Oral Discussions on Session: "Markets" – Part I

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Chair: Shmuel Oren (University of California at Berkeley)

Abstract

This paper contains the first part of the transcribed oral discussions of Session "Markets" of the 2013 IREP Symposium-Bulk Power System Dynamics and Control Sunday, held on Wednesday morning, August 28, 2013. Papers [1]-[4] were presented.

Discussion

Chair (Shmuel Oren): I will use the Chair's prerogative and start the questions. My question is directed to Alex Papalexopoulos [3]. You know the RUC is now considered as a good area where we can introduce stochastic optimization. And this becomes very important when you start to have a lot of renewables. So you cannot do it in the day-ahead market but you can do it in the RUC, introduce uncertainty and optimize with respect to that. Combining RUC into the day ahead market takes away this opportunity of doing stochastic or robust optimization. And the other question is from the point of view of pricing. You think that the pricing effect of the RUC is actually reflected to the virtual transactions that are in the day-ahead market, which kind of pretty much anticipate what the RUC is going to do? So, I don't see much value of having a separate pricing run if you have virtual trading.

A. Papalexopoulos (ECCO International): OK. Great questions. With respect to the first one, I agree. One of the things that we are looking into is indeed if you integrate the two functions, you forego the opportunity to do stochastic optimization in RUC, which is becoming more and more important in view of the presence of massive penetration of renewables. So, I agree. This is a problem. It needs to be evaluated. Actually we have discussions with the ISO about this. The ISO is proceeding as you may know with a surveillance committee that is proceeding with the RUC integration with the day-ahead market. Also other ISOs are interested about this too. But you are right. A negative aspect of that is we forego the stochastic aspect that we could put in RUC. In terms of the virtual bids, to me this is an even more important discussion. In the formulation we have so far, indeed we have not included virtual bids yet. Actually in the next formulation, when we submit a paper like this in the Transactions, we plan to address this issue in more detail. You see, all the issues that relate to the virtual transaction may anticipate what happens in RUC. So I am not in a position right now to tell you exactly how the virtual bids will interplay with RUC. But this is an area that we have addressed in our paper, it is in your proceedings, but we have not answered that question. It is part of the ongoing research. So it is a very important issue.

Nikos Hatziargyriou (NTUA): I am not sure if it is the same question. I guess the RUC depends on the difference you have between the forecasted load and the actual load. So how do you define that in the day ahead? Do you assume certain error?

A. Papalexopoulos: No. It‘s the difference not to forecasted vs. actual. It's the difference between forecasted and bid-in load demand. At 10:00 am, when the gate closes you have all the offers and bids from generators and loads. So at that point, you know exactly what is the bid-in load in the system. So, for example you have, let's say for the California system, load bids coming in that amount to 40,000 MW. At the same time, the ISO has done a forecast for the next day's peak and the peak load for tomorrow, based on the load forecasting function, is 55,000 MW. So, we have a difference of 15,000 MW. That's the scary part. How you cover that gap. So, the motivation is that you need a function after the day-ahead market closes to cover the ISO with additional commitment to meet next day's peak. And this function is basically the result of the California energy crisis. We didn't have it at that time. So, we were going into real time without having a back stop reliability function to have enough committed units to meet next day's peak. Now the key question is: why could the bid-in load demand be so different from the forecast? These are market participants. They do their own forecasts, why then do they under-forecast so much? There are many possible reasons. Over the last 10 years we have studied all sorts of games. This could be simply a result of load forecast error, but we are more concerned about some more gaming going on here that many participants may decide to under-bid even though they have load for 10,000 MW may be, but they

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submit 9,000 MW in order to submit the remaining in real time, do under-scheduling, if they are chasing, let's say, lower prices in real time. So there is strategic bidding that may be going on, and that explains sometimes the gap between the bid-in load and the forecast. So that's the gap that RUC tries to cover.

Fernando Alvarando (Wisconsin): My question is also to Alex, sorry... As you know, one of my views is that the lack of virtual bidding was perhaps the main reason for the crisis. The fact that you couldn't achieve convergence…

A. Papalexopoulos: No, it was not the main reason.

F. Alvarando: Well, I said, in my opinion is one of the main reasons. Not the main reason, OK. So without addressing the problem of virtual bidding right up front, you will have a problem still. But my question really is: have you done any experiments and do you have you any idea how different would the numbers be in the prices that the day-ahead markets will see with the RUC vs. the more conventional approach? Are we talking 5%, 10% or talking occasional situations, where the differences are huge, and most of the time it doesn't make any difference.

A. Papalexopoulos: That's a good question. We have done some testing for large ISOs. The difference depends on the conditions and actually depends on how big the gap is. But as you know, the commitment costs of the RUC units are being charged to the market participants that cause the deviation. So there is an incentive, there is a feedback loop in the market, for the participants to bid close to their actual demand. So, that minimizes the gap. But if that gap is high, then the price differentials could be high. I have seen differentials even 10% in some cases. But if you look at the mature markets in the East, for example, New York ISO or PJM, you see that that gap may require the commitment of, let's say, 10 units. Let's say maybe 3,000-4,000 MW. So, if we assume that that's the gap we are talking about, then the price differentials are not very high. But clearly we can show that if you integrate the energy price and the ancillary services' prices, will be lower. But the commitment cost could be higher because the commitment is changing.

Chair: One of the suggestions I once made and no one took me seriously is that instead of the gap they should allow the ISOs to submit virtual bids and then you can test the performance of the ISO. If they made money at the end of the year or they lost money.

A. Papalexopoulos: That's a great question Shmuel. I am not so sure that nobody took you seriously. Everybody takes you seriously. But the issue is that if you allow the ISO to be in that business, it is changing the role of the ISO, right? I understand it is a price taker but we don't want the ISO to be influencing the market. ISO is a neutral party that should not be taking positions…

George Gross (University of Illinois): Independent!

A. Papalexopoulos: OK! OK, George, independent. But in terms of the mechanics, what Shmuel is saying is a very good suggestion. Simply in my mind it violates the role of the ISO, of taking positions in the market. And we don't want to do that. Now if we could change the role of the ISO, this is something that certainly is welcome and a very important suggestion that could help.

Chair: But at the end of the year, you could see if they made money by arbitraging the real time and the day-ahead market, then you know that they were doing well. If they lost money it means that they were overly conservative.

A. Papalexopoulos: Sure, I understand.

Michael Chertkov (Los Alamos National Laboratory): I have a question to the last speaker. Emmanuel Loukarakis [4].Very nice work and my understanding is that you are doing distributed optimization.

Emmanuel Loukarakis (Durham University): Yes.

M. Chertkov: And in doing so you have local measurements which are consumptions or generation, right? That's what you are accounting in the scheme. That's the only observable which you have. Correct?

E. Loukarakis: Not exactly. What I have is specific values not measurements: the results of the optimization problem, the optimization sub-problem results that are exchanged between market participants.

M. Chertkov: I understand. But your measurements are those consumptions and generation, right?

E. Loukarakis: Yes.

M. Chertkov: So now my question is if you additionally measure voltages or flows through.

E. Loukarakis: I know. Voltages are taken into account. So…

M. Chertkov: Are you accounting them as a result of your cyber solution or is it something that you measure and plug in? That is my question. There are various ways how you can do it.

E. Loukarakis: What I have is the full AC equations that include both power, active and reactive, and voltages, magnitudes and angles. So these are within the optimization problem. They are all optimized together, solved together. I don't know if this answers your question.

M. Chertkov: Well, I understood that. But you can either get those as a result of the solution or you can measure them. If you measure them directly, that's additional information that you can use. And you can converge faster, that type of things.

E. Loukarakis: Essentially this is something that runs on the computer… Actually there is nothing to be measured because this is something run computationally.

M. Chertkov: I am asking if you add that, additionally to your computations, if you measure. Can it help you? Can it converge faster? Can you stabilize prices faster? That is what I am asking.

C**hair**: The iterations are done in the computer. So what you are suggesting is if we can actually do the iterations physically and then measure.

M. Chertkov: Exactly! I am asking to mix those. I am asking if it is possible to mix and if it accelerates.

E. Loukarakis: No, I don't think it is possible to mix those things because if we have demand fluctuating in real time or actually being able to measure that response, then there will be great fluctuations everywhere in the system. Essentially that's something that should be avoided…

M. Chertkov: So you are judging by results that you didn't get. You are saying that they are not because you cannot do it. Because you anticipate this type of behaviour. But this is something to be studied, right?

E. Loukarakis: I am not sure I understand what you are getting at.

Chair: It's alright, we'll take it offline.

E. Loukarakis: Yes, we can discuss that.

Chair: Is your method somehow related to the Baldick and Kim method, there is a paper in '97 [5], where basically, they partitioned the network and replicated the variables in the boundaries.

E. Loukarakis: Replication of variables is more or less standard method that goes with various decomposition approaches. What I used is a particular method that attempts to decompose the augmented Lagrangian of the problem. And it's actually a method whose parallel implementation I haven't seen before being applied in power systems.

Chair: Baldick and Kim did exactly that. They solved an OPF, breaking up their OPF into sub-areas and replicating the variables.

E. Loukarakis: There are two basic differences from their work. The first is, they had a method similar to this but it was implemented in a serial manner. So the formulation that I've done actually enables the matrix to solve everything in parallel. Second, the tests they conducted were limited to 3-4 areas, so what I was trying to do was go to a very much larger number of areas to see what happens in the system.

A. Papalexopoulos: But they discuss parallelization though. They talk about parallelization. They do talk about parallelization in that paper.

E. Loukarakis: I am talking about the other two methods they presented.

A. Papalexopoulos: OK.

Dionysis Aliprantis (Purdue University): This is a question for Alex Papalexopoulos and it is related to the previous discussion about the ISO being independent. Perhaps you mentioned this, but I may have missed it. So, you have a forecast of the load in the day-ahead. Who creates that forecast? Isn't it the ISO?

A. Papalexopoulos: OK. That's a very important question that we have dealt for years. Actually it is a very sensitive question, because I have dealt with pretty much every ISO in the country. The ISO is responsible for the forecast. The ISO has its own processes, very advanced methodologies, they produce their own forecast, they use advanced methods, such as neural networks, they break down this in zones. All ISOs have that, so they do a good job. However, they also get some forecast indications from, let's say, the measure utilities. But they are responsible for combining this and coming up with a forecast. Here is the issue. The issue is not what the forecast number the ISO process gives you. The ISO is responsible for reliability first, keeping the lights on, and then it is responsible for markets. Therefore, because of their responsibility, they have the tendency to adjust the forecast upwards, even though in violation of operating procedures. In other words, I am a dispatcher. It's the end of the day, around the forecast, at 5:00 pm, there is a heat wave in the valley in California, and I know that the forecast will be going higher and higher. They get a forecast of 50,000. It's natural to say "OK, I'll jack it up and I enter to the system 52, even though the forecast gave me 50". So they sometimes are trying to be conservative by adjusting the forecast to commit more units. It's not money from their pocket. Who pays for the additional units to cover the gap? It's the market. The market on the other hand wants to reduce the number of committed units because they are absorbing the cost: they are paying for the commitment cost. So there is a friction between the conservative approach the ISO follows to make sure the reliability is met the following day vs. the market who wants to be paying less and less costs. So what we have done as a result of these intense debates, if you go to the stakeholder process in the US, you will see very controversial and very confrontational discussions between markets and the ISO. How they set up their RUC target, which is exactly your point. So what we have decided to do is: OK, the ISO is conservative, we cannot change that. But if the ISO over-forecasts and keeps over-forecasting, it is not fair to the market to be allocated all those commitment costs. So we have a two-tier process. There is a certain level of commitment costs, which are being charged to the people who cause the gap, the people who under-schedule, but if that cost goes above a certain level, meaning the ISO is over-forecasting, adjusting the forecast upwards, the additional costs are spread over to the entire market. In other words, the forecast errors, really, are being absorbed by the entire market. This is the only way we have really to control a little bit the ISO, but you are right, there is a tendency under certain conditions to adjust the forecast upwards to commit more units because they think they need them.

Chair: And it is going to get even more complicated because now they are talking about committing the flexible ramping capability to deal with renewables and again it will be the same deal of how you allocate the cost of flexible ramping to the people they cause the need for.

A. Papalexopoulos: Excellent. That's right. That's exactly right. So, that's how we try to do it. Institutionally we have an issue with the ISO being too conservative and trying to commit more units. That's another issue. It's another area what Shmuel is talking about. That we need to think through, how we allocate those costs.

Janusz Bialek (Durham University): I think this whole discussion is grossly unfair to all the other speakers, because all concentrate on Alex, who dominates the discussion. So, I will just add one more question. It is not a question. It is a comment to this discussion. It seems to me that this discussion is ideological, in terms whether the ISO can take position in the market, in the day-ahead market. So, I will make a comment on the British situation. In the GB market, which is not nodal, it is bilateral, but it is a regular situation that the bids to the balancing mechanism are either higher or lower than the forecasted demand. And what the National Grid does regularly, it runs its balancing mechanism, which is an auction to meet the forecasted demand, which is they take position, because at the end of the day it is their responsibility to balance the market. And because those imbalances are charged, imbalance charges, they add charges to the participants who got it wrong, which means there is a difference between what they bid and what is actually their physical position.

Chair: They are for-profit.

A. Papalexopoulos: That's exactly right.

J. Bialek: That's why they are charged the imbalance cost. So what I am saying with that example is that ISO actually takes position in the market and balances the system…

A. Papalexopoulos: In the US this is a violation of the most important principle of keeping the ISO independent. Otherwise the ISO is creating winners and losers. And they have no place in the market. That's a very important principle in the US design. And by doing what you are saying, you violate that principle.

J. Bialek: But it works.

A. Papalexopoulos: It works for whom?

J. Bialek: For the market

A. Papalexopoulos: Now the question is getting ideological…

J. Bialek: But you started from the principle of the lights going out in California. The lights have not been going out, despite all its flaws, in the British market. It's very reliable.

A. Papalexopoulos: OK. Let's say…

Costas Vournas (NTUA) OK. Let's say, that's the end of it!

(Laughter)

A. Papalexopoulos: OK, all right.

Claudio Cañizares (University of Waterloo): Following with the discussion, and picking on Alex again, looking at the model in your paper for the combined day-ahead market and RUC, it looks very much similar to the unconstrained real-time market that we have in Ontario, where they clear the market, with all these constraints, without the transmission constraints. And they do this every five minutes. By the way in Ontario the day-ahead market is a joke: it is not binding. So, it's basically on the books, but it doesn't quite work. However, what I am trying to understand is what would be, because you said that there is some complexities in solution…

A. Papalexopoulos: Yes.

C. Cañizares: From the experience in Ontario, that hasn't been the case; the market is very similar and works fine. The problems are other, other types of problems. That's one of the comments and questions. The other question I had is: in the case of Ontario the loads don't really bid. I mean it's a fraction of the load. So the forecast is basically what defines what the load should be and when it should be supplied which is very accurate if you look at the IESO website, but they don't deviate more than 5% in the worst of cases. So, in that context, how do you see this working when you have a pretty accurate load forecast? Thanks.

A.Papalexopoulos: Maybe there is a miscommunication here. The RUC is not very like the real time market. Actually, I was involved in the design of the market in Ontario with ABB for many, many years. I am very familiar with that market. The RUC is really a day-ahead function that includes full transmission and it is a commitment. It is not like a dispatch on a 5-minute basis, which clearly is a process that has been fully vetted and we know exactly how it works and where the problem is. Indeed, it works very well in Ontario and in many other places. Again, this is a day-ahead process with full transmission modeling and co-optimization of all the day-ahead commodities. It means energy, ancillary services, transmission and the RUC capacity. So everything is in day-ahead: full transmission, full unit commitment, and full co-optimization of energy and ancillary services.

C. Cañizares: The second part was what happens when you don't have a bid-in load. When your forecast is accurate.

A. Papalexopoulos: Again the RUC clears. The only similarity between RUC and real time is that they both use the load forecast to clear. The day-ahead market uses the bid-in load, the RUC uses the forecasted load and indeed in real time the 5-minute market uses the bids and clears with the load forecast for 5 minutes. That's why we propose to put RUC first in order to maximize the efficiency for the real time operations which are more important than the day-ahead operations.

Chair: Yes, but the RUC basically is trying to make sure that if some of the load shows up in real time, then there will be units there turned on to satisfy them. And that doesn't get reflected (in day-ahead market clearing). Otherwise you are going to have infeasibility in real time.

Tasos Bakirtzis (Aristotle University of Thesssaloniki): I have one short question for Alex and another one for Manolis Loukarakis. Alex, in many North American markets there is a multi-day RUC to commit extra-long start units. Is your proposal to combine day-ahead market and multi-day RUC as well? Have you considered how to incorporate this integration in multi-day RUC? And a short one on timing requirement issues. You almost double the size of the network. Is it within the timing constraints of the market clearing?

A. Papalexopoulos: Yes, Tasos, great questions. Indeed many North American markets for the RUC portion, they go beyond the first day. And they go beyond the first day because there is the reliability function and they want to look ahead to do the best procurement to meet next day's peak. But how you go to day two, to day three, you saw my time diagram there, I also talk about day two and day three and day four; there are negatives to that. The negatives are the replication of bids. In other words, you solve the problem but you may create another one because the replication of bids includes errors. Let's say it's Thursday, so bids are coming for Friday; then you replicate Friday bids for Saturday and Sunday. So, how accurate that replication is for a different day-type? So, replication may introduce some errors. There are ways to go about it, to develop a better process for replication of the bids. But yes, indeed, we want to go to day 2 and day 3 for RUC for all ISOs and this process that I presented here also has the day-ahead, also goes to day 2 and day 3, together with RUC to have multiday. That's the next thing. But our main concern is what errors are introduced by the replication of the bids. Because once you couple three days...

C. Vournas: You could forecast it…

A. Papalexopoulos: Right, but this is even worse, because then the ISO gets into the business of forecasting bids on behalf of market participants; so at least we use the participants' bids, we replicate them, but this replication process introduces errors. So, the question is whether the benefits from replication supersede some errors introduced from the replication of bids. That is the issue. In terms of timing, this process let's say in California, 5,000 bus system, full unit commitment with RUC, you can do it in sequential, you can do it in 15-20 minutes. It's an amazing performance. Now, if you combine it, from the tests we have done for smaller systems, we compared the execution times of the combined vs. adding the times for the sequential approach, and we found that the combined approach is even faster. Because, remember the commitment for the second step locks in the results of the first step and that locking process through penalty functions really makes that optimization difficult. It's not an easy optimization. Think about it. Too many penalty functions. Too many must-run units. Too many hard requirements.

So that optimization has a hard time converging. You follow? So, if you do it in one shot, it is a much cleaner approach. So, we do better in terms of timing.

T. Bakirtzis: Thank you, Alex. And one question for Manolis Loukarakis. There has been some recent literature on consensus-based optimization, which is a distributed way of solving optimization problems without any central information exchange. Do you believe that this kind of optimization could be applied to solve the optimal power flow problem?

E. Loukarakis: The basic issue that I see in this kind of approach is perhaps that transmission constraints might not be very easy to be handled. Perhaps it could be a very simple thing to apply this kind of approach and calculate power imbalances in the network and perhaps based on that, update the marginal prices and converge the price. But if there are system constraints, I am not so sure how easy it is to incorporate these constraints into the method.

G. Gross: There was another paper about transmission, cost allocation [2] and I don't want that paper to be orphaned completely because it was in the wrong session. So my question is: you did talk about counter flows and tried to put some kind of consideration. But counter flows are totally a property of the network. They are not a property of a particular participant. So the idea is that when you have a particular entity that causes a counter flow, it only happens at that point in time because of network conditions, but also if the dominant flow would go away, that counter flow will become the dominant flow. So how do you plan to take this into account in terms of doing a cost allocation for that?

Pavlos Georgilakis (NTUA): Thank you for the question. I totally agree with the comment. Because of that reason we used three different approaches regarding counter flows. The first approach, the absolute one, does not charge counter flows. The second approach, gives credit to counter flows in case they exist. The last one does not take counter flows into account at all. So, we have comparative results and we study the impact of taking or not taking counter flows into account. So in that way, according to the market someone can see what fits better to the market needs. Thank you.

G. Gross: So one last question… do we have time? We had Manolis' paper [4] which was the last one and we had the first paper [1] and they are two exactly opposite direction topics. So I am wondering whether these two speakers could convince each other which way to go. Should we integrate? Or should we disintegrate?

(Laughter)

Chair: OK. I'll let them do that over coffee. Thanks everybody.

References

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