway..

*Question:* In the real world there are utilities with assets that are fully depreciated that are running on behalf of the ratepayers who are benefiting. It also happens that these plants are sold and the ratepayers get that money back. How should these situations be valued by the regulator.

*Speaker 4:* The valuations I've seen have a salvage value to address the different end period for contracts.

*Speaker 2:* Sometimes that discount rate is off the mark. It's good they didn't apply a discount rate to hydro assets in Oregon years ago and assert that after 20 years there's no value any more. Those facilities are gold.

One concern is that a contract for a wind facility runs out in 15 years. In Oregon they have a 25% by 2025 mandate and just as they need all the renewables to kick in they lose that portfolio and have to get it back at a much higher market rate. And all the other states are trying to get the same renewable portfolio at that time too. The discount rate is often quite incorrect. Customers and customer advocates should think longer term than they normally do with discount rates. Discount rates discount the future and I plan to be here for the future and my children too. One of the problems with the competitive market is it doesn't provide enough credit to the future. It's one of the reasons utilities in the northwest are arguing they ought to build wind themselves. When one considers the RPS numbers in the future, those renewable facilities will be far more valuable and it could be very good to own those assets.

*Speaker 1:* I'll counter with a case study. There are two 70s era coal plants in Oregon and Washington built with the same technology at the same time. One of them was sold to an IPP who invested close to \$300 million in order to meet the Clean Air Act. The other remains in utility rate base and continues to be out of

compliance. These are complicated things. I like it when I see investments made to bring a coal fired plant into the 21<sup>st</sup> century. This is more complicated than it seems on the surface.

I do like the idea of a portfolio carve out. The utility would reserve 50% of the next round of acquisitions for IPPs because there's value in diversifying between owning and renting. That could work.

*Question:* I'll discuss this from the perspective of a large utility. They turn to the market for the bulk of their purchases. They like the option of utility ownership as a backstop but view the models very differently. The IPPs take the bulk of the risk. In the utility ownership model the customer is has both the risk and the value of the long term ownership.

A head to head competition is not possible because there are inherently different attributes here. There's life of asset versus a 10-20 year PPA. One can develop a mathematical equation to compare the two but the assumptions will be flawed, and the decisions are political in any case. It's useful for a utility to do most of its procurement via PPAs but maintain the option and backstop of new plant generation.

The concern is that in the model with risks on one side versus the other there's a blurring of those lines that's disturbing. In the context of new technology, changing market conditions, commodity price volatility, there are an increasing number of IPPs who want to re-negotiate their contracts. This has occurred in areas like renewables where turbine cost escalations are very high. In general, climate change is pushing newer technologies and those have a lot more risk attached to them. As utilities and IPPs partner up in new technologies, how do we ensure risk stays with those who have contracted for it?

*Speaker 1:* These seem like unrealistic bids.

*Question:* They are viewed as realistic bids up front. The utility is protecting them with credit and collateral but it's still a problem.



*Speaker 1:* A more robust bid process with tough evaluation of the credibility of these parties is needed. The credit markets will put discipline on the ability of people to raise the money. This is particularly hard in the current economy.

*Question:* The problem is that there's such a long sequence: evaluation, selection, contract formation, then the development period. By the time the utility is hearing about the contract renege, it's too late. There's a near term need that has to be addressed by the current contract.

*Speaker 1:* It's the reverse of my horse leaving the barn in the problem. The IPPs should put some money down, hedge it by exerting more discipline on the part of that bidder. All bidders are not alike. With IPPs, there's development optimism and a utility has to manage and challenge that.

*Speaker 3:* New technologies, no matter who built them, have more risks. The risks have to be managed. Once folks get to new technologies they're going to have to get away from a price only RFP. They'll have to consider the source.

Here's an example. In recent RFPs for gas, coal, and IGCC the world's explosion of commodity costs and construction costs really got into the RFPs. Nobody could honestly tell you they had a fixed price on that aspect of facility development. The world is topsy turvy, China's economics, etc. One can try to manage this construction risk via a fixed EPC but that may be exorbitant. A cheaper contract might index some portion of the construction cost until financing is arranged. There are ways to adapt and improve risk management.

*Speaker 4:* Contract law is relevant for this. The extent to which the counter parties are really clear about which part of these risks are unmanageable. These can be outlined within the contract. These go back on customers because they're just not manageable by anybody.

*Question:* So customers end up holding the risk. The more of those risks on customers' then the narrower the range of the costs that are being

managed by the IPP and the less risk management value going away from the cost of service model, right?

*Speaker:* I agree.

*Question:* There's concerns for utility self build bias, concerns that a PPA may lose the long term value of a facility, debt equivalence, risk management differences inherent in the PPA versus the utility mode, debt equity financing differences, differences in flexibility. These all demonstrate there is clearly significant differences between the two kinds of entities in head to head competition.

Since there are differences, and a bias that can't be addressed, and it will provide the wrong portfolio then perhaps head to head competition is the wrong approach. Perhaps a better model is competition on a default basis between PPAs, but if there are circumstances where a utility build seems to make sense then the utility brings that to the commission. Then regulatory decision making determines whether it should be buy versus build. This would be the better way to go.

*Speaker 2:* I think so. Perhaps include the build versus buy, and the risk discussion in the IRP. A portfolio approach could be considered too. The buy portion goes out to bid with a self build option. There's been discussions about apples to apples comparisons but it's not even apples to oranges here, it's apples to pork chops and it's hard to turn a pork chop into an apple. [laughter]

*Speaker 3:* The list you just discussed is correct. However, the main concern is risk. So you suggest carve out a portion with PPAs where risk is shifted back to the supplier. And carve out another where cost of service ratemaking applies with the utility and risk is on the ratepayer. You haven't really addressed risk, you've made no attempt to get apples to apples.

*Question:* I wasn't suggesting anything that prescriptive either. One can't get it right and be prescriptive given the complexity of it. One has to address it on a case by case basis.

