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Transcript of CleanLaw Episode 19: Jacob Mays And Ari Peskoe Talk About Capacity Markets, May 3, 2019

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Robin Just: Welcome to CleanLaw, from the Environmental and Energy Law Program at Harvard Law School. In this episode, Ari Peskoe, our Electricity Law Initiative Director, talks with electricity market expert Dr. Jacob Mays about capacity markets. We hope you enjoy the podcast.

Ari: This is Ari Peskoe, Director of the Electricity Law Initiative and I'm here with Dr. Jacob Mays. Just completed his PhD at Northwestern University. Jacob, thanks for being here.

Jacob: Thanks for having me.

Ari: First off, congratulations on that.

Jacob: Thank you.

Ari: I want to talk about your recent paper called Asymmetric Risk and Fuel Neutrality in Capacity Markets that you wrote along with David Morton of Northwestern and Richard O'Neill of FERC. Before I get there, I want to take a step back because we're just going to talk about capacity markets. And really what we're going to be getting at is investment in electric generation. So I want to start at the beginning in the early 20th century where it used to be that the utilities that provided electric service to consumers were also the primary builders of electric generation capacity. And under that model, utilities essentially finance that through rates paid by consumers.

Ari: And that model went south when some of these utility projects went way over budget. And the problem with this model was that consumers essentially were on the hook for those cost overruns. So they faced all of the risk from the downside of these projects. So the innovation that happened in the late '90s was these energy markets that formed. Wholesale energy markets regulated by FERC. We've talked about those previously here with Bill Hogan, with Jesse Jenkins. But what we haven't talked about is how those energy markets connect to capacity investment. Can you make that connection for us?

Jacob: Right. In principle, if you design energy markets correctly, what happens is that the revenue that generators are able to earn from the sale of energy and ancillary services in those energy markets is enough to incentivize the construction of new generation. And if the prices in the energy markets are high enough and set correctly, then everything works out and you get the right level of investment in generation capacity. But in contrast to the vertically integrated setting, the risk is born by the investors who are making the decision to make that investment.

Ari: So that's a key shift going from the risk on consumers to now shifting the risk in these energy markets on to investors. And so we had in this country about 10 years of energy markets before capacity markets were a thing. What sort of happened here? Why did we even have capacity markets? Why weren't the energy markets enough to give us the investment that we wanted?

Jacob: What they found in the early days of the deregulated markets is that when we had enough capacity on the system to meet the reliability requirement or targets that we had set, the prices didn't actually get high enough to support that capacity. So there's a couple things going on.

Jacob: Number one is that there were a lot of issues with market power early on and that led regulators and market operators to put in a variety of price caps and offer caps that prevented the prices from getting too high. So there's these caps put in place as a market power mitigation tool. And then in addition to that, there's various actions that operators of the electricity systems will take responding to situations as they come up that are unpriced by the markets. And so when they take those actions, they in general have the effect of suppressing prices. The overall impact of this has been referred to as the missing money problem. So there's not enough revenue to sustain the level of generation investment that you would need to satisfy the reliability targets that you've set.

Ari: Right. So it's important to say it's right that when these markets were starting out, the capacity all ready existed. It was just sort of being transferred from one regulatory model to another, one pricing structure to another. And we all ready had a reliable system when we made that transition, but the problem was that what we thought we were going to get new investment and more efficient capacity and that wasn't quite happening. One issue you mentioned I want to just make sure we define it is market power because I think that's going to come up in our discussion of capacity market. Can you just explain what that means?

Jacob: What market power really boils down to is that a generator has the ability through its manipulating its offer to change the price that's arising in the market. So if you run into a situation where you're short on capacity, that is true of a lot of generators. So if they withhold, if they say that they have a unit offline or they can only produce up to a smaller amount, then that will have a gigantic impact on the price that arises in the market.

Ari: And so they're withholding capacity or withholding energy with the purpose of driving up the price.

Jacob: Right.

Ari: Not every generator can do that. There's only certain generators who sort of have the power to do that.

Jacob: Right. And it's very difficult to differentiate between a very high price arising from the exercise of market power, which is something we want to avoid versus a legitimate high price that's a signal that there's legitimate scarcity on the market and we need people to come off the system or generators to come onto the system.

Ari: So the bottom line was in the early days of these wholesale energy markets, this is sort of the early 2000s. People weren't satisfied with the amount of investment coming in because prices were too low to bring in that investment. Bring us then to how we got to the capacity market solution.

Jacob: Right. In the early 2000s to mid 2000s, a number of people started formulating the idea of, "Okay, well we have this missing money, the prices don't get to the levels that they need to in theory to support the level of capacity we think we need. So let's put in a capacity market that basically replaces that missing money. If we can essentially calculate what we think the prices need to be in theory and subtract what the prices actually are in practice, then that's an estimate of the revenue that we need to make up through some other means."

Ari: It sounds like what you're saying is they decided how much money there should be and then sort of reversed engineered that outcome. Is that a fair way to-

Jacob: I think that's a fair way of characterizing it. I think what you really start with is you have some engineering judgment on what the total amount of capacity that you need in the system is to satisfy the reliability requirement that's set by, this case NERC. So we have a requirement of no loss, a one day in 10 years requirement in terms of how infrequently we have involuntary load shutting. And so you can calculate the amount of capacity required in order to deliver that kind of reliability standard.

Ari: And so that's the system operator. It's usually the regional transmission organization that's setting the demand in the market. And what other factors... I guess what I'm getting at here is there's a nomenclature issue of whether or not this is a market or whether this is a market-based mechanism because the market operator is setting the demand and they're also these days setting various performance characteristics. For example, in some of the capacity markets that have evolved in PJM and in New England, the capacity needs to meet some performance standard and the market operator also comes up with a penalty structure and a bonus structure.

Ari: And so I guess I'm wondering how you see this as part of the process of getting the money that we think there should be. So we're sort of engineering the solution and there's a lot of these variables that go into it.

Jacob: Yeah. I think there's at least two issues that you just raised. One is, is this a market or is this a market-based mechanism? One of the interesting features here is that if you do an economic analysis on what the value of reliability is, what's the value of loss load? You usually get something around... Well, it really ranges, but in the five to $20,000 per megawatt hour range. If you instead start with the engineering requirement on the one day in 10 years and calculate the value of loss load implied by that, it's about $200,000 a megawatt hour or in that range. So it's about 10 times higher. So, the reliability standard that's enforced in the capacity markets is far higher than what we might expect to arise in a pure market type setting.

Ari: In a pure market where sort of consumers could decide how much they're willing to pay for that reliability, is that a fair--

Jacob: Exactly. If the estimates of the value of last load of something like $10,000 a megawatt hour are close to accurate, then we think consumers would choose a far lower level of reliability than the one day in 10 year standard.

Ari: So the market operators are procuring more capacity than people would otherwise procure.

Jacob: That's the inference. It's not really up to them in the sense that this is how they interpret the NERC standard. So it's rational on their part in that sense, but there is certainly this conflict between the economic and the engineering conceptions of what it means to be reliable.

Ari: And one thing that has changed over time in these markets that have capacity market. Maybe we should stop there and just talk about, just note that not all markets have these capacity markets today.

Jacob: That is true although I think there is some confusion along these lines as well. So ERCOT in Texas certainly does not have a capacity market. And the expectation in ERCOT is that all of the revenues, the generators in ERCOT ultimately derive from the sale of energy and ancillary services.

Jacob: That's a little bit different from the case in CAISO and SPP, where the load serving entities in those markets have a capacity obligation that they have to satisfy. So even if there isn't a market there, they have to procure capacity either through bilateral contracts or through resources that they themselves own and they are providing the extra revenue to those units directly.

Ari: So those markets don't have the sort of centralized capacity construct market-based mechanism that we're talking about here, but they do impose requirements on utilities.

Jacob: Right. There has been a continued reevaluation of what we actually need from these capacity markets. If we think about it as we could construct the prices as they kind of should be in a theoretically ideal market and compare that to the prices that actually come about in the real world market and compute that difference. If you do that accurately, you have to take into account generator failures, how well the output of generators corresponds to the needs of the system, the locations of the generators, because the LMPs can be quite different and in different locations depending on the transmission constraints and all of these are pretty difficult things to ascertain.

Jacob: We've had issues with PJM in the Polar Vortex in 2014. A lot of units were offline and unable to perform when we needed them in that January and that prompted PJM and ISO New England as well to reevaluate the performance standards for generators and make sure that they were actually able to deliver on the capacity obligation.

Jacob: In California, they've had issues with flexibility, so there's no explicit recognition of flexibility characteristics in the capacity markets. And California has decided that that's insufficient and they need to have a separate designation on how much flexible capacity the LSEs need to supply.

Ari: I think this is a good opportunity to get into your research and your paper because what you've just articulated is that now the market operators are not just setting the amount of capacity, but they're also setting various characteristics for that capacity as well. And in theory these are all just based on performance. You just have to meet certain performance characteristics. It doesn't matter what sort of fuel you're using, whether you're wind or solar or natural gas, as long as you meet these objective criteria, you can qualify for the market and get paid in the market. And that's where I think your research comes in because you're showing that that's ostensibly true, but actually it leads towards particular results.

Jacob: Right. What I wanted to say in the paper is that even if you get that perfectly, if you figure out all of the nuances of the how do we value variable resources and how do we value storage resources and how do we account for generator failures and all of those nuances, you'll still have this other effect that I think was recognized in the original conception of the capacity markets, but not fully. The implications were not fully thought out.

Jacob: So one of the big impacts, the financial impact of having a capacity market is that you replace these very volatile scarcity prices that may occur only once in a couple of years or even more infrequently depending on the setup of the market. And you're replacing those very volatile revenues with a very stable revenue stream coming from the capacity market.

Ari: And that volatility just to be clear is in the energy market.

Jacob: Right.

Ari: And that's what happens in these energy-only markets that prices can go up to thousands of dollars, a megawatt hour during really stressful periods on the system, high demand periods. And so you can have particular generators who are really just making all their money just from those extreme situations. And when you have a capacity market, they're always accompanied by a price cap in the energy market. So you don't get that sort of extreme volatility, and so that connects to the missing money. Right?

Jacob: Right. You have either an explicit or implicit price cap in the sense that you have so much capacity on the system that-

Ari: You never get to that volatility.

Jacob: ... you never get prices that high.

Ari: What does that do to investment? How does that bias investment?

Jacob: The paper argues that this has an asymmetric, so the asymmetric in the title comes from the fact that different generation technologies have different risk profiles, different exposure to the prices coming out of the energy market. And the point that the paper makes is that peaking plants, so these are plants with high marginal costs are particularly exposed to these scarcity prices. They're the ones that are really reliant on those rare occurrences of extremely high prices in an energy-only setting.

Ari: Because these plants are normally not economic, only when prices get really high that they can make money on the system.

Jacob: The effect is when you introduce a capacity market to replace those high scarcity prices, the risk profile of those generators is completely collapsed. They guarantee a substantial portion of their revenue. So I just took some hypothetical numbers and if you have a plant that has a $100 megawatt-hour operating cost in PJM, it's expecting to earn about 90% of its operating profits from the capacity markets.

Ari: When you put that same unit in ERCOT in Texas, there is no capacity market and it's going to completely rely on those scarcity periods.

Jacob: Exactly. Right.

Ari: And so is that peaker unit then more attractive in one market versus the other? How we think about the investment decision here?

Jacob: Well, all of the things equal, you would expect it to be more attractive in PJM. The reason that all other things are not equal is that there's a seven and a half percent reserve margin in Texas and a 28% reserve margin or something like that in PJM. So there's these other factors affecting the expected revenue that you would generate from investing in the two markets.

Ari: One thing that you touch on in your paper, and I guess I want to go a little bit deeper on this risk point. Because when someone invests in one of these peaking plants, there are usually, I would imagine in some way they're hedging that investment. Can you talk about how that affects the two different models?

Jacob: Right. One, we have this built-in hedge from the capacity market. That's one aspect of it, but then investors in generation will also go to the banks and try to sign contracts to hedge risk that way through a variety of swaps and contracts. And then in certain cases, other generators, so this is less common with peakers, but renewables will sign longer term contracts with commercial entities or utilities that are willing to sign longer term PPAs to hedge risk that way.

Ari: Let's go back to the peaker example. I want to understand a little bit more as to why the capacity markets changes the risk profile there. And I think what you're saying is because the investor in that asset is less reliant on that scarcity price that may only come up once a year or something like that. That that would then make it a lower risk investment in PJM. Right?

Jacob: Right.

Ari: You did mention that there is sort of this in Texas state we kind of know we're going to have some scarcity pricing just because of the low reserve margin. But in general, that would make it a lower cost investment for an investor in PJM, is that right?

Jacob: Right. You would expect the cost of capital to be lower because they are... As opposed to an energy-only market where they might literally earn zero net profit in a given year, they have a certain amount of guaranteed operating profit coming from the capacity market revenues, which should be at least enough to cover their debt for that portion of the finance cost.

Ari: And your paper explains that the... And as you just explained, the capacity market changes the risk profile, but I want to understand a little more about that... The connection between operating and capital cost and the capacity market. So can you go into that a little bit? Explain why a unit with a lower operating costs like a wind unit for example, doesn't benefit as much from the capacity construct as the peaker unit does.

Jacob: Right. It will benefit from the capacity construct a little bit in the sense that it does earn some operating profits from the capacity market. The difference is that if you have a lower operating cost unit that's being dispatched whenever it can, it's exposed to the entire range of risks coming from the energy prices. I think I said before that if you have a unit with $100 a megawatt-hour operating cost, it would expect to earn about 90% of its revenues or operating profits from the capacity market. If you have a unit with a $10 a megawatt-hour cost, you would expect to earn about 17% of its operating profits from the capacity market. It does get an advantage in the sense that that 17% is de-risked. But that obviously has a much smaller impact on the overall risk profile than a unit that's de-risking a full 90% of its profits.

Ari: And I guess maybe I'll think about this the wrong way, but when talking about the peaker unit has a low capital cost compared to the wind unit as well. And so is that what we're talking about here? That because it's able to get such a significant chunk of that debt from the capacity construct, it's a relatively low risk investment.

Jacob: Right.

Ari: Okay, I finally get it. And so what that means for investors that if you're looking for a lower risk investment, you're going to go for the lower capital cost, higher operating cost investment.

Jacob: Right. With the additional assumption that the wind farm in this case hasn't been able to go out and get a PPA or some other contract that equivalently hedges its risk because that would reduce the cost of capital and guarantee revenue for them in an analogous way.

Ari: We've seen since really the PJM market started in the late '90s, natural gas has been the dominant sort of new... A new investment has been natural gas fired capacity and there's a couple pieces of that story. The typical facts are that we've had better technology in natural gas fired power plants, combined cycle generation has really improved a lot. And then combine that with the fact that natural gas prices have been persistently really low. That's going to motivate additional investment in natural gas and particularly since PJM is sitting on top of the largest shale formation. And so you're suggesting here that your paper suggests rather that there's this additional factor that's kind of turbocharging the natural gas investment and you're adding another piece to this story.

Jacob: Right. I certainly don't claim that this mechanism is more important than the economic fundamentals of the shale revolution and the improvements in combined cycle technology. But I do think there's potential that it's part of the story and even if it isn't part of the story yet, if you think about moving forward into a lower carbon grid of the future, you would expect this to become increasingly relevant.

Ari: If you wanted to address this issue, how might you go about thinking about that?

Jacob: Well, I think this is the classic academic response. More research is needed. But I think one of the big issues moving forward is that in theory this isn't a problem because the banks, the financial industry can step in and create the trading products that we need to support the risk trading that is discussed in the paper.

Jacob: In practice, I'm not sure how much exactly we trust the financial industry to create those types of products and push us in the direction that we want to go. And there's a sense in which the very existence of capacity markets kind of implies that we don't fully trust the financial markets in this regard. One direction is you say we're going to get rid of the capacity markets and go to the energy-only design and let the banks figure it out.

Ari: Let's just to assume that capacity markets are here to stay because this is an entrenched regulatory model and it's going to be tough to get rid of it. How might you think about reforming capacity markets?

Jacob: Well, I think one step that we seem to be moving in the direction of anyway is for capacity markets to be less important. And so with the implementation of operating reserve demand curves for instance, which should increase revenues coming from energy and ancillary services, that makes the capacity markets less relevant moving forward. So the more we can do on that front, I think the better

Ari: Let me just mention that we talked about those with Bill Hogan in a previous discussion. So people who want to catch up on that, go look for our earlier episode on that. I mean, the reason we have capacity markets in the first place as we said, is because the energy markets weren't working essentially, the prices weren't high enough. And back then, when capacity markets were being debated, people said, "Well, let's fix the energy market. Let's not do capacity markets." And now we're sort of back to that solution where we have capacity markets, but let's deemphasize them by going back to fixing the energy market.

Jacob: Right, right. And I think if the capacity markets or some resource adequacy requirement still continues to play a big part in the overall paradigm than we ought to think about supplementing the existing capacity markets with different sorts of longterm contracts and financial hedges.

Ari: I guess you talk about in the paper that states with retail competition where end users can sort of pick the company that's going to sell them power, that those are typically short-term agreements and that in a sense could be a barrier to these longer term contracts. Is that right?

Jacob: Right. And this is something that I don't think there's a, there's a great understanding of, but if you look at the types of deals that are structured in vertically integrated markets, often there's 20-year contracts, 30-year contracts for the generators. And if you look at the-

Ari: Implicit contracts usually.

Jacob: Implicit, right.

Ari: Sort of they're getting their money through the retail rates and it's typically depreciated it on like a 30-year basis.

Jacob: Right. And there's this general conception that customers are very risk averse and that's what justifies these longterm contracts. And then if you go to the deregulated markets, what you observe is one to two-year contracts and no evidence that the customers themselves are risk averse. So there's a kind of a mystery here and what role do the customers actually want to play in.

Ari: And so is there a mismatch then between what states are doing on the retail side? Because the states are the ones that are really regulating the interactions between the consumer and whoever is selling them power and delivering them power versus what's happening at the wholesale side with these capacity markets. Should there be a better alignment between these two systems?

Jacob: I think that certainly we would like to see the demand side of the market more engaged on all levels. This starts from the short term day ahead in realtime markets, but then going up to these longer term investment decisions. You would like to see more action and in this case, more disciplined hedging coming from the demand side of the market.

Ari: Just to switch gears a little bit, one area that I've done a lot of legal research on is state programs to support existing nuclear plants. Where you have these plants, because wholesale prices are so low, they're choosing either to retire or go to state legislatures and ask for payments. You mentioned in your paper some of the... I think you mentioned a problem associated with the phenomena that you're studying nuclear plants. Could you explain what that is?

Jacob: Right. I think that looking at the economics of these plants, and there's a little bit of a debate on are they losing money? Exactly how much money are they losing? But if you think about it in the grand scheme, these are units that could potentially produce power for let's say $38 a megawatt-hour for the next 20 years. Historically, that's an extraordinarily good deal. So there is a little bit of a mystery to me why has nobody just bought that power, sign them up for a longterm contract and said, "I'm willing to take that bet." Maybe I don't think prices will get that high, but it's at least worth having in the portfolio.

Jacob: And the fact that those contracts don't exist, either my intuition is wrong about the economics and they just don't make sense, or the generators think that they can get a better deal from the state regulators, or there's some other explanation. But the proposal that the paper makes is maybe that there just is no viable counterparty that's both financially viable and legally tenable that would be able to sign a contract like that. And then if that's the case, that would be a market issue that we would want to address.

Ari: Right. This actually gets back to what we were just talking about with the retailers only doing kind of two-year deals, where a retail entity in one of these restructured states just wouldn't sign an eight-year deal with a nuclear plant. Again, there's sort of this mismatch between what consumers are signing up for and what might actually support the kind of capacity that we would want to see in the market.

Ari: What's the big takeaway from your research for designing markets that are going to enable a low-carbon grid?

Jacob: This has been a popular topic of conversation on what is the market design of the future look like. And one of the things that a number of us who are working on this have noticed is that in theory nothing changes. And what the paper is saying though is that the move to a low-carbon future where everything is near zero marginal cost does exacerbate some of the issues that are all ready present in the markets. And one of those is the implementation of the capacity markets and the way we handle risk. That's kind of where this is trying to go.

Ari: This all comes back to the idea of risk, which is what we started with, where initially in the vertically integrated model you had consumers on the hook for all the risk. Now in the energy-only market and in capacity market as well, it's the investors who have the risks, but then it's a question of how do we allocate that risk among investors, developers, consumers. We're still talking about how to allocate that risk and we haven't quite figured out the right mix of that. The market hasn't figured out-

Jacob: That's the role of the consumers, the banks, the investors and how do we manage that risk in the most efficient way.

Ari: And capacity markets rearrange that risk, but maybe not in a way that's necessarily compatible with a low-carbon grid of the future.

Jacob: Possibly.

Ari: Possibly, yeah. Good academic answer. And so the question is, do we have regulators try to reallocate that risk again, or do we just leave it to the market to reallocate that risk?

Jacob: That's a good summary.

Ari: Okay. All right. Dr. Mays, thanks very much for talking to us about this today.

Jacob: Thanks.

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