Oral Discussions on Session: "Advanced Operations" – Part II

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Abstract

This paper contains the second part of the transcribed oral discussions of Session "Advanced Operations" of the 2013 IREP Symposium-Bulk Power System Dynamics and Control, held on Thursday morning, August 29, 2013. Papers [1]-[4] were presented.

Discussion

Chair: So, we have a question… a comment?

Pavlos Georgilakis (NTUA): First of all congratulations to all authors for very interesting presentations and very important contributions. I have a remark for the second paper by Christos Nakos [2]. I am very pleased to see the presentation and how they manage to use a tool in a very effective way. The Center for Renewable Energy Sources, as Christos presented, uses TIMES model, previously known as TIMES-MARKAL model, which is a macroeconomic model dedicated to very long–term planning (let's say thirty-, forty-year planning) of combined generation and transmission expansion planning in multiple stages, let's say in a five-year step. So they adapt this model in order to capture phenomena related to renewable energy sources. As everybody here knows one model is never better and I think very nicely Christos mentioned that this model has one shortcoming: the fact that it doesn't take into account the network. Just to mention here and this is my remark, that this problem is, let's say, in the process of being solved through a project financed by the European Union, where CRES in collaboration with NTUA and other partners are currently validating a model that will be used on a country level, regional level, and in European level for making energy policy decisions. Thank you very much and once again congratulations to all of you.

Chair: This is just a comment, I take it.

P. Georgilakis: Yes, just a comment

Tasos Bakirtzis (Aristotle University of Thessaloniki): I also have a question for Christos Nakos [2]. You mentioned that you use pumping in relation to renewable energy generation. In the studies we have made in our laboratory, we notice that it is very unlikely to spill wind energy, if you plan 10 days ahead. As I noticed from your presentation, your scheduling period is 10 days. So what you give your scheduling algorithm is a 10-day wind forecast. So if you have a 10-day wind forecast during your unit commitment, you commit fewer units according to your wind forecasts, so the likelihood to spill wind is very low. Wind spillage will happen because of wind forecast errors which I don't believe you model in your simulations here. This is one comment and another question is how you schedule your water releases in your 10-day periods. And last question, why 10 days and not two weeks, so that you capture two fully weekly cycles in your simulation.

Christos Nakos (CRES): I will answer in a reverse way. 10 days is just 10 days. For two-week scheduling period I saw that the computational time was much more increasing, so I stayed at 10 days, which is more or less an empirically accepted time frame. The scheduling of hydro is coming from another model. I give the energy that comes from another model and the allocation of the hydro energy is done in a 10-day scheduled period. Now the case of pumping is a little bit difficult. I tried to combine it with rejected energy. So each time the model, the optimization, sees that it will have to reject energy, from wind let's say, then it pays a penalty. Whenever this price is very high, then it activates the pumping load. In the final run it cannot be made, because I have the constraint for unserved load. So I take the sum of consumption load and pumping load and the model has to serve it. That's why I am using the pre-runs, where I don't have this unserved load constraint. If I understand well your question, you said that there is not going to be in a 10-day period a wind spillover, a RES curtailment to speak the same language, because of a perfect foresight? Yes, but there is the possibility that technical constraints will activate the penalty cost, so because the rejected energy is the last in the hierarchy of penalty costs, whenever another constraint is going to

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be violated, then it chooses to reject energy. So that's an answer, or I don't understand your question…

A. Bakirtzis: I will continue my question. My point is that once you have perfect foresight, there is only a slight possibility to have rejected energy, or you will underestimate your rejected wind energy by much. I think the correct way to do it is model both the real-time operation of the power system and model the error of the day-ahead or whatever wind forecast according to which you will perform your scheduling, your unit commitment. This is an on-going research in our laboratory in the framework of a state funded project (Alex Papalexopoulos is also an external advisor in this project) and we are trying to model both the short-term, the hour-by-hour, and the day-ahead operation of the power system, to capture the wind spillage in a more realistic way.

C. Nakos: In this sense, I agree. I underestimated the rejected wind energy.

Chair: I think Marian has a question in the back.

Rachid Cherkaoui (Swiss Federal Institute of Technology, Lausanne): I already have the microphone.

Chair: I think then basically you have the floor. What can I say?

R. Cherkaoui: My question is for João Peças Lopes [3] concerning the restoration. Did you account for the computation time consideration, while in this restoration process? Because I guess that your methodology is designed for real-time restoration. So can you elaborate on this piece of information? Thank you.

João Peças Lopes (INESC, Porto): Yes, I agree with you. We haven't been concerned with the time simulation. We were just trying to identify the way, how we can contribute to system restoration. This is not a tool to help system operators to do the system restoration. This is more research in terms of identification of the problems that we may have to face and how to cope with them. We are at the first stages. However, we feel that it is important to optimize and this optimization is somehow also related to the need to identify procedures that we could pass to the dispatching operators to help them in this restoration approach.

Marian Anghel (Los Alamos): I have a comment and a question for the first paper [1]. Very nice work, congratulations! Congratulations for that matter to all of you. It seems to me that the confidence levels are chosen by the users, which is fine, but there is some measure of risk and there is a cost associated to risk. So, in this regard, it is more natural to me to enhance your cost function and to add a weighted cost of risk in that function and transform these alpha parameters (confidence levels) into decision variables. And then when you minimize this enhance cost, I suspect you'll get in your expansion cost versus confidence level, you will find a minimum, which of course depends on how the users select to balance the expansion cost vs. the cost of risk. So I wonder if this is a sensible approach and how difficult it will be to modify your algorithm to include this confidence level as decision variables in your algorithm.

Monishaa Manickavasagam (University of Calgary): Thank you for your question. If I understood your question correctly, you mean to address the objective function as a probabilistic measure and having this alpha parameter also as a decision variable. It can be done. It of course will complicate the problem, and in this case we are more concerned in having simulation results for any confidence level. The simulation can be run for any confidence level and you can have corresponding answers for that. But of course if, as you say, if it is a decision variable, you will know the corresponding cost, it is a much better solution. It can be done and we will explore that further.

Alex Papalexopoulos (ECCO international): I have two comments for the second paper [2], and a question for the first paper [1]. First of all, I fully agree with Tasos Bakirtzis. Tasos' comments are very important for this paper. The second comment is: you don't include transmission in the analysis, which is also tied to the first comment. Based on our experience, especially when you do studies for unserved energy and also for curtailment of renewables, you need to include transmission. We have seen that with the penetration of renewables, if you don't include transmission you lose many events. We have seen that in many systems, not only in one or two, from our studies. And also to make decisions about curtailment, physical curtailment (of course contractual curtailment is another issue, if you are allowed to do this), but for physical curtailment, you've got to include transmission. That's the comment. Now, the question about the first paper. I really enjoyed your paper. I especially agree with your approach to include slack variables in the bus level and get visibility in the bus level about issues, about load shedding or what you call stressed buses. We fully support this approach in order to get visibility in the bus level. You didn't have the chance to talk about the coefficient that goes with the slack variable, which is very important. Usually for that coefficient, that penalty that you put in the objective, it could vary, because it is the loss of load value, could be, depending on studies, from 3,000 to 40,000, it depends. So the question is this: have you done any analysis for your system, with your method playing with this penalty, especially in relationship with penalties for other controls or constraints in your OPF formulation? I assume you use penalties for other constraints as well.

This ties to constraint relaxation policy you have, for example for transmission lines. The relative value of that penalty with respect to other penalties can change your results a lot. I am not sure if you have any insights about this. Do you care to comment on that?

M. Manickavasagam: I have only one penalty function, which is added only to the supply-demand constraint. I don't have any other penalties in my formulation. That's because we do not consider any other chance constraints. We are mainly concerned only with generation adequacy as a problem and so we don't have it on transmission lines. With respect to the cost that we have chosen for the penalty, we tried different values, it was mostly on a trial and error basis. The only things that we were concerned about were that the penalty should not appear for any feasible cases, the first thing, and it should appear only when there is no other alternative. These two we made sure and the least, when we tried different values, the least one that was able to give the results, we had chosen. So there is no other parameter to compare…

A. Papalexopoulos: So you don't force transmission constraints in your formulation.

M. Manickavasagam: I have transmission lines constraints yes. I have minimum-maximum capacity constraints but not as probabilistic ones and hence I don't relax these constraints with the slack variables.

Sandro Corsi (Italy): I have two questions to Damir Novosel [4]. You introduce your system as a synchrophasor system. But looking at your presentation and pictures, it only appeared like a complete EMS SCADA system. Now I wonder how flexible is your system to interface with the existing SCADA EMS system in a way to add, introduce the functionality related to the PMUs and so on. This is the first question.

Damir Novosel (Quanta Technologies): Let me answer the first…

S. Corsi: You prefer to answer?

D. Novosel: Yes, thanks, Sandro. By the way I really want to acknowledge Sandro for providing his work and was really helpful in us moving forward with the work we have done. So thank you, Sandro. The key issue really here is how many PMU measurements you really have. You saw that slide, where I am showing how we are going from conservative to aggressive: you add more and more PMU measurements. So the bottom line is that you can use this system, either with the SCADA measurements or with the PMU measurements. But of course, and that's the whole point, that with SCADA measurements you are going to miss some of the major continuous events and you will not then be able to do the calculation in the time that you need to do the calculation at. So the bottom line is you can use both, but of course it is preferable to use the synchrophasor data. Am I answering the question?

S. Corsi: Yes. The second question is related to my understanding, I could be wrong about the way the computation is performed. It appears like a fully centralized system on the one hand, but on the other you said you can also use directly the PMU measurements for some functionalities, for some indicators. So my question is: is your system also able to allow a decentralized control, in case it is possible to use directly the PMU measurements for some functionalities?

D. Novosel: Yes, and it comes back to that stepwise process, where we are using the phasor system for various functions. We are for example using now our distributed method for fault location calculations. So you can actually use it between two substations, you can use the phasor measurement system that is distributed. And then you have an application like EMS application and state estimation, where they are using the centralized approach. So essentially how the project was structured was that GE would have applications in the substation and ALSTOM would have application in the central control room. And the reason was because PG&E is using ALSTOM tools and they don't really like to change the tools. The key is, and I didn't mention that actually during the presentation, that it is so important to actually exchange the data with the neighbors. And you really want to have a system that you are comfortable with and then build on top of it. So, to add to this point, we are going on the distributed level to the substations, and then you go to the central control room, but we also go to the wide-area system, and it's actually my key point here. We call it wide-area monitoring, protection and control. At the same time it is sometimes very difficult to share data. I am sure there are issues with ENTSO-E here in Europe with this. But it really defies the purpose. If you really want to use this technology, you should be able to find a way (and I know there are legal issues and I know that lawyers are involved, you don't want to hear these stories, it's not a simple issue), but at the same time, if you want to benefit, if there is an event in the system, you are really going to have operators in Belgium and operators in Greece to see the similar thing. And you don't really need to have exactly the same tool. You don't' have to have one vendor to do it. But if you have standards, if you have a way to represent the visualization, then you can actually resolve this. So to answer your question the system should cover from distributed to the wide area Western Interconnection system showing data across Western Interconnection.

Louis Wehenkel (University of Liege). I have a couple of questions for the first paper [1]. And the first one is about some clarifications to make sure that I understand correctly. The uncertainties in the load model for your problem is a Gaussian model, but I want to know whether you, at the different buses, you consider independent load variations, totally independent or totally correlated ones, just to clarify. And the second question: your method is basically in iterative fashion replacing this chance constraint by some deterministic constraint trying to find the right, let's say, overestimation of the demand at each bus, such that you reach this alpha level of confidence. And in each situation you solved like 1000 OPFs of the network. So I wanted to know how fast this converges. So these were the clarification points. In the examples, how many iterations do you need? And more on the method: you compared your method with the standard uniform Z-update algorithm and you find that you get better solution, but you cannot claim that your solution is really the best solution satisfying the chance constraint. So do you have any idea how far you are from a really optimal solution of your original chance constrained problem? Thank you.

M. Manickavasagam: For the first question, yes, we consider 100% correlation. So that's how the simulation results are that far. In terms of the iterations, for any confidence level I require at least three iterations, because I choose two starting points, a lower and a higher, and then I need at least one more to reach my target. So the minimum will be 3 iterations. And after that it depends on the random samples generated. On an average, for all my simulations, it was around 5 iterations, but I have never come across more than 7. I don't know about the other question. Do you ask me if it is a global optimum? Is that the question?

Louis Wehenkel: Yes.

M. Manickavasagam: As you can see the problem is non-convex, because I assume a normal distribution, which is a non-convex assumption. I don't have any closed form solution to prove that this is a global optimum, but we tried with various starting points, the initial two starting points, and in terms of the solution, of course there will be a difference in the cost, because it is not just the investment cost, but also the operation cost. So the amount of power it dispatches might vary, but in terms of the number of new units installed, that was the same for any starting point. That is the major outcome of the expansion problem, I need to know how many new units I need.

Louis Wehenkel: So my sub-question then is: if you say it is relatively robust in terms of where you put a new generation, is there any difference between the modified algorithm and the original one in this respect?

M. Manickavasagam: I'm able to identify the stressed buses, and so I can say those are the potential places for new installation and thus avoiding unnecessary overestimation of load at all buses. I am also able to say the number of new units. The difference is that I am able to identify the areas of installation. That is the main difference between the modified and the older method.

Chair: Let's go from Louis to Luis.

Luis Vargas (University of Chile): This is a couple of questions for the third paper, for João Peças Lopes [3]. The first is related to other possible technologies that also use power converters, for example, solar or PV. The question is, do you foresee a similar application, or do you see any differences or problems with solar technologies, as compared to wind power that you chose? And the second question is related to a comment you made, I believe. You said that this may lead to new PSR procedures and you mentioned this could possibly lead to faster restoration times. Could you make comments on that?

João Peças Lopes (INESC Porto): Well regarding solar PV, or even some large storage devices that are interfaced with the grid via electronic interfaces, I think that it is possible to have them participating in the preliminary stages of the power system restoration, either by providing reactive power support, as well as active power in terms of participating in frequency regulation. However, in this case, for instance in the case of PV solar, this is a little bit more complex, because of course you can also de-load to bring the PV panels away from the maximum power extraction curve, and so operate in a similar manner. The problem is that if you have a day where solar resources are changing too fast, it will be more difficult. And in this case, what we foresee is to have on the DC link a storage device and that storage device will be such to be capable to serve as a buffer and in this case to support in some way the contributions, the fast contributions, for frequency regulation. So, that's the way we see it. Regarding your second question, we believe that it is possible to have these units contributing for a faster power system restoration, because if for instance we have very large converters, like the case of offshore wind farms, they can participate in the control of voltage, which is one of the critical issues in all power system restoration. This is needed to absorb the surplus of reactive power that exists during the first stages, where lines are not enough loaded. So, if we are capable to energize the lines that go up to these generation facilities and to connect these converters, I think they will support the first stages in terms of the contribution to voltage regulation, which is one of the critical stages in all the power system restoration approach. But as I said this is very much dependent on the system structure, on the mix of the generation, on the topology and on everything. So we have to test it. But I believe that this is possible.

Chair: Thank you. Claudio Canizares has been waiting there for quite some time, so I think you have enough storage now to ask the questions.

Claudio Canizares (University of Waterloo): Thank you, George. First let me congratulate Damir Novosel for his presentation, I found it entertaining and very interesting as well. It's nice to see the industry perspective in all of this, this type of development, applications and integrating people like yourself, industry people, in these meetings and I look forward to your participating in the Banff conference. Now, moving forward to my question to Joao Pecas Lopes [3]. Very interesting to see how you are evolving these applications of VSC technologies: starting with voltage control, moving on to frequency control, and then you are proposing restoration applications. Congratulations for that. If I understood correctly basically this is based on the HVDC link that you are using basically for frequency regulation, right? Now as you move to DFIG, you have more distributed resources; you don't have this common link. So how do you see this other type of resources participating on this, as you sort of mentioned that, and in that context, in the case of Portugal, how much DFIG vs. this HVDC link technologies are available for this type of application.

J. Peças Lopes: In Portugal we don't have off-shore wind farms at the moment, but we will see for the future. What we have presently are large wind farms, very large wind farms, for instance 200 MW wind farms. And so in this case we also foresee the possibility of having them participating in these restoration procedures. However, the problem is that not all of them have this kind of capabilities. So what is important for us is that they are capable to behave like StatComs for voltage control. It is important that they are capable to provide primary frequency control contribution. And this is in fact not fully available in all wind energy converters. In Portugal we have launched a few years ago a tender for wind generation installation and we have asked for this kind of capabilities. So this means that presently 1,500 MW out of 4,500 MW that we have installed in Portugal already have these capabilities. But the others don't. So for the others, I don't see this to happen so easily. But for the rest, yes, it is feasible and if we also think that some of the wind farms will have to be replaced after some time, because the wind generators will reach the end of their lives, and therefore we will have retrofit of some of the units, then it is important to require those capabilities, for these units to start participating in the provision of this type of ancillary services.

C. Canizares: Thanks for the answer. A follow-up question regarding this: as you increase these capabilities, you increase also the cost of the converters, bigger capacitors, bigger converters. Do you foresee as you add these capabilities, do you foresee additional cost involved in this?

J. Peças Lopes: Yes, there are some additional costs. The cost is mainly the cost of the converter, of course, and also some of the controls. And also, but this is not the case for power system restoration, this is the case if you require these wind generation facilities to be for a long time participating in primary frequency control. And then it's not only the price of the converter, it's also the amount of money that the wind farm developers will lose just because they will be operating at lower power output. But this is very simple: you tell them you either reduce 10% and you are capable to provide primary frequency control or you are disconnected from the grid. And they will prefer the first one. I can assure you of that.

(Laughter)

Chair: Incentives do work. We have one last question over here and then we can break.

Yannis Blanas (IPTO, Greece): Thanks George for permitting me the last question. It is not actually a question, it is a remark. I am from the Hellenic system operator, ADMIE as we call it in Greek. My comment is for the last speaker [4]. I enjoyed the presentation, but what I wanted to emphasize (and to make a request about it) is that the system operation becomes very complex. We all know this. And it is very important to develop smarter and more advanced visualization tools in order to help operators to identify very fast where the problem is. I have seen the products from three big vendors, which I don't want to name, but I was disappointed. They are good to confuse operators in a difficult situation. So my request to the academic community and all those involved is that it is a serious problem and there is a lot of room for improvement. Another point I want to make is that all these awareness functions are very important, but I wanted to inform you, regarding ENTSO-E, that they have installed a centralized system (now in the integration phase, some TSOs are already connected to it), but it is much below our expectations. It is just the information for the frequency to identify if there is an islanding in Europe. So we need smarter and more expert tools to help. Thanks.

Chair: If you come to the next IREP meeting we will have a session on smart confusion systems.

(Laughter)

Y. Blanas: I will try!

Chair: I would like to thank all speakers. Thank you very much.

References

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[2] C. Nakos, "Impact assessment of large scale RES penetration for the Hellenic power system; a market simulation model analysis," Bulk Power Systems Dynamics and Control – IX (IREP), August 25-30, 2013, Rethymnon, Crete, Greece.

[3] L. Seca, H. Costa, C. Moreira and J. Pecas Lopes, "An Innovative Strategy for Power System Restoration using Utility Scale Wind Parks," Bulk Power Systems Dynamics and Control – IX (IREP), August 25-30, 2013, Rethymnon, Crete, Greece.

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