**STATE OF CONNECTICUT**

**BEFORE THE PUBLIC UTILITIES REGULATORY AUTHORITY**

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| **DPUC Review of Peaking Generation Projects** | **)<br>)<br>)<br>)** | **Docket No. 08-01-01RE05** |

# DIRECT TESTIMONY OF

## PAUL CHERNICK

**ON BEHALF OF**

## THE OFFICE OF CONSUMER COUNSEL

Resource Insight, Inc.

**MAY 25, 2018**

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## I. Identification & Qualifications

**Q: Mr. Chernick, please state your name, occupation, and business address.**

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

**Q: Summarize your professional education and experience.**

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

**Q: Have you testified previously in utility proceedings?**

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. Federal agencies. This testimony has included many reviews of purchased power arrangements, marginal costs, rate design, and related issues.

**Q: Have you testified previously before the Public Utilities Regulatory Authority (the "Authority")?**

A: Yes. I have testified in over twenty proceedings before the Authority:

- No. 83-03-01, a United Illuminating (UI) rate case, on Seabrook costs.
- No. 83-07-15, a Connecticut Light and Power (CL&P) rate case, on behalf of Alloy Foundry, on industrial rate design.
- No. 99-02-05, the CL&P stranded-cost docket.
- No. 99-03-04, the UI stranded-cost docket.
- No. 99-03-35, the UI standard-offer docket.
- No. 99-03-36 (initial phase), the CL&P-standard-offer docket.
- No. 99-08-01, investigation into electric capacity and distribution.
- No. 99-09-12, the nuclear-divestiture plan for CL&P and UI.
- No. 99-09-03, on the performance-based ratemaking proposal of Connecticut Natural Gas.
- No. 99-09-12 RE01, on the Millstone auction.
- No. 99-03-36 RE03, on CL&P's Generation Services Charge.

- Nos. 99-04-18 Phase 3 and 99-09-03 Phase 2, on the proposed earnings-sharing mechanism of Southern Connecticut Natural Gas and Connecticut Natural Gas.
- No. 03-07-02, on behalf of AARP, on the distribution investment plan and rates for CL&P.
- No. 03-07-01, on behalf of AARP, on the application of the rate cap to CL&P's transitional standard offer.
- No. 03-07-01RE1 and 03-07-15RE2, on CL&P and UI requests for incentives for mitigating transitional standard offer costs.
- No. 05-07-18, on whether capacity contracts impose costs on the electric utilities.
- Nos. 06-01-08, 14-01-01, 14-01-02, 15-01-01 and 15-01-02, on multiple rounds of procurement results, on lessons learned from the procurements, and on procurement options.
- No. 05-07-14PH2, on the cost-effectiveness of capacity contracts proposed under the Energy Independence Act.
- No. 07-08-24, on the process for the procurement of peaker capacity.
- No. 08-01-01, on the evaluation and selection of contracts for new peakers, for with this proceeding is a reopener.
- No. 08-07-01, on the 2008 Statewide Integrated Resource Plan.

Except as noted above, this testimony was on behalf of the OCC. I also testified on behalf of the OCC in Connecticut Siting Council Docket No. 217, on transmission upgrades to southwestern Connecticut and Docket No. 370A, on the Greater Springfield Reliability Project.

## II. Introduction

**Q: On whose behalf are you testifying?**

A: I am testifying on behalf of the Office of Consumer Counsel.

**Q: What is the scope of your testimony?**

A: I evaluate and respond to the joint proposal by GenConn Energy LLC and PSEG New Haven LLC (the Suppliers or Generators) to amend the allocation of credits and charges under the Contract for Differences (CfD) under which each company delivers generation services from certain peaker units to UI and CL&P.

**Q: What is the purpose of this proceeding?**

A: Starting on June 1, 2018, rewards and penalties for performance by generation resources in the ISO New England (ISO-NE) capacity market will change important portions of the compensation for power plant reliability. The major changes in the Pay for Performance (PfP) rules are as follows:[1]

- The definition of a Shortage Event that would trigger PfP penalties and rewards will be broadened. Events under 30 minutes would be included for the first time, and the number of events over 30 minutes would also increase dramatically.
- The penalties for under-performing during a shortage event and the credits for over-performing change. Under the old rules overperforming generators received a pro rata share of penalties from underperforming units, so the exact value of performance is hard to quantify in advance. Under the PfP rules, penalty and charge rates are the same:

[1] Generator Testimony, Exhibit B provides the new market rules.

$2,000/MWh in delivery year 2018/19 through 2020/21, $3,500/MWh in delivery year 2021/22 through 2023/24, and $5,455/MWh thereafter..

- Maximum penalties will increase by more than 20% because of a change in the stop-loss calculation.

In the prefiled testimony of Peter D. Fuller and Joel S. Gordon (Generator Testimony), the Generators argue that these changes will affect the balance of the risks and rewards of the CfDs to the Suppliers and to the ratepayers. In particular, the new PfP capacity market design offers new revenue streams and new penalties associated with unit performance during scarcity events. They propose changes to the allocation of charges and revenues associated with the market rule changes, as shown in Table 5 of the Generator Testimony. The Generators argue that their proposed revenue allocation will offer the "same financial outcome" as under the old rules, which they equate to the goal to 'restore the economic balance' under Section 12(7)g.3 of the CfD.

**Q: What concerns have you identified?**

A: I have identified three issues with the proposed allocation:

- The Generator proposal would result in windfalls for the generators, rather than the same financial outcome as under the existing ISO rules and existing CfD.
- The Generator Testimony overstates their risk under the new market rules.
- The proposed terms would shift the allocation of risk and reward compared to the existing CfD.

- The Generator proposal would apply different treatment to short scarcity events and long events, even though the risk and reward profiles of those events are similar.

**Q: How large a windfall would the Generators enjoy under their proposal?**

A: Using data provided by the Generators, I estimate that their net PfP revenues are likely to rise from an expected value of approximately $43,000 per year under the existing rulesto over $1.7 million per year with the new rules and proposed CfD amendment, for an increase of roughly 4000%. Obviously, the expected revenues are subject to variance based on the specific circumstances arising each year, but on balance PfP has created an expectation of substantial new revenue for the Generators. The Generators, who are operating new, fast-start units, are extraordinarily well-positioned to deal with the new PfP environment. Since the new revenue opportunity has been backstopped by the ratepayers through the long-term, cost-of-service contract that facilitated the financing and construction of the GenConn and PSEG fast-start power plants, a fair outcome would assign the majority of this new revenue opportunity to the ratepayers for rate relief.

**Q: Would the Generator risk rise proportionally?**

A: No. Risk can be measured in many ways, but one common measure is the maximum downside to the Suppliers. The new rules would increase the maximum annual penalty from $22 million to $55 million, an increase of 150%. Of course, one would not expect that the plants' realistic risk even approaches those figures, which reflect a total failure to operate despite their cost-of-service contracts and relatively recent construction. Still, the maximum downside is useful for a risk/reward comparison. The net expected

PfP revenue, as a multiple of the maximum PfP penalty, will increase about 16-fold, on a risk-adjusted basis, even taking the downside risks into account.

**Q: Do the Generators propose to allocate the increased revenues in a manner equivalent to the increase in risk?**

A: No. The Generators propose to keep most or all of the net credits—expected to be $1.7 million to $2.8 million annually—for themselves. This would be an exceptionally generous allocation, offering the Generators significantly more revenue with little additional risk.

### *A. Changes in the Pay for Performance Rules*

**Q: What market rules are changing in the new PfP capacity market and how do these compare to the current market rules?**

A: In both the existing capacity market as well as the new "pay-for-performance" capacity market, resources are offered financial incentives for good performance during periods of operating reserve scarcity. Resources are also penalized for underperformance during these same periods.

Under the old rules, Scarcity Events could be called if there was a scarcity of operating reserves lasting for 30 minutes or more. Under the Shortage Events scheme, units unable to operate at their full Capacity Supply Obligation (CSO), subject to various exemptions, would be charged a penalty equal to 5% of the resource's annual base capacity revenue per unavailable MW for events lasting five hours or fewer, and an additional penalty of 1% for each hour thereafter. Shortage Event penalties were distributed to the resources that were able to operate at or above their capacity obligations. Only two Shortage Events occurred in the period 2010–2018, resulting in total payments to the Generators of $331,000.

Under the new rules, Scarcity Events are renamed as Capacity Scarcity Conditions (CSC), and are triggered by reserve shortages as brief 5 minutes in duration. These CSCs are forecast to be much more frequent than the old Scarcity Events. Each generator's availability performance during a CSC will be compared to its required output during the scarcity event, which is the generator's Capacity Supply Obligation (CSO) times the ratio of load and operating-reserve requirement at the time of the event to the total contracted obligation for the current delivery year. Resources that cannot provide their prorated obligation during the event will be penalized at a fixed $/MWh rate for the shortfall, and those that can provide more than their prorated obligation will earn Capacity Performance Payments (CPP) at the same $/MWh rate. The CPP revenues are equal to:

**CPP = CSO × (A – BR) × PPR × H**

Where:

CSO = the generator's Capacity Supply Obligation secured in the FCA,

A = the generator's availability during the CSC, as a fraction of its capacity,

BR = the Balancing Ratio, equal to market energy and reserves during the CSC, divided by the sum of all resources' FCA Capacity Supply Obligations,

PPR = the fixed $/MWh performance rate for each delivery year, and

H = the duration of the event measured in hours.

Capacity Performance Payments are positive (credits or revenues) if a generator's availability is greater than its BR requirement. CPP are negative (charges) if the availability is less than the BR.

**Q: In what ways do the PfP rules change the risks and rewards offered to the Generators?**

A: The generators have identified several new risks. First, the Generators suggest CSC events will be far more frequent than the existing Shortage Events. On the other hand, more frequent scarcity events offer more opportunity for overperformance revenue as well as more opportunities to have a bad start. Second, CSC events can be shorter in duration than Shortage Events. However, as discussed below, the risks associated with short duration events are similar to those of longer events, and so I do not see how including the short events as creating a material new risk. Third, the maximum annual penalty (stop-loss penalty) is higher under the new rules than the current. Under the old rules, the annual limit penalties equaled the entirety of a generators annual FCA revenue. Under the new stop-loss limits, a generator is liable for no more than the entire annual capacity revenue plus three months of the difference between the starting price in the applicable FCA and the clearing price in that auction. This change does indeed increase the worst-case downside risk by 20% or more.

At the same time, peakers like the GenConn and PSEG plants will likely receive significantly more revenue in the PfP market during scarcity events than they do under the current rules. Higher revenues arise partly because there are more events in which the peakers can generate over-performance revenues and partly because penalty revenues received from non-performing parties will be higher.

The changes would tend to provide additional revenues to the generators that can provide operating reserves (since they will be treated as available for the entire event, even if they are not operating) and increase charges to units that are slower to respond to CSCs, including steam plants that are off-line much of the year, start up slowly, ramp slowly, and cannot provide non-spinning reserves. GenConn and PSEG should be expected to be big winners under the new rules, and should not be viewed as parties facing significant risks. If GenConn and PSEG do not achieve material net profit over the next several years under the new rules, then something has gone seriously wrong with plant maintenance and the ratepayers would not be getting the reliable, fast-start plants for which they are paying cost-of-service rates.

### *B. Summary of Generator Proposal*

**Q: How do the generators propose to allocate these new risks and rewards?**

A: For short events (those less than 30 minutes in duration), the generators propose that all credits and charges associated with PfP Performance credits should flow through to ratepayers. The Generators argue that they should be exempt from all risks and revenues of these events because, under the old rules, there were no penalties or credits for these short duration events.

For longer events, the Generators propose to assume all risk of charges, while retaining all the credits through May 2021, taking 89% of revenues from June 2021 to May 2024 and taking 57% of revenues thereafter. The Generators developed this schedule to give them the same revenues *per event* that they would have received under the old Shortage Event rules. Recognizing that revenues under the new rules are likely to vastly exceed those of the old rules, the Generators propose to split revenues with ratepayers based on the ratio of *per event* revenues under the old rules divided by *per event* revenues under the new rules. While the Generators do not explicitly articulate that this is their approach, it is the method by which they compute revenue shares. The specific allocation depends on value of the

PPR, which will start at $2,000/MWh, rising to $3,500/MWh in June 2021 and rising again to $5,455/MWh in June 2024. As the value of scarcity events increases because of higher Performance Payment Rates (PPRs), the Generators propose to take a smaller share of revenues. A summary of their proposal is presented in Table 1.

**Table 1: Generator-Proposed Allocation of PFP Credits & Charges**[2]

<table>
<tr><th colspan="7">Pay for Performance Supplier & Buyer Values for PfP Credits and Charges Beginning June 1, 2018</th></tr>
<tr><th rowspan="2">FCA Period</th><th colspan="2">Scarcity Conditions<br>< 30 Minutes</th><th colspan="4">Scarcity Conditions<br>≥ 30 minutes</th></tr>
<tr><th>Buyer % PfP Credits & Charges</th><th>Supplier % PfP Credits & Charges</th><th>Buyer % PfP Credits</th><th>Supplier % PfP Credits</th><th>Buyer % PfP Charges[a]</th><th>Supplier % PfP Charges[a]</th></tr>
<tr><td>FCA9-FCA11<br>(June 1, 2018 - May 31, 2021)</td><td rowspan="3">100%</td><td rowspan="3">100%</td><td>Calculated value = -55% Proposed = 0%</td><td>Calculated value = 155% Proposed = 100%</td><td>0%</td><td>100%</td></tr>
<tr><td>FCA12-FCA14<br>(June 1, 2021 - May 31, 2024)</td><td>11%</td><td>89%</td><td>0%</td><td>100%</td></tr>
<tr><td>FCA15-Beyond<br>(June 1, 2024 - forward)</td><td>43%</td><td>57%</td><td>0%</td><td>100%</td></tr>
</table>

[a] Excluding exemptions as defined per original contract and penalty caps.

**Q: In total dollars, what is the allocation of expected revenues between the Generators and ratepayers?**

A: Table 2 calculates the revenue allocation of revenues by period. Under the Generators' proposal, they would receive $1.8 to $2.8 million per year, while ratepayers would receive $1.1 million to $5.1 million per year under their

[2] Reproduced from Generator Testimony Table 5.

proposal. Table 2 calculates the revenue allocation of revenues by period. The generators receive more than half of all PfP scarcity revenues between 2018 and 2024. Thereafter they will receive about one-third of the total revenues.

**Table 2: Expected Revenues, Existing Rules and Generator Proposal**

| | Gross Revenues ($M/yr) | | Generator Share (%) | | Expected Revenues ($M/yr) | |
|---|---|---|---|---|---|---|
| | <30 Min | >=30 Min | <30 Min | >=30 Min | *Generator* | *Ratepayers* |
| **Old Shortage Event Rules** | | | | | | |
| Actual Outcome | — | $0.04 | N/A | 100% | $0.04 | — |
| Scaled Outcome | — | $0.10 | N/A | 100% | $0.10 | — |
| **New Rules, Allocation as Proposed by the Generators** | | | | | | |
| 6/2018 to 5/2021 | $1.10 | $1.78 | 0% | 100% | $1.78 | $1.10 |
| 6/2021 to 5/2024 | $1.93 | $3.12 | 0% | 89% | $2.78 | $2.27 |
| After 5/2025 | $3.00 | $4.87 | 0% | 57% | $2.77 | $5.10 |

**Q: How well do the generators expect to perform under the new PfP rules?**

A: Very well. The Generators admit that their units are "ideally suited" for the PfP capacity market design, because the peaking units are a proven technology with a short start-up time, and a history of reliability and high availability (Generator Testimony p. 25).

**Q: To what standard do the Generators claim to have designed their proposed changes?**

A: Citing Section 12.7(g) 3 of the CfDs, the generators argue that changes to the market rules require changes to the CfDs:

> "the intent of the proposal described herein is to '*restore the economic balance*' under the CfDs by either replicating in the CfDs elements of the current ISO-NE Tariff that are being eliminated or modifying provisions in the CfDs to counterbalance changes in the ISO-NE Tariff that materially shift the allocation of economic risks or benefits between the parties to the CfDs. *The objective of the proposed changes is to maintain the original balance of risk of loss and opportunity for revenue* that was the basis for agreement as part of the solicitation for these projects, which was ultimately reflected in the executed CfDs approved by the Authority. (Generator Testimony, p. 6, emphasis mine)

Elsewhere, the Generator Testimony argues that the proposed changes would allow for the generators to "be in the same financial condition" (p. 43, line 8) and "achieve the same financial outcome" (p. 42, line 17) as they would have been under current Shortage Event market rules.

**Q: Do the Generators define "same financial outcome" or "maintain the original balance of risk of loss and opportunity for revenue"?**

A: No. Their analysis implicitly defines these terms to mean that the Generators would expect to receive the same revenue per event as under the current rules. The Generators take this approach in allocating revenues from events over 30 minutes, and in deciding that all short-duration scarcity event credits and charges (which did not exist in the old structure) should flow to ratepayers.

**Q: What is problematic about using a *per event* metric to determine a fair apportionment of PfP revenues?**

A: The primary problem with the *per event* approach is that events under the new rules are fundamentally different than those under current rules. There are different expectations for the duration of scarcity events, the frequency of events, generator performance during events, and the value of credits and charges. By taking *revenues per event* from the old system and applying those revenues to a different set of events, the Generators inflate the share of the revenues to which they are entitled. Neither risks nor rewards vary directly with the number of events, since the new PfP revenues are proportional to event duration. In addition, while the expected revenue from the new PfP rules is dozens of times higher than under the old rules, the worst-case downside risk to the Generators is only about twice as high.

Further, the Generators assume that their historic revenues per event for Shortage Events–based on two events in eight years–are a reasonable target for revenues they should receive per event in a market where such events are expected to be 27 times more common. As I will discuss in the next section, the generators selected a definition of "same financial outcome" that leads to unreasonably high revenues. Under their proposal, they will receive windfall profits while being subject to only modestly more risk. The Generators' proposed allocation of PfP charges and credits does not restore the "original balance of risk of loss and opportunity for revenue" or yield the "same financial outcome." It leads to windfalls for Generators, based on the rule changes and not based on increased performance.

### *C. Recommendations*

**Q: What approaches would more reasonably restore the "original balance of risk of loss and opportunity for revenue"?**

A: The CfDs could be modified in many ways to mimic the original balance of risk and reward. While the language of the CfD does not define the goal with any precision, the "same financial outcome" could be defined to give the Generators the same expected net annualized revenues as under the current rules, or the same revenues per unit of risk.

That said, providing exactly the same net annualized revenues would not account for increases in the risks embedded in the new rules, so some risk adjustment seems appropriate.

**Q: Please summarize your conclusions and recommendations.**

A: The CfD provision changes proposed by the Generators should not be approved. Two changes should be made. First, there is no need for the distinction between short and long scarcity events. The new PfP capacity market differs in many ways from the existing rules, but it is not clear that the shorter events have a different risk/reward profile than the longer events.

Second, revenues should not be allocated based on *event frequency.* The Generators' proposal combines the payment for each rare event under the old rules with the higher number of events under the new rules, confusing apples with oranges. Under the new PfP rules, the Generators should receive the same expected net revenues that they received under the old rules, adjusting for changes in risk. The generators should not receive the level of windfall profits that they forecast they would receive under their proposed contract amendments. The Generator proposal will not result in the same financial outcomes as before, nor the same balance of risk and reward.

Prior CfD revisions should be maintained as requested by the Generators.

## III. Treating All Capacity Scarcity Conditions Consistently

**Q: Why do the Generators make a distinction between events over and under 30 minutes?**

A: Under the existing rules, Scarcity Events could be called if there was a shortage of operating reserves lasting for 30 minutes or more. Under the new PfP rules, the Scarcity Event concept has been replaced with the new of the Capacity Scarcity Condition (CSC) concept. Capacity Scarcity Conditions are subject to different activation rules than the older Shortage Events and can be as short as five minutes in duration. The Generators consider CSC events longer than or equal to thirty minutes to "correspond well to the definition of Shortage Events" (p30). The Generators argue that the short-duration CSC events offer a new form of risk, separate from those enumerated in the CfD. They suggest ratepayers should receive all revenues from the shorter duration CSC events and bear all the risk.

**Q: Do you believe that the Shortage Events can be proxied using CSC events over 30 minutes?**

A: No. While long CSC events are the same length as Shortage Events, there are differences in activation rules and revenues. Scarcity Events were a very uncommon occurrence and offered only modest opportunity for revenue. The new CSC events, even when considering just the over-30-minute events, are expected to be quite common and offer significant revenue potential for available resources.

Between 2010 and 2018, two Scarcity Events were called, for a total duration of 3.3 hours. On average, the generators were offered one opportunity every four years to receive revenues associated with Scarcity Events. On an annualized basis, there were 25 minutes of scarcity.

The ISO and the Generators expect CSC events to be much more common. To understand the potential frequency and revenue effects of these events, ISO-NE conducted a backcast that applied the new rules to historic data for 9.67 years, from January 2007 to August 2016 (Generator Testimony, Appendix A.9), a period overlapping the period in which the Shortage Event mechanisms were in effect. The backcast identifies 191 events that would have met the CSC criteria, with a total duration of 95.5 hours. Of these events, 66 lasted thirty minutes of longer, with a total duration of 66.6 hours, or nearly seven hours of annual scarcity conditions. Under the new rules, the ISO would declare scarcity conditions sixteen times more often than under the existing rules.

Table 3 summarizes the different gross revenues for the Generators (before any flow-through to ratepayers) under the old rules and the new rules, for events longer than 30 minutes. Under the new rules, annual expected revenue increases by 43 times, events by 27 times, and annual shortage hours by 16 times.

**Table 3: Event Frequency, Duration, and Expected Revenue, > 30 Minutes**

| | Current Rules | | PfP Rules | | |
|---|---|---|---|---|---|
| | Historic Outcome | Scaled Outcome | Short Events | Long Events | All Events |
| **Scarcity Event Metrics** | | | | | |
| Analysis Period | 2010-2018 | | 2007-2016 | | |
| Analysis Duration (Yrs) | 8 | 8 | 9.67 | 9.67 | 9.67 |
| Gross Revenues ($) | 331,149 | 810,709 | 10,651,280 | 17,259,617 | 27,910,897 |
| Event Frequency (#) | 2 | 2 | 125 | 66 | 191 |
| Event Duration (Hrs) | 3.3 | 3.3 | 28.9 | 66.6 | 95.5 |
| **Calculated Metrics** | | | | | |
| Annual Events | 0.25 | 0.25 | 12.9 | 6.8 | 19.8 |
| Annual Scarcity Hours | 0.4 | 0.4 | 3.0 | 6.9 | 9.9 |
| $/MW-Year | 41,394 | 101,339 | 1,101,477 | 1,784,862 | 2,886,339 |
| $/Event | 165,575 | 405,355 | 85,210 | 261,509 | 146,130 |
| $/MWh | 100,348 | 245,669 | 368,344 | 259,218 | 292,261 |
| **Difference in Event Metrics from the Historic Outcome** | | | | | |
| Annual Events | | 0% | 5071% | 2630% | 7801% |
| Annual Scarcity Hours | | 0% | 625% | 1569% | 2294% |
| $/MW-Year | | 145% | 2561% | 4212% | 6873% |
| $/Event | | 145% | -49% | 58% | -12% |
| $/MW-Hour | | 145% | 267% | 158% | 191% |

Table 3 suggests that the new events are far from analogous to the old events.

**Q: Are there risks specific to short-duration CSC events that would warrant separate treatment?**

A: Not that I can see. Short CSC events offer the same general risk and reward profile as longer events. Each unit is subject to the same maximum annual penalty for underperformance (the annual stop-loss ceiling), irrespective of whether those losses were incurred from short outages or long ones.

Under the old rules, there was a sharp distinction between under-30-minute events (which were ignored) and over 30-minute events (which had identical outcomes for all events from 30 minutes to five hours). Under the new rules, there is no such distinction, with the effects of an event scaling in proportion to the length of the event, from five minutes to many hours.

For short events, new market rules also make under-performance unlikely. As the Generators point out, the PfP metric for performance during a scarcity event is either (1) the actual energy and reserves delivered from online resources or (2) the capacity available within 30 minutes (Generator Testimony, p. 6). As the peakers can reach full output in less than 30 minutes, they should always receive full credit, so long as they are not on a forced outage.[3] They need not even operate to be treated as performing.

There is always the possibility that a unit could be on a forced outage at the time of a CSC, or could experience a failure to start when called on during a CSC. Since GenConn has eight units, and PSEG has three units, a Generator may profit from a CSC, even if one unit is out of service and penalized.

On average, more events and longer total annual hours provide the Generators with additional opportunities for earning over-performance credits and increasing revenues. Even for unit availability of much less than 100%, short-duration events will tend to provide additional net revenues.

## IV. Revenue Allocation to Maintain Expected Value

**Q: Would setting the expected value of Generator revenues under the new rules equal to expected value under the old rules ensure that the**

[3] The CfD has already been amended to shift costs off the Generators if they happen to be in a planned maintenance outage at the time of a shortage event.

**Generators receive the same financial outcome as under the old rules and the existing CfD?**

A: Yes. Given the profound differences between the new rules and the old rules, it would be difficult to force the actual annual outcome for the Generators to be identical to what would have happened under the older rules. The best way to maintain the "same financial outcome" for the generators is to amend the CfD to provide them with the same expected value under the new rules as they received under the old rules. By expected value, I mean the probability-weighted average of all possible values. The modern, fast-start peaking units are expected to perform well during shortage events, given their proven technology, quick startup and ability to provide non-spinning reserves. The Generators will almost certainly over-perform on average. It is also possible that there will be an occasional failure to start or long-term forced outage. That downside risk is capped at monthly and annual stop-loss limits. Expected value combines these different possible outcomes and weights each outcome by its likelihood.

**Q: How do you calculate expected value of the Shortage Event rules and of the CSC Event rules?**

A: Calculating expected value depends on potential revenues and potential costs. In the following model, the generator is assumed to be either in good working order with an availability factor of 100%, or on a forced outage such that it is forced to incur the maximum annual penalty. In this case, expected value (E[V]) equals the sum of:

- The probability of regular operation (*P*) times the expected credits and charges from scarcity events offered to the generators.
- The probability of serious failure (1–*P*) times the annual stop-loss penalty.

Combined outcomes, weighted for expectation, offer the expected value of the scarcity event deal. The two deals—old market rules and new market rules—can be made equivalent by changing the share of gross revenues offered to the Generators. These two deals should offer the "same financial outcome."

**Q: Between 2010 and 2018 what revenues did the generators receive?**

A: Over this period, the Generators received $331,480 in revenue, which equates to $43,000/year.[4]

**Q: How much would the Generators be expected to earn from the old Shortage Event revenues if those rules continued to apply in future years?**

A: Under the old deal, the Generators would have received more revenue in the next few years than in the historical period, because the credits and charges were proportional to capacity prices. The Generators estimate average revenue of $101,000 annually going forward, based on their forecast of capacity prices.

**Q: Would setting the Generators' compensation for the PfP revenues at this level be fair, going forward?**

A: While the annual credit of $100,000 per year would provide the same financial outcome as the existing CfD with the old rules, the new ISO rules

[4] The Generators say that they earned $328/MW per event; multiplied by the Generators' 504.8 MW capacity and the two events yields $331,148. Dividing by eight years equals $43,000 annually.

also increase risks to the Generators.[5] Under the old rules, the Generators never experienced a penalty for underperformance, but they were theoretically exposed to a maximum penalty of up to their entire annual revenues from the FCA.[6]

Table 4 calculates the maximum annual penalty by year, for 2010 to 2018. The Generators were theoretically exposed to an average potential annual $23 million penalty for underperformance.

**Table 4: Maximum Downside and Annual Revenue, 2010–2018**

| FCA | | FCA Clearing Price | Maximum Penalty for Underperformance | Annual Revenue |
|---|---|---|---|---|
| # | Period | $/kW-Mo | $M/year | $M/year |
| 1 | 2010/11 | $4.50 | $27.259 | 0.000 |
| 2 | 2011/12 | $3.60 | $21.807 | 0.000 |
| 3 | 2012/13 | $2.95 | $17.870 | 0.000 |
| 4 | 2013/14 | $2.95 | $17.870 | Redacted |
| 5 | 2014/15 | $3.21 | $19.445 | 0.000 |
| 6 | 2015/16 | $3.43 | $20.778 | 0.000 |
| 7 | 2016/17 | $3.15 | $19.081 | Redacted |
| 8 | 2017/18 | $7.025 | $42.555 | 0.000 |
| | Average | | $23.333 | 0.043 |

**Q: What was the historical ratio of return to maximum downside risk?**

A: The ratio of the historical revenues to the potential liability is 0.17 percent. This indicates that the existing rules and CfD resulted in a maximum downside potential approximately 500 times the average upside revenue. Because revenues and liabilities are both proportional to FCA capacity prices under the prior rules, the resulting ratio would be the same with the higher

[5] The Generators say that, with expected future FCA prices, they would earn $803/MW per event; multiplied by the Generators' 504.8 MW capacity and the two events yields $810,709. Dividing by eight years equals $101,338 annually.

[6] That extremely unlikely outcome would require many shortage events and that each of the Generator units be unavailable in most of those events.

capacity prices in the next few years, and projected by the Generators for later years.

**Q: In the new PfP capacity market, what are the expected revenues from over-performance from CSC events?**

A: Potential revenues are significantly higher under the new rules than the old, because the new rules will likely increase the number of hours of reserve scarcity and because the upside potential per event is generally higher.

Gross revenue under the new rules depends on how well a generator responds to a scarcity event, overall load in the market, scarcity duration, and the PPR.

The ISO backcast indicates that PfP revenues for events lasting 30 minutes or longer would average $1.7 million per year when the PPR equals $2,000/MWh, $3.1 million per year when the PPR equals $3,500/MWh, and $4.8 million per year when the PPR equals $5,455/MWh.[7]

**Q: Is there a risk of underperformance charges eroding these revenues?**

A: Yes, but only to a very modest degree. Gross revenues from over-performance would be reduced if availability were less than 100%. The higher frequency of CSC events creates more instances in which credits can be earned and charges can be incurred. Under the PfP market rules, the maximum hourly charge for failing to respond to a CSC will generally exceed the maximum hourly credit for over-performance.

These risks, however, are modest for two reasons. First, peaking units have high availability factors, meaning that the plants should be available as reserves or as energy sources. The CfDs already "implicitly require 100%

[7] These estimates assume that the Generators have an availability factor of 100%.

performance of the Peaking Facilities at all time" (Generator Testimony, p. 37). Second, the larger number of events offer more opportunities for the generator to make up for a rare bad start or forced outage.

Since the availability of the Generators' units is so high, credits will almost always exceed charges. A generator would need to be available just 75% of events to have the overperformance bonus payments offset underperformance charges. As most peaking units have an availability factor of 98%, an availability factor of 75% is very unlikely.[8]

**Q: What is the maximum loss a generator could incur under for underperformance in the PfP capacity market?**

A: Yes. Under the new rules, the maximum annual penalty payment for underperformance is higher than it was previously. Under the old rules, the annual limit penalties equaled the entirety of a generators annual FCA revenue. Under the new stop-loss limits, a generator is liable for up to the entire annual capacity revenue plus three months of the difference between the starting price in the applicable FCA and the clearing price in that auction. Table 5 summarizes the maximum downside in each future delivery year under the new and old rules.

**Table 5: Maximum Downside for Underperformance, New and Old Rules**

| | | **Auction Prices** | | **Maximum Annual Penalty** | | |
|---|---|---|---|---|---|---|
| FCA | Period | Starting Price $/kW-Mo | Clearing Price $/kW-Mo | Old Rules $M/yr | New Rules $M/yr | New-Rule Max ÷ Old-Rule Max |
| 9 | 2018/19 | $17.728 | $9.55 | $57.85 | $70.23 | 121% |
| 10 | 2019/20 | $17.296 | $7.03 | $42.58 | $58.13 | 137% |
| 11 | 2020/21 | $18.624 | $5.30 | $32.11 | $52.28 | 163% |
| 12 | 2021/22 | $12.864 | $4.63 | $28.05 | $40.52 | 144% |
| Average FCA 9-12 | | | | *$40.15* | *$55.29* | *141%* |

[8] *ISO-NE CONE and ORTP Analysis*, Concentric Energy Advisors, January 13, 2017, page 65. https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf

For the next four delivery years, the maximum penalty for underperformance averages $55.29 million. This is 147% higher than the average $23.3 million stop-loss in the delivery years from 2010 to 2018. Higher FCA capacity prices drive most of this increase, but the new rules also increase the theoretical downside.[9] As the capacity market continues to develop, the maximum downside will continue to change.

**Q: To maintain the traditional ratio of expected credit to maximum charge, what share of revenues should the Generators retain going forward?**

A: To retain the current reward/risk ratio of 0.177%, with an average maximum annual penalty of $55.3 million, the generators would need to earn approximately $98,000/year in the PfP market to have the same expected value.[10]

Table 6 summarizes the share of revenue that the Generators should receive to cover the $98,000 revenue target. approximately 5.5% of revenues when the PPR equals $2,000/MWh, 3.1% of revenues when the PPR equals $3,500/MWh, and 2.0% percent of revenues when the PPR equals $5,455/MWh. As the Performance Payment Rates increase, a smaller share of over-performance revenues will give the Generators the same total risk-adjusted revenues. With these revenue shares, the generators will receive an average of $98,000 per year, commensurate with their added risk.

[9] The Generators project that future capacity prices will average $7.48/kW-month; the maximum penalty with that price would be about $45 million, assuming that the FCA starting price remains similar to that in FCA 12.

[10] $98,000 = 0.177% x $55 million Stop Loss.

**Table 6: Proposed PfP Revenue Allocation to Maintain Status Quo ($M/year)**

| | Generator Share of Revs | Annual Stop-Loss | Gross Revenues | Generator Revenues | Gross Rev/Risk | Generator Rev/Risk |
|---|---|---|---|---|---|---|
| **Old Shortage Event Rules** | | | | | | |
| Actual Outcome | 100% | $23.333 | $0.041 | 0.041 | 0.2% | 0.177% |
| Scaled Outcome | 100% | $57.195 | $0.101 | 0.101 | 0.2% | 0.177% |
| **PfP Market Rules with revised Revenue Allocation** | | | | | | |
| 6/2018 to 5/2021 | **3.398%** | $55.292 | $2.886 | 0.0981 | 5.2% | 0.177% |
| 6/2021 to 5/2024 | **1.942%** | $55.292 | $5.051 | 0.0981 | 9.1% | 0.177% |
| After 5/2024 | **1.246%** | $55.292 | $7.872 | 0.0981 | 14.2% | 0.177% |

**Q: How would any charges for under-performance affect this computation?**

A: So long as the sum of credits exceeds the sum of charges annually, the Generators would receive the share of revenues shown in Table 6. In the unlikely event that the charges for a year were to exceed the credits, the affect Generator would bear the net charges. For calendar years that are split between two levels of the PPR (2021 and 2024), that computation would be performed separately for the two periods (January to May and June to December), so that different credit shares can be applied to each period.

## V. Simple 10% Allocation Approach

**Q: The expected value allocation approach you propose, like the Generator's per-event approach, are somewhat complicated. Do you have a simpler alternative, if the Authority prefers?**

A: Yes. If the Authority would prefer an allocation method which was easier to compute and conceptually simpler, then I would propose that the generators receive a flat 10% of PfP revenues. Under this approach, the generators would receive the same share of revenue of all events (both long duration and short duration). If the generators were to receive a flat 10% of PfP revenues, then they would be compensated more generously than they would under my same expected value approach, but far less than they would under their proposal.

**Q: Are there non-revenue benefits to this approach?**

A: Yes. By offering the Generators a share of revenue from all events, rather than just the over-30 minute events, the Authority would give the Generators added incentive to keep their plants in good working order and able to reliability start-up and quickly ramp-up to meet the demands of scarcity conditions.

**Q: Under this 10% allocation method, what revenues would the Generators typically receive?**

A: The Generators would typically receive $289,000 to $787,000 annually from PfP scarcity events. Table 7 depicts the generator revenues as a function of the PPR. As the PPR increases from $2,000/MWh to $5,455/MWh, so too would Generator revenues.

**Table 7: Expected Generator Revenues Using a Flat 10% Allocation**

| | Generator Share of Revs | Annual Stop-Loss $M/year | Gross Revenue $M/year | Generator Revenue $M/year |
|---|---|---|---|---|
| **PfP Market Rules with revised Revenue Allocation** | | | | |
| @ PPR = $2,000/MWh | **10.000%** | $55.292 | $2.9 | $0.289 |
| @ PPR = $3,500/MWh | **10.000%** | $55.292 | $5.1 | $0.505 |
| @ PPR = $5,455/MWh | **10.000%** | $55.292 | $7.9 | $0.787 |

If the Authority elects to allow the Generators to retain 10% of revenues, then the Generators would receive a share of revenues several times higher than they would under my proposed expected-value approach, which itself would give them 2.5 times their historical revenues.

## VI. Comparison of Revenue Allocation Methods

**Q: How do the revenue allocations you have proposed compare to the allocation proposed by the Generators?**

A: Table 7 summarizes the allocation proposals, and compares those results with the Generator revenues under existing rules.

**Table 8: Expected Revenues by Allocation Method ($M/year)**

| | Gross Revenues | | Generator Rev Share | | Expected Revenues | |
|---|---|---|---|---|---|---|
| | <30 Min | ≥30 Min | <30 Min | ≥30 Min | *Generators* | *Ratepayers* |
| **Old Shortage Event Rules** | | | | | | |
| Actual Outcome | — | $0.04 | N/A | 100% | $0.04 | — |
| Scaled Outcome | — | $0.10 | N/A | 100% | $0.10 | — |
| **Generator Revenue as Proposed by the Generators** | | | | | | |
| 6/2018 to 5/2021 | $1.10 | $1.78 | 0% | 100% | $1.78 | $1.10 |
| 6/2021 to 5/2024 | $1.93 | $3.12 | 0% | 89% | $2.78 | $2.27 |
| After 5/2025 | $3.00 | $4.87 | 0% | 57% | $2.77 | $5.10 |
| **Generator Revenue to Maintain Expected Value** | | | | | | |
| 6/2018 to 5/2021 | $1.10 | $1.78 | 3.4% | 3.4% | $0.0981 | $2.73 |
| 6/2021 to 5/2024 | $1.93 | $3.12 | 1.9% | 1.9% | $0.0981 | $4.89 |
| After 5/2025 | $3.00 | $4.87 | 1.2% | 1.2% | $0.0981 | $7.71 |
| **Generator Revenue at 10% Share** | | | | | | |
| 6/2018 to 5/2021 | $1.10 | $1.78 | 10% | 10% | $0.29 | $2.60 |
| 6/2021 to 5/2024 | $1.93 | $3.12 | 10% | 10% | $0.51 | $4.55 |
| After 5/2025 | $3.00 | $4.87 | 10% | 10% | $0.79 | $7.08 |

**Q: Does this conclude your direct testimony?**

A: Yes.