Application 22-05-002
Exhibit No. CLECA-01_____

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of its Demand Response Programs, Pilots and Budgets for Program Years 2023-2027.	**Application 22-05-002 (Filed May 2, 2022)**
And Related Matters	**Application 22-05-003 Application 22-05-004 (Consolidated)**

Direct Testimony of

SAM HARPER

on behalf of

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

April 21, 2023

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ADVISORY

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EXECUTIVE SUMMARY

California continues to experience a resource supply crunch and inexorably increasing prices for electricity resources. The reliance on Demand Response (DR) programs like the Base Interruptible Program (BIP) has dramatically increased due to extreme heat conditions since 2020. High usage of the program has caused significant customer fatigue, leading to loss of program participation across the state. The reliability of the electricity grid requires retaining current resources and integrating new resources—including reliable, cost effective, zero-carbon, preferred resources like BIP. Higher incentives and prudent program design changes are appropriate to achieve reliability for an increasingly dynamic grid. Appropriate BIP program limits are critical to enable customers to continue to enroll in the program. Expansion of BIP program obligations or changes in dispatch order would exacerbate customer departures from the program and negatively impact reliability. Instead, in the short term the Commission should

clarify dual participation baseline treatment for ELRP events during non-BIP events to incentivize existing BIP customers who could provide incremental demand response. And in the long term, dual participation multi-use and value stacking should be explored comprehensively for proven, reliable, demand response customers.

INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Sam Harper. My business address is Harper Advisory LLC, 1401 Lake Plaza Drive, Suite 200-107, Spring, TX 77389.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of energy markets and policy.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A Please see Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the California Large Energy Consumers Association (CLECA). CLECA is an organization of large, high load factor industrial customers of PG&E and SCE. The members are in the cement, steel, industrial gas, medical gas, pipeline, beverage, cold storage, and minerals processing industries, and share the fact that electricity costs comprise a significant portion of their costs of production.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to address BIP program parameters and incentive levels, promote continuation of robust demand response programs necessary for grid reliability, and explore reasonable dual participation opportunities. To the extent that I do not address a particular issue raised by any party, my silence should not be interpreted as a tacit endorsement of that party's position on that issue. I focus on Southern California Edison (SCE) and Pacific Gas & Electric Company (PG&E) demand response programs, and some concerns and recommendations are applicable statewide.

Q HOW IS YOUR TESTIMONY ORGANIZED?

A First, I provide an overview of CLECA members' operations and experience with engaging in DR programs like BIP. Then, I address recent trends in BIP enrollment and dispatch, conditions driving those trends, the impacts on industrial operations, and BIP's value in meeting the state's clean energy and reliability goals. Finally, I provide my direct responses to Phase II Scoping Issues 1, 2, 3, 5, 8, 9, and 10.[1]

SUMMARY OF RECOMMENDATIONS

Q PROVIDE A SUMMARY OF YOUR POSITIONS IN THIS TESTIMONY.

A I take the following positions regarding the utility proposals for demand response activities for the period 2024-2027:

1. Support a process for evaluating whether the goals of integrating demand response in the CAISO market are being achieved;
2. Support modest increases to BIP incentive levels;
3. Propose an incremental "All Other Hours" incentive;

[1] *Assigned Commissioner's Amended Scoping Memo and Ruling and Assigned Administrative Law Judge's Ruling on Two Motions*, Application (A.) 22-05-002, Dec. 19, 2022 at pp. 5-6.

4. Support BIP customers' eligibility for Automated Demand Response incentives;
5. Support PG&E's proposal to add a 15-minute BIP option;
6. Strongly oppose design changes to RA-eligible emergency DR programs that would unnecessarily increase dispatches and exacerbate customer fatigue;
7. Support extension of the temporary increase in DR reliability capacity;
8. Support the cost effectiveness of SCE and PG&E BIP programs;
9. Support reasonable limits on BIP events on consecutive days and within a rolling 30-day window;
10. Support continued exemption of energy storage resources not coupled with fossil-fueled generation from the prohibited resources policy;
11. Propose modifying the BIP-ELRP dual participation compensation rule for non-overlapping hours;
12. Support PG&E's proposal for a dual participation working group;
13. Support program enhancement flexibility; and
14. Oppose continued funding for modeling DR potential.

CLECA MEMBERS' OPERATIONS AND EXPERIENCE WITH DEMAND RESPONSE

Q DO CLECA MEMBERS PRODUCE ESSENTIAL GOODS AND SERVICES?

A Yes. CLECA members produce goods and services that serve critical functions for the state economy, and which are essential for daily life. For example, CLECA members produce seismic grade materials required for critical infrastructure, water storage, and housing; medical gasses for hospitals; and refrigerated food distribution.

Q WHAT IS CLECA'S EXPERIENCE WITH DEMAND RESPONSE?

A All CLECA members engage in demand response programs. CLECA members have participated in the BIP and its predecessor interruptible programs since the early 1980s. CLECA members have historically provided additional incremental load reductions to the

extent that dual participation was allowed, in programs such as the Demand Bidding Program (DBP) and Emergency Load Reduction Program (ELRP). CLECA has been actively engaged in Commission regulatory proceedings related to demand response since the mid-1980s.

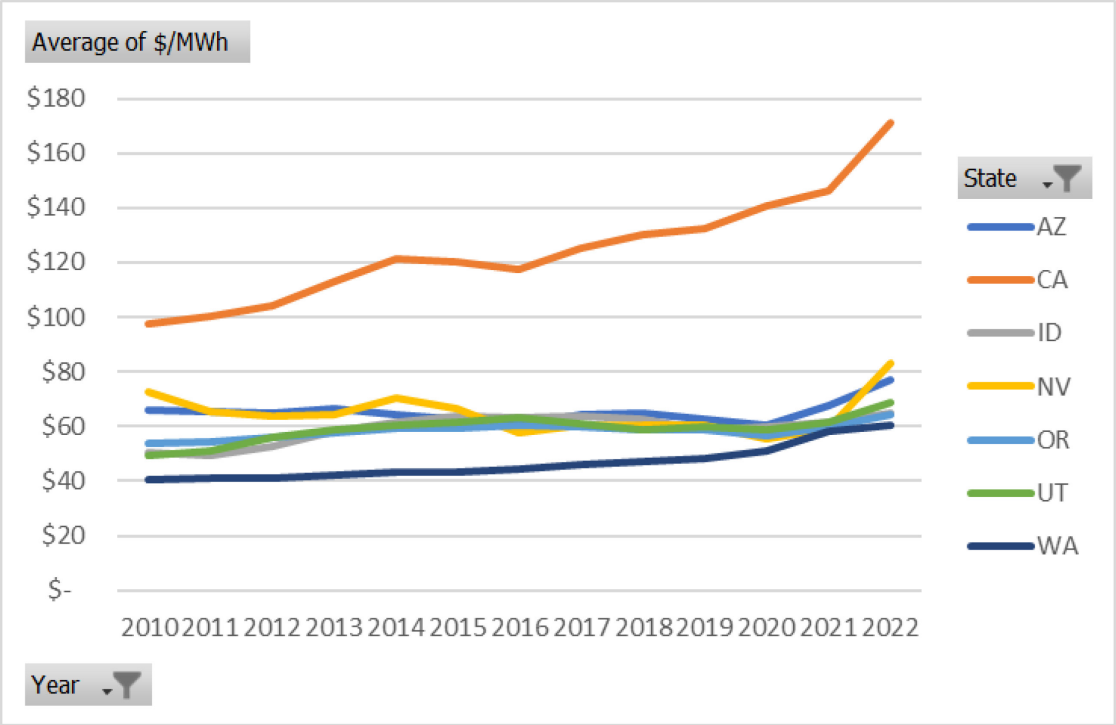
Q WHY DO CLECA MEMBERS PARTICIPATE IN DEMAND RESPONSE PROGRAMS?

A CLECA members operate sophisticated large scale industrial facilities. Electricity supply is a critical input to their production processes, which are dependent on a reliable grid. Electricity also accounts for a significant portion of their cost of production. CLECA members participate in demand response to both promote grid reliability, and help mitigate the high cost of electricity in California and its impact on their competitiveness.

Q ARE CLECA MEMBERS UNDER COMPETITIVE PRESSURE FROM OUT OF STATE?

A Yes, CLECA members typically produce commodities that can be traded across state lines or internationally. For CLECA members, electricity cost is often the number one cost of converting raw materials to finished product. Electricity cost can determine whether an industrial facility can compete with facilities outside of the state. According to the Energy Information Agency (EIA), the gap between California average industrial electricity rates and the average of neighboring states has grown considerably in the last decade, and in 2022 California industrial rates were 138% higher than their neighbors.

Figure 1: EIA INDUSTRIAL AVERAGE RATES BY STATE[2]



Notably, the only remaining steel melting facility in the state of California was closed in 2020, citing high costs.[3]

Q WHAT ARE THE POLICY IMPACTS OF INDUSTRIAL CUSTOMER COMPETITIVENESS?

A Most CLECA members are Energy Intensive and Trade Exposed (EITE) with the associated risk of emissions leakage. Emissions leakage occurs when emissions apparently decrease within California, but increase globally. The Commission explains, "Emissions leakage could occur if a production facility moved out of California to a

[2] U.S. Energy Information Administration, Form EIA-861M, *Monthly Electric Power Industry Report*, url: https://www.eia.gov/electricity/data/eia861m/.

[3] Kevin Smith, *Commercial Metals to Shutter Rancho Cucamonga Steel Mill, Citing High Costs in California,* San Gabriel Valley Tribune, Oct. 16, 2020, url: https://www.dailybulletin.com/2020/10/16/commercial-metals-to-shutter-rancho-cucamonga-steel-mill-citing-high-costs-in-california/.

jurisdiction without a Cap-and-Trade Program or other climate goals."[4] One example of emissions leakage would be an EITE industrial facility unable to compete in California and closing its facility. But because the goods it formerly produced are critical, they are imported from a jurisdiction with less robust environmental regulations or climate goals, and shipped longer distances by truck or ship.

Another policy impact of losing industrial customer competitiveness is reduced demand response resources available to support grid reliability if an industrial customer reduces its operations, or closes a facility that had participated in BIP. Any such industrial facilities that have closed or reduced their production have also reduced the demand response resources available to the grid.

Q ARE BIP RESOURCES INCREASING OR DECREASING?

A Decreasing. SCE explains, "Enrollment and participation in BIP significantly decreased after the grid reliability emergencies that occurred in the summer of 2020."[5] PG&E BIP enrollment also declined significantly, from 300 MWs in 2017 to 170 MWs in 2022, a loss of over 40%.[6] Notably, customers can only leave the program during the subsequent annual enrollment window, or else they face significant excess energy charges.

[4] California Public Utilities Commission, *California Industry Assistance*, url: https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-industry-assistance#:~:text=Eligible%20EITE%20facilities%20that%20report%20to%20CARB%20%28California,works%20with%20the%20utilities%20to%20deliver%20the%20credit.

[5] Ex. SCE-04 at p. 10.

[6] Ex. PG&E-2 at p. 3-7, Table 3-3.

Table 1: PG&E EX ANTE: AUGUST PEAK[7]

Line No.	Item Detail	2017	2018	2019	2020	2021	2022
1	Enrollment	330	362	421	512	308	268
2	MWs	300	221	254	236	183	170

The loss of significant demand response resources is likely the result of several factors—including closure of industrial operations which previously provided demand response, and customer fatigue from dramatically increased usage of demand response. PG&E cites "customer fatigue and hardship due to the number, duration, and consecutive nature of the 2020 BIP events. Even though only one BIP event was dispatched in 2021—as illustrated in Table 3-3—the program has continued to experience attrition and low enrollment compared to historical years."[8] SCE explains, "Because of an increase in DR events resulting from grid constraints over the past few years, customers have become discontented with the disruption to their core business operations that occur when DR events are called. From the customer's perspective, the value proposition has become less compelling and is a leading driver of customer attrition in DR programs."[9]

Q HOW HAS THE USAGE OF BIP EVOLVED?

A BIP has historically been used infrequently as an emergency program. BIP was dispatched typically 1-2 times per year, including an annual test. However, that changed dramatically in 2020 with extreme weather events that included devastating heatwaves,

[7] Ex. PG&E-2 at p. 3-7, Table 3-3.
[8] Ex. PG&E-2 at p. 3-7.
[9] Ex. SCE-01 at p. 18.

wildfires, and drought. PG&E explains, "BIP was heavily relied upon for multiple and consecutive days in 2020 to provide load reduction during systemwide grid emergencies caused by extreme heatwaves in August and September. Most BIP participants were dispatched for up to seven emergency events: five consecutive days in August and two consecutive days in September."[10] For SCE's eight BIP events in 2020, "Two of the events were called as CAISO Stage 2 emergencies, five were called as CAISO warnings, and one was called for local reliability."[11] The heavy reliance on BIP to address extreme grid emergencies continued with an event in 2021, and three events in 2022. As PG&E further explains, "how often BIP is dispatched has evolved since 2020 to include frequent and consecutive systemwide grid emergencies associated with California's changing climate and grid needs."[12]

Q WHAT ARE THE OPERATIONAL IMPACTS OF FREQUENT AND CONSECUTIVE DISPATCH ON BIP CUSTOMERS?

A BIP events are extremely disruptive to industrial operations. BIP customers have signed up to interrupt their operation and are well prepared to do so, as evidenced by their historical reliability. However, as the frequency of events increases, especially on consecutive days, the ability of BIP customers to manage the operational disruption gets much more difficult. BIP customers typically manage BIP event disruptions by shifting their production schedule for lost production time, or by carrying extra inventory to satisfy their customer demands. As event frequency increases, these customers may run

[10] Ex. PG&E-1 at p. 3-5.
[11] Ex. SCE-03 at pp. 12-13.
[12] Ex. PG&E-2 at p. 3-6.

through their inventory, or there may be no extra time available to make up lost production. BIP customers often produce critical goods and services, so an inability to meet customer demands can have cascading impacts on the state economy and, with medical gasses, potentially life-threatening shortages of supplies necessary for hospitals. One example of the latter is the increased need for medical oxygen during a COVID surge, which has coincided with an extended heat wave and multiple BIP events. Reasonable limits on the number of events and consecutive events are essential to enable existing BIP customers to remain on the program, and to encourage new BIP customers to enroll their loads in the program.

Q ARE THE ENVIRONMENTAL IMPACTS AND GRID CONDITIONS THAT LED TO INCREASED BIP USAGE LIKELY TO CONTINUE?

A Yes, the extreme conditions that the state has experienced in recent years including heat storms, drought, and wildfires are likely to continue leading to continued high usage of demand response resources. The step change in BIP reliance since 2020 may be the start of a new trend even with the current dispatch order, which is very concerning. "These climate-related conditions are expected to persist, and effective utilization of DR can play a role in mitigating their effect on grid reliability."[13]

Q HAVE BIP RESOURCES PERFORMED RELIABLY?

A Yes, BIP customers have performed reliably for many years. As SCE explains: "BIP is the largest DR program (in MW) in SCE's portfolio and has consistently performed well during program events, particularly in the last two years when reliability events

[13] Ex. PG&E-1 at p. 1-1.

have occurred."[14] Further adding, "Participants have maintained a consistent Firm Service Level (FSL) achievement rate at or above 90% through all of the recent critical reliability events, where the full BIP portfolio was dispatched."[15]

Table 2: SCE BIP 2020 and 2021 Load Reductions By Event[16]

Line No.	Event Date	Dispatch Type	Average Load Reduction (MW)	FSL Achievement Rate
1	08/14/20	Full Dispatch	484	90%
2	08/15/20	Full Dispatch	451	91%
3	08/16/20	Full Dispatch	427	93%
4	08/17/20	Full Dispatch	514	91%
5	08/18/20	Full Dispatch	520	90%
6	09/05/20	Full Dispatch	411	93%
7	09/06/20	Full Dispatch	418	91%
8	09/07/20	Partial Dispatch	8	49%
9	07/09/21	Full Dispatch	409	94%

Q WHAT IS THE VALUE OF RESOURCE DIVERSITY?

A Resource diversity is valuable because it reflects that every resource has inherent limitations. And some of these limitations are difficult to fully quantify across unpredictable extreme contingency conditions. Wind and solar are weather dependent with availability that varies across hours, days, and even months. Conventional thermal generation relies upon complex upstream supply chains to deliver its fuel. For example, natural gas generation relies upon functioning natural gas wells at the right locations.

[14] Ex. SCE-03 at p. 12.
[15] Ex. SCE-03 at p. 13.
[16] Ex. SCE-03 at p. 13, Table III-5.

Many natural gas wells froze in Texas in February 2021, contributing to its storm Uri reliability crisis. Furthermore, in recent heat storms we have seen conventional thermal generation resources fail to operate reliably. Batteries are limited by their need to charge before the next event, and a 4-hour battery can only provide its rated capacity for 4 hours; yet an extreme contingency event could last much longer. Demand response resources that are weather dependent can provide valuable resources, but may not always be available. For example, you cannot turn down your air conditioning in an extreme winter event and provide demand response. In contrast, demand response from industrial facilities is highly reliable year-round in all weather conditions. An industrial facility can be shut off even if the sun is down or the wind isn't blowing, or the natural gas supply chain is compromised, but it has use limitations due to the operational impact of curtailment events. The value of resource diversity is that uncorrelated attributes of each resource category provide robustness to the grid and improve reliability.

Q WHAT IS THE ROLE OF DEMAND RESPONSE TO MEET FUTURE GRID NEEDS?

A Demand response is a zero-carbon preferred resource that will continue to play a critical role in achieving the state's ambitious renewable energy and climate targets. Moreover, demand response could play a greater role if there were more types of demand response made available for industrial customers. The Commission recognizes, "California's electricity system is undergoing a rapid transformation on the pathway to 100% renewable power" and that "Demand Response (DR) continues to play an

important role in achieving California's clean energy goals."[17] Demand response programs like BIP have been increasingly relied upon since 2020. Growing the BIP program and other industrial demand response programs will be essential to managing the increasingly dynamic electricity grid. SCE seeks to increase BIP program participation and enrollment.[18] PG&E also plans to increase its demand response portfolio, forecasting a 73% increase in BIP from 184 MWs in 2022 to 319 MWs in 2027.[19] Incentives need to be properly designed in order for demand response to grow to meet the needs of the increasingly dynamic grid, particularly given the recent high usage rates.

PHASE II SCOPING ISSUES FOR 2024-2027 UTILITIES' DEMAND RESPONSE PROGRAMS

1. ***Do the applications of PG&E, SCE, and SDG&E requesting approval of Demand Response Programs and budgets for Years 2024 through 2027 advance the goals, principles, directives, and guidance adopted in D.16-09-056 and comply with the directives in D.16-09-056, D.17-12-003, and D.21-03-056, as well as other directives in Commission decisions and rulings under the DR, summer reliability, and other applicable proceedings?***

CAISO MARKET INTEGRATION OF DEMAND RESPONSE

Q WHAT DO THE UTILITIES PROPOSE REGARDING CAISO MARKET INTEGRATION OF DR?

[17] *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation*, Jun. 22, 2022, url: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf at p. 1.

[18] Ex. SCE-04 at p. 10.

[19] *Application of Pacific Gas & Electric Company for Approval of its Demand Response Programs, Pilots, and Budgets for Program Years 2023-2027*, A. 22-05-002, May 2, 2022 at p. 2.

A SCE and PG&E both propose a process for evaluating whether the goals of integrating demand response in the CAISO market are being achieved. Both utilities cite challenges of integration after nearly of decade of experience, and propose a process to determine the appropriate path forward. SCE explains, "A more complete and granular evaluation of the CAISO market integration is needed, now that IOUs and DR stakeholders have been operating under the current construct developed by the Commission for almost a decade. SCE believes that this proposed assessment, and recommendations for improvement that focus on maximizing DR benefits and lowering costs, will help ensure the success of this critical resource going forward."[20] PG&E argues:

> [I]ntegrating DR into the CAISO market has been challenging due to existing RA supply plan rules, which were designed for conventional generation resources. Although CAISO and the Commission have done an admirable job of creating initiatives and modifying certain policies and rules to better support DR market integration, there are still gaps.[21]

Q DO YOU AGREE WITH THE PROPOSAL FOR A REASSESSMENT OF DR MARKET INTEGRATION?

A Yes, I agree that a reassessment is appropriate at this time. The integration of DR resources to the CAISO market continues to present challenges after almost a decade of experience, despite the best efforts of many parties. Demand response has played a critical role in maintaining grid reliability over this period, and will continue to do so if the method of dispatch is determined to be more effective under a different paradigm.

[20] Ex. SCE-01 at p. 37.
[21] Ex. PG&E-2 at p. 2-7.

Q DO YOU AGREE WITH THE GOALS OF THE DR MARKET INTEGRATION EVALUATION PROPOSED BY THE UTILITIES?

A Yes, I agree with the proposed goals of an independent assessment. PG&E proposes, "rethinking or significantly improving the market integration paradigm for DR and to achieve the goals set forth in the DR Order Instituting Rulemaking (OIR)."[22] SCE recommends conducting an independent assessment to:

> Evaluate if the goals developed by the Commission for integrating DR into the CAISO market are being met; Identify regulatory and operational issues related to the DR CAISO market integration, and opportunities to improve the efficiency and effectiveness supply-side resources, including alternative options for DR participation in the CAISO market; and Develop recommendations, including potential changes to rules and policy.[23]

2. *Are PG&E's, SDG&E's, and SCE's proposed demand response programs and activities, including pilot recommendations, Emergency Load Reduction Program, and modifications to existing programs and policies, reasonable, and should they be adopted?*

BASE INTERRUPTIBLE PROGRAM

Q WHAT IS BIP?

A BIP is a reliability-based emergency DR program for large commercial and industrial customers. The program is a modified version of prior interruptible rate programs that have been in place since the 1980s. BIP is the largest DR program and has been highly reliable over many years, particularly during the recent extreme heat waves. BIP is a capacity DR program with incentives paid to participating customers for making their capacity available to mitigate reliability grid events. Any market revenues achieved

[22] Ex. PG&E-2 at p. 2-7.
[23] Ex. SCE-01 at p. 37.

during BIP deployment flow to all ratepayers, not directly to BIP participants. BIP customers are required to be available for interruption all hours of the day, every day of the year. BIP customers enroll their load for an entire year, agreeing to reduce their operation to a designated FSL within 15 or 30 minutes of notification. BIP customers are subject to very high excess energy charges if they consume any load above their FSL during a BIP event. The very high excess energy charges are a significant reason why BIP has been highly reliable for so long.

BIP can be dispatched by the CAISO during emergency conditions, or by the utilities for local transmission and distribution contingencies. BIP customers sign up for a year-long commitment subject to excess energy charges, with the understanding that they will only be called when there is a true grid emergency.

Q WHAT ARE THE PROPOSED CHANGES TO BIP INCENTIVE LEVELS?

A PG&E proposes no change in incentive for the November – April season, and a $2/kw increased incentive for the May – October season.[24] SCE proposes a range of increases across time periods and customer voltages as detailed in the table below.

[24] Ex. PG&E-2 at p. 3-10.

Table 3: SCE's Current and Proposed BIP Credits[25]

Credit ($/kW-Month)	Current			Proposed		
Description	Summer On-Peak	Summer Mid-Peak	Winter Mid-Peak	Summer On-Peak	Summer Mid-Peak	Winter Mid-Peak
15-Minute Option						
Secondary Service	(26.11)	(2.04)	(10.97)	(31.35)	(7.18)	(10.31)
Primary Service	(26.11)	(1.70)	(10.26)	(30.06)	(4.46)	(9.00)
Sub-Transmission Service	(17.84)	(0.86)	(6.46)	(23.54)	(2.61)	(6.41)
30-Minute Option						
Secondary Service	(23.54)	(1.84)	(9.89)	(27.40)	(6.28)	(9.01)
Primary Service	(23.14)	(1.50)	(9.07)	(26.27)	(3.90)	(7.87)
Sub-Transmission Service	(15.37)	(0.73)	(5.54)	(20.57)	(2.28)	(5.60)

SCE's and PG&E's proposed increases are modest considering the reliance on BIP to maintain grid reliability, and the paradigm shift in usage which is likely to continue.

The proposed increases in BIP incentives are intended to combat customer fatigue, retain the existing enrolled load, and grow this portfolio of reliable resources. The state of California is in a supply crunch, and increasingly relies upon demand response to manage extreme grid events. SCE explains:

> As grid reliability has been challenged over the past few years by climate change induced heat events, droughts, and wildfires, DR has provided a clean, reliable, flexible resource that helps avoid blackouts at a reasonable cost. By that measure, one could argue that the value of DR has been increasing over the past several years.[26]

Furthermore, the updated Avoided Cost Calculator (ACC) for 2022 shows a dramatic increase in the cost of new resources. SCE's avoided cost of generation capacity for 2024 jumped from $92/kW-yr as calculated based on the 2021 ACC, to $257/kW-yr based on the 2022 ACC.[27] PG&E's avoided cost of generation capacity for 2024 jumped from $96/kW-yr as calculated based on the 2021 ACC, to $257/kW-yr

[25] Ex. SCE-04 at p.7, Table II-3.
[26] Ex. SCE-01 at p. 34.
[27] Ex. SCE_12 at p. 3.

based on the 2022 ACC.[28]The BIP incentives for 2024-2027 were proposed prior to these dramatic resource cost increases, and have not yet been updated.

Q ARE THE PROPOSED CHANGES SUFFICIENT TO ACCOMPLISH THE STATED GOALS?

A The proposed incentive levels are a step in the right direction and will help to mitigate customer fatigue and help maintain the current enrolled load. However, they are likely inadequate to effectively grow participation levels aligned with the utilities' stated goals. Current and potential new BIP customers will have to weigh the impact on their business of modestly increased incentives compared to dramatically higher expected curtailments.

The proposed incentive changes also fail to substantially offset the dramatic increase in retail rates to industrial customers in recent years. These extremely high retail rates compared to neighboring states will continue to put competitive pressure on existing BIP customers, and their ability to continue to operate their businesses, which impacts their ability to continue to provide demand response.

Q WHAT ADDITIONAL CHANGES TO BIP INCENTIVE LEVELS DO YOU PROPOSE?

A I propose an "All Other Hours" additional nominal $1/KW incentive applied to the average customer load, minus FSL for the aggregate period in any month that otherwise does not have an incentive. For example, SCE would add a $1/KW incentive level for the period summer all other hours; and PG&E would add a $1/KW incentive for summer hours outside of the current 4:00-9:00 pm measurement period. This proposal

[28] Ex. PG&E-7 at p. 12-8.

would effectively add $12/KW to the overall annual incentive level for BIP participants. First, this modest overall increase in incentive levels would continue to be cost effective by a wide margin, using the 2022 ACC reflecting the dramatic avoided cost increase for alternative resources. Second, the incentive would continue to be weighted heavily towards existing on peak time of use periods. However, the additional incentive would accurately reflect that BIP customers commit to curtail during **ALL** hours of the day, **EVERY DAY** of the year. The additional incentive would also reflect the growing reality that resources are required 24 hours a day in all 12 months, as reflected in the resource adequacy slice of day framework.

AUTO-DR INCENTIVES

Q ARE THE UTILITIES PROPOSING FOR BIP CUSTOMERS TO BE ELIGIBLE AUTOMATED DEMAND RESPONSE (AUTO-DR OR ADR) INCENTIVES?

A Yes, PG&E, "proposes RDRR resources, such as the Base Interruptible Program (BIP), be eligible to receive ADR control incentives."[29] SCE proposes to "add BIP-15 as a qualifying DR program eligible to receive Auto-DR incentives."[30] Both utilities cite the recent history of increased deployment and benefits of automated control technology to the program and grid reliability.

Q DO YOU SUPPORT BIP ELIGIBILITY FOR AUTOMATED DEMAND RESPONSE INCENTIVES?

A Yes, BIP customers should be eligible for Auto-DR incentives. The historical reason to exclude the program was based on low dispatch frequency; however, that

[29] Ex. PG&E-2 at p. 4-10.
[30] Ex. SCE-01 at p. 20.

reason is no longer applicable after the experience of frequent dispatch starting in 2020. Auto-DR technology can improve the reliability, speed, certainty, and operational impact of curtailments. Auto-DR could increase the number of MWs enrolled in the program for existing customers by automating difficult to curtail loads. For example, a particular motor may be difficult to access manually within 15 or 30 minutes, but could be controlled remotely with the right automated technology solution. Auto-DR could also provide an incentive for new loads to participate and help retain existing customers who receive Auto-DR incentives, given the program requirements to provide demand response for a certain period after receiving an incentive.

Q DO YOU RECOMMEND ANY CHANGES TO THE AUTO-DR PROPOSALS BY PG&E AND SCE?

A Yes, the SCE Auto-DR program should be available for both 30-minute and 15-minute BIP customers. The 30-minute program would benefit from Auto-DR by speeding up the response time, and may include loads that are more difficult to curtail without automation. Both programs should integrate the automated response with the overall customer curtailment procedure for its entire site, and allow emergency manual override capability. BIP customer loads require a precise sequence of curtailment for operational, safety and environmental reasons. For example, a water-cooling system may need to run for a specific period after the heat generating production process is curtailed, to avoid overheating equipment. For these reasons, I propose a clarification to the following SCE statement, “when a customer installs Auto-DR controls their load will

immediately drop as soon as they receive a signal from SCE."[31] When a customer installs Auto-DR controls, as soon as they receive a signal from SCE, a countdown begins to curtail the controlled loads within 15 or 30 minutes, according to the customer curtailment procedure.

PG&E 15-MINUTE BIP OPTION

Q WHAT DOES PG&E PROPOSE AND DO YOU SUPPORT THE PROPOSAL?

A PG&E proposes to add a 15-minute BIP option to "help address emergency grid needs and local capacity requirements, as market resources that can respond in less than 20 minutes can meet local Resource Adequacy (RA) requirements."[32] I support the proposal. Additional resources eligible for local RA will improve grid reliability. Some existing PG&E BIP customers may be able to curtail within 15 minutes, and be willing to provide this faster response. The higher incentive level for 15-minute response may encourage new customers to enroll. Additionally, alignment amongst utilities' BIP curtailment options is desirable, especially for customers who have multiple facilities spread across multiple utility territories.

c. To improve program cost-effectiveness, usefulness, and system reliability, should the Commission consider design changes to RA-eligible emergency DR programs, such as (but not limited to) dispatch conditions and requirements, compensation & penalties, and performance measurement techniques?

Q IS BIP, AN RA-ELIGIBLE EMERGENCY DR PROGRAM, ALREADY COST-EFFECTIVE AND USEFUL?

[31] Ex. SCE-03 at p. 61.
[32] Ex. PG&E-02 at p. 3-2.

A Yes. The updated cost-effectiveness showings demonstrate that BIP is very cost-effective, with Total Resource Cost (TRC) ratios of 2.56 for PG&E's BIP with ADR, 2.76 for SCE's BIP-15, and 3.32 for SCE's BIP-30. And as stated earlier in this testimony, BIP has been very useful at reducing or preventing rolling blackouts in the 2020 and 2022 extended heat waves.

Q IS CUSTOMER FATIGUE ALREADY A PROBLEM?

A Yes. RA-eligible emergency DR programs like BIP have been dispatched at a significantly higher rate since 2020 due to the extreme impacts of drought, wildfires, and other climate-related conditions. These challenges are likely to persist in the coming years with the associated high frequency of demand response dispatch. The customers enrolled in these programs are already experiencing dispatch fatigue, as evidenced by the shrinking levels of participation across the state. SCE explains:

> Because of an increase in DR events resulting from grid constraints over the past few years, customers have become discontented with the disruption to their core business operations that occur when DR events are called. From the customer's perspective, the value proposition has become less compelling and is a leading driver of customer attrition in DR programs.[33]

The state is in a supply crunch, and a reduction in RA-eligible emergency DR programs would have a deleterious impact on grid reliability and overall resource cost. Therefore, for the sake of reliability and to avoid increased costs, the Commission should not change dispatch order, and should consider increasing availability limits to encourage existing DR customer retention and new customer enrollment. For example, a 3-day

[33] Ex. SCE-01 at p. 18.

limit on consecutive event days and a rolling 30-day availability window, as proposed by PG&E,[34] would give customers additional confidence to plan their inventory and production schedules, thereby encouraging enrollment in BIP.

Q SHOULD THE COMMISSION CHANGE BIP DISPATCH CONDITIONS?

A No. The dispatch trigger for emergency DR programs like BIP should not be changed. I am aware that the Energy Division has proposed that BIP events be called much earlier in the EEA process, as early as in anticipation of an EEA Watch.[35] Adopting this proposal would be a serious mistake. Calling BIP events repeatedly for situations where the grid is not in emergency conditions would dramatically increase customer fatigue and lead to even great erosion of BIP participation. Tight grid conditions are likely to persist over the coming years, leading to the continued need for frequent dispatch with the current dispatch order. Dispatching emergency DR resources when there is not a real emergency wastes the availability of a valuable resource and worsens future grid reliability.

The Commission dispatch order policy has been consistent for many years with clear rationale:

> We confirm the use of Reliability Demand Response Resource (RDRR) can occur anytime within the Warning State, in the case of both In-Market dispatch and Out-Of-Market dispatch, otherwise known as exceptional dispatch. Given the collective concern regarding the frequency of notices, we conclude that the

[34] Ex. PG&E-2 at p. 3-2.

[35] *Administrative Law Judge's Ruling on Energy Division's Phase 3 Proposals*, R. 21-10-002, Jan. 20, 2023 at Appendix A.

Commission should not allow RDRR to be triggered prior to the Warning Stage at this time.[36]

When CAISO changed its emergency conditions construct from Alerts, Warnings, and Emergency (AWE) to Energy Emergency Alert (EEA) in 2021, the long-standing dispatch policy was consistently maintained. The CAISO Operating Procedure 4420 for System Emergency describes an EEA 2 notice as "formerly known as 'Warning' and 'Stage 1' notices," and EE1 notice as "formerly known as a 'Warning' notice." The long-standing policy under the AWE construct of dispatching RDRR after a Warning is consistent with the current CAISO dispatch order.[37]

Q SHOULD THE COMMISSION INCREASE BIP AVAILABILITY REQUIREMENTS?

A No. Reasonable availability limits are essential to the viability of the entire BIP program. Customers need to reasonably anticipate the frequency of curtailments to sign up for a yearlong mandatory commitment with very high excess energy charges. Dramatically increasing the number of expected interruptions will lead to significant erosion of customer participation.

It is reasonable to limit the frequency of BIP events. All resources have inherent use limitations which generally are reflected in their availability obligations. A 4-hour battery can only provide its rated capacity for 4 hours, even if a grid emergency lasts longer. Conventional thermal generators can submit outages; and submit offers according to their start-up times and ramp rates. Demand response is a preferred

[36] Decision (D.) 18-11-029, *Decision Resolving Remaining Application Issues for 2018-2022 Demand Response Portfolios and Declining to Authorize Additional Demand Response Auction Mechanism Pilot Solicitations*, A. 17-01-012 et al, Nov. 29, 2018 at p. 23.
[37] CAISO Operating Procedure 4420 at pp. 8-9.

resource that provides much needed reliability and increases the diversity of resources available to the grid. Demand response resources' long-established use limitations should be respected, as the use limitations of other resources are respected.

The longstanding dispatch order and availability requirements of BIP reflect its purpose as an emergency resource. If changes are made to that fundamental program purpose, then existing customers should have the opportunity to opt out or change their FSL commitment prior to implementation of the changes, even within a BIP enrollment cycle. The utilities should plan for additional administrative support to handle the likely volume of opt-out requests.

Q SHOULD THE COMMISSION CHANGE BIP PERFORMANCE MEASUREMENT OR PENALTIES?

A No. Emergency DR programs like BIP already face very significant excess energy charges for failure to perform, which provides a strong incentive to comply with their load reduction commitments. I continue to support these high excess energy charges and do not encourage reducing them, as properly incentivizing compliance is essential to an emergency reliability program like BIP.

Emergency DR programs like BIP are already cost effective, especially when considering the dramatic increase in resources procurement costs as reflected in the 2022 ACC. They do not need to be dispatched earlier or be more available to be cost effective.

Utilizing the response capabilities of existing demand response customers for new expanded purposes, like dispatch prior to an emergency, should be done only through the addition of a program designed to allow voluntary dual participation for

that expanded purpose. For example, voluntary dual participation in the Emergency Load Reduction Program or a successor energy program for non-overlapping events would provide an appropriate signal and incentive for existing customers that are able to participate, based on their unique operational circumstances. On the other hand, it is inappropriate to make extreme changes to the historical dispatch order, availability requirements, and fundamental purpose of a critical reliability program like BIP.

d. Should the temporary increase in the DR reliability cap to 3 percent be extended?

A Yes, the state is undergoing a severe supply crunch with unprecedented and growing demand for electricity. Reliability-based DR has consistently stepped up over decades, including during the extreme heat events beginning in 2020. The cap should be extended through 2027 irrespective of whether ELRP is extended.

3. Did PG&E, SCE, and SDG&E accurately follow the Commission´s DR cost-effectiveness protocols to determine their programs´cost-effectiveness score, and are their programs cost-effective?

A The PG&E and SCE BIP programs are highly cost effective. Based on preliminary analysis utilizing updated 2022 ACC values, the PG&E BIP program, including ADR, shows a TRC Ratio of 2.65; and the SCE BIP programs show a TRC ratio of 2.76 for BIP-15, and 3.32 for BIP-30. These scores indicate cost effectiveness with a comfortable margin of error.

The 2022 ACC is the appropriate reference to determine cost effectiveness. As CLECA explained:

> The Commission undertakes annual updates to the ACC in an effort to improve its accuracy and to reflect changing market conditions and state policies. These updates help to establish the

full benefits of DR, and to provide participating customers with fair compensation.[38]

The 2022 ACC is the latest measure available, and more accurately reflects the significant increases in the rate of inflation and the dramatic escalation in resource costs that have occurred since the utilities filed their original DR Applications. Furthermore, the importance of demand response to grid reliability has amplified during that period. As PG&E explains, "the historic heat events in 2020 and 2022 which highlighted the pivotal role that active and consistent participation in DR programs play in supporting grid reliability."[39]

5. Should fund-shifting rules be revised to allow Utilities greater discretion?

Q DO YOU SUPPORT ALLOWING THE UTILITIES GREATER DISCRETION IN FUND SHIFTING?

A Yes, I support allowing greater discretion in shifting funds amongst demand response programs for the purpose of addressing evolving grid reliability needs over the course of the 2024-2027 period. The needs of the grid are likely to be particularly dynamic over this period, therefore general flexibility in tweaking program design is appropriate. For example, the proposed dual participation working group may identify additional multi-value opportunities to improve grid reliability.

8. Should the Commission continue the exemption of energy storage resources not coupled with* fossil-*fueled generation from the Demand Response Prohibited Resources Policy (as established in D.18-06-012)?

Q DO YOU SUPPORT THE CONTINUED EXEMPTION?

[38] *California Large Energy Consumers Association Motion for Clarification of Phase II Cost-Effectiveness Considerations*, A. 22-05-002 et al., Jan. 06, 2023 at p. 2.
[39] Ex. PG&E-7 at p. 12-5.

A Yes, I support the continued exemption of energy storage resources that are not coupled with fossil-fueled generation. Energy storage resources are a valuable tool for improving grid reliability, and for customers to meet their operational and reliability requirements. Energy storage resources that are non-emitting should remain available to customers participating in demand response programs to use in meeting those program requirements.

9. Should dual participation rules be modified or clarified?

Q WHY SHOULD DUAL PARTICIPATION RULES ACCOMMODATE BIP CUSTOMERS?

A BIP customers provide a highly valuable emergency reliability service. They agree to curtail their large-scale operations upon 15 or 30 minutes notice of emergency grid conditions. The commitments are year-long, with modest use limitations and very high excess energy charges if the BIP customers do not perform. BIP customers are able to make this commitment in large part because they understand they will only be called in a true emergency, and they can reasonably predict the frequency of interruptions to their operation. BIP and its precursor tariffs have performed reliably for decades under these basic parameters, especially so since the recent extreme grid conditions began in 2020. I oppose changes to these basic program parameters, such as dispatch order or deterioration of modest use limitations, because they would harm reliability. Significant numbers of existing BIP customers will no longer be willing to enroll in BIP, or will need to reduce their committed MWs, if they are obligated to curtail beyond those longstanding basic parameters. Furthermore, the program growth identified by the

utilities and helpful for reliability will be very difficult to achieve with such changes in requirements.

However, some BIP customers may be willing at some times to provide additional value to the grid depending on their operational schedule, inventory levels, market conditions, labor contracts, and a multitude of possible considerations unique to each customer. A particular customer may not be able to provide any curtailment beyond their historic BIP commitment. Another customer may be able to provide incremental curtailment but only on certain days of the week, another only during the slow season, another only if inventory levels are sufficient to satisfy its customer needs. This additional value should be tapped with careful program design to achieve incremental and complementary grid value based on modified, reasonable dual participation rules.

Q HOW SHOULD DUAL PARTICIPATION RULES FOR BIP CUSTOMERS BE MODIFIED?

A The Commission should modify the rules for BIP-ELRP dual participants to provide compensation for incremental curtailment during non-overlapping events. This modification would incent incremental load reduction during standalone ELRP events, and for reductions during ELRP periods before or after a BIP event. The modification would increase resources available during ELRP events, and improve reliability without risking the exodus of BIP participants unable to curtail beyond their existing obligations.

This modification has been supported by both SCE[40] and PG&E,[41]and could be implemented quickly statewide.

The modification would align with the Commission's principles for dual participation in energy and capacity demand response programs. BIP is an emergency capacity program, and ELRP is an energy program. The proposed change to dual participation only affects compensation rules during non-overlapping events, therefore is not relevant to the prohibition on duplicative payments for the same load reduction. Furthermore, BIP is activated on the day of the event, while ELRP can be activated a day prior, which is consistent with other eligible dual-participation programs.

Energy and capacity demand response programs provide different values to the grid, and sending a voluntary energy signal is appropriate before dispatching an emergency program. By accepting and compensating these voluntary reductions in ELRP, emergency capacity programs can be reserved for current or future emergencies, thereby avoiding warnings or emergency declarations. Dual participation in energy and capacity demand response programs is common across North American electric grids, and would benefit California as well. I continue to support current rules which provide that during overlapping events BIP customers are only compensated for load reductions below their FSL; this adequately prevents duplicative payments for the same load reduction.

[40] SCE Advice Letter (AL) 4950-E.
[41] PG&E Errata Testimony, R. 20-11-003, Sep. 2, 2021 at pp. 2-4 and 2-5. (available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/opening-testimony/pdfa_emergencyreliabilityoir_test_pge_20210902.pdf).

Q WHAT ARE ADDITIONAL OPPORTUNITIES FOR BIP CUSTOMERS TO PROVIDE INCREMENTAL VALUE WITH MODIFICATIONS TO DUAL PARTICIPATION RULES?

A PG&E proposes a working group framework to develop broad and consistent dual participation rules to address current and future grid needs. PG&E explains:

> [B]eyond the most urgent issue of capacity and energy shortfalls, the future needs of the grid will require thoughtful design and the ability to realize multiple-use and value stacking to capture additional grid services including support for localized transmission and distribution needs and emission reduction.[42]

I agree with the need and framework proposed by PG&E, and encourage the Commission to convene a working group as soon as practicable.

Beyond the opportunity to address urgent capacity and energy shortfalls through modified BIP-ELRP dual participation rules which can be implemented quickly, opportunities for additional grid services and policy goal support require detailed technical discussion through a working group framework.

Demand response value stacking is common across North American grids, which seek to maximize the resources available to the grid subject to the unique abilities and constraints of different customers. For example, PJM is the largest ISO in North America, as measured by peak demand, and offers a suite of demand response options available to customers. Customers can commit to mandatory curtailment during system emergencies with ongoing payments for availability and significant penalties, like BIP in California. Customers can also provide energy demand response when prices are high, and can provide a suite of ancillary services including Synchronized Reserves, Day-Ahead

[42] Ex. PG&E-2 at p. 1-8.

Scheduling Reserves, and Regulation. Customers can and do provide all three categories of demand response; their bids are co-optimized for each hour to deliver the maximum value to the grid, and careful dual participation rules ensure only a single payment for a particular instance of curtailment.[43] California is experiencing dynamic grid challenges, and should explore every opportunity to responsibly maximize multiple-use demand response resources.

10. Should ratepayers provide funding in 2024-2027 for continued modeling of DR potential and related research overseen by Energy Division?

Q WHAT IS YOUR POSITION ON THIS PROPOSED FUNDING?

A I am concerned about any funding request that does not directly lead to the provision of cost-effective resources, given the affordability crisis ratepayers are facing, including large commercial and industrial ratepayers. However, if continued funding for modeling and related research is awarded, it should include industrial demand response potential for new customer participation, additional participation of existing demand response customers, and explore opportunities to increase the value of existing industrial demand response customer participation through multi-use and value stacking. The modeling and related research, if approved, should include support of the dual participation working group proposed by PG&E, and supported in this testimony.

CONCLUSION

Q WAS THIS MATERIAL PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A Yes, it was.

[43] PJM, *Retail Electricity Consumer Opportunities for Demand Response in PJM's Wholesale Markets*, url: https://pjm.com/-/media/markets-ops/dsr/end-use-customer-fact-sheet.ashx.

Q **INSOFAR AS THIS MATERIAL IS FACTUAL IN NATURE, DO YOU BELIEVE IT TO BE CORRECT?**

A Yes, I do.

Q **INSOFAR AS THIS MATERIAL IS IN THE NATURE OF PROFESSIONAL OPINION OR JUDGMENT, DOES IT REPRESENT YOUR BEST PROFESSIONAL OPINION OR JUDGEMENT?**

A Yes, it does.

Q **DO YOU ADOPT THIS TESTIMONY AS YOUR SWORN TESTIMONY IN THESE CONSOLIDATED PROCEEDINGS?**

A Yes

Q **DOES THIS CONCLUDE YOUR TESTIMONY?**

A Yes.

APPENDIX A

QUALIFICATIONS OF SAM HARPER

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Sam Harper. My business address is Harper Advisory LLC, 1401 Lake Plaza Drive, Suite 200-107, Spring, TX 77389.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of energy markets and policy. I am employed by Harper Advisory LLC.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I have fifteen years of experience in energy procurement, utility regulation, ISO/RTO governance, renewable energy development, and demand response. I have direct experience with commercial energy arrangements, demand response, and the stakeholder processes in PJM, MISO, ERCOT, CAISO, IESO, CENACE, and various unorganized markets. In my current role as a consultant, I advise organizations that engage across the energy supply chain, including large energy consumers for whom energy is a significant percentage of their cost of production.

Prior to consulting, I was the Director of Energy of North American operations for Gerdau, a major steel producer with significant energy requirements and active demand response participation. From 2013-2022, I held a variety of positions for Gerdau, which included Regional Energy Manager and Assistant Vice President of Operations for Gerdau's subsidiary load serving entity. My responsibilities included demand response operations, RTO/ISO stakeholder process, utility regulatory

intervention, commercial energy contract negotiations, commodity risk management, and renewable energy development.

I was elected each year from 2016 through 2021 to the Board of Directors of the Electric Reliability Council of Texas (ERCOT). I served on the Human Resources and Governance Committee throughout my tenure, and in 2021 was elected Vice-Chair. I served during the Storm Uri reliability crisis in February 2021 and its aftermath.

I served on the Advisory Board for the Renewable Development Fund of Minnesota from 2017-2020, ensuring renewable energy grants were awarded and executed prudently and consistent with state policy goals.

From 2008-2013, I was employed by ArcelorMittal, a global steel producer, ending as the Sourcing Manager of Electricity for US Operations. During that time, I created and managed a load serving entity and curtailment service provider in the PJM territory.

I earned a Bachelor of Science degree in Business Administration from the University of Illinois at Urbana-Champaign in 2008, graduating with Honors.