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Transcript of CleanLaw Episode 8: Ari Peskoe speaks with Jesse Jenkins on renewables and electricity markets, November 29, 2018

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Robin Just:	Welcome to this podcast from the Environmental & Energy Law program at Harvard Law School. In this episode, our Electricity Law Initiative director, Ari Peskoe, interviews Jesse Jenkins, a postdoctoral fellow at the Harvard University Center for the Environment. Ari and Jesse discuss fundamental principles of electricity market design and whether these principles will continue to apply to a low carbon grid with high levels of wind and solar power. We hope you enjoy this podcast.
Ari Peskoe:	This is Ari Peskoe, Director of the Electricity Law Initiative, and I'm pleased to be joined by Jesse Jenkins, an Environmental Fellow at the Harvard University Center for the Environment. Jesse, thanks for being here.
Jesse Jenkins:	Thanks. It's a pleasure to be here.
Ari:	So Jesse, your work over at the Harvard University Center for the Environment, or HUCE, is about electricity market design. I want to start there. What is electricity market design?
Jesse:	Well, electricity markets are interesting constructs. They're a little bit different from, say, like a commodity market you might think of, like buying and selling currency or buying and selling oil or gas futures. Electricity markets are really fundamentally shaped by regulatory and policy decisions, and the electricity markets that we use to drive efficient investment in power plants and now energy storage devices and also to coordinate their operation tend to be a little bit more structured and designed than the kind of natural buying and selling exchanges that might arise around other resources.
Jesse:	And the reason for that, I think, is probably a couple fold, but one is electricity needs to be balanced instantaneously in real time, and you have real physical constraints that make operating the grid challenging. And so if we want to use markets to coordinate that operation efficiently, we have to also respect the physical constraints and make sure the lights stay on. And so that requires some careful attention to how those markets are designed so that they not only allocate money but also help organize and dispatch different power plants to help keep the lights on and meet our energy demand on a millisecond by millisecond basis. And because we care a lot about electricity and its role in the economy, we also want to make sure that certain policy or public objectives can

be achieved too to make sure that we can have the sort of level of reliability that we count on and things like that are ...

Jesse: So that, I guess in short, there's a heavier hand in electricity markets than perhaps in other markets. And so there are design decisions that policy makers make that the independent system operators or regional transmission organizations, which are the entities that operate the multistate markets that we use in the US, have to make about how these markets function. So the question for me is as we transition towards a low carbon economy and towards a hopefully zero-carbon electricity mix, that's going to change the mix of resources that we rely on, and the question is are the electricity markets that we currently have, the different flavors operating across the world, suitable to that task, or are we going to need to make some further tweaks to guide that transition towards a zero-carbon economy?

Ari: So let's start with what we have today. Market designers have to respect the physical constraints, basically make sure the lights always stay on. And so are there a standard set of sort of operating principles or procedures that are common to most electricity markets' designs?

Jesse: Yeah. So over time as the electricity markets in the US really started to get off the ground in the late 1990s, early 2000s, during a period when regulators and policymakers restructured the way the electricity sector function in the US. So prior to that, we had basically vertically integrated monopoly utilities that would run everything from generation to operations down to retail sales and the transmission and distribution networks you needed. And in many states, now over half of the US and other countries abroad, regulators and policy makers decided to let market forces and competition drive at least the generation side of that market and, in some cases, the retail sales as well.

Jesse: And so over time as different markets experimented with different design options, a standard model emerged, which my advisor, Bill Hogan at the Harvard Kennedy School, calls the Security Constrained Economic Dispatch with Locational Marginal Pricing or Bid-Based Locational Marginal Pricing Model, or I call it the Standard Market Model, since that acronym is impossible to remember. But basically what that means is there are sort of standard features for how to sync up the economics and the physical aspects. So you can break that down.

Jesse: Bid-based, which means instead of relying on knowledge of the operating costs of different power plants to organize operations, we're relying on bids, competitive bids from generators, who tell you the sort of price and quantity that they're willing to submit as well as some of the physical constraints on their power plants. This is one of the ways in which these markets differ from commodity. So they're saying, "I can sell you a certain amount of energy at a certain price, but I also can't change the output in my power plant by more than a certain amount per minute. I can't go below a certain amount of output as a percentage of my maximum, because that's sort of the minimum stable operating point for my power plant. If I turn off, I have to wait a few hours before I turn on." Those sorts of physical constraints are also revealed in those bids.

Jesse: Security constrained means that we care a lot about keeping the lights on. And so we're not just going to dispatch whoever's cheapest. We're also going to dispatch a set of resources that we know are going to reliably meet demand over the next time period, and that includes holding some reserves, so some backup power plants that aren't fully utilized, but are there and ready to ramp up or down their output if we need them. And it means we're paying attention to the flows of power across the transmission grid. And we even usually use what's called n-1 dispatch, which means we're able to survive any one failure of a power line or a large power plant across the grid and make sure that if that were to happen in the next, say, 30 minutes, we could still operate the grid reliably. So that's the security part.

Jesse: And locational marginal pricing refers to the fact that the value of electricity varies across the transmission grid for two reasons. One because of losses, so as you transmit power across the transmission line, it generates heat from resistance, and that heat is wasted energy. And so just like the cost of moving goods from one market to another, you have to truck it from one market to the other, that changes the local price at different markets. Moving electricity across the grid also changes the price due to losses.

Jesse: And sometimes you hit a constraint in the grid. You just can't move more power across a set of lines from, say, the west to east, and that leads to a bifurcation in the market where a power plant on one side of the constraint is the one that sets the marginal price, and on the other side of the constraint, you might have to dispatch a more expensive power plant to meet the demand locally on that part of the grid. And so that sets a different marginal price, and that can lead to fairly large discontinuities in the prices in different regions. So in reality, there isn't a single price for electricity. There's a price at every single node in the transmission system or point where the transmission lines meet or a demand or generation connect to that transmission grid. And so that's the locational marginal prices piece.

Ari: So we now have about 20 years of experience of the standard model, and can we say something about whether or not it's successful? I know there's a pretty robust sort of set of mathematics that underlies this, that shows that it's optimal. That's sort of on paper, and this is supposed to match sort of the physics or the paper. What happens in the math really matters because we have to match up the physics in reality. But what about the economics of this? Is there something we can say about whether or not this is really working?

Jesse: So I think that there's sort of a general consensus that the electricity market model, this standard market model, works very well to organize the sort of day-to-day in real time operation of the grid. And there are some trade-offs that can be made between simplicity and efficiency, ways to kind of get around and to sort of deviate from the perfect ideal model and still have the grid function. And those tend to incur some additional costs that are inefficient, but might be desirable for simplicity reasons. So different models, different countries and different regions differ somewhat from that standard market model, but they're all pretty close, and they're pretty close because it really is an efficient way to organize the operation of a bunch of different power plants and consumers across a complicated transmission grid.

Jesse: Where there's, I think, more debate is about whether or not that model provides the sufficient expectation of revenue over time that is needed to drive efficient investment in big capital-intensive, long-lived power plants. And so in a lot of the world, really the majority of electricity markets, they don't just leave it to that short term or spot market for electricity to drive investment. They layer on other market mechanisms or policies to provide additional revenue or revenue certainty to drive investment in new power plants. And that could take the form of what are known as capacity markets or capacity mechanisms, which try to use basically some sort of auction-like process in the longer term to say, "We need a certain amount of generation to be online three years from now, for example. Who's the cheapest set of generators that are going to be able to meet that demand and how much do they need to either keep operating or invest in that time period? And we'll run an auction, and we'll agree to pay people a certain premium for that reliable capacity." That's one option.

Jesse: And the other option is we've used a lot of public policies to say we want X, Y or Z type of electricity, usually cleaner electricity sources, and we're willing to either subsidize those or require utilities to procure a certain amount of, say, renewable energy, renewable portfolio standards are the mechanism of choice in the US, and we're going to use those policies to drive investment as well. So even though we have this sort of market on the short run, there are other mechanisms and policies that are used to shape investments in the longer term.

Ari: Yeah, so it seems like the challenge here is sort of getting the mix of resources that we want and sort of making sure that everything is priced into the market that we want to be priced into the market. And so that gets me to wind and solar, and how those fit into this model, because you were saying that because we have a bid-based model that automatically sort of accounts for the constraints of each resource, because each resource operating on the system and bidding into the system will account for its own ramp times or other physical limits like that. Wind and solar have a different set of physical limits because they're constrained by the weather. Is that something that each operator then sort of sets their own bid parameters, and it's just like any other resource, or are there unique challenges that wind and solar present?

Jesse: Yeah. Wind and solar, at least as they're treated in the US, is a little bit different. Generally, the assumption is they have no marginal costs, so they're not burning fuel, and variable operation and maintenance costs are pretty much zero. So they're generally seen as price takers. They'll generate power as long as the price is above zero, or in some cases even negative because they receive production subsidies. And so they're sort of, "If I'm there, take it. If not, I'm not there." And so in the US they, they tend to not actually submit the same kind of bids as another generator. And instead, the market operators, the regional transmission operators or independent system operators, they produce their own forecasts of available wind, and they use that to help clear and schedule the market.

Jesse: That has some disadvantages to it in that it's not clear that the independent system operator should have better insight about the wind forecast for a particular wind farm in the next hour than the wind farm owner itself, nor is the system operator necessarily the best person to manage that risk if the forecast is wrong, because, of course, every forecast is going to be wrong to some degree, and those forecasts get better the closer to real time we get. And so unfortunately in the US markets, there's not a lot of incentive for wind farms to forecast and to update their forecasts over time, as they get more information, and those forecasts can become more accurate.

Jesse: -That contrasts with Europe, where electricity markets more and more require the wind operators to bid just like anybody else. And so they have to do their own forecasts and estimate in the next day, if I'm bidding in the day-ahead market for futures, I think I can produce 110 megawatts in this hour. But then six hours later, I get a new forecast, and now I know that the wind is going to be lower or higher than I thought. They have an incentive to update and resubmit another bid, because they know that if they're wrong, they're exposed to a balancing market to basically account for the mismatch between their forecasted position that they bid and the actual generation that they submit later. And they are going to see the cost if they're off, right? If their forecast is wrong, they internalize that cost, and that encourages wind and solar generators to get better at forecasting and managing that risk. And that's something that isn't happening yet in the US, but it might be something we need to move towards in the future.

Ari: One thing that we haven't talked about yet is how these markets set the price. And when you have more resources that are essentially bidding in at zero, as I understand wind and solar do here in the US, then is the effect of that, then, just to reduce the price essentially for other resources as well? And so it seems like there's a challenge both through wind and solar to make their money, and also the more wind and solar you have, the more it's going to be challenging for other resources to make their money as well.

Jesse: Yeah. So the way electricity markets set prices is similar to other markets in that you need to think about Econ 101. You've got a supply curve that's increasing, different generators that have higher costs, all revealing how much they can produce, and you put them in order, and you get an increasing supply curve. Then you've got some amount of demand, and where that demand crosses the supply, the cost of the last generator you need to produce power to meet demand will set the price. Now, that's in a vacuum in a transmission grid. As I said before, that actually used to get a bunch of different prices because of losses and congestions. There may actually be more than one generator. If there's a constraint in the transmission grid, you'll get one extra generator for each constraint setting prices in the region that they're able to meet the marginal demand, and losses will be accounted for when you think about the price at each location. So similar to the sort of classic Econ 101, but affected by the constraints and losses in the transmission grid.

Jesse: So in general, then what happens is you think about you have a set of power plants, you might have wind and solar and nuclear, that all have very low prices. They'll be the bottom of the supply curve. Then you'll have a set of natural gas plants or coal plants with increasing cost, and those will make kind of a nice, smooth increase in the supply curve. And then we have a few power plants that maybe burn oil or inefficient gas-fired power plants that we call peakers, because they're only used occasionally to meet the peak or highest levels of demand. That's how things look today, and that presents a fairly smooth sloping supply curve that's similar to sort of other markets that you would expect to see a kind of gradual supply curve.

Jesse: If you move to the future where we're going to have a lot more low-carbon resources and lot more wind and solar, hydro, nuclear, geothermal, all those resources have one thing in common, which is they have basically no fuel cost. And so what that does is it sort of shifts out the supply curve, it flattens it and it shifts it. So you end up with a bunch of resources that are bidding close to zero, and it creates a nice long flat piece of the supply curve near zero. And then you might still have some infrequently operated peaking power plants. You might have demand response, so people who are willing to curtail their consumption, if the price goes higher than their value, the value they get from consuming electricity.

Jesse:

And you might have storage operators, battery storage or pumped hydro storage facilities, that are bidding their opportunity costs, not their marginal cost. But the chance that if I discharge my battery now, I might not be available in a future hour when the price is higher. And so they have to internalize that opportunity cost, that sort of scarcity into my bid, and so I might bid something that's not zero as well. And if I think there might be a supply scarcity in the next few hours and prices are going to get really high, I'll actually bid a fairly high price. So all of those resources will present sort of a rapidly increasing part of the supply curve, so it looks sort of like an L instead of a nice gradual increase.

Ari: So I see at least two challenges here with this potential for this new resource mix. One is, as I mentioned, so how did these resources earn their money if you have this long flat part of the graph where everybody's sort of bidding in at zero? And then the second challenge is making sure that you have a set of resources that are going to be flexible enough to sort of keep that balance between supply and demand at all times, which is so critical to keeping the lights on. So which one of those do you want to tackle first, the... challenge or the flexibility challenge?

Jesse: Those are both great challenges, and they're actually kind of related. The way you solve them, at least in theory, is more or less the same, which is just to go back to the principles of that standard market design, which is that we're going to try to take into account all of these technical constraints and marginal prices, and we're just going to continue to clear the market in the way that meets that demand reliably at the lowest cost. And what that's going to mean is that we're going to have basically two periods, two types of events. One is where we have plenty of those low marginal cost resources, wind, solar, nuclear, hydro. As long as those are abundant and able to meet demand, prices will be effectively zero. That's the first period. We'll call that an abundance period.

Jesse: And then the second is a period where we don't have enough of those resources, and we have to start using our more expensive peaking generators or discharging storage or using demand response or the demand side to settle the market. So we'll call that a scarcity period. We don't have quite enough wind, solar, hydro, etc., and so prices have to be set at a non-zero amount, high enough to induce those other actors to generate electricity or to curtail their consumption. And so in those hours, when prices are high, all of the other wind, solar, hydro, etc., that have zero marginal costs are going to be making a gross profit in that hour. They're going to generate power that costs them zero in the low term, in the short term to produce, it cost them zero in the short term to produce, but they're going to be making a bunch of money because, say, an expensive power plant or a demand response sets the price at several hundred dollars per megawatt hour.

Jesse And it's that inframarginal rent, that extra margin that they earned in those hours, that would have to help cover their fixed costs and their cost of investment. And that's really no different than today. That's how generators pay for their costs as well, as they're relying on periods when they're not the most expensive power plant setting the marginal price. There's something below that, and there's somebody more expensive setting the price, and they're going to earn that extra margin. The difference is that in today's markets only peaking power plants rely on those scarcity periods to make all of their revenue. Everybody else can make a bunch of money in other periods of the time when, say, just a less efficient natural gas plant is producing and setting the price, and that's higher than their marginal price. And so all of their revenues are going to be concentrated in these few hours when there's scarcity, and the rest of the time, the abundance periods, prices are going to be zero.

Jesse: And so you're going to have an environment where either we really need to get those scarcity prices down well, and we need to be able to have generators count on them for revenue, which is something that we've struggled with in a lot of electricity markets, and we can talk more about why, or we need to rely more heavily on those other mechanisms I talked about earlier that supplement the market signals for long-term investment, capacity mechanisms or other policy supports, because they're going to really be dependent on revenue in those scarcity periods to earn all their money. And that's not just peakers, but everybody, wind farms, solar farms, storage plants, nuclear plants, etc.

Ari: Yeah. Just to emphasize your point a little bit, my understanding of how, say, a wind farm gets built today is that almost all wind farms in the US today have a longterm agreement with an off-taker, and that agreement often will specify a fixed price. It may vary each year or something like that, but a per-megawatt hour price for each unit of energy, and so the developer knows, they have a really high degree of certainty that they're going to get paid back, because that contract is probably then backed by some third party with a very high credit rating, and so the risk is relatively well understood.

Ari: And as you move into this environment where you're talking about, where basically a wind farm costing hundreds of millions of dollars is going to be relying on these very short windows, these scarcity periods, to make all of their money, it raises the question of who's going to invest in that type of resource? And so how do you approach that question? You think about who the investors are going to be, and whether or not they're going to be a sort of willing to take on this new type of risk.

Jesse: Yeah. I think this is really the heart of the issue. I think there's been a lot of discussion about whether this sort of transition to zero-carbon electricity markets sort of breaks the fundamentals of electricity markets, or we need to sort of start from scratch and design something new. I think that that's not the case. I think that the core economics are the same, the rules of economics are sound, and the fundamental principles of the standard market model are sound. The challenge is that the risk shifts around a lot. And so if that risk environment looks very different from today, we're going to either need new financial instruments that are capable of appropriately sharing that risk between different counterparties, whether that's banks or financial entities, the investors in the power plants themselves, or consumers or their agents, like retailers, who also want to be hedged against certain types of risks, particularly the risk that we don't have enough electricity and prices are very high for a long period of time.

Jesse: So there are opportunities to trade risk between all those counterparties. And the question for me, the research question, is what is that risk environment going to look like? It's not something we've seen historically, so can we use modeling and forecasting to try to get a handle on what these future market environments might look like, and what the risk for generators of different types of storage assets would look like, and compare that to what we're used to today and see how different that is. And then think carefully about whether we would expect banks and other financial institutions to create hedging mechanisms and long-term contracts of various types to manage that risk, or whether that's a bridge too far, and that the risk we're looking at is simply something that there aren't counterparties that are able to take that on their books, or they're not going to be willing to do it without charging an enormous premium for that risk.

Jesse: And then we might have to think carefully about whether we can continue to achieve the kind of same goals of markets, which is not just organized efficient, short-run operation, but also efficient investment and reliability. And if we don't think there are financial entities that are willing to do this and we're not going to have natural contracts emerge, what might we have to do with market design or policy to manage that risk. Those are the kinds of questions I'm looking at right now, and I wish I knew the answers, but that's what research is for.

Ari: Your mentioning of new financial instruments raised sort of a legal regulatory issue for me, which is there's this principle that basically every transaction in the electricity industry is regulated by someone. And so if you come up with these new financial instruments, that sounds like something that's sort of outside the purview of the traditional regulators, like the Federal Energy Regulatory Commission at the national level, or like state public utility commissions at the state level. And so is this sort of a financial product that the CFTC or the SCC or somebody else might be involved in, or what sort of new regulatory structure might this need? I guess we'll sort of figure that out as you get deeper in your research and kind of figure out what this sort of instrument might look like.

Jesse: Yeah, and there are a variety of different hedging instruments that are already used today by merchant power plants, whether those are merchant, meaning they're competitive generators that sell into the wholesale markets, whether those are natural gas plants or wind farms or solar farms. And some of them have physical longterm contracts, so they're a power purchase agreement for some quantity of electricity at a certain point in the grid. And those might be regulated by FERC because they're physical sales of electricity, but a lot of the products are just financial mechanisms, so they're just like some kind of swap or contracts for differences or forward or hedge. These are the various different structures for managing risks that are financial instruments and are regulated by financial regulatory institutions and not something the electricity regulators touch.

Jesse: So a lot of wind farms, for example, many of them do have physical PPAs, power purchase agreements, where they're selling directly to a utility or a utility buys the power plant and owns it, but about half, I think, are merchant power plants that just sell their electricity into the wholesale market, but they don't only do that because that would be too risky to finance, so they also layer on top various financial hedges. And they do that in order to attract the kind of upfront investment that they need to build an asset that is effectively all capital, right? It's a wind farm, it's all upfront costs, very little operating costs, no fuel cost, so you need a bunch of money up front to build the thing, and then once it's there, it's just going to generate revenue for you with very little O&M.

Jesse: And so the competitiveness of that project hinges on their ability to attract for relatively low-cost capital, whether from debt or equity markets. And they're not going to attract a lot of low-cost capital if they're taking a lot of project risk on and passing that on to their investors. And so they try to off-shore some of that risk upfront by signing certain hedging contracts, and those effectively all are some flavor of, "I will pay, the wind farm owner will pay some fixed amount or take some reduction in their expected revenue in order to reduce that risk and get some greater certainty in their revenue over time." And so those are the kinds of mechanisms that I think would be needed more and more for all types of resources in a zero-carbon power system where you're much more reliant on these few scarcity periods to get your revenues.

Ari: And so what we may be looking at is are a similar set of financial instruments, but the scale might be so different that it really changes the calculation for these institutions that are already doing this sort of thing.

Jesse: Yeah, exactly. The scale, the sums of money involved, the type and numbers of power plants that are going to need these types of contracts is probably going to change significantly. And I think some natural gas plants are relatively unhedged. They might buy hedges to fuel price volatility, to natural gas prices, because that's their main uncertainty. And then there are liquid futures markets for natural gas that go out 10, 15 years into the future. But because gas and electricity prices are highly correlated, particularly the times when natural gas plants are generating, they're less exposed to electricity price risk.

Jesse: That's not true in a world where renewables, the variability of renewables output becomes one of the big risk elements. And so you've got this sort of new driver of risk that isn't fuel price volatility, but it's hour-to-hour or year-to-year, even variation in wind and solar output. I think we can learn lessons in that world from markets that are dominated by hydropower that have big swings year-to-year, month-to-month in the availability of hydro due to rainfall patterns and precipitation. And so places like the Pacific Northwest or Brazil or Colombia or elsewhere that have large hydro-dominated systems have been dealing with a lot of these sort of same challenges of weather dependent variability in their electricity markets for some time. And so that's one area I think we can look for lessons today, existing lessons for what that future renewables dominated future might look like. And we can also rely on modeling and studies that simulate what that future environment would look like.

Ari: Are you optimistic that the core principles of market design that we've talked about are going to get us to that low carbon future, or do you think we start to really seriously need to look at some sort of addition to the standard market design?

Jesse: So I think that it's important to remember that the electricity markets are not designed to drive a transition to clean energy. That's a public policy objective that reflects the need to take into account externalities, or what have traditionally been externalities, from those electricity markets, so the fact that we're driving climate change or air pollution or water pollution with the combustion of fossil fuels. And so I don't think we should put all of our hopes on electricity market design to drive the clean energy transition, but it can either be an enabler or an impediment to that transition, because in order to go from where we are today to a low-carbon power system, we're going to need a lot of investment to be made, a lot of capital to be plowed into low-carbon resources.

Jesse: And if those electricity markets aren't able to attract that capital, or they're going to increase the premium, the risk premium, that that capital requires to be invested, then it could slow or raise the cost of that clean energy transition. So I think it's sort of a secondary factor, but it can either be supportive or a major detriment. The only thing that's going to drive a transition towards clean energy is some kind of public policy intervention.

Jesse: Whether that's a price on carbon that's sufficient enough to change the economic calculus and shift towards clean energy resources or a blunter instrument like some sort of performance mandate or clean energy mandate that's going to simply require a greater share of electricity to come from these cleaner sources. Historically, that's what's been driving the transition already, policies like renewable portfolio standards, and I think we have to sort of separate the two. There's a clean energy policy requirement, there are policies that are more or less market friendly, and that's a really important question as well. And then there are market design questions about whether the markets can continue to attract capital and continue to efficiently operate the grid.

Ari: Well, I was thinking about your hydro thing. I thought that was really interesting about what we could learn from these, like Pacific Northwest or whatever, but it seems like one difference there is just that the government came in and built all these things, so you didn't have the same investment challenge. But I wondered what you were learning from ...

Jesse: But all of the other power plants in those markets face the same risk exposure. So say you're going to build a gas plant in the Pacific Northwest or in Brazil, they are affected by those sorts of risks. And so a lot of them don't use the same market mechanisms. They use different mechanisms to, they use sort of longterm contracts of different types and auction procurement mechanisms, and maybe that's the answer too. But I do think it's worthwhile to look at those as examples of what we might learn. Because I do think it's actually the year-to-year or at least seasonal variability that's more of a challenge from an investment perspective than within the year.

Jesse: You can buy short run derivatives, and you can manage that short term uncertainty with better forecasting from minute-to-minute or hour-to-hour. It's pretty hard to survive a year when you simply don't have any scarcity pricing, because wind produced 15% more than you thought it was going to, which happens, or wind produced 15% less, and you have 15 months of scarcity or something like that, or much, much higher percentage of the scarcity pricing. So it's those longer term correlated variabilities that I think present a bigger concern to investors where they really need these longterm mechanisms to hedge that risk exposure. And electricity futures themselves are really only traded for like a year or two in advance, so there hasn't been a liquid market for longterm electricity futures the way there is for natural gas or oil or certain other things.

Jesse: And so they've had to rely on these other sort of bespoke mechanisms to do their hedging, and they're less liquid markets, so they tend to be more expensive, and maybe that will change. But if you don't have a reason to hedge, because you don't have exposure to scarcity pricing because we haven't got the short term markets, you may not see those markets emerge. So it's sort of a Catch-22.

Ari: We will leave it there for now. Jesse, thank you so much for joining us. And we look forward to hearing more about your research.

Jesse: Yeah. I'd love to come back in the future. Thanks.

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