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Comments On:
The Economic Ramifications of Resource Adequacy Whitepaper
January 2013, prepared by Astrape Consulting for EISPC and NARUC

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March 24, 2013

I. Background

The Economic Ramifications of Resource Adequacy Whitepaper ("Whitepaper") was prepared for the Eastern Interconnection States' Planning Council ("EISPC") under U. S. Department of Energy funding.[1] On December 18, 2012 I was asked to peer review a draft. To better understand the analysis and support my review I asked the authors for several additional sensitivity analyses, of which just one was performed. I provided a draft of my review to the authors for their comment, and after reflecting their comments, I provided my final review memo to EISPC on January 14, 2013 ("January Review"). The January Review focused on the modeling documented in the draft Whitepaper that supported its main conclusions. It criticized the problem definition and some of the modeling assumptions, and recommended changes to those assumptions and additional sensitivity analyses. The January Review also criticized the draft Whitepaper's discussion of resource adequacy as applied to restructured wholesale markets (as opposed to regions with traditionally regulated, vertically integrated utilities, the main focus of the Whitepaper). The authors provided a written response to the January Review, and those reactions are reflected in this note.

While the final version of the Whitepaper does includes some additional documentation, it does not correct any of the issues I raised about the problem definition or assumptions, nor does it include the recommended additional sensitivity analyses that would have at least made the impact of the questionable assumptions transparent. While the discussion of resource adequacy in restructured markets was substantially changed in the final version, the Whitepaper still fails to clearly identify or evaluate the fundamental issues about resource adequacy in such contexts. Accordingly, nearly all of the criticisms in my January review apply equally to the final Whitepaper. This note provides a critique of the final version of the Whitepaper, reflecting the authors' reactions to my January Review. I again strongly recommend that EISPC and NARUC request additional sensitivity analyses to augment the Whitepaper's documentation.

II. Summary

1. The focus of the Whitepaper is on determining what it calls "economically optimal" reserve margins, and it arrives at the surprising conclusion that economically optimal reserve margins are generally considerably higher than those that follow from the widely-used "one day in ten years" ("1-in-

[1] The Whitepaper is available at http://communities.nrri.org/web/eispc/share-and-view-files-members/-/document_library/view/389888

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10") resource adequacy criterion (in the Whitepaper's case study, the "economically optimal" reserve margin is 13%, while the 1-in-10 reserve margin is 9.75%; pp. 41-43). The Whitepaper claims it determines higher reserve margins because it considers additional benefits that have been missed in other analyses.

From my review of the Whitepaper and additional information received from its authors I conclude that its recommended "economically optimal" reserve margins are way too high due to issues I describe in this note. When these issues are addressed the economically optimal reserve margins resume their place somewhat below the highly conservative 1-in-10 level, consistent with the consensus of many researchers, myself included, who have questioned the 1-in-10 criterion over many years based on economic analysis.[2] That correcting these issues would result in an economically optimal reserve margin below the 1-in-10 level was shown in the one additional sensitivity analysis the authors performed at my request, discussed further below.

2. The Whitepaper's "economically optimal" reserve margins are far too high for two principal reasons. First, "economically optimal" is identified from the narrow perspective of a single utility's consumers, ignoring offsetting impacts on consumers in neighboring regions, as I will explain. The Whitepaper states as follows (p. 2) regarding what it means by "economically optimal":

> The point at which the cost of further resource additions is equal to the economic benefit provided by such additions is herein referred to as the economic reserve margin or economically optimal reserve margin or risk neutral economic reserve margin.

Sounds reasonable, right? But read on; the very next sentence changes the definition significantly:

> For the case study included in this paper, the economic optimal reserve margin is based on minimizing total systems costs *from the perspective of the customers of a vertically integrated utility*. [emphasis added]

Thus, the Whitepaper's analysis determines an "economically optimal" reserve margin by optimizing only for the study region's consumers, while ignoring an important economic impact – the benefits to consumers in neighboring regions from their utility's cross-border energy sales into the study region, that generate revenues to offset the costs the neighboring consumers must pay. Put another way, under the Whitepaper's definition of "economically optimal", a transfer of wealth from consumers in neighboring regions to the study region's consumers is considered a "benefit" to be optimized even though it is economically inefficient and raises overall cost.

[2] See, for instance, Telson, Michael E., *"The economics of alternative levels of reliability for electric power generation systems,"* Bell Journal of Economics Vol. 6 No. 2 (Autumn 1975) p. 679; Cramton, Peter and Steven Stoft*, "The Convergence of Market Designs for Adequate Generating Capacity,"* April 25, 2006, p. 32; Joskow, Paul L., *"Competitive Electricity Markets and Investment in New Generating Capacity,"* June 12, 2006, p. 48-49; Hogan, William W., *Regulation and Electricity Markets: Smart Pricing for Smart Grids*, presentation to the Energy Bar Association Electricity Committee Meeting, Oct. 16, 2009, pp. 21-23; Wilson, James F., *Reconsidering Resource Adequacy, Part 1: Has the one-day-in-10-years criterion outlived its usefulness?,* Public Utilities Fortnightly, April 2010; The Brattle Group, *ERCOT Investment Incentives and Resource Adequacy*, report prepared for ERCOT, June 1, 2012, p. 102.

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I believe this is an inappropriate perspective for a regulator to knowingly adopt, and especially inappropriate for EISPC, which I understand was formed to establish coordinated planning between the states to realize greater benefits from the interconnected grid. The very high reserve margins recommended by the Whitepaper would lead to each region building additional resources to reduce the need for purchases from neighboring regions, leading to low utilization of the interconnection and failure to realize its full value for both reliability and market efficiency, contrary to the mission of EISPC as I understand it.

As a result of this definition that considers wealth transfers to be benefits, the resulting "economically optimal" reserve margin is not economically efficient, is not optimal from the standpoint of consumers over a broader region, and is not optimal if it is recognized that neighboring utilities would also wish to set "economically optimal" reserve margins.

The Whitepaper's flawed notion of "economically optimal" also cannot be applied to a market context, where resource adequacy is achieved through market mechanisms rather than being the choice of a single decision-maker, and the dollars consumers pay for high-cost purchases at times of system stress play a key role in achieving resource adequacy. Instead, "economically optimal" should mean economically efficient, that is, optimal from the standpoint of society or consumers inclusively, with all costs and benefits of the decisions included in the accounting. The inappropriate definition of economically optimal makes a large difference in the identified "optimal" reserve margin, because it results in identification of "benefits" of higher reserve margins that are actually transfers of wealth rather than true benefits.

The message that reserve margins higher than the traditional 1-in-10 level can be economically justified is popular with utilities and grid operators (who are responsible for reliability, but pass along its cost), with capacity sellers where there are capacity markets (as higher reserve targets can sharply raise capacity prices), and with many regulators, who hope that even the one day in ten years never occurs. However, it seems rather pointless for EISPC and NARUC to sponsor work based on optimizing for a single region's consumers, when that concept must be discarded when any of the obvious extensions of the work are pursued:

- The concept goes away when impacts on the immediately neighboring utilities are considered, as noted above;
- The concept goes away if the entire Eastern Interconnection is modeled, as EISPC contemplates; this too would result in properly internalizing the impacts on neighboring regions;
- The concept also goes away under any attempt to model a market context, which also requires internalizing all of the impacts of any reserve level.

3. The Whitepaper's "economically optimal" reserve margins are also way too high because it adopts several unrealistic assumptions and model structure choices that drive reserve margins higher:

   a. Assuming that the capacity quantity is fixed four years in advance of a delivery year, and never adjusted even if there is four years of rapid economic growth leading to stronger than expected peak load growth. This is unrealistic; when peak loads grow faster than expected,

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utilities take a variety of actions to maintain reserve margins. This flawed assumption drives the "economically optimal" reserves margins higher.

b. Understating the role of demand response ("DR") in achieving resource adequacy at reasonable prices, by assuming all DR providers will continue to consume energy until prices reach $2,500/MWH, rather than recognizing that some will voluntarily reduce consumption in response to much lower prices; and assuming all DR is available only 150 hours per year, even at higher DR penetration levels, after which the very high Value of Lost Load ("VOLL") price of $15,000/MWh applies.

c. Overstating the scarcity pricing, assuming very high prices will occur even when reserves remain well above critical levels.

d. Overstating VOLL ($15,000/MWh), by assuming high-value commercial and industrial customers would be curtailed as often as lower-value residential customers; ignoring the fact that curtailments due to resource adequacy have lower impact due to likely advance notice and fixed duration; and ignoring that many customers have backup generation and, accordingly, suffer a much lower cost when their power from the grid is curtailed.

e. Some simplifying assumptions may also lead to understating, rather than overstating, the "economically optimal" reserve margins, such as ignoring fuel or transmission disruptions; however, I expect that such additional low-probability events, which typically are not modeled in resource adequacy studies because of their low frequency or impact, would have a very small impact on the results compared to the issues noted above.

4. The authors performed an additional sensitivity analyses at my request, which used the following alternative assumptions: a) only actual production costs, not transfers of wealth, were included in the cost to be optimized (societal perspective); b) one year of economic growth was modeled, to reflect that capacity would be adjusted year-by-year for longer term growth; c) some DR is either called or self-dispatches at lower prices: 15% at $500/MWh, 40% at $1,000/MWh, the rest at $2,500/MWh; d) DR is not subject to the 150 hour limit (or, the amount that is limited is small enough such that the limit is not binding); e) neighboring regions share resources while maintaining minimum operating reserves of 2%. The authors report that under these assumptions, the economically optimal reserve margin is 6%, compared to 13% under the Whitepaper's base case assumptions, and 9.75% that achieves 1-in-10. While the 6% would be somewhat higher, but still well below the 1-in-10 level, if the neighboring regions were set at the same level as the study region (rather than frozen at the 1-in-10 level), I believe these alternative assumptions are collectively far more realistic than the Whitepaper's base case (for reasons discussed further below).

5. Perhaps regulators, grid operators and other stakeholders would be uncomfortable with the conclusion that the optimal reserve margin is somewhat lower than the 1-in-10 level, at around 6% to 8% in the case study (although, keep in mind the study region is assumed to have access to roughly and additional 8% of reliable supply from neighboring regions at peak periods). Such discomfort might reflect a sense that the modeling may not accurately represent all of the risks associated with lower reserve margins. While this may be a reasonable concern, appropriate ways to address such a concern include 1) more detailed documentation of the analysis, to understand its limitations; 2) further

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development of the modeling to represent the additional uncertainties and risks, and 3) perhaps transparently choosing a target reserve margin somewhat higher than the modeling proposes, as a policy choice to provide an additional layer of conservatism. But adopting an inappropriate concept to be optimized, and unrealistic input assumptions (as has been done here, in my opinion) is not the right way to justify higher reserve margins.

6. Overall, the Whitepaper's analysis represents the world beyond a utility system's own resources as very hostile, and low reserves as potentially very costly; the Whitepaper invokes the "California Energy Crisis" (p. 1).[3] By assuming that when on-system reserves are low very high prices will likely be paid for help from outside (and also that the system's own DR resources are only used when prices are very high), very high "optimal" on-system reserve margins are needed to protect against such high costs. I do not think this is accurate, for the reasons briefly noted above and described in more detail below. My January Review recommended detailed documentation of how the most extreme cost outcomes, which undoubtedly drive the results, occur within the simulation, which I expect would reveal that they result from unrealistic assumptions, but such documentation has not been provided.

7. The Whitepaper's unrealistic assumptions also present demand response, and its contribution to resource adequacy, in a very negative light. DR and price-responsive demand hold the potential to make wholesale and retail electricity markets much more efficient, and ultimately to obviate the need for market interventions such as administrative resource adequacy requirements and capacity constructs, as I have explained in my published papers.[4] The Whitepaper assumes a large fixed quantity of DR that is only activated at very high prices and is only available 150 hours per year. The "economically optimal" reserve margins are so high partly in order to obviate the need to rely on the DR that, when used, drives prices so high.

8. For the readers of the Whitepaper to have confidence in its conclusions, they would need to have a clear understanding of the structure of the analysis, how the main assumptions determine the result, and how the result would change if reasonable alternative assumptions are used. However, some of the most important assumptions underlying the analysis are not clearly documented and reasonable alternatives were not evaluated. In my January Review, I recommended several sensitivity analyses that would have revealed the impact of key assumptions on the results, as noted above. It is never too late to perform these sensitivity analyses, which I list below, and which likely would take only minutes to perform.

9. The Whitepaper makes a pitch for reserve margins even higher than 1-in-10 would suggest, but ignores the "elephant in the room": the simple fact that higher targeted reserve margins greatly increase the clearing prices in capacity markets and resulting consumer cost, while the benefit resulting from these payments is uncertain. For instance, in PJM's most recent capacity auction, a 1.1% increase in the target

[3] The very high costs that occurred in the California market during 2000-2001 had more to do with flawed market design and resulting market manipulation than resource adequacy, although low reserves at times contributed to the vulnerability. Such flawed market design does not exist anywhere anymore, nor is such conduct possible anymore.

[4] Wilson, James F., *Reconsidering Resource Adequacy, Part 1: Has the one-day-in-10-years criterion outlived its usefulness?,* Public Utilities Fortnightly, April 2010; Wilson, James F., *Reconsidering Resource Adequacy, Part 2: Capacity planning for the smart grid*, Public Utilities Fortnightly, May 2010; links at the end of this note.

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capacity requirement for the MAAC region (the Whitepaper suggests a much larger increase) would have raised the capacity price for that zone by 16%, or about a half billion dollars.[5]

10. The authors were unwilling to adopt the more appropriate "cost to society" perspective (or even to provide a sensitivity analysis to demonstrate the impact of their definition of "economically optimal"), and were unwilling to adopt more reasonable assumptions about demand response or load uncertainty (or to even perform sensitivity analysis to demonstrate the impact of these questionable assumptions). In this regard, it is notable that the authors were already committed to their conclusion that "economically optimal" reserve margins are higher than 1-in-10 before this project began, having previously published a paper, based on essentially the same assumptions and analysis, that more-or-less announces that conclusion in its title.[6] That paper was more explicit about how the analysis could be used to justify high target reserve margins and resulting high capacity costs; it suggests that the analysis can be used to "inform stakeholders about the value customers are receiving from paying for reserve capacity" (p. 1), despite including no analysis of the relationship between target reserve margins and actual capacity costs.

11. "Resource adequacy" is about reliability. Or at least it always has been and should be. But according to the analysis described in the Whitepaper, resource adequacy is not about reliability at all, as evidenced by the fact that the results don't change if the VOLL is set to $5,000/MWh or $30,000/MWh (p. 60). The recommended "economically optimal" reserve margins are so high loss of load isn't occurring; the reserve margin is pushed up to the point where there is no reliability issue, and then even higher. Yet the Whitepaper misleadingly labels any cost above the marginal cost of a combustion turbine "reliability costs" (p. 29; p. 37 Figure 6; p. 43 Figure 11; p. 44 Figure 12). Under the Whitepaper's assumptions and with its focus on consumers in a single region, resource adequacy is instead about minimizing the need to use DR and high-cost purchases. In a market context resource adequacy is again only about reliability – market interventions such as administrative capacity markets are only justified because it is believed that otherwise, the level of physical reliability will be unacceptable.

12. The Whitepaper's analysis assumes vertically integrated utilities rather than markets. The authors acknowledge that they have only used their model in such contexts (in the southeastern U.S.), and not in regions with Regional Transmission Organizations ("RTOs") and resource adequacy achieved through wholesale markets.[7] The Whitepaper attempts to discuss resource adequacy in what it calls the "structured market" context, but the Whitepaper never quite makes the transition (and I doubt their modeling approach can be adapted to the market context, as explained below). In a market context, the dollars consumers pay for high-cost supplies when reserves are low, which in the Whitepaper are

[5] PJM, Sensitivity Scenario Analysis Results for the 2015/2016 Base Residual Auction, Scenario 12 (decreasing annual supply in MAAC by 750 MW, which is equivalent to a 1.1% increase in the reliability requirement, and resulting in a clearing price increase for annual resources from $167.46/MW-day to $195/MW-day).

[6] Carden, Pfeifenberger, Wintermantel, *The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On*, NRRI, April 2011.

[7] Astrape Consulting, *NARUC/EISPC Study: 1 Day in 10 and the Economics of Resource Adequacy*, presentation to EISPC, October 19, 2012, slides 17-18, available at http://communities.nrri.org/web/eispc/share-and-view-files-members/-/document_library/view/382457/7325?_20_redirect=http%3A%2F%2Fcommunities.nrri.org%2Fweb%2Feispc%2Fshare-and-view-files-members%2F-%2Fdocument_library%2Fview%2F382457.

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considered a cost to be minimized, are exactly the dollars that provide consumers benefits by attracting new generation (under any market regime) and also by lowering the capacity payments consumers must pay to achieve resource adequacy (under a capacity market regime). So the Whitepaper's fundamental flaw – that it considers reducing high cost purchases at times when reserves are low a benefit, ignoring any other impacts – becomes an even more serious error in the market context, where those payments are an essential part of the mechanisms that achieve resource adequacy.

13. I also comment on the nature of the model used in the Whitepaper, which utilizes what I call the "Over/Under" approach, assuming a single decision-maker selecting a capacity level, leading to the U-shaped total cost graphic shown in Whitepaper Figure 11. Resource adequacy in a market context is more commonly and appropriately analyzed using dynamic models that capture the dynamic inter-relationships between capacity levels, energy price levels, the strength of incentives to add new capacity, and the energy and capacity price levels necessary to entice market participants to build new capacity. I believe the applicability of the Over/Under approach for evaluating resource adequacy in a market context is doubtful.

The remainder of this comment focuses on further describing the flaws in the definition and calculation of "economically optimal" reserve margin levels, because this is a focus of the Whitepaper and has led to its incorrect main conclusions. This note also provides additional comments on a few other topics in the Whitepaper.

III. Identification of "economically optimal" reserve margins

The final version of the Whitepaper now defines what it means by an "economically optimal" reserve margin (the draft did not), although contradictory definitions are given, as noted above. The Whitepaper identifies "economically optimal" from the narrow standpoint of consumers in the study region, ignoring impacts on consumers in neighboring regions. (The Whitepaper also ignores impacts on generators, but under the premise of traditionally-regulated, vertically integrated utilities, there are none). I believe the more appropriate standpoint is a broader view that captures all of the primary impacts of a reserve margin decision, including on consumers in neighboring regions. For brevity I will call this the societal perspective, although that term could suggest an even broader analysis that considers environmental and other impacts.

To identify the economically optimal reserve margin from the standpoint of the cost to society as a whole (or, roughly equivalently, to consumers broadly, since all costs can be assumed to ultimately flow back to consumers, at least over the longer run), the total cost of meeting electric demand (including VOLL as a "cost" when the demand is not fully met) based on each candidate reserve margin level would be simulated and the minimizing reserve level identified, taking into account impacts in neighboring regions. Note that this would be production cost, not prices paid; when prices are paid for resources that exceed their variable costs, the excess over variable cost is simply a transfer of wealth from consumers to producers (or to neighboring consumers, through cost-of-service regulation) and is not a <u>cost</u> to society. The Whitepaper's case study clearly does not find the economically optimal reserve margin from society's perspective (as the authors acknowledge), because the total cost (as illustrated in Figure 11)

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includes, as a cost to be minimized, the cost of energy purchased from neighboring regions based on (very high) prices paid.

To make this flaw clear, consider the region that is the focus of the Whitepaper's analysis: the PJM Rest of MAAC region (p. 38). Most of this area is in central Pennsylvania, and it is interconnected with eastern and western Pennsylvania. Suppose that under a 12% reserve margin, the Rest of MAAC region must purchase energy during the peak period from western Pennsylvania, at $110. Suppose further the production cost of this energy is $80, so there is a $30 margin. Under the case study's assumption of traditionally regulated, vertically integrated utilities, this $30 margin flows to the western Pennsylvania consumers. Now suppose that raising the Rest of MAAC reserve margin to the "economically optimal" 13% provides additional energy at a total cost of $100, eliminating the need for the purchase from the west. Since the $100 in cost saves having to make the $110 purchase, it benefits the Rest of MAAC consumers and justifies the higher reserve margin, according to the Whitepaper's concepts. However, it increases the cost western Pennsylvania consumers will bear, because the $30 margin on the sale to Rest of MAAC is lost.

While "economically optimal" under the Whitepaper's definition, it is clear in this example that total production cost rises, total cost to all Pennsylvania consumers rises, and the result is economically inefficient. I do not believe the Pennsylvania Public Utilities Commission would approve the higher reserve margin. (While, as the Whitepaper's authors claim, some southern states may have accepted this approach, I doubt they would have, had it been more transparent what the analysis was assuming and optimizing).

The final version of the Whitepaper tries to rebut the appropriateness of the societal cost perspective, by giving an example where scarcity pricing causes a large transfer of wealth from consumers to generators, and suggesting that a societal cost approach ignores such transfers (p. 31). But now the authors have switched paradigms from vertically integrated utilities (where all sellers only recover costs) to markets. In a market context, if consumers want a higher reserve margin, they have to entice markets to provide it, whether its an energy-only approach or a capacity market; and transfers of wealth from consumers to producers are part of the mechanism and interdependent with the reserve margin. If consumers don't compensate capacity through scarcity pricing, they will have to provide compensation in some other form. The challenge in a market context is not to choose the right reserve level, but to design institutions that will achieve efficient results.

To modify the analysis and Figure 11 to represent cost to society, the green bars representing the cost of purchases would be replaced by the much, much smaller production cost of those resources. This calculation would reflect the fact that there are very few resources with costs in the thousands, or even hundreds, of dollars per MWh; the total supply curve goes very steep after, say $100 or $200/MWh. While it is quite true that prices can be very high when reserves are short, these are prices reflecting scarcity rents and are not cost-based. Such events result in large transfers of wealth but the actual cost of those last few resources pulled into operation is much lower. Figure 11, modified to represent cost to society, would be much closer to Figure 6, which shows the Over/Under graph focusing on VOLL and cost of capacity, but does not reflect the high production costs that can occur when reserves are low.

Note that because the economically optimal reserve margin from a societal perspective focuses on cost not prices, the calculation is the same whether a region is characterized by traditionally regulated,

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vertically integrated utilities or instead is restructured with wholesale markets administered by an RTO. This is a great relief, because modeling the dynamic inter-relationships between energy and capacity prices, new entry, and market rules to achieve resource adequacy targets in a market context is very complex and is only attempted in a greatly simplified form. The analysis described in the Whitepaper does not attempt to model a market context.

In my January Review, I strongly recommend that EISPC require that the analysis be changed to identify "economically optimal" reserve margins from the standpoint of society or consumers broadly, but this change was not made. I also recommended including a sensitivity analysis to demonstrate the impact of this key assumption; that too was not done.

IV. Flawed assumptions used in the analysis

The analysis of "economically optimal" reserve margins adopts the following assumptions that I consider incorrect or at least highly unrealistic, and that substantially raise the identified "optimal" reserve margins.

1. <u>Four year forward reserve margin and capacity quantity with no adjustment for unexpected growth.</u> The reserve margin is assumed set, with the corresponding capacity quantity frozen, four years in advance of each delivery year (this assumption is not clearly documented but is acknowledged by the authors). The analysis models subsequent unexpected load growth of up to 5.11% due to economics (p. 39) with no adjustment to the capacity quantity, leading to actual delivery year reserve margins that can be much lower than planned (for instance, a 10% target reserve margin four years in advance becomes less than 5% in the delivery year). This is totally unrealistic; utilities, and market participants, would respond to strong economic growth by adjusting capacity quantities year-by-year. PJM, for example, holds annual auctions to adjust capacity commitments if there is such load growth, and there are plenty of short-lead-time resources that can be acquired (overall, through nine delivery years under PJM's RPM capacity construct, over two-thirds of the incremental capacity has been various short-lead-time resources such as demand response, existing plant uprates, or deferred retirements).[8] To accurately model the consequences of a years-forward planning reserve margin choice, you must either model the contingent actions to adjust capacity over time (as the EPRI Over/Under model did in the 1970s;[9] this is quite complex but possible) or, more simply, only model one year or less of the year-to-year load growth to reflect the fact that the capacity quantity would be adjusted year by year (this is the approach used by PJM in its reserve margin studies, and in the sensitivity analysis I requested).[10] The result of this unrealistic assumption is suggested in Figure A.7, which shows that the most extreme economic growth scenario, combined with the worst weather scenario, results in nearly 200 hours with price over

[8] PJM, *2015/2016 Base Residual Auction Report*, p. 24 Table 10.

[9] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

[10] PJM, 2012 *PJM Reserve Requirement Study*, p. 20, available at http://www.pjm.com/~/media/planning/res-adeq/2012-pjm-reserve-requirement-study.ashx.

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$2,000/MWh, and roughly 50 hours with prices over $6,000/MWh, under a 10% target reserve margin (which falls to below 5% by the delivery year).

2. Modeling of DR as a $2,500/MWh resource. The analysis assumes 8% DR penetration, and DR providers are not called to reduce, and do not voluntarily reduce, until price hits $2,500/MWh (p. 61). This is totally unrealistic and apparently results in prices achieving $2,500/MWh whenever DR is needed (which, at 8% penetration, should be rather frequent). This greatly misrepresents the contribution of DR to achieving reliability at reasonable cost. Many DR providers would voluntarily reduce long before prices hit that level. In effect, DR takes the place of VOLL in the model, and the high "optimal" reserve margins result from the value of eliminating the need for DR calls, which lead to high prices. While DR is assumed to be 8% of capacity, it is only called 4.5 hours per year on average under a 10% reserve margin (Table 10, p. 59); DR call hours for the "economically optimal" 13% reserve margin are not reported, but must be near zero. The additional sensitivity analysis I requested reflected self-dispatch of a fraction of the DR at lower prices, using thresholds based on discussions with some DR providers.

3. Modeling of all DR as limited to 150 hours per year. The Whitepaper also assumed that all of the DR is available only 150 hours per year. This assumption likely results in the DR resource being totally exhausted on the highest demand scenarios (which, recall assume four years of unexpected load growth with no adjustment of capacity quantity), leading to the multi-billion-dollar "California Energy Crisis" extreme cost scenarios suggested in Figure 12 (showing that "reliability energy cost" can be as high as $2.5 billion, compared to a median value of about $100 million, with a 13% reserve margin[11]). This is unrealistic; PJM, for instance, requires most DR to provide unlimited service, and limits such restricted DR to a small percentage.[12] The additional sensitivity analysis I requested assumes that the amount of the DR subject to a 150 hour limit is small enough so that the limit is never binding.

4. Limited assistance through interties. The modeled region has 9,000 MW of import capability (p. 41), but this capability only reduces the needed reserves by about 2,400 MW (8% of 30,000 MW; p. 56). The model assumes neighbors set capacity at the 1-in-10 level and will not provide further assistance to neighboring regions when their on-system prices hit $2,000/MWh (which, under the assumed scarcity pricing, occurs when there are still 4% reserves; Figure A-6, including 2% minimum operating reserve). This also means that there is no further assistance through interties at any time when any DR is needed. In actual practice, the use of the interties is much more efficient than this; indeed, the Rest of MAAC region that is the subject of the case study is embedded within an RTO that optimizes transmission flows into it at all times, including when reserves are low. Energy also flows more-or-less efficiently across seams between RTOs in response to prices, including when prices are very high. The modeling of the interties is not at all transparent and details of their utilization in the simulation were not provided. The additional sensitivity analysis I requested allows resources to be transacted through the interties as long as each region maintains its minimum operating reserve.

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[11] The draft of the Whitepaper for peer review was provided in MS Word format, which allowed expanding and changing the axes ranges for the graphics to view portions in greater detail.

[12] PJM, *2015/2016 RPM Base Residual Auction Planning Period Parameters*, sheet "Min Res Req'ments" (showing that Limited DR is restricted to between 4.8% to 6.5% of the forecast peak for various regions).

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5. <u>Scarcity pricing is overstated.</u> The scarcity pricing formula (Figure A-6) overrides marginal production costs to set high prices even when there are substantial reserves. The scarcity pricing curve has prices rise to $500/MWh when there are 6% reserves (the 4% shown in Figure A6 plus the assumed 2% additional, minimum operating reserve), to $1,000/MWh when reserves are at 5%, and to $2,000 when reserves are at 4%. PJM's FERC-approved scarcity pricing function, by contrast, has prices rise to $850/MW when reserves fall to about 3.1%, and to $1,700/MWh when reserves fall to about 2.4%. As with the interties, the impact of the scarcity pricing, and how it interacts with the assumptions about DR and the interties, is not at all transparent as few details are provided. The additional sensitivity analysis I requested includes in total costs only actual production costs, consistent with the perspective of consumers broadly rather than in a single area.

6. <u>VOLL is overstated</u>. While the analysis as it stands is not sensitive to the VOLL assumption, when the issues raised above are addressed VOLL will be a key assumption driving the result, as it must be if resource adequacy is about reliability. While the Whitepaper does not describe exactly how the VOLL value of $15,000/MWh was determined based on the cited LBL report, there is enough information to identify three problems with the VOLL determination.

a. First, the VOLL assumes all customer types are curtailed equally (p. 30). That is, the Whitepaper assumes utilities would curtail Main Street, or Industrial Boulevard, as often as they curtail residential neighborhoods. This is not the practice in many areas, where load drop would be at least somewhat disproportionately imposed on residential neighborhoods where there may be fewer essential use or high value customers, and whose VOLL is much lower. (If there are utilities out there that plan to curtail all customer types "equitably", the question would be – why? According to Table 4 on p. 33, residential customers suffer two orders of magnitude less cost/KWh when curtailed, so it certainly makes sense to focus the load drop on residential neighborhoods, and perhaps compensate such customers for this "service" through somewhat lower rates.)

b. Second, the VOLL ignores backup generation. The Whitepaper does not acknowledge that customers with higher VOLL increasingly self-provide reliability with backup generation or other on-site facilities; and the penetration of such equipment has been increasing as its costs have dropped in recent years. Such customers may have high VOLL, but place little value on the reliability delivered by the grid because they are not exposed to it. For the purposes of determining an appropriate average VOLL to use in the study, very low values should be used for such customers. While the cited LBL data was based on surveys that did ask about backup generation, the report acknowledges that the VOLL responses may not have consistently reflected backup generation, and there apparently was insufficient data to evaluate its impact on VOLL.

c. Third, the VOLL ignores that the curtailments that would occur from resource adequacy are typically controlled, rotating outages, likely on days of very high load, likely foreseen a day or more in advance, likely announced hours in advance, and likely lasting a fixed duration of, say, one hour for each affected customer. The impact of such outages is much lower than the impact of the much more common distribution system disturbances (the focus of the LBL data), which occur unpredictably and, while interrupted, consumers have no idea how long the outage will last. The LBL surveys did ask about advance notification, but not about advance notification of outage duration, and too little data was available to identify the impact of these factors.

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Recognizing these points would result in using a VOLL for this modeling much closer to the values typically used for such analyses,[13] in the range of $2,000 to $5,000/MWh rather than $15,000/MWh, resulting in lower economically optimal reserve margins. The additional sensitivity analysis I requested used $3,500/MWh, the value chosen by the Midwest Independent Transmission System Operator (MISO) for its scarcity pricing rule.

7. More detailed results and additional sensitivity analysis, if provided, would likely surface additional questions and issues about the assumptions used in the analysis.

V. Recommended additional sensitivity analysis

To provide greater understanding and transparency about the Whitepaper's analysis and the assumptions that are driving the results, and to correct the various flaws in the analysis that were discussed above, my January Review recommended the following additional sensitivity analyses:

1. Include in total cost only production costs (not prices) of all resources, including imports and during times of scarcity, and VOLL when there is loss of load (societal cost perspective).
2. Set VOLL to $3,500/MWH (based on a MISO study).
3. Set the economic growth load uncertainty to one year of such growth (a maximum of approximately 1%).
4. Set scarcity pricing to rise from zero at larger reserve levels to $850/MWH at 3.1% total reserves (including the 2% minimum); to $1,700/MWh at 2.4% total reserves; and to VOLL at 1.5% or lower total reserves (based on PJM).
5. Remove the 150 hour limit for DR, under the assumption that such DR would be restricted such that the limit does not bind.
6. Remove the 150 hour limit for DR and assume DR self-dispatches and/or is called, in the study region and neighboring regions, as follows: 15% @ $500/MWh, 40% @ $1,000/MWh, the remainder @ $2,500/MWh (based on discussions with DR providers about recent evidence of such reductions).
7. Remove the constraint on power sales between regions when prices hit $2,000/MWh; allow energy to move between regions based on prices as long as each region maintains its minimum operating reserves of 2%.
8. Also perform a sensitivity analysis with #1 through #7 of the above alternate assumptions.
9. Remove all DR from all regions (to understand the impact of it on the results).
10. Remove weather year 1988 (to understand the impact on results of this extreme weather year).

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[13] See, for instance, the summary in Wilson, James F., *Reconsidering Resource Adequacy, Part 1: Has the one-day-in-10-years criterion outlived its usefulness?,* Public Utilities Fortnightly, April 2010, p. 35 (reviewing multiple sources, and suggesting that values in the $3,000 to $5,000 range are most appropriate for resource adequacy studies); or The Brattle Group, *Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update*, p. 50 (suggesting that VOLL is in the range of $3,000 to $7,500).

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11. Perform the optimization by adding/subtracting CTs and DR proportionately, rather than holding DR penetration constant and only adding CTs.
12. Perform the optimization by adding/subtracting only DR as the marginal capacity resource.
13. Remove all study region generation resources with marginal costs greater than a CT (to understand the extent to which higher reserve margins are justified to push existing high-cost resources off the dispatch stack).
14. Report the "Island sensitivity" (p. 46) "economically optimal" reserve margin result.

Of these, only one sensitivity analysis (#8, or something very similar to it), which combined #1 through #7, was performed. This resulted in an economically optimal reserve margin of 6% (and keep in mind that the study region also benefits from roughly 8% assistance at peak times from neighboring regions; p. 56). I believe this represents a more accurate estimate of the "economically optimal" reserve margin for the study region addressed in the Whitepaper, although the 6% value would be slightly higher if neighboring regions were assumed to adopt the same reserve margin (the Whitepaper freezes them at the 1-in-10 level).

The other sensitivity analyses would greatly increase the transparency of the Whitepaper's analysis, and help readers to understand the impact of the assumptions I have questioned. I again strongly recommend that EISPC and NARUC request the authors to provide the additional sensitivity analysis and post the results along with the Whitepaper. Providing a few additional sensitivity analyses of an existing model is not burdensome.

VI. Comments on the Over/Under modeling approach utilized by the SERVM model

Astrape's SERVM model that was used for the analysis documented in the Whitepaper applies what I call the Over/Under approach, fundamentally the same approach as used in the Electric Power Research Institute's Over/Under Model in the 1970s.[14] Using the Over/Under approach, the decision is the quantity of capacity to plan years in advance. More capacity results in better reliability and lower market prices, but the capacity costs money. The Over/Under approach therefore results in the "U shaped curve" shown in Whitepaper Figures 2, 3, 5, 6 and 11.

The Over/Under approach considers the level of capacity a choice controlled by a single utility planner or regulatory authority. By contrast, in restructured wholesale markets, retirement and entry decisions are made by market participants responding to anticipated energy and capacity price levels. A higher reserve margin would drive down energy prices; but this would weaken the economics of marginal resources, both new and existing, requiring higher capacity prices to make up the lost revenue and achieve a target reserve margin. Or, without higher capacity prices, retirements and reduced entry would result in failing to realize the target reserve margin. To capture these dynamics, resource adequacy in restructured wholesale markets is generally modeled using a fundamentally different, dynamic approach. This was the approach used by Prof. Benjamin Hobbs in support of PJM's 2005 RPM application, and that The Brattle

[14] Decision Focus Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978.

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Group has applied in support of its reviews of RPM in 2008 and 2011. While I do not have a lot of faith in these dynamic modeling efforts (they enormously simplify the market interactions), at least this approach captures the fundamental structure of the problem in a market context, unlike the Over/Under approach.

VII. Comments on the discussion of "structured markets" (sections V.D through V.G)

Whitepaper sections V.D through V.F attempt to drop the assumption of traditionally-regulated, vertically integrated utilities and address restructured markets. In such contexts, there is no longer a single decision-maker selecting the reserve level (although a target can serve as a parameter of a capacity construct), and its no longer necessarily the case that the industry only recovers cost so all impacts flow to consumers through regulation. However, the Whitepaper never quite makes the transition. The Whitepaper suggests that in an energy-only market context, consumers should desire very high reserve margins (p. 47) and notes that the market would likely provide a much lower reserve margin. The Whitepaper then suggests capacity markets (p. 48), stating, "While the idea that a reserve margin well above 20% is ideal for consumers fully exposed to the energy market may be counterintuitive, it is simple to demonstrate." The simple calculation provided again fails to appreciate the dynamic relationship between reserve levels, energy and capacity market prices, and the incentives to build new and retain existing generation in a market context.

The notion of a single decision-maker choosing the reserve level on behalf of consumers, which makes some sense in a context of traditionally-regulated utilities, doesn't carry over to the market context; but the Whitepaper can't seem to let go of it. This leads to statements such as on p. 49: "This lends some credence to our theory that consumers exposed to the energy markets can receive substantial benefits with new resources even at high reserves margins." Here and elsewhere, the Whitepaper seems to suggest that intervention to push reserve levels higher would benefit consumers in a market context. But such actions, which constitute an exercise of buyer market power, are unsustainable, so it seems pointless to even discuss them. For instance, while regulators might subsidize new entry in order to create excess capacity that would benefit consumers by suppressing prices, as the Whitepaper seems to propose, this beneficial result is not sustainable, as new entrants will know that once they enter they, too, will be subject to such discrimination.

The authors further discuss the "missing money" argument that energy-only markets will under-compensate generation and under-provide resource adequacy (p. 49) and suggest capacity markets to address the problem (p. 52).

> Forward capacity markets have been designed in many of the existing structured markets to alleviate this disconnect. In this capacity market design, all generators are provided additional capacity payments to allow new generators to recover fixed costs at a reserve margin that meets 1-in-10 LOLE standard. The setback to this approach is that while consumer energy costs are reduced at the 1-in-10 LOLE level, the fact that capacity payments are paid to all capacity forces total customer costs to be higher than if reserve margins remained at the lower energy only economic reserve margin target.

The lament that capacity markets compensate all providers of capacity again suggests that the authors have not quite made the transition to a market context.

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Section V.F provides a summary table that purports to compare total system costs under a regulatory utility regime, energy-only market, or energy plus capacity market context (p. 53). While the approach underlying this bold data is not described in detail, it is clear that the authors have not defined the specific market institutions and modeled the dynamic relationships between a target reserve margin, actual reserve margins, energy prices, capacity prices, and entry/exit decisions under those institutions that are key to evaluating any market context.

That the authors have not made the transition to market is further reflected in the discussion in section V.G (p. 54) of the "marginal resource" assumption to use in reserve planning.

> It is important to remember that the identification of a target reserve margin based on economics is contingent on the marginal resource used to vary reserve margins… The economic trade-off analysis is highly dependent on the characteristics of the capacity being added. All capacity is not equal. Adding demand response capacity will not provide as much economic benefit since it is not dispatched until prices are much higher or reliability is a more pressing concern…
>
> While 1-in-10 LOLE is an attractive metric because of its simplicity, the reserve margin determined through this method treats all capacity the same. If a resource can keep the lights on as effectively as a combustion turbine, the different product characteristics are immaterial. But the metric doesn't provide guidance to **what type of resources should be used to meet peak requirements and leads to many uneconomic resource procurements**. Resource planning is unfortunately a complicated process that requires the assessment of both the economic and physical reliability contributions of resources. [p. 54, emphasis added]

Under the authors' static, Over/Under approach, "optimal" reserve margins depend on what resources or purchases are displaced if new capacity is added, and the cost of the new capacity assumed to be added, which is very situation- and time-specific. If the modeled circumstances include some very high cost existing generation, and the new capacity provides low cost energy, a high reserve margin seems attractive to push out the high cost generation. If, instead, the marginal existing resources are more economic, and the resources that would be added are assumed to have high energy costs (such as DR), the "optimal" reserve margin is much lower. But this makes no sense in a market context, where the focus must be on designing institutions that will achieve sustainable outcomes over the long run based on market participants' choices, rather than deciding how much capacity of what type to push into the market under particular circumstances.

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Mr. Wilson's recent prior work on resource adequacy includes:

Wilson, James F., *One Day in Ten Years? Resource Adequacy for the Smarter Grid*, 28th Annual Eastern Conference of the Center for Research in Regulated Industries, May 2009 Link

Wilson, James F., *One Day in Ten Years? Resource Adequacy for the Smart Grid*, November 2009 Link

Wilson, James F., *Reconsidering Resource Adequacy, Part 1: Has the one-day-in-10-years criterion outlived its usefulness*? Public Utilities Fortnightly, April 2010 Link

Wilson, James F., *Reconsidering Resource Adequacy, Part 2: Capacity planning for the smart grid,* Public Utilities Fortnightly, May 2010 Link

Wilson, James F., *Forward Capacity Market CONEfusion,* Electricity Journal, November 2010 Link

Wilson, James F., *Comments on Proposed Reliability Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment And Documentation,* FERC Docket No. RM10-10, December 2010 Link

Wilson, James F., *Reliability and Economics: Separate Realities?* Harvard Electricity Policy Group Sixty-Fifth Plenary Session, December 2011 Link

Wilson, James F., *One Day in Ten Years? Economics of Resource Adequacy,* Mid-America Regulatory Conference Annual Meeting, June 2012 Link

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